REMEDIATION OF LEAKAGE FROM CO_2 STORAGE RESERVOIRS

Technical Study

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REMEDIATION OF SEEPAGE FROM CO_2 STORAGE FORMATIONS

Background to the Study

The storage of CO_2 in geological formations is viewed as a mitigation option that, when used in combination with other options like energy efficiency and renewable energy, could achieve deep reductions in atmospheric greenhouse gas emissions. Many of the geological formations that will be considered for CO_2 storage have held hydrocarbons for millions of years. This has led people to surmise that, because their integrity with oil/gas, when CO_2 is injected into these formations it will also remain secure for geological timescales. However, it is not improbable that CO_2 could seep out of these formations. Mechanisms that conceivably could lead to migration[1] or seepage[2] out of the formation and ultimately leakage[3] to the atmosphere could include: unwarranted intrusion, equipment failure e.g. wells, fault activation due to over-pressurisation or geochemical reactions between the CO_2 and the cap rock.

Clearly, if leakage were to occur to any significant degree by any route then the principal advantage of geological storage, the removal of the CO_2 from the atmosphere, will have been eroded. Also, if leakage from geological storage formations is considered to be even a remote possibility then this might adversely affect the public acceptance of the technology. However, if it can be demonstrated that any seepage, which may result in leakage, can be simply and cost effectively remediated then this will be very important information for policy makers. There is therefore, a need to determine what can be done in the event of seepage from a CO_2 storage formation being detected.

The aim of this study was to assess what remediation techniques and approaches are available if seepage of CO_2 is identified from a geological storage formation. The objective of the study was to develop a report that can act as a reference manual for IEA Greenhouse Gas R&D Programme (IEA GHG) members in their discussions with policy makers. The report sets out the remediation plan that can be adopted in the event of any seepage being detected based upon different types of seepage event and their associated remediation methods. This report also estimates the costs of different remediation measures.

This study was undertaken by Advanced Resources International, USA.

Results and Discussion

The following aspects of the study are discussed in this overview. Full details on all these topics are presented in the main report:

- The five-part strategy for seepage prevention and remediation,
- Classification of a CO_2 seepage event,
- CO_2 seepage well remediation procedures,
- Remediating the subsurface impacts of CO_2 migration,
- Cost of CO_2 seepage prevention and remediation.

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[1] Migration is defined as the movement of CO_2 out of the formation.
[2] Seepage is defined as the movement of CO_2 out of the formation into the sub-surface.
[3] Leakage is defined as the movement of CO_2 from the sub-surface into the atmosphere.

The five-part strategy for seepage prevention and remediation

A comprehensive strategy for seepage prevention and remediation would contain five main elements:

1. Selecting favourable storage sites with low risks of CO_2 leakage. No other single aspect of a seepage prevention and remediation strategy is more important than selecting a safe, secure site in the first place.

2. Placing Emphasis on Well Integrity. There are three key priorities for ensuring long-term well integrity at a CO_2 storage site, identifying all old abandoned wells in the vicinity of the proposed CO_2 storage site, designing and installing the CO_2 injection wells so that are resistant to CO_2, and ensuring proper closure of the CO_2 storage site.

3. Conducting a phased series of formation simulation-based modelling to track and predict the location and movement of the CO_2 plume£. Multiple stages of formation simulation should be used including; initial site selection, collection of more site specific geological and formation data after the drilling of the injection and observation wells, and repeat surveys after injection to calibrate modelling.

4. Installing and maintaining a comprehensive monitoring system for the CO_2 storage. The overall CO_2 monitoring system will need to be designed as an early warning system of any impending CO_2 leakage event, and to provide on-going information on the movement and immobilization of the CO_2 plume.

5. Establishing a "Ready-to-Use" contingency plan/strategy for remediation. Operators should have a response plan ready in the event that seepage of CO_2 occurs from the storage formation which should contain remediation options for all the most likely leakage scenarios.

It should be noted that modelling and monitoring will be required during all phases of a CCS operation but the extent of work required during different phases will vary. In addition, monitoring and modelling activities will continue for a period after the site has been closed although it was not the specific aim of this study to attempt to define that time period. For the purposes of the costing exercise of this study it has been assumed that detailed monitoring will be curtailed 20 years after closure and well monitoring will end 50 years after closure. Any remediation plan will be required to be available for a similar time period after site closure.

Classification of a CO_2 migration or seepage event

If migration or seepage occurs the ease and method of remediation will depend largely on the type of formation used for storage and the nature of seepage event that has occurred.

CO_2 stored in structurally confined depleted oil and gas fields will be the most effectively contained and easiest to monitor, offering the best chance of successful remediation. CO_2 stored in saline formations, particularly those lacking structural closure, will be much more challenging to remediate should it be necessary, given the degree of dispersion of CO_2 under the cap rock that will occur over time.

However, irrespective of the type of formation, if migration or seepage occurs the first step is to assess the nature of the seepage event as this will dictate the method and pace of the remediation required (should mitigation be required at all). Below, a number of possible migration and seepage mechanisms[4] are listed:

- *CO_2 seepage due to seal failure*. This mechanism could involve CO_2 seeping through the cap rock, either due to excessive pressure build up in the formation which could exceed the formation fracture pressure and result in a fracture opening, or the presence of a permeable (non-sealing) fault or fracture.

- *Migration out of the confining structure*. This would occur either through the natural hydrodynamic movement of dissolved CO_2 or due to excess injection of CO_2 past the confining "spill point" of the formation.

- *Seepage due to lack of well integrity*. Seepage through operating or abandoned well bores has been highlighted by risk assessment studies as the most probable seepage pathway for a CCS project. There are a number of reasons why the integrity of a well may be compromised. Three possible options are a follows:
  - The well was poorly designed or completed allowing gas migration up the well or wellbore,
  - An unanticipated well failure could occur, such as a parted casing,
  - When abandoned the well was inadequately plugged.

CO_2 seepage well remediation procedures

Assuming the CO_2 storage site is geologically stable and secure; the loss of well integrity and possible blow-out during injection would represent the greatest potential risk of CO_2 seepage. Experience of remediation procedures for a well based CO_2 seepage event could be gained from the natural gas storage industry, however, it must be taken into consideration that CO_2 is generally injected in a supercritical state, which means some additional thought must be given to the temperature, pressure and velocity of the leaking fluid. This section will concentrate on practices associated with remediating well integrity and well blowouts by presenting standard well service and repair procedures and guidelines should a CO_2 seep occur.

- *Mechanical integrity and monitoring procedures*. The loss of a well's mechanical integrity can lead to internal and external CO_2 seepage. Current injection guidelines in other industries[5] require an underground injection control program which involves data collection, tests to ensure well integrity, and methods for early detection of seepage. During the injection, monitoring efforts will generally include, an analysis of injected fluids, continuous monitoring of injection pressure, flow rate, and volume, demonstration of mechanical integrity once every five years, and placement of monitoring wells to assess any migration of fluids out of the formation. If monitoring indicates movement out of the formation, then preventive actions must be taken. These actions will include additional monitoring and reporting requirements; prompt corrective action; or permit termination and well closure.

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[4] The seepage mechanisms listed are not set out in any proposed order of occurrence or likelihood, they are merely listed for reference purposes

[5] Industries include oil and gas production, natural gas storage

- *Identifying fugitive emissions or fluids*. Should there be any indication of CO_2 seepage; several methods are available to aid in pinpointing its location. These methods can also provide insights into the best method of remediation. These methods include; well monitoring, down hole video camera, noise logs, temperature logs, radioactive tracers, cement bond logs.

- *Remediating the loss of mechanical integrity in the injection well*. There are several corrective actions that can be used to address a seepage event due to loss of mechanical integrity in the injection well. Remediation may include one or some of the following; wellhead repair, packer replacement, tubing repair, squeeze cementing, patching casing, repairing damaged or collapsed casing, plugging the well.

- *Remediating a seeping abandoned well*. In the event a previously abandoned well is found to be seeping, a series of steps can be employed to restore the well for temporary use, remediate the seep, and re-abandon the well. The steps are as follows;
  - Review all available well data records,
  - Formulate a detailed plan for well intervention and remediation,
  - Perform any drilling required to access to the well head,
  - Assess the nature of the seepage,
  - For a casing seep, remediation can be done by injecting a heavy brine to stop inflow ("killing" the well) and either installing a casing patch or squeeze cementing,
  - For a poor abandonment plug, re-plug the well according to best practice methods.

- *Modifications to remediation practices to account for CO_2*. CO_2 in combination with water can form carbonic acid, which can be corrosive to standard well casings as well as cements. When working with CO_2 it must be ensured that the interaction between the materials used and the CO_2 is understood. Items for particular focus are, packers, casing and tubular goods, and the cement.

Remediating the subsurface impacts of CO_2 seepage and leakage

As well as stopping the seepage, it may be necessary to rectify any damage or potential damage resulting from any CO_2 that did leave the storage formation. Below are listed potential options for remediating CO_2 effects on different parts of the sub-surface:

- *Accumulation of CO_2 in groundwater*. CO_2 contamination of groundwater can be remediated by pumping the water to the surface and aerating to flash the CO_2. The water can then be either pumped back underground or used.

- *CO_2 leakage into vadose zone*[6]. This is an area of ongoing research however it is thought that large amounts of CO_2 could be removed from the vadose zone using soil vapour extraction technology.

[6] The vadose zone is the zone between surface and the water table.

- *CO_2 in near-surface accumulations*. Horizontal pinnate (leaf-vein pattern) drilling can be used to access and extract CO_2 in near-surface formations and accumulation zones.

Costs of seepage prevention and remediation

The costs of remediation will impact overall CO_2 storage costs, therefore, these need to be considered in the context of the overall CO_2 storage project. The likelihood of needing remediation will be greatly reduced through rigorous site selection. If seepage occurs, the work required for remediation can at times be greater or equal to, that associated with original CO_2 storage site selection, project design and implementation.

1. Seepage Prevention Costs

There are three main activities that are crucial to the prevention of a CO_2 seepage event, rigorous site selection, on-going monitoring, and periodic testing for well integrity.

Costs for rigorous site selection and project design
The major components of a rigorously selected, installed and operated CO_2 storage facility are as follows:

- Project definition and design,
- Detailed site and formation characterization,
- Continuing monitoring and modelling activities.

The costs for site selection and project design could range from $5,000,000 to $20,000,000 per site. The largest single cost item will be the cost of drilling and testing the formation characterization and observation wells. Other significant costs will involve establishing the regional geological framework, conducting formation modelling of the expected flow and trapping of the CO_2 plume, and testing the integrity of the formation cap rock.

The actual costs will depend on the amount of existing data at the site as well as the type and depth of the project, the amount of CO_2 to be stored, the conditions at the surface overlying the storage formation and, perhaps, most important, the regulatory and permitting requirements imposed on the project.

Costs for project monitoring and seepage detection
The costs of project monitoring and seepage detection will depend heavily on the type of formation in question as well and the rigorousness of the monitoring package. Three formation types were used to estimate the different costs. These were:

1. An enhanced oil recovery project followed by CO_2 storage
2. A saline aquifer storage project with a high residual gas saturation (RGS), where the CO_2 plume does not move significantly after injection
3. A storage project in a saline aquifer with a low residual gas saturation (RGS), where the CO_2 plume keeps moving for a considerable amount of time after injection

Each of the formations was then evaluated using both a basic and enhanced monitoring package. The monitoring costs associated with the combination of each monitoring package with each project type are summarized below:

Costs of Monitoring Strategies

Cost Component	Estimated Monitoring Costs (Million Dollars US)					
	EOR		Saline Aquifer			
			Low RGS		High RGS	
	Basic Package	Enhanced Package	Basic Package	Enhanced Package	Basic Package	Enhanced Package
Pre-Operational Monitoring	$0.9	$3.3	$7.5	$9.4	$5.9	$8.1
Operational Monitoring	$34.7	$59.3	$23.1	$38.3	$23.1	$38.3
Closure Monitoring	$9.1	$14.8	$18.4	$32.2	$13.8	$26.7
TOTAL	$45	$78	$49	$80	$43	$73

Costs for well bore integrity monitoring
Well bore integrity monitoring and logging costs will be a function of the depth of the well, the condition of the well, and the number and types of logs required. The costs for monitoring well integrity are estimated as follows:

Costs of Well Integrity Logging		
Well Depth	Well Integrity Logging Costs (Million dollars US)	
	Per Log	Total*
5,000 feet	$0.12	$12
7,500 feet	$0.15	$15
10,000 feet	$0.18	$18

* Total assumes 10 CO_2 injection wells and 10 logging runs in 50 years, for a total of 100 logging runs.

It is assumed that, for the most part, the costs for a more comprehensive set of well bore integrity logs, essential for providing up-to-date information on the condition of the CO_2 injection wells, are not included in the costs for project monitoring and leak detection outlined in the *Costs of Monitoring strategies* table.

2. Seepage Remediation Costs

Depending on the nature of the CO_2 seepage event, the costs of remediation can vary significantly. Below are cost estimates for locating the seepage source, plugging old wells, remediating active CO_2 injection wells, and remediating seepage in the cap rock.

Costs for locating the source of CO_2 seepage
The cost of locating seepage will differ depending on predicted source: abandoned well, injection well, geological CO_2 seepage.

For abandoned wells, considerable expertise exists for identifying the source and reasons for CO_2 seepage. The costs for locating a single well (or even a group of wells) is estimated to be $100,000 per survey (including interpretation), with significant economies of scale in multi-well situations.

For the CO_2 injection wells, a new set of logs or other diagnostic tools may be needed to more precisely identify the exact location and cause of the seepage in the new injection well. With two diagnostic logs costing $200,000 plus a diagnostic and management charge of $100,000, the costs for a well bore-based seepage detection procedure would be on the order of $300,000 per well.

Establishing the cause and source of any geologically-based CO_2 seepage may require investigating a large area, with emphasis on areas of potential cap rock weakness, faults/fissures, and structural “spill points”. A 3D seismic survey covering 5 to 20 square miles may be needed where surface leakage has been detected. In addition, new horizontal wells may need to be drilled and tested to more precisely locate the source for the CO_2 leak. 3D seismic survey including processing and interpretation will cost around $100,000 per square mile with every new horizontal costing $4 million.

Costs for well plugging
Well plugging costs will depend on whether the requirement is to plug a recently abandoned well, an old, previously plugged and abandoned well, or a well that was never plugged. The costs will also depend on what must be done to plug the well and on the location of the well being plugged.

It is estimated that the costs of plugging in a typical 7,500 foot well would be between $20,000 and $80,000. On average, most well plugging operations cost $50,000 per well, without considering the salvage value of the casing, if any.

Costs for well remediation
The cost of a simple well bore seepage repair could vary considerably depending on the nature of the seepage and the condition of the well bore but is estimated in the range of $30,000 to $50,000. If a more substantial section of the well is seeping or is damaged more involved remediation such as installing a smaller diameter liner inside the well casing may be required. The costs of this more involved remediation is estimated at $100,000 per well.

In some cases, a seeping well cannot be repaired, and must be plugged. In this case, the costs would include plugging the seeping well and drilling a new replacement CO_2 injection well. The costs of drilling new wells depend on the depth of the well; however an average depth well (7,500 foot) would be estimated to cost around $2.5 million. The cost of well construction has increased significantly recently so this estimate may rise.

Costs for remediation of seepage through the cap rock
The first step in mitigating CO_2 seepage in the cap rock would be to stop CO_2 injection and, if possible, to inject water into a formation above the cap rock to create a positive pressure barrier. Creating a positive pressure barrier above a CO_2 seepage would involve drilling and completing two horizontal water injection wells and installing a water source well and water injection facilities. We estimate the water source and injection facility costs at $2 million.

There are no documented cases of fully remediating seepage in cap rock for either a CO_2 or natural gas storage project. In general, performing such a remediation effort is speculative. Consequently, the costs associated with this remediation action are unknown and have not been estimated. The development of possible approaches for remediating seepage in cap rock remains an important area for future research.

Example Storage Case

To further illustrate the costs of remedation, a scenario has been created around a saline aquifer CO_2 storage site. This scenario loosely follows the high residual gas saturation (RGS) aquifer discussed in the *Costs for project monitoring and leak detection* section of this report.

The main assumptions for the scenario are as follows:

- The storage site serves one 1,000 MW coal-fired power plant, with 8.6 million metric tons of annual CO_2 emissions,
- The site will operate for 50 years, with 30 years for CO_2 injection and 20 years for post-closure monitoring,
- The CO_2 storage site has 10 CO_2 injection wells, each capable of injecting 2,500 tonnes of CO_2 per day with a 94% operating factor,
- The CO_2 plume extends radially and underlies an area of about 80 square miles (216 km^2) at the end of 50 years,
- An "enhanced" CO_2 monitoring system consistent with a rigorous site selection program and highly supportive of the diagnostic systems essential for identifying the sources for CO_2 leakage, should these occur.

Based on this example, the cost for a comprehensive CO_2 seepage prevention, monitoring and remediation program is estimated to be on the order of $120 to $130 million per site. Assuming the injection of 258 million tones of CO_2, the cost per tonne for these efforts would range from $0.45 to $0.50 per tonne.

If the CO_2 seepage problems can not be rectified, which is only likely to occur if a fault is activated due to over-pressurisation or if the site was poorly characterized initially, the remediation costs would become large. These costs could potentially include establishing a new storage facility, transporting some or all of the CO_2 to the new facility, remediating the impacts of CO_2 losses to the potable water and vadose zone, and losing the value of any CO_2 credits for the CO_2 lost to the atmosphere or other undesirable locations.

Expert Group Comments

The draft report on the study was sent to a number of expert reviewers and IEA GHG's members who had expressed interest in reviewing it. The study was generally well received by the reviewers. Most of the comments received were general in nature and referred to general issues on the report contents which have been addressed by the contractors in the final draft of the report. Several reviewers raised some specific issues, particularly on the costs within the report. These issues, which were not fundamental in their nature, were discussed by the contractors and the IEA GHG project manager concerned and, where appropriate, modifications to the reports contents were agreed and then implemented by the contractor.

Conclusions

The most important aspect of seepage prevention and remediation strategy is selecting a safe, secure storage site to begin with. Assuming that a secure CO_2 storage site has been selected, the loss of well integrity and blowouts will most likely represent the greatest risk of CO_2 seepage. In both cases there is experience in other industries for remediation.

In terms of cost, if seepage occurs, the work required for remediation can range from being relatively low to at times being greater or equal to, the costs associated with original CO_2 storage site selection, project design and implementation. However to put these costs in perspective, for a typical storage case the costs for site selection monitoring and remediation could range from \$0.45 to \$0.50 per tonne CO_2. Compared to the total cost of a CCS project (\$35 -50/t CO_2) the additional cost for minimising seepage can be considered as low. Whilst, the financial cost of remediation is low its contribution to public safety and public acceptance cannot be understated and regulatory bodies will not allow projects to proceed without remediation.

Recommendations

Following this study there are a number of recommendations for possible strategies to progress the understanding and development in the area of remediation as well as address some gaps in knowledge.

- Develop a "best practices" remediation manual for CCS.
- Undertake a series of "best practice" large-scale field tests to develop procedures for selecting sites with cap rock and well bore integrity and to integrate aspects of CO_2 monitoring, CO_2 seepage detection, and remediation.
- Develop new procedures and technology for locating and assessing the integrity of abandoned wells
- Invest in research into on procedures for identifying and sealing failures in the cap rock and into materials and procedures for improving well integrity.
- Address concerns on lack of structural confinement in "open system" saline formations. Specifically, gain a better understanding of aquifer hydrodynamics, potential for pore space and hysterisis trapping of CO_2 in alternative geological settings, understand the dynamics of CO_2 displacement of stored saline water, and identification of geologic features that would provide assurance of up-dip trapping of the CO_2 plume.

REMEDIATION OF LEAKAGE FROM CO_2 STORAGE RESERVOIRS

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EXECUTIVE SUMMARY

The purpose of this report is to broadly address a topic integral to safe and secure carbon sequestration - - preventing and remediating the leakage of carbon dioxide (CO_2) injected into three types of geological formations, namely oil fields, natural gas fields, and deep saline reservoirs.

Risk assessments of storing CO_2 in rigorously selected geological formations, such as at Weyburn, In Salah and Sleipner, indicate that the inherent risks and potential quantities of CO_2 leakage will be minimal. However, CO_2 leakage in less geologically favorable settings and over geological time is not improbable and could result from leaky abandoned wells, from an inadequate caprock or the breaking of the reservoir seal, and from the migration of CO_2 beyond a confining structure. Clearly, if sustained CO_2 leakage were to occur to any significant degree, by any pathway, the advantage of geological storage would be reduced. As important, the image of this technology would be impaired in the views held by policy makers, environmental groups and the public.

A series of actions, the discussion of which constitutes the body of this report, will be central to preventing and correcting sustained leakage of CO_2 from geological formations, namely - - rigorous site selection, assured well integrity, long-term modeling of the CO_2 plume, monitoring of the injected CO_2 (including early identification of leakage), and prompt remediation actions should any CO_2 leakage occur. For this, the report is organized around a series of chapters that address the tasks set forth in the scope of work for the study:

1. Determine the potential CO_2 leakage pathways in the above three types of geological storage reservoirs.

2. Formulate site selection and reservoir screening requirements to minimize the risks of CO_2 leakage.

3. Discuss modeling and monitoring techniques that would help identify potential CO_2 leakage pathways and any actual leakage, should it occur.

4. Review and set forth procedures for promptly remediating CO_2 leakage from these geological formations.

5. Develop and characterize leakage prevention and remediation strategies.

The report then draws on the discussion of the above topics to set forth a series of strategies for preventing and remediating CO_2 leakage, including estimating the impacts that the prevention and remediation options would have on the overall costs of storing CO_2 in geological formations. The report concludes by recommending additional research and investigations that would improve upon the science and practice of preventing and remediating leakage of CO_2 from geological formations.

It is important for the report reader to be informed of the ground rules for conducting the five tasks set forth for study and for preparing this report:

- Tasks 1, 2, and 3 were to draw heavily on available technical information, requiring minimum original work. As such, the initial chapters of the report provide a distilled summary of what we believe reflects the best of the currently available science on Understanding CO_2 Leakage Pathways (Task 1), Site Selection and Reservoir Screening (Task 2), and Modeling and Monitoring (Task 3).

- The bulk of the study effort and report were to be directed toward Task 4: Review of Methods to Remediate Leakage, and Task 5: Formulation and Discussion of Leakage Prevention and Remediation Strategies.

- Finally, the study was to be limited to remediation of leakage from the geological storage reservoir itself and should not extend to remediation of the consequences of CO_2 leakage into potable water, into the vadoze zone, or into buildings. This topic is the subject of a separate IEA study.

We have drawn heavily on the impressive volume of past work on understanding the causes of CO_2 leakage and on modeling and monitoring strategies that would provide “early warning” of CO_2 leakage. We acknowledge the researchers who have conducted this fine work in our references and trust that we have appropriately captured and summarized their insights. We also recognize that the science and technology of remediating CO_2 leakage is still emerging. As such, we hope that our discussion and recommendations on this topic will help accelerate new research on the many critical issues surrounding safe and reliable storage of CO_2.

We have also looked, in detail, at the information available on industry's extensive experience with natural gas storage, involving nearly 100 years of operation in currently over 600 gas storage sites in the United States, as well and throughout the world. The "lessons learned" from this vast pool of experience, particularly testing procedures for safe site selection, field monitoring procedures for leak detection, and mitigation actions for responding to leaks, have been incorporated into our analysis. Portions of these findings have been selectively highlighted in the "Sidebars" to our report.

Finally, in preparing this report, we have also relied on our own site assessment work for power companies and other industrial firms looking to store their CO_2 emissions, as well as on our reservoir engineering and field operations experience in remediation actions to control leakage. This experience is augmented by our on-going site characterization, site selection, modeling and monitoring design work on the DOE Regional Carbon Sequestration Partnership (SECARB)-sponsored Tuscaloosa Test Site involving CO_2 injection into a deep, regionally extensive saline formation along the Gulf Coast of Mississippi.

With appropriate leak prevention and mitigation strategies, we believe it will become possible to achieve the challenging goal facing the storage of CO_2 in geological formations - - enabling the security of CO_2 storage to increase with time, Figure EX-1.

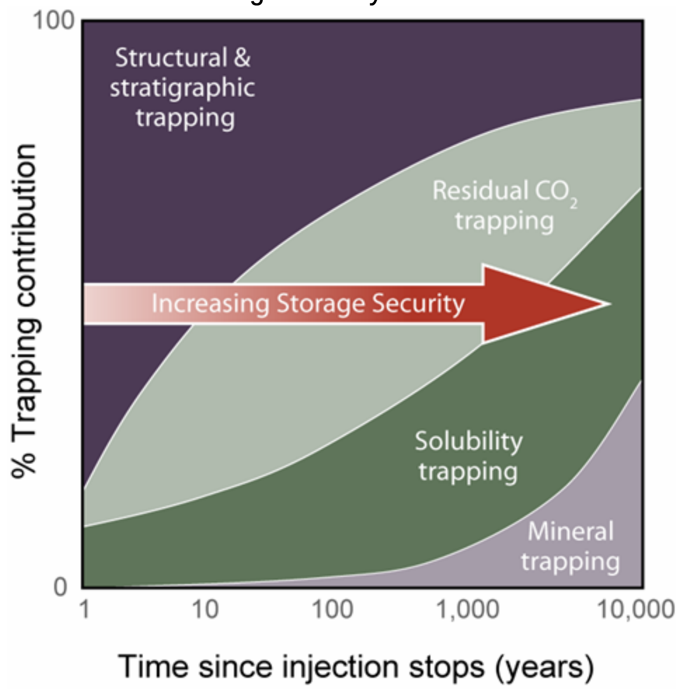
In summary, our proposed five-part leak prevention and mitigation strategy consists of:

- Carefully selecting favorable storage sites with low risks for CO_2 leakage.
- Putting high priority and emphasis on ensuring well integrity.
- Conducting a phased series of reservoir simulation-based modeling efforts to project and track the CO_2 plume.

- Installing and maintaining a comprehensive monitoring system for the CO_2 storage site.

- Establishing a "ready-to-use" contingency plan and strategy for remediation, if necessary.

Figure EX-1. CO_2 Storage Trapping Mechanisms and Increasing Storage Security with Time



Source: Heidug, 2006.

Importantly, in the rare cases where leakage does occur, we believe that remediation options are available to respond, though some may be costly. In many cases the geologic and engineering effort associated with such remediation would be comparable to, and in many cases could exceed, that associated with up-front site selection, design and project implementation. Inevitably, attempts to save money in the site selection, project design and field implementation stages could result in costs for remediating the problem caused by leakage that would be substantially greater than that associated with proper site selection, design and implementation.

Despite this, CO_2 leakage and remediation, especially remediation, has received less attention and priority than this topic deserves. In particular, fruitful next steps could include:

- A “best practices” manual for CO_2 leak prevention and remediation
- Further study of remediation experiences in the natural gas storage industry
- Investment in research and development (R&D) on remediation approaches and technologies, with focus on corrosion-resistant wellbore materials and procedures for sealing failures in caprock
- Development of improved procedures and techniques for locating and assessing the integrity of abandoned wells
- Addressing concerns associated with reservoir systems, primarily saline aquifers, not defined by structural traps.

I. INTRODUCTION AND OVERVIEW

An extensive set of geological research and engineering studies, plus past experience with injecting and storing fluids, indicates that the storage of carbon dioxide (CO_2) in deep underground geologic reservoirs can be a technically feasible strategy for reducing emissions of anthropogenic-sourced CO_2.[1] The subsurface storage of CO_2 was first proposed as a greenhouse gas (GHG) mitigation option in the 1970s, but little research and development (R&D) was performed on CO_2 storage until the early 1990s. Since then, major geological CO_2 storage projects, such as Sleipner, In Salah and Weyburn, are building confidence in this promising but still emerging option.

A. OVERVIEW OF STORAGE OPTIONS

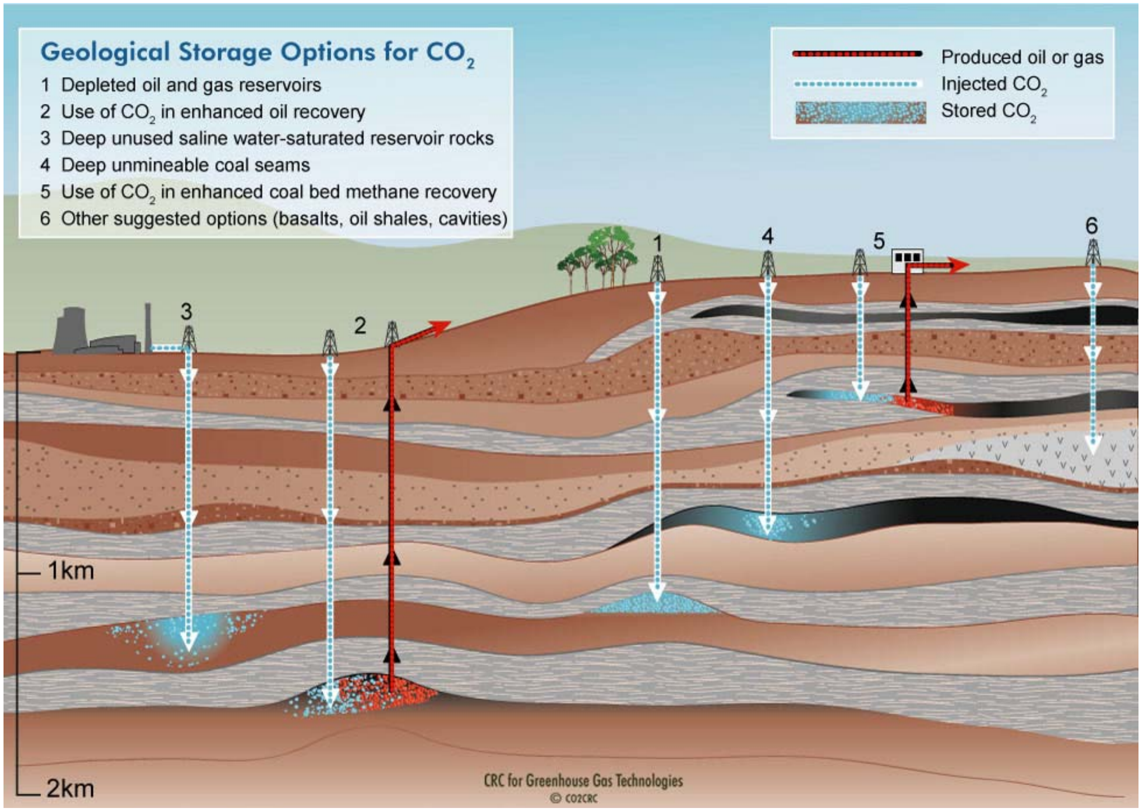
Three types of geological formations - - oil reservoirs, depleted gas reservoirs and saline formations - - are currently the best understood and thus are the most attractive candidates for geologic storage of CO_2. These three geological storage options, as well as the other less defined options, are illustrated on Figure 1-1.

- Oil and Gas Reservoirs. More than 100,000 oil and gas fields have been discovered around the world[2]. These oil and gas fields have favorable geological features, such as a sealing caprock and a well defined structure, that have supported long-term (millions of years) trapping and containment of fluids in the subsurface. These same containment and trapping mechanisms could apply to long-term, secure storage of CO_2. In addition, more is known about the geology and characteristics of oil and gas reservoirs than of the other CO_2 storage options under consideration.

  In some cases, increased recovery from an oil reservoir can be enhanced by injecting CO_2 into the reservoir to mobilize "left-behind" oil, a process called enhanced oil recovery (EOR). A similar application for natural gas fields is conceivable, but has yet to be demonstrated. Even when the prospects for additional oil and gas recovery are unfavorable, CO_2 can still be injected into these depleted oil and gas fields for long-term storage.

[1] This is perhaps best summarized in the Intergovernmental Panel on Climate Change (IPCC) Special Report entitled, *Carbon Dioxide Capture and Storage*, Summary for Policymakers (IPCC, 2005).
[2] Oil fields outnumber gas fields by a factor of 2 to 1, according to Klett, et al., 2005.

Figure 1-1. Geologic Formations Targeted for CO_2 Storage



Source: Image courtesy of the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)

- Saline Formations. A second geological setting for storing CO_2 involves injecting high pressure CO_2 into deep saline formations. While saline formations will not produce "value-added" by-products such as oil and gas, they can have other advantages. Of high importance is that the estimated storage capacity of saline formations is believed to be quite large - - substantially larger that the storage capacity offered by oil and gas reservoirs. Moreover, deep saline formations are much more geographically dispersed and available than oil and gas reservoirs, often providing close proximity to high volume sources of industrial CO_2 emissions.

- Unmineable Coal Seams. Coal beds typically contain large amounts of methane-rich gas that is adsorbed onto the surface of the coal. The current practice for recovering methane from coal seams involves depressurizing the seam, usually by pumping out water. Similar to that for oil reservoirs, injection of CO_2 into the coal seam can enhance methane recovery. In this process, the injected CO_2 essentially displaces the methane adsorbed on the coal seam, with the CO_2 remaining sequestered in the coal seam. Enhanced coalbed methane recovery (ECBM) by CO_2 injection and storage of CO_2 in coals have been demonstrated in a limited number of field tests, but much more work is necessary to understand and optimize this CO_2 storage process. Because the storage of CO_2 in coal seams is still considered to be immature, this storage option is outside of the scope of work for this report.

- Other CO_2 Storage Options. Alternative potential CO_2 storage options include gas shale formations, basalts, salt caverns, and abandoned coal mines, though the state of research and confidence associated with CO_2 storage in these formations is much less than for other types of geologic candidates. As such, these alternative options are not further assessed in this report.

B. CO_2 STORAGE CAPACITY IN GEOLOGICAL FORMATIONS

The Intergovernmental Panel on Climate Change (IPCC) report suggests that there is at least 2,000 billion tonnes of CO_2($GtCO_2$)(IPCC, 2005) of storage capacity in geologic formations worldwide, summarized in Table 1-1 (IPCC, 2005). Assuming an average annual injection rate of 10 Gt, these geological formations would provide at least 200 years and possibly over 1,000 years of CO_2 storage.

Table 1-1. CO_2 Storage Capacity by Reservoir Type

Reservoir Type	Lower Estimate of Storage Capacity ($GtCO_2$)	Upper Estimate of Storage Capacity ($GtCO_2$)
Discovered Oil and Gas Fields	675	900
Unmineable Coal Seams	3 – 15	200
Deep Saline Formations	1,000	Unknown, but possibly 10,000

Source: IPCC, 2005

C. SECURITY OF GEOLOGICAL CO_2 STORAGE

The oil and gas reservoirs targeted for CO_2 storage have held hydrocarbons or other fluids for millions of years, making them favorable candidates for CO_2 storage. Moreover, the oil industry already has three decades of safe operational experience in injecting CO_2 underground for enhanced oil recovery (EOR) in a great variety of oil reservoirs. The natural gas industry has a similar exemplary record of operating natural gas storage fields for nearly 100 years. These records of past performance by the oil production and gas storage industries give confidence that geologic formations can become a publically accepted, safe and secure option for storing CO_2.

Sidebar 1. A Relevant Analog: Overview of the Natural Gas Storage Experience. This overview summarizes the incidents and estimated leakage volumes from natural gas storage fields.

While, comparison with the natural-gas storage industry can be quite constructive when evaluating the future storage integrity of CO_2 storage, it is important to recognize one fundamental difference. Natural gas storage is a cyclic operation that takes place over a year interval, and sometimes even more frequently, while CO_2 storage is continuous and permanent, and the volumes that accumulate may/will be considerable, hence extracting, transporting and reinjecting the CO_2 will be quite different in scale.

There is always some degree of risk that the injected CO_2 could leak out of its intended storage site into surrounding strata, into potential underground sources of drinking water (USDWs), into the near-surface (vadose) environment and, eventually, into the atmosphere itself. Because of these concerns, considerable research has been directed toward investigating the potential pathways for leakage of CO_2 from geological storage reservoirs.

**SIDEBAR 1. A RELEVANT ANALOG:
OVERVIEW OF THE NATURAL GAS STORAGE EXPERIENCE**

The Natural Gas Storage Experience Provides a Useful Analog of the Incidents and Estimated Leakage That Could Occur from Geological Storage.

In a recent public opinion poll of the public's perception of the acceptability of geological storage, the presence of "positive analogs" ranked highest among the factors that would support acceptability of CO_2 storage. As such, the exemplary performance of the natural gas storage industry and its close analog to CO_2 storage should provide a very "positive analog" for gaining public acceptance for CO_2 storage.

An in-depth look at gas storage gives confidence that, with proper site selection, rigorous well design, thorough modeling, targeted monitoring, and workable mitigation strategies, the storage of CO_2 in geological formations can be safe and secure.

The gas storage industry has operated efficiently, and with very few incidents of leakage, for nearly 100 years. Many of the gas leakage incidents in gas storage were due to problems with well integrity and were promptly remediated. Improper site selection, particularly the inadequate testing of the gas storage formation's caprock (seal), accounts for the remaining incidents of natural gas leakage.

The incidents of reported leakage from the more than 600 gas storage sites, many in operation for 30 to 50 years or more (approximately 25,000 site years of operation) are quite small, with only 10 such leakage incidents identified by a GTI study of the U.S. natural gas storage industry (Perry, 2004).

Even smaller are the volumes of gas leakage, estimated at 0.015% per year of stored volume. Assuming that about 80% of the gas that leaked was captured by shallow wells, the volume of gas leakage to the atmosphere has been even less, estimated at 0.003% per year of stored volume.

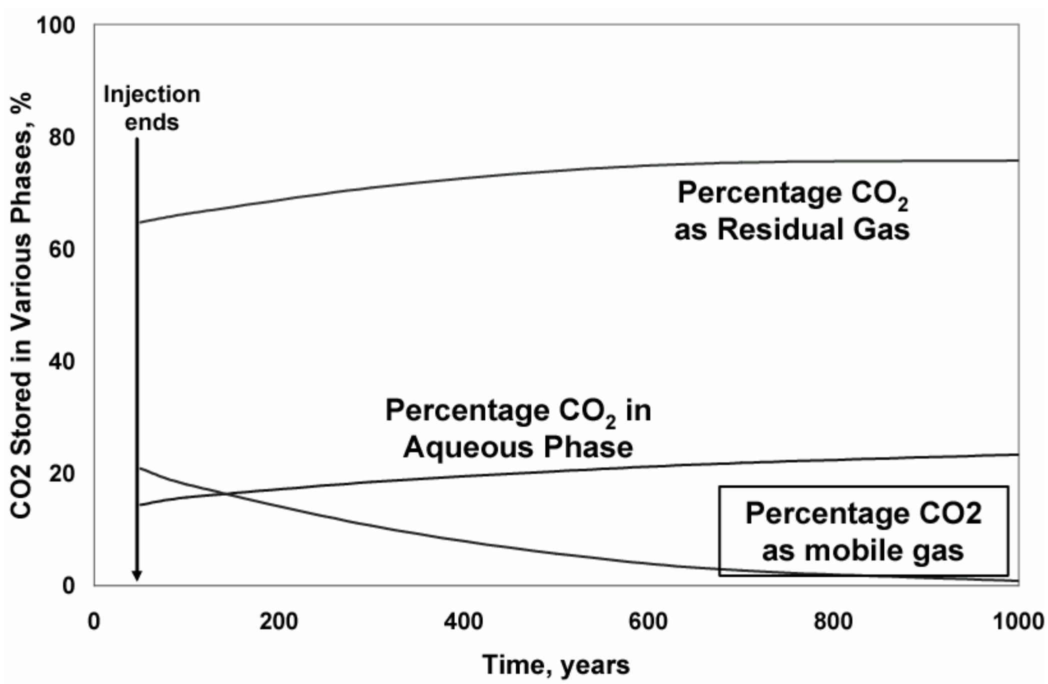
With more rigorous site selection procedures helping to avoid areas with inadequate reservoir caprock (seals); with modern well design, materials, and completion procedures helping improve well integrity; with considerably more rigorous CO_2 plume modeling and installation of CO_2 monitoring systems; and with the much less buoyant nature and lower mobility of the CO_2, the levels of leakage in CO_2 storage fields should be considerably less than experienced in the past by natural gas storage fields.

The pathways that could enable large amounts of CO_2 to leak from geologic formations include leakage through poor quality or aging well completions, leakage up abandoned wells, and leakage due to transmission through the caprock, faults and/or natural fractures.

In open saline formations (lacking structural closure), leakage could also occur as CO_2 migrates horizontally away from the injection point and reaches one of the vertical leakage pathways toward updip potable water and the outcrop. Episodic instances of CO_2 leakage could also occur due to improper CO_2 storage operations, including leakage during injection and filling a reservoir past its spill point.

In addition, current science indicates that CO_2 stored in a geologic formation may become more secure over time. Several mechanisms account for the potential for increasing storage security. After the injection of CO_2 into a formation has been completed, the formation pressure will decay over time, reducing the driving pressure. (Chalaturnyk and Gunter, 2004; Senior, 2005). Similarly, recent modeling work on saline formations shows that the amount of mobile supercritical CO_2 in a representative reservoir decreases to less than 10% of the total stored CO_2 after 500 years, with the remainder being either dissolved in brine or locked in rock pores, Figure 1-2. (Note that the analysis in Figure 1-2 is based on a series of advanced injection technology assumptions)(Holtz, et al., 2004). As both the formation pressure and percent free CO_2 decrease, so does the driving force for leakage.

Figure 1-2. Free CO_2 in a Saline Formation Storage Site Decreases Over Time



Source: Holtz, et al., 2004.

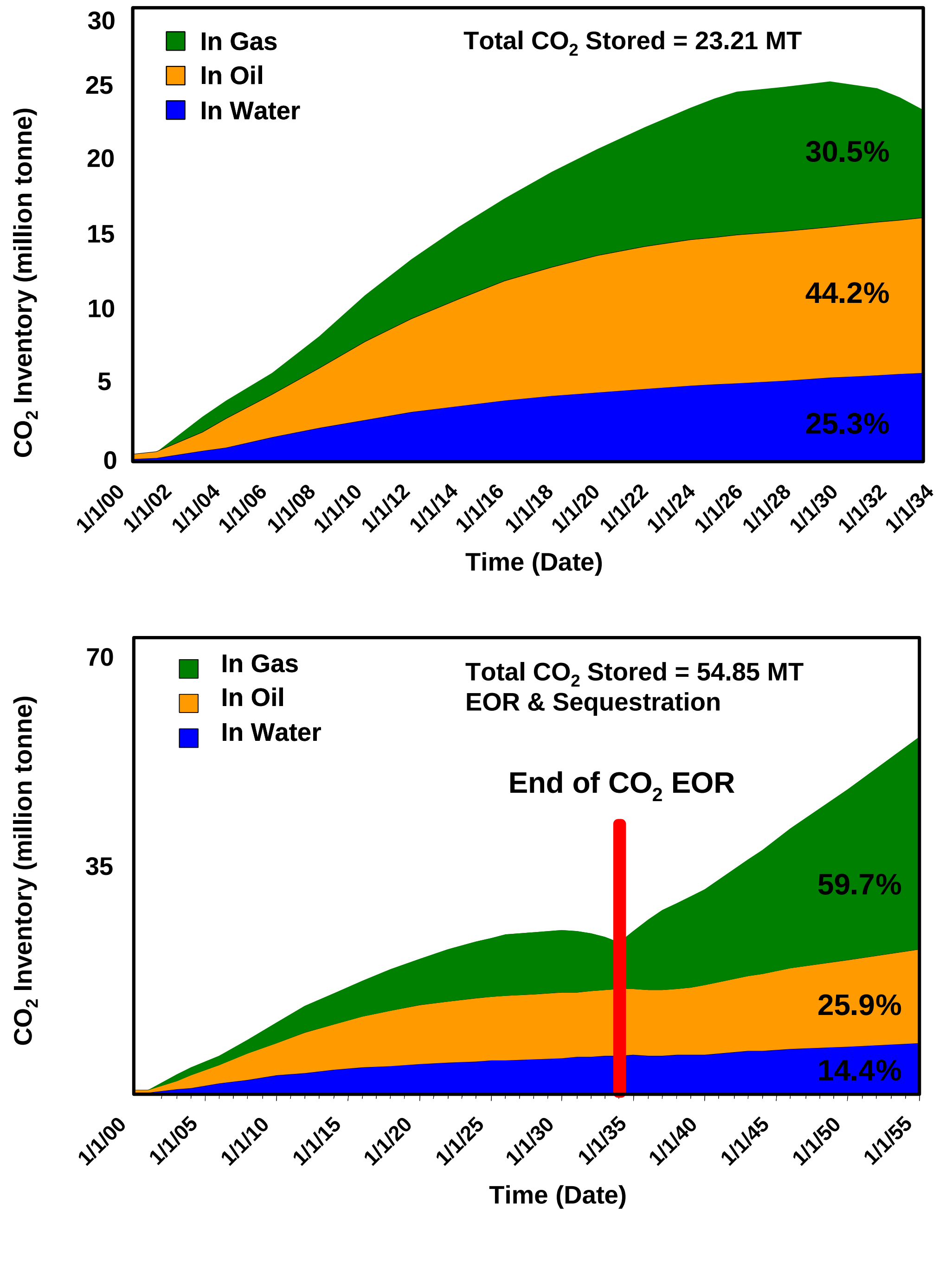
A second, in-depth study of the long-term storage mechanisms and risks of CO_2 leakage is provided by the Weyburn CO_2 Monitoring and Storage Project (Hewitt, 2005). Weyburn is a major CO_2-EOR and CO_2 sequestration field project, currently injecting over 2 million tonnes of industrial CO_2. The source of the CO_2 is the Northern Great Plains gasification plant in North Dakota, and the CO_2 is injected into the Midale Formation of the Weyburn oil field in Saskatchewan, Canada.

- During the CO_2-EOR phase of the project, from years 2000 to 2035, EnCana, the operator of the Weyburn oil field, plans to store 23 million tonnes of CO_2 in the Midale oil formation. Subsequent to the CO_2-EOR project, and during the CO_2 sequestration phase from years 2035 to 2055, the operator plans to inject and store another 32 million tonnes of CO_2. As such, a total of nearly 55 million tonnes of CO_2 will be stored in this oil field, Figure 1-3.

- The trapping and long-term storage of CO_2 at Weyburn is expected to occur by four mechanisms. The major mechanism, accounting for 44% of long-term storage, is dissolution in the oil left behind after the CO_2-EOR project. Solubility trapping in water and mineral trapping are each estimated to account for about 28% of long-term storage. Ionic trapping of CO_2 in water makes only a small contribution, Figure 1-4.

Given the presence of these various CO_2 trapping mechanisms and the competence of the caprock, the presence of structure, and the safety provided by overlying sediments, a risk assessment of the Weyburn Project, based on a long-term reservoir simulation study, estimated that only 0.2% of the injected CO_2 will leak to the atmosphere in 5,000 years, Figure 1-5.

Figure 1-3. Projected CO_2 Injection and Storage at Weyburn Oil Field



Source: Hewitt, 2005.

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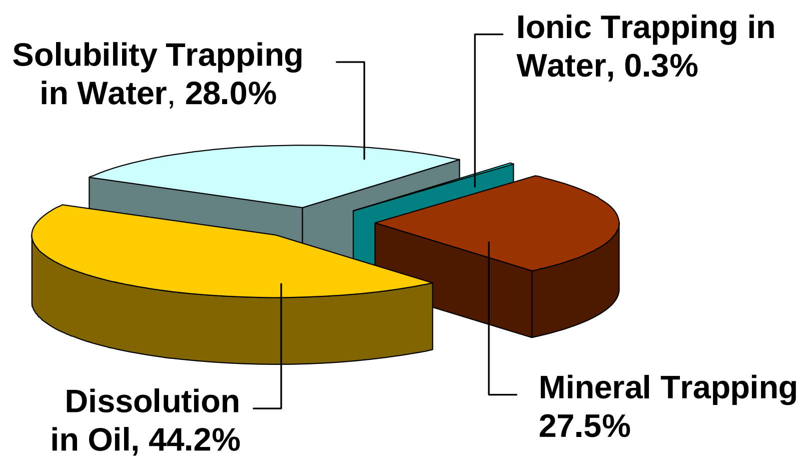
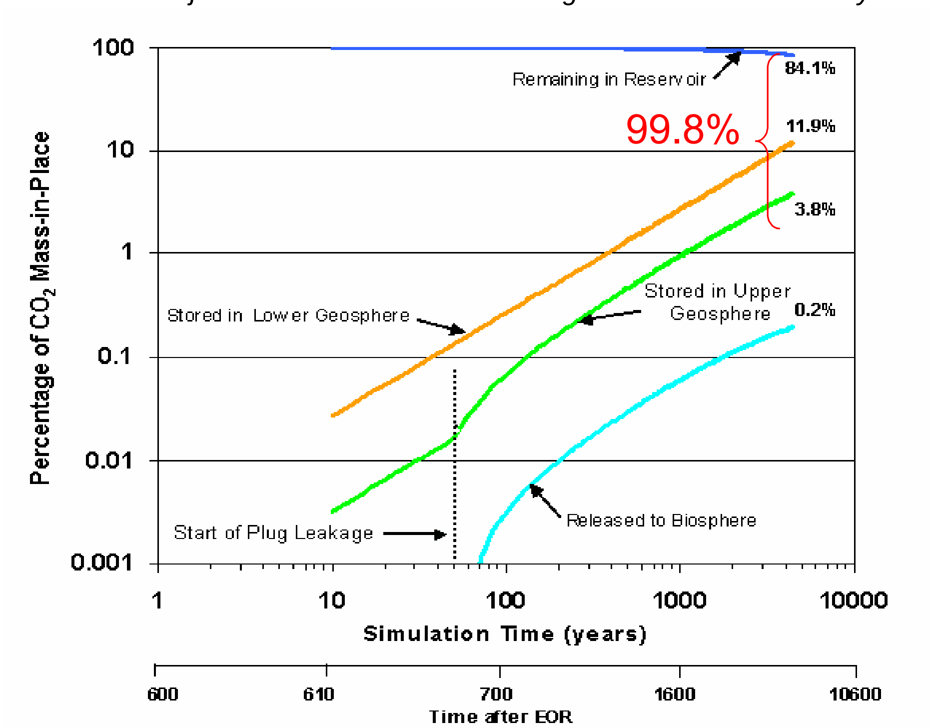
Figure 1-4. Long-Term CO_2 Trapping and Storage at Weyburn Oil Field



Source: Hewitt, 2005.

Figure 1-5. Long-Term Leakage Risk Assessment for the Weyburn CO_2 Storage Site

99.8% of the injected C02 will be stored underground for at least 5000 years



Source: Hewitt, 2005.

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D. PRIORITIES FOR THE PATH FORWARD

Geologic storage sites will need to be selected with primary emphasis on assuring high-quality seal integrity and structural confinement. However, while the storage reservoir itself may be defined by geophysical data sets gathered from earlier petroleum development, the caprock is often assumed to be adequate and may not have been sufficiently investigated. Likewise, the challenges to long-term integrity of well bores, down-hole tubulars, and cements in the presence of CO_2 is just beginning to be understood. In many reservoirs, existing wellbores (both in producing and in plugged and/or abandoned wells) may be the primary potential conduit of CO_2 flow from the storage reservoir. As such, considerable additional R&D and technical investigation need to be devoted to these three topics - - seal integrity, structural confinement and well integrity.

Continued investments in the science and technology surrounding proper site selection, including testing of the caprock and mapping of structural confinement, in conjunction with advances in the design of CO_2 injection wells, will greatly improve the reliability of the selected CO_2 storage site. Development and demonstration of reliable modeling, monitoring and mitigation strategies, once added to the overall storage system, will further reduce the risks of CO_2 leakage -- whether from geologic features or well bores. As such, strong R&D efforts in modeling and monitoring accompanied by field pilots and large-scale demonstrations will help assure that industrial-scale implementation of geologic CO_2 storage will be available when required (Espie and Gale, 2004).

E. PURPOSE OF THE STUDY

The purpose of this study is to provide a comprehensive assessment of strategies for preventing CO_2 leakage in the first place, and a full discussion of the steps that should be taken should CO_2 storage sites leak and require remediation. The study also assesses the technical status and economics of alternative remediation techniques and approaches to address potential leakage from geologic CO_2 storage reservoirs. Our intent is that this information will help guide more detailed research and investigations into new and improved remediation technologies for the future.

Specifically, this report serves to provide a comprehensive discussion of the following: the potential CO_2 leakage pathways that could exist at CO_2 storage sites; how storage sites can be selected, configured, and operated to minimize the chance of leakage; how current modeling and monitoring technologies can help identify settings where leakage could occur; and, most importantly, when leakage does occur, what set of strategies and steps can be taken to remediate CO_2 leakage. The report also provides some perspective on the costs of various remediation approaches that could be applied to CO_2 storage.

II. POTENTIAL LEAKAGE PATHWAYS FROM GEOLOGICAL STORAGE RESERVOIRS

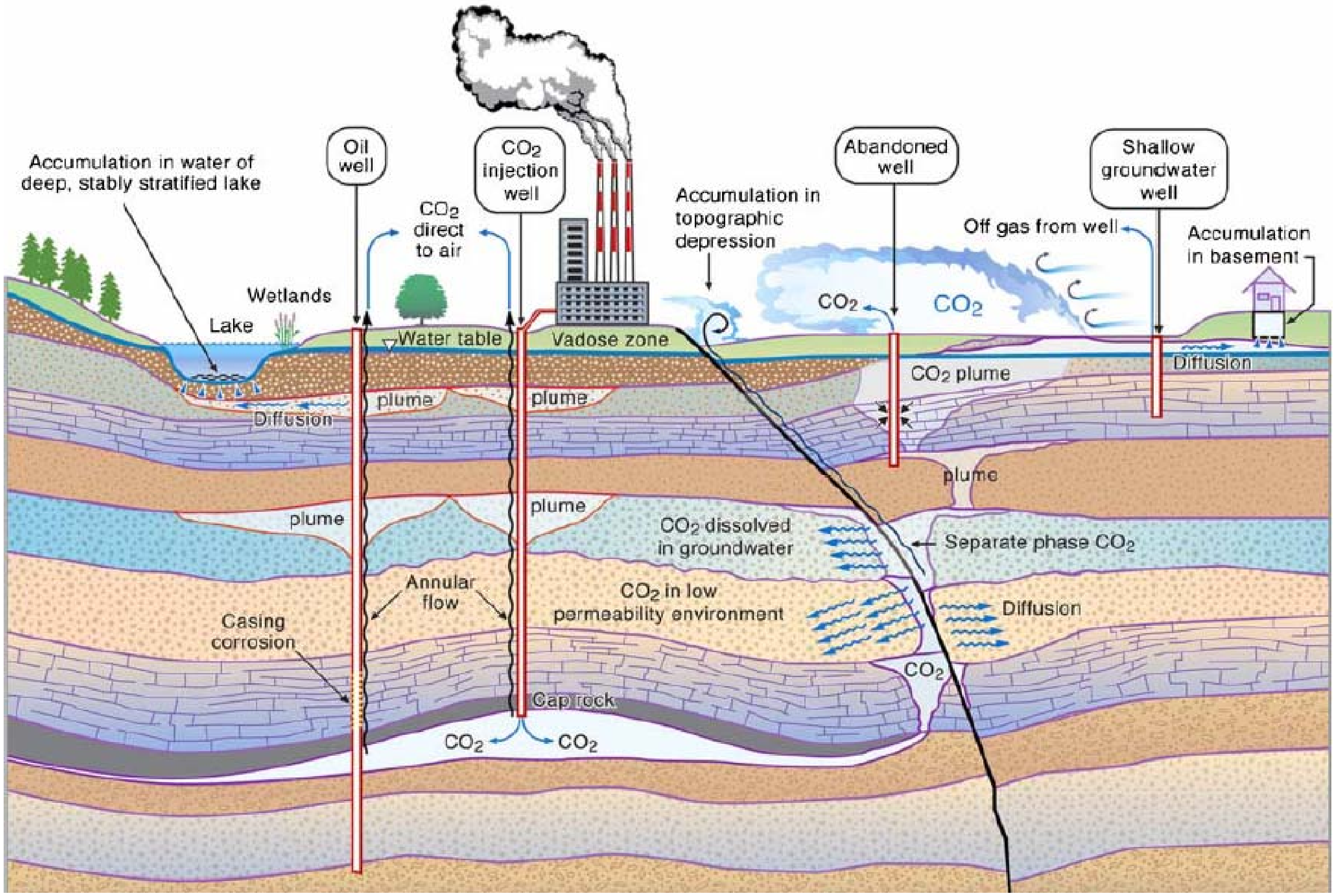
A. OVERVIEW OF LEAKAGE PATHWAYS

An important first step in addressing the issue of leakage from CO_2 storage reservoirs is to identify the potential leakage pathways for CO_2. The second step is to evaluate the likelihood of the CO_2 plume reaching and escaping through these leakage pathways. Then, depending on the nature of the leak, step three is to assess the volume and potential risks of CO_2 leakage whether it be to potable aquifers, to the vadose zone, or to the atmosphere.

Since CO_2 is buoyant compared to water, it will have a tendency to migrate, both vertically and laterally, along the most transmissive pathways available. Transmissive differences between the extent and nature of the buoyancy of the CO_2 steam injected and water will depend on the bulk density of the injected gas mixture, which is a function of the properties of both the CO_2 and other gases composing the injected stream. These transmissive pathways could be beds of porous and permeable sedimentary rock, transmissive fractures or fissures that cut through impermeable rock, or improperly completed or abandoned wells and boreholes in the vicinity of the CO_2 plume. Some of these pathways are illustrated in Figure 2-1 (Benson, et al., 2002).

Although large-scale leakage of CO_2 and other gases from geologic reservoirs is relatively rare, it is not unknown. This is especially true in the case of natural gas storage, where a several well-documented cases of leakage exist (Perry, 2005). In addition, in the relatively short time frame (geologically) of CO_2 injection for EOR, seals are retaining CO_2 in the subsurface, and the CO_2 appears to be behaving as expected (Grigg, 2002). Nonetheless, further documentation of CO_2 fate in the subsurface in EOR projects in probably warranted, since leakage would obviate the benefits of CO_2 capture, while reducing the public's and policy maker's confidence in this important CO_2 mitigation technology.

Figure 2-1. Illustration of Potential Leakage Pathways and Consequences



Source: Benson and Hepple, 2005.

B. OVERVIEW OF RISKS AND RELEVANT ANALOGS

The concept of storing CO_2 in geologic reservoirs is relatively new. However, researchers can draw on the considerable experience and understanding gained from oil and gas production, from commercial EOR projects (Grigg, 2002), from underground natural gas storage (Perry, 2004), from natural CO_2 reservoirs (Stevens, 2004), and from natural releases of CO_2 (Holloway, 2005). Operating experience with "sour gas" or "acid gas" production, treatment and disposal is also relevant (Krilov, et al., 2000).

To provide some perspective, it is important to recognize that the likelihood of leakage from properly selected, well-managed, and well-operated storage reservoirs is believed to be small. According to the recent IPCC report (IPCC, 2005):

> *"Observations from engineered and natural analogues as well as models suggest that the fraction retained in appropriately selected and managed geological reservoirs is very likely* to exceed 99% over 100 years, and is likely** to exceed 99% over 1,000 years."*

* "Very likely is a probability between 90% and 99%

** "Likely is a probability between 66% and 90%

This assessment is based on the IPCC's thorough examination of research, project performance and risk assessments performed to date demonstrating the potential geologic integrity of likely CO_2 storage reservoirs.

Similarly, using natural gas storage as an analog, only ten of the approximately 600 storage reservoirs in the United States have experienced any reported leakage (Perry, 2005). This is based on a survey of 55 operators in 16 countries, 42 of which provided information to the project cited. In the U.S., 42 operators responded to the survey. All of the geologically related natural gas leaks through a caprock were in converted aquifer-based gas storage fields lacking the assured seal available in abandoned oil and gas fields (see Sidebar 2). The remainder of the leaks in gas storage operations were associated with lack of well integrity or loss of well control, generally attributable to poor well completion and workover practices. A companion study, including internationally operated gas storage fields, showed a similarly safe and reliable operating history (Woodhill Frontier, 2005). In general, reservoir engineering principles determine maximum allowable reservoir pressure allowable in a natural gas storage reservoir to maximize storage gas deliverability without damaging the reservoir. These same principles would apply to CO_2 storage reservoirs as well.

Sidebar 2 to this report provides an overview of the U.S. natural gas storage leakage experience relevant for CO_2 storage.

C. MECHANISMS OF CO_2 TRAPPING AND STORAGE.

CO_2 storage security depends on a combination of physical and geochemical trapping, with the relative importance of these two trapping mechanisms changing over time. Of initial and primary importance is structural and/or stratigraphic trapping of the CO_2 beneath a secure caprock. Over time, capillary trapping (also called residual CO_2 trapping) and solution trapping (in oil or water) begin to make a larger contribution. As time increases, mineral trapping and density inversion trapping become increasingly important. (These two important CO_2 trapping mechanisms involve CO_2 precipitating out in the form of carbonates (mineral trapping) and more dense CO_2 saturated waters flowing downward and downdip (density inversion).

Under favorable conditions, the amount of CO_2 that can be sequestered via mineralization can become comparable with capillary trapping and solution in oil or water, though the relative contribution of each trapping mechanism will vary considerably with rock type (Xu, et al., 2000). Figure 2-2 illustrates the relative importance of each of these CO_2 storage and trapping mechanisms and their role in establishing that the security of CO_2 storage increases with time.

An important portion of our current understanding of trapping and storing CO_2 in oil reservoirs has been gained from the numerous CO_2 enhanced oil recovery projects, in the U.S. and elsewhere. The gas storage industry, which preferentially uses depleted natural gas fields in the U.S., also provides a most valuable base of knowledge for storing CO_2 in oil and gas fields. Finally, much of the knowledge on CO_2 trapping and storage mechanisms for deep saline aquifers has been gained from the valuable experiences at Sleipner (Johnson et al., 2004).

SIDEBAR 2. ASSESSMENT OF NATURAL GAS STORAGE LEAKAGE AND OPERATING EXPERIENCE

The Natural Gas Storage Experience Provides Insights as to Likely Pathways for CO_2 Leakage.

Natural gas has been stored and recycled in geologic formations for nearly 100 years. Approximately 600 U.S. storage reservoirs containing nearly 8 Tcf (equal to about 2 billion metric tons of CO_2 storage volume) of natural gas help meet peak gas demand during winter and provide a repository for excess gas production during summer.

A survey of U.S. gas storage operations was conducted for the CO_2 Capture Project by K. Perry of the Gas Technology Institute (GTI, 2002, 2004). In this study, Perry identifies only 10 examples of natural gas leakage, mostly occurring prior to 1970 before the use of modern site appraisal and well completion practices, as summarized on Table 1.

Table 1. Gas Storage Fields with Some Type of Leak

Field Type and Location	Type of Leak	Remediation Action Taken
1. Caprock and Seal Problems		
Aquifer – Indiana, U.S.	Reservoir Too Shallow	Field Abandoned
Aquifer – Illinois U.S.	Caprock	Aquifer Pressure Control
Aquifer – Midwest U.S.	Caprock	Shallow Gas Recycle
Aquifer – Midwest U.S.	Caprock	Field Abandoned
Aquifer – Midwest U.S.	Caprock	Reservoir Abandoned, Deeper Zone Developed for Gas Storage
2. Wellbore and Casing Problems		
Aquifer Storage, Wyoming, U.S.	Wellbore Leak	Wellbore Remediation
Depleted Gas Field, Canada	Wellbore Leak	Wellbore Remediation
Depleted Gas Field, W. Virginia, U.S.	Casing Leak	Wellbore Remediation
Depleted Field, California, U.S.	Improperly Plugged Well	Re-Plug Old Well
Salt Cavern, Kansas, U.S.	Wellbore Leak	Wellbore Remediation

In addition to providing very valuable information on the portfolio of technologies used by the underground gas storage industry to monitor, detect and remediate leakage, the 42 U.S. gas storage operators that responded to the GTI survey identified the following examples of gas leakage and migration.

Caprock Leaks. Five of the gas storage leakage incidents involved leakage of gas through the caprock or seal, requiring that three of the gas storage field or reservoirs be abandoned:

- In the late 1960's, an overly shallow aquifer-based gas storage field was established in Northern Indiana (USA). After leakage was detected in a number of the nearby water wells, the gas storage field was drawn down and abandoned. (Current regulations would no longer allow or certify such a shallow gas storage field.)
- In mid-1953, shortly after the Herscher-Galesville aquifer-based gas storage field in Illinois (USA) was put on operation, bubbles of gas appeared in shallow water wells in the area. Four actions were taken that have enabled this gas storage project to continue operating for 50 years, namely: (1) drilling of shallow wells to capture the leaked gas; (2) reinjection of the captured gas back into the Galesville Formation; (3) injection of water into a formation above the Galesville to provide a pressure boundary; and, (4) maintaining lower pressures in the main Galesville gas storage zone.

SIDEBAR 2. NATURAL GAS STORAGE LEAKAGE EXPERIENCE (Cont'd)

Caprock Leaks (Cont'd)

- Gas leakage through the caprock was noted in two Mt. Simon and one adjacent St. Peter Sandstone aquifer-based gas storage fields in the Midwest (USA). In one case, shallow gas well drilling plus gas recycling was implemented to remediate the problem. In the second case, the gas storage field was abandoned leaving behind a small volume of stored gas. In the third case, the shallower zone was abandoned and a deeper formation in the field was developed for gas storage.

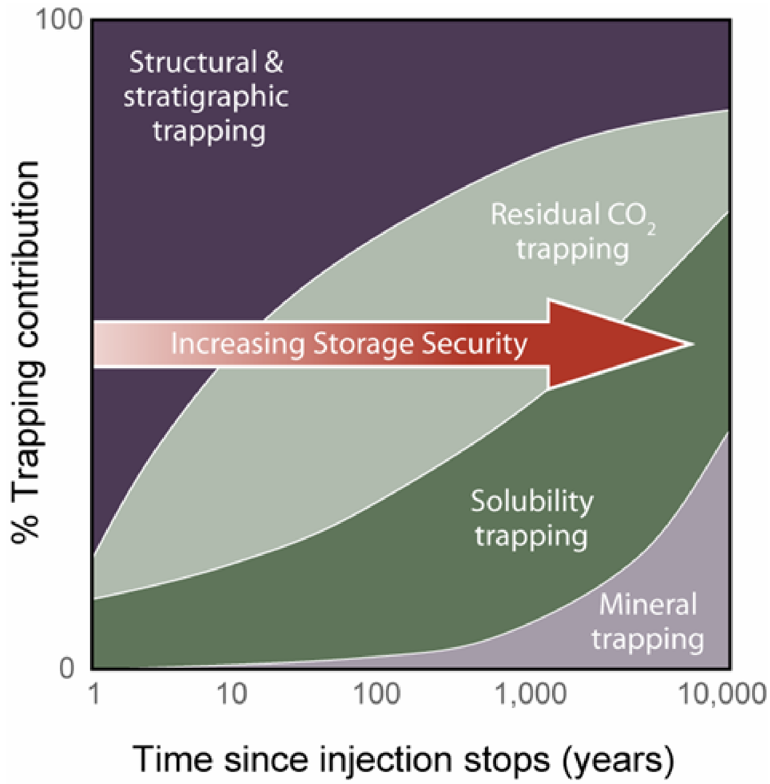
Wellbore and Casing Leaks. Five of the gas storage leakage incidents involved temporary wellbore or casing leaks that were corrected with wellbore remediation and well plugging:

- In the early 1980's, the Leroy aquifer-based gas storage field in the Thaynes Formation, Uinta County, Wyoming (USA) observed gas bubbling to the surface from a wellbore leak. The problem was corrected by reducing the gas injection and operating pressures and conducting a wellbore remediation.
- Casing and wellbore leaks were detected in depleted gas formation-based gas storage fields in West Virginia (USA) and in Ontario, Canada. Repairing defective casing and reworking the wells were undertaken to remediate this problem.
- In the 1970's, the gas storage operator at Montebello, California observed that an old well, plugged before current standards were put in place was causing gas to migrate into a shallower zone (but not to the surface). Proper plugging of this old well to today's standards remediated the problem.
- In early 2001, high pressure natural gas began escaping from a casing leak at one of the 70 salt caverns at the Yaggy gas storage field outside of Hutchison, Kansas (USA). The 60 million cubic feet of gas in the S-1 man-made salt cavern escaped and traveled toward Hutchinson, a town with a population of 40,000. The lateral migration pathway was a thin dolomite interval above the top of the storage cavern. The leaked gas led to a series of explosions, gas geysers and two deaths, the first-ever deaths from a natural gas storage facility. The Yaggy gas storage field was closed for two years before further diagnostic and remediation efforts enabled this gas storage field to resume operations. (Additional discussion of the Yaggy gas leakage experience is provided in Chapter III, Sidebar 3.

Source: Perry, 2003; Perry, 2004.

Nonetheless, additional research is need to better understand the processes that contribute to effective, long-term storage of CO_2 in geologic reservoirs, including - - physical trapping beneath low permeability cap rocks, trapping in the immobile residual phase in the pore space of the reservoir, and geochemical trapping in fluids and/or the reservoir rock (Benson, 2005).

Figure 2-2. CO_2 Storage and Trapping Mechanisms and Increasing Storage Security with Time



Source: Heidug, 2006.

The following provides a brief synopsis of the key CO_2 trapping and storage mechanisms in geological formations and their applicability to the three main CO_2 storage options.

1. Pore Volume Trapping (Aquifer, Oil and Gas). Two mechanisms naturally trap CO_2 within reservoir pores - - CO_2 saturation below a critical value and depletion (imbibition) hysteresis. Critical gas saturation determines the minimum saturation of CO_2 that is required to initiate flow of the CO_2 through the reservoir pore space. This saturation is defined by the reservoir rock's relative permeability curves for CO_2, oil and water, see Figure 2-3. Subsequent CO_2 trapping through relative permeability hysteresis is primarily a post-injection phenomenon due to the differences between drainage (production) and imbibition (injection) CO_2 relative permeability, see Figure 2-4, where liquid imbibition begins at a given initial gas saturation (S_{gi}) thereby creating a new, larger trapped gas saturation (S_{gt}) .

2. Solubility in Water. CO_2 is soluble in water, and when injected into a saline water formation or an oil reservoir (for example during the CO_2-EOR process), a portion of the CO_2 will dissolve in the formation water, Figure 2-5. The amount of CO_2 dissolved in water is affected by several factors including: temperature and pressure within the reservoir; salinity of the reservoir water; and how much of the reservoir's brine is contacted by CO_2 (as governed by the reservoir's heterogeneity and geometry). Subsequent inversion of the more dense CO_2 saturated brine will serve to increase the contact of the CO_2 with the reservoir's brine, as shown on Figure 2-6.

3. Mineral Trapping. Mineral trapping is the permanent sequestration of CO_2 through chemical reactions, primarily with minerals in the reservoir's matrix. Through field studies and numerical modeling, it has been determined that CO_2 is primarily trapped through precipitation of calcite ($CaCO_3$), siderite ($FeCO_3$), dolomite ($CaMg(CO_3)_2$) and dawsonite ($NaAlCO_3(OH)_2$) (Xu, et al., 2001; Xu, et al., 2003). In order for mineral trapping through carbonate precipitation to occur, minerals rich in Mg, Fe, Na and Ca, such as feldspars and clays, must be present in the reservoir rock. Therefore, immature sands having an abundance of unaltered rock fragments (unweathered igneous and metamorphic minerals and clays rich in Mg, Fe and Ca) are most effective (Bachu, et al., 1994; Pruess, et al., 2001). The abundances and ratios of these primary minerals can have a tremendous effect on the type of secondary minerals that are precipitated as well as on the overall total amount of CO_2 that may be permanently sequestered.

4. Solubility in Oil. As part of the CO_2-EOR process, CO_2 will condense into the reservoir's oil phase and CO_2 will also vaporize the lighter oil fractions into the injected CO_2 phase. (From the perspective of EOR, this leads to two reservoir fluids that become miscible (mixing in all parts), with favorable properties of low viscosity, a mobile fluid and low interfacial tension.) As such, considerable volumes of CO_2 will remain in the reservoir in solubility with the unproduced, residual oil.

Figure 2-3. Relative Permeability of CO_2 and Brine.

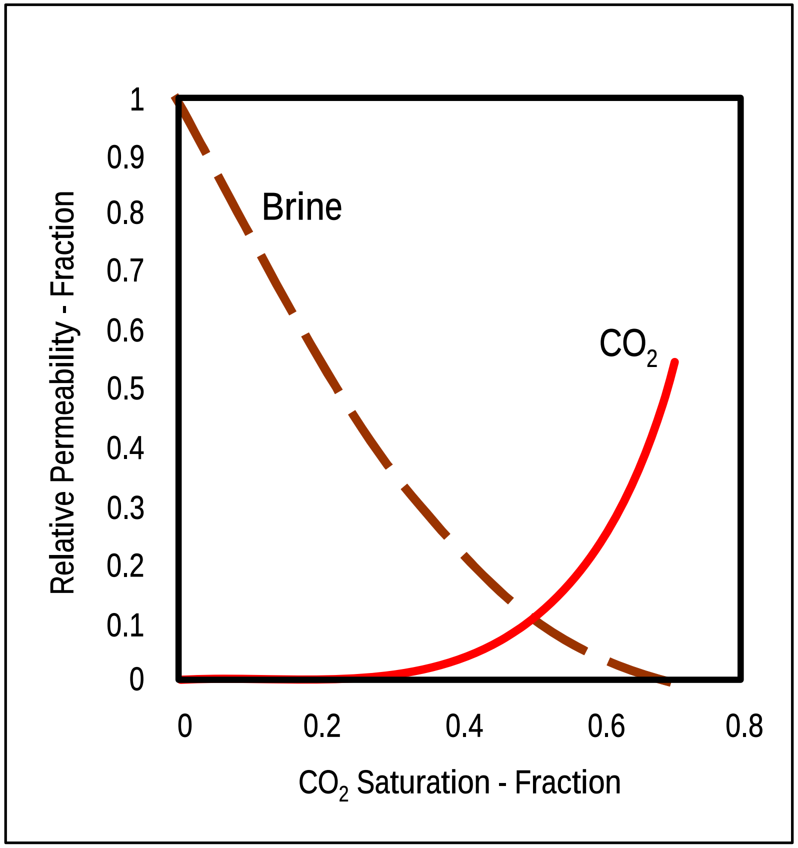


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Figure 2-4. Hysterisis Effects on Relative Permeability of CO_2 and Brine.

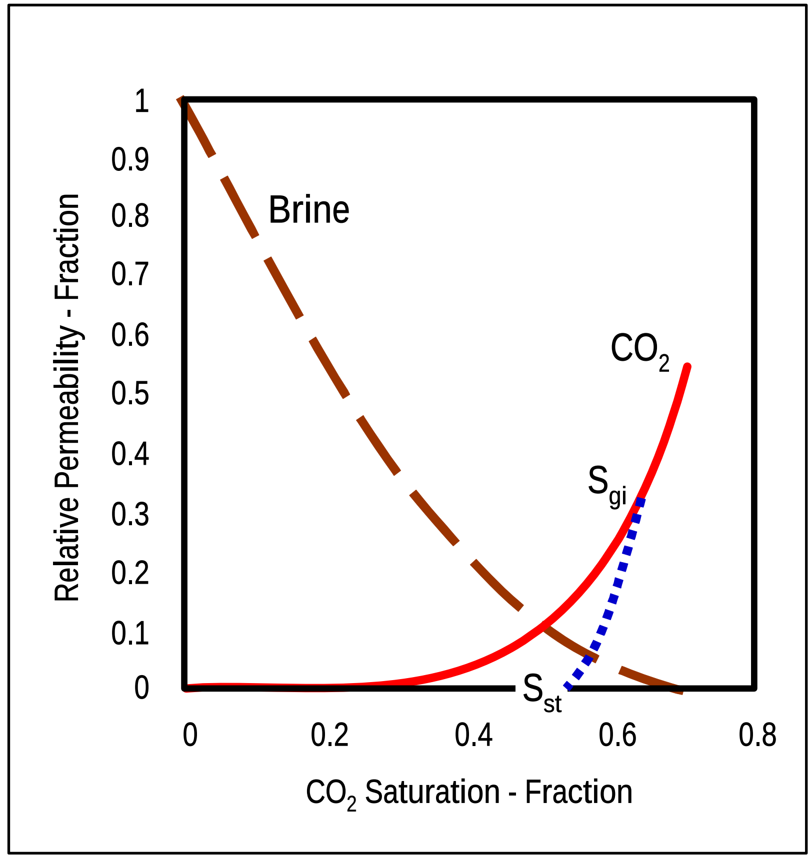
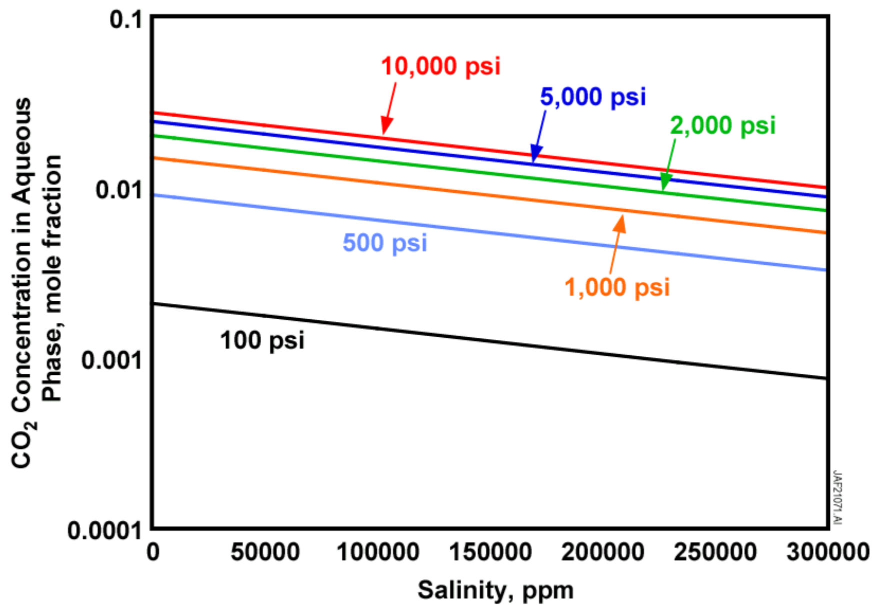


Figure 2-5. Increasing Brine Salinity Reduces CO_2 Solubility in Aqueous Phase



Source: G.A. Pope, UT Austin (Orr, 2004)

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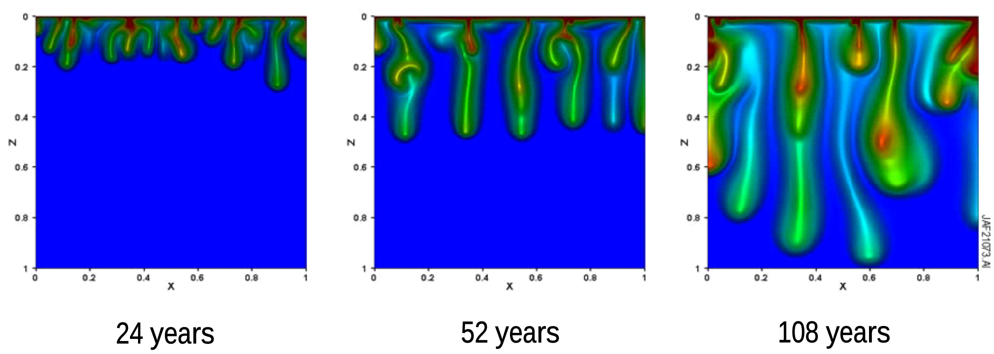
Figure 2-6. Mixing and Dissolution of CO_2 in Saline Waters



Source: A. Riaz, M. Hesse, H. Tchelepi, Stanford University, 2004 (Orr, 2004).

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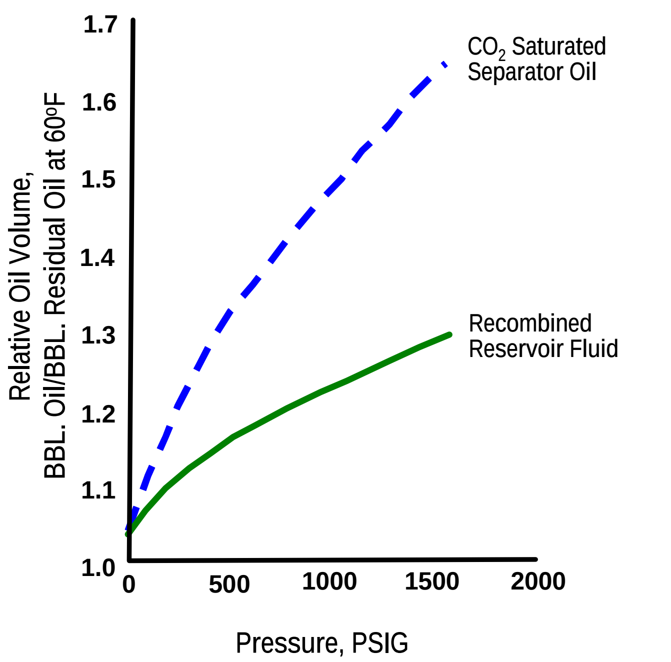
The solubility of CO_2 in oil leads to oil swelling, an important mechanism for both miscible and immiscible CO_2 injection. Laboratory work on a light, West Texas oil shows that the injection of CO_2 (at 1,500 psig or 105 Kg/cm^2) can increase the volume of the reservoir's oil by 30%, Figure 2-7. Laboratory work on reservoir oil in Turkey shows that, even for heavy oil, the volume of oil can be increased by 15% to 20% under high pressure, Figure 2-8.

5. Structural Confinement. A most critical CO_2 trapping and storage mechanism for oil, gas and saline water formations is structural confinement, due to anticlinal geology, stratigraphic features or sealing faults. The free CO_2 in the reservoir will be trapped within the geologic structure, much as oil or natural gas has been trapped in conventional hydrocarbon fields. As long as the volume of CO_2 injected does not exceed the reservoir's "spill point", structural confinement provides one of the most secure mechanisms for precluding CO_2 migration and subsequent leakage.

The following section of Chapter II discusses, in more depth, the geological (nature-created) leakage pathways as well as the non-geological (human-created) leakage pathways that may enable CO_2 to migrate out of its intended storage setting.

- Of primary concern for geological (nature-created) leakage pathways is the lack of caprock integrity which is essential for providing a seal for the CO_2 storage container. This concern is particularly noted for saline formations which may lack structural containment ("open-system"). Natural faults and fractures when open, or reopened during the course of CO_2 injection, are a second leakage pathway of concern. New leakage pathways may also be created by volcanic or tectonic activity subsequent to the injection of CO_2, although the one recently documented tectonic event in Japan, a major earthquake (6.8 on the Richter scale) in the vicinity of the Nagaoka CO_2 storage deep coal seam pilot operation, had no effect on the integrity of the CO_2 storage container (IPCC, 2005).

Figure 2-7. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid



Source: Holm and Josendal, 1982

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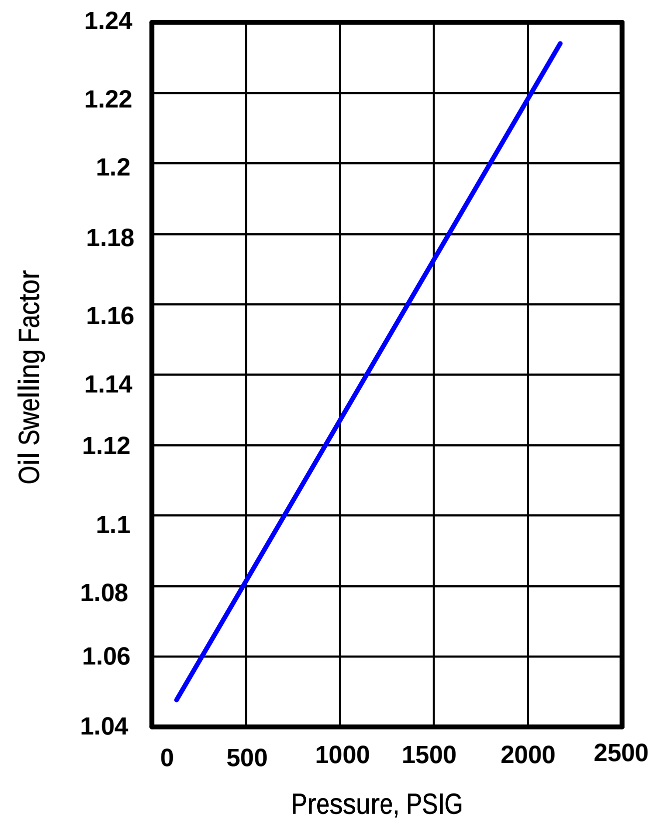
Figure 2-8. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey



Source: Issever and Topkaya, 1998.

- The human created (non-geological) leakage pathways of highest concern and thus further discussed in this report include: (1) leakage from improperly completed or abandoned wells; (2) leakage during injection operations; (3) leakage from injection induced faulting or fault reactivation; (4) leakage due to storage reservoir overfill; and (5) leakage due to post-storage disruption of the storage container.

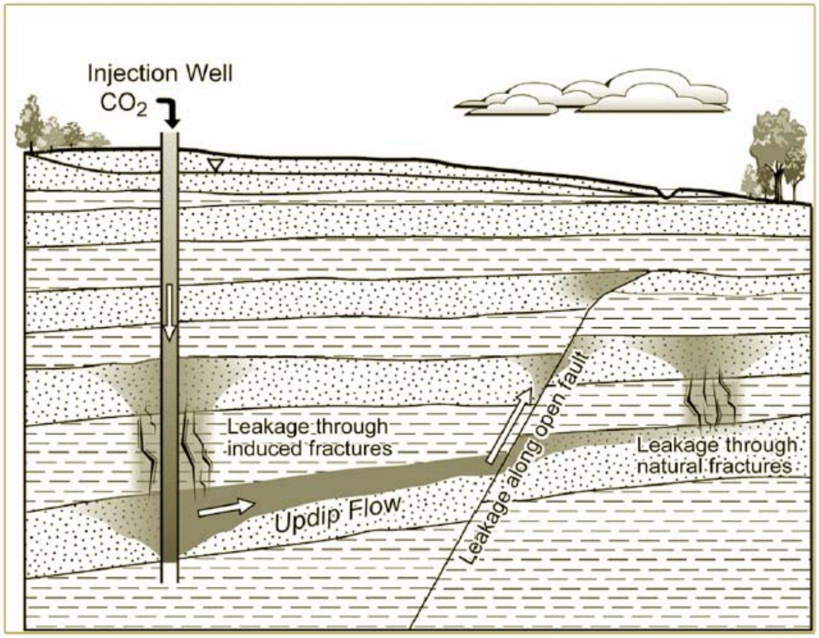
D. EXAMINATION OF LEAKAGE PATHWAYS

Much of the initial technical work on CO_2 leakage from geologic storage sites has focused on the many natural processes that could act to mitigate CO_2 leakage, rather than on examining the leakage pathways themselves. As such, valuable information exists on permeability trapping of buoyant CO_2 in overlying layers; ponding of dense CO_2 at the groundwater table; solubility trapping by water; and, dilution of CO_2 by mixing with ambient soil gases. This research, supported by numerical modeling, is reassuring in suggesting that leaking CO_2 can face numerous natural obstacles that will slow or prevent its escape to the atmosphere (Oldenburg and Unger, 2003).

In this section of Chapter II, we set forth and discuss the numerous potential pathways whereby CO_2 may leak from a geologic storage reservoir. These include both geologic pathways and non-geologic (or human created) pathways, as illustrated in Figures 2-9 and 2-10. In general, these pathways are common to all types of reservoir settings and geological storage options.

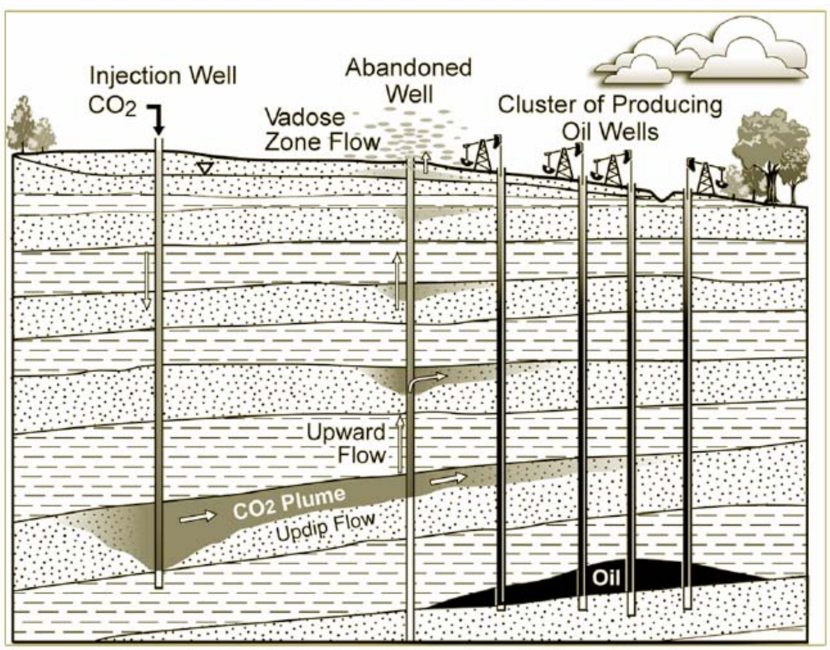
1. Geological Leakage Pathways. Selecting a geologically favorable reservoir with long-term ability to safely and securely store CO_2 depends on picking a site with no natural leakage pathways. Most important for all three of the storage options is avoiding geological settings where vertical leakage could occur through an overly thin or an overly permeable caprock. For saline formations, the geological settings to avoid are those that lack a regionally extensive overlying seal or that lack an updip structural closure. These types of settings could enable CO_2 to migrate laterally and reach a subsequent leakage pathway.

Figure 2-9. Geologic Leakage Pathways



Source: Bachu and Celia, 2006 (in press)

Figure 2-10. Abandoned and Producing Well Leakage Pathway



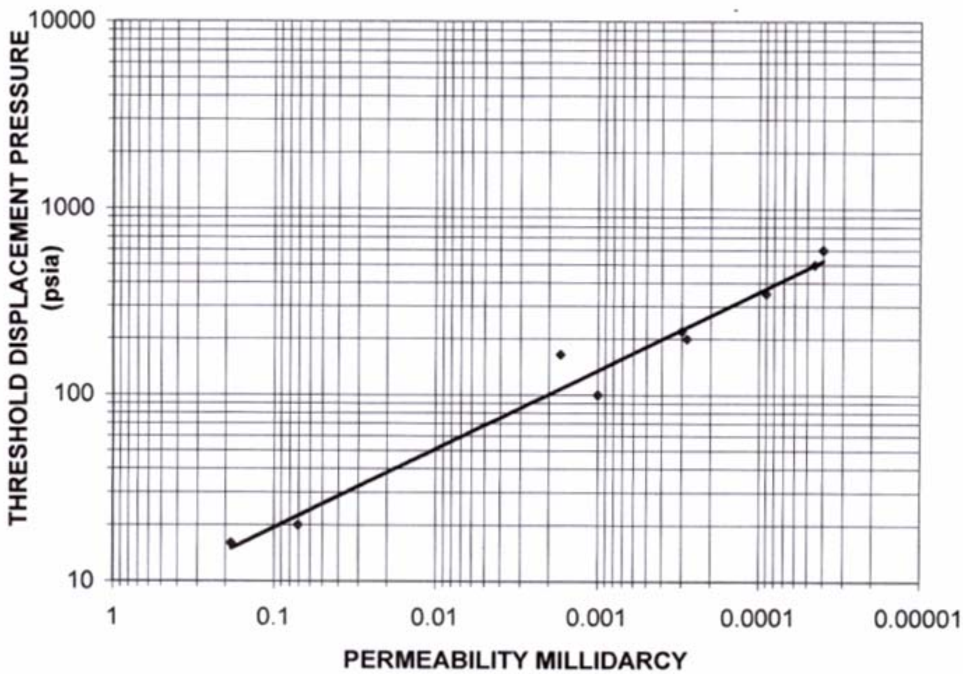
Source: Bachu and Celia, 2006 (in press)

In addition, it is important to avoid geological settings with extensive natural fractures and non-sealing faults which can provide leakage pathways through otherwise low permeability rock. Moreover, areas with seismic, volcanic, or other natural geologic events that may compromise the security of the CO_2 storage reservoir should be avoided. Fortunately, each of these leakage pathway risks can be minimized through careful site assessment and evaluation. Finally, other potential beneficial factors include a storage reservoir being part of a regional geologic structure or system, enhancing the possibilities to dissipate pressure buildups due to high rate CO_2 injection, and a storage reservoir with a relatively small footprint (for example, thick reservoir rocks are better than thin reservoir rocks).

a) Leakage Through the Caprock. CO_2 can migrate through fissures in the caprock or, when permeability and pressure are sufficiently high, even directly through the caprock itself, Figure 2-11. In general, depleted oil and gas fields can make attractive storage sites because they have already demonstrated long-term caprock integrity. However, even depleted oil and gas field caprocks may be degraded by development and production with the stress threshold highly dependent on reservoir conditions (Zoback and Zinke, 2002). For example, the stress of depletion and subsequent re-pressurization with CO_2 can create fissures that may transmit CO_2 through the caprock.

Studies of naturally CO_2-charged geologic systems provide valuable analogs to predict which reservoirs may or may not be good CO_2 storage candidates (Shipton, et al., 2005). Large natural sub-surface accumulations of CO_2 can be found around the world, in a wide variety of geological settings. Many of these natural CO_2 accumulations, such as those in the Colorado Plateau of the Rocky Mountains in the U.S., are in geological settings comparable to settings selected for industrial CO_2 storage. Three of these fields – the Jackson, McElmo, and St. Johns Domes – have been extensively studied (Stevens, 2004). Together, these fields contain over 2.4 billion tons of CO_2 and have stored CO_2 for millions of years. In two of these fields, Jackson and McElmo, there is no evidence of CO_2 leakage to the overlying strata while some presence of CO_2 has been noted in the soil near and above the St. Johns Dome.

Figure 2-11. Threshold Displacement Pressure Versus Water Permeability



Important insights on caprock integrity have been gained from studying these naturally occurring CO_2 fields. For example, the 400-m thick salt and 1200-m thick shale caprock at the McElmo Dome field has provided an excellent seal that has contained CO_2 in the Leadville reservoir for approximately 60 million years. In contrast, the thin anhydrite seals at St. Johns Dome appear to be less effective due to a large bounding fault that reaches to surface, and the presence of groundwater across the fault.

b) Leakage Through Natural Faults and Fractures. Transmissive natural faults and fractures, caused by tectonic activity or loading and unloading of overburden, can provide leakage pathways when these faults and fractures are non-sealing (open). Human induced reactivation of faulting and fracturing can also occur, perhaps due to nearby mining, construction or similar activities, as is discussed in more detail below.

Recent work on “leaky” natural analogs - - such as in Italy or parts of the Colorado Plateau -- has demonstrated that faults can be conduits for CO_2 leakage (Allis, 2004). However, faults can also serve as effective seals. Fault geometry, stress regime, and fault juxtaposition with stratigraphy all are key elements establishing which faults are seals and which are leakage pathways (Pasala, et al., 2003). Also, the heterogeneity of subsurface formations suggests that the sealing capacity of faults could vary spatially, complicating assessments of the role of faults on storage integrity.

Extensive research has been performed on the propensity of faults to act as seals or, conversely, as conduits, particularly for hydrocarbon flow (Davies and Handschy, 2003). Recent research in the fields of hydrocarbon exploration and geologic storage has led to improved predictive concepts and tools by which to determine whether or not faults will act as seals. The mechanisms which generally allow a fault to act as a seal or a conduit include:

- Clay smear or gouge developed along the fault zone, particularly in poorly lithified shales, can inhibit fluid flow.
- Juxtaposition of low-permeability strata against a hydrocarbon reservoir can seal a fault. One factor contributing to the potential effectiveness of a fault in providing an effective seal is the relative proportion of sand to shale. One reported rule of thumb is if the proportion of sand to shale is greater that 0.5, the ability of the fault to provide an effective seal should be carefully evaluated (Durham, 2005).
- Pore pressure below a formation closure or parting pressure will keep rocks on both sides of a fault in close contact, inhibiting fluid flow.
- Obtaining core samples from faults zones can provide valuable information that will help determine their effectiveness at providing reservoirs seals, or in characterizing their propensity to leak. Information on clay content and cementation, petro-physical properties such as capillary entry pressures and permeability, and microstructures such as cataclasis or grain crushing within the fault zone can be obtained from core plug samples (Davies and Handschy, 2003).

c) Leakage Due to Subsequent Volcanic and Tectonic Activity. Seismic activity, tectonic uplift, recent volcanism and other processes could affect the integrity of CO_2 storage. Major documented releases of dangerous volumes of CO_2 have all come from areas with high levels of volcanic activity. Independent research suggests that these areas may not be appropriate for long-term geologic storage of CO_2.

d) Leakage Due to Unconfined Lateral Migration. An important but mostly overlooked CO_2 leakage pathway is the potential for lateral migration of CO_2 in "open-system" saline formations. Until the CO_2 is fully immobilized by the various trapping mechanisms discussed above, this buoyant fluid (or gas) will tend to migrate updip, primarily along a bounding rock strata or the caprock. In turn, the CO_2 in solution in the saline waters of the formation will also migrate, although this migration may take some time, and will be in the direction of aquifer flow, which can be either down or up-dip.

Three important containment mechanisms can help retard the lateral migration of CO_2 in a saline formation. First is the structure which would make the saline formation a "closed system" and would enable the CO_2 to accumulate, much as in a traditional oil or natural gas reservoir. The second is a stratigraphic barrier or sealing fault that would provide updip closure to the saline formation. The third is the complete solubility of the CO_2 in the saline water of the formation leading to density inversion. Laboratory work shows that water saturated with CO_2 is slightly more dense than unsaturated formation water. Over time and in favorable reservoir settings, the CO_2 saturated waters will invert (flow downwards) enabling the unsaturated CO_2 formation waters to become the bouyant fluid.

2. Human-Created Leakage Pathways. Five categories of human-created CO_2 leakage pathways may occur. Of these, the most likely, as demonstrated by the natural gas storage industry, is CO_2 leakage from improperly completed or abandoned wells. CO_2 injection operations may also create leaks, either by a failure in operations from reservoir overfill, or from injection-induced faulting. Finally, post-storage release of CO_2 could occur if wells were drilled without pre-knowledge of the CO_2 storage reservoir.

a) *Leakage from Improperly Completed or Abandoned Wells.* Petroleum fields (and to a lesser extent, saline formations) that are converted to CO_2 storage sites often contain abandoned wellbores from past decades of drilling that need to be located and properly sealed to prevent CO_2 leakage. The location and number of some of these open well bores may be initially unknown to the storage operator. Even seemingly harmless shallow well bores that do not penetrate the targeted storage reservoir could become hazards should CO_2 leak into overlying strata (Gunter, et al., 1998).

b) *Leakage During Injection Operations.* CO_2 may leak during injection operations due to equipment malfunction, corrosion, inappropriate operational procedures, or other factors. Leakage may occur anywhere within the CO_2 supply and injection system ranging from the hot tap at the main CO_2 pipeline, the distribution manifold and lines, the wellhead, and the tubing, casing, downhole packer assembly within the well.

c) *Leakage Due to Storage Reservoir Overfill.* Inaccurate mapping of the storage reservoir structure could also cause storage capacity to be overestimated and lead to excess injection of CO_2. One underground gas storage site in the Illinois Basin experienced leakage of natural gas due to overfill. In addition, one of the natural analogs - - St. Johns Dome in Arizona - - appears to leak along its edge, not because the caprock is impaired, but rather because the naturally generated CO_2 overfilled its structural storage containment capacity.

Sidebar 3 provides more detailed summary of the leakage that occurred at the Yaggy Gas Storage Field due to failure of well casing and the subsequently unconfined lateral migration of natural gas.

d) *Leakage from Injection-Induced Faulting.* Another set of potential risks relate to the large quantities of CO_2 that could be injected, and the potential production/withdrawal induced faulting that can result from this injection. The risks could include:

- Sheared injection wells and casing
- Hole instability during injection well drilling
- CO_2 leakage along new or reactivated fault planes
- Induced earthquakes and ground uplift/subsidence.

SIDEBAR 3. THE YAGGY GAS STORAGE LEAKAGE INCIDENT

One example of the potential risks associated with lateral gas migration due to improperly completed wells happened at the Yaggy Gas Storage field in Kansas.

On January 17, 2001 a natural gas leak at this field led to an explosion that destroyed two buildings in the town of Hutchinson, Kansas. The next day, another explosion occurred five kilometers (km) away at a mobile home park, killing two people. In total, an estimated four million cubic meters of natural gas leaked and migrated 10 km from an injection/withdrawal well.

Apparently, the leaked gas from a well in this underground salt cavern storage field (Figure 1) flowed up-dip to the town of Hutchinson. It reached the near-surface via a high-permeability fractured dolomite, and then reached the surface through abandoned brine wells (Figure 2).

Figure 1. Schematic of Gas Flow at the Yaggy Gas Storage Field Blowout

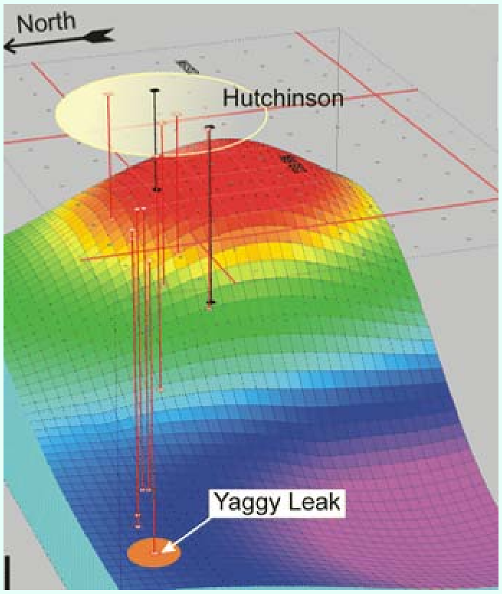
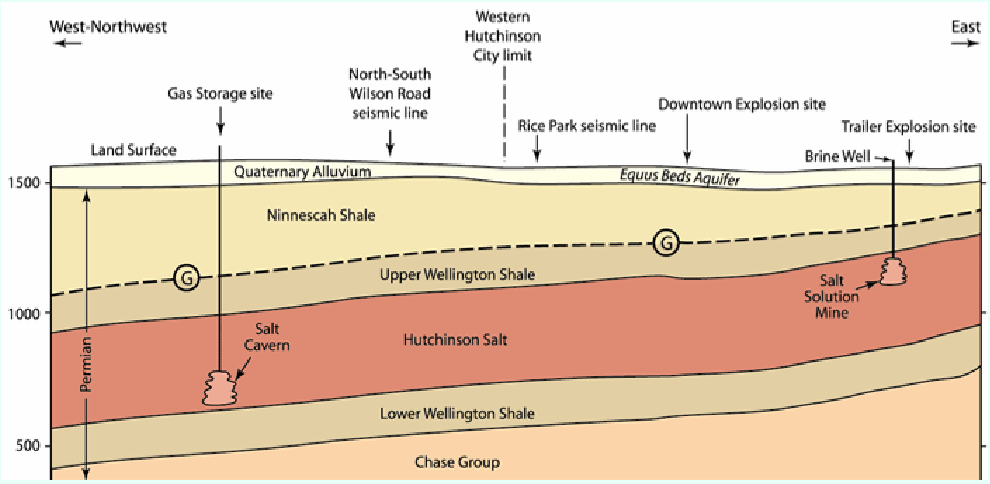


Figure 2. Schematic of the Geology and Wells Near the Yaggy Gas Storage Field



According to the post-incident investigation, a casing leak occurred in the S-1 storage well, just below top salt and 56 m above the top of the salt cavern. Salt dissolution caused flexure and fracturing in the overlying 8- meter thick dolomite, allowing a pathway for gas. These fracture apertures were opened by high-pressure gas injection.

The leaking S-1 well was plugged and abandoned, and a large scale remediation effort was undertaken. The theory is that the casing failed due to mill work conducted in this well eight years earlier (in 1993) weakening the pipe. This failure would have most likely been detected if minimal levels of monitoring were utilized.

Source: Nissen, 2004.

Another issue of concern would relate to the injection rates and pressures. Avoiding excess CO_2 injection pressure may seem obvious, but injection wells usually lose "injectivity" (i.e., plug up) over their life because of chemical deposition near the well bore, saturation of reservoir porosity, or other factors. Short-term injection spikes may occur due to pipeline or injection pressure anomalies. This may cause injection pressure to exceed the fracture gradient of the rock, creating a "frac" (i.e., man-made hydraulic fracture) in the reservoir that may cause CO_2 to leak outside the targeted storage zone. Low-permeability settings with low formation parting pressures are at particular risk of unintentional fracturing.

Sidebar 4 provides an example of CO2 leakage during operation and the remediation measures taken to address this problem.

Another study of a depleting reservoir in a Gulf of Mexico field showed where depletion stabilized the reservoir's stresses and curtailed normal faulting. In this case, the initial stress and poroelastic condition favored active normal faulting, and the depletion stress path moved the reservoir away from the active faulting envelope (Chan and Zobeck, 2002). However, in this instance, if the converse occurred (e.g., if CO_2 was injected into the reservoir) the reservoir would revert back to its original state, potentially promoting additional faulting. This study also provides a method for predicting the potential for faulting as the reservoir stress changes due to depletion or injection.

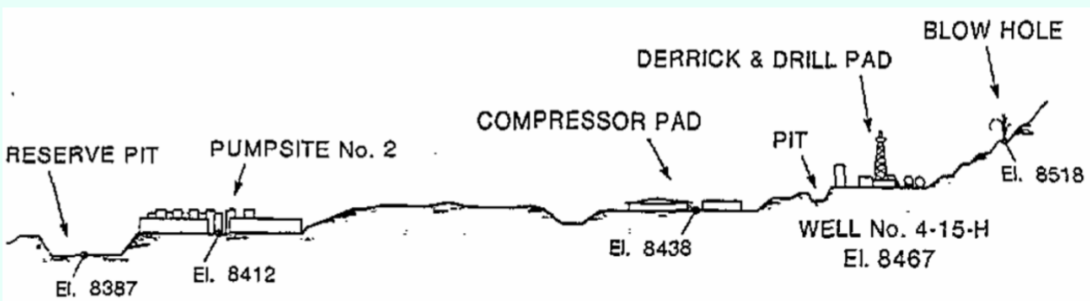
SIDEBAR 4. SHEEP MOUNTAIN CO_2 LEAKAGE INCIDENT

A well blowout occurred at the Sheep Mountain natural CO_2 field in Southern Colorado. This incident provides an example of CO_2 leakage and the remedial actions taken to control the situation.

The Sheep Mountain CO_2 field contains 110 million tons, or 2 trillion cubic feet (Tcf), of original CO_2 gas in place (OGIP). The CO_2 reserves are contained in the K Dakota sandstone reservoir at a depth of about 1 kilometer (about 3,300 feet). The field currently supplies about 3,000 tonnes/day (54 million cubic feet per day (MMcfd)) of CO_2 (down from 15,000 tonnes/day in 1987) for use in CO_2-EOR operations in the Permian Basin.

On March 17, 1982, a directional CO_2 production well at Sheep Mountain (Well 4-15-H) blew out during coring operations. The well flowed for 18 days at an estimated rate of 11,000 tonnes/day (200 MMcfd) of CO_2. Total emissions from the blowout were estimated at 190,000 tonnes, or 3.6 billion cubic feet (Bcf) of CO_2. The CO_2 vented out of surface rock fractures on the slope of a hill directly above the drill site. (Figure 1)

Figure 1. Flow Path of Sheep Mountain CO_2 Well Blowout



This well blowout occurred early in the Sheep Mountain field's life, when pressure in the field was still high, and the subsurface structure was poorly understood. The underground blowout apparently occurred at the base of surface casing (84 m), with the released CO_2 connecting with offset wells and surface fissures. The blowout was induced by reduction in mud weight to remove solids for improved coring.

The operator was initially unable to control the well by injecting overbalanced fluids (generally the simplest solution) because the small tubing size of the well (11.4-cm or 4.5-in) caused excessive frictional pressure losses. Instead, the well was finally controlled by use of dynamic control technology where the frictional pressure was reduced by adding friction reducers to the $CaCl_2$-brine fluid. Approximately 1,500 barrels of fluid were required to control the well. This mixture was injected through a snubbing unit at a rate of 570 cubic meters per hour down the production tubing. This well was then plugged and abandoned. Fortunately, no adverse environmental or health impacts occurred in this sparsely populated area.

The incident demonstrated that industry's well control techniques can be successfully applied to CO_2 production and (by analogy) injection.

Unlike the over-pressured Sheep Mountain field, some of the future CO_2 storage sites are likely to be depleted oil and gas fields, with lower risk of blowout during injection, and will have much more geological data. However, because saline formations are already, in general, at hydrostatic pressure, CO_2 injection will entail high pressure, calling for additional reservoir characterization and safety measures to assure safe options in these types of CO_2 storage reservoirs.

Source: Stevens, 2005.

The implications of production- and withdrawal-induced faulting for CO_2 remediation conclude that, once faulting has been induced, water injection or pressure maintenance programs may not cause faulting to stop. The subsidence at the nearby Ekofisk field was not quelled, nor even slowed, by water injection. In fact, in this case, water injection merely exacerbated fault plane slippage and subsidence. In general, there will be a need for conducting stress and poroelastic analysis to screen candidate storage reservoirs prior to CO_2 injection. Moreover, storage should be avoided in reservoirs where stress and pore pressure data indicate active faulting under original or depleted conditions, e.g., as indicated by well casing shear during development.

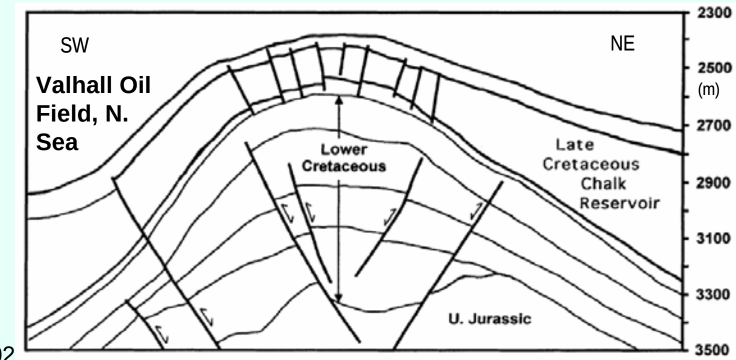
e) *Leakage Due to Post-Storage Disruption.* After the CO_2 storage site has been filled and successfully capped, it is still possible that future human activity may disrupt the field and cause CO_2 leakage. For example, future petroleum exploration or mining activity may penetrate the CO_2 zone.

Sidebar 5 provides an example where production and changes in operating pressure may create faulting.

SIDEBAR 5. EXAMPLE OF PRODUCTION RELATED FAULTING

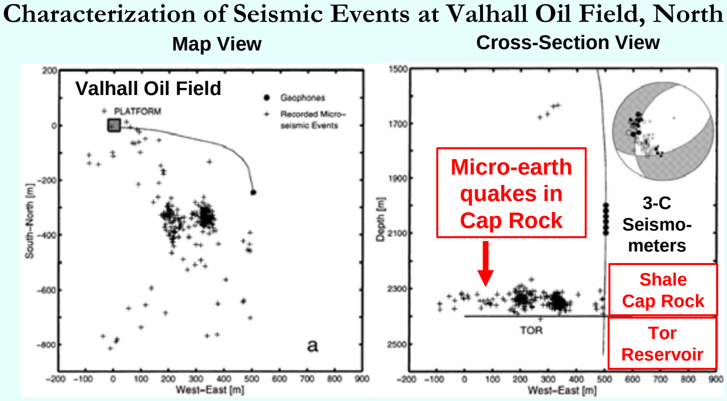
Under certain conditions, oil field production operations can induce faulting within a field. The initial reservoir study of the Valhall and Ekofisk oil fields in the North Sea showed that normal faulting existed on the crest of the structures in these two fields. Reservoir depletion appeared at Ekofisk to create faults on the flanks (Figure 1). Passive seismic monitoring at these fields measured micro-earthquakes which corroborated active normal faulting (Figure 2).

Figure 1. Nature of Production Related Induced Faulting – Valhall Oil Field, North Sea



Zoback & Zinke, 2002

Figure 2. Characterization of Seismic Events at Valhall Oil Field, North Sea



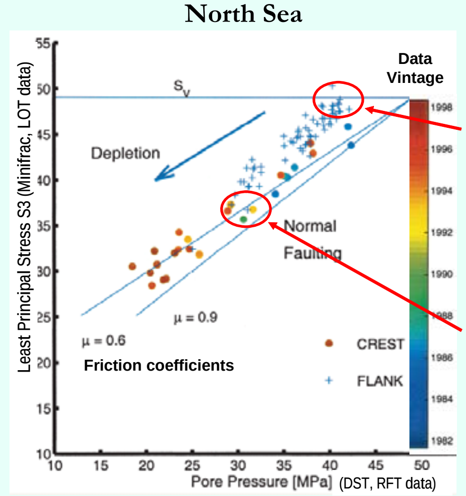
Zoback & Zinke, 2002

The production-related induced faulting at the Ekofisk Field was identified based on problems associated with sheared well casings, subsidence, and gas leakage through the caprock. The 15 years of reservoir depletion reduced the pore pressure in the reservoir (Figure 3).

Initially, stress on the crest was high enough to cause active normal faulting over geologic time, although these faults appeared to have sealed (approximately 30 to 40 MPa). Production operations caused the stress regime to cross into normal faulting regime (<30 MPa) as the reservoir was depleted.

Injection of water and the maintenance of pore pressure in the reservoir would have helped mitigate the induced faulting.

Figure 3. Least Principal Stresses vs. Pore Pressure for Tor Reservoir at Valhall Oil Field, North Sea



E. EXAMINATION OF RISKS FROM CO_2 LEAKAGE

Approaches for remediation for CO_2 leakage should be based, at least in part, on the risks this leakage can pose. Given the long history of industrial experience with handing and using CO_2, the health risks associated with CO_2 exposure are well understood. Humans can tolerate exposures of up to 1% CO_2 (10,000 ppm) with no adverse effects. Significant effects on respiratory rate and physical discomfort is experienced at concentrations approaching 3-5% CO_2, and death is imminent at concentrations greater than 30% for several minutes. These concentrations serve as the current basis for federal occupational safety and health set standards for CO_2 exposure in the workplace (Benson, et al., 2002).

In most instances, even where large releases of CO_2 have occurred, these releases have been quickly dispersed into the atmosphere, and have not resulted in any significant hazard. Significant risks do exist in situations where released CO_2 is not effectively dispersed, such as at Lake Nyos. However, these situations have been rare.

In addition to concerns about CO_2 exposure to human populations, potential ecosystem impacts need to be considered. Ecosystem impacts pertain to the effects of elevated CO_2 concentrations on the soil system (roots, insects, burrowing animals), or impacts on deep geological ecosystems. Soil system impacts relate to the physiology, ecology, and likely responses of animals, plants, and microorganisms at the surface and in subsoil ecosystems. They can also pertain to emerging risk considerations about impacts on subsurface microbial organisms.

Sidebar 6 provides a case study of a naturally leaky geologic CO_2 storage system and an examination of its long-term impact.

SIDEBAR 6. A NATURALLY LEAKY GEOLOGICAL CO_2 STORAGE SYSTEM

An in-depth study of leaky CO_2 reservoirs in the northern Paradox Basin, Utah (USA) provides valuable information on: (1) the subsurface CO_2 migration and flow system; (2) how CO_2 reacts with ground water and reservoir rocks in the subsurface; and (3) the effects on surface environments when CO_2 leaks to the surface. Insights from this "leaky system" for designing mitigation strategies will help establish more accurate risk assessment models and procedures.

1. *The CO_2 Migration and Flow System.* The natural CO_2 stems from clay-carbonate reactions in deeply buried Paleozoic source rocks in the Paradox Basin.

   As the CO_2 migrates upward through fractures related to the fault damage zone, it accumulates in a series of shallow sandstone groundwater reservoirs. As the accumulation of CO_2 builds, the CO_2 saturated water and free CO_2 escape into the atmosphere through a series of springs and geysers along the faults, Figure 1.

2. *Role of Abandoned Wells.* The natural leakage of CO_2 through the fault-related fractures has occurred for more than 150 years. The accumulation of carbonate minerals has been insufficient to seal these naturally occurring fractures. The subsequent drilling of oil, gas and water wells (now abandoned) provided pathways for more rapid transport of CO_2-charged groundwater to the surface. Most of the wellbore leakage is from abandoned oil and gas exploration wells and no record exists of the kind of cement or casing that was used in these wells.

3. *Effects of CO_2 on Subsurface Groundwater and Rocks*. The groundwater in the vicinity of the CO_2 leaks is saline and slightly acid, with 14,000 to 21,000 mg TDS per liter and with pH values of 6.07 to 6.55. The water appears to be supersaturated with respect to carbonate phases resulting in carbonate precipitation.

4. *Effects of CO_2 Leaking to the Surface.* At the surface, the rapid degassing of CO_2-charged groundwater results in the formation of travertine mounds around the active springs. However, only about 10% of the leaked CO_2 appears to be trapped by travertine mineralization. The bulk of CO_2 escapes to the atmosphere.

   The study's principal investigators, that included participants from earth science departments at three universities (Utah State University, Trinity College and Saint Louis University), found "no evidence of adverse effects of this leakage on wildlife or humans."

   The CO_2 geyser and springs provide somewhat saline water for plants in the high desert environment. In addition, the initial observations showed that there was little or no impact on the local biological ecosystems, with no observed changes in plant growth around any of the leakage sites. The CO_2 effusion has resulted in no reported casualties even though the area is visited by locals and tourists.

SIDEBAR 6. (Cont'd)

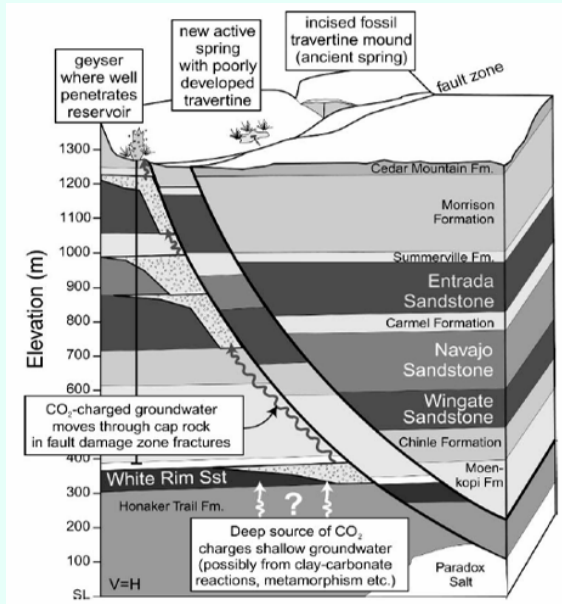
5. *Lessons Learned from "Leaky Systems" for Safe, Secure CO_2 Storage Site Selection.* A series of lessons can be learned from studying this naturally leaky CO_2-charged systems:

    - Faults and fracture systems can pose a leakage risk to a geological storage site. As such, detailed structural characterization and an understanding of caprock integrity will be essential for any project.

    - The presence of older wells and their relationship to the storage reservoir, as well as to the shallower leakage trapping reservoirs, must be clearly defined and, where necessary, remediated with modern well plugging and abandonment procedures.

    - Ground water flow can transport CO_2 for considerable distance before the CO_2 reaches the surface. As such, a more complete understanding of the groundwater hydrology and flow paths would help define the transport of any CO_2 that may leak from a CO_2 storage site.

Figure 1. Schematic cross-section of a typical oil and gas field showing how faults can act as seals or barriers to movement.



Shipton et al., 2005

In addition, geologic CO_2 storage and leakage from reservoirs may lead to the dissolution of metal from minerals and the mobilization of these metals by the aqueous phase, along with the potential concentration of organic compounds in the supercritical CO_2, due to its solvent properties. Undesirable impacts could also arise from the displacement of saline fluids into shallower potable water zones by the injected CO_2. Initial research efforts are underway to understand the likelihood, rates and consequences of these processes, which should subsequently help guide appropriate approaches for remediation, if necessary.

One important category of risks is related to the health and safety of workers and, possibly, those that may live or work near a large CO_2 storage field or operation. These are risks associated with handling large volumes of CO_2. Fortunately, this is one area where we can take advantage of the long history of industrial experience in understanding and addressing potential operational risks associated with handling, injecting and storing large volumes of CO_2. As such, the risks are generally well understood, and primarily relate to the effects of CO_2 exposure, or the effects of CO_2 management at very high pressures and temperatures.

Operational risks are the primary risks addressed by analogous operations today, and occupational standards have been established to address these risks. Risks to local populations will also need to be addressed, with the primary concern being sensitive populations near the CO_2 storage site. Addressing these risks will generally involve implementing processes and procedures to minimize CO_2 releases, as well as CO_2 control and response procedures to deal with the risks should releases occur.

III. SITE SELECTION AND RESERVOIR SCREENING

A. INTRODUCTION

The dominant strategy for leak prevention and remediation is obviating the need for remediation in the first place, by selecting storage sites that have an extremely low risk of leakage over geologic time. In selecting geologically favorable, safe and secure storage sites, five considerations stand out:

- Caprock (Seal) Integrity. Does the proposed reservoir's caprock and bounding layer(s) have sufficient thickness, low permeability, and no faulting to serve as essentially a permanent seal for stored CO_2?

- Assured Natural Confinement. Does the proposed storage reservoir have a structural component or other mechanisms that would confine the updip migration of CO_2? Has the reservoir site been selected in areas or where tectonic activity would not potentially compromise storage confinement?

- Assured Wellbore Integrity. Are there any older producing or abandoned wells in the expected path of the CO_2 plume? To what extent have the wells been designed for safe, long-term operations involving CO_2 injection? Will the procedures for plugging and abandoning the CO_2 injection wells assure essentially no leakage?

- Sufficient Reservoir Storage Capacity. Will the proposed geological formation be able to store sufficient volumes of CO_2 without exceeding a "spill-point" or reaching an escape conduit?

- Sufficient Reservoir Injectivity Rate and Safe Pressures. Will the proposed geological formation accommodate sufficient rates of CO_2 injection and pressure without creating fracturing or other leakage pathways?

These five topics and their associated questions form the substance of the discussion in this chapter.

In addition to the geological criteria for preventing leakage, which are the primary site selection criteria that are the focus of this report, it is important to recognize that, in case there is leakage, surface/shallow subsurface characteristics, such as topography, presence of sensitive areas (nature reserves, etc.), population density, and presence of groundwater aquifers (used for drinking water supplies etc.), may also be of importance for the screening process.

B. KEY CO_2 STORAGE SITE AND SUITABILITY STEPS AND CONCERNS

When examining the sustainability of a geologic formation to store CO_2, the first step is gathering detailed geological and reservoir data, both local and regional. This will help provide the essential understanding of the expected long-term (100's to 1,000's of years) movement and storage of the injected CO_2 in the subsurface. When evaluating sites for their potential to store CO_2, in addition to calculating the volumetric size of the repository, it is also important to quantify the reservoir's trapping and storage mechanisms. As such, the quantification of a reservoir's ability to receive, maintain and store the CO_2 within the geologic unit provides the foundation for selecting a suitable site.

After the initial characterization of the storage site, it will be important to verify and, if needed, modify the initial assumptions on the location flow and storage of CO_2. This can be accomplished with available reservoir engineering methods (such as well testing and pressure measurements) during the injection of CO_2 and rigorous flow following the injection of CO_2. Technologies that help monitor the location and movement of CO_2 include modeling (Jazrawi, et al., 2004), time-lapse (4-D) seismic (Arts, et al., 2004), observation wells, soil (Norman, et al., 1992) and air sampling (Anderson and Farrar, 2001), and natural tracers (Hoefs, 1987), as further discussed in Chapter IV.

1. Evaluating Potential for CO_2 Migration and Leakage of CO_2. Loss of CO_2 from within a geologic storage site can occur in two primary ways - - lateral migration of the gas away from the injection site and vertical leakage toward the subsurface.

a) *Lateral Migration*. The lateral migration of CO_2 in a dipping geologic formation will generally be updip, until it reaches a confining structure. Should the migrated CO_2 encounter a setting with an inadequate caprock or a natural break in the overlying caprock before reaching a confining structure, the CO_2 can then escape (leak) vertically through the overlying formation. As such, it is important to not only develop a sound understanding of a reservoir's caprock in the vicinity of the injection site, but also (particularly for saline formations) the integrity of the caprock for the larger regional area.

In addition, the potential "spill" points of the reservoir, as well as the geologic closure of the storage reservoir, should be rigorously defined. It is important to note that lateral migration of CO_2 within saline reservoirs will occur without clear structural confinement through the normal dynamics of aquifer flow, while depleted oil and gas reservoirs generally have well defined structural closure.

b) *Vertical Leakage*. When considering vertical leakage of CO_2, there are two primary mechanisms: 1) seal failure; and 2) wellbore failure (Senior, et al., 2005).

- Failure of the seal can occur both naturally, through inherent flaws (faults and fractures) in the overlying caprock, and mechanically, through induced fracturing of the caprock during CO_2 injection. Therefore, considerable effort should be taken to ensure injection pressures, while sufficient to achieve efficient gas injection, will not promote induced fracturing. Finally, as CO_2 tends to rise due to density differences among the native reservoir fluids (water and oil), the permeability of the reservoir seal should be very low to preclude the permeation of CO_2 through the seal.

- Wellbore failure can occur in both the short- and long-term. In the near-term, poor or ineffective cementing of the well's casing strings, a problem that can be exacerbated with high CO_2 injection pressure, can create pathways for the gas to migrate vertically within the wellbore and into the overlying formation. Wellbore failure could allow the injected CO_2 to enter the potable water table as well as cause rapid release of CO_2 to the atmosphere. In the long-term, prolonged contact of the CO_2 with the wellbore cement and well casing may lead to degradation of the well completion and allow subsequent leakage and vertical migration through the wellbore.

2. Steps to Take to Minimize CO_2 Migration and Leakage. The potential for CO_2 migration and leakage need to be thoroughly addressed during the preliminarily screening of the reservoir and its caprock. The steps to take to minimize the potential for leakage will involve the following:

- Assessing the integrity of the caprock and any faulting and/or fracturing of reservoir seal and the overlying rock strata
- Evaluating the locations of structural closure and the gross storage volume contained within the structurally closed area
- Identifying the location and vertical penetration of all wells drilled in the vicinity of the potential CO_2 storage site
- Assembling key reservoir properties (thickness and porosity) for calculating net storage
- Assessing the reservoir's injectivity and safe operating pressure.

Each of these important site assessment steps are further discussed and developed in this Chapter.

C. SELECTING SAFE, SECURE AND FAVORABLE GEOLOGICAL SETTINGS

1. Assessing Caprock Integrity. Assessing the integrity of the caprock is one of the essential steps in site selection, especially when selecting a saline aquifer for CO_2 storage.

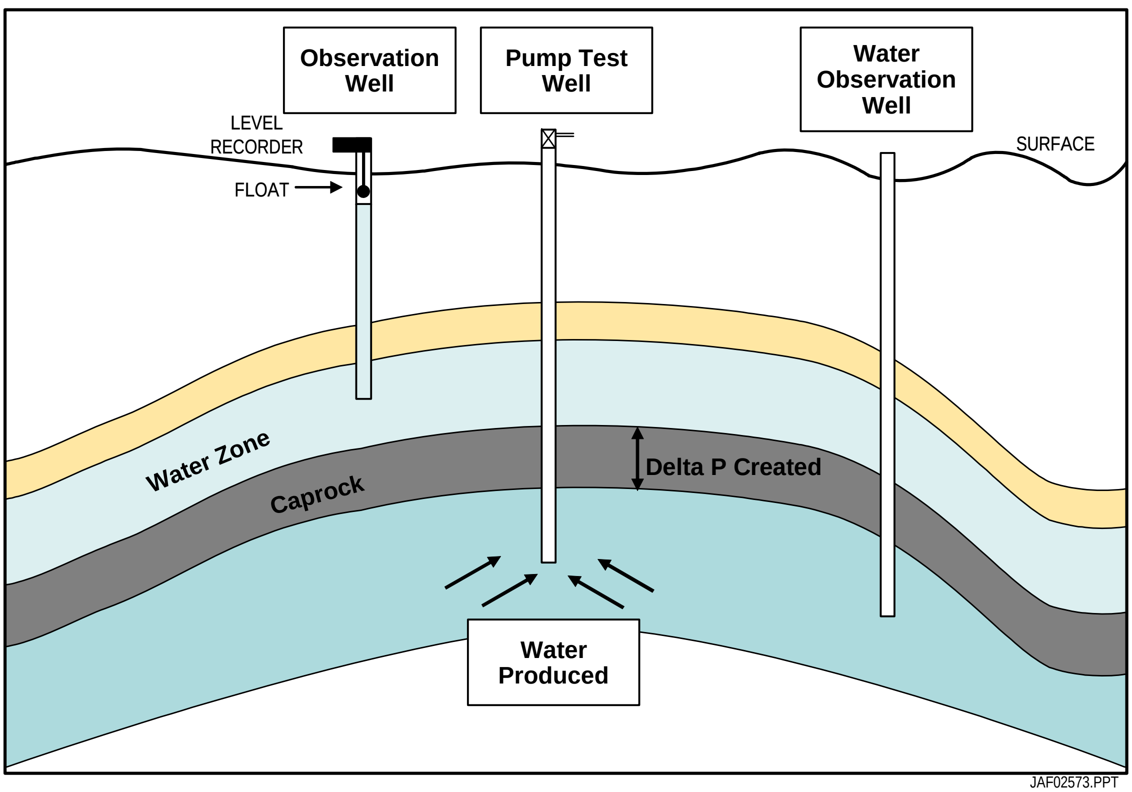
The first step is to develop a sound, overall understanding of the geological formations and particularly the regional extent of the caprock and the storage reservoir. This would be followed by undertaking a very detailed investigation of the geological formations at the storage site. Regional cross-sections are essential for understanding the regional extent of the caprock, as well as for identifying large anticlinal structures and other features that would contain and thus limit the movement of the injected CO_2.

Detailed log evaluations of the subsurface at and around the storage site will help place the local data into a regional context.

The second step is to take core samples of the caprock and test the samples for the threshold pressure of the caprock. This is particularly important for establishing the safe maximum bottomhole pressure during injection and storage of CO_2.

The third step is to conduct a series of permeability tests of the caprock involving water withdrawal from the zone below the caprock to create a pressure differential across the caprock. Any unexpected changes in pressure above the caprock would indicate the potential for faults or other paths of permeability whose presence would compromise the integrity of the caprock. Figure 3-1 illustrates the use of pump testing to assess the integrity of the caprock.

Figure 3-1. Pump Testing of a Potential CO_2 Storage Field to Assess the Integrity of the Caprock

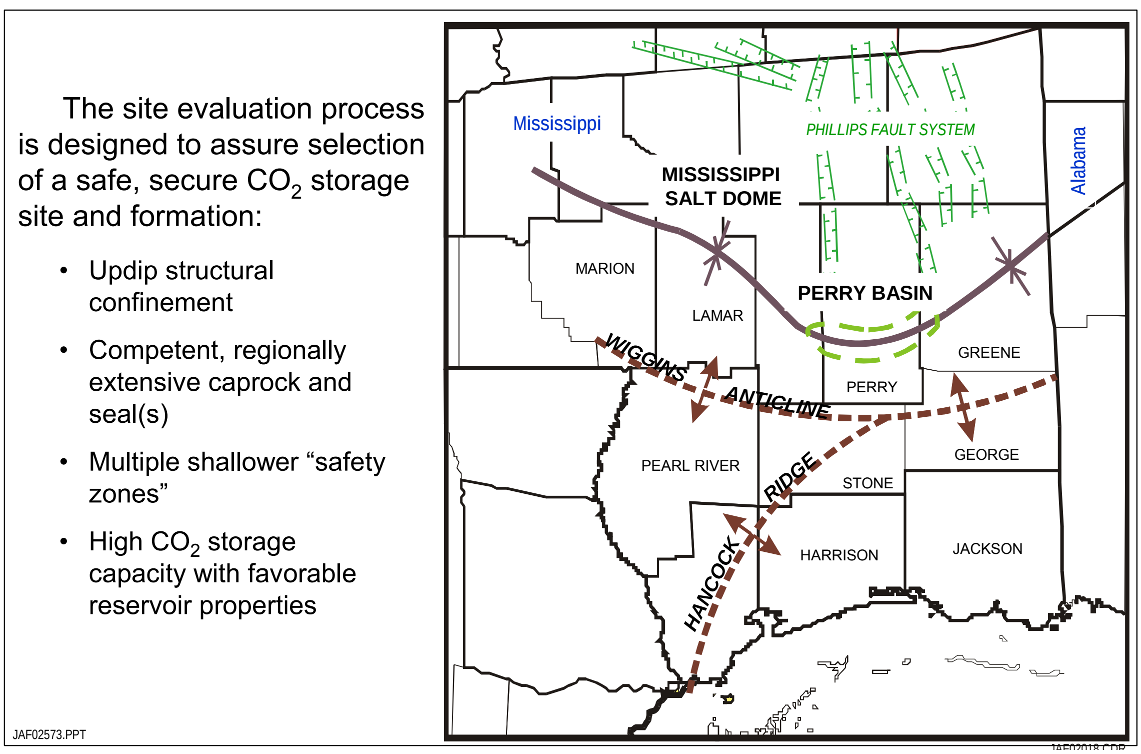


2. Assessing Structural Confinement. Structural confinement is a critical component for a safe, secure storage site. By definition, oil and natural gas fields have an established history of structural confinement. However, when assessing saline aquifers for secure CO_2 storage, structural confinement can often also be important to ensure storage integrity and certainty. The site assessment activity should look for two types of structural confinement:

- The first type of structural confinement is a distinct, classic anticline (dome) that would trap CO_2, much as the structures found over conventional oil and gas fields or used for establishing an aquifer-based natural gas storage field.

- The second type of structural confinement is an updip closure, created by an arch or a major discontinuity. Figure 3-2 for Southern Mississippi in the United States shows how the Wiggins Arch and Hancock Ridge provide important updip and lateral closure for the saline formations in the area.

Figure 3-2. Structural Confinement Evaluation for Southern Mississippi, USA



The areal and vertical extent of structural close can be established using traditional oil and gas field logs, high resolution surface seismic, and rigorously constructed cross-sections of the region and local site. Of particular importance is to map the formation dip and examine the updip structures that would control the overall volume of CO_2 confinement and storage.

3. Assessing Wellbore Integrity. The initial step for wellbore integrity is to identify the location and vertical penetration of all wells drilled in the vicinity of the potential CO_2 storage site. State oil and gas boards, geological surveys and private well record archives are the first place to look for the locations and completion records for abandoned wells.

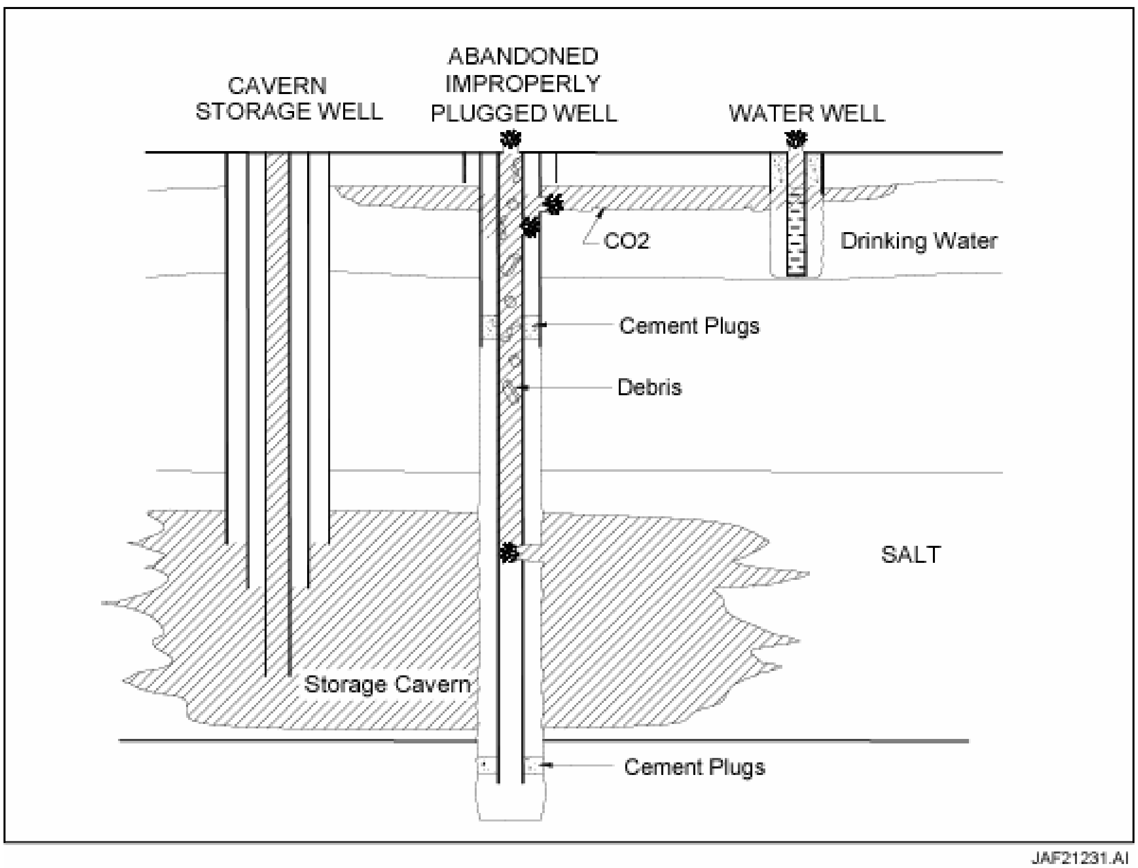
In some cases, particularly where the abandoned wells have been drilled some time ago and prior to more modern well recording and abandonment standards, it may be essential to independently locate the old, abandoned wellbores. New techniques, such as those being developed and tested by the U.S. DOE Carbon Sequestration Program provide one means by which to locate these older, poorly recorded wells that could create a CO_2 leakage pathway. More than likely, these independently identified wells will need to be properly recorded and re-plugged.

For wells whose locations are correctly identified in state or other records, and are (or will be) in the path of the CO_2 plume, it will be important to assess the completion methods that were used on the well, including:

- The extent and nature of well cementing (partial or fully to the surface), particularly for wells still in operation
- The specifics of the well casing, particularly across the interval of interest (if the casing is still in-place)
- The prior use of hydraulic fracturing (particularly in the interval of interest), to determine whether a hydraulic fracture may have created a leakage pathway though the caprock
- The actual well plugging and abandonment procedures that were recorded and used.

A properly plugged well should provide an adequate seal against fluid and CO_2 migration. However, as an example, the well depicted in Figure 3-3 was not properly plugged. The wellbore contains debris that may actually compromise the sealing qualities of drilling mud left in the tubing. CO_2 is depicted entering the central tubing, and exiting at the surface, and at a break. The CO_2 then migrates up the annulus between the tubing and the outer casing to a shallow porous and permeable aquifer. It then moves laterally and exits to the surface via a shallow well. While some aspects of Figure 3-3 are a worst-case situation, the figure depicts the concepts that CO_2 may migrate vertically by various paths within a single well, and laterally in porous zones to encounter another well.

Figure 3-3. CO_2 Migration in an Abandoned, Improperly Plugged Well.



In addition to undertaking direct observation of well integrity, it may be useful to conduct indirect observations, such as: (1) evaluating whether the surface areas around the plugged and abandoned wells indicate higher than normal concentrations of methane (for oil and gas wells); and, (2) whether there are indications of casing pressures (the presence of gas between the casing and the formation) for operating wells.

4. Assessing Favorable Storage Capacity. An ideal CO_2 storage site (or combination of closely located sites) would accommodate and accept CO_2 injection volumes for 30 to 50 years, equal to the CO_2 emissions from a plant (or combination of plants). For example, a single 500 MW coal-fired power plant, with annual CO_2 emissions of about 3 million tonnes (depending on the efficiency of the plant), will need on the order of 90 to 150 million tonnes of overall CO_2 storage capacity.

To provide some perspective on this capacity, we will translate this CO_2 storage requirement into oil and gas field terminology and benchmarks:

- Storing 100 million tonnes of CO_2 is equal in volume to a 1 billion barrels (original oil in-place and thus theoretical capacity) oil field (or collection of nearby fields).
- Only about 15% to 30% of this theoretical CO_2 storage capacity will be available following conventional oil recovery practices or be used under traditional CO_2-EOR activities.
- However, advanced CO_2-EOR and CO_2 storage designs could increase the usable storage capacity by several fold, as illustrated on Figure 3-4 and summarized in Table 3-1.
- As an example of advanced storage design, the CO_2-EOR and CO_2 storage project at the Weyburn oil field, with 1.4 billion barrels of original oil in-place, is planning to store 23 million tonnes of CO_2 during EOR, plus an additional 32 million tonnes of CO_2 as part of its CO_2 storage phase, over a period of about 55 years, Figure 3-5.

Table 3-1. Expanding CO_2 Storage: A Case Study

	"State of the Art" (millions)	"Next Generation" (millions)
CO_2 Storage (tonnes)	19	109
Storage Capacity Utilization	13%	76%
Oil Recovery (barrels)	64	180

Figure 3-4. Expanding CO_2 Storage: A Case Study

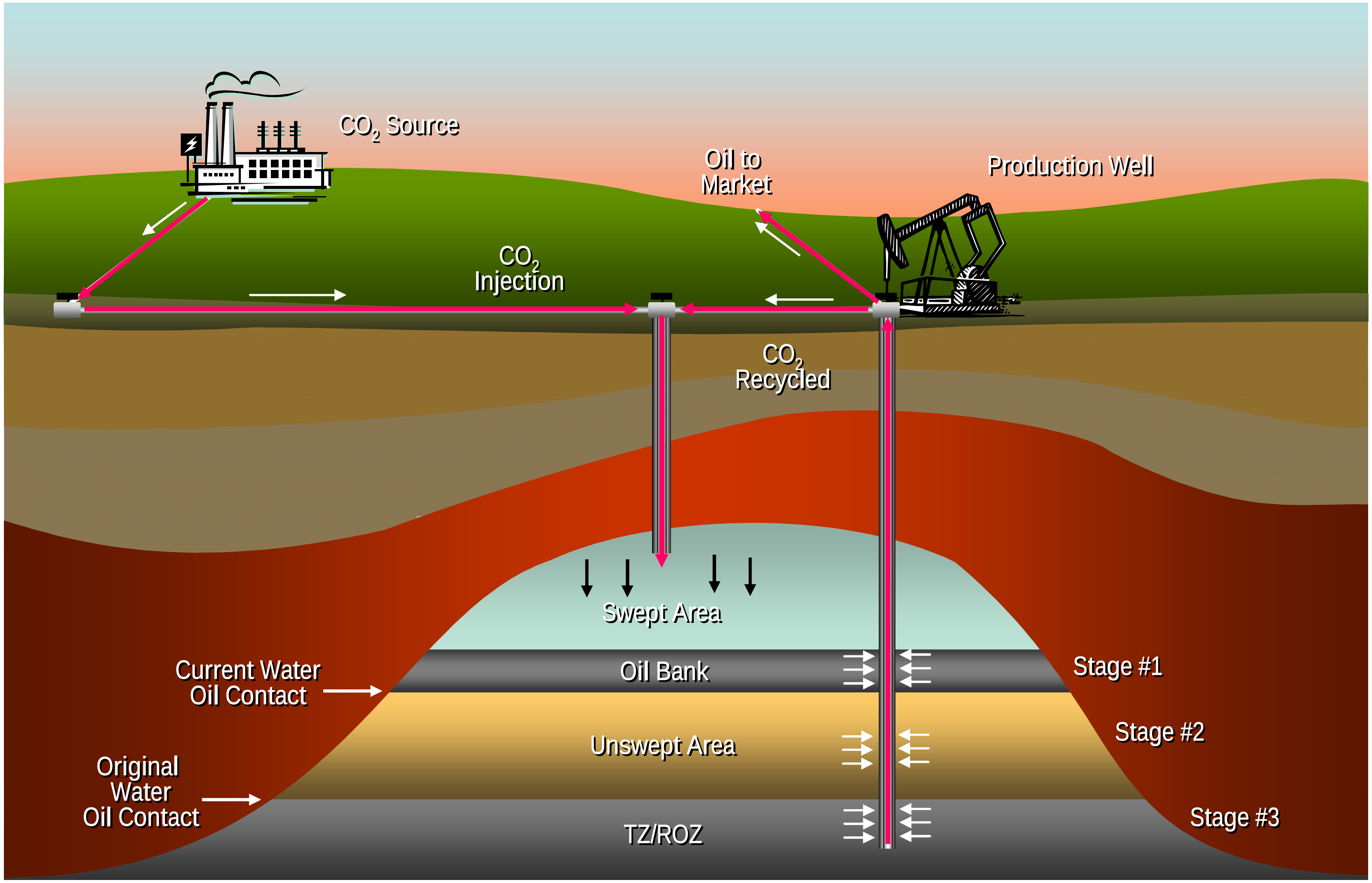
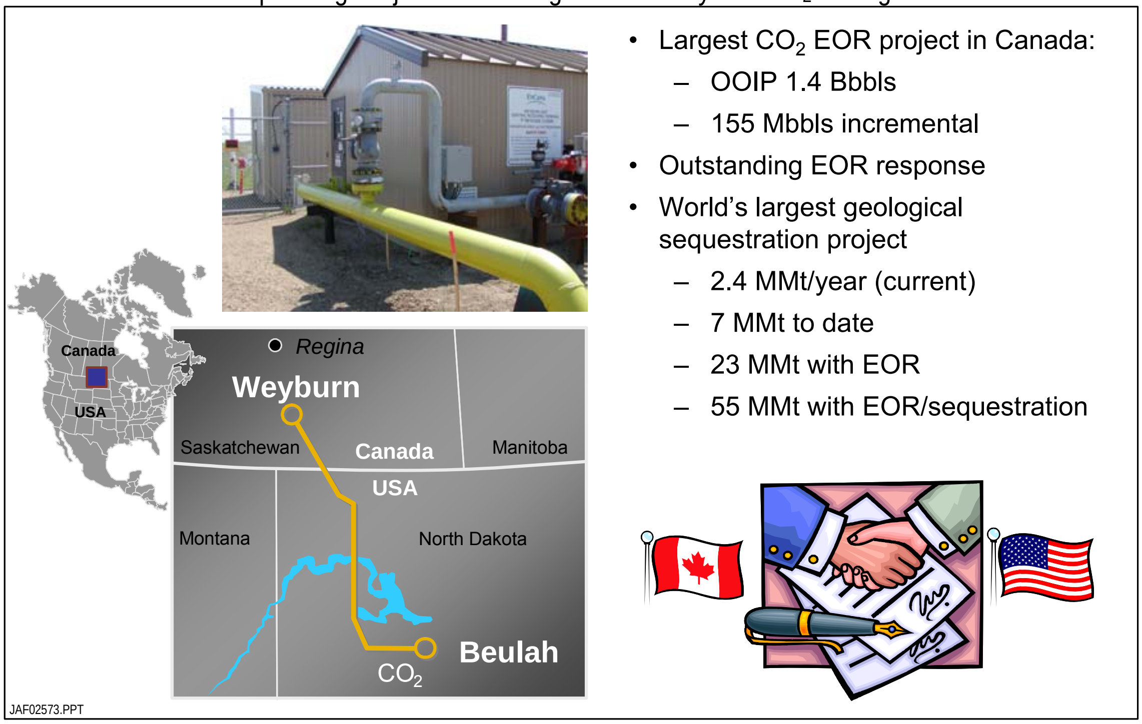


Figure 3-5. Weyburn Enhanced Oil Recovery Project.

An Operating Project Maximizing Oil Recovery and CO_2 Storage

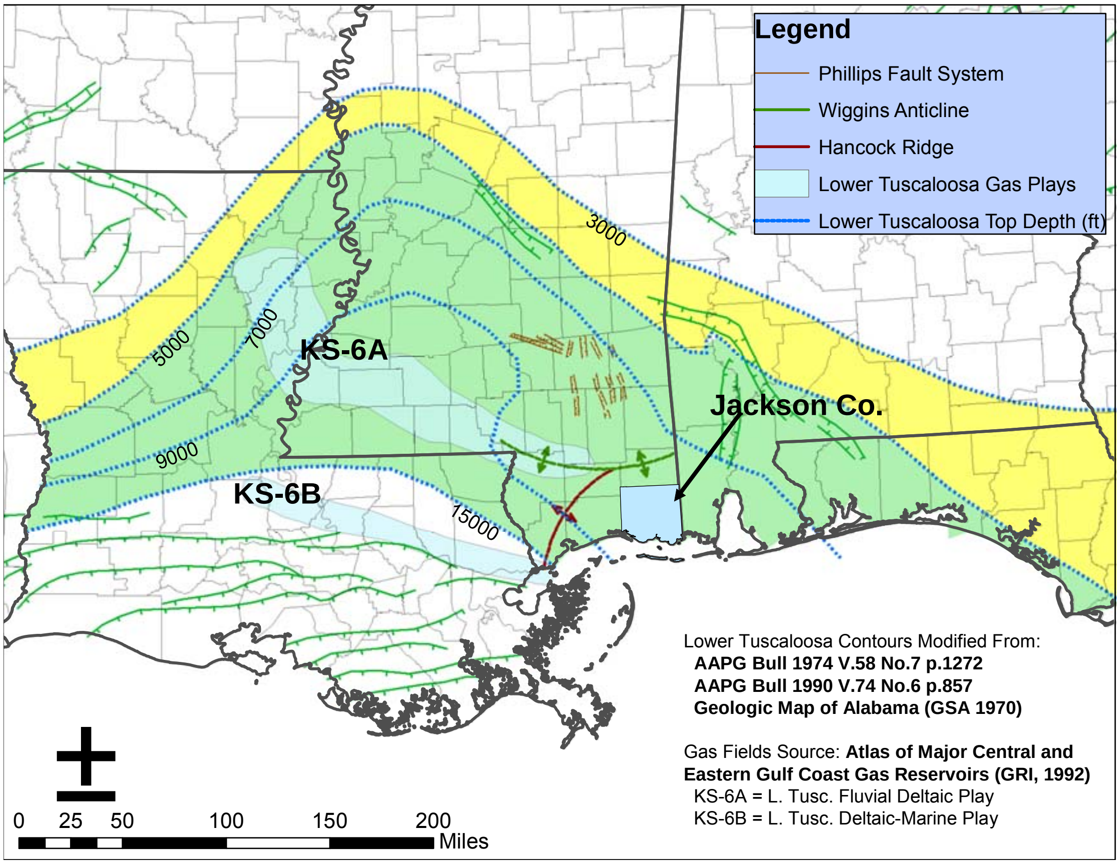


Saline formations can offer very high theoretical CO_2 storage capacity. For example, the Tuscaloosa Formation in Southern Mississippi offers several million tonnes of potential CO_2 storage capacity per square mile with up to 5 billion tonnes of CO_2 storage capacity in just one county (Jackson), Figure 3-6. Overlying and deeper saline formations could substantially increase this storage capacity.

However, only a moderate fraction of this storage capacity can be practically accessed using traditional well completion and CO_2 storage designs. Depending on the actual well design installed and the internal architecture of the saline formation, the practical storage fraction will range from a few percent to over 20 percent.

While "first-order" estimates of CO_2 storage capacity may be derived from using rules of thumb, full-scale reservoir simulation of CO_2 injection and storage will be required to establish a reliable value. Further discussion of modeling and calculating CO_2 storage volume is provided in Chapter IV.

Figure 3-6. Regional Extent of the Lower Tuscaloosa Massive Sand Unit



5. Assessing Reservoir Injectivity and Safe Operating Pressure. Once caprock integrity, structural confinement, wellbore integrity and storage capacity are addressed, assessing the reservoir's ability to safely accept CO_2 via injection is the next step in the evaluation process. The key reservoir parameters that control the injection rate of CO_2 are:

- reservoir permeability and relative permeability
- reservoir net thickness
- the current and the maximum safe reservoir pressure.

Many of the same tools and procedures for gathering information for establishing CO_2 storage discussed above will be used to collect geologic and reservoir data that will help define the CO_2 injectivity of the reservoir.

D. SITE SELECTION DATA SETS, TOOLS AND PROCEDURES

For purpose of efficiency, the geologic sites being evaluated for CO_2 storage would already have large existing regional and local data sets that could be used for screening the site and designing the storage container. However, these data sets will most likely need to be augmented by additional site specific geological data prior to drilling an expensive CO_2 injection well, particularly for deep saline formations that may have only regional geologic data available.

This section of Chapter III discusses the variety of site characterization tools and procedures that are available for undertaking the essential regional and local geological site assessment.

- ***Well Logging.*** Geophysical well logs are the "workhorse" of geological site characterization. They include resistivity, gamma ray, sonic velocity, and other downhole tools that can be used to evaluate the physical properties of the reservoir and caprock. Although some of the early exploration wells at a depleted oil and gas field may have logged the caprock, the later development wells will have generally logged only the reservoir. While commercial log libraries and state geological survey offices can be sources for past information and well logs, a new, comprehensive suite of well logs across the entire subsurface (from the top of the vadose zone to below the base of the storage formation) is highly recommended.

- ***Seismic.*** Seismic methods are a second, important tool for evaluating and monitoring geologic CO_2 storage sites (Hoversten, 2003). Surface and downhole 2D and 3D seismic data are useful in defining the basic structure of the storage field. Shear-wave seismic can help locate natural fracturing. 4D (time lapse) seismic can be used to monitor CO_2 movement, including leakage and migration of the CO_2 outside the confining structure. Cross-well seismic tomography is a more costly but also a higher resolution tool for tracking the location of the CO_2 plume between offset wells. The seismic tool(s) chosen will be site-specific, depending on data sets available, surface and sub-surface considerations, and budget. An important role of seismic will be to establish the potential for future CO_2 leakage through any faults and fractures that may exist in the area.

- ***Core Data.*** A field operator often takes cores from the petroleum reservoir, but generally not of the caprock itself. Core data is an important complement to well logging particularly for calibrating well logs. Core data also provides a wealth of information on the storage reservoir's porosity, permeability, fluid composition, and geochemistry. Many states have well-established core libraries or depositories to which industry has contributed their previously taken core samples. In settings where very limited or only old core data is available, new core samples, particularly of the caprock, will be most valuable.

- ***Regional Geologic Mapping.*** A geologic information system (GIS) provides an efficient and powerful way to comprehensively evaluate geological data to define the regional reservoir structure and caprock integrity. This step will be valuable for locating formation pinchouts, four-way closures, sealing caprocks, and other features that would minimize the risk of CO_2 migration and leakage. Likewise, a GIS can help identify geologic features such as leaky faults, facies changes in otherwise permeable sandstones or carbonates, structural saddles, and other geological hazards. A thorough vertical and horizontal regional mapping of the CO_2 storage area is essential for sound site selection.

- ***Well Integrity Assessments.*** The status and condition of all wells that penetrate the caprock and the reservoir at the storage site should be evaluated. Cement logs can help establish integrity of the current cement sheath. The location and status of abandoned wells need to be documented, measured, recorded and replugged, where necessary.

- ***Augmented Caprock Core.*** Whole core or less expensive sidewall cores may be gathered from a well drilled through the caprock of a CO_2 storage site, providing information on vertical permeability and the geochemistry of the crucial CO_2 – caprock interface. Efforts are underway to core the caprock at several natural CO_2 fields in the USA, which would be the first such attempt, and, when available, would provide valuable information on changes in caprock integrity with time. Detailed analysis of the core could show that the security of the CO_2 – caprock interface can be reinforced by chemical alterations and mineral precipitation.

- ***Augment Seismic.*** Additional new seismic acquisitions tuned for caprock characteristics rather than simply the storage reservoir could be taken. In addition, sequential VSP profiles could be run in offset observation wells to track the flow of the CO_2 in the reservoir.

- ***Isotope Geochemistry.*** Isotope geochemistry, particularly of stable carbon and noble gases, can be a powerful and low-cost tool for monitoring reservoir architecture, fluid flow, and leakage (Ballentine, et al., 2000).

E. EXAMINATION OF NATURAL AND INDUSTRIAL ANALOGS

Another source of data, valuable for understanding the risk of CO_2 leakage, are naturally occurring CO_2 deposits, underground gas storage sites, and CO_2 floods for enhanced oil recovery.

- ***Natural CO_2 Fields:*** The best engineered CO_2 storage site may well be a fully depleted natural CO_2 field (such as McElmo Dome). However, few such sites exist near anthropogenic CO_2 sources. Still, a well-defined natural CO_2 field could be evaluated as a predictive analog for a nearby depleted oil and gas field with similar reservoir and caprock geology. In addition, the geologic criteria extracted from natural analogs could be used to define screening criteria for CO_2 storage sites.

- ***Underground Gas Storage:*** Over 500 gas storage facilities have been developed worldwide in depleted oil fields and gas fields. Additional gas storage fields have been developed in aquifers, often in the same geological settings (such as the Mt. Simon Sandstone) that are candidates for CO_2 storage. Their experience with respect to leakage and other operational issues germane to CO_2 storage, investigated by Perry (2003), provides a valuable source of relevant information.

- ***EOR Projects:*** There has been more than three decades of CO_2 injection and monitoring experience in the oil fields of the Permian Basin, Rocky Mountains, and other areas. A particularly valuable study that has begun to examine industry's experience is the comprehensive study of CO_2-EOR projects performed by Grigg (2002).

Sidebar 7 to this report provides, in summary, the lessons learned from gas storage aquifers for CO_2 storage and site selection.

F. EVALUATING DEPLETED AND NEAR-DEPLETED OIL AND GAS FIELDS FOR CO_2 STORAGE

1. Geologic Screening Criteria. The primary screening criteria for selecting depleted oil and gas fields for CO_2 storage are: reservoir depth, maximum safe CO_2 injection pressure and bottom hole temperature (to enable CO_2 to be stored in a super critical phase); the presence of a competent seal (generally available in oil and gas reservoirs that have held natural gas for millions of years); sufficient net pay, porosity and area to provide a significantly large volume of storage capacity; and, the absence of seal penetrating faults that may become reactivated by geologic stress, either changes in natural stress or stress induced by the injection of CO_2.

In addition, the reservoir properties that would be most favorable for storing CO_2 would include: low current reservoir pressure; absence of a strong bottom water drive; high permeability; and a competent well infrastructure. Depleting oil and gas reservoirs (as opposed to a fully depleted, abandoned reservoir) will be more favorable because a quality infrastructure may still be in place, and ongoing CO_2 injection and gas production at the site may be more publicly acceptable.

SIDEBAR 7. LESSONS LEARNED FROM GAS STORAGE OPERATIONS FOR SITE SELECTION

A review of natural gas storage sets forth the following geological conditions essential for successful, safe storage:

- An impermeable caprock
- Rigorous mapping and remediation of all old abandoned wells
- An anticline with sufficient and clearly defined structural closure
- A porous and permeable reservoir with sufficient pore volume and depth to provide storage capacity.
- A sufficiently deep reservoir to provide safe distance from sources of potable water.

Caprock Leakage. All noted incidents of caprock leakage were associated with aquifer-based natural gas storage. Aquifer storage accounts for a relatively small (13%) of the natural gas storage installations in the United States, as shown below:

Type of Storage Site	Number of Sites	% of Total	Incidents of Caprock Leakage
Oil and Gas Fields	529	83.5%	-
Aquifers	80	12.6%	5
Salt Caverns/ Other	25	3.9%	-
TOTAL	**634**	**100.0%**	**5**

Each of these five incidents of caprock leakage occurred prior to 1980.

Abandoned Oil and Gas Wells. Natural gas storage operators give particular attention to evaluating the presence of abandoned oil and gas wells that could compromise the integrity of the gas storage site.

In spite of the potential problems with older wells, and the large number of depleted oil and gas fields being used for underground natural gas storage, only one incident of gas leakage is reported due to an old, improperly plugged well.

- In the 1970's, natural gas was detected as leaking from abandoned oil and gas wells in the West Montebello, California (USA) gas storage field.
- The leaked natural gas was trapped and thus accumulated in a shallower zone and did not reach the surface.
- The problem wells were plugged and the natural gas in the shallower zones may eventually be produced.

Structural Closure for Aquifer Storage. Gas storage operators spend considerable effort to select closed aquifer systems, with structural closure provided by dome-like formations sealed with an impermeable caprock. Natural gas (like CO_2) is buoyant, less dense than the water in an aquifer and will remain in the dome, preventing horizontal and lateral migration.

When selecting an aquifer with structural closure, it is important to establish the "spill point", the lowermost position of the dome that would prevent natural gas from spilling out and escaping structural confinement. The lack of proper definition and observance of the "spill point" led to one example of gas leakage.

In 1992, a salt cavern gas storage field in Benham, Texas (USA) was overfilled. Natural gas entered into an adjoining brine pit and then formed a low-lying cloud several hundred yards long. The released natural gas exploded, killing three people, injuring 21 people and causing $9 million (U.S.) of damage.

Source: Perry, 2003.

Oil and natural gas reservoir production can be classified into two types: (1) depletion drive, and (2) water drive.

- Under depletion drive, oil and natural gas flow out of the wells under their own pressure and oil/gas recovery is a function of the pressure decline. As such, depletion drive reservoirs with their low pressures at depletion and the small volumes of residual oil and gas are ideal formations for CO_2 storage.
- Under water drive, the water in underlying formations enters the reservoir as the oil and natural gas is produced, replacing the pressure decrease from production. Water drive reservoirs fill with water as the oil and gas is removed, limiting recovery of a portion of the oil and gas in the reservoir, filling the pore space with an incompressible fluid, and maintaining a higher reservoir pressure at depletion.

2. Identifying "Value Added" CO_2-EOR and CO_2 Storage Candidates. In some settings the potential for joint operations involving CO_2 storage and enhanced oil recovery (EOR) may be favorable, providing revenues to offset some or all of the costs of CO_2 storage.

Five prominent screening criteria can be used to identify the initial group of reservoirs technically favorable for joint EOR and storage of CO_2. These are: reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil composition. These values can be used to establish the minimum miscibility pressure for conducting miscible CO_2-EOR and for selecting reservoirs that would be amenable to this oil recovery process. Reservoirs not meeting the miscibility pressure standard can be considered for immiscible CO_2-EOR.

Additional screening criteria for selecting favorable depleted and depleting oil fields for joint CO_2-EOR and CO_2 storage are provided in Table 3-2.

Table 3-2. Screening Criteria for Joint CO_2-EOR and CO_2 Storage

Property Name	Relates To	Positive Indicators	Cautionary Indicators
Reservoir Properties			
$S_o Ø$	Oil Storage Capacity	≥ 0.05	< 0.05 Consider filling reservoir voidage if capacity is large
Kh (m^3)	Flow within the Reservoir	≥ 10^{-14} – 10^{-13}	< 10^{-14} If kh is less, consider whether injectivity will be sufficient
Seals	Permanence of CO_2 Storage	Adequate characterization of caprock, minimal formation damage	Areas prone to fault slippage
Oil Properties			
P (°API, kg/m^3)	Oil Density	> 22	< 22
μ (mPa s)	Oil Viscosity	< 10	>10
	Composition	High concentration of C_5 to C_{12}	Significant levels of aromatics

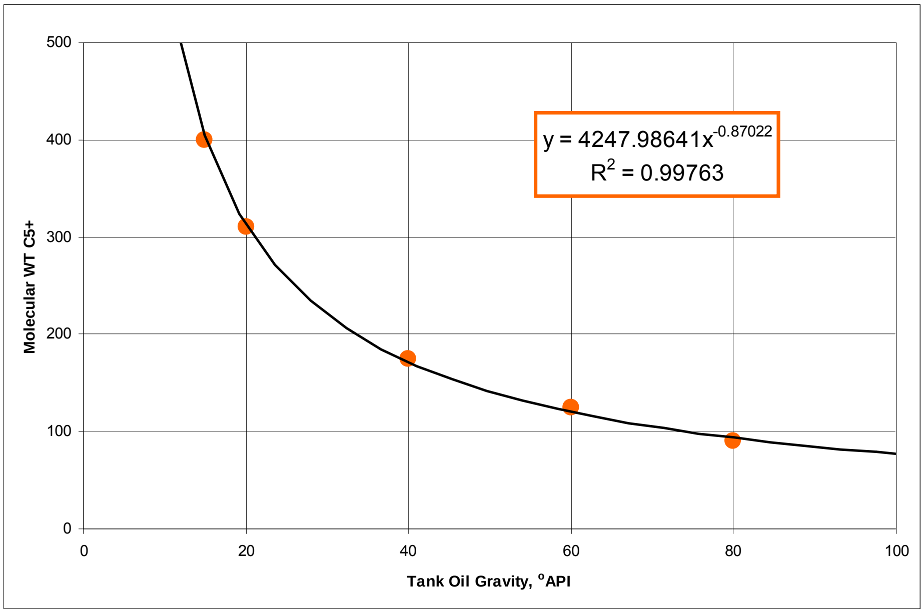
S_o = oil saturation, ø = porosity, Kh = permeability-thickness product
°API – degrees API gravity, μ = viscosity
Source: Advanced Resources International, 2004

a) `*Meeting the Depth and "Light Oil" Criteria*. The preliminary screening step involves selecting the deeper oil reservoirs that have sufficiently high oil gravity. A minimum reservoir depth of 3,000 feet, at the mid-point of the reservoir, may be used to ensure the reservoir could accommodate high pressure CO_2 injection. However, under other favorable conditions, such as a low temperature and high oil gravity, this strict depth limit may be relaxed. A minimum oil gravity of 20° API may be used to ensure that the first group of reservoirs selected have an oil that has sufficient mobility and may have favorable oil composition for miscibility.

b) *Meeting the Miscibility Criteria*. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and oil composition, is to determine whether the reservoir would hold sufficient pressure to attain miscibility. Where temperature and oil composition data are missing, correlations can be used to estimate these data.

If not available, the temperature of the reservoir can be estimated from the thermal gradient in the basin. Similarly the molecular weight of the pentanes and heavier fraction of the oil can be estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure 3-7.

Figure 3-7. Correlation of MW C5+ to Tank Oil Gravity



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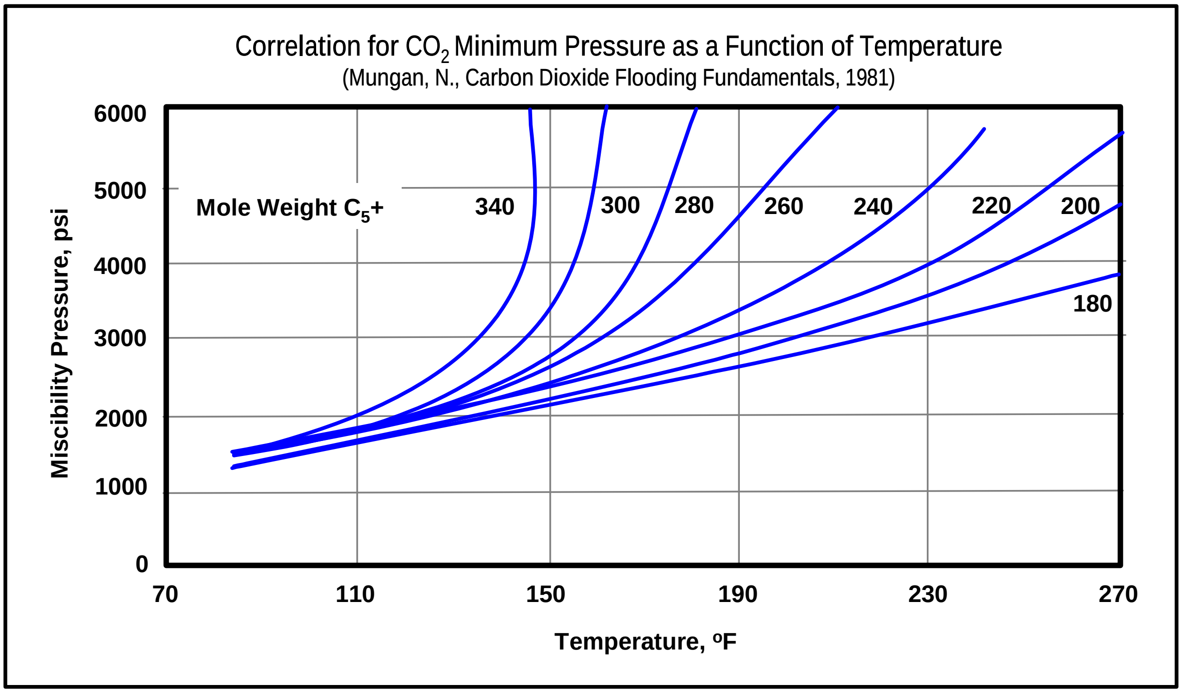
To determine the minimum miscibility pressure (MMP) for any given reservoir, one can use the Cronquist correlation or type curves. The Conquist formulation determines MMP based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil, without considering the mole percent of methane. (Most depleted oil reservoirs have produced the bulk of their methane during primary and secondary recovery.) The Cronquist correlation is set forth below and provides a reliable "first order" estimate for minimum miscibility pressure:

$$MMP = 15.988 * (0.744206+0.0011038*MW\ C5+)$$

Where: T is Temperature in °F, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

The type curves for estimating minimum miscibility, provided on Figure 3-8, have been developed by Mungan (1981) and have been used for twenty five years. They also provide a reasonable “first order” estimate.

Figure 3-8. Estimating CO_2 Minimum Miscibility Pressure



Ultimately, particularly when the safe maximum reservoir pressure is close to the minimum miscibility pressure estimated by the equation or the type curve, a more thorough laboratory investigation of the miscibility pressure of the reservoir’s oil is warranted.

c) *Meeting the Pressure Criteria*. Once the minimum miscibility pressure (MMP) for a given reservoir is calculated, the next step is to compare it to the maximum allowable pressure. The maximum pressure is determined from the reservoir’s fracture gradient, with an allowance for safety, and/or the regulatory allowed injection pressure. If the minimum miscibility pressure is below the maximum safe injection pressure, the reservoir is classified as a miscible flood candidate. Oil reservoirs that do not screen positively for miscible CO_2-EOR may be selected for consideration for immiscible CO_2-EOR or for regular storage of CO_2.

d) *Estimating Oil Recovery*. A critical step for evaluating the site is estimating the volume of oil that would be recovered using CO_2-EOR. A variety of methods may be used to provide an initial estimate of oil recovery. One reasonably rigorous method for providing a preliminary estimate is to utilize CO_2-PROPHET to calculate incremental oil produced using CO_2-EOR. CO_2-PROPHET was developed by the Texaco Exploration and Production Technology Department as part of a U.S. Department of Energy cost-share research program ("Post Waterflood CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir"; DOE Contract No. DE-FC22-93BC14960).

Once a first order estimate of oil recovery has been established using CO_2-PROPHET, a more rigorous evaluation needs to be undertaken using a full-scale compositional simulator to provide more confident, finer-grain estimates for oil recovery, CO_2 injection rates, water production, and well requirements and other key evaluation data.

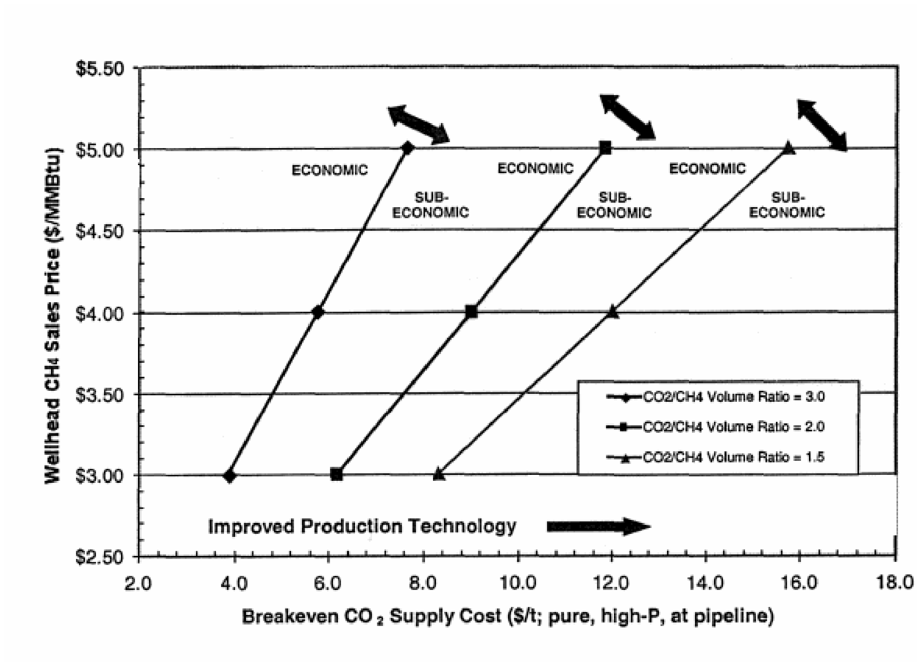
CO_2-PROPHET is available in the public domain, and generates streamlines for fluid flow between injection and production wells, and performs oil displacement and recovery calculations along the established streamlines. (A finite difference routine is used for oil displacement calculations.)

e) *Meeting the Economic Threshold*. In general, an oil field needs to be sufficiently large and offer promise of efficient use of the injected CO_2 to be selected for CO_2-EOR on a stand-alone economic basis. Credits or requirements for storing CO_2 would significantly change these economic criteria.

3. Identifying "Value-Added" Enhanced Gas Recovery (EGR) and CO_2 Storage Candidates. In some cases, it may be feasible to inject CO_2 for the joint purpose of storing CO_2 and enhancing gas recovery. Here CO_2 would be injected into a depleted or depleting natural gas reservoir at locations some distance from production wells. The CO_2 would displace the remaining methane in the reservoir toward production wells and create a pressure differential, thereby accelerating methane production and constraining water entry into the reservoir. The density and viscosity difference between CO_2 and methane would tend to limit the degree to which the two gases will intermingle and mix. The dense CO_2 would be injected at the bottom of the reservoir, while methane would be produced from the top. When CO_2 is injected in the lower portion of the reservoir, it tends to fill the reservoir, from the bottom as methane is produced form higher in the reservoir.

Work by Oldenburg, et al. (2004) provides an economic analysis of EGR. The key variables are the wellhead price for natural gas and the costs of (or credits for) storing CO_2. Figure 3-9 provides a breakeven cost analysis for a sample depleting natural gas field in California.

Figure 3-9. Economic Analysis of Enhanced Oil Recovery



There may also be benefits from CO_2 injection beyond additional gas production for reservoirs still under production. Injecting CO_2 can help maintain reservoir pressure, and thereby reduce water entry. The injected CO_2 may also prevent land subsidence, a problem in some fields.

G. EVALUATING SALINE FORMATIONS FOR CO_2 STORAGE

1. Geologic Screening Criteria. The primary CO_2 storage site selection criteria for saline formations are: sufficient depth (to assure that the CO_2 is in a highly compressed dense phase); sufficient reservoir thickness and porosity (to provide high local storage capacity); adequate permeability (to limit the number and location of CO_2 injection wells); and the presence of a competent caprock (to provide a safe, secure seal for the formation).

Like for other geological CO_2 storage sites, the most favorable saline aquifer sites would contain some geologic structure to help trap the CO_2 and would not be in highly faulted or fractured settings that would limit the aquifer area or that may compromise the reservoir seal.

In addition, it is important to establish the direction and rate of flow of the saline waters in the aquifer, map the surface exist points for the displaced water (if applicable), and define the nature of the geologic strata above the target CO_2 storage formation.

Key reservoir properties need to be assembled to calculate both theoretical and practical CO_2 storage capacity, as discussed previously. In addition, as further set forth below, these reservoir properties can also be used to calculate the daily and annual volumes of CO_2 that may be injected into the aquifer by one or more CO_2 injection wells.

2. Site Selection Procedures. Considerable geologic and reservoir study needs to accompany CO_2 storage assessments for saline aquifers. For example, there is need for:

- Structure contour, depth and gross interval isopach maps for each of the overlying reservoir seals
- Pressure, temperature and CO_2 phase diagrams for each CO_2 storage formation
- Geologic cross-sections to illustrate and define the characteristics of the key CO_2 storage reservoirs

- Sufficient assembly of data to enable a realistic estimate for each of the key CO_2 storage mechanisms, including estimating CO_2 in solution in the reservoirs' brines, CO_2 trapped in the reservoirs' pore space, and free CO_2 contained at the top of the reservoir's boundary layer(s).

In evaluating the storage site, it will be valuable to recognize that the extent of CO_2 trapping will vary according to the reservoir's pore structure and rock characteristics. Additional data collection and laboratory work will be required to reliably define this mechanism. In addition, structure and stratigraphy will enhance CO_2 storage volume and, over time, enable the CO_2 to go into solution via density inversion and flow.

Understanding and defining the reservoir boundaries are essential for estimating storage capacity in saline aquifers. Mapping of saline aquifer structure is essential for defining fractures that will help immobilize CO_2 movement.

In addition, there is a need to estimate CO_2 injectivity. CO_2 injectivity is controlled by permeability, net reservoir thickness, and pressure differential. The "pseudo pressure" flow equation used to calculate the CO_2 injection rate shows that for the particular reservoir conditions set forth in Table 3-3, about 18 MMcfd could be injected into a structurally unconfined reservoir.

Table 3-3. Calculating CO_2 Injectivity for a Saline Aquifer

$$q_{sc} = \frac{(\Psi_2 - \Psi_1)kh}{\gamma T P_t}$$

Where:		
	q_{sc} = CO_2 injection rate (MMscfd)	**(result) 18**
	Ψ_2 = maximum pseudo pressure (E+6psia^2/cp)*	190
	Ψ_1 = current pseudo pressure (E+6psia^2/cp)*	301
	k = permeability (md)	16
	h = thickness (ft)	100
	γ = constant	1.422×10^6
	T = temperature (ºR = ºF + 460º)	574
	P_t = 1/2(ln t_D+0.80907)*	11.6
	t_D = dimensionless time	

*Note: Standard reservoir engineering equations are used to generate the pseudo pressure values as a function of reservoir pressure, temperature, gas compressibility and the gas deviation factor.

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IV. MODELING CO_2 FLOW AND MONITORING CO_2 LEAKAGE

This chapter addresses two closely linked topics, modeling and monitoring. These two topics, when properly coordinated, can help avoid leakage of CO_2 and, should leakage occur, quickly establish its source and degree of risk.

A. MODELING CO_2 FLOW

The goals of a comprehensive CO_2 storage reservoir model are: (1) to predict how the CO_2 plume will flow and become physically trapped in the short-term; and (2) to understand the effects of chemical reactions (and other mechanisms) that will immobilize the CO_2 over the longer term. The basic capability to model fluid transport and, to some extent, chemical reactions within geologic reservoirs already exists. These models are currently used to manage secondary and tertiary oil recovery and to examine the long-term fate of underground hazardous waste disposal. Activities are underway to adapt these models to help plan, manage, and monitor geologic CO_2 storage.

The first step in modeling is characterizing in detail the CO_2 storage formation, using data from regional geologic assessments, well bore measurements, seismic surveys, and fluid samples. By including probabilistic data and assumptions, these models can be used to develop a range of possible CO_2 transport and reaction scenarios. The output from these models can be used to communicate the security of CO_2 storage to the public and regulating agencies. In addition, these models can be valuable for setting priorities for the monitoring and remediation strategies for geological CO_2 storage sites.

1. Phases of Reservoir Modeling. Reservoir modeling is an ongoing process and the models themselves will need to be updated as new information is gathered. We have set forth four key phases for the reservoir modeling process:

- The first phase of reservoir modeling needs to occur during the site selection phase, even though only regional data may be available by which to populate and constrain the model, and a significant range of uncertainty will exist with regard to the first phase modeling results.

- The second phase of reservoir modeling should occur after new information is obtained from the drilling of the first well or wells - - be they reservoir delineation wells, the initial set of observation and monitoring wells, or the CO_2 injection wells. At this point, considerably more detailed and local reservoir data will be available, particularly on the internal architecture of the CO_2 storage reservoir. With benefit of additional data, the range of uncertainty on modeling results will narrow.

- The third phase of reservoir modeling should occur after CO_2 has been injected for some period of time and the arrival of CO_2 is measured and/or detected in the near-by observation well or set of observation wells. At this point, valuable information is now available on the nature of CO_2 flow, the efficiency of the various CO_2 trapping mechanisms, and the progress of the CO_2 plume, providing greater confidence and certainty on modeling results.

- The final phase of reservoir modeling involves periodically revising the model based on post-injection observations of the CO_2 plume as well as observed changes in chemical reactions and the composition of the reservoir fluids.

The major CO_2 storage field tests, particularly at Sleipner and Weyburn, have gained significant insights by following this multiple-phase approach to reservoir modeling. Figure 4-1 shows the potential predictive capabilities of the models used in the Weyburn Field study (Jazrawi, et al., 2004).

Two additional reservoir simulation studies, undertaken as part of planning new CO_2 storage tests, further illustrate the value of reservoir modeling. Figure 4-2 shows how the modeling of CO_2 flow and trapping in two very distinct saline formations can enable the CO_2 storage operator understand the likely path of the CO_2 plume and craft an effective CO_2 injection and monitoring plan (GCEP, 2004). Figures 4-3 and 4-4 show the CO_2 flow and CO_2 saturation from running a 100-year reservoir model of CO_2 injection into a saline formation.

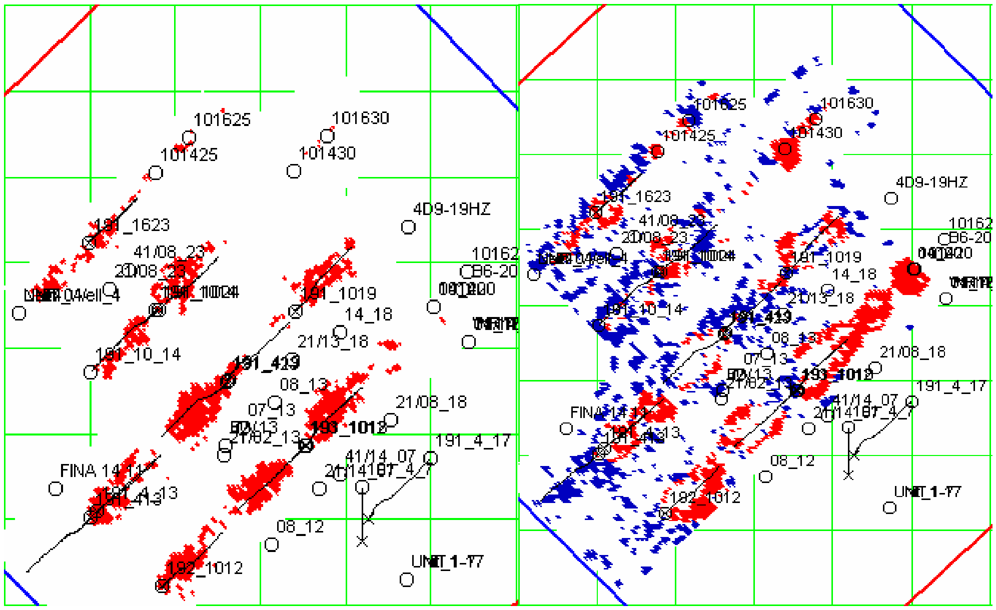

Figure 4-1. Comparison of Reservoir Simulation Versus Time-Lapse Seismic. Results are shown for the 9-pattern Phase-1A area of the Weyburn enhanced oil recovery field. Grid cells where both the seismic and simulator indicate increased CO_2 saturation are shown in red.

Source: Jazrawi, et al., 2004

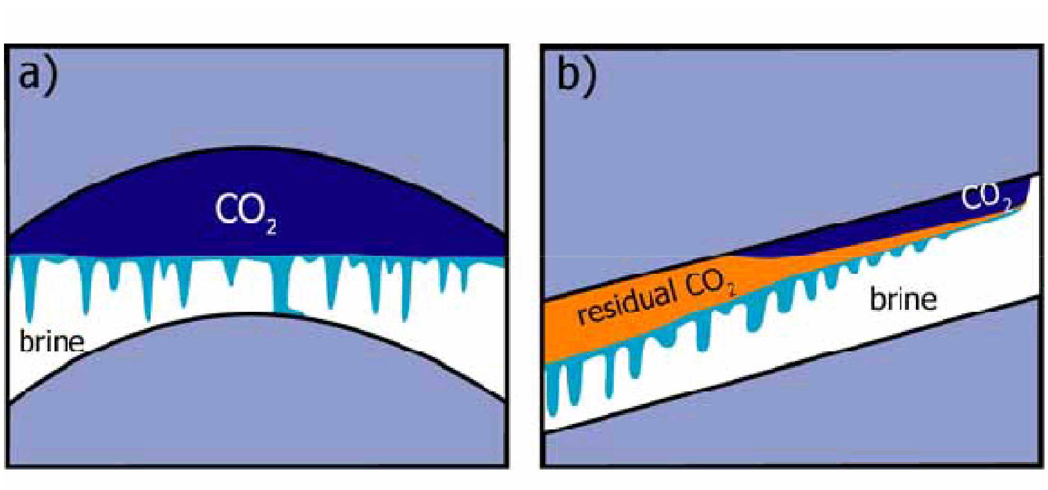

Figure 4-2. Schematic of CO_2 Dissolution in Two Aquifers. The mobile CO_2 gas phase is dark blue, the dissolved aqueous CO_2 is light blue, and the residual CO_2 is orange. In aquifer A, CO_2 gas is held under a structural trap. Dissolution of CO_2 into the brine and subsequent CO_2 saturated brine inversion reduces the CO_2 gas phase volume. In aquifer B, the CO_2 gas phase migrates along the top of a sloping aquifer, leaving behind a region of residual CO_2 trapped in the pore space and dissolved in brine.

Source: GCEP, 2004

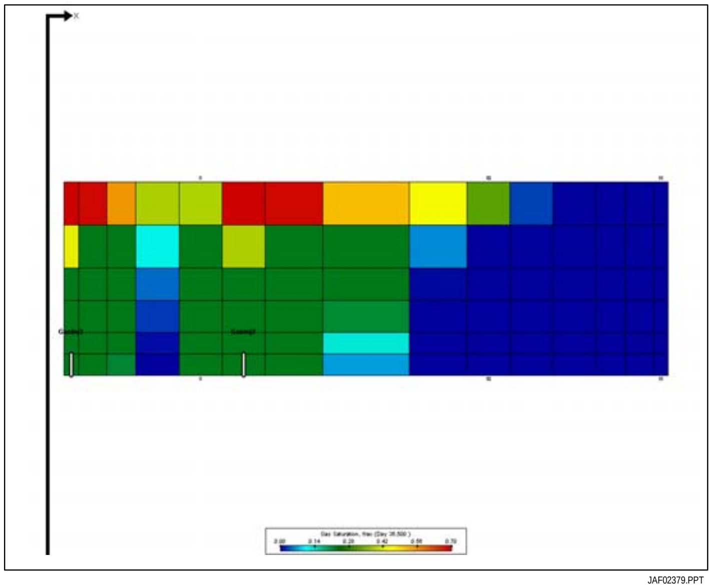

Figure 4-3. CO_2 Saturation and Concentration in a Saline Reservoir (Cross-Section, at 100 Years). CO_2 injection is on the left side of the grid.
Source: Advanced Resources, 2006

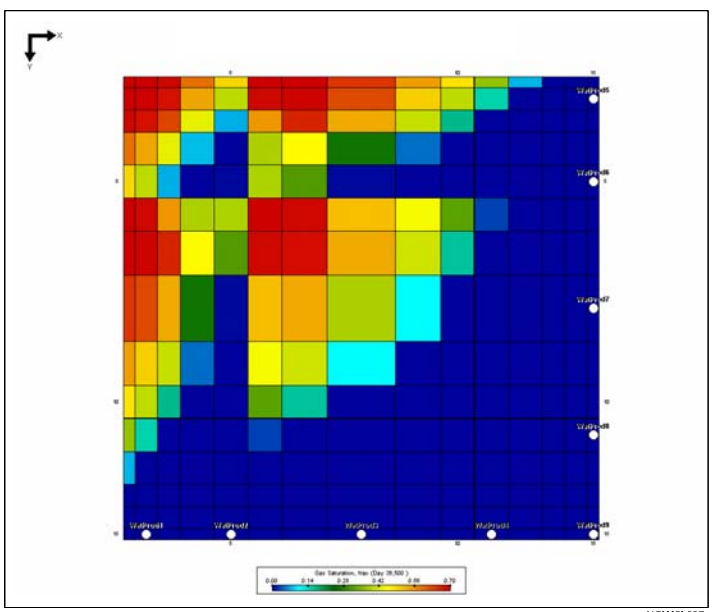

Figure 4-4. CO_2 Saturation and Concentration in a Saline Reservoir (Top Layer, at 100 Years). CO_2 Injection is in the NW corner of the Grid.
Source: Advanced Resources International, 2006

2. Available Reservoir Modeling Tools. A number of reservoir simulation tools, each with particular areas of strength and emphasis, are available for planning and managing CO_2 storage projects. On one end of the scale is COMET3, a general purpose, "user friendly" reservoir simulator that can evaluate CO_2 storage in all types of reservoirs. It is particularly suited for use in fractured reservoirs and for evaluating storage of CO_2 in coal seams or organic shale. At the other end of the scale are ECLIPSE and GEM, compositional reservoir simulators, particularly suited for complex modeling problems and storage of CO_2 with miscible-flooding.

In addition, a series of special purpose, research supportive reservoir models have been developed by research institutes, such as SIMEDII, SIMUSCOPP, TOUGH2, and UTCOMP. Table 4-1 contains a list of seven commercially available reservoir simulators capable of assessing CO_2 injectivity, capacity and flow as part of CO_2 storage (Law, et al., 2002; Pruess, et al., 2004).

Table 4-1. Reservoir Modeling Tools for Geologic Storage of CO_2

Name	Application	Organization
COMET3	• General purpose reservoir simulator with additional features for CO_2 storage modeling • Capable of handling fractured reservoirs, sorption-based gas storage (3 gas components) and two phases	Advanced Resources International, Inc. (ARI)
ECLIPSE	• Black oil simulator with additional features for CO_2 storage modeling • Capable of handling two gas components	Schlumberger GeoQuest
GEM	• Compositional simulator with additional features for CO_2 storage modeling • Capable of handling 3 or more gas components	Computer Modeling Group (CMG)
SIMED II	• Compositional simulator with additional features for CO_2 storage modeling • Capable of handling 3 or more gas components	CSIRO
SIMUSCOPP	• General purpose reservoir simulator • Capable of assessing environmental impact at geologic storage sites for CO_2 and other acid gases	IFP (Institute Francais du Petrole)
TOUGH2	• General purpose reservoir simulator with special gas module	Lawrence Berkeley National Laboratory (LBNL)
UTCOMP	• Compositional miscible-flood simulator with CO_2 solubility in brine formations	Center for Petroleum and Geosystems Eng. – UT

3. Estimating CO_2 Storage Capacity Using Modeling

a) Saline Formations. Estimating the CO_2 storage capacity of a deep saline formation is a relatively complex undertaking, requiring considerable baseline geologic data on the characteristics of the reservoir, as well as an in-depth understanding of the dynamics of water and CO_2 flow through the reservoir.

To accurately estimate CO_2 storage capacity in an aquifer, one needs to fully account for the main storage functions present in the reservoir, namely: (1) the solubility of CO_2 in the reservoir's saline water; (2) the trapped CO_2 in the pore space; and (3) the extent of free CO_2 and its distribution, generally along the confining layers of the reservoirs. Of particular importance is the characterization of the vertical heterogeneity of the reservoir and the selection of an injection well pattern that optimizes the long-term storage of CO_2 in the aquifer.

Sidebar 8. Illustrative Example of Estimating CO_2 Storage Capacity in a Saline Formation. This example shows that even with rigorously established CO_2 injection designs, only a small fraction, in this case 12%, of the theoretical CO_2 storage volume can be practically stored in a saline formation.

(1) *Calculating Storage Capacity*. The illustrative example in Sidebar 8 provides some guidelines and "rules of thumb" for estimating CO_2 storage capacity in saline aquifers and for performing certain of the key capacity calculations. The guidelines and "rules of thumb" are based on experiences gained from conducting a series of COMET3 reservoir simulation runs of CO_2 storage and flow:

- The first step involves setting forth the basic data for the storage reservoir.
- The second step involves defining the operating conditions for the CO_2 injection and storage project.
- The third step involves calculating overall storage capacity as well as the capacity provided by each of the three key storage mechanisms.

SIDEBAR 8. ILLUSTRATED EXAMPLE OF ESTIMATING CO_2 STORAGE CAPACITY IN A SALINE FORMATION

Basic Data.

- Reservoir properties:
  - 5,000 feet of depth
  - Slightly under-pressured
  - Porosity of 10%, for 90 feet of net sand
  - Temperature of 114° F
  - Salinity of water of 30,000 ppm
  - Vertical/horizontal permeability of 0.02

Operating Conditions.

- Assume an unbounded aquifer system
- Inject CO_2 into the aquifer for 25 years
  - 1.3 MMcfd per year
  - 25,000 tons per year
  - 11.9 Bcf/0.63 million tons, total
- Shut in the aquifer for 75 years
- Examine distribution of CO_2 and its concentration, at end of 100 years

The example calculation of CO_2 storage capacity, starting with estimating overall reservoir pore volume and ending with CO_2 storage by individual storage mechanisms, is set forth in Figures 1 through 4.

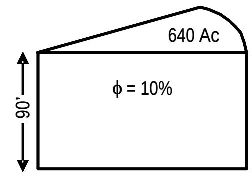

Figure 1

For sample reservoir, CO_2 in solution is 125 cf/bbl.

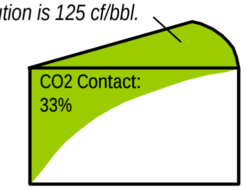

Figure 2

For sample reservoir, residual CO_2 in pore space is 18.3%.

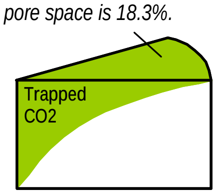

Figure 3

For sample reservoir, free CO_2 in pore space is 27%.

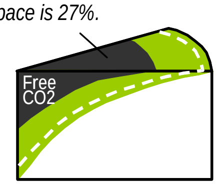

Figure 4

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1. Establish Reservoir Pore Volume. (Figure 1)

Pore volume = Area * Thickness * Porosity
= 640 Acres * 90 feet * 0.1 = 5,760 AF

Unit conversion (5,760 AF * 7758 B/AF) = 44.7 MMB reservoir pore volume

If all of the reservoir pore volume were filled with supercritical CO_2 (2.26 Mcf/barrel at 2,000 psi and 114°F), the reservoir would hold 101 Bcf, or 5.3 million metric tons CO_2.

Theoretical storage volume = 44.7 MMB * 2.26 Mcf/B = 101 Bcf
= 5.3 million metric tons

SIDEBAR 8. ILLUSTRATED EXAMPLE OF ESTIMATING CO_2 STORAGE CAPACITY IN A SALINE FORMATION (Cont'd)

2. Estimate CO_2 Contacted Pore Volume. Based on ARI's modeling of the example saline aquifer, only 33% of the reservoir comes in contact with injected CO_2. This is due to CO_2's buoyancy in a brine formation and its strong tendency to flow upwards. Figure 2 shows the shape of the CO_2 plume as the CO_2 travels upward and horizontal until it reaches the caprock.

3. Calculate CO_2 in Solution. The CO_2 dissolution mechanism provides storage in the portion of the reservoir in contact with CO_2, Figure 3. At 2,000 psi and 30,000 ppm TDS, 1 barrel of brine holds 125 cubic feet CO_2.

CO_2 in solution = total pore vol. * CO_2 contact * solution capacity in brine
= 44.7 MMB * 33% * 125 cf/bbl
= 1.8 Bcf (0.10 million mt CO_2)

4. Calculate CO_2 Trapped in Pore Space. The CO_2 trapping in pore space varies according to the nature of the reservoir's rock. In the portion of the reservoir contacted with CO_2, the amount of CO_2 trapped varies from a few percent to 23 percent, for an average of 18.3%.

CO_2 trapped in pore space = total pore vol. * CO_2 contact * CO_2 trapping factor * CO_2 volume factor
= 44.7 MMB * 33% * 0.183 * 2.26 Mcf/B
= 6.1 Bcf (0.32 million mt CO_2)

5. Calculate CO_2 in Free Phase. CO_2 that is not dissolved or trapped in pore space will remain as free phase CO_2 along the upper sealing boundary of the storage formation:

Free phase CO_2 = total CO_2 injected - CO_2 in solution - CO_2 trapped
= 11.9 Bcf – 1.8 Bcf – 6.1 Bcf
= 4.0 Bcf (0.21 million mt CO_2)

Figure 4 shows the free phase CO_2 within the contacted portion of the reservoir.

The table to the right shows the amount of CO_2 stored by the various mechanisms. The overall CO_2 storage in one square mile of area is 0.63 million metric tons. This is equal to 12% of the theoretical pore space volume of 5.3 million metric tons of CO_2.

CO_2 Storage Mechanisms	**Bcf**	**Million Metric Tons**
CO_2 in solution	1.8	0.10
Trapped Pore Space CO_2	6.1	0.32
Free CO_2	4.0	0.21
Total	11.9	0.63

(2) *Gaining Insights On Storage Capacity*. While the overall CO_2 storage capacity and role of each of the three storage mechanisms are only valid for the basic data and operating conditions of the sample saline aquifer, the example serves to illustrate the relative role of each CO_2 storage mechanism. In addition, the example begins to define the overall extent of the CO_2 storage requirements as well as the areal extent of the free and mobile CO_2 phase in the saline aquifer.

b) Oil Fields. Oil fields, involving a combination of CO_2-EOR and CO_2 sequestration, will likely be the most prominent initial geologic formations where CO_2 is stored. A "first-order", minimum estimate of CO_2 storage capacity in depleted oil fields can be estimated from the following equation, in terms of Mcf of CO_2:

CO_2 Storage Capacity = Area (acres) * Net Pay (feet) * Porosity * 7758 barrels/acre-foot * A (pore space, filled with mobile fluid, assume 0.7) * E (effective reservoir contact, assume 0.5) * 2 Mcf/barrel.

Note: The conversion factor of 2 Mcf/barrel of pore space may range from 1.5 to 2.5, depending on actual reservoir conditions. Mcf of CO_2 can be converted to metric tons of CO_2 by the factor 18.9 Mcf of CO_2 equals 1 ton of CO_2.

More precise estimates of CO_2 storage capacity in depleted oil reservoirs can be obtained by performing a reservoir simulation that incorporates the reservoir boundaries and allowable pressure buildup in the reservoir.

Increasing CO_2 storage (while optimizing oil recovery) is a goal worth pursuing and may be achieved by the following strategies:

1. Use well completions that reduce the adverse effects of preferential flow of injected CO_2 through high permeability zones, particularly toward the top of the reservoir. For example, should high permeability intervals be toward the top of the reservoir, the strategy would be to inject CO_2 at the base of the reservoir, enabling the CO_2 to vertically contact as much of the reservoir area as possible.

2. Optimize gas and water injection (timing, injection rates) to minimize CO_2 cycling and maximize CO_2 storage. While injection of water can impede preferential CO_2 flow through high-permeability pathways in a reservoir, thus improving the distribution of CO_2 throughout the reservoir, water can also block reservoir pore volume that otherwise would be available for or accessible by CO_2.

3. Consider injecting a portion of the CO_2 into the underlying aquifer, where present.

4. Consider using a gravity-stable CO_2 flooding design in reservoir settings where this approach appears feasible.

5. Undertake reservoir repressurization after the end of oil production.

One action to enhance CO_2 storage capacity would be to use partial completions in both injection and production wells or use horizontal wells to better distribute the injected CO_2. Because of gravity effects, completing injection wells low in the formation rather than over the entire reservoir column improves the contact of the CO_2 with a greater portion of the reservoir's volume. Production wells completed low in the formation also delay break-through of the CO_2.

CO_2-EOR operations often include water as well as CO_2 injection. This process is called WAG (water alternating gas) injection. In one version of WAG, alternate slugs of water and CO_2 are injected. In another version, CO_2 is injected continuously until significant CO_2 breakthrough. At CO_2 breakthrough, WAG injection is started. The benefits of WAG injection are several. First, gravity forces cause the water and CO_2 to sweep different portions of the pore space - - CO_2 generally gravitates to the top of the reservoir, while water contacts the lower portion. In addition, the presence of water reduces the mobility of the CO_2, thereby reducing CO_2 breakthrough. Further, sequencing of CO_2 and water injection across a large field offers significant opportunities for increased gas storage.

CO_2 could also be injected into an aquifer below the oil field instead of only into the oil zone. CO_2 injection into the aquifer may displace oil trapped in the transition zone between the water filled and the oil filled pore space, increasing oil recovery.

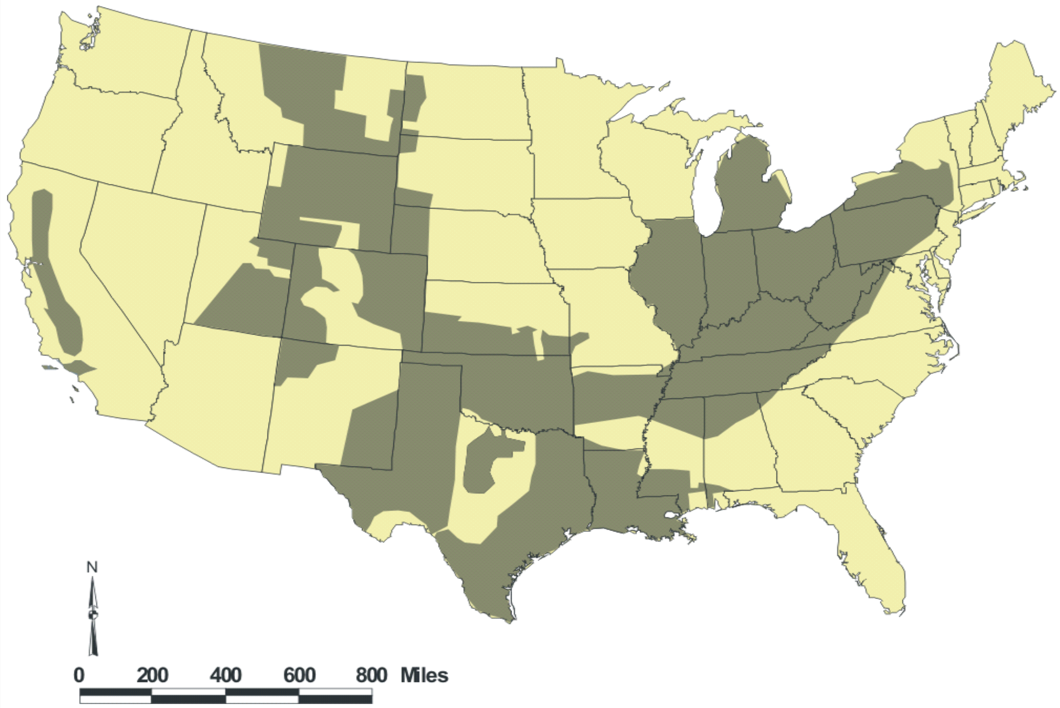
Finally, it is possible to continue CO_2 injection after oil production ceases. Further pressurizing the reservoir, provided that the reservoir seals are not damaged, allows substantial additional increase in storage.

c) Depleted Natural Gas Fields. Depleted natural gas fields, at or below 2,500 feet of depth, can also provide a favorable option for CO_2 storage. In general, these fields have been well characterized from prior well drilling and logging, may contain available distribution facilities and injection wells for CO_2, and should provide considerable assurance of long-term containment for the CO_2. In some cases, the injection of CO_2 provides the potential for enhancing and/or accelerating recovery of the natural gas still remaining in the natural gas field (Oldenberg, et al., 2001).

In the process of producing and depleting a natural gas field, the pressure is reduced considerably, unless a strong water drive maintains a portion of the reservoir's pressure. As a result, both the CO_2 storage capacity and the CO_2 injectivity in pressure depleted natural gas fields can be favorable. The great majority of the 600 domestic natural gas storage sites are in depleted natural gas reservoirs, confirming that depleted natural gas fields could be excellent candidates for CO_2 storage.

A vast number of natural gas fields and reservoirs exist across the U.S., as shown on Figure 4-5. Many of these gas fields are at or near the end of their economically productive life, particularly the very mature natural gas fields in the Appalachian and Mid-Continent basins. The U.S. DOE/NETL natural gas data base, GASIS, tabulates nearly 20,000 gas reservoirs in 21 gas producing states (GASIS, 1999). This data base provides an excellent starting point for selecting depleted natural gas fields for geologic storage of CO_2.

Figure 4-5. Locations of Depleted Gas Reservoirs



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The CO_2 storage mechanisms in depleted natural gas fields are similar to those in depleted oil fields with a few notable differences: (1) depleted gas fields will generally be at a lower pressure than depleted oil fields, because pressure maintenance, critical for maximizing recovery in oil fields, is not generally practiced in gas fields; and (2) depleted gas fields will contain less water in the reservoir and thus will generally have higher storage capacity than a comparable size oil field. This is because water injection, important for maximizing recovery in oil fields, is not practiced in gas fields.

As such, the primary CO_2 storage mechanisms in depleted gas fields is the compressibility of the CO_2 in the available pore spaces of the reservoir, where CO_2 compressibility is a function of pressure and temperature. Typically, one barrel of available reservoir pore space can contain 2 Mcf of CO_2, with a range of 1.5 Mcf to 2.5 Mcf of CO_2 per barrel of available pore space, depending on reservoir temperature and pressure conditions. A "first-order", minimum estimate of CO_2 storage capacity in depleted natural gas fields can be estimated from the following equation, in terms of Mcf of CO_2:

Area (acres) * Net Pay (feet) * Porosity * 7758 barrels/acre-foot * 2 Mcf/barrel * A (available pore space, assume 0.7) * E (effective reservoir contact, assume 0.8) * PL (pressure limit of the confined depleted gas reservoir, need to calculate from pressure, temperature and volume equation).

Note: The conversion factor 2 Mcf/barrel of pore space may range from 1.5 to 2.5, depending on actual reservoir conditions. Mcf of CO2 can be converted to metric tons of CO2 by the factor 18.9 Mcf of CO2 equals 1 ton of CO2.

More precise estimates of CO_2 storage capacity in depleted natural gas reservoirs can be obtained by performing a reservoir simulation that incorporates the reservoir boundaries and allowable pressure buildup in the reservoir.

4. Probabilistic Storage Capacity Injectivity and Flow Modeling. As additional reservoir information is gathered, it will become possible to provide more sophisticated modeling of CO_2 storage capacity, injectivity and flow. This more rigorous use of the full distribution of geological and reservoir properties will enable the operator to better understand and communicate the likely range of outcomes at the selected storage site. Use of probabilistic modeling also helps establish the value of gathering additional data that could help narrow the expected range of estimates for CO_2 storage capacity, injectivity and likely flow paths.

5. Wellbore Integrity Modeling. High priority is being given to better understanding wellbore integrity in CO_2 storage. As such, numerous efforts are underway to understand wellbore-based leakage mechanisms, the causes of well failure and the potential risks associated with wellbore leakage. Wellbore leakage modeling may also be a primary interest of regulatory authorities for understanding and addressing wellbore integrity concerns.

Currently one, two, and three-dimensional wellbore models are under development to simulate the processes observed in the laboratory and the field. For example, researchers at the University of Alberta have developed a comprehensive methodology for assessing the transport properties of wellbores used for the geologic storage of CO_2 (Chalaturnyk and Moreno, 2004). This methodology identifies a variety of possible failure mechanisms and systematically represents these mechanisms and the interactions among them analytically. The methodology is sufficiently flexible to allow new mechanisms to be added, allows for properties to change over time, incorporates assumptions for missing data, and enables addition of new data as these become available.

The initial research by the University of Alberta, which is consistent with work by Princeton University, indicates that the two most critical points of wellbore leakage in CO_2 storage include the annuli between the cement and the well casing and the interval between the cement and the reservoir rock. Of particular concern is the subsequent dissolution of cement by CO_2 interactions in both of these cement filled spaces.

Research is also underway by the Carbon Mitigation Institute (CMI) at Princeton University to develop analytical and semi-analytical solutions for estimating the probability distribution for leakage rates through abandoned wells (Nordbotten, et al., 2005). These techniques are being applied in the Alberta Basin, using a study area with a large number of existing wellbores (Celia, et al., 2006).

6. Geomechanical Modeling of CO_2 Injection. The injection of CO_2, particularly in hydrostatic saline formations, requires that the formation pressure be exceeded as the injected fluid needs to displace or compress the fluid in the storage reservoir.

Geomechanical modeling is used to help ensure that the injection of CO_2 avoids damaging the reservoir or fault seals of the CO_2 storage site. Geomechanical modeling is used to predict the evolution of effective stresses in rocks and faults and the maximum sustainable fluid pressure that can be safely used during CO_2 injection. The geomechanical models used for estimating fault and rock stability rely on Mohr-Columb criteria, where effective stress is defined as total stress minus the pore-fluid pressure, and the classic Mohr circle is used to predict rock failure.

Pressure-depletion scenarios can have a significant impact on effective stress, causing damage to reservoir seals and fault seals. However, it is not clear whether fluid injection will have significant effects on total stress at reservoir scale. New work on combining geomechanical modeling (particularly the poro-elastic behavior of the reservoir) and injection-related pore pressure/stress coupling, and application of geophysical monitoring (to be discussed in the next section of this Chapter) would provide improved means for controlling the geomechanical effects of CO_2 storage.

The assessments of fault stability and maximum sustainable fluid pressures for CO_2 injection require information on in situ stress, fault geometries and rock strength. Drilling data and induced micro-fracturing can be used to establish in situ stress; fault geometry can be determined from a depth-converted 3D seismic survey; and rock strength (including the strength of the reservoir rock, the caprock and faults) can be established from laboratory tests.

Geochemical Modeling. The purpose of geochemical modeling is to better understand the expected reactions between the injected CO_2 (including the CO_2 in solution with reservoir brines) and the in-place reservoir minerals (in the storage formation and the caprock). Modeling of the interaction of CO_2 and the minerals in the storage formation will help establish the long-term CO_2 storage and trapping offered by mineralization. Modeling of the interaction of CO_2 and the caprock will help establish the extent to which this interaction will improve or weaken the sealing ability of the caprock. (Laboratory and analytical studies conducted to date appear to indicate that CO_2 interaction with the caprock tends to lower caprock permeability, although much more work and geologic variability are required to establish more conclusive results.)

B. MONITORING OF CO_2 LEAKAGE

Monitoring in a geologic CO_2 storage project helps to determine the location of the injected CO_2 and, most importantly, to detect leaks or other deterioration of storage integrity. Monitoring, in turn, is also essential for remediation of CO_2 leakage, as discussed in the next chapter, enabling one to rapidly respond to CO_2 leakage in the event that such leakage should occur (NETL, 2004).

1. Value of Monitoring. Three most important reasons exists for monitoring at CO_2 storage projects: (1) assessing the performance of the CO_2 injection and storage process by tracking the subsurface movement and immobilization of the injected CO_2; (2) providing an “early warning” system should CO_2 seepage or leakage occur; and, (3) providing information, particularly for meeting public and regulatory concerns, that no adverse actions are occurring or likely to occur in the storage reservoir.

In addition, as discussed previously, monitoring serves an important role in helping verify and calibrate the performance of the reservoir and wellbore models used to assess long-term CO_2 movement and storage integrity, particularly after CO_2 injection operations have ceased. Monitoring and modeling of long-term performance will also be important for obtaining permits and gaining public acceptance.

Monitoring is aimed at helping to avoid and, should it occur, to quickly provide information on the local, as well as the global, risks related to leakage of stored CO_2. Of particular concern are rapid releases, leading to local health and the environment risks, including CO_2 accumulation in buildings or low-lying areas, damage to plants, and contamination of underground drinking water. Monitoring can help avoid and better respond to these risks. Monitoring can also help assess the global risk that a particular storage site will be ineffective due to slow but persistent leakage of CO_2.

For the most part, all of the monitoring techniques currently being considered are adaptations from other -- albeit similar -- applications. Much can be learned from the monitoring efforts used by CO_2-EOR projects and particularly by the gas storage industry (Benson, et al., 2002).

- In CO_2-EOR projects, the principal method used to monitor CO_2 movement in the reservoir has been the direct observation of the composition of the produced fluids (Grigg, 2002). Increased use is being made of seismic methods, particularly in pilot tests and experimental projects, including cross-well tomography, surface 3-D and 4-D seismic, and vertical seismic profiling, as shown on Figure 4-6.

- Much more extensive use of monitoring is common in the natural gas storage industry that tends to extensively rely on a series of special purpose observation wells, as shown on Figure 4-7.

Benson (2004) identifies a number of important purposes that the monitoring system will need to serve:

- Monitoring to ensure effective CO_2 injection controls

- Monitoring to detect the location of the injected CO_2 plume

- Monitoring of the integrity of shut-in, plugged, or abandoned wells
- Monitoring to identify and confirm CO_2 storage efficiency and processes
- Monitoring to detect and quantify any CO_2 surface seepage.

A suite of monitoring technologies will need to be employed to achieve these objectives, providing complimentary information and planned redundancy. In addition, a variety of monitoring approaches will be required depending on the leakage pathways and risks that are of concern. Figure 4-8 provides an illustration of the various targets for monitoring and the approaches for conducting the monitoring.

Two general categories of monitoring will need to be installed at a CO_2 storage site (Chalaturnyk and Gunter, 2005).

a) Comprehensive Leakage Monitoring and Safety Assurance. Carbon dioxide is a commodity useful in a wide variety of applications. In addition to its importance for enhancing oil recovery, CO_2 is used in manufacturing carbonates and urea. Dry ice (solid CO_2) is used as a refrigerant. CO_2 is also used in carbonated beverages and in fire extinguishers. Supporting this large CO_2 industry is a vast infrastructure for storing, delivering, and processing CO_2. For example, CO_2 injection operations in West Texas are supported by over 2,200 miles of high pressure (1,500 – 2,000 psi) pipelines. Eight major CO_2 processing plants dry, separate and compress produced CO_2 to prepare it for reinjection (Melzer, 2004).

All of these systems and facilities have worker safety procedures and protections, such as CO_2 sensors near injection wells and other equipment to detect leakage and ensure worker safety. An immediate objective of such monitoring is to protect human health by alerting project operators of dangerous CO_2 concentrations.

Figure 4-6. Using Surface, Vertical Seismic Profiling (VSP) and Crosswell Seismic for Monitoring CO_2 Storage.

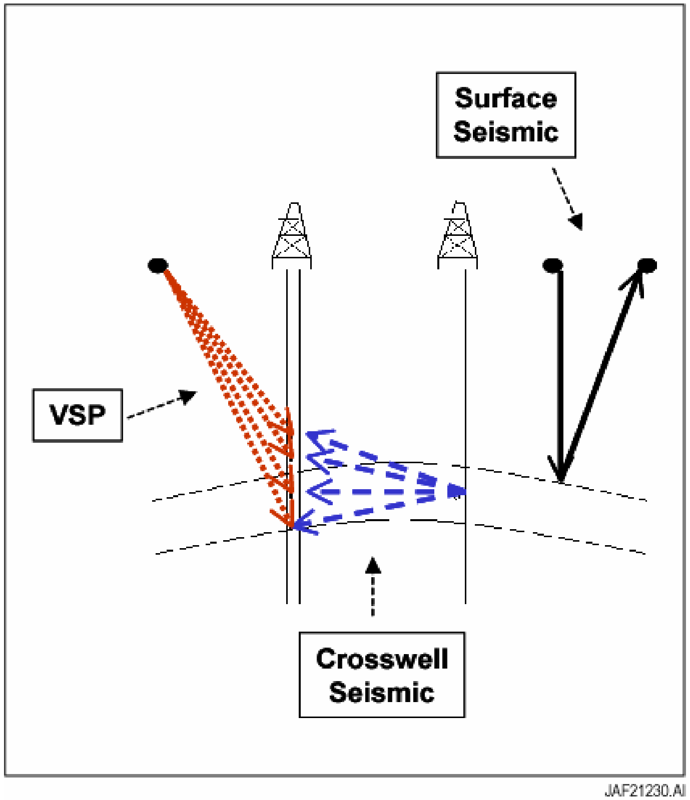
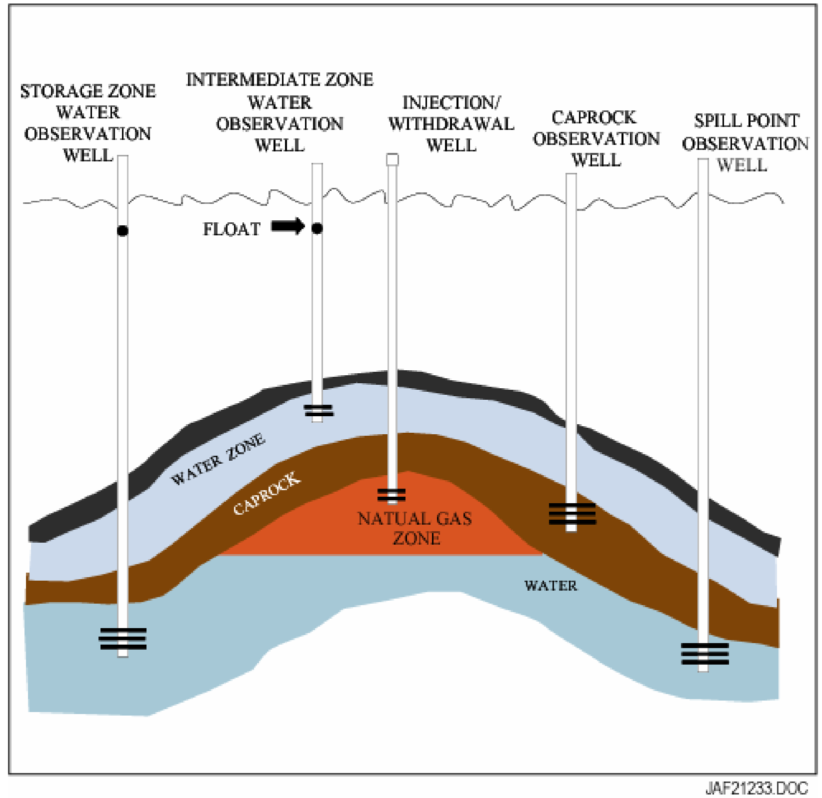
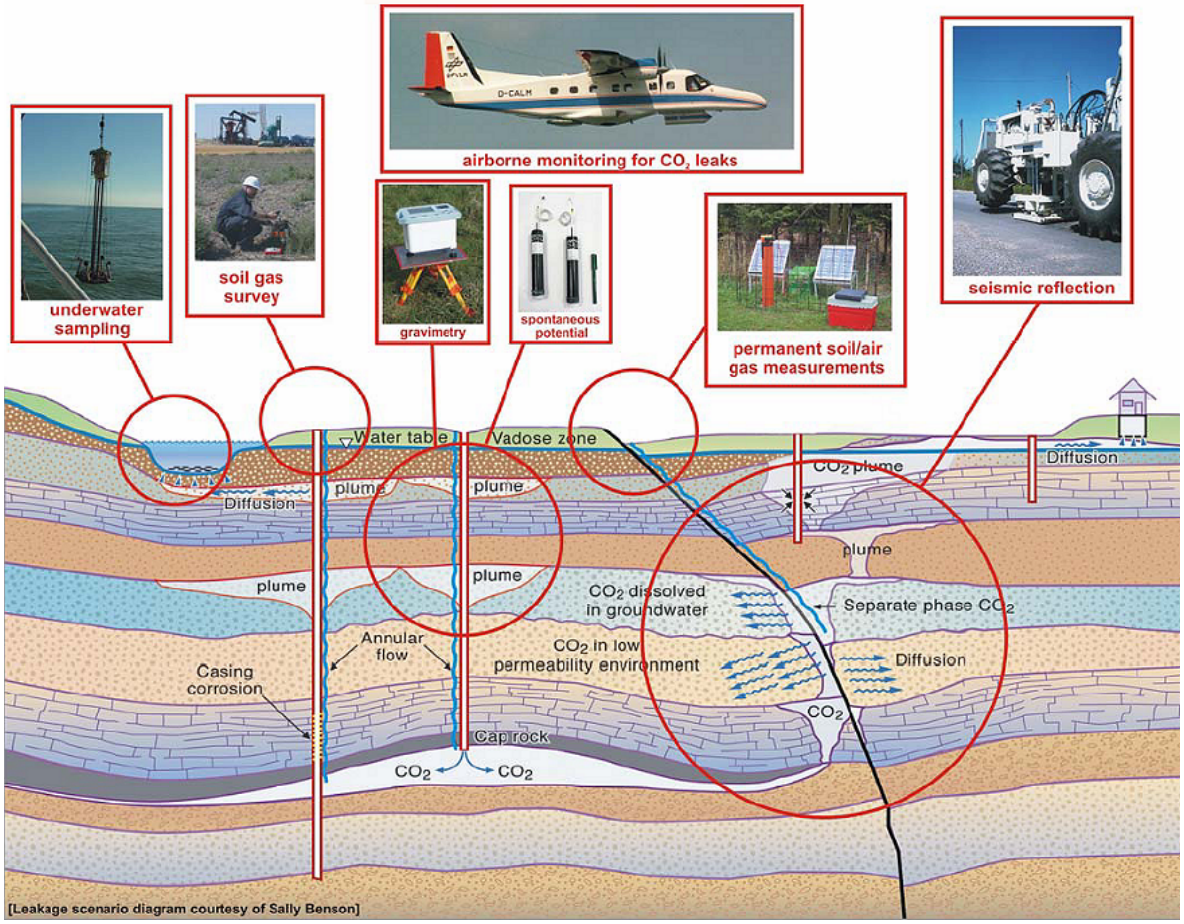


Figure 4-7. Locating Observation Wells for Monitoring Storage.



Modified from Underground Storage of Gases, University of Michigan Engineering Summery Conference, 1978.

Figure 4-8. Various Monitoring Approaches for Various Leakage Pathways



Courtesy British Geological Service

Source: Heidug, 2006

b) Comprehensive Seepage Monitoring and Storage Assurance. Seepage monitoring serves as a backstop for leakage monitoring, and also offers direct protection of ecosystems and human health. Key to this monitoring is the availability of high quality data on baseline conditions. All such monitoring faces the problem of filtering out the natural CO_2 concentrations and fluxes, which change with atmospheric conditions, temperature, soil moisture, and intensity of sunlight.

2. Phases of Reservoir Monitoring. All CO_2 storage projects will likely require a detailed monitoring plan. The actual monitoring plans for each project will need to be based on the characteristics of the storage reservoir, including its development history (if it is a depleted oil and gas reservoir). Four distinct monitoring phases should be considered in the life-cycle of a geologic CO_2 storage project (Benson, 2004). The four phases are:

- Pre-operation phase - - as the base-line conditions are established, the geologic setting is defined and the storage design is formulated, the specific role of the monitoring systems for providing information and reducing risks needs to be set in-place;

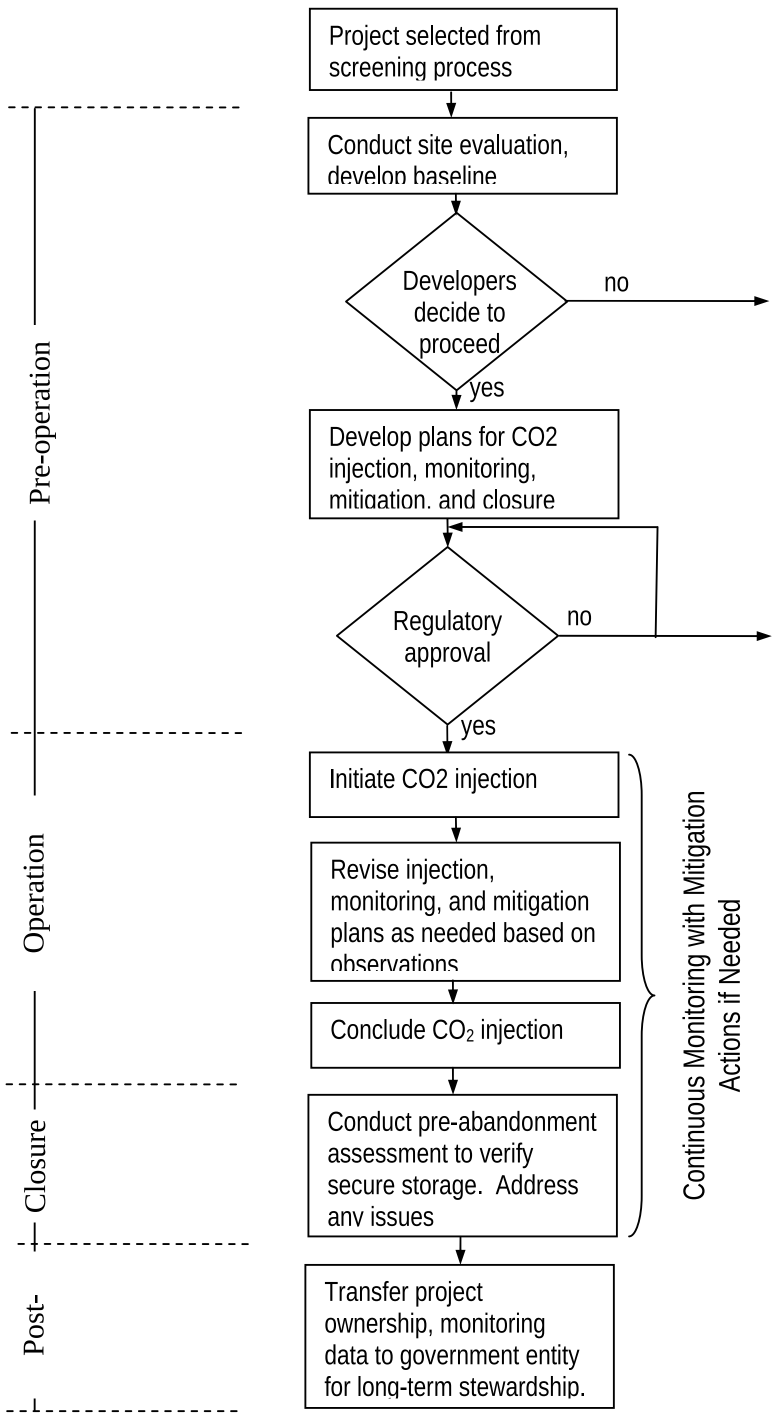
- Operation phase - - during the 30 to 50 years time period when CO_2 will be injected into the storage reservoir, an active program of monitoring and feedback will need to be in operation;

- Closure phase - - after injection has stopped, passive but still ongoing monitoring will be used to demonstrate that the storage project is performing as expected and that it is safe to discontinue further monitoring;

- Post-closure phase - - after some time period following the closing of the project, monitoring may no longer be required except in the event of leakage, legal disputes, or other matters that may require new information about the status of the storage project.

Figure 4-9 shows the phases of a CO_2 storage project and how monitoring activities are integral throughout.

Figure 4-9. Role of Monitoring During Four Phases of a Geologic CO_2 Storage Project



3. Wellbore Integrity Monitoring. Leaking wellbores will, most likely, be a high concern for safe, secure CO_2 storage. During operations, monitoring of injection and production rates can provide the first source of information of where wellbore leakage may be occurring, followed closely by monitoring of wellbore and formation pressures and temperatures. Fluid sampling, vertical seismic profiling (VSP), and cross well seismic are other techniques for monitoring of leakage from wellbores. These techniques are most applicable during injection operations.

For prevention of future CO_2 leakage from wells, mechanical integrity tests (MI) are the most common means of demonstrating that the CO_2 injection wells have integrity. Although relatively simple in theory, a wide variety of methods could be used for conducting MI tests (MITs), with the applicability a function of the reservoir setting, type of well, location, specific regulatory requirements, and fluids injected. The types of MIT tests that could be considered include: annulus pressure tests (SAPT), annulus monitoring tests (SAMT), radioactive tracer surveys (RTS), water-brine interface tests (W-BIT), "Ada" pressure tests, water in annulus tests (WIAT), single point resistivity test (SPRT), dual completion monitoring tests (DCMT), temperature logs, noise logs, oxygen activation method tests, downhole cameras and visualization tools, and the use of cementing records including cement bond logs and casing inspection logs.

Cement quality and bonding is usually evaluated using sonic and ultrasonic tools, while ultrasonic tools combined with electromagnetic sensing or caliper measurements (Mulders, 2006) provides a means to evaluate casing conditions. (For a more detailed description these varies techniques for testing mechanical integrity of injection wells, see http://www.epa.gov/region5/water/uic/r5guid/r5_05.htm#A).

In the case of CO_2 injection wells, diagnosis of potential leakage of CO_2 from the wellbore is not always easy, and each technique has its unique applicability and each has its strengths and weaknesses (Vrignaud, 2006). For example, cased hole logging is good for tubing, but can only assess production casing during workovers when tubing is removed. Temperature logs help identify hot spots due to flow from deeper formations, while noise logs provide a signature of flow behind pipe.

Looking forward, the CO_2 Capture Project is currently conducting a well “autopsy” and “prognosis” study for use on a decommissioned well that has been used for CO_2 injection for 20 to 30 years. This study is intended to provide quantitative information on well stability during injection, to be extrapolated to provide a realistic prognosis for long term stability and integrity. It is anticipated that this work will provide insights into well design and materials, along with appropriate methods and regulatory criteria for well abandonment, intervention, and remediation (Imbus, 2006).

4. Monitoring and Controlling Geomechanical Effects of CO_2 Injection. The reactivation of pre-existing faults will result in the generation of micro-seismic events which can be monitored with geophysical instruments such as an array of geophones. The purpose of monitoring will be to establish the location of fault-reactivation and the advancement of fluid pressure during CO_2 injection. If the micro-seismic events are detected in the overlying caprock, close monitoring of caprock integrity will be essential.

The monitoring for CO_2-induced micro-seismic events will help detect accidental over-pressuring of the CO_2 storage formation, allowing real-time adjustment of the injection pressure. Passive seismic monitoring will also provide a means to minimize the potential for damage from inadvertent overestimation of maximum sustainable fluid pressures.

Finally, periodic monitoring should be conducted to test for pore pressure/stress coupling during CO_2 injection by performing leak-off tests and hydraulic-fracturing tests to determine the total horizontal stress. However, it is not clear whether the poro-elastic behavior of the reservoir rock during CO_2 injection would significantly affect either effective or total stress on a reservoir scale.

5. Overview of Monitoring Approaches. A number of monitoring approaches are available to help monitor the efficacy of CO_2 storage. The applicability of the various methods will depend, in large part, on the specific storage situation, formation, and site and reservoir characteristics. In addition, and perhaps most importantly, the choice of method will depend not only on its applicability, but also on its cost to implement. Finally, it is quite likely that a combination and/or sequence of approaches will be required over the life of a storage project.

Some monitoring approaches are classified as "indirect" since they infer the presence of CO_2. For example, seismic techniques are based on interpreting sound waves to infer information. In contrast, "direct" monitoring technologies entail the actual measurements of CO_2. Indirect methods can be highly accurate and efficient for monitoring relatively large areas. Direct methods can serve as a useful back stop in the event that something unusual or unexpected happens. Table 4-2 presents monitoring options for a range of potential issues.

Sidebar 9 provides three CO_2 storage monitoring case studies that discuss alternative approaches being used for monitoring at these fields sites.

6. Discussion of Monitoring Technologies.

a). Use of Wellbores for Monitoring CO_2 Storage. Properly designed observation and pressure monitoring wells can provide an important source for information on CO_2 storage project performance.

(1) Observation Wells. Observation wells are drilled within a storage formation some distance from an injection well, and are used to directly measure temperature, pressure, and fluid composition at a specific location. Observation wells are a relatively expensive monitoring option, but provide invaluable data that can be used to "ground truth" both seismic interpretation and reservoir models.

Observation wells can also be drilled into either nearby or overlying formations into which CO_2 is being stored. Fluids can be periodically drawn from the wells and tested for CO_2 contamination. CO_2 seepage through the cap rock can be detected long before any CO_2 would reach the surface. If CO_2 is detected, the observation well can be converted to a CO_2 recovery well.

Table 4-2. Monitoring Approaches for Geologic CO_2 Storage	
Target for Monitoring	Current Monitoring Approaches
CO_2 Plume Location	• Two and three dimensional time-lapse seismic reflection surveys • Vertical seismic profiling and cross wellbore seismic surveys • Electrical and electromagnetic surveys • Satellite imagery of land surface deformation • Satellite imagery of vegetation changes • Gravity measures • Reservoir pressure monitoring • Wellhead and formation fluid sampling • Natural and introduced tracers • Geochemical changes identified in observation or production wells
Early warning of storage reservoir failure	• Two and three dimensional time-lapse seismic reflection surveys • Vertical seismic profiling and cross wellbore seismic surveys • Satellite imagery of land surface deformation • Injection well and reservoir pressure monitoring • Pressure and geochemical monitoring in overlying formations • Microseismicity or passive seismic monitoring
CO_2 concentrations and fluxes at the ground surface	• Real time infrared based detectors for CO_2 concentrations • Air sampling and analysis using gas chromospectrometry • Eddy flux towers • Monitoring for natural and introduced tracers • Hyperspectral imagery
Injection well condition, flow rates and pressures	• Borehole logs, including casing integrity logs and radiotracer logs • Wellhead and formation pressure gauges • Wellbore annulus pressure measurements • Well integrity tests • Orifice or other differential flow meters • Surface CO_2 measures near injector points and high risk areas
Solubility and mineral trapping	• Formation fluid sampling using wellhead or deep well concentrations of CO_2 • Major ion chemistry and isotopes • Monitoring for natural and introduced tracers
Leakage up faults and fractures	• Two and three dimensional time-lapse seismic reflection surveys • Vertical seismic profiling and cross wellbore seismic surveys • Electrical and electromagnetic surveys • Satellite imagery of land surface deformation • Reservoir and aquifer pressure monitoring • Microseismicity or passive seismic monitoring • Groundwater and vadose zone sampling • Vegetation changes
Groundwater quality	• Groundwater sampling and geochemical analysis of monitoring wells • Natural and introduced tracers

Source: Chalaturnyk and Gunter, 2004

SIDEBAR 9. CO_2 STORAGE MONITORING CASE STUDIES

This Sidebar summarizes the monitoring activities underway at three significant CO_2 storage projects - - Weyburn, Sleipner and Frio.

1. IEA GHG Weyburn CO_2 Monitoring and Storage Project

The Weyburn CO_2-EOR and Sequestration Project, led by Encana, is located in southeastern Saskatchewan near the U.S. border with North Dakota. The CO_2 source is from a coal gasification demonstration facility in North Dakota and the CO_2 is transported 204 miles to the Weyburn field, where it is injected into an oilfield to enhance recovery.

The project utilizes advanced 4-D seismic, reservoir simulation and other methods to better understand the behavior of injected CO_2 in the subsurface.

Extensive simulation and monitoring studies (funded through the IEA GHG Programme) are being conducted to assess the fate and transport of the injected CO_2, the quantities of CO_2 stored in the reservoir, and the time expected for the CO_2 to remain sequestered in the reservoir. Results to date indicate:

- Soil gas levels over the CO_2 injection area are normal; with no evidence for escape of injected CO_2 from depth
- Monitoring methods deployed clearly show physical and chemical effects associated with CO_2 injection
- Geochemical processes observed show good spatial correlation in areas with the highest CO_2 injection volumes. These processes include CO_2 dissolution into the reservoir brine, reservoir carbonate mineral dissolution, and an increase in total dissolved solids in reservoir brine
- Good results are obtained from using 4D seismic, with results demonstrating no evidence of CO_2 escape, zones of possible enhanced flow (perhaps due to fractures), and volume estimates accurate to $\pm$ 20%. These results are also contributing to improved simulations.

Source: White, 2004

2. Sleipner/ Saline Aquifer CO_2 Storage (SACS) Project (http://www.ieagreen.org.uk/sacshome.htm)

The Saline Aquifer CO_2 Storage (SACS) at Sleipner project is the world's first commercial-scale CO_2 storage project. Natural gas produced from the Sleipner West field contains about 9% CO_2, which must be reduced to 2.5% before the gas can be sold. CO_2 is separated from the produced gas stream by two absorption columns. The separated CO_2 is then injected into a large, deep saline reservoir, the Utsira formation, 800 meters below the bed of the North Sea. Statoil operates the Sleipner field on behalf of a group of partners, and has implemented several programs to monitor the storage of CO_2 in this unique facility.

The first phase of the SACS monitoring project was completed in December 1999, with the results reported to the European Commission. Since 1996, nearly 1 million tonnes per year of CO_2 has been injected into the reservoir. In the summer of 1999, a seismic survey of the reservoir was completed, with the initial results clearly identifying the position of the injected CO_2 within the Utsira reservoir.

SIDEBAR 9. CO_2 STORAGE MONITORING CASE STUDIES (Cont'd)

3. Frio Brine Pilot Experiment (Hovorka, 2006)
From October 4–14, 2004, the Frio Brine Pilot injected 1,600 tons of CO_2 into a high permeability brine-bearing sandstone of the Frio Formation beneath the Gulf Coast of Texas, USA.

The Frio Brine Pilot experiment is funded by the Department of Energy (DOE) National Energy Technology Laboratory (NETL) and led by the Bureau of Economic Geology (BEG) at the Jackson School of Geosciences, The University of Texas at Austin. Major technical support was provided by GEO-SEQ, a national lab consortium led by Lawrence Berkeley National Lab (LBNL). The project had four major objectives:

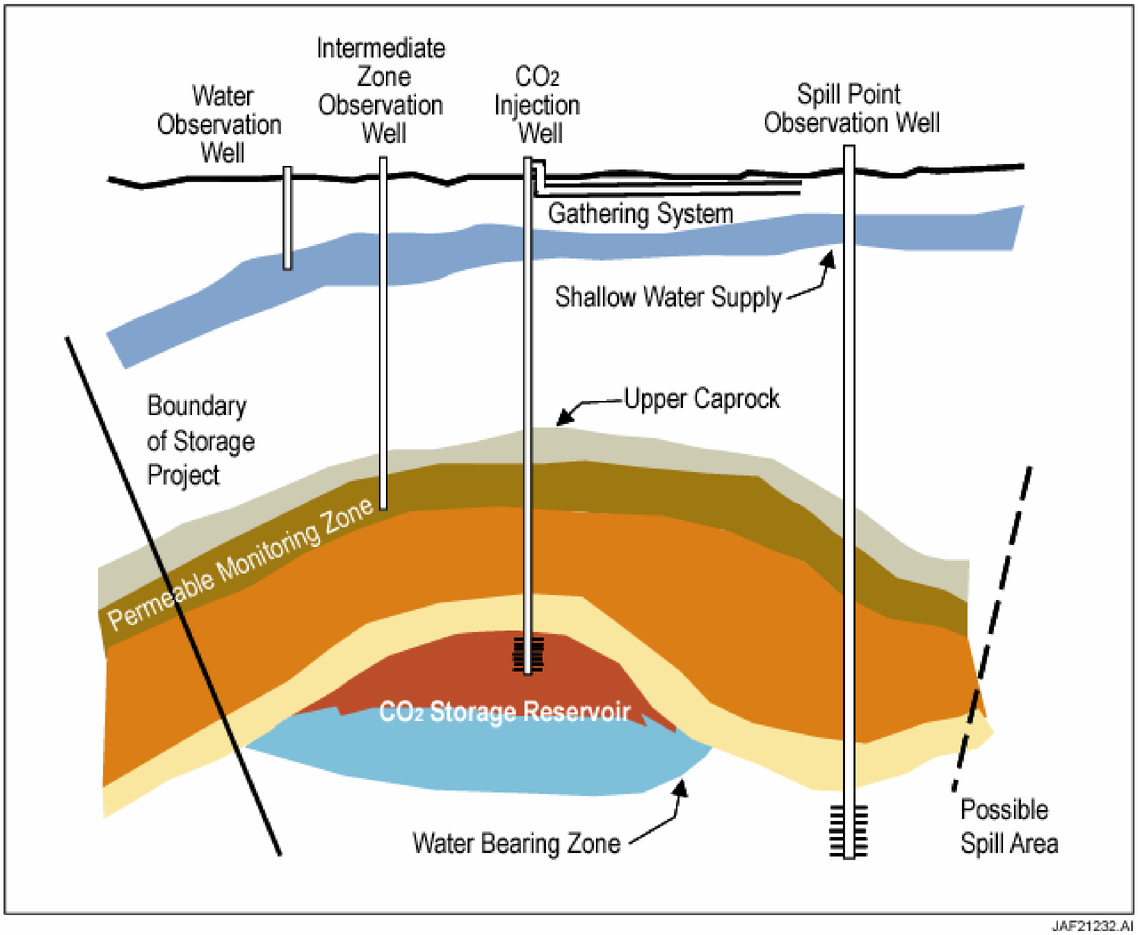
- Demonstrate to the public and other stakeholders that CO_2 can be injected into a brine formation without adverse health, safety, or environmental effects
- Measure subsurface distribution of injected CO_2 using diverse monitoring technologies
- Test the validity of conceptual, hydrologic, and geochemical models
- Develop experience necessary for development of larger-scale CO_2 injection experiments.

Diverse monitoring technologies were tested in both the injection zone and in the shallow near-surface environment. The monitoring results were used to better refine and calibrate the models developed for this reservoir. In general, both geochemical and geophysical monitoring techniques were successfully demonstrated, showing that significant volumes of CO_2 are being stored by dissolution and two-phase trapping in this deep saline aquifer.

Observation wells have been required for some natural gas storage and hazardous waste disposal applications, depending on the risks at a particular site and the discretion of the regulating entity. An overarching theme for observation wells is that they should not compromise the integrity of the CO_2 storage repository.

Figure 4-10 and Table 4-3 set forth four types of observation wells that may be valuable for monitoring at a CO_2 storage site.

Figure 4-10. Monitoring in Natural Gas Storage Fields



Modified after Katz, D.L, and K.H. Coats, *Underground Storage of Fluids*, Ulrich's Books, 1968.

Table 4-3. Alternative Observation Well Options for Monitoring CO_2 Storage

Types of Monitoring Wells	Primary Usage
Injection Well	One or more of the original CO_2 injection wells would remain shut-in for constant measurement of reservoir pressure.
Water Observation Wells	Water observation wells would be drilled to monitor water pressure in the storage interval outside the CO_2 plume.
Spill Point Observation Well	Observation wells could be strategically located to monitor the structural spill point or most likely point for CO_2 leakage out of the structure.
Intermediate Zone Observation Well	Intermediate zone observation wells, located above the storage reservoir caprock, would be used to monitor pressure changes that could be caused by leaks due to lack of well bore integrity or caprock integrity.

(2) Pressure Monitoring Wells. Pressure monitoring wells have been suggested by some researchers as an alternative to seismic and other indirect methods. However, some question whether such pressure transient methods have the sensitivity necessary to detect leakage from a large storage reservoir, and if applied, how many monitoring wells would be required. Preliminary work seems to indicate that in some reservoir settings, such pressure monitoring wells could be effective, though considerably more work is required to further verify their applicability (Benson, 2006).

b). Use of Geophysical Methods for Monitoring CO_2 Storage. A variety of seismic monitoring methods can be incorporated into a CO_2 storage monitoring system.

(1) Seismic Methods. A number of geophysical monitoring approaches and technologies are available to help monitor the efficacy of CO_2 storage, ranging from borehole based seismic to electromagnetic techniques. Seismic technology is currently the workhorse technology for oil and gas exploration, and it will likely be the workhorse for the monitoring of geologic storage of CO_2 as well. However, extensively using seismic methods will be costly.

Fundamentally, seismic technology involves “shooting” the ground (using either an explosion or a large weight) and listening to sound reflections. Different types of rock reflect sound differently and seismic practitioners are able to develop detailed pictures of underground rock formations based on these reflections. Notably, rocks that are saturated with gas or a highly compressible fluid, as opposed to brine, leave a distinctive “bright spot” on a seismic read-out enabling CO_2 to be “observed”.

Historically, a seismic test would consist of one point where the ground was being “shot” and a single line of “receivers” spaced apart with the shooting point in the middle. With the advent of fast computers in the 1970s, seismic tests can now be conducted with a second line of receivers perpendicular to the first and so create a three-dimensional view of the rock. The latest development, and one that is highly useful for CO_2 storage, is time-lapse seismic in which 3D snapshots of a formation are taken over several months and years and the changes observed. This technique is sometimes referred to as 4D seismic, with time being the fourth dimension.

Seismic imaging enables developers to track the progress of the CO_2 plume as it flows up through the storage formation, rises against the caprock, and expands laterally along the caprock. Figure 4-11, from Weyburn, shows a distinctive CO_2 signature (Jazrawi, 2004). This is not surprising given the large difference between the density, viscosity, and compressibility of supercritical CO_2 versus brine. This test provides confidence in the ability of seismic technology to track the CO_2 front, though accurate estimation of CO_2 volume remains a challenge.

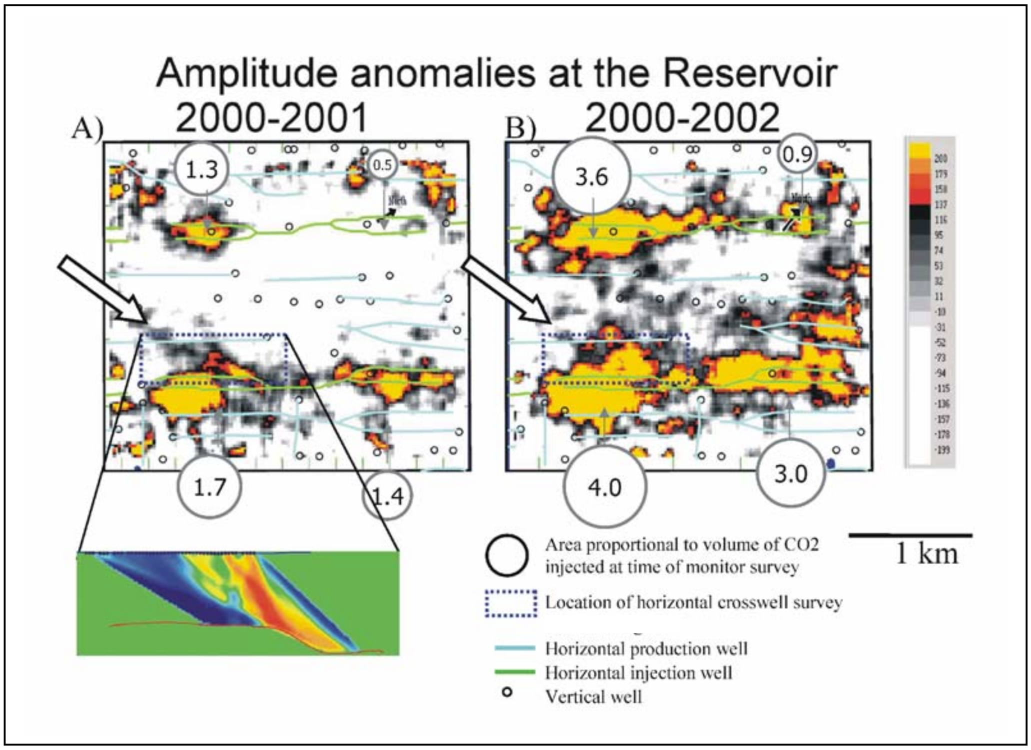


Figure 4-11. P-Wave Amplitude Difference Maps for a) baseline minus 2001 survey, and b) baseline minus 2002 survey, determined from the 3D P-wave surface seismic data within a 4-pattern subregion of the Phase-1A area. A horizontal crosswell survey is shown in an expanded panel in A.

Scientific progress on 4D seismic is moving forward, and high-resolution, time-lapse seismic appears to have considerable promise in most settings. For example, an evaluation of 4D seismic data from Sleipner has shown that both the location of CO_2 in the reservoir and the mechanism through which it is stored can be deduced (Arts, et al., 2004). This is significant as storage via dissolution and pore space trapping is much more stable than “free” supercritical CO_2.

(2) Electrical and Electromagnetic Methods. Electromagnetic methods rely on changes in the electrical conductivity and dielectric properties of fluids caused by different composition. As such, a decrease in brine-saturated fluids should be detectable when CO_2 is injected, increasing CO_2 concentration in the fluid.

(3) Gravitational Methods. Gravitational methods, such as surface and downhole gravity surveys, detect changes in bulk density as a function of changes in density of subsurface fluids and may provide a lower cost geophysical method for tracking CO_2.

(4) Deformation Methods. Minor displacement of the Earth's surface can occur with changes in the pore pressure of a subsurface formation. In a closed storage reservoir, such a change would be caused by the injection of CO_2. This deformation can be monitoring by technologies such surface tiltmeters and perhaps other approaches.

c) Use of Geochemical Methods for Monitoring CO_2 Storage. The carbon associated with the injected CO_2 will have a distinct isotopic composition relative to that in the reservoir fluids. This enables geochemical methods to identify the CO_2 front through fluid sampling. Artificial tracers can also be used to monitor CO_2 movement in a reservoir.

(1) *Measuring CO_2 in Soil*. Soil monitoring has the advantage of being a direct observation, but it has the disadvantages that some leakage pathways may bypass the soil and go directly into the air. Improved technologies to both measure CO_2 fluxes through the soil and to predict soil fluxes from air measurements are being developed.

Even relatively modest CO_2 leakages can cause high CO_2 fluxes and concentrations in the overlying shallow subsurface (Oldenburg and Unger, 2003). A monitoring program for elevated CO_2 in soil may consist of either a sampling and testing program or the operation of a network of accumulation chambers (Norman, et al., 1992). For example, an accumulation chamber (AC) with an open bottom (cm^2 scale) can be placed either directly on the soil surface or on a collar installed on the ground surface. A sample of air is circulated through the AC and the infrared gas analyzer (IRGA). The rate of change of CO_2 concentration in the chamber is used to derive the flux of CO_2 across the ground surface at the point of measurement.

Increased CO_2 in the soil has a negative effect on plant life. The general health of plants and density of different plant species in the area above a geologic storage site can be used as a proxy for monitoring abnormally high CO_2 flux. Importantly, plant health and species modification spatial patterns accumulate over time and so plant surveying methods can pick up on small quantities of leaked CO_2 that would otherwise be hard or impossible to detect by direct observation.

(2) *Measuring CO_2 in Groundwater*. Groundwater monitoring focuses on one of the primary focal points of concern associated with potential CO_2 leakage from a storage reservoir. Groundwater monitoring equipment consists of pumps and a wide variety of possible instruments that can tap into the water table to measure CO_2 concentrations in water. Critical is understanding the amount of free gaseous CO_2 that may be leaking into groundwater, and establishing how much is dissolved in the groundwater. CO_2 instruments to measure dissolved CO_2 include a submerged probe that is covered by a thin organic membrane. When the probe is submerged, CO_2 diffuses through the membrane at a rate proportional to its partial pressure, which is a function of the concentration of the dissolved CO_2.

(3) *Measuring CO_2 in Air*. A variety of techniques exist to measure CO_2 in air. Point detectors for monitoring CO_2 concentrations could be placed strategically at high risk locations, for example at abandoned well locations. Satellite and laser-based analyzers are being developed and have the potential to screen an area as large as several square miles at relatively low cost. Also being developed are methods to precisely quantify the variations in baseline CO_2 concentrations. One such approach is eddy covariance where a tower-based laser spectrometry is used to establish CO_2 flux near the surface (Anderson and Farrar, 2001; Baldocchi, et al., 1996). The detection limits and accuracy of remote/aerial detection methods remains uncertain and needs to be further confirmed.

(4) *Using Tracers*. Tracers are a topic that cross-cut all direct CO_2 monitoring technologies. Natural tracers can enable practitioners to identify the source of detected CO_2. For example, leaking natural source CO_2 will have a carbon-14 signal that is distinct from atmospheric and most biogenic respiration sources (Hoefs, 1987). Other naturally occurring tracers include carbon-13, stable isotopes of O, H, C, S, and N, and noble gases. While there is an extra expense in

testing a sample of CO_2 for natural tracers, such an analysis can provide definitive information in a situation where the flux measurements indicate a possible leak.

Another approach is to inject a minute amount of an artificial tracer (e.g., perfluorocarbons, PFTs) with the CO_2 to be stored. Generally, by design, the artificial tracers are easy to detect at low levels. Also, one can vary the amount of tracer or change tracers during CO_2 injection to gain detailed information about the CO_2 flow paths. At present, such approaches are primarily aimed at gaining scientific understanding, and may not be a part of a monitoring program for a commercial demonstration.

V. REMEDIATION OPTIONS FOR CO_2 LEAKAGE

All CO_2 storage projects will be designed and conducted with the goal and expectation that no CO_2 will leak from the containment formation. But, unexpected things can and do happen. Therefore, this Chapter discusses remediation actions designed to address the highest likelihood CO_2 leakage events. This will accomplish two purposes: (1) the monitoring and pre-preparation actions associated with remediation will enable quick action to be taken once evidence of a leak or other problems are observed; and (2) the pre-established documentation of expected risks will provide an established understanding of the potential impacts of particular leakage events, which will greatly help guide the appropriate remediation efforts.

Much can be learned from past efforts to remediate oil and gas reservoirs and gas storage reservoirs that have leaked. A portion of this past learning has also been incorporated into this Chapter, Remediation Options for CO_2 Leakage.

A. RESERVOIR ASPECTS OF REMEDIATION

The remediation actions, should leakage occur, will depend, to a considerable extent, on the type of reservoir in which the CO_2 is stored, as discussed below.

1. Depleted Oil and Gas Fields. CO_2 stored in this class of structurally confined reservoirs will most likely be the most effectively contained and easiest to monitor, offering the best chance of successful remediation.

Once leakage has been detected, the first step would be to measure, as possible, the extent and nature of the leakage, which will help guide the method and pace of remediation. For example, if leakage merely transports CO_2 into a securely sealed, secondary storage reservoir, remediation may not be needed. On the other hand, if the CO_2 leak is detected at the surface, prompt action will be essential.

Initial steps for remediating minor leakage in wellbores may involve injecting mud, cement, or conformance-enhancing polymers to seal off the suspected leakage source. Should these steps fail or should leakage be worryingly rapid, a more radical approach may involve producing CO_2 back up the injection wells to the surface, then reinjecting the CO_2 into a more secure stratigraphic zone or reservoir within the field, or even transporting it to another site, preferably without venting. Contingency plans to deal with leakage will be needed for each CO_2 storage site in an oil and gas formation, so that remediation action can be taken promptly should leakage occur.

However, it is important to recognize that, as a remediation measure, extraction (or production) and transportation of the injected CO_2 without venting, while recommended, can be a complicated, time-consuming, and costly process. In particular, considering the very large volumes of CO_2 being stored, transporting and injecting it at another site may take years of design and construction. One or more production wells will be needed, and a pipeline may be needed if the leakage is at a different location from where the leakage is occurring. While the new storage operation is being put in place, venting may be unavoidable.

2. Saline Formations. CO_2 stored in saline formations, particularly those lacking structural closure, will be much more challenging to access and recover should remediation be necessary. Over time, CO_2 injected into a saline formation becomes increasingly dispersed due to the regional hydrologic flow.

Like that for other settings, the first step will involve, to the extent possible, determining the location, nature, and extent of the leak. Wellbore leaks in saline aquifers can be addressed in a manner similar to that in oil or gas reservoirs. In cases where the leakage has been caught early and the risks posed are low, the most prudent option may be to just stop injection in the location near the leakage and allow the reservoir to stabilize. However, this will only work if the CO_2 leakage is driven mainly by a lateral pressure differential away from the injection well, and not by CO_2 buoyancy, or a significant pressure differential in the vertical direction.

If the CO_2 leaked is significant, it may be necessary to produce the CO_2 from the reservoir near where the leak occurred, and reinject the CO_2 elsewhere in a more suitable location in the saline formation or in an alternative geologic structure, as described for depleted oil and gas reservoirs above.

Contingency plans to deal with leakage events, should they occur, will also need to be developed for each storage project injecting into a saline aquifer.

In general, regardless of the type of geologic storage formation, other than plugging the source of the leak (such as in a wellbore or fracture), if possible, there are three basic mechanisms to stop leakage from the reservoir:

- Reduce the pressure in the storage formation
- Increase the pressure in the formation into which the leakage is occurring
- Intercept the CO_2 plume and extract the CO_2 from the reservoir before it leaks such that it poses undue risks, and, if possible, reinject in another formation.

These scenarios and actions are discussed in more detail in the paragraphs below.

B. CLASSIFICATION OF CO_2 LEAKAGE SCENARIO

A number of authors have set forth potential sub-surface leak scenarios around which CO_2 storage remediation can be structured. For example, Espie (2005) summarizes three main sub-surface leak events, as follows:

- Seal failure (capillary failure, faults and fractures)
- Bypassing of trap (spillage, aquifer migration)
- Wellbore failure.

A more detailed categorization of potential CO_2 escape mechanisms has been set forth by the Australian CO2CRC, as displayed in Figure 5-1. In addition, the CO2CRC has, in a very brief form, matched each potential escape mechanism with a potential remediation measure. In addition, Perry (2005) offers a series of conceptual mitigation steps that apply in the case of a leak in an aquifer gas storage field. In general, these conceptual steps would apply, perhaps with some modification, to any type of geologic storage, including CO_2 storage. These steps are summarized as follows:

1. When a leak is first observed or reported, the geographic area of the leak should be surveyed for homes, farms, businesses, etc., that could be

impacted or endangered. State and local officials should be notified as necessary and/or required.

2. Injection into the storage reservoir, at least in the vicinity of the leak, should be halted immediately.

3. An investigation into the source of the leak should begin immediately.

    - Other wellbores, if they exist, should be checked for anomalous pressures.

    - Well logs may be run in suspect wells.

4. In the case of a suspected caprock leak, the local geology should be reviewed for the most likely area of CO_2 accumulation above the storage zone. (Ideally, this characterization should have been done as part of the site selection process, and should be readily available.) These secondary CO_2 accumulation settings will generally consist of permeable, porous formation above the storage formation, with some type of impermeable caprock overlaying it.[3]

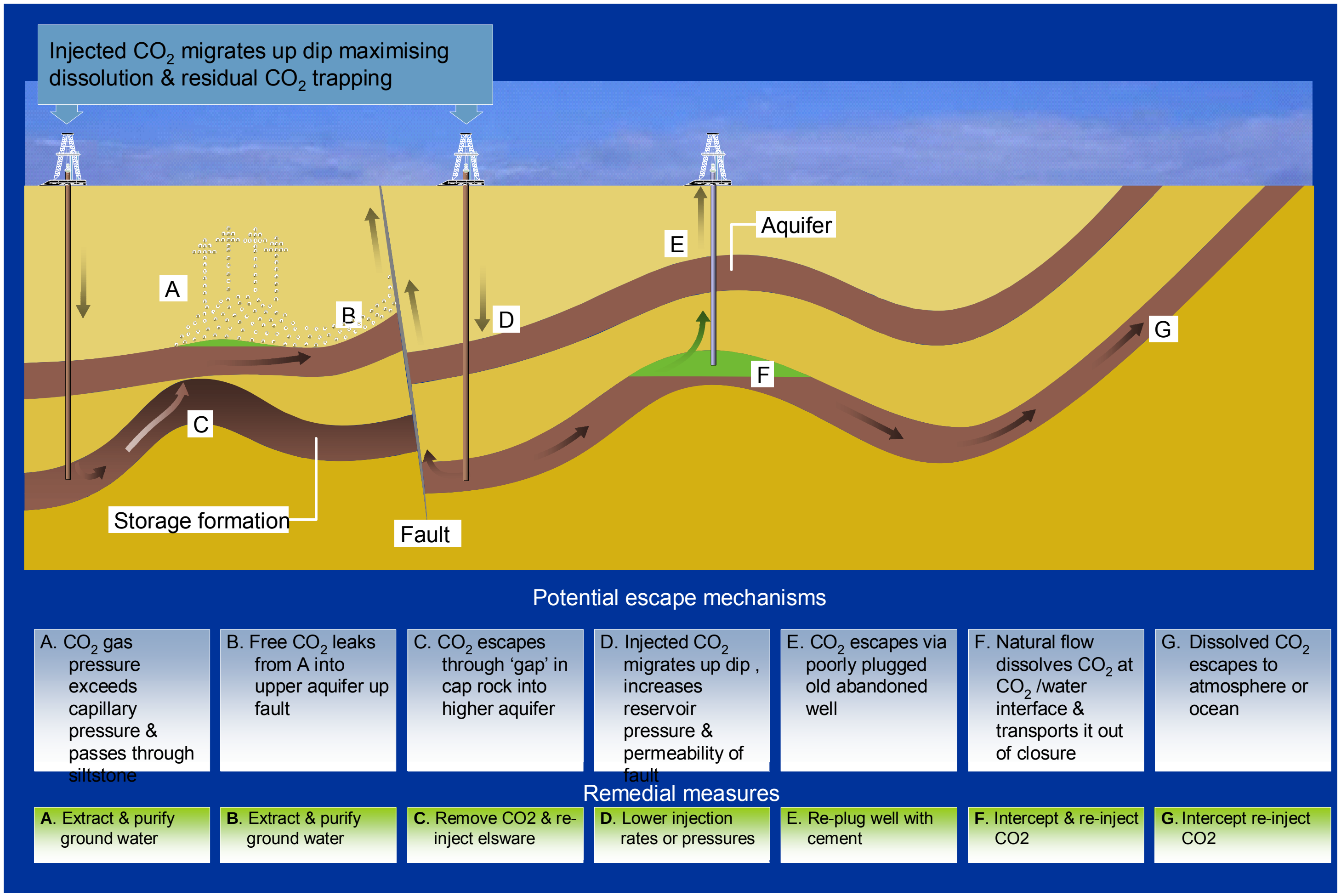
5. Once the shallow geology is reviewed, a study should be conducted integrating all information on hand, such as the surface location of the CO_2 leak in relation to structural high points in shallow zones.

6. Based on this information, one or more wells may need to be drilled in the shallower zones to locate and recover any CO_2 migrating to those zones.

7. This process may need to be repeated and modified if the first wells do not locate the migrating CO_2, or if the CO_2 has migrated to multiple horizons.

[3] A good description of this process for geological investigation, as it applies to gas storage reservoirs, is provided in Katz and Coats (1968)

Figure 5-1. Overview of Potential CO_2 Escape Mechanism and Associated Remediation Measures



Source: Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC).

8. Alternatively, the leak, depending on circumstances, may also be controlled by lowering the pressure in the storage zone, or by creating a hydraulic barrier by increasing the pressure upstream from the leak

9. The final mitigation step is to either plug the leak, if located, or reconfigure that storage operation to reduce the likelihood of future leakage.

Sidebar 10 summarizes four CO_2 leakage scenarios and the remediation options available to mitigate and address these problems.

SIDEBAR 10. REMEDIATION OPTIONS FOR CO_2 LEAKAGE FROM GEOLOGICAL STORAGE PROJECTS (Modified from Benson and Hepple (2005).

Scenario	**Remediation Options**
1. Leakage through caprock	• Lower injection pressure by injecting at a lower rate or through more wells; • Lower pressure by removing water or other fluids from the storage reservoir; • Intersect the leakage with extraction wells in the vicinity of the leak; • Create a hydraulic barrier by increasing pressure upstream of the leak; • Stop CO_2 injection and produce the CO_2 from the storage reservoir and reinject it into a more suitable storage structure.
2. Leakage Out of Confining Structure	• Injection into the storage reservoir should be halted immediately. • Begin investigation into the source of the leak immediately; check wellbores for anomalous pressures, run well logs on suspect wells • Review local geology for the most likely area of CO_2 accumulation above the storage zone. Integrate all information on hand, such as the surface location of leak in relation to structural high points in shallow zones. • Based on this information, drill in the shallower zones to locate and recover any migrating CO_2, or control by lowering the pressure in the storage zone, or by creating an hydraulic barrier by increasing the pressure upstream from the leak • The mitigation step is to either plug the leak, if located, or reconfigure the CO_2 storage operation to prevent further leakage.
3. Leakage due to lack of well integrity	• Repair leaking injection wells with standard oil and gas field well recompletion techniques; • Repair leaking injection wells by squeezing cement behind the well casing to plug leaks behind the casing; • Plug and abandon injection wells that cannot be repaired by any method, including the two main methods listed above;
4. Leakage due to well blow out	• Remediate injection or abandoned well blow-outs with standard techniques to 'kill' a well such as injecting a heavy mud into the well casing. • If the wellhead is not accessible, a nearby well can be drilled to intercept the casing below the ground surface and 'kill' the well by pumping mud down the interception well.

In most cases, the geologic and engineering effort, analysis, and time associated with such mitigation would be comparable to, and may often exceed, that associated with site selection, project design, and construction and development. Inevitably, attempts to save money and time on the front end site selection and project design phase would likely result in losses, perhaps several times over, in the geologic, engineering and development effort undertaken to remediate problems that may result from inadequate work up front.

This Chapter will use the seven part categorization of potential CO_2 leakage mechanisms set forth in Figure 5-1 and develop, in more depth, the set of remediation measures the could be used to address, mitigate and correct a CO_2 leakage problem.

1. CO_2 Leakage Due to Seal Failure. The first four leakage mechanisms, shown as A, B, C and D in Figure 5-1, involve leakage of CO_2 through the caprock, either due to excess gas pressure, CO_2 buoyancy, and/or the presence of a permeable (non-sealing) fault or fracture. The appropriate remediation plans and actions will need to take into consideration the specific seepage pathway of the leaked CO_2. In some cases, it may be that the leaked CO_2 will be passively dissipated or contained in upper, secondary storage formations and no action needs to be taken. However, in most cases, remediating this problem will be required, involving the following steps:

a) *Locating and Sealing Leaks in the CO_2 Storage Reservoir Caprock.* The first step would be to locate the source of the leak. The likely pathways could be natural or induced faults or fractures located near a steeply dipping flank of a confining structure. A variety of tests could be used to locate, as closely as possible, the source of the leak, including:

- Undergound pressure and flow monitoring
- Tracer surveys
- Subsurface injection and production tests
- Seismic surveys and analyses.

The first three may require new wells and access to the subsurface, and likely a period of time to conduct conclusive monitoring.

Technologies for locating CO_2 leaks should be a subject of future R&D. For example, the above noted techniques were used to attempt to locate a leak in a Midwestern Mt. Simon aquifer gas storage field with inconclusive results.

b) *Locating and Remediating the Accumulation of Leaked CO_2*. More likely, if the CO_2 has leaked through the caprock, portions of it could accumulate in, shallower strata. An investigation of the local geology surrounding the leak, as well as the use of advanced seismic techniques, could indicate which of the strata might be storing portions of the leaked CO_2. A likely secondary storage or accumulation might exist in the structural high points of shallower formations overlain by competent caprock.

It is again important to note that an investigation of the geology around the leak, as recommended, may require new wells to be drilled, which may, perhaps, increase the risk of future leakage.

Having identified the formations holding the leaked and stored CO_2, the next step would be to drill a series of shallow wells into the strata holding the leaked CO_2 to capture and remove the accumulated CO_2. This action will also serve to lower the pressure in the zone, helping mitigate CO_2 movement to the surface.

c). *Other Actions to Mitigate and Further Remediate Caprock Leakage.* To reduce the rate of CO_2 leakage through the caprock, faults or fractures, several steps could be taken, as follows:

- The pressure in the storage reservoir could be lowered by withdrawing water or CO_2 from the storage reservoir.
- The pressure in the strata above the storage reservoir could be increased by injecting water into the strata.

Both of these steps would lower the driving pressure between the storage reservoir and the overlying strata, reducing (or eliminating, at least temporarily) the rate of CO_2 leakage if this driving pressure is the primary contributor to the extent and nature of the leakage.

Assuming that the location of the leak has been established, the remediation approach would be to attempt to seal the leak by drilling a nearby well and injecting foam, time setting gels, or cements; or using other sealing substances to close the leakage pathway (Perry, 2005). However, while theoretically possible, this caprock remediation technique has yet to be accomplished in actual practice.

d) *Abandoning the Leaking CO_2 Storage Reservoir*. Should the above three approaches for remediating CO_2 leakage through a caprock not be successful, the final alternative would be to deplete and abandon the initially selected CO_2 storage reservoir and store the CO_2 in an alternative, more secure location.

2. Leakage Out of the Confining Structure. The next two leakage mechanisms, shown as F and G in Figure 5-1, involve leakage of CO_2 out of the confining structure. As discussed in more depth in Chapter III: Leakage Pathways, the "leakage" (movement) of CO_2 out of a confining structure may de due to: (1) natural hydrodynamics of a saline formation that transports dissolved CO_2 out of a closure; or (2) excess injection of CO_2 past the confining "spill point" of the formation. Once the CO_2 has escaped its confining structure, the horizontal leakage of CO_2 can readily turn vertical and escape through a permeable pathway or an outcrop to the atmosphere.

Obviously, proper site selection and project design, with appropriate precautions taken for geologic and operational uncertainties, should ensure that leakage outside of the confining structure does not occur. In addition, proper monitoring and reservoir modeling during injection operations should also play a key role in ensuring that leakage outside of the confining structure does not happen. However, if such overfilling does occur during injection operations, and some of the stored CO_2 leaks out from the formation, injection should cease immediately, and the remediation steps described above for leakage through caprock should be implemented.

3. Leakage Due to Lack of Well Integrity. The third leakage mechanism, shown as E in Figure 5-1, involves leakage of CO_2 from loss of well integrity. This may be due to: (1) a poorly designed and constructed CO_2 injection well; (2) an unanticipated well failure, such as a parted casing; or (3) a poorly plugged old, abandoned well.

The natural gas production and storage industry has well-developed capabilities for repairing small leaks in injection wells. These include replacing the tubing or re-cementing the well. Casing leaks can be stopped by injecting heavy mud into the well. If the leaking well is not accessible, a nearby well can be drilled to intercept the casing below ground and stop the leak.

Of particular concern is CO_2 leakage through poorly plugged and abandoned wells. A number of states have programs that address this topic because, in addition to serving as potential CO_2 leakage pathways, poorly plugged wells may cause other potential problems, such as contamination of groundwater and leakage of hydrocarbons into the atmosphere.

Sidebar 10 presents information from the Indiana Department of Natural Resources that addresses the topic of "Orphaned and Abandoned Wells in Indiana."

a) *Insuring Wellbore Integrity*. Of all of the possible leakage pathways from a geologic storage reservoir, leakage through operating injection and production wells and through improperly abandoned wells are the most likely. In general, based on current knowledge and practice, wellbore integrity is a greater concern than the geologic integrity of the reservoir. This is because considerable attention is being given to finding storage areas with a competent seal and a confining structure.

However, restoration of well integrity if a wellbore does leak is a more challenging topic. Leakage can occur though the wellbore, through the annulus between the well tubing and casing, or on the outside of the casing. Figure 5-2 provides a schematic diagram of a wellbore showing potential CO_2 leakage pathways.

In addition, similar to production and injection wells, it is important to recognize that improperly documented or poorly completed CO_2 injection wells could represent an operational liability; affecting injection rates, reservoir pressurization, and/or production. Consequently, during operations, wellbore leakage problems will generally be recognized relatively quickly, allowing them to be quickly addressed by the operator.

SIDEBAR 10. ORPHANED AND ABANDONED WELLS IN INDIANA

How many oil and gas wells are there in Indiana? There have been more than 70,000 oil and gas wells drilled in Indiana. Many were drilled during the original "gas boom" in east central Indiana that began in the 1890's. About 5,000 wells are in use today. While Indiana had well plugging standards as early as 1893, many methods used to abandon wells prior to 1947 do not meet modern standards.

Why does a well need to be plugged? When no longer used for production of oil or gas, a well is required to be plugged to ensure that:

- it does not cause or contribute to the contamination of ground or surface water;
- it does not allow oil, gas, or water to discharge onto the ground or into the air;
- all oil, gas, and water are confined in their original formations; and
- the well does not pose a hazard to public health or safety or interfere with agricultural or other uses of the land after the well is no longer in active use.

Who is responsible for plugging the well? Indiana law requires a well to be plugged by the owner or operator whenever it is no longer used for oil or gas production. In addition to plugging it, the operator is required to remove all equipment used in the production of the well and restore the site to a suitable condition.

How is a well plugged? After all of the tubing and other equipment in the well is removed, the well is plugged with Portland Cement. The cement plug is placed in the well across all zones that had produced oil or gas and also from below the base of the deepest fresh groundwater zone to the top of the well to ensure that all fresh groundwater zones are protected with a solid column of cement.

How will I know if I have an abandoned well on my property? Unless the well casing, wellhead, or surface production equipment is still present, it can be difficult to determine whether an abandoned oil or gas well is on your property. Many of these wells have been found buried under buildings, driveways, as well as streets and highways. Some signs that may indicate an abandoned well are:

- areas of distressed vegetation;
- areas where the ground has settled or caved in from a collapsed wellbore;
- oily or salty water seeps;
- the odor of natural gas or crude oil; or
- a water well contaminated with saltwater, crude oil, or natural gas.

How many orphaned or abandoned wells are there in Indiana? The number of inventoried orphaned or abandoned wells as of July, 2006, was 1,323. This list is continually updated as new wells are added and as wells are either plugged or returned to production by other operators.

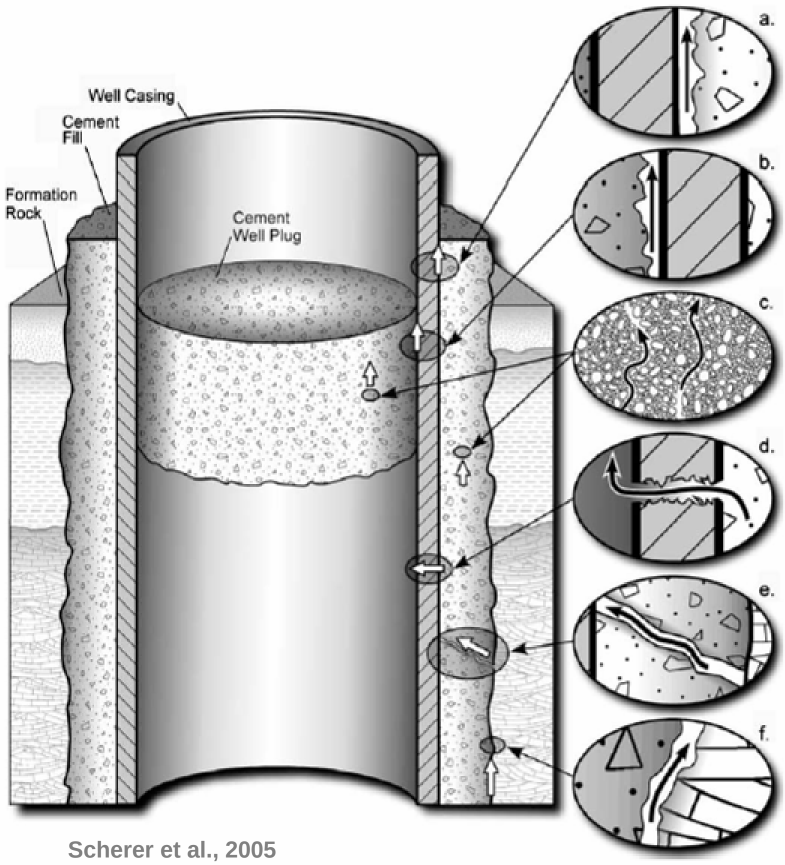
What are the procedures for plugging an orphaned or abandoned well? By law a representative from the Division of Oil and Gas must witness oil or gas well plugging operations. In addition to safety and environmental concerns previously mentioned, cutting the casing off from an abandoned well and covering it with soil or other material is an unacceptable method of plugging which can create substantial risks to public health or safety and result in the contamination of groundwater.

Never attempt to remove abandoned equipment or abandon a well without first notifying the Division of Oil and Gas and seeing that the work is performed by an experienced well plugging contractor.

Source: Indiana Department of Natural Resources, Orphaned & Abandoned Well Program www.dnr.IN.gov/dnroil

Appendix 1 to this report provides the "Casing, Cementing, Drilling and Completion Requirements for Onshore Wells", as set forth in Rule 3.13 of the Texas Administrative Code and as administered by the Railroad Commission of Texas, Oil and Gas Division.

Figure 5-2. Schematic Diagram of Wellbore Showing Leakage Pathways



b) *Identifying Leakage in Wellbores*. Leakage through wellbores can occur in two main ways:

- Through loss of wellbore integrity. This mechanism is more likely to result from slower processes related to the age of the well and the materials used in its completion and/or plugging.
- Through well blowouts: Though relatively rare, notable case studies have demonstrated the significant impacts should well blowouts release large amounts of CO_2. This would most likely occur as a result of poor completion practices. Because of higher safety danger of CO_2 well blowouts, this topic is discussed in more depth in a separate section of this Chapter.

The larger focus of concern is the long-term integrity of wellbores in the presence of stored CO_2 in a geologic reservoir, particularly in storage fields that are no longer in operation. Factors affecting overall wellbore integrity and the potential for leakage include the drilling and completion practices used, the technical competence of the company that drilled and completed the well, the quality and integrity of the materials used, and the age and operational history of the well. Of particular concern are older operating and abandoned wells that may not have been plugged to more recent standards – newer wells are generally drilled and completed to higher specifications designed to reduce the potential for leakage.

c) *Addressing Wellbore Integrity Concerns*. Addressing concerns associated with wellbore integrity in CO_2 storage projects involves the following:

- Characterizing the location and condition of old wells, including production, injection and abandoned wells.
- Selecting CO_2 storage sites where the impacts of wellbore leakage from existing, abandoned, and new wells are minimal and/or manageable.
- Understanding leakage and corrosion mechanisms in wellbores, along with effectively modeling these processes in field conditions, by developing techniques to better understand and model the mechanisms contributing to wellbore integrity problems.
- Evaluating the reactivity of well construction materials to CO_2, and selecting materials that can withstand exposure to CO_2 over sufficiently long periods to minimize the effects of corrosion.
- Developing and implementing effective, low-cost techniques for monitoring wellbores for leakage, to identify in the early stages of injection the likely wellbore integrity problems.
- Developing and implementing well completion practices and configurations to reduce the potential for wellbore leakage of CO_2 in operating wells, including well design, materials, and construction.

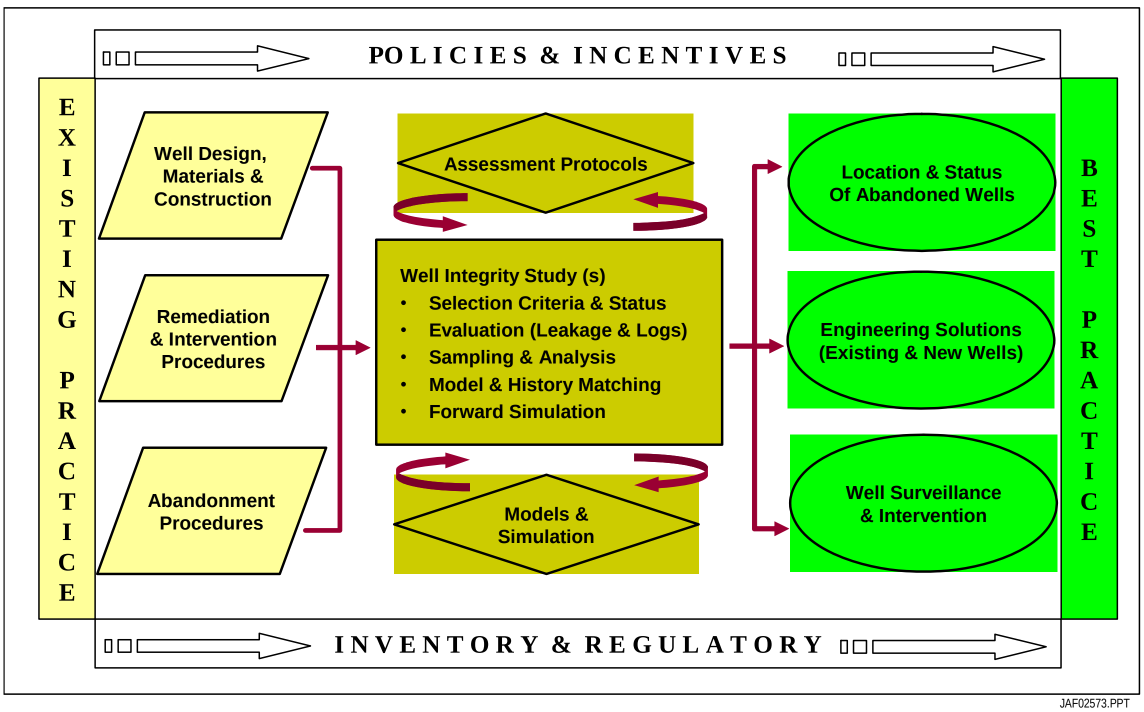
- Developing and implementing effective, low-cost techniques for monitoring wellbores for leakage.

- Developing and implementing well plugging procedures to reduce the potential for wellbore leakage in abandoned wells.

- Intervening and mitigating any problems once identified, through plugging practices and other wellbore leakage remediation actions.

Such a multi-phased approach is illustrated schematically in Figure 5-3. Each of the various aspects associated with addressing the issue of ensuring wellbore integrity is discussed in the following sections.

Figure 5-3. Comprehensive Well Integrity Program



Source: Imbus and Stark, 2006

d) *Locating and Characterizing Existing and Abandoned Wells*. In many regions of the world, such as the United States and Canada, existing fields may contain hundreds of wells that have been abandoned, or that are currently idle. In the U.S., as many as two million wells have been drilled to produce oil and natural gas, with over one million wells drilled in Texas alone. Likewise, in the Alberta Basin in Canada, nearly 400,000 wells have been drilled to date. Additional wells are used in gas storage operations, and for injecting (predominantly liquid) wastes and acid gases.

Locating and characterizing the condition of these wells is a formidable task. The experience from an exercise to develop a database of wellbores just at the Weyburn oil field alone shows that even in an area that has good public records there are lots of gaps (Princeton, 2004). In many areas of the world, extensive well completion records will not have been kept or have been lost. More importantly, well completion and abandonment approaches, technologies, and regulatory requirements have evolved and improved over times – implying wells drilled and/or abandoned many years ago most likely do not meet today's standards.

Currently, in most established oil and gas producing areas, applicants for injection well permits are required to conduct an "area of review", or AOR, as part of the permit application process. The objective of an AOR is to identify any potential conduits for the flow of injected fluids from the proposed well out of the intended formation, and remediate any conduits to flow that could exist. Within the AOR, the permit applicant must identify and determine the age and condition of any existing and/or abandoned wells.

In the United States, the AOR, while varying somewhat from state-to-state, is generally defined as ¼ mile (about 0.4 kilometers) for saltwater injection wells, and 2.5 miles (about 4 kilometers) for hazardous waste injection wells. Sometimes, the AOR is determined by formula based on reservoir conditions.

Similar procedures will need to be applied to CO_2 storage wells as well. However, traditional approaches assume that the injectant is liquid, usually saline brine. In the case of CO_2 storage, the buoyancy of the CO_2 adds another dimension to be considered in establishing an appropriate AOR for CO_2 storage. This may imply the need for establishing an AOR requirement based on both reservoir conditions and the likely volume of CO_2 to be injected. This will help assure that the potential “zone of endangering influence”, or ZEI, is not larger than the applied for AOR (Nicot, et al., 2004).

Other mechanisms could also be used to locate and characterize previously drilled wells. For example, research is underway to use high resolution magnetic (Xia, et al., 2003), soil gas surveys[4], and/or other techniques to locate abandoned wells. No matter the method for locating and characterizing abandoned wells, and wells that may pose a risk of leakage will need to be remediated. In general, these wells will need to be re-plugged using state-of-the-art techniques designed to be resistant to CO_2-laden fluids (see discussion below).

Developing national databases of plugged and abandoned wells might be considered, but this will not be an easy task. Moreover, in addition to a historical record of past drilling, some type of regulatory body would need to maintain records of all future wells drilled. Ideally, these databases should contain details on the well locations and the processes and materials used for plugging and abandoning these wells. Issues to consider include establishing responsibility for developing such a database and for implementing remediation measures, once the reservoirs have been abandoned and after injection operations have ceased.

e) *Well Completion and Plugging Practices*. The integrity of wellbores over hundreds or thousands of years will be one of the primary considerations in establishing the “permanence” of geologic storage. Therefore, it is important that operational procedures and regulatory mechanisms are established to ensure minimal leakage of stored CO_2 from both operating and plugged and abandoned wells.

[4] http://www.microseeps.com/html/carbon_seq_latest.html

Current requirements for injection wells in the United States and elsewhere, including those for gas and water injection in oil recovery operations, gas injection for storage, and waste disposal, have resulted in a good history of performance. In fact, EPA states that "…When wells are properly sited, constructed, and operated, underground injection is an effective and environmentally safe method to dispose of wastes."[5] The record of performance in the current applications of CO_2 injection for enhanced oil recovery has also been exemplary (Grigg, 2002). The same standards should apply to CO_2 storage.

The issue of wellbore integrity as it relates to CO_2 storage has been explored extensively in several recent workshops sponsored by IEA GHG.[6] These workshops have investigated the cases where failures have occurred, to understand why they occurred, and have begun to develop approaches to minimize such occurrences in the future. Work to date has focused on the development and testing of well materials that are resistant to the effects of CO_2.

In general, wellbore leakage problems are identified by sustained casing pressure (SCP), or excessive pressure in the annulus of the wellbore, indicating a failure in the pressure envelope of the well. This can be caused by leaks in packers, tubing and/or casing failure, cement degradation (including at the interface of the reservoir and the casing), wellhead leaks, and potential fractures and faults intersecting the wellbore.

Specific standards are established for injection wells used in oil and gas recovery operations, which also include CO_2 injection wells for enhanced oil recovery.[7] Moreover, based on over 30 years of experience, current CO_2 operators have, by necessity, developed well design and completion standards for CO_2 injection wells to minimize corrosion and wellbore leakage. These designs utilize corrosion resistant cements, casing, tubulars and packers, as well as preferred methods for stimulating CO_2 injection wells to enhance injectivity.

Some of the more important features of the most recently established well completions designs are described below.

[5] http://www.epa.gov/safewater/uic/whatis.html
[6] http://www.co2captureandstorage.info/networks/wellbore.htm
[7] http://www.epa.gov/region5/water/uic/r5guid/r5_05.htm#A

(1) Well Cements. Leakage due to well cement failure appears to be the most common mechanism for wellbore failure (Chalaturnyk, 2006). In particular, traditional Portland cements used in well drilling and plugging operations are known to degrade in the presence of CO_2, especially if water is also present. The process involves carbonation of the primary cement constituents, where Portlandite and calcium silicate hydrates are converted into carbonate minerals such as aragonite, calcite and vaterite. This degradation results in a loss of density and strength, and an increase in porosity of the cement. Efforts to date show that, at least under laboratory conditions, this degradation can occur quite rapidly. However, the degradation process is quite complex, and further work to understand the processes involved is required.

Limited field investigations have shown that cement degradation also occurs in the field, but has not been a major problem. Cement has not been a particular problem in the West Texas CO_2-EOR projects, some of which have been underway for 30 years. Cement failure was not the cause of the blowout at the Sheep Mountain CO_2 field, discussed elsewhere in this report (Christopher, 2006). In some field studies, CO_2 pathways appear along the casing-cement and cement formation interfaces (Figure 5-2, above), though the amount of CO_2 that would leak along these interfaces is not clear. Moreover, the degree and rate of the reaction may not necessarily be comparable in the laboratory and the field. Important factors believed to control this rate include water saturation and relative humidity, the age of the cement, and the ratio of water to cement.

Collaborative efforts are underway by researchers with the Carbon Mitigation Initiative (CMI) at Princeton University, in collaboration with the DOE's Rocky Mountain Oilfield Test Center (RMOTC) at the Teapot Dome field in Wyoming. CMI will acquire samples of cement from old wells, attempt to recreate the cement/formation interface to replicate existing properties, and seek to better understand the properties and failure mechanisms in old cemented wells.

Research by the CO_2 Capture Project is attempting to characterize the responsiveness of Portland cement to extended CO_2 exposure, with the goal of developing a comprehensive, systematic understanding of degradation mechanisms and rates, and the development of specifications for new cements and sealants applicable to CO_2 storage applications (Imbus and Christopher, 2004). Moreover, this work is attempting to understand how cement composition, additives, water chemistry, and the conditions of curing impact this process.

In addition, both academic and industry researchers are conducting novel experiments to assess the potential for cement failure in wells (Barlet-Gouedard, et al., 2004). These experiments are focusing on the factors impacting well cement degradation, and on the physical and chemical changes that occur at the interface where the well cement and reservoir rock meet. This work is looking at the impact of carbonate brines and high pressures on potential corrosivity and wellbore failure. Early geochemical experiments have shown that pressure has only minimal effects on mineral dissolution in deep aquifers.

Moreover, this work is looking at alternative cements and sealants applicable to CO_2 storage applications. These could potentially include calcium phosphate cements, which appear not to be affected by exposure to CO_2, or other non-reactive cements under development by service companies. In this regard, some standard methods for testing cements for application in CO_2 storage projects will probably be necessary.

(2) Casing and Tubulars. CO_2 resistant casing and tubulars are also critical to minimizing leakage from CO_2 storage wells. Combinations of corrosion and/or erosion mechanisms seem to cause an increase in the rate of metal loss compared to the summation of separate mechanisms (Mulders, 2006). To minimize corrosion in production tubing, most operations are utilizing specialized stainless steel tubulars set to high standards (such as API 5CT), much of which is plastic or poly-lined. In addition, corrosion resistant connectors, packers, wellheads, and rings are being used at current operations to minimize corrosion to CO_2 (Larkin, 2006).

(3) Alternative Well Designs and Configurations. To minimize the potential for leakage, industry groups have developed guidelines and standards, such as recent standards on flow prevention and remediation through practices aimed at isolation of potential flow zones (Sweatman, 2006). Moreover, alternative designs and well configurations are being considered to minimize risk even when wellbore leakage occurs.

(4) Well Plugging and Abandonment Practices. While regulatory standards and industry guidelines for well plugging are well established and common,[8] new standards for CO_2 storage wells will probably need to be established. These standards are likely to evolve over time as new knowledge on corrosion resistant materials and plugging practices improves.

4. Leakage Due to Well Blowout. Well blowouts for wells in CO_2 storage are essentially no different that those associated with wells in natural gas production operations (in particular those from gas fields containing relatively high concentrations of CO_2) or associated with natural gas storage operations. The lessons learned from previous well blowouts have formed the regulatory requirements and industry practices, such as standards and recommended procedures published by the American Petroleum Institute and the UK Offshore Operators Association.

Appendix 2 to this report sets forth the Texas Administrative Code Rule 3.20 for "Notification of Fire Breaks, Leaks and Blowouts". Appendix 3 provides State of Utah regulation for "Reporting of Undesirable Oil and Gas Events."

One particularly important distinction for CO_2 relative to natural gas storage is the fact that CO_2 is generally injected, and will likely be stored, in a supercritical state. Should pressure control be lost in the reservoir, like that from a blowout, the phase change from a supercritical fluid to a vapor results in significant and rapid expansion of the CO_2, a process that can be extreme and violent. Because of the rapid expansion in pressure, flow rates for CO_2 in this situation, especially if through small openings, can reach sonic velocities.

In addition, this expansion can lead to rapid cooling of the wellbore and fluid streams. In some cases, solid dry ice particles can form quickly in the wellbore and surface equipment, can create a "cloud" around the well reducing visibility, and may be forced out of the well as pea-to-marble sized projectiles at very high velocities.

[8] See, for example, UK Offshore Operators Association, Well Operations Subcommittee on Permanent Well Abandonment, *Guidelines for the Suspension and Abandonment of Wells*, Issue 1, July 2001

Preventative measures for reducing the probability for CO_2 storage well blowouts, are essentially the same as those for other types of well blowouts. These include (Skinner, 2003):

- Regular wellbore integrity surveys on existing wells
- Use of blow out prevention equipment (BOPE), especially during workover operations, along with regular inspection and maintenance
- Installation of additional BOPE on suspect or high-risk wells and use of annular BOPE
- Extensive crew awareness and well control training
- Proactive blowout contingency and emergency response planning and training for operator personnel.

Even though it is unlikely in the case of a CO_2 storage operation, such operations should have in place emergency management tools, contingency plans, and appropriately trained personnel in place should a CO_2 well blowout occur. Blowout contingency plans (BCPs) are common in conventional oil and gas production operations, especially on offshore platforms.

In general, BCPs can either be general or specific. General plans are strategy manuals without specific well or site information that outlines how a particular operator will respond to blowouts. These guidelines are used as a training guides or workbooks. Specific plans expand upon general plans and offer specific guidance in particular areas and blowout scenarios, including a complete intervention process.

According to well blowout advisors John Wright Co., effective BCPs should include the following:[9]

- Emergency blowout task force (BTF) management, including organization and job descriptions; mobilization priorities; initial procedures and instructions; pre-qualification of critical equipment, personnel, contractors and suppliers; data

[9] http://www.jwco.com/technical-litterature/p01.htm; and http://www.jwco.com/technical-litterature/p04.htm

acquisition needs for site survey and files; safety, documentation and audits; emergency classifications, risks and consequences

- General intervention strategies for relief well or surface control
- Blowout scenarios that define and classify critical wells and structures based on subjective risk assessment by local management and advisors
- Specific intervention strategies that identify relief well and surface needs for hypothetical blowouts on critical structures and exploration wells
- Logistics and support information that, in detail, describe source equipment, material and services requirements based on scenarios and local capabilities
- Drilling and completion procedure audits that review and critique well plans and risks, summarizing possible corrective measures, anticipated geology and reservoir conditions
- Blowout prevention and well control inspections of ongoing drilling operations, listing results and recommended corrective actions
- An Appendix that includes items useful if a blowout occurs (such as wind data, surface topography maps, local water sources, etc.).

C. CO_2 LEAKAGE WELL REMEDIATION PROCEDURES

Thus far, this chapter has discussed in detail four classifications of potential CO_2 leakage - - through the caprock, out of a confining structure, due to loss of well integrity and well blowout. In addition, the chapter has set forth, in general, how to remediate these CO_2 leakage events. Assuming that a competent, secure CO_2 storage site has been selected, the loss of well integrity and blowouts will represent the greatest risk of CO_2 leakage. As such, this section will concentrate on practices associated with remediating well integrity and well blowouts by presenting standard well service and repair procedures and guidelines should a CO_2 leak occur.

1. Overview of Existing Mechanical Integrity and Monitoring Procedures. The loss of a well's mechanical integrity (MI) can lead to internal CO_2 leaks in the casing, tubing, or packer, and external leaks allowing fluid movement behind the casing and/or cement into underground sources of drinking water (USDW). A major portion of each state's underground injection control (UIC) program centers on the mitigation of fluid movement into USDWs. The UIC program sets forth steps for automated data collection, annual or multi-annual tests to ensure well integrity, and efforts for early detection of leakage.

UIC Class I wells, for example, which inject hazardous or other municipal waste, are required to demonstrate the mechanical integrity of each injection well, which is defined as the absence of any significant leaks in the casing, tubing, or packer of a well and the absence of significant fluid movement into a USDW through vertical channels adjacent to the well bore[10]. Testing is typically performed by pressuring the casing or tubing strings and monitoring pressure for a stated duration to ensure no pressure leaking-off.

During the injection phase, subsequent monitoring efforts will generally include:

- An analysis of injected fluids
- Continuous monitoring of injection pressure, flow rate, and volume
- Demonstration of mechanical integrity once every five years
- Placement of a sufficient number of monitoring wells to assess any migration of fluids into a USDW.

If monitoring indicates leakage into a USDW, then preventive actions must be taken. These actions will include additional monitoring and reporting requirements; prompt corrective action; or permit termination and well closure[11]

2. Identifying Fugitive Emissions or Fluids. Should the mechanical integrity testing (MIT) or leakage monitoring protocols indicate fugitive movement of the injectant, several methods are available to aid in pinpointing the location of the leak.

[10] Underground Injection Control Program. Code of Federal Regulations, Part 146, Title 40, 40CFR146; www.gpoaccess.gov.

[11] Underground Injection Control Program. Code of Federal Regulations, Part 144, Title 40, 40CFR144; www.gpoaccess.gov.

These methods can also provide insights into the best method of remediation. Some of these are highlighted below and may be used with one another for improved accuracy.

- Monitoring wells – These will generally indicate external leakage away from the injection well and may indicate injectant movement outside of the containment reservoir through a poor cement sheath, a fault or fracture in the reservoir seal, or injection past the reservoir spill point.

- Loss of annular pressure - Most injection wells are required to inject through packer-set tubing, with annular brine at higher pressure than the injection operation. The UIC permit also requires continuous monitoring of this annular pressure. As such, this monitoring technique is perhaps the first indicator of a potential leak and can be identified by a loss of pressure at the surface. This will generally indicate a leak has occurred in the packer, tubing or casing and will not provide a definitive location of the leak.

- Increase of pressure – In abandoned wells or monitoring wells, the location where pressure is increasing (external versus internal production string) will be a key indicator of what corrective action will be necessary to repair the well. Should the increase in pressure be annular, grouting or a cement bond log followed up with squeezing may be necessary to seal the well. Internal pressure increases may be indicative of a failed cement abandonment plug or a leaky casing.

- Pressure testing – Through the use of a retrievable plug or inflatable packer, the tubing and/or casing can be pressure tested, much like the MIT, to ensure that pressure integrity is maintained. This method provides an overall look at the entire tubular section and will indicate which aspect of the completion is leaking.

- Downhole video camera – This tool can provides visual evidence, linked to depth and orientation measurements, of the leaking location.

- Noise Log – An acoustic log is able to “listen” to the sound within the casing string. It can provide the depth where fluid is entering or leaving the wellbore, if leakage is due to a casing failure.

- Temperature log – This log indicates fluid movement via temperature shifts from a baseline. Cooling or warming of the borehole environment may indicate fugitive fluid movement.

- Radioactive tracers – Various tracers exist that can be tracked via downhole geophysical tools to indicate the fugitive movement path of the injectant.

- Cement bond log – If the fugitive movement appears to be external to the well completion, the use of a cement bond log, or the acoustic imager, can help determine whether the injection well's cement sheath is still maintaining a quality bond between the steel casing and reservoir face.

3. Remediating Fugitive Emissions and Fluids. Once the leakage is determined to be internal or external to the injection well, remediation plans can be put forth to correct the issue. From a mechanical integrity standpoint for the injection well, there are several corrective actions that can be used to address the leak(s). The method(s) employed will stem from the results of the above procedures to determine the location and nature of the leak and may include the following:

- Wellhead repair – The wellhead should be the first item checked prior to any in-depth leak detection investigation. Wellhead equipment, including valves, flanges, etc., can be easily inspected due to their above ground location.

- Packer replacement – Should annular pressure be lost or waning, and the casing and tubing strings are shown to hold pressure, it is most likely the packer sealing element that has failed. Since the tubing string and packers are retrievable, this can be a very simple repair involving the removal of the existing tubing injection string and swapping the potentially leaky packer for a new one. Most packers are mechanically set, generally involving rotation or the application of force to initiate inflation, so most well completion units are able to pull and reset these packers. A packer that has begun to leak over time should be replaced and not reset, as a new leak may develop in the future.

- Tubing repair – If the leak is in the tubing, a completion unit can be mobilized to pull the injection string and readily replace the faulty tubing joint. The string can then be run back into the well and pressure tested to ensure integrity. It is important to visually inspect all tubing joints as they are run out of and into the well. If a tubing joint appears excessively worn at the connections, replacement of this tubing joint may eliminate future leaks.

- Squeeze cementing – A leaky casing string can be restored to high-pressure injection operations by forcing the cement slurry by pressure to specified points in a well to provide seals at the points of squeeze. Once the leak location is detected, the area of the leak is perforated and then isolated by a packed tubing string to direct cement flow during pumping. This operation will generally use a low pressure "push" to force the cement into the perforations to mitigate fracturing. This method is the industry standard corrective measure for a loss of casing integrity.

- Patching casing – A new alternative to squeeze cementing is the use of expandable casing patches to restore casing integrity. The application of a casing patch involves positioning the setting tool at depth and hydraulically "inflating" the tool. The exterior of this tool contains the expandable patch which continues to deform as the inner pressure increases until it reaches the internal diameter of the casing string, whereupon it creates a seal across the leaky area. (*See **Appendix 4** for State of Kansas procedure for internal casing repair.)*

- Repairing damaged or collapsed casing – If the casing is found to be collapsed or deformed due to external pressure, the well can be temporarily or sometimes permanently restored to previous use through the use of a swage. A swage (shown in Figure 5-4) is a repair device that acts like a circular wedge to push back damaged casing and install liners. The lower end is tapered to fit into reduced diameter pipe, then hydraulic power is used to open the jaws of the swage and push casing back to about the original diameter. The pressure exerted by the swage can be as great as 50 tons per square inch.[12] (See Appendix 4)

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[12] http://www.welenco.com/well_repair.htm

- Plugging a well – Each State will have unique requirements for permanent well abandonment that may include deployment of cement plugs across USDWs, active hydrocarbon production zones and/or across open perforations as well as cement squeezes into non-cemented, cased holes across USDWs (See **Appendices 5, 6 and 7** of this report for Texas, Utah and Washington State regulations regarding well plugging and abandonment). State-to-State variations are primarily due to regional geology and drilling development. The height of the cement plug will vary for each application, but it generally is on the order of 100 feet per plug. States may also require a section of casing (up to ten feet from surface) to be removed from the site with the wellhead equipment.

Figure 5-4. A Typical Large Diameter Swage

4. Remediating a Leaking Abandoned Well. In the event a previously abandoned well is found to be leaking, a series of steps can be employed to restore the well for temporary use, remediate the leak, and re-abandon the well. They include:

1. Inform the relevant oversight agency that a leak has been detected in an abandoned well.

2. Review all available well data records, including well completion, abandonment and geophysical logs to assess the current disposition of the well.

3. Formulate a detailed plan for well intervention and remediation and file a copy with the lead regulatory agency.

4. Set up a drilling rig above the location of the leaking well and drill the reclaimed soil above the abandoned well, enabling the intersection of the abandoned completion string. This may require the drilling of a cement plug at the surface.

5. Use swages and/or overshots to help make secure connections between new casing and the abandoned casing strings. These may include (from largest to smallest in diameter) surface, intermediate and production casing strings.

6. Measure pressures within each connected casing string to ascertain from where the leak is originating and proceed with the appropriate remediation plan.

   - If the leak is occurring within the production casing string, the previous abandonment or the casing string itself may be leaking. Remediation efforts here might require the drilling out of the original plugs and determining whether the leak was through the plug or through a leaky casing string

     - For a casing leak, remediate by "killing" the well (loading with a heavy brine to stop inflow) and either installing a casing patch or squeeze cementing

     - For a poor abandonment plug, re-plug the well according to state regulations (see **Appendix 8** of this report for Colorado regulations regarding re-abandonment)

   - If the leak is external to the production string, the leak may be moving through the cement sheath or between the cement sheath and the rock behind it. Locate the leak by drilling out the cement plug, "killing" the well, and running a ultra-sonic cement bond log to determine where the cement channels or areas of poor bonding exist. Remediate the well by squeezing channeled cement in areas of poor bonding

Alternatively, if the injectant has been radioactively traced, 3-dimensional tracer logs can be lowered into the well to show the path of the fugitive injectant. Remediate by squeeze cementing

7. Re-plug the well according to state regulations (see **Appendix 8** of this report for Colorado regulations regarding re-abandonment).

5. Modifications to Remediation Practices to Account for CO_2. Carbon dioxide in combination with water can form carbonic acid, which is corrosive to standard oilfield tubulars as well as cements. Items of concern when used with CO_2 are:

- Permanent and Retrievable Packers – Packers employed in CO_2 environments should be refitted with stainless steel elements, where appropriate, and fit-for use inflation elements. Storage project operators should clearly state the intended use of the packer in a CO_2-rich environment to the vendor.

- Casing and Tubular goods – To mitigate corrosion and extend tubular life the use of fiberglass-lined or stainless steel casing and tubular strings are often employed where CO_2 is present. In the injection well, the CO_2 will be most likely "dried" before injection. For wells that the CO_2 and water plumes will intersect, proper corrective actions or replacement of downhole tubulars may be required. Similarly, all casing repairs employing casing patches may need to consider the use of CO_2 resistant materials.

- Cement – The oilfield service industry recognizes the adverse effects carbonic acid can have on standard oilfield cements, and is working hard to bring state-of-the-art cements to the market for use with CO_2. One such cement is Schlumberger's CemCrete™ product. It is a low water-use cement that was specifically designed to reduce the development of microannuli within the cement sheath. When employed in a CO_2-rich environment, this type of cement is more resistant to CO_2 invasion due to the cement's low porosity.

D. REMEDIATING THE ASSOCIATED IMPACTS OF CO_2 LEAKAGE

The scope of work set forth for this study requested that our examination of remediation be limited to the geological storage formations. For completeness, however, we briefly introduce, in this last section of Chapter V, the efforts involved with remediating the impacts of CO_2 leakage. Table 5-1, modified from Benson and Hepple (2005) and the text below set forth these additional remediation options.

Table 5-1. Options for Remediating the Impacts of CO_2 Leakage Projects (Modified from Benson and Hepple, 2005).

Remediating accumulation of CO_2 in groundwater	• Accumulations of CO_2 in groundwater can be removed by drilling wells that • intersect the accumulations and extracting the CO_2; • Residual CO_2 that is trapped as an immobile gas phase can be removed by dissolving it in water and extracting it as a dissolved phase using groundwater extraction wells; • CO_2 that has dissolved in the shallow groundwater could be removed, if needed, by pumping to the surface and aerating it to remove the CO_2; • For metals or other trace contaminants that have been mobilized by acidification of the groundwater, 'pump-and-treat' methods can be used to remove these contaminants. Alternatively, hydraulic barriers can be created to immobilize and contain the contaminants by appropriately placed injection and extraction wells.
Remediating leakage into the vadose zone and CO_2 accumulation in soil gas	• CO_2 can be extracted from the vadose zone and soil gas by standard vapor extraction techniques from horizontal or vertical wells; • Fluxes from the vadose zone to the ground surface could be decreased or stopped by caps or gas vapour barriers. Pumping below the cap or vapour barrier could be used to deplete the accumulation of CO_2 in the vadose zone; • Since CO_2 is a dense gas, it could be collected in subsurface trenches. Accumulated gas could be pumped from the trenches and released to the atmosphere or reinjected back underground; • Passive remediation techniques that rely only on diffusion and 'barometric pumping' could be used to slowly deplete one-time releases of CO_2 into the vadose zone; • Acidification of the soils from contact with CO_2 could be remediated by irrigation and drainage. Alternatively, agricultural supplements such as lime could be used to neutralize the soil;
Remediating large releases of CO_2 in near-surface atmosphere	• For releases inside a building or confined space, large fans could be used to rapidly dilute CO_2 to safe levels; • For large releases spread out over a large area, dilution from natural atmospheric mixing (wind) will be the only practical method for diluting the CO_2; • For ongoing leakage in established areas, risks of exposure to high concentrations of CO_2 in confined spaces (e.g. cellar around a wellhead) or during periods of very low wind, fans could be used to keep the rate of air circulation high enough to ensure adequate dilution.
Remediating accumulation of CO_2 in indoor environments	• Slow releases into structures can be eliminated by using techniques that have been developed for controlling release of radon and volatile organic compounds into buildings. The two primary methods for managing indoor releases are basement/substructure venting or pressurization. Both would have the effect of diluting the CO_2 before it enters the indoor environment

1. Remediating Accumulation of CO_2 in Groundwater. CO_2 contamination of groundwater can be remediated by the "pump and treat" method. Water is pumped to the surface and aerated to flash the CO_2. The water can then be either pumped back underground or used. CO_2 migrating to a drinking water reservoir will likely leach some amount of minerals along the way and transport them into the water. Treatment for such constituents is more involved and expensive, but could be accomplished with the "pump and treat" approach.

2. Remediating the CO_2 Leakage into Vadose Zone. The Lawrence Berkeley National Laboratory (LBNL) looked at vadose zone remediation of CO_2, based on the similarity of CO_2 transport to the transport of other common vadose zone contaminants. LBNL assumed that soil vapor extraction (SVE) technology could be used for removing CO_2 from soil. Several soil remediation scenarios were examined with the TOUGH2 numerical simulator. The results indicated that large amounts of CO_2 could be removed from the vadose zone using SVE technology. In addition, design enhancements to improve process efficiency were identified (Zhang, et al., 2004).

3. Extracting CO_2 from Near-Surface Accumulations. Horizontal pinnate (leaf-vein pattern) drilling, which has been commercially developed for coalbed methane development, can provide a useful method for accessing CO_2 in near-surface reservoirs and accumulation zones (von Shoenfeldt, et al., 2004).

4. Remediating Surface Accumulations of CO_2. If CO_2 were to migrate up through the soil and into populated areas, there is a danger of CO_2 collecting in basements and low-lying areas and creating an asphyxiation hazard. Mitigation efforts could include fans and CO_2 detectors. In addition, shallow wells could be drilled to intercept and vent the migrating CO_2.

VI. STRATEGIES FOR LEAKAGE PREVENTION AND REMEDIATION

A. OVERVIEW OF THE LEAK PREVENTION AND REMEDIATION STRATEGY

A comprehensive strategy for leak prevention and remediation would contain five main elements: (1) obviating the need for remediation of CO_2 leakage in the first place by selecting favorable storage sites with extremely low risks of leakage; (2) placing considerable emphasis on well integrity, including identifying and properly plugging, where necessary, previously drilled wells; rigorously designing the newly drilled CO_2 injection (and observation) wells so they remain secure during the injection and operating life of the well; and, properly plugging and abandoning the CO_2 injection and observation wells so that they remain secure for “a thousand years”; (3) conducting a phased series of short- and long-term reservoir modeling efforts to establish the flow and trapping of the CO_2 plume; (4) installing a reliable and comprehensive CO_2 plume location and “early warning” leak detection monitoring; and (5) preparing and updating, as necessary, a “ready-to-use” set of procedures and responses for remediating CO_2 leakage should it occur.

B. THE FIVE-PART STRATEGY

This five-part leak prevention and remediation strategy for CO_2 storage is further discussed and developed below.

1. Selecting Favorable Storage Sites With Low Risks of CO_2 Leakage. No other single aspect of a leak prevention and remediation strategy is more important than selecting a safe, secure site in the first place. Chapter II of this report reviews the potential CO_2 leakage pathways that would need to be fully addressed for evaluating the favorability of a storage site. Chapter III of this report provides an extensive discussion of the tools and procedures for helping select a safe, secure CO_2 storage site.

2. Placing Emphasis on Well Integrity. There are three key priorities for ensuring long-term well integrity at a CO_2 storage site.

- The first is identifying the older, abandoned wells in the vicinity of the proposed CO_2 storage site and replugging these wells, where necessary. Using CO_2 resistant cements for plugging these previously abandoned wells and rigorously documenting their locations are two important steps.

- The second priority is designing and installing the CO_2 injection wells so that they will resist loss of cement integrity and corrosion of casing from the acidic CO_2 and water mixture. Chapter V of this report discusses preferred well design and completion practices for CO_2 storage wells

- The third priority is properly closing the CO_2 storage site, including plugging all CO_2 injection and observation wells to promote long-term storage integrity. Chapter V of this report also contains discussion on well plugging and abandonment procedures for CO_2 storage wells.

3. Conducting a Phased Series of Reservoir Simulation-Based Modeling to Track and Project the Location of the CO_2 Plume. Based on experiences to date, we recommend multiple stages of reservoir simulation for supporting leak prevention and remediation efforts in CO_2 storage. The first stage of reservoir simulation and modeling would be undertaken during the initial site selection process. The purpose here is to assemble the available reservoir data, often extrapolated from a regional data set, to establish the injectivity and storage capacity of the site, as well as to project the anticipated movement and location of the CO_2 plume.

The second stage of reservoir simulation modeling would be undertaken after the CO_2 injection and observation wells have been drilled and more site specific geological and reservoir data have been collected. Of particular importance will be the modeling of the internal architecture of the storage formation, including the nature and extent of any shale breaks that might serve as baffles for promoting increased CO_2 contact with the reservoir. Also important would be incorporating into the reservoir model the newly collected data on relative permeability to better estimate CO_2 injectivity and the pore-space (capillary) trapping mechanisms essential for long-term immobilization of the CO_2 plume.

The third stage of reservoir simulation, which would involve repeated runs, would be initiated once the CO_2 monitoring systems provide new information on the flow direction and location of the CO_2 plume. Of particular value is incorporating seismic data and results from subsurface observation wells for calibrating the reservoir model. This third stage of reservoir simulation, often repeated, would be used to project the long-term (1,000 year) trapping and immobilization of the CO_2 plume.

Chapter IV of this report provides additional discussion on the role of reservoir modeling for supporting safe CO_2 storage.

4. Installing and Maintaining a Comprehensive Monitoring System for the CO_2 Storage Site. The overall CO_2 monitoring system will need to be designed to serve several purposes. First and foremost, the CO_2 monitoring system will need to serve as an "early warning system" of any impending CO_2 leakage. For this, there is need for downhole pressure data, CO_2-sensitive logging tools, and near-surface CO_2 detection systems to identify any leakage through or around the reservoir seal. In addition, a variety of pressure monitors and cement bond logs will need to be used for assuring wellbore integrity.

Second, the CO_2 monitoring system will need to provide on-going information on the movement and immobilization of the CO_2 plume. Seismic methods, both surface and downhole, real-time information from offset observation wells, plus regional surface-based leak detection and sub-surface monitoring techniques would be used to augment this information.

Chapter IV of this report provides additional discussion on installing a comprehensive MMV system for monitoring CO_2 storage.

5. Establishing a "Ready-to-Use" Contingency Plan/Strategy for Remediation. The remaining discussion in Chapter VI sets forth a response and mitigation strategy once a leak in the CO_2 storage field has been detected. The procedures and options associated with the response and mitigation strategy are outlined in Chapter V.

C. COSTS OF LEAK PREVENTION AND REMEDIATON

Inevitably, the costs of remediation will impact the overall costs for CO_2 storage in geologic reservoirs. As such, the remediation strategy needs to be considered in the context of the overall CO_2 storage project. The likelihood of needing remediation will be greatly reduced if a rigorous geologic and engineering analysis is performed up front as part of overall site selection and storage project design.

As described in the previous chapter, if a leak occurs, the geologic and engineering effort for remediating the leak can at times be comparable to, and may exceed, that associated with original CO_2 storage site selection, project design and implementation. Therefore, attempts to save money on the front-end site selection, project design and planning phases could result in even higher expenses for remediating problems that could have been avoided by more thorough up-front work. For example, if the causes of a CO_2 leak cannot be remediated, the CO_2 storage site may have to be terminated with the CO_2 transferred to an alternative site. In this extreme case, the entire investment in the initial CO_2 storage project will have been lost.

Two additional costs could also be incurred from leakage of CO_2, assuming significant vertical migration of the CO_2. First would be the cost for remediating the impacts of CO_2 accumulation in the potable water and vadoze zone. The second would be the loss of any CO_2 credits for storing CO_2. Even a modest CO_2 leak involving 25,000 tons of CO_2 (one day of CO_2 emissions from the example power plant) would result in a loss of \$1 million (assuming a CO_2 credit of \$40 per tonne, in U.S. dollars).

The costs associated with the various activities for both preventing leaks and for remediating them after they occur are summarized below. *(All costs are reported as U.S. dollars.)*

1. Leak Prevention Costs. Three important activities - - rigorous site selection, on-going monitoring, and periodic testing for well integrity - - are at the heart of CO_2 leak prevention.

a) Costs for Rigorous Site Selection and Project Design. The major components of a rigorously selected, installed and operated CO_2 storage facility are outlined in Table 6-1. The costs include a comprehensive geological assessment, multiple-phases of reservoir modeling, and a variety of supportive activities. The front-end costs would also include the drilling of reservoir characterization wells which would, subsequently, be converted to long-term observation and monitoring wells.

Table 6-1. Major Components of Site Selection and Project Design

Project Definition and Design
• Initial Geologic and Reservoir Characterization • Test Site Design and Plan • Reservoir Modeling/Simulation • Comprehensive MMV Protocols • Remediation Strategy and Procedures • Regulatory/Permitting Activities
Detailed Site and Reservoir Characterization
• MMV Baseline Studies • Observation, Characterization and Monitoring Well(s) • Seismic Survey(s) • Well Tests
Continuing Activities
• Updated Geologic/Reservoir Model • Operational Monitoring System

The costs for site selection and project design could range from \$5,000,000 to \$20,000,000 per site. The largest single cost item will be the cost of drilling and testing the reservoir characterization and observation wells. Other significant costs will involve establishing the regional geological framework, conducting reservoir modeling of the expected flow and trapping of the CO_2 plume, and testing the integrity of the reservoir caprock. Seismic, while an essential part of site characterization and selection, is not included in these costs as this cost component is included in the monitoring system, as discussed below. The actual costs will depend on the type and depth of the project (e.g., oil and gas field, deep saline aquifer), the amount of CO_2 to be stored, the conditions at the surface overlying the storage formation (industrial, suburban, farmland, etc.), and, perhaps, most important, the regulatory and permitting requirements imposed on the project.

For the illustrative example, we assume the need to drill 6 observation wells costing $2.5 million each, plus $3 million for the remaining aspects of rigorous site selection and project design.

The overall costs for site selection and project design will be combined with the other leak prevention and leak remediation costs (as discussed below) and then converted to a cost per tonne of stored CO_2, using an illustrative example of storing CO_2 in a deep, saline formation.

b) <u>Costs for Project Monitoring and Leak Detection</u>. The costs for implementing monitoring and leak detection protocols for geologic storage of CO_2 have been modified from the original study by Benson, et al., (2005).

This study set forth two monitoring scenarios (a "basic monitoring package" and an "enhanced monitoring package") to evaluate the applicability and costs of conducting monitoring over the life-cycle of a CO_2 storage project. The monitoring systems were designed for three types of projects: (1) an enhanced oil recovery project followed by CO_2 storage; (2) a storage project in a saline aquifer with a high residual gas saturation (RGS), where the CO_2 plume does not move significantly after CO_2 injection stops; and (3) a storage project in a saline aquifer with low residual gas saturation (RGS), where the CO_2 plume keeps moving for a considerable amount of time after injection stops, Table 6-2.

In our remediation study, we have selected the saline aquifer with high RGS and the "enhanced monitoring package" in the illustrative example. However, we reduced the closure monitoring phase in the example to 20 years, from the 50 years set forth in Table 6-2, modified some other costs, and worked to ensure no significant duplication of effort (such as for the seismic survey). As a result, our modified costs for monitoring and leak detection are estimated at $62.5 million. (See discussion in illustrative example, below.)

Table 6-2. Costs of Alternative Monitoring Strategies

Cost Component	Estimated Monitoring Costs (Million Dollars)					
	EOR		Saline Aquifer			
			Low RGS (2)		High RGS (2)	
	Basic Package	Enhanced Package	Basic Package	Enhanced Package	Basic Package	Enhanced Package
Pre-Operational Monitoring						
Well Logs	$0.0	$0.0	$1.1	$1.1	$1.1	$1.1
Wellhead Pressure	$0.0	$0.0	$0.1	$0.1	$0.1	$0.1
Formation Pressure	$0.0	$0.0	$0.3	$0.3	$0.3	$0.3
Injection and Production Rate Testing	$0.0	$0.0	$0.6	$0.6	$0.6	$0.6
Seismic Survey	$0.0	$0.0	$3.8	$3.8	$2.4	$2.4
Microseismicity (Baseline)	$0.5	$0.5	$0.5	$0.7	$0.5	$0.7
Gravity Survey (Baseline)	$0.0	$0.4	$0.0	$0.2	$0.0	$0.2
Electromagnetic Survey (Baseline)	$0.0	$0.4	$0.0	$0.2	$0.0	$0.4
Atmospheric CO2 Monitoring (Baseline)	$0.3	$0.6	$0.1	$0.2	$0.1	$0.2
CO2 Flux Monitoring	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Pressure/Water Quality in Upper Formation	$0.0	$1.0	$0.0	$1.0	$0.0	$1.0
Subtotal	$0.8	$2.9	$6.5	$8.2	$5.1	$7.0
Management (@15%)	$0.1	$0.4	$1.0	$1.2	$0.8	$1.1
Subtotal	$0.9	$3.3	$7.5	$9.4	$5.9	$8.1
Operational Monitoring						
Well Logs	$0.0	$13.2	$0.0	$6.0	$0.0	$6.0
Wellhead Pressure	$1.5	$1.5	$1.7	$1.7	$1.7	$1.7
Injection and Production Rates	$6.5	$6.5	$3.4	$3.4	$3.4	$3.4
Wellhead Atmospheric CO2 Monitoring	$2.5	$2.5	$1.8	$1.8	$1.8	$1.8
Microseismicity	$3.7	$3.7	$3.7	$3.7	$3.7	$3.7
Seismic Survey	$16.0	$16.0	$9.5	$9.5	$9.5	$9.5
Gravity Survey	$0.0	$1.4	$0.0	$0.9	$0.0	$0.9
Electromagnetic Survey	$0.0	$1.4	$0.0	$0.9	$0.0	$0.9
Continuous CO2 Flux Monitoring (10 stations)	$0.0	$4.8	$0.0	$4.8	$0.0	$4.8
Pressure/Water Quality in Upper Formation	$0.0	$0.6	$0.0	$0.6	$0.0	$0.6
Subtotal	$30.2	$51.6	$20.1	$33.3	$20.1	$33.3
Management (@15%)	$4.5	$7.7	$3.0	$5.0	$3.0	$5.0
Subtotal	$34.7	$59.3	$23.1	$38.3	$23.1	$38.3
Closure Monitoring						
Seismic Survey	$7.9	$7.9	$16.0	$16.0	$12.0	$12.0
Gravity Survey	$0.0	$0.7	$0.0	$1.5	$0.0	$1.1
Electromagnetic Survey	$0.0	$0.7	$0.0	$1.5	$0.0	$1.1
Continuous CO2 Flux Monitoring (10 stations)	$0.0	$3.2	$0.0	$8.0	$0.0	$8.0
Pressure/Water Quality in Upper Formation	$0.0	$0.4	$0.0	$1.0	$0.0	$1.0
Wellhead Pressure Monitoring (1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Subtotal	$7.9	$12.9	$16.0	$28.0	$12.0	$23.2
Management (@15%)	$1.2	$1.9	$2.4	$4.2	$1.8	$3.5
Subtotal	$9.1	$14.8	$18.4	$32.2	$13.8	$26.7
TOTAL	$45	$78	$49	$80	$43	$73

Notes: (1) Conducted for 5 years, after which the wells are abandoned; (2) RGS – Residual gas saturation
Source: Benson, et al., 2005.

c) Costs for Wellbore Integrity Monitoring. Wellbore integrity monitoring and logging costs will be a function of the depth of the well, the condition of the well, and the number and types of logs required. Based on cost quotes received by Advanced Resources for conducting ultrasonic cement bond logging (including rig time), the costs for monitoring well integrity are estimated as follows:

Well Depth	Well Integrity Logging Costs	
	Per Log	Total *
5,000 feet	$120,000	$12 million
7,500 feet	$150,000	$15 million
10,000 feet	$180,000	$18 million

*Total assumes 10 CO_2 injection wells and 10 logging runs in 50 years, for a total of 100 logging runs.

We assume that, for the most part, the costs for a more comprehensive set of wellbore integrity logs, essential for providing up-to-date information on the condition of the CO_2 injection wells, are not included in the costs for project monitoring and leak detection set forth in Table 6-2.

2. Leak Remediation Costs. Depending on the nature of the CO_2 leakage problem being addressed, the costs of leak remediation can vary widely. Set forth below are estimated costs for solving four types of problems - - locating the source(s) of the CO_2 leak, plugging old wells, remediating active CO_2 injection wells, and remediating a leak in the caprock.

a) Costs for Locating Source(s) of CO_2 Leaks. Assuming a rigorous site selection process (as discussed above), the most likely source for CO_2 leaks will be the wells themselves, either the older, abandoned wells or because of problems with newly drilled wells. Considerable expertise exists for identifying the source and reasons for CO_2 leaks in wells. As such, the well leak diagnostic procedures are relatively straightforward, with much of the essential information expected to be provided by the on-going project monitoring and leak detection program, discussed above.

Locating an old, abandoned well can be accomplished by numerous means, as set forth in Chapter V. The costs for locating a single well (or even a group of wells) will be modest, set at $100,000 per survey (including interpretation), with significant economies of scale in multi-well situations. We assume, for the illustrative example purposes, a need to conduct ten such surveys in the 50 year life of the project.

For the CO_2 injection wells, a new set of logs (such as a cement bond log) or other diagnostic tools (such as a downhole wireline video camera or a spinner survey) may need to be run to more precisely identify the exact location and cause of the leak in the new injection well. Assuming two diagnostic logs costing $200,000 (including rig time) plus a diagnostic and management charge of $100,000, the costs for a wellbore-based leak detection procedures would be on the order of $300,000 per well. We assume 10 wellbore leaks need to be remediated during the 50 year life of the project.

The process and costs for locating geologically-based CO_2 leaks in a storage formation are much more challenging, as discussed in Chapter V. The costs will be a function of the size of the leakage area, the conditions at the surface overlying the storage formation (industrial, suburban, farmland, etc.), and, perhaps, most important, the requirements imposed by regulatory authorities.

Establishing the cause and source of the geologically-based CO_2 leak may require investigating a large area, with emphasis on areas of potential caprock weakness (such as faulted areas) and structural "spill points". As such, a new large scale seismic survey covering 5 to 20 square miles may need to be conducted over the area where surface leakage has been detected. In addition, new leak detection wells (potentially horizontal wells) may need to be drilled and tested to more precisely locate the source for the CO_2 leak and, ultimately, capture the leaked CO_2 for reinjection.

For the illustrative example, we assume a 20 square mile seismic survey and a cost of $100,000 per square mile for 3D seismic (including processing and interpretation). We also assume $4 million for each horizontal leak detection well (including testing and subsequent operations).

b) Costs for Well Plugging. Well plugging costs will depend on whether the requirement is to plug a recently abandoned well, an old, previously plugged and abandoned well, or a well that was never plugged. Second, the costs will depend on what must be done to plug the well, with the range of possible requirements described in Chapter V. Third, costs will depend on the location of the well being plugged. For example, a well located in an easily accessible, remote location will have much different costs than a well in a difficult-to-access location or in a densely populated area.

Nonetheless, well plugging (in a typical 7,500 foot well) could cost as little as $20,000 and as high as $80,000. On average, most well plugging operations cost $50,000 per well, without considering the salvage value of the casing, if any. In the illustrative example, we assume the need to plug 20 old, abandoned wells leaking CO_2.

c) Costs for Well Remediation. Remedial cementing jobs, intended to repair a simple wellbore leak, would cost in the range of $30,000 to $50,000, on average, but could vary considerably depending on the nature of the leak and the condition of the wellbore. A more involved remediation, required when a substantial section of the well has leaks or damage, would require placing and cementing in place a smaller diameter liner inside the well casing. The costs of this remediation step is estimated at $100,000 per well.

In some cases, a leaky well cannot be repaired, and must be plugged. In this case, the costs would include plugging the leaking well and drilling a new replacement CO_2 injection well. The costs of drilling new wells depend on the depth of the well, with an average well cost of $1,000,000 (in 2003) for a 7,500 foot (2,300 meter) well. These costs can range from $500,000 for a shallow 5,000 foot (760 meter) well, to $5.5 million for a deep 15,000 foot (4,600 meter) well (API, 2005). However, well costs have increased by about 150% in the last three years, and now a 7,500 foot CO_2 injection well costs on the order of $2.5 million. The main cost components that have dramatically increased are rig fuel (diesel oil), tubulars (steel), and the day-rate for drilling rigs.

For the illustrative example, we assume one significant remediation for each of the CO_2 injection wells (10 remediations) and the need to re-drill one CO_2 injection well.

In the case of a well blow-out, an extremely rare event in natural gas storage operations, the operator may need to inject heavy fluids or even drill a directional well to intercept the damaged well. The costs can range from relatively moderate costs of well plugging to very high costs for drilling a costly directional well by which to access the blow-out and then converting this well (or drilling a new well) for CO_2 injection. Because of the unique circumstances and rare occurrence of this problem, we have not estimated these costs.

d) Costs for Remediation of Leaks in Caprock. The first step in mitigating a CO_2 leak in the caprock would be to stop CO_2 injection and to inject water into a formation above the caprock to create a positive pressure barrier, if possible. This would involve drilling and operating new water injection wells, with costs comparable to those set forth above.

To create a positive pressure barrier for mitigating the CO_2 leak would, we assume, involve the drilling and completing two horizontal water injection wells and installing a water source well and water injection facilities. We estimate the water source and injection facility costs at $2 million.

There are no documented cases of fully remediating a leak in a caprock, in either a CO_2 storage or a natural gas storage project. In general, performing such a remediation effort is speculative at best. Consequently, the costs associated with this remediation action are unknown and not estimated by this study. The development of possible approaches for remediating leaks in caprock remains an important area for future research.

3. Example Storage Case. To further illustrate the costs of remedation, we have selected a sample saline aquifer CO_2 storage site. (For consistency, we have constructed this illustrative CO_2 storage example to be relatively similar to the high RGS saline aquifer example set forth by Benson (2005)). The main assumptions are as follows:

- The storage site serves one 1,000 MW coal-fired power plant, with 8.6 million metric tons of annual CO_2 emissions. The site will operate for 50 years, with 30 years for CO_2 injection and 20 years for post-closure monitoring.

- An "enhanced" CO_2 monitoring system has been assumed to have been implemented, involving $7 million of pre-operational monitoring (integrated with site characterization), $33 million for operational monitoring (including continuous pressure and atmospheric monitoring and periodic seismic and other geophysical surveys), $10 million for post-closure monitoring and $12.5 million (25%) for G&A/management. As such, this $62.5 million monitoring strategy is consistent with a rigorous site selection program and is highly supportive of the diagnostic systems essential for identifying the sources for CO_2 leakage, should these occur.

- For consistency purposes, we also assume that the CO_2 storage site has 10 CO_2 injection wells, each capable of injecting 2,500 tonnes of CO_2 per day with a 94% operating factor. (This is a highly optimistic CO_2 injection assumption given the effects of two-phase relative permeability, interference among the 10 relatively closely spaced CO_2 injection wells, and the steadily increasing pressure in the saline formation.)

- The CO_2 plume extends radially and underlies an area of about 80 square miles (216 km^2) at the end of 50 years.

Based on this example, the overall costs for leak prevention and leak remediation (including the comprehensive monitoring effort) would be as shown in Table 6-3:

Table 6-3. Representative Costs for Leak Prevention and Remediation

	Activity	Mid-Range Costs (millions)	Comments
A. BASIC COSTS			
	1. Site Selection and Project Design	$18.0	Includes 6 observation wells plus other site selection costs
	2. Monitoring and Leak Detection	$62.5	Includes the comprehensive seismic program otherwise included in site selection
	3. Wellbore Integrity	$15.0	Includes multiple periodic ultrasonic cement bond logs and well integrity tests in 10 CO_2 injection wells
	Sub-Total	$95.5	
B. REMEDIATION COSTS (If Needed)			
	1. Locating Sources of CO2 Leaks		
	• Old, Abandoned Wells	$1.0	Assumes 10 leaking, abandoned well surveys
	• New CO_2 Injection Wells	$3.0	Assumes 10 sets of diagnostic logs
	• Caprock/Spill Point	$10.0	Includes seismic and 2 horizontal leak detection wells
	2. Well Plugging	$1.0	Includes plugging of 20 old wells
	3. Well Remediation	$3.5	Includes 10 well remediations and drilling one new CO_2 injection well
	4. Caprock Leakage		
	• Pressure Boundary	$10.0	Includes two horizontal water injection wells plus a water plant
	• Other Problems	Large	May need to abandon original storage site and build a new site
	Sub-Total	$28.5+	
	TOTAL	$124.0+	

The cost for a comprehensive CO_2 leak prevention, monitoring and remediation program estimated to be on the order of $120 to $130 million per site. Assuming the injection of 258 million tones of CO_2, the cost per tonne for these efforts would range from $0.45 to $0.50 per tonne. However, should the CO_2 leakage problems not be able to be remediated, the costs would become large and include establishing a new storage facility, transporting some or all of the CO_2 to the new facility, remediating the impacts of CO_2 losses to the potable water and vadoze zone, and losing the value of any CO_2 credits for the CO_2 lost to the atmosphere or other undesirable locations.

D. OBSERVATIONS AND RECOMMENDATIONS

1. Observations. Our work in conducting this study and preparing this report convinces us that, with a properly designed and rigorously implemented leakage prevention and remediation strategy, the use of geologic storage of CO_2 can be safe, secure and worthy of public acceptance.

Of particular note is the excellent reliability and safety record of the natural gas storage industry, the closest long-term analog for CO_2 storage. We have summarized this experience and performance record in the many "Sidebars" to this report.

Similarly, our review and summary of naturally stored CO_2, in places such as McElmo Dome and the Paradox Basin, provides a second set of valuable analogs that show: (1) under a favorable combination of caprock, structural confinement and well integrity conditions, CO_2 can be safely and securely stored for millions of years; and (2) even when nature has created leakage pathways for deep-earth generated CO_2, these leakage pathways, once understood and monitored, can be accommodated with practical and reasonable mitigation actions.

We observe that CO_2 leakage diagnosis and remediation, particularly remediation, has received much less attention and priority than this important topic deserves. For example:

- A search of the technical literature identifies very few technical reports or papers that concentrate on CO_2 leakage remediation. Generally, this topic, even when addressed, is given only "high level" and brief discussion in papers addressing geological CO_2 storage.

- We find only two in-depth studies of remediation experiences and "lessons learned" for the most analogous activity to CO_2 storage - - the natural gas storage industry. The work by Perry (2003) is most valuable and provides original data and investigation of this topic, including its relevance to CO_2 storage. The work by Woodhill (2005) mainly repeats the work by Perry and others on the gas storage experience and adds little original work to the body of knowledge.

We are pleased to observe, and duly applaud, that the U.S. DOE's *Carbon Sequestration Technology Roadmap and Program Plan for 2006* (U.S. DOE, 2006) contains a section on CO_2 leakage mitigation and remediation. The term MMV, which has traditionally stood for monitoring, *measurement* and verification, now refers to monitoring, *mitigation,* and verification in the DOE roadmap and program plan. For the mitigation topic, the program is investigating steps that can be taken, should CO_2 leakage occur, to arrest the flow of CO_2 and mitigate negative impacts. Examples of activities under consideration include lowering the pressure within the storage formation to reduce the driving force for CO_2 flow (including closing unintended fracturing or faulting); forming a "pressure plug" by increasing the pressure in the formation into which the CO_2 may be leaking; intercepting the leakage path; or plugging the region where leakage is occurring with low permeability materials, such as, for example, "controlled mineral carbonation" or "controlled formation of biofilms."

DOE's Carbon Sequestration Program is also performing research on various potential breakthrough concepts. One such concept with potential applicability to long-term CO_2 leakage mitigation is the examination of naturally occurring bacteria ("methanogens") that may have the ability to convert CO_2 into methane within geologic reservoirs (many natural gas fields have been created this way). Efforts are underway to develop technology for introducing such organisms into geologic CO_2 storage sites to harness their natural ability to generate future potentially producible natural gas resources. The activities associated with the initial phases of this work are to: (1) identify and define the biological requirements of bacterial consortia most appropriate for remediating geologic CO_2 sequestration sites, (2) assess the geochemical conditions required for successful application of methanogens in geological settings; and (3) screen known oil and gas reservoirs in the U.S. to quantify potential application of methanogens and to identify high-graded sites for further laboratory and field application.[13]

2. Recommendations. Clearly, this overview study and report on CO_2 leak prevention and remediation serves as merely a first step forward. Fruitful next steps would include the following:

[13] http://www.er.doe.gov/sbir/awards_abstracts/sbirsttr/cycle21/phase1/049.htm

a) Develop a "Best Practices" Remediation Manual. It would be most valuable to develop and maintain an up-to-date "Best Practices" Manual on CO_2 Leak Prevention and Remediation. Similar "best practices" efforts are underway on topics such as site assessment and selection and monitoring. Summaries of this work could be incorporated without duplication, into the Remediation Manual to provide a comprehensive strategy for CO_2 Leak Prevention and Remediation. As new insights on remediation are developed, these would need to be added to this "Best Practices" CO_2 Leak Prevention and Remediation Manual to keep it "evergreen".

b) Study Remediation in the Natural Gas Storage Industry. Given its value as the most relevant analog to CO_2 storage, we recommend undertaking additional studies of the remediation experiences, practices and "lessons learned" of the natural gas storage industry. Fruitful areas for exploration would be further detailed on leak source identification and the cost of remediation.

c) Invest in Research and Technology Development in Remediation for CO_2 Storage. Of high priority would be much more intensive investigations and field trials of procedures for identifying and then sealing a failure in the caprock. Equally valuable would be work on materials and procedures for greater well integrity, leading toward a "thousand year well."

d) Develop New Procedures and Technology for Locating and Assessing the Integrity of Abandoned Wells. Valuable work on this topic has been undertaken by the U.S. DOE/NETL, but much more needs to be done to develop cost-effective means for reliably locating and assessing the status of old, abandoned wells near a CO_2 storage site. As valuable would be the development of new procedures and technologies for securely plugging these old, abandoned wells.

e) Launch a Series of "Best Practice", Large-Scale Field Tests of CO_2 Storage. An important emphasis in these large-scale field tests would be testing and assessment procedures for selecting sites with caprock and wellbore integrity. Equal emphasis in these large-scale field tests would be on establishing and testing an integrating system involving CO_2 monitoring, CO_2 leak detection, and remediation. A valuable side benefit would be learning, much more reliably, the actual costs of installing such an integrated system.

f) Address Concerns on Lack of Structural Confinement in "Open System" Saline Formations. If the large "open system" saline formations are to become viewed as safe, secure sites for injecting CO_2, considerable new investigation and research is required. Of particular importance are the following research topics - - aquifer hydrodynamics, potentially for pore space and hysterisis trapping of CO_2 in alternative geological settings understanding the dynamics of CO_2 displacement of stored saline water, and identification of geologic features that would provide assurance of updip trapping of the CO_2 plume, among others.

* * * * * *

We have been pleased to conduct the study and prepare this report on a most important topic involving geological storage of CO_2 - - Remediation of Leakage from CO_2 Storage Reservoirs. We trust this initial work will stimulate additional, more intensive investigations and investments in technologies on CO_2 leakage detection and remediation.

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REMEDIATION OF LEAKAGE FROM CO_2 STORAGE RESERVOIRS

APPENDIX

IEA/CON/04/108

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Appendix 1.
Casing, Cementing, Drilling and Completion Requirements for Onshore Wells

Rule §3.13: Texas Administrative Code
Railroad Commission of Texas
Oil and Gas Division

Texas Administrative Code

TITLE 16 ECONOMIC REGULATION
PART 1 RAILROAD COMMISSION OF TEXAS
CHAPTER 3 OIL AND GAS DIVISION
RULE §3.13 Casing, Cementing, Drilling, and Completion Requirements
(a) General.

(1) The operator is responsible for compliance with this section during all operations at the well. It is the intent of all provisions of this section that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all potentially productive zones be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing. When the section does not detail specific methods to achieve these objectives, the responsible party shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology.

(2) Definitions. The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(A) Stand under pressure--To leave the hydrostatic column pressure in the well acting as the natural force without adding any external pump pressure. The provisions are complied with if a float collar is used and found to be holding at the completion of the cement job.

(B) Zone of critical cement--For surface casing strings shall be the bottom 20% of the casing string, but shall be no more than 1,000 feet nor less than 300 feet. The zone of critical cement extends to the land surface for surface casing strings of 300 feet or less.

(C) Protection depth--Depth to which usable-quality water must be protected, as determined by the Texas Commission on Environmental Quality (TCEQ) or its successor agencies, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(D) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in commercial quantities in the area.

(b) Onshore and inland waters.

(1) General.

(A) All casing cemented in any well shall be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the well. For new pipe, the mill test pressure may be used to fulfill this requirement. As an alternative to hydrostatic testing, a full length electromagnet, ultrasonic, radiation thickness gauging, or magnetic particle inspection may be employed.

(B) Wellhead assemblies shall be used on wells to maintain surface control of the well. Each component of the wellhead shall have a pressure rating equal to or greater than the anticipated pressure to which that particular component might be exposed during the course of drilling, testing, or producing the well.

(C) A blowout preventer or control head and other connections to keep the well under control at all times shall be installed as soon as surface casing is set. This equipment shall be of such construction and capable of such operation as to satisfy any reasonable test which may be required by the commission or its duly accredited agent.

(D) When cementing any string of casing more than 200 feet long, before drilling the cement plug the operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the casing string by 0.2. The maximum test pressure required, however, unless otherwise ordered by the commission, need not exceed 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 10% or more from the original test pressure, the casing shall be condemned until the leak is corrected. A pressure test demonstrating less than a 10% pressure drop after 30 minutes is proof that the condition has been corrected.

(E) Wells drilling to formations where the expected reservoir pressure exceeds the weight of the drilling fluid column shall be equipped to divert any wellbore fluids away from the rig floor. All diverter systems shall be maintained in an effective working condition. No well shall continue drilling operations if a test or other information indicates the diverter system is unable to function or operate as designed.

(2) Surface casing.

(A) Amount required.

(i) An operator shall set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the TCEQ. Before drilling any well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable field rules, an operator shall obtain a letter from the TCEQ stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the commission.

(ii) Any well drilled to a total depth of 1,000 feet or less below the ground surface may be drilled without setting surface casing provided no shallow gas sands or abnormally high pressures are known to exist at depths shallower than 1,000 feet below the ground surface; and further, provided that production casing is cemented from the shoe to the ground surface by the pump and plug method.

(B) Cementing. Cementing shall be by the pump and plug method. Sufficient cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement does not circulate to ground surface or the bottom of the cellar, the operator or his representative shall obtain the approval of the district director for the procedures to be used to perform additional cementing operations, if needed, to cement surface casing from the top of the cement to the ground surface.

(C) Cement quality.

(i) Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.

(ii) An operator may use cement with volume extenders above the zone of critical cement to cement the casing from that point to the ground surface, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed.

(iii) In addition to the minimum compressive strength of the cement, the API free water separation shall average no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B.

(iv) The commission may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area.

(D) Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures adopted by the American Petroleum Institute, as published in the current API RP 10B. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished the commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure.

(i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement.

(ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.

(E) Cementing report. Upon completion of the well, a cementing report must be filed with the commission furnishing complete data concerning the cementing of surface casing in the well as specified on a form furnished by the commission. The operator of the well or his duly authorized agent having personal knowledge of the facts, and representatives of the cementing company performing the cementing job, must sign the form attesting to compliance with the cementing requirements of the commission.

(F) Centralizers. Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers shall meet API spec 10D specifications. In deviated holes, the operator shall provide additional centralization.

(G) Alternative surface casing programs.

(i) An alternative method of fresh water protection may be approved upon written application to the appropriate district director. The operator shall state the reason (economics, well control, etc.) for the alternative fresh water protection method and outline the alternate program for casing and cementing through the protection depth for strata containing usable-quality water. Alternative programs for setting more than specified amounts of surface casing for well control purposes may be requested on a field or area basis. Alternative programs for setting less than specified amounts of surface casing will be authorized on an individual well basis only. The district director may approve, modify, or reject the proposed program. If the proposal is modified or rejected, the operator may request a review by the director of field operations. If the proposal is not approved administratively, the operator may request a public hearing. An operator shall obtain approval of any alternative program before commencing operations.

(ii) Any alternate casing program shall require the first string of casing set through the protection depth to be cemented in a manner that will effectively prevent the migration of any fluid to or from any stratum exposed to the wellbore outside this string of casing. The casing shall be cemented from the shoe to ground surface in a single stage, if feasible, or by a multi-stage process with the stage tool set at least 50 feet below the protection depth.

(iii) Any alternate casing program shall include pumping sufficient cement to fill the annular space from the shoe or multi-stage tool to the ground surface. If cement is not circulated to the ground surface or the bottom of the cellar, the operator shall run a temperature survey or cement bond log. The appropriate district office shall be notified prior to running the required temperature survey or bond log. After the top of cement outside the casing is determined, the operator or his representative shall contact the appropriate district director and obtain approval for the procedures to be used to perform any required additional cementing operations. Upon completion of the well, a cementing report shall be filed with the commission on the prescribed form.

(iv) Before parallel (nonconcentric) strings of pipe are cemented in a well, surface or intermediate casing must be set and cemented through the protection depth.

(3) Intermediate casing.

(A) Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet above the shoe. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented from the shoe up to a point at least 600 feet above the top of the shallowest productive horizon or to a point at least 200 feet above the shoe of the next shallower casing string that was set and cemented in the well.

(B) Alternate method. In the event the distance from the casing shoe to the top of the shallowest productive horizon make cementing, as specified above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such possible productive horizons and prevent fluid migration to or from such strata within the wellbore.

(4) Production casing.

(A) Cementing method. The producing string of casing shall be cemented by the pump and plug method, or another method approved by the commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 feet above the shoe. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such possibly productive horizons by one of the methods specified for intermediate casing in paragraph (3) of this subsection.

(B) Isolation of associated gas zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact.

(5) Tubing and storm choke requirements.

(A) Tubing requirements for oil wells. All flowing oil wells shall be equipped with and produced through tubing. When tubing is run inside casing in any flowing oil well, the bottom of the tubing shall be at a point not higher than 100 feet above the top of the producing interval nor more than 50 feet above the top of a line, if one is used. In a multiple zone structure, however, when an operator elects to equip a well in such a manner that small through-the-tubing type tools may be used to perforate, complete, plug back, or recomplete without the necessity of removing the installed tubing, the bottom of the tubing may be set at a distance up to, but not exceeding, 1,000 feet above the top of the perforated or open-hole interval actually open for production into the wellbore. In no case shall tubing be set at a depth of less than 70% of the distance from the surface of the ground to the top of the interval actually open to production.

(B) Storm choke. All flowing oil, gas, and geothermal resource wells located in bays, estuaries, lakes, rivers, or streams must be equipped with a storm choke or similar safety device installed in the tubing a minimum of 100 feet below the mud line.

(c) Texas offshore casing, cementing, drilling, and completion requirements.

(1) Casing. The casing program shall include at least three strings of pipe, in addition to such drive pipe as the operator may desire, which shall be set in accordance with the following program.

(A) Conductor casing. A string of new pipe, or reconditioned pipe with substantially the same characteristics as new pipe, shall be set and cemented at a depth of not less than 300 feet TVD (true vertical depth) nor more than 800 feet TVD below the mud line. Sufficient cement shall be used to fill the annular space back of the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations.

(B) Surface casing. All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi) or reconditioned pipe that has been tested to an equal pressure. Sufficient cement shall be used to fill the annular space behind the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Surface casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations. In all cases, surface casing shall be set prior to drilling below 3,500 feet TVD. Minimum depths for surface casing are as follows.

(i) Surface Casing Depth Table.

Proposed Total Vertical Depth of Well	**Surface**
to 7,000 feet	25% of proposed total depth of well
7,000-10,000 feet	2,000 feet
10,000 and below	2,500 feet

(ii) Casing test. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling plug or initiating tests. Casing shall be tested by pump pressure to at least 1,000 psi. If, at the end of 30 minutes, the pressure shows a drop of 100 psi or more, the casing shall be condemned until the leak is corrected. A pressure test demonstrating a drop of less than 100 psi after 30 minutes is proof that the condition has been corrected.

(C) Production casing or oil string. The production casing or oil string shall be new or reconditioned pipe with a mill test of at least 2,000 psi that has been tested to an equal pressure and after cementing shall be tested by pump pressure to at least 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 150 psi or more, the casing shall be condemned. After corrective operations, the casing shall again be tested in the same manner. Cementing shall be by the pump and plug method. Sufficient cement shall be used to fill the calculated annular space above the shoe to protect any prospective producing horizons and to a depth that isolates abnormal pressure from normal pressure (0.465 gradient). A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating tests.

(2) Blowout preventers.

(A) Before drilling below the conductor casing, the operator shall install at least one remotely controlled blowout preventer with a mechanism for automatically diverting the drilling fluid to the mud system when the blowout preventer is activated.

(B) After setting and cementing the surface casing, a minimum of two remotely controlled hydraulic ram-type blowout preventers (one equipped with blind rams and one with pipe rams), valves, and manifolds for circulating drilling fluid shall be installed for the purpose of controlling the well at all times. The ram-type blowout preventers, valves, and manifolds shall be tested to 100% of rated working pressure, and the annular-type blowout preventer shall be tested to 1,000 psi at the time of installation. During drilling and completion operations, the ram-type blowout preventers shall be tested by closing at least once each trip, and the annular-type preventer shall be tested by closing on drill pipe once each week.

(3) Kelly cock. During drilling, the well shall be fitted with an upper kelly cock in proper working order to close in the drill string below hose and swivel, when necessary for well control. A lower kelly safety valve shall be installed so that it can be run through the blowout preventer. When needed for well control, the operator shall maintain at all times on the rig floor safety valves to include:

(A) full-opening valve of similar design as the lower kelly safety valves; and

(B) inside blowout preventer valve with wrenches, handling tools, and necessary subs for all drilling pipe sizes in use.

(4) Mud program. The characteristics, use, and testing of drilling mud and conduct of related drilling procedures shall be designed to prevent the blowout of any well. Adequate supplies of mud of sufficient weight and other acceptable characteristics shall be maintained. Mud tests shall be made frequently. Adequate mud testing equipment shall be kept on the drilling platform at all times. The hole shall be kept full of mud at all times. When pulling drill pipe, the mud volume required to fill the hole each time shall be measured to assure that it corresponds with the displacement of pipe pulled. A derrick floor recording mud pit level indicator shall be installed and operative at all times. A careful watch for swabbing action shall be maintained when pulling out of hole. Mud-gas separation equipment shall be installed and operated.

(5) Casinghead.

(A) Requirement. All wells shall be equipped with casingheads of sufficient rated working pressure, with adequate connections and valves available, to permit pumping mud-laden fluid between any two strings of casing at the surface.

(B) Casinghead test procedure. Any well showing sustained pressure on the casinghead, or leaking gas or oil between the surface casing and the oil string, shall be tested in the following manner. The well shall be killed with water or mud and pump pressure applied. Should the pressure gauge on the casinghead reflect the applied pressure, the casing shall be condemned.

After corrective measures have been taken, the casing shall be tested in the same manner. This method shall be used when the origin of the pressure cannot be determined otherwise.

(6) Christmas tree. All completed wells shall be equipped with Christmas tree fittings and wellhead connections with a rated working pressure equal to, or greater than, the surface shut-in pressure of the well. The tubing shall be equipped with a master valve, but two master valves shall be used on all wells with surface pressures in excess of 5,000 psi. All wellhead connections shall be assembled and tested prior to installation by a fluid pressure equal to the test pressure of the fitting employed.

(7) Storm choke and safety valve. A storm choke or similar safety device shall be installed in the tubing of all completed flowing wells to a minimum of 100 feet below the mud line. Such wells shall have the tubing-casing annulus sealed below the mud line. A safety valve shall be installed at the wellhead downstream of the wing valve. All oil, gas, and geothermal resource gathering lines shall have check valves at their connections to the wellhead.

(8) Pipeline shut-off valve. All gathering pipelines designed to transport oil, gas, condensate, or other oil or geothermal resource field fluids from a well or platform shall be equipped with automatically controlled shut-off valves at critical points in the pipeline system. Other safety equipment must be in full working order as a safeguard against spillage from pipeline ruptures.

(9) Training. Effective January 1, 1981, all tool pushers, drilling superintendents, and operators' representatives (when the operator is in control of the drilling) shall be required to furnish certification of satisfactory completion of a USGS-approved school on well control equipment and techniques. The certification shall be renewed every two years by attending a USGS-approved refresher course. These training requirements apply to all drilling operations on lands which underlie fresh or marine waters in Texas.

Source Note: The provisions of this §3.13 adopted to be effective January 1, 1976; amended to be effective April 8, 1980, 5 TexReg 1152; amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective January 1, 1983, 7 TexReg 3982; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective January 11, 1991, 16 TexReg 39; amended to be effective August 13, 1991, 16 TexReg 4153; amended to be effective August 25, 2003, 28 TexReg 6816

Appendix 2.
Notification of Fire Breaks, Leaks and Blow-outs

Rule §3.20: Texas Administrative Code
Railroad Commission of Texas
Oil and Gas Division

Texas Administrative Code

TITLE 16 ECONOMIC REGULATION
PART 1 RAILROAD COMMISSION OF TEXAS
CHAPTER 3 OIL AND GAS DIVISION
RULE §3.20 Notification of Fire Breaks, Leaks, or Blow-outs

(a) General requirements.

(1) Operators shall give immediate notice of a fire, leak, spill, or break to the appropriate commission district office by telephone or telegraph. Such notice shall be followed by a letter giving the full description of the event, and it shall include the volume of crude oil, gas, geothermal resources, other well liquids, or associated products lost.

(2) All operators of any oil wells, gas wells, geothermal wells, pipelines receiving tanks, storage tanks, or receiving and storage receptacles into which crude oil, gas, or geothermal resources are produced, received, stored, or through which oil, gas, or geothermal resources are piped or transported, shall immediately notify the commission by letter, giving full details concerning all fires which occur at oil wells, gas wells, geothermal wells, tanks, or receptacles owned, operated, or controlled by them or on their property, and all such persons shall immediately report all tanks or receptacles struck by lightning and any other fire which destroys crude oil, natural gas, or geothermal resources, or any of them, and shall immediately report by letter any breaks or leaks in or from tanks or other receptacles and pipelines from which oil, gas, or geothermal resources are escaping or have escaped. In all such reports of fires, breaks, leaks, or escapes, or other accidents of this nature, the location of the well, tank, receptacle, or line break shall be given by county, survey, and property, so that the exact location thereof can be readily located on the ground. Such report shall likewise specify what steps have been taken or are in progress to remedy the situation reported and shall detail the quantity (estimated, if no accurate measurement can be obtained, in which case the report shall show that the same is an estimate) of oil, gas, or geothermal resources, lost, destroyed, or permitted to escape. In case any tank or receptacle is permitted to run over, the escape thus occurring shall be reported as in the case of a leak. (Reference Order Number 20-60,399, effective 9-24-70.)

(b) The report hereby required as to oil losses shall be necessary only in case such oil loss exceeds five barrels in the aggregate.

(c) Any operation with respect to the pickup of pipeline break oil shall be done subject to the following provisions. The provisions hereafter set out shall not apply to the picking up and the returning of pipeline break oil to the pipeline from which it escaped either at the place of the pipeline break, or at the nearest pipeline station to the break where facilities are available to return such oil to the pipeline; provided, that such operations are conducted by the pipeline operator at the time of the pipeline break and its repair; provided, further, that such authority as is herein granted for the picking up of pipeline break oil shall not relieve the operator of such pipeline of notifying the commission of such pipeline break, and the furnishing to the commission of the information required by the provisions set out in subsection (a) of this section for reporting such pipeline breaks.

(1) Any person desiring to pick up, reclaim, or salvage pipeline break oil, other than as provided in this subsection, shall obtain in writing a permit before commencing operations. All applications for permits to pick up, reclaim, or salvage such oil shall be made in writing under oath to the district office.

(2) Applications to pick up, reclaim, or salvage pipeline break oil shall state the location of such oil, the location of the break in the pipeline causing the leakage of such oil, the name of the pipeline, the owner thereof, and the date of the break.

(3) Pipeline break oil that is not returned to the pipeline from which it escaped shall be offered to the applicant to reclaim by the operator of such pipeline but shall be charged to such pipeline stock account.

Source Note: The provisions of this §3.20 adopted to be effective January 1, 1976.

Appendix 3.
Reporting of Undesirable Oil and Gas Events

Rule 649-3-32: Division of Oil, Gas and Mining
Department of Natural Resources
State of Utah

UTAH OIL and GAS

Division of Oil, Gas and Mining - State of Utah - Department of Natural Resources

Definition of Major Event

- **Leaks, breaks or spills which result in the discharge of more than 100 barrels of liquid.**
- **Equipment failures or accidents which result in the flaring, venting, or wasting of more than 500 Mcf of gas.**
- **Any fire which consumes the volumes shown above.**
- **Any spill, venting, or fire, regardless of the volume involved, which occurs in a sensitive area stipulated on the approval notice of the initial APD for a well, e.g., parks, recreation sites, wildlife refuges, lakes, reservoirs, streams, urban or suburban areas.**
- **Each accident which involves a fatal injury.**
- **Each blowout; loss of control of a well.**

R649-3-32. Reporting of Undesirable Events.

1. The division shall be notified of all fires, leaks, breaks, spills, blowouts, and other undesirable events occurring at any oil or gas drilling, producing, or transportation facility, or at any injection or disposal facility.

2. Immediate notification shall be required for all major undesirable events as outlined in R649-3-32-5.

2.1. Immediate notification shall mean a verbal report submitted to the division as soon as practical but within a maximum of 24 hours after discovery of an undesirable event.

2.2. A complete written report of the incident shall also be submitted to the division within five days following the conclusion of an undesirable event.

2.3. The requirements for written reports are specified in R649-3-32-4.

3. Subsequent notification shall be required for all minor undesirable events as outlined in R649-3-32-6.

3.1. Subsequent notification shall mean a complete written report of the incident submitted to the division within five days following the conclusion of an undesirable event.

3.2. The requirements for written reports are specified in R649-3-32-4.

4. Complete written reports of undesirable events may be submitted on Form 9, Sundry Notice and Report on Wells. The report shall include:

4.1. The date and time of occurrence and, if immediate notification was required, the date and time the occurrence was reported to the Division.

4.2. The location where the incident occurred described by section, township, range, and county.

4.3. The specific nature and cause of the incident.

4.4. A description of the resultant damage.

4.5. The action taken, the length of time required for control or containment of the incident, and the length of time required for subsequent cleanup.

4.6. An estimate of the volumes discharged and the volumes not recovered.

4.7. The cause of death if any fatal injuries occurred.

5. Major undesirable events include the following:

5.1. Leaks, breaks or spills of oil, salt water or oil field wastes that result in the discharge of more than 100 barrels of liquid, that are not fully contained on location by a wall, berm, or dike.

5.2. Equipment failures or other accidents that result in the flaring, venting, or wasting of more than 500 Mcf of gas.

5.3. Any fire that consumes the volumes of liquid or gas specified in R649-3-32-5.1 and R649-3-32-5.2.

5.4. Any spill, venting, or fire, regardless of the volume involved, that occurs in a sensitive area stipulated on the approval notice of the initial APD for a well, e.g., parks, recreation sites, wildlife refuges, lakes, reservoirs, streams, urban or suburban areas.

5.5. Each accident that involves a fatal injury.

5.6. Each blowout, loss of control of a well.

6. Minor undesirable events include the following:

6.1. Leaks, breaks or spills or oil, salt water, or oil field wastes that result in the discharge of more than ten barrels of liquid and are not considered major events in R649-3-32-5.

6.2 Equipment failures or other accidents that result in the flaring, venting or wasting of more than 50 Mcf of gas and are not considered major events in R649-3-32-5.

6.3. Any fire that consumes the volumes of liquid or specified in R649-3-32-6.1 and R649-3-32-6.2.
6.4. Each accident involving a major or life-threatening injury.

Appendix 4.
Procedure for Internal Casing Repair

Procedure #: UICLPG-12
Kansas Department Of Health & Environment
State of Kansas

KANSAS DEPARTMENT OF HEALTH & ENVIRONMENT
PROCEDURE FOR INTERNAL CASING REPAIR
Procedure #: UICLPG-12

Narrative:
The operator shall submit a plan for casing repair to the Kansas Department of Health and Environment (KDHE) prior to repairing any casing in any underground hydrocarbon storage well. The operator shall not commence any repair operations until the plan is approved by KDHE.

The casing shall be repaired in a manner that will ensure the integrity of the well is maintained.

The plan for casing repair shall include the following information:

- A schematic of the well configuration, including casing size and weight
- The condition of the well, including any restrictions in the casing, hole deviation, and condition of the cement
- The external and internal pressure rating of the casing patch
- A description of the leak, including the depth, type, size, diameter, length, and width
- A description of the method and equipment used to locate the leak
- A description of the hole preparation before running the casing patch
- A description of the casing patch and installation method
- A description of safety precautions to be used while running the casing patch and the procedure to be used if the casing patch becomes stuck
- A description of the method to be used to pressure test the casing patch.

Procedure:

1. Depressure the cavern by removing all product that can feasibly be removed. Describe the procedure for removing product from the cavern, including any product trapped behind the casing.
2. Fill the cavern with brine.

3. Remove all tubing string(s) from the well.
4. Conduct a casing evaluation to determine the condition of the entire casing string. The operator should determine the following:
    a. The type of leak
    b. The internal diameter of the casing to determine if it is oversized
    c. The position of the hold down.
    d. The location of the leak.
5. Additionally, a gamma ray log shall be run to correlate the depth of the leak and the patch position.
6. Initiate any hole preparations and procedures required for the type of leak identified and approved by KDHE for repair.
7. Run a casing scraper to clean the casing in the patch area.
8. Make a gage or drift run to identify any restrictions in the casing. Describe tentative procedures for removing any restrictions.
9. Run a casing caliper log if the internal diameter of the casing is not known or is questionable. Determine the amount of reduction to the inside diameter of the casing after the patch is applied.
10. Determine the pressure requirements for the patch and confirm that the patch is designed for the size and weight of the casing. Refer to any charts provided by the patch manufacturer.
11. Follow manufacturer's recommended safety precautions while running the patch.
12. When setting the patch, overlap the leak by 6 to 8 feet on each end. When patching corroded casing, cover the full joint of casing with a 6 to 8 foot overlap at each end.
13. Pressure test the patch. Allow the patch to set at lest 24 hours before testing. Do not exceed differential pressure ratings provided by the manufacturer.
14. Submit a casing repair report, including description of field work, to KDHE.

Appendix 5.
Well Plugging

Rule §3.14: Texas Administrative Code
Railroad Commission of Texas
Oil and Gas Division

Texas Administrative Code

TITLE 16 ECONOMIC REGULATION
PART 1 RAILROAD COMMISSION OF TEXAS
CHAPTER 3 OIL AND GAS DIVISION
RULE §3.14 Plugging

(a) Definitions and application to plug.

(1) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(A) Active operation--Regular and continuing activities related to the production of oil and gas for which the operator has all necessary permits. In the case of a well that has been inactive for 12 consecutive months or longer and that is not permitted as a disposal or injection well, the well remains inactive for purposes of this section, regardless of any minimal activity, until the well has reported production of at least 10 barrels of oil for oil wells or 100 mcf of gas for gas wells each month for at least three consecutive months.

(B) Approved cementer--A cementing company, service company, or operator approved by the Commission to mix and pump cement for the purpose of plugging a well in accordance with the provisions of this section. The term shall also apply to a cementing company, service company, or operator authorized by the Commission to use an alternate material other than cement to plug a well.

(C) Delinquent inactive well--An unplugged well that has had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months and for which, after notice and opportunity for hearing, the Commission has not extended the plugging deadline.

(D) Funnel viscosity--Viscosity as measured by the Marsh funnel, based on the number of seconds required for 1,000 cubic centimeters of fluid to flow through the funnel.

(E) Good faith claim--A factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate.

(F) Groundwater conservation district--Any district or authority created under §52, Article III, or §59, Article XVI, Texas Constitution, that has the authority to regulate the spacing of water wells, the production from water wells, or both.

(G) Operator designation form--A certificate of compliance and transportation authority or an application to drill, deepen, recomplete, plug back, or reenter which has been completed, signed and filed with the Commission.

(H) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in producible quantities in the vicinity of an unplugged well.

(I) Related piping--The surface piping and subsurface piping that is less than three feet beneath the ground surface between pieces of equipment located at any collection or treatment facility. Such piping would include piping between and among headers, manifolds, separators, storage tanks, gun barrels, heater treaters, dehydrators, and any other equipment located at a collection or treatment facility. The term is not intended to refer to lines, such as flowlines, gathering lines, and injection lines that lead up to and away from any such collection or treatment facility.

(J) Reported production--Production of oil or gas, excluding production attributable to well tests, accurately reported to the Commission on a monthly producer's report.

(K) To serve notice on the surface owner or resident--To hand deliver a written notice identifying the well or wells to be plugged and the projected date the well or wells will be plugged to the surface owner, or resident if the owner is absent, at least three days prior to the day of plugging or to mail the notice by first class mail, postage pre-paid, to the last known address of the surface owner or resident at least seven days prior to the day of plugging.

(L) Unbonded operator--An operator that has a current and active organization report on file with the Commission that filed a nonrefundable annual fee as financial security prior to September 1, 2004, and is not required by §3.78 of this title (relating to Fees and Financial Security Requirements) to file an individual performance bond, blanket performance bond, letter of credit, or cash deposit as its financial security until the first date for annual renewal of the operator's organization report after September 1, 2004.

(M) Usable quality water strata--All strata determined by the Texas Commission on Environmental Quality or its successor agencies to contain usable quality water.

(N) Written notice--Notice actually received by the intended recipient in tangible or retrievable form, including notice set out on paper and hand-delivered, facsimile transmissions, and electronic mail transmissions.

(2) The operator shall give the Commission notice of its intention to plug any well or wells drilled for oil, gas, or geothermal resources or for any other purpose over which the Commission has jurisdiction, except those specifically addressed in §3.100(e)(1) of this title (relating to Seismic Holes and Core Holes) (Statewide Rule 100), prior to plugging. The operator shall deliver or transmit the written notice to the district office on the appropriate form.

(3) The operator shall cause the notice of its intention to plug to be delivered to the district office at least five days prior to the beginning of plugging operations. The notice shall set out the proposed plugging procedure as well as the complete casing record. The operator shall not commence the work of plugging the well or wells until the proposed procedure has been approved by the district director or the director's delegate. The operator shall not initiate approved plugging operations before the date set out in the notification for the beginning of plugging operations unless authorized by the district director or the director's delegate. The operator shall notify the district office at least four hours before commencing plugging operations and proceed with the work as approved. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices

when a workover or drilling rig is already at work on location, and ready to commence plugging operations. Operations shall not be suspended prior to plugging the well unless the hole is cased and casing is cemented in place in compliance with Commission rules. The Commission's approval of a notice of intent to plug and abandon a well shall not relieve an operator of the requirement to comply with subsection (b)(2) of this section, nor does such approval constitute an extension of time to comply with subsection (b)(2) of this section.

(4) The surface owner and the operator may file an application to condition an abandoned well located on the surface owner's tract for usable quality water production operations. The application shall be made on the form prescribed by the Commission, the Application of Landowner to Condition an Abandoned Well for Fresh Water Production.

(A) Standard for Commission Approval. Before the Commission will consider approval of an application:

(i) the surface owner shall assume responsibility for plugging the well and obligate himself, his heirs, successors, and assignees to complete the plugging operations;

(ii) the operator responsible for plugging the well shall place all cement plugs required by this rule up to the base of the usable quality water strata; and

(iii) the surface owner shall submit:

(I) a signed statement attesting to the fact that:

(-a-) there is no groundwater conservation district for the area in which the well is located; or

(-b-) there is a groundwater conservation district for the area where the well is located, but the groundwater conservation district does not require that the well be permitted or registered; or

(-c-) the surface owner has registered the well with the groundwater conservation district for the area where the well is located; or

(II) a copy of the permit from the groundwater conservation district for the area where the well is located.

(B) The duty of the operator to properly plug ends only when:

(i) the operator has properly plugged the well in accordance with Commission requirements up to the base of the usable quality water stratum;

(ii) the surface owner has registered the well with, or has obtained a permit for the well from, the groundwater conservation district, if applicable; and

(iii) the Commission has approved the application of surface owner to condition an abandoned well for fresh water production.

(5) The operator of a well shall serve notice on the surface owner of the well site tract, or the resident if the owner is absent, before the scheduled date for beginning the plugging operations. A representative of the surface owner may be present to witness the plugging of the well. Plugging shall not be delayed because of the lack of actual notice to the surface owner or resident if the operator has served notice as required by this paragraph. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location and ready to commence plugging operations.

(b) Commencement of plugging operations, extensions, and testing.

(1) The operator shall complete and file in the district office a duly verified plugging record, in duplicate, on the appropriate form within 30 days after plugging operations are completed. A cementing report made by the party cementing the well shall be attached to, or made a part of, the plugging report. If the well the operator is plugging is a dry hole, an electric log status report shall be filed with the plugging record.

(2) Plugging operations on each dry or inactive well shall be commenced within a period of one year after drilling or operations cease and shall proceed with due diligence until completed. Plugging operations on delinquent inactive wells shall be commenced immediately unless the well is restored to active operation. For good cause, a reasonable extension of time in which to start the plugging operations may be granted pursuant to the following procedures.

(A) Plugging of inactive wells operated by unbonded operators. During the interim period between September 1, 2004, and the first date for annual renewal of an unbonded operator's organization report after September 1, 2004, the Commission or its delegate may administratively grant an extension of up to one year of the deadline for plugging an inactive well that is operated by an unbonded operator if the following criteria are met:

(i) The well and associated facilities are in compliance with all other laws and Commission rules;

(ii) The operator's organization report is current and active;

(iii) The operator has, and upon request provides evidence of, a good faith claim to a continuing right to operate the well; and

(iv) The operator has tested the well in accordance with the provisions of paragraph (3) of this subsection and files with its application proof of either:

(I) a fluid level test conducted within 90 days prior to the application for a plugging extension demonstrating that any fluid in the wellbore is at least 250 feet below the base of the deepest usable quality water stratum; or,

(II) a hydraulic pressure test conducted during the period the well has been inactive and not more than four years prior to the date of application demonstrating the mechanical integrity of the well.

(B) Plugging of inactive wells operated by bonded operators. An operator that maintains valid, Commission-approved financial security in the form of an individual performance bond, blanket performance bond, letter of credit, or cash deposit as provided in §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78) will be granted a one-year plugging extension for each well it operates that has been inactive for 12 months or more at the time its annual organizational report is approved by the Commission if the following criteria are met:

(i) The well and associated facilities are in compliance with all laws and Commission rules; and,

(ii) The operator has, and upon request provides evidence of, a good faith claim to a continuing right to operate the well.

(C) Revocation or denial of plugging extension.

(i) The Commission or its delegate may revoke a plugging extension if the operator of the well that is the subject of the extension fails to maintain the well and all associated facilities in compliance with Commission rules; fails to maintain a current and accurate organizational report on file with the Commission; fails to provide the Commission, upon request, with evidence of a continuing good faith claim to operate the well; or fails to obtain or maintain financial security as required by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78).

(ii) If the Commission or its delegate declines to grant or continue a plugging extension or revokes a previously granted extension, the operator shall either return the well to active operation or, within 30 days, plug the well or request a hearing on the matter.

(3) The operator of any well more than 25 years old that becomes inactive and subject to the provisions of this subsection or the operator of any well for which a plugging extension is sought under the terms of subparagraph (A) of paragraph (2) of this subsection shall plug the well or successfully conduct a fluid level or hydraulic pressure test establishing that the well does not pose a potential threat of harm to natural resources, including surface and subsurface water, oil and gas.

(A) In general, a fluid level test is a sufficient test for purposes of this paragraph. The operator shall give the district office written notice specifying the date and approximate time it intends to conduct the fluid level test at least 48 hours prior to conducting the test; however, upon a showing of undue hardship, the district director or the director's delegate may grant a written waiver or reduction of the notice requirement for a specific well test. The director or the director's delegate may require alternate methods of testing if necessary to ensure the well does not pose a potential threat of harm to natural resources. Alternate methods of testing may be approved by the director or the director's delegate by written application and upon a showing that such a test will provide information sufficient to determine that the well does not pose a threat to natural resources.

(B) No test other than a fluid level test shall be acceptable without prior approval from the district director or the director's delegate. The district director or the director's delegate shall be notified at least 48 hours before any test other than a fluid level test is conducted. Mechanical integrity test results shall be filed with the district office and fluid level test results shall be filed with the Commission in Austin. Test results shall be filed on a Commission-approved form, within 30 days of the completion of the test. Upon request, the operator shall file the actual test data for any mechanical integrity or fluid level test that it has conducted.

(C) Notwithstanding the provisions of subparagraph (B) of this paragraph, a hydraulic pressure test may be conducted without prior approval from the district director or the director's delegate, provided that the operator gives the district office written notice specifying the date and approximate time for the test at least 48 hours prior to the time the test will be conducted, the production casing is tested to a depth of at least 250 feet below the base of usable quality water strata, or 100 feet below the top of cement behind the production casing, whichever is deeper, and the minimum test pressure is greater than or equal to 250 psig for a period of at least 30 minutes.

(D) If the operator performs a hydraulic pressure test in accordance with the provisions of subparagraph (C) of this paragraph, the well shall be exempt from further testing for five years from the date of the test, except to the extent that the Commission or its delegate may require the operator to perform testing more frequently to ensure that the well does not pose a threat of harm to natural resources. The Commission or its delegate may approve less frequent well tests under this paragraph upon written request and for good cause shown provided that less frequent testing will not increase the threat of harm to natural resources.

(E) A well subject to the testing requirements of this paragraph shall not be returned to active operation unless a fluid level test of the well has been performed within 12 months prior to the return to activity or a mechanical integrity test of the well has been performed within 60 months prior to the return to activity.

(4) The Commission may plug or replug any dry or inactive well as follows:

(A) After notice and hearing, if the well is causing or is likely to cause the pollution of surface or subsurface water or if oil, gas, or other formation fluid is leaking from the well, and:

(i) Neither the operator nor any other entity responsible for plugging the well can be found; or

(ii) Neither the operator nor any other entity responsible for plugging the well has assets with which to plug the well.

(B) Without a hearing if the well is a delinquent inactive well and:

(i) the Commission has sent notice of its intention to plug the well as required by §89.043(c) of the Texas Natural Resources Code; and

(ii) the operator did not request a hearing within the period (not less than 10 days after receipt) specified in the notice.

(C) Without notice or hearing, if:

(i) The Commission has issued a final order requiring that the operator plug the well and the order has not been complied with; or

(ii) The well poses an immediate threat of pollution of surface or subsurface waters or of injury to the public health and the operator has failed to timely remediate the problem.

(5) The Commission may seek reimbursement from the operator and any other entity responsible for plugging the well for state funds expended pursuant to paragraph (4) of this subsection.

(c) Designated operator responsible for proper plugging.

(1) The entity designated as the operator of a well specifically identified on the most recent Commission-approved operator designation form filed on or after September 1, 1997, is responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning plugging of wells.

(2) As to any well for which the most recent Commission-approved operator designation form was filed prior to September 1, 1997, the entity designated as operator on that form is presumed to be the entity responsible for the physical operation and control of the well and to be the entity responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning plugging of wells. The presumption of responsibility may be rebutted only at a hearing called for the purpose of determining plugging responsibility.

(d) General plugging requirements.

(1) Wells shall be plugged to insure that all formations bearing usable quality water, oil, gas, or geothermal resources are protected. All cementing operations during plugging shall be performed under the direct supervision of the operator or his authorized representative, who shall not be an employee of the service or cementing company hired to plug the well. Direct supervision means supervision at the well site during the plugging operations. The operator and the cementer are both responsible for complying with the general plugging requirements of this subsection and for plugging the well in conformity with the procedure set forth in the approved notice of intention to plug and abandon for the well being plugged. The operator and cementer may each be assessed administrative penalties for failure to comply with the general plugging requirements of this subsection or for failure to plug the well in conformity with the approved notice of intention to plug and abandon the well.

(2) Cement plugs shall be set to isolate each productive horizon and usable quality water strata. Plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Texas Commission on Environmental Quality or its successor agencies. The operator shall verify the placement of the plug required at the base of the deepest usable quality water stratum by tagging with tubing or drill pipe or by an alternate method approved by the district director or the district director's delegate.

(3) Cement plugs shall be placed by the circulation or squeeze method through tubing or drill pipe. Cement plugs shall be placed by other methods only upon written request with the written approval of the district director or the director's delegate.

(4) All cement for plugging shall be an approved API oil well cement without volume extenders and shall be mixed in accordance with API standards. Slurry weights shall be reported on the cementing report. The district director or the director's delegate may require that specific cement compositions be used in special situations; for example, when high temperature, salt section, or highly corrosive sections are present. An operator shall request approval to use alternate materials, other than API oil well cement without volume extenders, to plug a well by filing with the director or the director's delegate a written request providing all pertinent information to support the use of the proposed alternate material and plugging method. The director or the director's delegate shall determine whether such a request warrants approval, after considering factors which include but are not limited to whether or not the well to be plugged was used as an injection or disposal well; the well's history; the well's current bottom hole pressure; the presence of highly pressurized formations intersected by the wellbore; the method by which the alternative material will be placed in the wellbore; and the compressive strength and other performance specifications of the alternative material to be used. The director or the director's delegate shall approve such a request only if the proposed alternate material and plugging method will ensure that the well does not pose a potential threat of harm to natural resources.

(5) Operators shall use only cementers approved by the director or the director's delegate, except when plugging is conducted in accordance with subparagraph (B)(ii) of this paragraph or paragraph (6) of this subsection. Cementing companies, service companies, or operators may apply for designation as approved cementers. Approval will be granted on a showing by the applicant of the ability to mix and pump cement or other alternate materials as approved by the director or the director's delegate in compliance with this rule. An approved cementer is authorized to conduct plugging operations in accordance with Commission rules in each Commission district.

(A) A cementing company, service company, or operator seeking designation as an approved cementer shall file a request in writing with the district director of the district in which it proposes to conduct its initial plugging operations. The request shall contain the following information:

(i) the name of the organization as shown on its most recent approved organizational report;

(ii) a list of qualifications including personnel who will supervise mixing and pumping operations;

(iii) length of time the organization has been in the business of cementing oil and gas wells;

(iv) an inventory of the type of equipment to be used to mix and pump cement or other alternate materials as approved by the director or the director's delegate; and

(v) a statement certifying that the organization will comply with all Commission rules.

(B) No request for designation as an approved cementer will be approved until after the district director or the director's delegate has:

(i) inspected all equipment to be used for mixing and pumping cement or other alternate materials as approved by the director or the director's delegate; and

(ii) witnessed at least one plugging operation to determine if the cementing company, service company, or operator can properly mix and pump cement or other alternate materials as approved by the director or the director's delegate according to the specifications required by this rule.

(C) The district director or the director's delegate shall file a letter with the director or the director's delegate recommending that the application to be designated as an approved cementer be approved or denied. If the district director or the director's delegate does not recommend approval, or the director or the director's delegate denies the application, the applicant may request a hearing on its application.

(D) Designation as an approved cementer may be suspended or revoked for violations of Commission rules. The designation may be revoked or suspended administratively by the director or the director's delegate for violations of Commission rules if:

(i) the cementer has been given written notice by personal service or by registered or certified mail informing the cementer of the proposed action, the facts or conduct alleged to warrant the proposed action, and of its right to request a hearing within 10 days to demonstrate compliance with Commission rules and all requirements for retention of designation as an approved cementer; and

(ii) the cementer did not file a written request for a hearing within 10 days of receipt of the notice.

(6) An operator may request administrative authority to plug its own wells without being an approved cementer. An operator seeking such authority shall file a written request with the district director and demonstrate its ability to mix and pump cement or other alternate materials as approved by the director or the director's delegate in compliance with this subsection. The district director or the director's delegate shall determine whether such a request warrants approval. If the district director or the director's delegate refuses to administratively approve this request, the operator may request a hearing on its request.

(7) The district director or the director's delegate may require additional cement plugs to cover and contain any productive horizon or to separate any water stratum from any other water stratum if the water qualities or hydrostatic pressures differ sufficiently to justify separation. The tagging and/or pressure testing of any such plugs, or any other plugs, and respotting may be required if necessary to ensure that the well does not pose a potential threat of harm to natural resources.

(8) For onshore or inland wells, a 10-foot cement plug shall be placed in the top of the well, and casing shall be cut off three feet below the ground surface.

(9) Mud-laden fluid of at least 9-1/2 pounds per gallon with a minimum funnel viscosity of 40 seconds shall be placed in all portions of the well not filled with cement or other alternate material as approved by the director or the director's delegate. The hole shall be in static condition at the time the cement plugs are placed. The district director or the director's delegate may grant exceptions to the requirements of this paragraph if a deviation from the prescribed minimums for fluid weight or viscosity will insure that the well does not pose a potential threat of harm to natural resources. An operator shall request approval to use alternate fluid other than mud-laden fluid by filing with the district director a written request providing all pertinent information to support the use of the proposed alternate fluid. The district director or the director's delegate shall determine whether such a request warrants approval, and shall approve such a request only if the proposed alternate fluid will insure that the well does not pose a potential threat of harm to natural resources.

(10) Non-drillable material that would hamper or prevent reentry of a well shall not be placed in any wellbore during plugging operations, except in the case of a well plugged and abandoned under the provisions of §3.35 or §4.614(b) of this title (relating to Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned (Statewide Rule 35); and Authorized Disposal Methods, respectively). Pipe and unretrievable junk shall not be cemented in the hole during plugging operations without prior approval by the district director or the director's delegate.

(11) All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(12) The operator shall fill the rathole, mouse hole, and cellar, and shall empty all tanks, vessels, related piping and flowlines that will not be actively used in the continuing operation of the lease within 120 days after plugging work is completed. Within the same 120 day period, the operator shall remove all such tanks, vessels, and related piping, remove all loose junk and trash from the location, and contour the location to discourage pooling of surface water at or around the facility site. The operator shall close all pits in accordance with the provisions of §3.8 of this title (relating to Water Protection (Statewide Rule 8)). The district director or the director's delegate may grant a reasonable extension of time of not more than an additional 120 days for the removal of tanks, vessels and related piping.

(e) Plugging requirements for wells with surface casing.

(1) When insufficient surface casing is set to protect all usable quality water strata and such usable quality water strata are exposed to the wellbore when production or intermediate casing is pulled from the well or as a result of such casing not being run, a cement plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and 50 feet below the base of the deepest usable quality water stratum. This plug shall be evidenced by tagging with tubing or drill pipe. The plug shall be respotted if it has not been properly placed. In addition, a cement plug shall be set across the shoe of the surface casing. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and below the shoe.

(2) When sufficient surface casing has been set to protect all usable quality water strata, a cement plug shall be placed across the shoe of the surface casing. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above the shoe and at least 50 feet below the shoe.

(3) If surface casing has been set deeper than 200 feet below the base of the deepest usable quality water stratum, an additional cement plug shall be placed inside the surface casing across the base of the deepest usable quality water stratum. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest usable quality water stratum.

(4) Plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Texas Commission on Environmental Quality or its successor agencies.

(f) Plugging requirements for wells with intermediate casing.

(1) For wells in which the intermediate casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum, but extend no less than 50 feet above and below the base of the deepest usable quality water stratum.

(2) For wells in which intermediate casing is not cemented through all usable quality water strata and all productive horizons, and if the casing will not be pulled, the intermediate casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(3) Additionally, plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Texas Commission on Environmental Quality or its successor agencies.

(g) Plugging requirements for wells with production casing.

(1) For wells in which the production casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum and across any multi-stage cementing tool. This plug shall be a

minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest usable quality water stratum.

(2) For wells in which the production casing has not been cemented through all usable quality water strata and all productive horizons and if the casing will not be pulled, the production casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(3) The district director or the director's delegate may approve a cast iron bridge plug to be placed immediately above each perforated interval, provided at least 20 feet of cement is placed on top of each bridge plug. A bridge plug shall not be set in any well at a depth where the pressure or temperature exceeds the ratings recommended by the bridge plug manufacturer.

(4) Additionally, plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Texas Commission on Environmental Quality or its successor agencies.

(h) Plugging requirements for well with screen or liner.

(1) If practical, the screen or liner shall be removed from the well.

(2) If the screen or liner is not removed, a cement plug in accordance with subsection (d)(11) of this section shall be placed at the top of the screen or liner.

(i) Plugging requirements for wells without production casing and open-hole completions.

(1) Any productive horizon or any formation in which a pressure or formation water problem is known to exist shall be isolated by cement plugs centered at the top and bottom of the formation. Each cement plug shall have sufficient slurry volume to fill a calculated height as specified in subsection (d)(11) of this section.

(2) If the gross thickness of any such formation is less than 100 feet, the tubing or drill pipe shall be suspended 50 feet below the base of the formation. Sufficient slurry volume shall be pumped to fill the calculated height from the bottom of the tubing or drill pipe up to a point at least 50 feet above the top of the formation, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(j) The district director or the director's delegate shall review and approve the notification of intention to plug in a manner so as to accomplish the purposes of this section. The district director or the director's delegate may approve, modify, or reject the operator's notification of intention to plug. If the proposal is modified or rejected, the operator may request a review by the director or the director's delegate. If the proposal is not administratively approved, the operator may request a hearing on the matter. After hearing, the examiner shall recommend final action by the Commission.

(k) Plugging horizontal drainhole wells. All plugs in horizontal drainhole wells shall be set in accordance with subsection (d)(11) of this section. The productive horizon isolation plug shall be set from a depth 50 feet below the top of the productive horizon to a depth either 50 feet above the top of the productive horizon, or 50 feet above the production casing shoe if the production casing is set above the top of the productive horizon. If the production casing shoe is set below the top of the productive horizon, then the productive horizon isolation plug shall be set from a depth 50 feet below the production casing shoe to a depth that is 50 feet above the top of the productive horizon. In accordance with subsection (d)(7) of this section, the Commission or its delegate may require additional plugs.

Source Note: The provisions of this §3.14 adopted to be effective January 1, 1976; amended to be effective February 29, 1980, 5 TexReg 499; amended to be effective January 1, 1983, 7 TexReg 3989; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective September 8, 1986, 11 TexReg 3792; amended to be effective November 9, 1987, 12 TexReg 3959; amended to be effective May 9, 1988, 13 TexReg 2026; amended to be effective March 1, 1992, 17 TexReg 1227; amended to be effective September 1, 1992, 17 TexReg 5283; amended to be effective September 20, 1995, 20 TexReg 6931; amended to be effective September 14, 1998, 23 TexReg 9300; amended to be effective December 28, 1999,24TexReg11711;amendedto be effective July 10, 2000, 25 TexReg 6487; amended to be effective November 1, 2000, 25 TexReg 9924; amended to be effective January 9, 2002, 27 TexReg 139; amended to be effective July 28, 2003, 28 TexReg 5853; amended to be effective December 3, 2003, 28 TexReg 10747; amended to be effective September 1, 2004, 29 TexReg 8271

Appendix 6.
Plugging and Abandonment of Wells

Rule 649-3-24: Division of Oil, Gas and Mining
Department of Natural Resources
State of Utah

UT Administrative Code
R649-3-24. Plugging and Abandonment of Wells.

1. Before operations are commenced to plug and abandon any well the owner or operator shall submit a notice of intent to plug and abandon to the division for its approval.

1.1. The notice shall be submitted on Form DOGM-9, Sundry Notice and Report on Wells.

1.2. A legible copy of a similar report and form filed with the appropriate federal agency may be used in lieu of the forms prescribed by the board.

1.3. In cases of emergency the operator may obtain verbal or telegraphic approval to plug and abandon.

1.4. Within five days after receiving verbal or telegraphic approval, the operator shall submit a written notice of intent to plug and abandon on Form 9.

2. Both verbal and written notice of intent to plug and abandon a well shall contain the following information:

2.1. The location of the well described by section, township, range, and county.

2.2. The status of the well, whether drilling, producing, injecting or inactive.

2.3. A description of the well bore configuration indicating depth, casing strings, cement tops if known, and hole size.

2.4. The tops of known geologic markers or formations.

2.5. The plugging program approved by the appropriate federal agency if the well is located on federal or Indian land.

2.6. An indication of when plugging operations will commence.

3. A dry or abandoned well must be plugged so that oil, gas, water, or other substance will not migrate through the well bore from one formation to another.

3.1. Unless a different method and procedure is approved by the division, the method and procedure for plugging the well shall be as follows:

3.2. The bottom of the hole shall be filled to, or a bridge shall be placed at, the top of each producing formation open to the well bore, and a cement plug not less than 100 feet in length shall be placed immediately above each producing formation open to the well bore.

3.3. A solid cement plug shall be placed from 50 feet below a fresh water zone to 50 feet above the fresh water zone, or a 100 foot cement plug shall be centered across the base of the fresh water zone and a 100 foot plug shall be centered across the top of the fresh water zone.

3.4. At least ten sacks of cement shall be placed at the surface in a manner completely plugging the entire hole. If more than one string of casing remains at the surface, all annuli shall be so cemented.

3.5. The interval between plugs shall be filled with noncorrosive fluid of adequate density to prevent migration of formation water into or through the well bore.

3.6. The hole shall be plugged up to the base of the surface string with noncorrosive fluid of adequate density to prevent migration of formation water into or through the well bore, at which point a plug of not less than 50 feet of cement shall be placed.

3.7. Any perforated interval shall be plugged with cement and any open hole porosity zone shall be adequately isolated to prevent migration of fluids.

3.8. A cement plug not less than 100 feet in length shall be centered across the casing stub if any casing is cut and pulled, a second plug of the same length shall be centered across the casing shoe of the next larger casing.

4. An alternative method of plugging, required under a federal or Indian lease, will be accepted by the division.

5. Within 30 days after the plugging of any well has been accomplished, the owner or operator shall file a subsequent report of plugging with the division. The report shall give a detailed account of the following items:

5.1. The manner in which the plugging work was carried out, including the nature and quantities of materials used in plugging and the location, nature, and extent by depths, of the plugs.

5.2. Records of any tests or measurements made.

5.3. The amount, size, and location, by depths of any casing left in the well.

5.4. A statement of the volume of mud fluid used.

5.5. A complete report of the method used and the results obtained, if an attempt was made to part any casing.

6. Upon application to and approval by the division, and following assumption of liability for the well by the surface owner, a well or other exploratory hole that may safely be used as a fresh water well need not be filled above the required sealing plugs set below the fresh water formation. The owner of the surface of the land affected may assume liability for any well capable of conversion to a water well by sending a letter assuming such liability to the division and by filing an application with and obtaining approval for appropriation of underground water from the Division of Water Rights.

7. Unless otherwise approved by the division, all abandoned wells shall be marked with a permanent monument showing the well number, location, and name of the lease. The monument shall consist of a portion of pipe not less than four inches in diameter and not less than ten feet in length, of which four feet shall be above the ground level and the remainder shall be securely embedded in cement. The top of the pipe must be permanently sealed.

8. If any casing is to be pulled after a well has been abandoned, a notice of intent to pull casing must be filed with the division and its approval obtained before the work is commenced.

8.1. The notice shall include full details of the contemplated work. If a log of the well has not already been filed with the division, the notice shall be accompanied by a copy of the log showing all casing seats as well as all water strata and oil and gas shows.

8.2. Where the well has been abandoned and liability has been terminated with respect to the bond previously furnished under R649-3-1, a $10,000 plugging bond shall be filed with the division by the applicant.

Appendix 7.
Procedures for Well Plugging

WAC 344-12-131
Washington State Legislature

Well Plugging
Washington State Legislature
WAC 344-12-131

Procedure for Well Plugging.
Each abandoned well drilled for the discovery of oil or gas or for any other purpose related to the exploration including seismic and core holes or production of oil and gas shall be plugged by or on behalf of the owner, operator, or producer who is in charge of the well or wells and responsible therefore. In general, cement plugs will be placed across specified intervals to protect oil and gas zones, to prevent degradation of potentially usable waters, and to protect surface conditions. Subject to approval of the supervisor, cement may be mixed with or replaced by other substances with adequate physical properties. The owner shall submit the proposed method and procedure for plugging to the supervisor on Form-3 (Notice of intention to abandon and plug well). Unless otherwise approved by the supervisor the method and procedure shall be as follows:

(1) Hole fluid. Drilling fluid having the proper weight and consistency to prevent movement of other fluids into the wellbore shall be placed in all intervals not plugged with cement, and shall be surface poured into all open annuli where required.

(2) Plugging by bailer. Placing of a cement plug by bailer shall not be permitted at a depth greater than 3,000 feet (914 meters). Water is the only permissible hole fluid in which a cement plug shall be placed by bailer.

(3) Surface pours. A surface cement-pour shall be permitted in an empty hole with a diameter of not less than 5 inches (12.7 centimeters). Depth limitations shall be determined on an individual well basis by the supervisor.

(4) Blowout prevention equipment. Blowout prevention equipment may be required during plugging and abandonment operations. Any blowout prevention equipment and inspection requirements deemed necessary by the supervisor shall appear on the approval issued by the supervisor.

(5) Junk in hole. Diligent effort shall be made to recover junk when such junk may prevent proper abandonment either in open hole or inside casing. In the event that junk cannot be removed from the hole and freshwater-saltwater contacts or oil or gas zones penetrated below cannot therefore be properly abandoned, cement shall be down-squeezed through or past the junk or a 100-foot (30-meter) cement plug shall be placed on top of the junk.

(6) A cement plug not less than 25 feet (7.6 meters) shall be placed in the hole and all annuli at the surface. All well casing shall be cut off at least 5 feet (1.5 meters) below the surface of the ground.

(7) Open hole.

(a) A cement plug shall be placed to extend from the total depth or at least 100 feet (30 meters) below the bottom of each oil or gas zone, whichever is less, to at least 100 feet (30 meters) above the top of each zone.

(b) A minimum 200-foot (61-meter) cement plug shall be placed across all underground source of drinking water-saltwater interfaces.

(c) An interface plug may be placed wholly within a thick shale if such shale separates the freshwater sands from the brackish or saltwater sands.

(d) The hole may be filled between plugs up to the base of the surface string, if this reaches below the freshwater zone, with approved heavy mud.

(8) Cased hole.

(a) All perforations shall be plugged with cement, and the plug shall extend 100 feet (30 meters) above the top of a landed liner, the uppermost perforations, the casing cementing point, or water shut-off holes, whichever is highest.

(b) If there is cement behind the casing across the underground source of drinking water-saltwater interface, a 100-foot (30-meter) cement plug shall be placed inside the casing across the interface.

(c) If the top of the cement behind the casing is below the top of the highest saltwater sands, squeeze-cementing shall be required through perforations to protect the underground source of drinking water. In addition, a 100-foot (30-meter) cement plug shall be placed inside the casing across the underground source of drinking water-saltwater interface. Notwithstanding other provisions of this section, the supervisor may approve a cavity shot followed by cementing operations at the base of the underground source of drinking water sands. The cavity shall be filled with cement and capped with a cement plug extending 100 feet (30 meters) above the cavity shot.

(9) Special requirements.

(a) Where geologic or ground water conditions dictate, special plugging procedures shall be required to prevent contamination of potentially usable waters by downward percolation of poor quality waters, and to separate water zones of varying quality, or varying hydrostatic pressure, and to isolate dry permeable strata that are brought into hydraulic continuity with ground water aquifers.

(b) The supervisor may set forth other plugging and abandonment requirements or may establish field rules for the plugging and abandonment of wells. Such cases include, but are limited to:

(i) The plugging of a high-pressure saltwater zone.

(ii) Perforating and squeeze-cementing previously uncemented casing within and above a hydrocarbon zone.

(10) In all holes open below the casing shoe, a cement plug shall extend from at least 50 feet (15 meters) below to at least 50 feet (15 meters) above the shoe of any cemented casing. If the hole cannot be cleaned out to 50 feet (15 meters) below the shoe, a 100-foot (30-meter) cement plug shall be placed as deep as possible.

(11) A steel plate at least one-quarter inch (0.64 centimeter) thick shall be welded to the top of the surface string of casing. The steel plate shall bear the drilling permit number and date of abandonment.

(12) Within thirty days after plugging of any well, the owner, operator, or producer responsible therefor who plugged or caused to be plugged the well shall file with the supervisor an affidavit on Form-4 (report on results of plugging well) setting forth in detail the method used in plugging the well.

(13) Inspection of plugging and abandonment operations. All plugging and abandonment operations shall be witnessed and approved as deemed necessary by the supervisor.

Appendix 8.
Requirements for Re-Abandonment of Previously Plugged and Abandoned Wells

Colorado Oil and Gas Conservation Commission

Colorado Oil and Gas Conservation Commission Policy
For Plugged and Abandoned Wells
Encountered By Surface Development Projects

WHEREAS, Colorado is experiencing rapid surface development along the Front Range corridor, as well as in other areas of the state. Housing and commercial developments in these areas have the potential to encounter previously plugged and abandoned oil and gas wells that interfere with earth moving operations. When these activities encounter previously plugged and abandoned wells, it may be necessary to cut the casing below grade and re-abandon them.

WHEREAS, Re-abandonment operations on previously plugged and abandoned wells are considered by the Colorado Oil and Gas Conservation Commission ("COGCC") to be "oil and gas operations" as defined in the Oil and Gas Conservation Act and in the COGCC Rules and Regulations, and may be required to be conducted by a registered operator who has provided financial assurance to ensure that the wells are properly plugged and abandoned.

NOW THEREFORE, The following are the requirements for re-abandonment operations when any oil or gas well is to be modified because of encroaching surface development:

REQUIREMENTS FOR THE RE-ABANDONMENT OF PREVIOUSLY PLUGGED AND ABANDONED WELLS:

The following are required whenever the wellbore of a previously plugged and abandoned well is modified and re-abandoned because of encroaching surface development:

(1) The surface developer or its designee that will conduct the re-abandonment operation shall be properly registered as an operator with the COGCC in accordance with Rule 302.

(2) The operator shall provide the COGCC with adequate financial assurance for the plugging and abandonment of the well(s) in accordance with Rule 706.

(3) A Change of Operator, Form 10 shall be submitted which shall indicate that the surface developer or its designee that will conduct the re-abandonment operation is the new operator of the well(s).

(4) The operator shall submit a Sundry Notice, Form 4 that includes a detailed description of the proposed re-abandonment operations. Approval of the Sundry Notice, Form 4 shall be obtained from the Director prior to commencement of operations.

(5) The operator shall provide a minimum seven (7) day written notice to the previous operator, if existing, of the intended re-abandonment operations and the date that such operations will commence. The operator shall confirm that this notice requirement has been completed or waived before the Director approves the Sundry Notice, Form 4.

(6) The operator shall provide verbal notice to the Director at least twenty-four (24) hours prior to the commencement of any operations to modify a wellbore or re-abandon a well.

(7) If during the re-entry of a previously plugged and abandoned well a surface cement plug is determined to be absent, then the operator shall determine the plugged back depth of the well and report such depth to the Director as soon as practicable. The Director may require remedial cementing operations consistent with the provisions for protecting aquifers and hydrocarbon bearing zones described in Rule 319. The operator shall obtain approval from the Director before proceeding with any further operations. If any cement or other plugging material is required to be placed in the well, the operator shall submit a Well Abandonment Report, Form 6 for approval from the Director prior to proceeding with any further operations. An additional Well Abandonment Report, Form 6, including third party Plugging Verification Reports, shall be required after the completion of the re-abandonment operations to provide documentation of the operations.

(8) The financial assurance required in (2) above shall not be released until the plugging operation can be verified through appropriate form submittals and the final reclamation threshold for release of financial assurance specified in Rule 1004.c. is met. If a variance to the 1000 Series Reclamation Rules is necessary for the surface lands where the re-abandoned well is located, the surface developer or its designee shall submit a Sundry Notice, Form 4 to request such variance. The variance request shall include a description of the planned surface use surrounding the re-abandoned well.

REMEDIATION OF LEAKAGE FROM CO_2 STORAGE RESERVOIRS

IEA/CON/04/108

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IEA Greenhouse Gas R&D Programme

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EXECUTIVE SUMMARY

The purpose of this report is to broadly address a topic integral to safe and secure carbon sequestration - - preventing and remediating the leakage of carbon dioxide (CO_2) injected into three types of geological formations, namely oil fields, natural gas fields, and deep saline reservoirs.

Risk assessments of storing CO_2 in rigorously selected geological formations, such as at Weyburn, In Salah and Sleipner, indicate that the inherent risks and potential quantities of CO_2 leakage will be minimal. However, CO_2 leakage in less geologically favorable settings and over geological time is not improbable and could result from leaky abandoned wells, from an inadequate caprock or the breaking of the reservoir seal, and from the migration of CO_2 beyond a confining structure. Clearly, if sustained CO_2 leakage were to occur to any significant degree, by any pathway, the advantage of geological storage would be reduced. As important, the image of this technology would be impaired in the views held by policy makers, environmental groups and the public.

A series of actions, the discussion of which constitutes the body of this report, will be central to preventing and correcting sustained leakage of CO_2 from geological formations, namely - - rigorous site selection, assured well integrity, long-term modeling of the CO_2 plume, monitoring of the injected CO_2 (including early identification of leakage), and prompt remediation actions should any CO_2 leakage occur. For this, the report is organized around a series of chapters that address the tasks set forth in the scope of work for the study:

1. Determine the potential CO_2 leakage pathways in the above three types of geological storage reservoirs.

2. Formulate site selection and reservoir screening requirements to minimize the risks of CO_2 leakage.

3. Discuss modeling and monitoring techniques that would help identify potential CO_2 leakage pathways and any actual leakage, should it occur.

4. Review and set forth procedures for promptly remediating CO_2 leakage from these geological formations.

5. Develop and characterize leakage prevention and remediation strategies.

The report then draws on the discussion of the above topics to set forth a series of strategies for preventing and remediating CO_2 leakage, including estimating the impacts that the prevention and remediation options would have on the overall costs of storing CO_2 in geological formations. The report concludes by recommending additional research and investigations that would improve upon the science and practice of preventing and remediating leakage of CO_2 from geological formations.

It is important for the report reader to be informed of the ground rules for conducting the five tasks set forth for study and for preparing this report:

- Tasks 1, 2, and 3 were to draw heavily on available technical information, requiring minimum original work. As such, the initial chapters of the report provide a distilled summary of what we believe reflects the best of the currently available science on Understanding CO_2 Leakage Pathways (Task 1), Site Selection and Reservoir Screening (Task 2), and Modeling and Monitoring (Task 3).

- The bulk of the study effort and report were to be directed toward Task 4: Review of Methods to Remediate Leakage, and Task 5: Formulation and Discussion of Leakage Prevention and Remediation Strategies.

- Finally, the study was to be limited to remediation of leakage from the geological storage reservoir itself and should not extend to remediation of the consequences of CO_2 leakage into potable water, into the vadoze zone, or into buildings. This topic is the subject of a separate IEA study.

We have drawn heavily on the impressive volume of past work on understanding the causes of CO_2 leakage and on modeling and monitoring strategies that would provide "early warning" of CO_2 leakage. We acknowledge the researchers who have conducted this fine work in our references and trust that we have appropriately captured and summarized their insights. We also recognize that the science and technology of remediating CO_2 leakage is still emerging. As such, we hope that our discussion and recommendations on this topic will help accelerate new research on the many critical issues surrounding safe and reliable storage of CO_2.

We have also looked, in detail, at the information available on industry's extensive experience with natural gas storage, involving nearly 100 years of operation in currently over 600 gas storage sites in the United States, as well and throughout the world. The "lessons learned" from this vast pool of experience, particularly testing procedures for safe site selection, field monitoring procedures for leak detection, and mitigation actions for responding to leaks, have been incorporated into our analysis. Portions of these findings have been selectively highlighted in the "Sidebars" to our report.

Finally, in preparing this report, we have also relied on our own site assessment work for power companies and other industrial firms looking to store their CO_2 emissions, as well as on our reservoir engineering and field operations experience in remediation actions to control leakage. This experience is augmented by our on-going site characterization, site selection, modeling and monitoring design work on the DOE Regional Carbon Sequestration Partnership (SECARB)-sponsored Tuscaloosa Test Site involving CO_2 injection into a deep, regionally extensive saline formation along the Gulf Coast of Mississippi.

With appropriate leak prevention and mitigation strategies, we believe it will become possible to achieve the challenging goal facing the storage of CO_2 in geological formations - - enabling the security of CO_2 storage to increase with time, Figure EX-1.

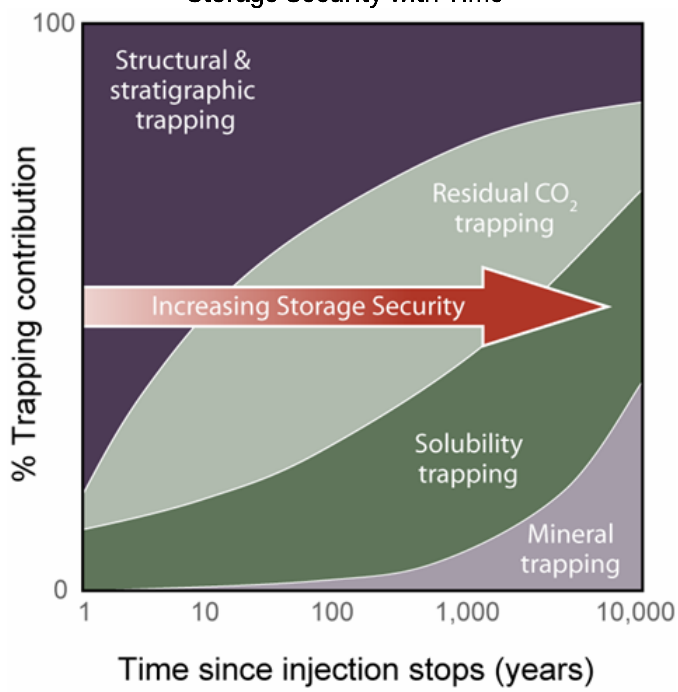
In summary, our proposed five-part leak prevention and mitigation strategy consists of:

- Carefully selecting favorable storage sites with low risks for CO_2 leakage.
- Putting high priority and emphasis on ensuring well integrity.
- Conducting a phased series of reservoir simulation-based modeling efforts to project and track the CO_2 plume.

- Installing and maintaining a comprehensive monitoring system for the CO_2 storage site.

- Establishing a "ready-to-use" contingency plan and strategy for remediation, if necessary.

Figure EX-1. CO_2 Storage Trapping Mechanisms and Increasing Storage Security with Time



Source: Heidug, 2006.

Importantly, in the rare cases where leakage does occur, we believe that remediation options are available to respond, though some may be costly. In many cases the geologic and engineering effort associated with such remediation would be comparable to, and in many cases could exceed, that associated with up-front site selection, design and project implementation. Inevitably, attempts to save money in the site selection, project design and field implementation stages could result in costs for remediating the problem caused by leakage that would be substantially greater than that associated with proper site selection, design and implementation.

Despite this, CO_2 leakage and remediation, especially remediation, has received less attention and priority than this topic deserves. In particular, fruitful next steps could include:

- A "best practices" manual for CO_2 leak prevention and remediation
- Further study of remediation experiences in the natural gas storage industry
- Investment in research and development (R&D) on remediation approaches and technologies, with focus on corrosion-resistant wellbore materials and procedures for sealing failures in caprock
- Development of improved procedures and techniques for locating and assessing the integrity of abandoned wells
- Addressing concerns associated with reservoir systems, primarily saline aquifers, not defined by structural traps.

I. INTRODUCTION AND OVERVIEW

An extensive set of geological research and engineering studies, plus past experience with injecting and storing fluids, indicates that the storage of carbon dioxide (CO_2) in deep underground geologic reservoirs can be a technically feasible strategy for reducing emissions of anthropogenic-sourced CO_2.[1] The subsurface storage of CO_2 was first proposed as a greenhouse gas (GHG) mitigation option in the 1970s, but little research and development (R&D) was performed on CO_2 storage until the early 1990s. Since then, major geological CO_2 storage projects, such as Sleipner, In Salah and Weyburn, are building confidence in this promising but still emerging option.

A. OVERVIEW OF STORAGE OPTIONS

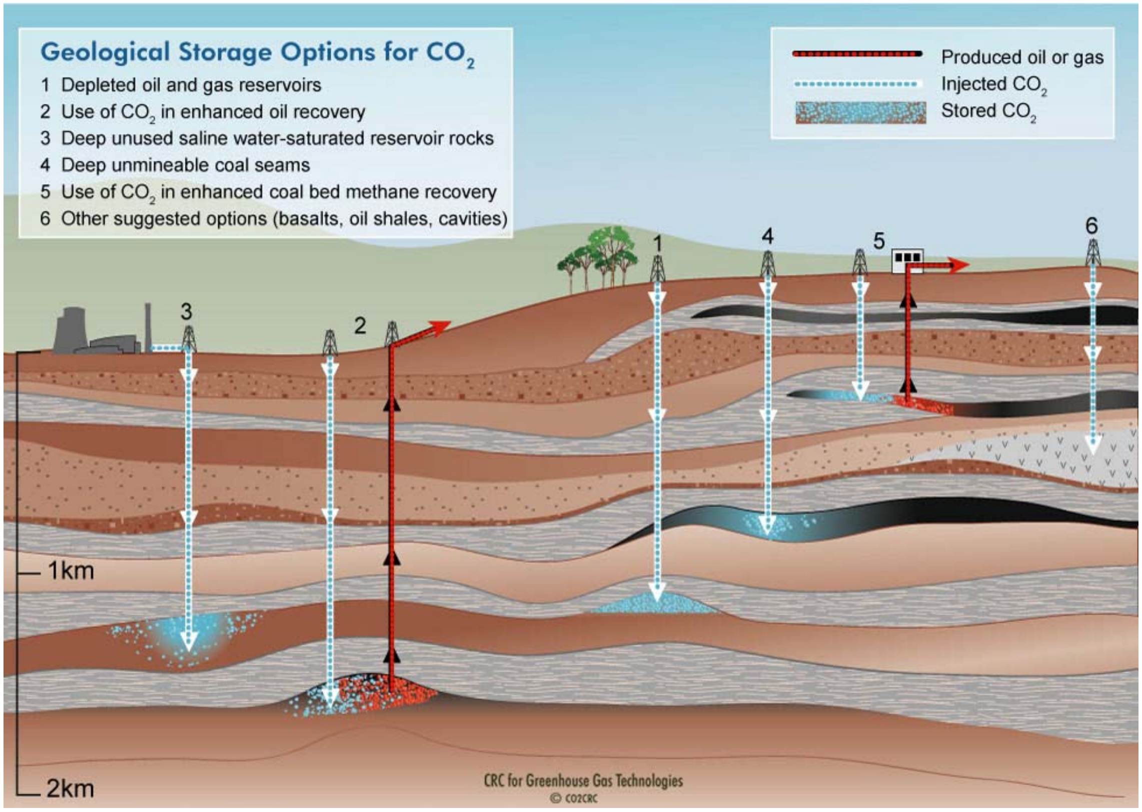
Three types of geological formations - - oil reservoirs, depleted gas reservoirs and saline formations - - are currently the best understood and thus are the most attractive candidates for geologic storage of CO_2. These three geological storage options, as well as the other less defined options, are illustrated on Figure 1-1.

- Oil and Gas Reservoirs. More than 100,000 oil and gas fields have been discovered around the world[2]. These oil and gas fields have favorable geological features, such as a sealing caprock and a well defined structure, that have supported long-term (millions of years) trapping and containment of fluids in the subsurface. These same containment and trapping mechanisms could apply to long-term, secure storage of CO_2. In addition, more is known about the geology and characteristics of oil and gas reservoirs than of the other CO_2 storage options under consideration.

  In some cases, increased recovery from an oil reservoir can be enhanced by injecting CO_2 into the reservoir to mobilize "left-behind" oil, a process called enhanced oil recovery (EOR). A similar application for natural gas fields is conceivable, but has yet to be demonstrated. Even when the prospects for additional oil and gas recovery are unfavorable, CO_2 can still be injected into these depleted oil and gas fields for long-term storage.

[1] This is perhaps best summarized in the Intergovernmental Panel on Climate Change (IPCC) Special Report entitled, *Carbon Dioxide Capture and Storage*, Summary for Policymakers (IPCC, 2005).
[2] Oil fields outnumber gas fields by a factor of 2 to 1, according to Klett, et al., 2005.

Figure 1-1. Geologic Formations Targeted for CO_2 Storage



Source: Image courtesy of the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)

- Saline Formations. A second geological setting for storing CO_2 involves injecting high pressure CO_2 into deep saline formations. While saline formations will not produce "value-added" by-products such as oil and gas, they can have other advantages. Of high importance is that the estimated storage capacity of saline formations is believed to be quite large - - substantially larger that the storage capacity offered by oil and gas reservoirs. Moreover, deep saline formations are much more geographically dispersed and available than oil and gas reservoirs, often providing close proximity to high volume sources of industrial CO_2 emissions.

- Unmineable Coal Seams. Coal beds typically contain large amounts of methane-rich gas that is adsorbed onto the surface of the coal. The current practice for recovering methane from coal seams involves depressurizing the seam, usually by pumping out water. Similar to that for oil reservoirs, injection of CO_2 into the coal seam can enhance methane recovery. In this process, the injected CO_2 essentially displaces the methane adsorbed on the coal seam, with the CO_2 remaining sequestered in the coal seam. Enhanced coalbed methane recovery (ECBM) by CO_2 injection and storage of CO_2 in coals have been demonstrated in a limited number of field tests, but much more work is necessary to understand and optimize this CO_2 storage process. Because the storage of CO_2 in coal seams is still considered to be immature, this storage option is outside of the scope of work for this report.

- Other CO_2 Storage Options. Alternative potential CO_2 storage options include gas shale formations, basalts, salt caverns, and abandoned coal mines, though the state of research and confidence associated with CO_2 storage in these formations is much less than for other types of geologic candidates. As such, these alternative options are not further assessed in this report.

B. CO_2 STORAGE CAPACITY IN GEOLOGICAL FORMATIONS

The Intergovernmental Panel on Climate Change (IPCC) report suggests that there is at least 2,000 billion tonnes of CO_2($GtCO_2$)(IPCC, 2005) of storage capacity in geologic formations worldwide, summarized in Table 1-1 (IPCC, 2005). Assuming an average annual injection rate of 10 Gt, these geological formations would provide at least 200 years and possibly over 1,000 years of CO_2 storage.

Table 1-1. CO_2 Storage Capacity by Reservoir Type

Reservoir Type	Lower Estimate of Storage Capacity ($GtCO_2$)	Upper Estimate of Storage Capacity ($GtCO_2$)
Discovered Oil and Gas Fields	675	900
Unmineable Coal Seams	3 – 15	200
Deep Saline Formations	1,000	Unknown, but possibly 10,000

Source: IPCC, 2005

C. SECURITY OF GEOLOGICAL CO_2 STORAGE

The oil and gas reservoirs targeted for CO_2 storage have held hydrocarbons or other fluids for millions of years, making them favorable candidates for CO_2 storage. Moreover, the oil industry already has three decades of safe operational experience in injecting CO_2 underground for enhanced oil recovery (EOR) in a great variety of oil reservoirs. The natural gas industry has a similar exemplary record of operating natural gas storage fields for nearly 100 years. These records of past performance by the oil production and gas storage industries give confidence that geologic formations can become a publically accepted, safe and secure option for storing CO_2.

Sidebar 1. A Relevant Analog: Overview of the Natural Gas Storage Experience. This overview summarizes the incidents and estimated leakage volumes from natural gas storage fields.

While, comparison with the natural-gas storage industry can be quite constructive when evaluating the future storage integrity of CO_2 storage, it is important to recognize one fundamental difference. Natural gas storage is a cyclic operation that takes place over a year interval, and sometimes even more frequently, while CO_2 storage is continuous and permanent, and the volumes that accumulate may/will be considerable, hence extracting, transporting and reinjecting the CO_2 will be quite different in scale.

There is always some degree of risk that the injected CO_2 could leak out of its intended storage site into surrounding strata, into potential underground sources of drinking water (USDWs), into the near-surface (vadose) environment and, eventually, into the atmosphere itself. Because of these concerns, considerable research has been directed toward investigating the potential pathways for leakage of CO_2 from geological storage reservoirs.

SIDEBAR 1. A RELEVANT ANALOG:
OVERVIEW OF THE NATURAL GAS STORAGE EXPERIENCE

The Natural Gas Storage Experience Provides a Useful Analog of the Incidents and Estimated Leakage That Could Occur from Geological Storage.

In a recent public opinion poll of the public's perception of the acceptability of geological storage, the presence of "positive analogs" ranked highest among the factors that would support acceptability of CO_2 storage. As such, the exemplary performance of the natural gas storage industry and its close analog to CO_2 storage should provide a very "positive analog" for gaining public acceptance for CO_2 storage.

An in-depth look at gas storage gives confidence that, with proper site selection, rigorous well design, thorough modeling, targeted monitoring, and workable mitigation strategies, the storage of CO_2 in geological formations can be safe and secure.

The gas storage industry has operated efficiently, and with very few incidents of leakage, for nearly 100 years. Many of the gas leakage incidents in gas storage were due to problems with well integrity and were promptly remediated. Improper site selection, particularly the inadequate testing of the gas storage formation's caprock (seal), accounts for the remaining incidents of natural gas leakage.

The incidents of reported leakage from the more than 600 gas storage sites, many in operation for 30 to 50 years or more (approximately 25,000 site years of operation) are quite small, with only 10 such leakage incidents identified by a GTI study of the U.S. natural gas storage industry (Perry, 2004).

Even smaller are the volumes of gas leakage, estimated at 0.015% per year of stored volume. Assuming that about 80% of the gas that leaked was captured by shallow wells, the volume of gas leakage to the atmosphere has been even less, estimated at 0.003% per year of stored volume.

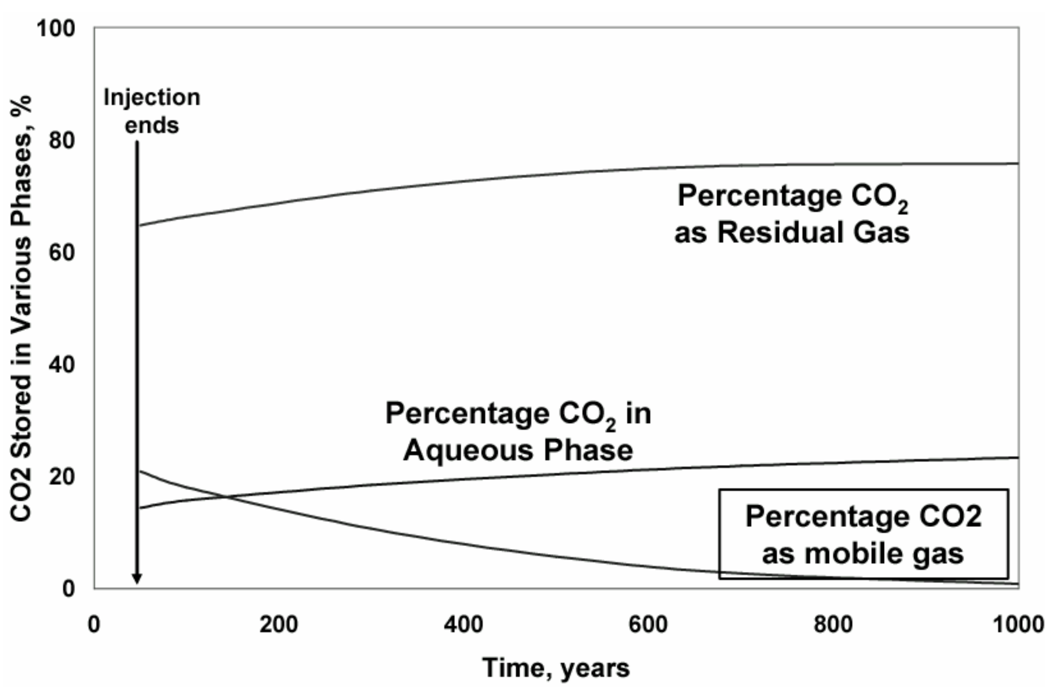
With more rigorous site selection procedures helping to avoid areas with inadequate reservoir caprock (seals); with modern well design, materials, and completion procedures helping improve well integrity; with considerably more rigorous CO_2 plume modeling and installation of CO_2 monitoring systems; and with the much less buoyant nature and lower mobility of the CO_2, the levels of leakage in CO_2 storage fields should be considerably less than experienced in the past by natural gas storage fields.

The pathways that could enable large amounts of CO_2 to leak from geologic formations include leakage through poor quality or aging well completions, leakage up abandoned wells, and leakage due to transmission through the caprock, faults and/or natural fractures.

In open saline formations (lacking structural closure), leakage could also occur as CO_2 migrates horizontally away from the injection point and reaches one of the vertical leakage pathways toward updip potable water and the outcrop. Episodic instances of CO_2 leakage could also occur due to improper CO_2 storage operations, including leakage during injection and filling a reservoir past its spill point.

In addition, current science indicates that CO_2 stored in a geologic formation may become more secure over time. Several mechanisms account for the potential for increasing storage security. After the injection of CO_2 into a formation has been completed, the formation pressure will decay over time, reducing the driving pressure. (Chalaturnyk and Gunter, 2004; Senior, 2005). Similarly, recent modeling work on saline formations shows that the amount of mobile supercritical CO_2 in a representative reservoir decreases to less than 10% of the total stored CO_2 after 500 years, with the remainder being either dissolved in brine or locked in rock pores, Figure 1-2. (Note that the analysis in Figure 1-2 is based on a series of advanced injection technology assumptions)(Holtz, et al., 2004). As both the formation pressure and percent free CO_2 decrease, so does the driving force for leakage.

Figure 1-2. Free CO_2 in a Saline Formation Storage Site Decreases Over Time



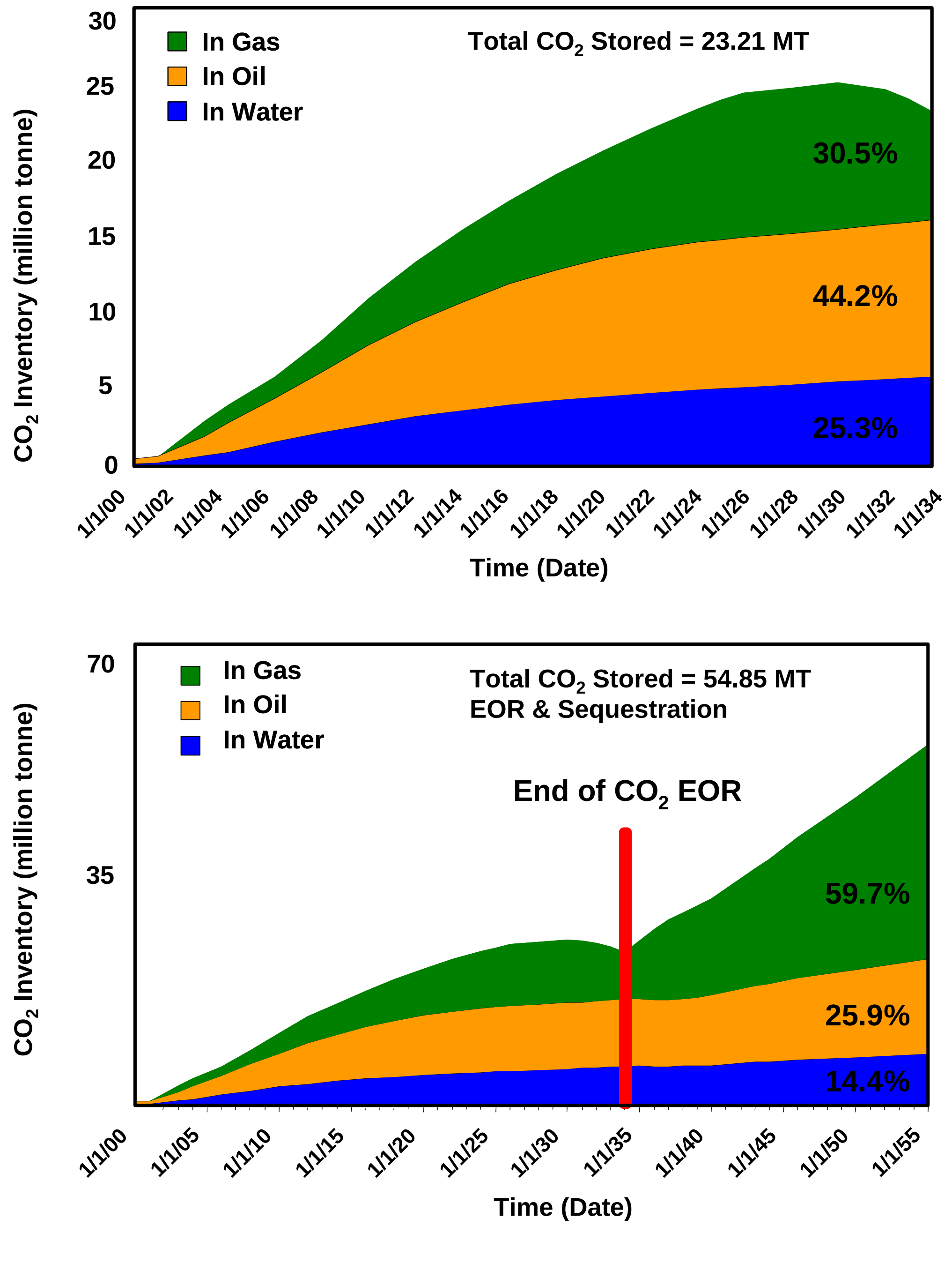
Source: Holtz, et al., 2004.

A second, in-depth study of the long-term storage mechanisms and risks of CO_2 leakage is provided by the Weyburn CO_2 Monitoring and Storage Project (Hewitt, 2005). Weyburn is a major CO_2-EOR and CO_2 sequestration field project, currently injecting over 2 million tonnes of industrial CO_2. The source of the CO_2 is the Northern Great Plains gasification plant in North Dakota, and the CO_2 is injected into the Midale Formation of the Weyburn oil field in Saskatchewan, Canada.

- During the CO_2-EOR phase of the project, from years 2000 to 2035, EnCana, the operator of the Weyburn oil field, plans to store 23 million tonnes of CO_2 in the Midale oil formation. Subsequent to the CO_2-EOR project, and during the CO_2 sequestration phase from years 2035 to 2055, the operator plans to inject and store another 32 million tonnes of CO_2. As such, a total of nearly 55 million tonnes of CO_2 will be stored in this oil field, Figure 1-3.
- The trapping and long-term storage of CO_2 at Weyburn is expected to occur by four mechanisms. The major mechanism, accounting for 44% of long-term storage, is dissolution in the oil left behind after the CO_2-EOR project. Solubility trapping in water and mineral trapping are each estimated to account for about 28% of long-term storage. Ionic trapping of CO_2 in water makes only a small contribution, Figure 1-4.

Given the presence of these various CO_2 trapping mechanisms and the competence of the caprock, the presence of structure, and the safety provided by overlying sediments, a risk assessment of the Weyburn Project, based on a long-term reservoir simulation study, estimated that only 0.2% of the injected CO_2 will leak to the atmosphere in 5,000 years, Figure 1-5.

Figure 1-3. Projected CO_2 Injection and Storage at Weyburn Oil Field



Source: Hewitt, 2005.

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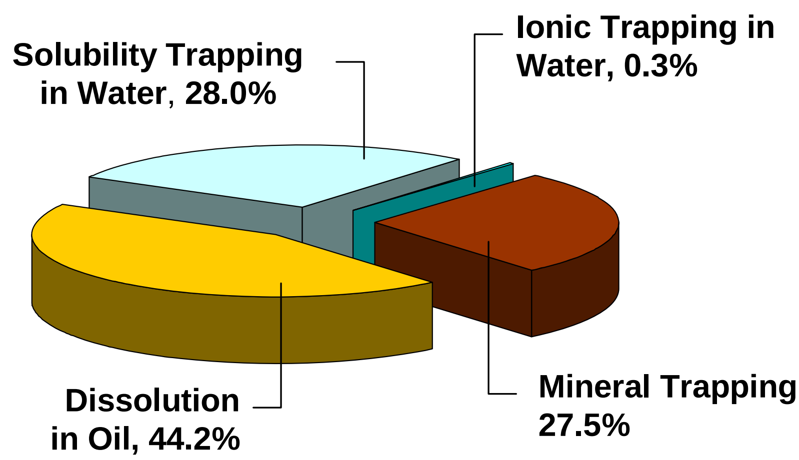
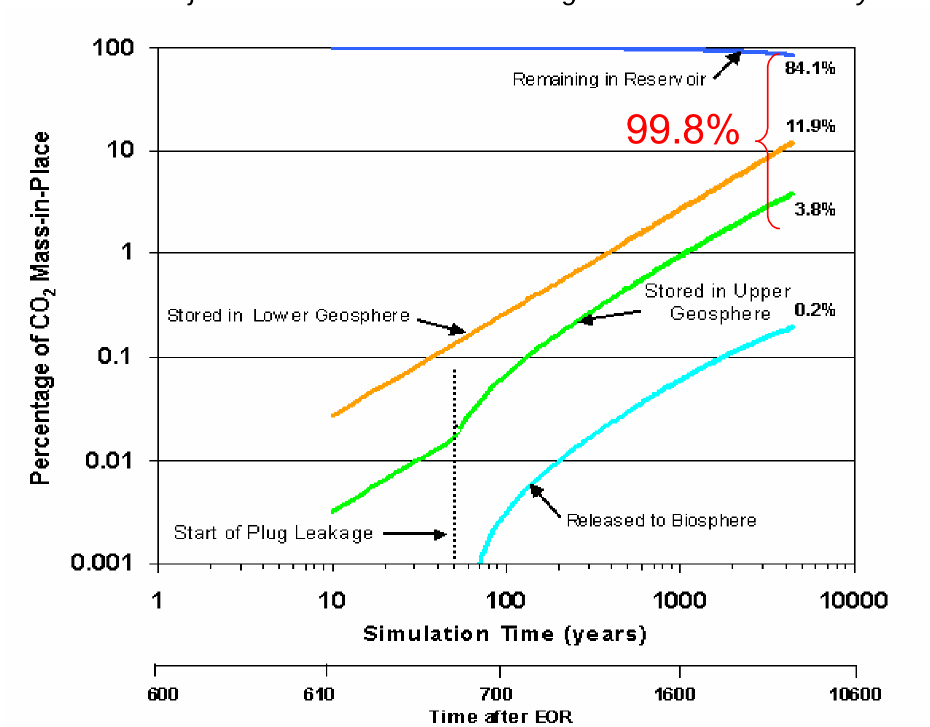
Figure 1-4. Long-Term CO_2 Trapping and Storage at Weyburn Oil Field



Source: Hewitt, 2005.

Figure 1-5. Long-Term Leakage Risk Assessment for the Weyburn CO_2 Storage Site

99.8% of the injected C02 will be stored underground for at least 5000 years



Source: Hewitt, 2005.

JAF02575.PPT

D. PRIORITIES FOR THE PATH FORWARD

Geologic storage sites will need to be selected with primary emphasis on assuring high-quality seal integrity and structural confinement. However, while the storage reservoir itself may be defined by geophysical data sets gathered from earlier petroleum development, the caprock is often assumed to be adequate and may not have been sufficiently investigated. Likewise, the challenges to long-term integrity of well bores, down-hole tubulars, and cements in the presence of CO_2 is just beginning to be understood. In many reservoirs, existing wellbores (both in producing and in plugged and/or abandoned wells) may be the primary potential conduit of CO_2 flow from the storage reservoir. As such, considerable additional R&D and technical investigation need to be devoted to these three topics - - seal integrity, structural confinement and well integrity.

Continued investments in the science and technology surrounding proper site selection, including testing of the caprock and mapping of structural confinement, in conjunction with advances in the design of CO_2 injection wells, will greatly improve the reliability of the selected CO_2 storage site. Development and demonstration of reliable modeling, monitoring and mitigation strategies, once added to the overall storage system, will further reduce the risks of CO_2 leakage -- whether from geologic features or well bores. As such, strong R&D efforts in modeling and monitoring accompanied by field pilots and large-scale demonstrations will help assure that industrial-scale implementation of geologic CO_2 storage will be available when required (Espie and Gale, 2004).

E. PURPOSE OF THE STUDY

The purpose of this study is to provide a comprehensive assessment of strategies for preventing CO_2 leakage in the first place, and a full discussion of the steps that should be taken should CO_2 storage sites leak and require remediation. The study also assesses the technical status and economics of alternative remediation techniques and approaches to address potential leakage from geologic CO_2 storage reservoirs. Our intent is that this information will help guide more detailed research and investigations into new and improved remediation technologies for the future.

Specifically, this report serves to provide a comprehensive discussion of the following: the potential CO_2 leakage pathways that could exist at CO_2 storage sites; how storage sites can be selected, configured, and operated to minimize the chance of leakage; how current modeling and monitoring technologies can help identify settings where leakage could occur; and, most importantly, when leakage does occur, what set of strategies and steps can be taken to remediate CO_2 leakage. The report also provides some perspective on the costs of various remediation approaches that could be applied to CO_2 storage.

II. POTENTIAL LEAKAGE PATHWAYS FROM GEOLOGICAL STORAGE RESERVOIRS

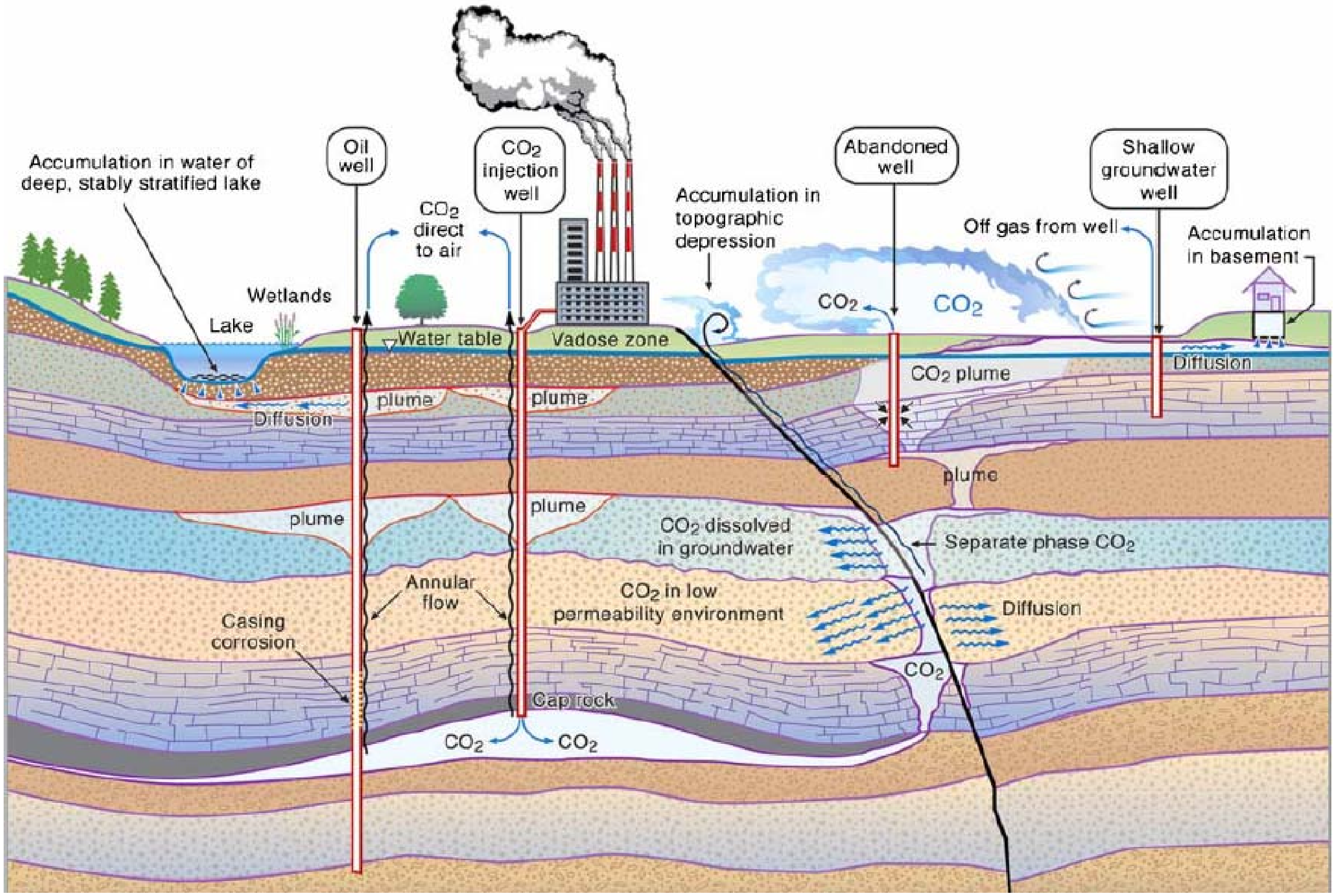
A. OVERVIEW OF LEAKAGE PATHWAYS

An important first step in addressing the issue of leakage from CO_2 storage reservoirs is to identify the potential leakage pathways for CO_2. The second step is to evaluate the likelihood of the CO_2 plume reaching and escaping through these leakage pathways. Then, depending on the nature of the leak, step three is to assess the volume and potential risks of CO_2 leakage whether it be to potable aquifers, to the vadose zone, or to the atmosphere.

Since CO_2 is buoyant compared to water, it will have a tendency to migrate, both vertically and laterally, along the most transmissive pathways available. Transmissive differences between the extent and nature of the buoyancy of the CO_2 steam injected and water will depend on the bulk density of the injected gas mixture, which is a function of the properties of both the CO_2 and other gases composing the injected stream. These transmissive pathways could be beds of porous and permeable sedimentary rock, transmissive fractures or fissures that cut through impermeable rock, or improperly completed or abandoned wells and boreholes in the vicinity of the CO_2 plume. Some of these pathways are illustrated in Figure 2-1 (Benson, et al., 2002).

Although large-scale leakage of CO_2 and other gases from geologic reservoirs is relatively rare, it is not unknown. This is especially true in the case of natural gas storage, where a several well-documented cases of leakage exist (Perry, 2005). In addition, in the relatively short time frame (geologically) of CO_2 injection for EOR, seals are retaining CO_2 in the subsurface, and the CO_2 appears to be behaving as expected (Grigg, 2002). Nonetheless, further documentation of CO_2 fate in the subsurface in EOR projects in probably warranted, since leakage would obviate the benefits of CO_2 capture, while reducing the public's and policy maker's confidence in this important CO_2 mitigation technology.

Figure 2-1. Illustration of Potential Leakage Pathways and Consequences



Source: Benson and Hepple, 2005.

B. OVERVIEW OF RISKS AND RELEVANT ANALOGS

The concept of storing CO_2 in geologic reservoirs is relatively new. However, researchers can draw on the considerable experience and understanding gained from oil and gas production, from commercial EOR projects (Grigg, 2002), from underground natural gas storage (Perry, 2004), from natural CO_2 reservoirs (Stevens, 2004), and from natural releases of CO_2 (Holloway, 2005). Operating experience with "sour gas" or "acid gas" production, treatment and disposal is also relevant (Krilov, et al., 2000).

To provide some perspective, it is important to recognize that the likelihood of leakage from properly selected, well-managed, and well-operated storage reservoirs is believed to be small. According to the recent IPCC report (IPCC, 2005):

> *"Observations from engineered and natural analogues as well as models suggest that the fraction retained in appropriately selected and managed geological reservoirs is very likely* to exceed 99% over 100 years, and is likely** to exceed 99% over 1,000 years."*

* "Very likely is a probability between 90% and 99%

** "Likely is a probability between 66% and 90%

This assessment is based on the IPCC's thorough examination of research, project performance and risk assessments performed to date demonstrating the potential geologic integrity of likely CO_2 storage reservoirs.

Similarly, using natural gas storage as an analog, only ten of the approximately 600 storage reservoirs in the United States have experienced any reported leakage (Perry, 2005). This is based on a survey of 55 operators in 16 countries, 42 of which provided information to the project cited. In the U.S., 42 operators responded to the survey. All of the geologically related natural gas leaks through a caprock were in converted aquifer-based gas storage fields lacking the assured seal available in abandoned oil and gas fields (see Sidebar 2). The remainder of the leaks in gas storage operations were associated with lack of well integrity or loss of well control, generally attributable to poor well completion and workover practices. A companion study, including internationally operated gas storage fields, showed a similarly safe and reliable operating history (Woodhill Frontier, 2005). In general, reservoir engineering principles determine maximum allowable reservoir pressure allowable in a natural gas storage reservoir to maximize storage gas deliverability without damaging the reservoir. These same principles would apply to CO_2 storage reservoirs as well.

Sidebar 2 to this report provides an overview of the U.S. natural gas storage leakage experience relevant for CO_2 storage.

C. MECHANISMS OF CO_2 TRAPPING AND STORAGE.

CO_2 storage security depends on a combination of physical and geochemical trapping, with the relative importance of these two trapping mechanisms changing over time. Of initial and primary importance is structural and/or stratigraphic trapping of the CO_2 beneath a secure caprock. Over time, capillary trapping (also called residual CO_2 trapping) and solution trapping (in oil or water) begin to make a larger contribution. As time increases, mineral trapping and density inversion trapping become increasingly important. (These two important CO_2 trapping mechanisms involve CO_2 precipitating out in the form of carbonates (mineral trapping) and more dense CO_2 saturated waters flowing downward and downdip (density inversion).

Under favorable conditions, the amount of CO_2 that can be sequestered via mineralization can become comparable with capillary trapping and solution in oil or water, though the relative contribution of each trapping mechanism will vary considerably with rock type (Xu, et al., 2000). Figure 2-2 illustrates the relative importance of each of these CO_2 storage and trapping mechanisms and their role in establishing that the security of CO_2 storage increases with time.

An important portion of our current understanding of trapping and storing CO_2 in oil reservoirs has been gained from the numerous CO_2 enhanced oil recovery projects, in the U.S. and elsewhere. The gas storage industry, which preferentially uses depleted natural gas fields in the U.S., also provides a most valuable base of knowledge for storing CO_2 in oil and gas fields. Finally, much of the knowledge on CO_2 trapping and storage mechanisms for deep saline aquifers has been gained from the valuable experiences at Sleipner (Johnson et al., 2004).

SIDEBAR 2. ASSESSMENT OF NATURAL GAS STORAGE LEAKAGE AND OPERATING EXPERIENCE

The Natural Gas Storage Experience Provides Insights as to Likely Pathways for CO_2 Leakage.

Natural gas has been stored and recycled in geologic formations for nearly 100 years. Approximately 600 U.S. storage reservoirs containing nearly 8 Tcf (equal to about 2 billion metric tons of CO_2 storage volume) of natural gas help meet peak gas demand during winter and provide a repository for excess gas production during summer.

A survey of U.S. gas storage operations was conducted for the CO_2 Capture Project by K. Perry of the Gas Technology Institute (GTI, 2002, 2004). In this study, Perry identifies only 10 examples of natural gas leakage, mostly occurring prior to 1970 before the use of modern site appraisal and well completion practices, as summarized on Table 1.

Table 1. Gas Storage Fields with Some Type of Leak

Field Type and Location	Type of Leak	Remediation Action Taken
1. Caprock and Seal Problems		
Aquifer – Indiana, U.S.	Reservoir Too Shallow	Field Abandoned
Aquifer – Illinois U.S.	Caprock	Aquifer Pressure Control
Aquifer – Midwest U.S.	Caprock	Shallow Gas Recycle
Aquifer – Midwest U.S.	Caprock	Field Abandoned
Aquifer – Midwest U.S.	Caprock	Reservoir Abandoned, Deeper Zone Developed for Gas Storage
2. Wellbore and Casing Problems		
Aquifer Storage, Wyoming, U.S.	Wellbore Leak	Wellbore Remediation
Depleted Gas Field, Canada	Wellbore Leak	Wellbore Remediation
Depleted Gas Field, W. Virginia, U.S.	Casing Leak	Wellbore Remediation
Depleted Field, California, U.S.	Improperly Plugged Well	Re-Plug Old Well
Salt Cavern, Kansas, U.S.	Wellbore Leak	Wellbore Remediation

In addition to providing very valuable information on the portfolio of technologies used by the underground gas storage industry to monitor, detect and remediate leakage, the 42 U.S. gas storage operators that responded to the GTI survey identified the following examples of gas leakage and migration.

Caprock Leaks. Five of the gas storage leakage incidents involved leakage of gas through the caprock or seal, requiring that three of the gas storage field or reservoirs be abandoned:

- In the late 1960's, an overly shallow aquifer-based gas storage field was established in Northern Indiana (USA). After leakage was detected in a number of the nearby water wells, the gas storage field was drawn down and abandoned. (Current regulations would no longer allow or certify such a shallow gas storage field.)
- In mid-1953, shortly after the Herscher-Galesville aquifer-based gas storage field in Illinois (USA) was put on operation, bubbles of gas appeared in shallow water wells in the area. Four actions were taken that have enabled this gas storage project to continue operating for 50 years, namely: (1) drilling of shallow wells to capture the leaked gas; (2) reinjection of the captured gas back into the Galesville Formation; (3) injection of water into a formation above the Galesville to provide a pressure boundary; and, (4) maintaining lower pressures in the main Galesville gas storage zone.

SIDEBAR 2. NATURAL GAS STORAGE LEAKAGE EXPERIENCE (Cont'd)

Caprock Leaks (Cont'd)

- Gas leakage through the caprock was noted in two Mt. Simon and one adjacent St. Peter Sandstone aquifer-based gas storage fields in the Midwest (USA). In one case, shallow gas well drilling plus gas recycling was implemented to remediate the problem. In the second case, the gas storage field was abandoned leaving behind a small volume of stored gas. In the third case, the shallower zone was abandoned and a deeper formation in the field was developed for gas storage.

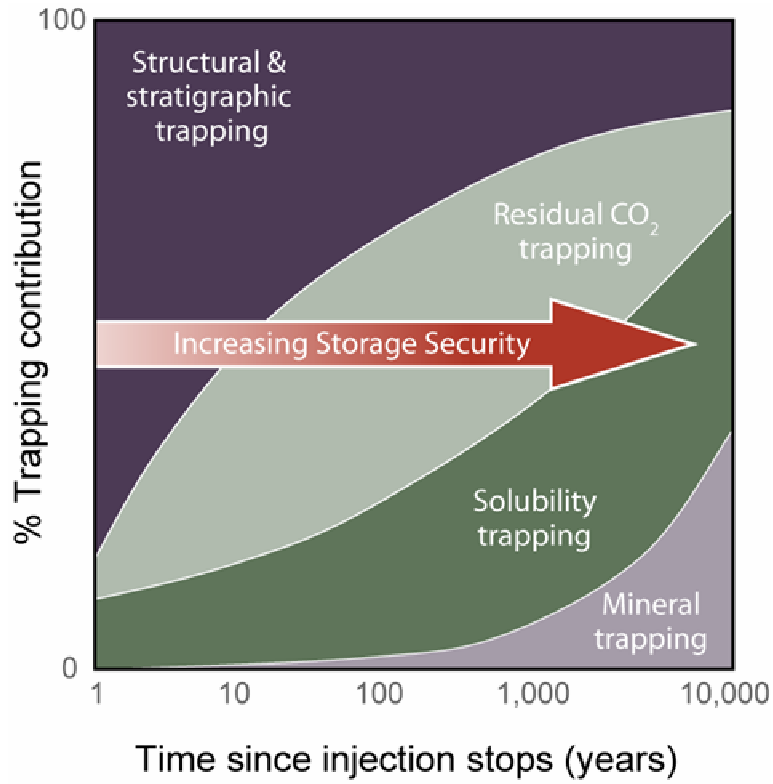
Wellbore and Casing Leaks. Five of the gas storage leakage incidents involved temporary wellbore or casing leaks that were corrected with wellbore remediation and well plugging:

- In the early 1980's, the Leroy aquifer-based gas storage field in the Thaynes Formation, Uinta County, Wyoming (USA) observed gas bubbling to the surface from a wellbore leak. The problem was corrected by reducing the gas injection and operating pressures and conducting a wellbore remediation.
- Casing and wellbore leaks were detected in depleted gas formation-based gas storage fields in West Virginia (USA) and in Ontario, Canada. Repairing defective casing and reworking the wells were undertaken to remediate this problem.
- In the 1970's, the gas storage operator at Montebello, California observed that an old well, plugged before current standards were put in place was causing gas to migrate into a shallower zone (but not to the surface). Proper plugging of this old well to today's standards remediated the problem.
- In early 2001, high pressure natural gas began escaping from a casing leak at one of the 70 salt caverns at the Yaggy gas storage field outside of Hutchison, Kansas (USA). The 60 million cubic feet of gas in the S-1 man-made salt cavern escaped and traveled toward Hutchinson, a town with a population of 40,000. The lateral migration pathway was a thin dolomite interval above the top of the storage cavern. The leaked gas led to a series of explosions, gas geysers and two deaths, the first-ever deaths from a natural gas storage facility. The Yaggy gas storage field was closed for two years before further diagnostic and remediation efforts enabled this gas storage field to resume operations. (Additional discussion of the Yaggy gas leakage experience is provided in Chapter III, Sidebar 3.

Source: Perry, 2003; Perry, 2004.

Nonetheless, additional research is need to better understand the processes that contribute to effective, long-term storage of CO_2 in geologic reservoirs, including - - physical trapping beneath low permeability cap rocks, trapping in the immobile residual phase in the pore space of the reservoir, and geochemical trapping in fluids and/or the reservoir rock (Benson, 2005).

Figure 2-2. CO_2 Storage and Trapping Mechanisms and Increasing Storage Security with Time



Source: Heidug, 2006.

The following provides a brief synopsis of the key CO_2 trapping and storage mechanisms in geological formations and their applicability to the three main CO_2 storage options.

1. Pore Volume Trapping (Aquifer, Oil and Gas). Two mechanisms naturally trap CO_2 within reservoir pores - - CO_2 saturation below a critical value and depletion (imbibition) hysteresis. Critical gas saturation determines the minimum saturation of CO_2 that is required to initiate flow of the CO_2 through the reservoir pore space. This saturation is defined by the reservoir rock's relative permeability curves for CO_2, oil and water, see Figure 2-3. Subsequent CO_2 trapping through relative permeability hysteresis is primarily a post-injection phenomenon due to the differences between drainage (production) and imbibition (injection) CO_2 relative permeability, see Figure 2-4, where liquid imbibition begins at a given initial gas saturation (S_{gi}) thereby creating a new, larger trapped gas saturation (S_{gt}) .

2. Solubility in Water. CO_2 is soluble in water, and when injected into a saline water formation or an oil reservoir (for example during the CO_2-EOR process), a portion of the CO_2 will dissolve in the formation water, Figure 2-5. The amount of CO_2 dissolved in water is affected by several factors including: temperature and pressure within the reservoir; salinity of the reservoir water; and how much of the reservoir's brine is contacted by CO_2 (as governed by the reservoir's heterogeneity and geometry). Subsequent inversion of the more dense CO_2 saturated brine will serve to increase the contact of the CO_2 with the reservoir's brine, as shown on Figure 2-6.

3. Mineral Trapping. Mineral trapping is the permanent sequestration of CO_2 through chemical reactions, primarily with minerals in the reservoir's matrix. Through field studies and numerical modeling, it has been determined that CO_2 is primarily trapped through precipitation of calcite ($CaCO_3$), siderite ($FeCO_3$), dolomite ($CaMg(CO_3)_2$) and dawsonite ($NaAlCO_3(OH)_2$) (Xu, et al., 2001; Xu, et al., 2003). In order for mineral trapping through carbonate precipitation to occur, minerals rich in Mg, Fe, Na and Ca, such as feldspars and clays, must be present in the reservoir rock. Therefore, immature sands having an abundance of unaltered rock fragments (unweathered igneous and metamorphic minerals and clays rich in Mg, Fe and Ca) are most effective (Bachu, et al., 1994; Pruess, et al., 2001). The abundances and ratios of these primary minerals can have a tremendous effect on the type of secondary minerals that are precipitated as well as on the overall total amount of CO_2 that may be permanently sequestered.

4. Solubility in Oil. As part of the CO_2-EOR process, CO_2 will condense into the reservoir's oil phase and CO_2 will also vaporize the lighter oil fractions into the injected CO_2 phase. (From the perspective of EOR, this leads to two reservoir fluids that become miscible (mixing in all parts), with favorable properties of low viscosity, a mobile fluid and low interfacial tension.) As such, considerable volumes of CO_2 will remain in the reservoir in solubility with the unproduced, residual oil.

Figure 2-3. Relative Permeability of CO_2 and Brine.

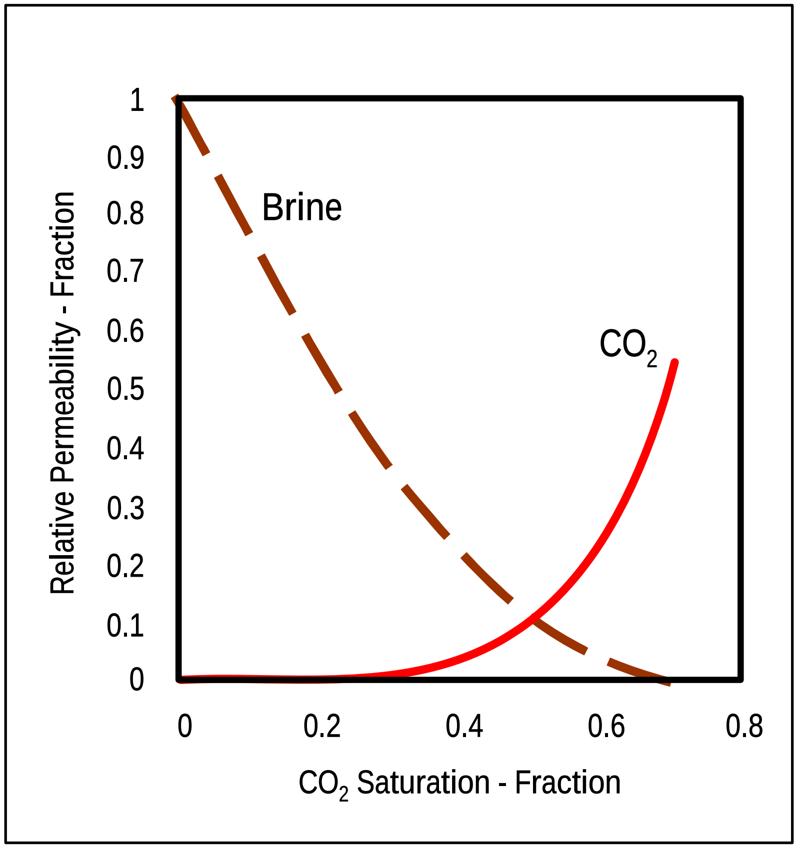


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Figure 2-4. Hysterisis Effects on Relative Permeability of CO_2 and Brine.

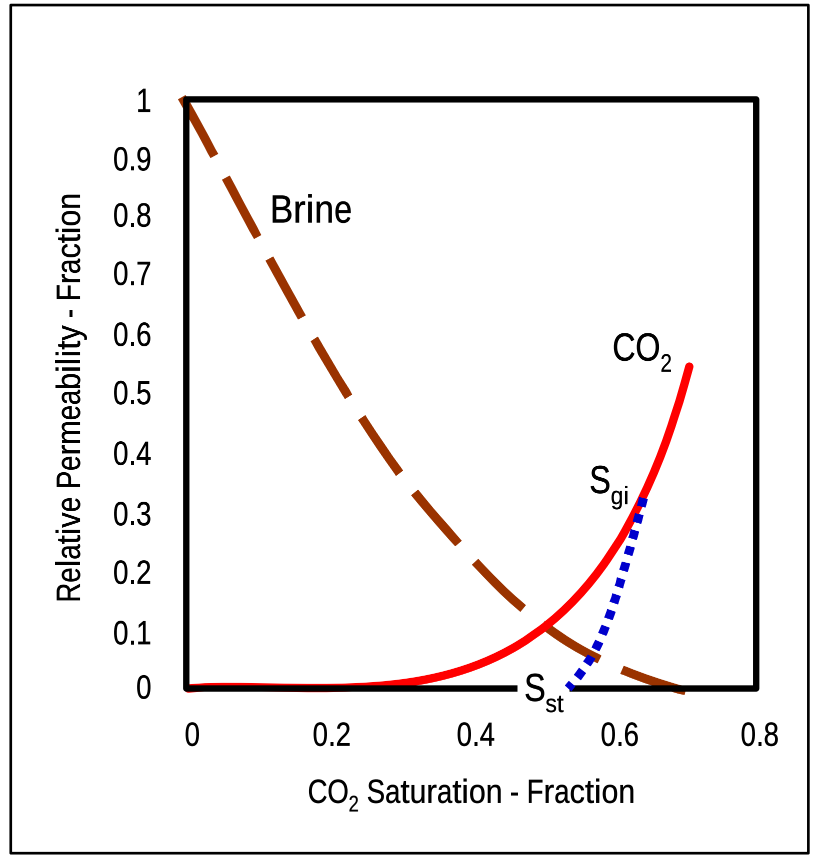
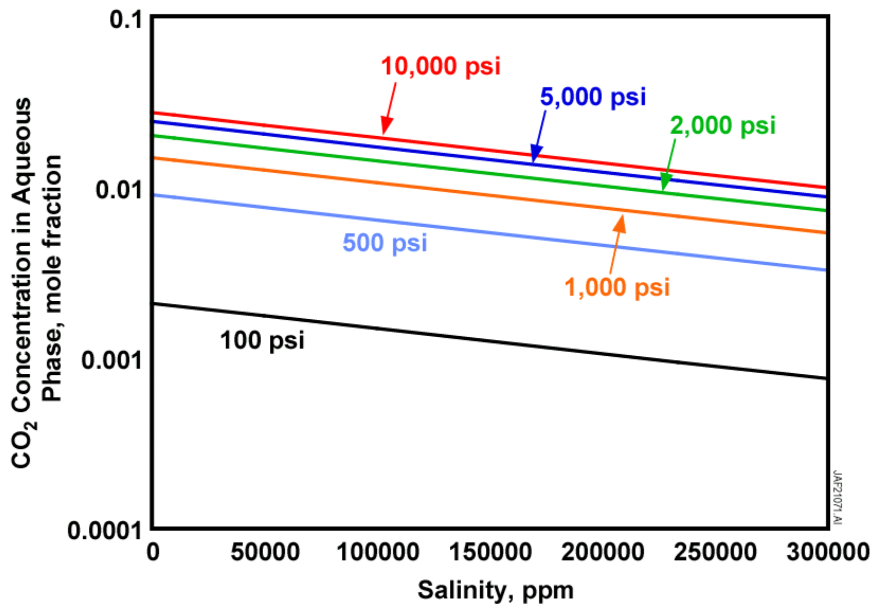


Figure 2-5. Increasing Brine Salinity Reduces CO_2 Solubility in Aqueous Phase



Source: G.A. Pope, UT Austin (Orr, 2004)

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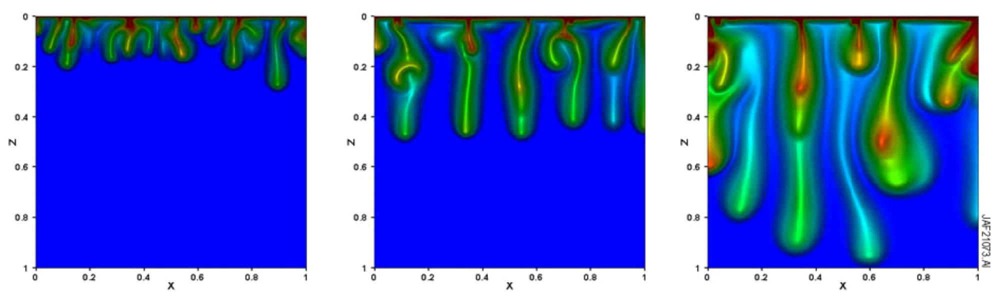
Figure 2-6. Mixing and Dissolution of CO_2 in Saline Waters



24 years 52 years 108 years

Source: A. Riaz, M. Hesse, H. Tchelepi, Stanford University, 2004 (Orr, 2004).

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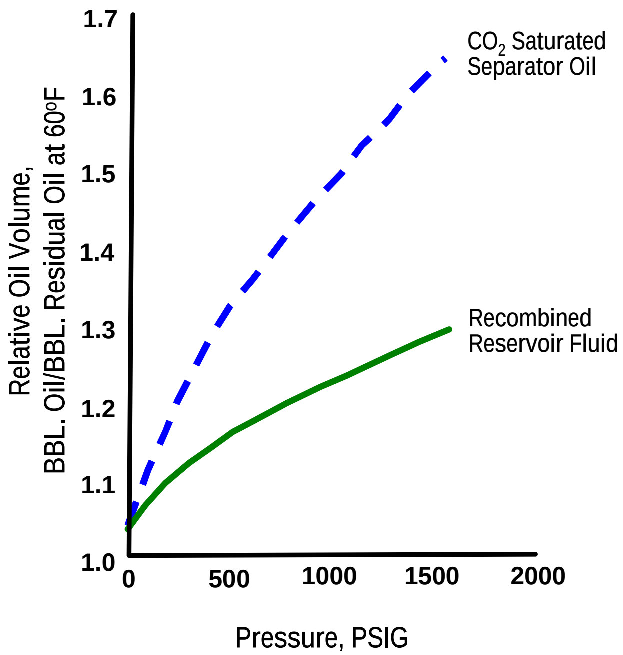
The solubility of CO_2 in oil leads to oil swelling, an important mechanism for both miscible and immiscible CO_2 injection. Laboratory work on a light, West Texas oil shows that the injection of CO_2 (at 1,500 psig or 105 Kg/cm^2) can increase the volume of the reservoir's oil by 30%, Figure 2-7. Laboratory work on reservoir oil in Turkey shows that, even for heavy oil, the volume of oil can be increased by 15% to 20% under high pressure, Figure 2-8.

5. Structural Confinement. A most critical CO_2 trapping and storage mechanism for oil, gas and saline water formations is structural confinement, due to anticlinal geology, stratigraphic features or sealing faults. The free CO_2 in the reservoir will be trapped within the geologic structure, much as oil or natural gas has been trapped in conventional hydrocarbon fields. As long as the volume of CO_2 injected does not exceed the reservoir's "spill point", structural confinement provides one of the most secure mechanisms for precluding CO_2 migration and subsequent leakage.

The following section of Chapter II discusses, in more depth, the geological (nature-created) leakage pathways as well as the non-geological (human-created) leakage pathways that may enable CO_2 to migrate out of its intended storage setting.

- Of primary concern for <u>geological (nature-created) leakage pathways</u> is the lack of caprock integrity which is essential for providing a seal for the CO_2 storage container. This concern is particularly noted for saline formations which may lack structural containment ("open-system"). Natural faults and fractures when open, or reopened during the course of CO_2 injection, are a second leakage pathway of concern. New leakage pathways may also be created by volcanic or tectonic activity subsequent to the injection of CO_2, although the one recently documented tectonic event in Japan, a major earthquake (6.8 on the Richter scale) in the vicinity of the Nagaoka CO_2 storage deep coal seam pilot operation, had no effect on the integrity of the CO_2 storage container (IPCC, 2005).

Figure 2-7. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid



Source: Holm and Josendal, 1982

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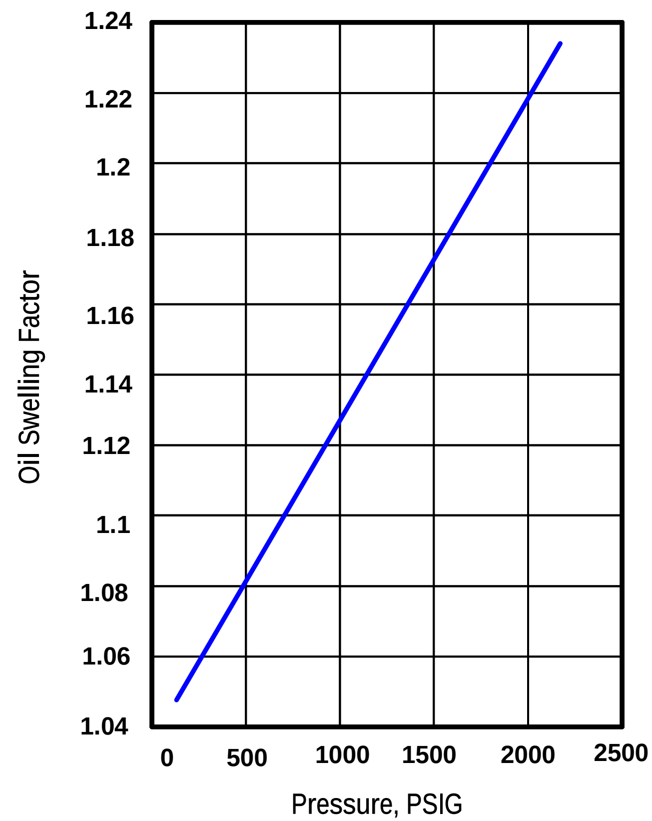
Figure 2-8. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey



Source: Issever and Topkaya, 1998.

- The human created (non-geological) leakage pathways of highest concern and thus further discussed in this report include: (1) leakage from improperly completed or abandoned wells; (2) leakage during injection operations; (3) leakage from injection induced faulting or fault reactivation; (4) leakage due to storage reservoir overfill; and (5) leakage due to post-storage disruption of the storage container.

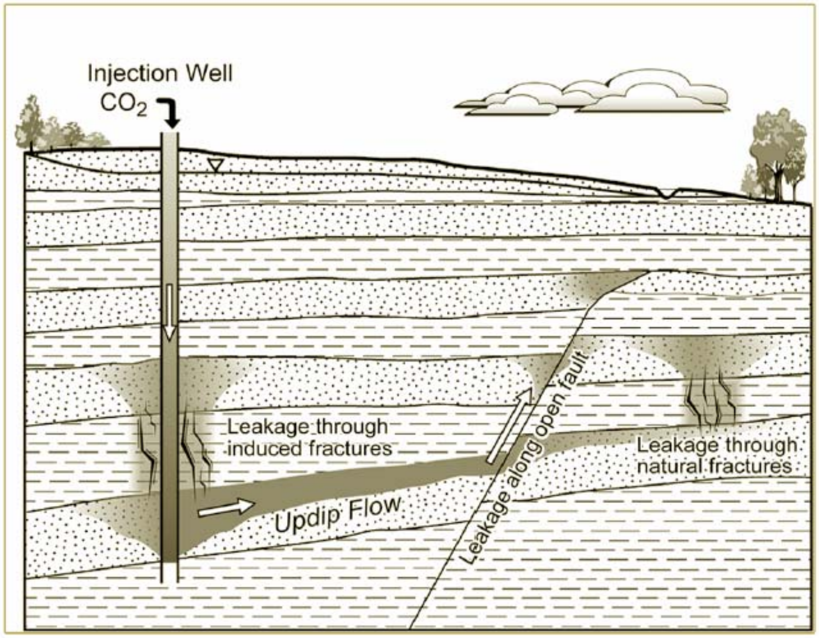
D. EXAMINATION OF LEAKAGE PATHWAYS

Much of the initial technical work on CO_2 leakage from geologic storage sites has focused on the many natural processes that could act to mitigate CO_2 leakage, rather than on examining the leakage pathways themselves. As such, valuable information exists on permeability trapping of buoyant CO_2 in overlying layers; ponding of dense CO_2 at the groundwater table; solubility trapping by water; and, dilution of CO_2 by mixing with ambient soil gases. This research, supported by numerical modeling, is reassuring in suggesting that leaking CO_2 can face numerous natural obstacles that will slow or prevent its escape to the atmosphere (Oldenburg and Unger, 2003).

In this section of Chapter II, we set forth and discuss the numerous potential pathways whereby CO_2 may leak from a geologic storage reservoir. These include both geologic pathways and non-geologic (or human created) pathways, as illustrated in Figures 2-9 and 2-10. In general, these pathways are common to all types of reservoir settings and geological storage options.

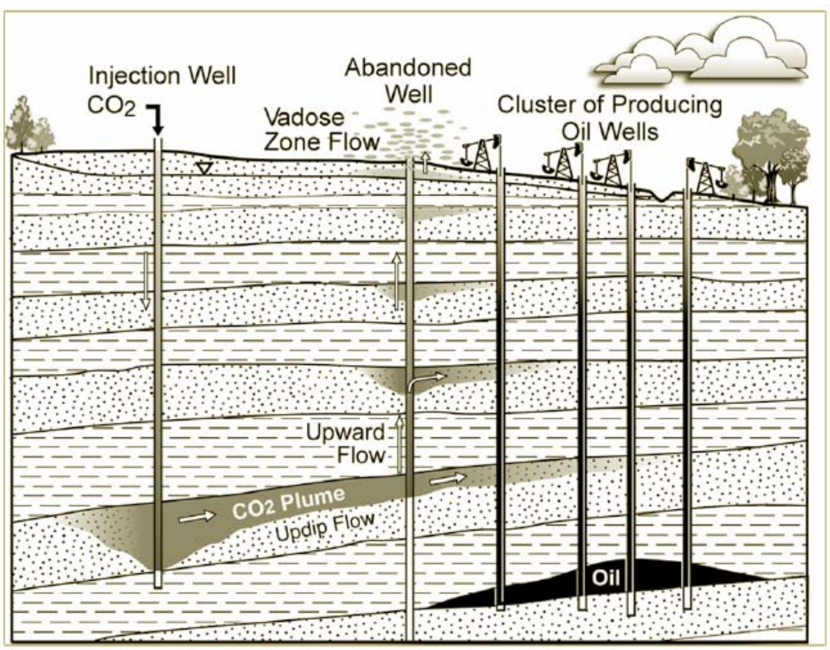
1. Geological Leakage Pathways. Selecting a geologically favorable reservoir with long-term ability to safely and securely store CO_2 depends on picking a site with no natural leakage pathways. Most important for all three of the storage options is avoiding geological settings where vertical leakage could occur through an overly thin or an overly permeable caprock. For saline formations, the geological settings to avoid are those that lack a regionally extensive overlying seal or that lack an updip structural closure. These types of settings could enable CO_2 to migrate laterally and reach a subsequent leakage pathway.

Figure 2-9. Geologic Leakage Pathways



Source: Bachu and Celia, 2006 (in press)

Figure 2-10. Abandoned and Producing Well Leakage Pathway



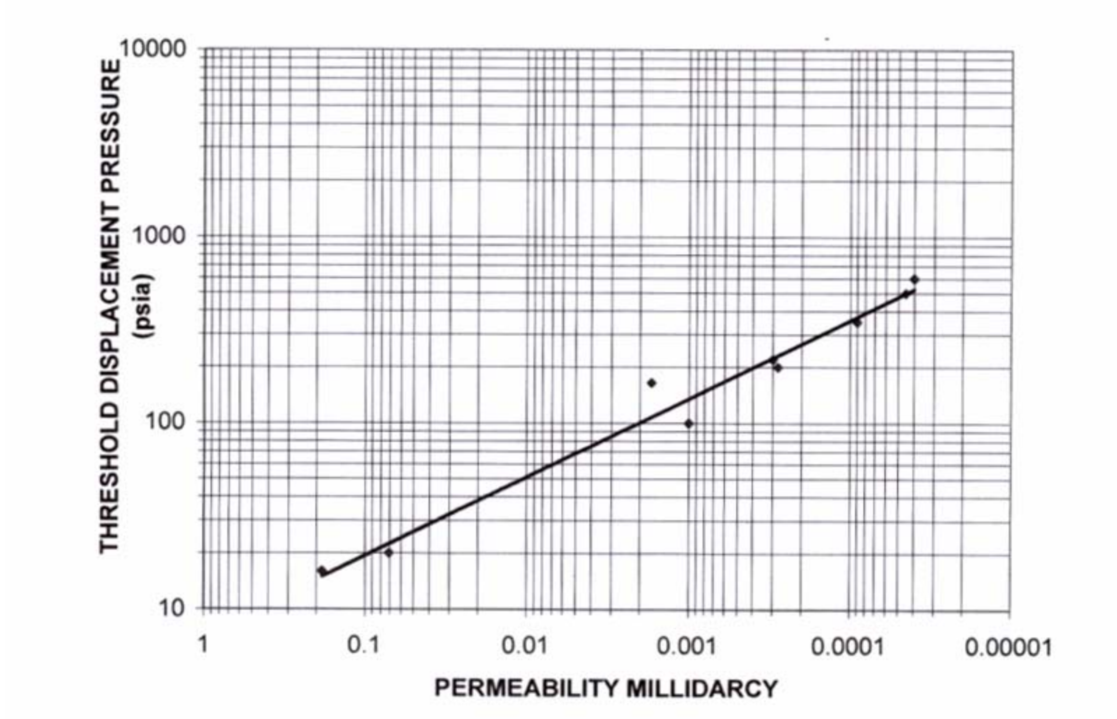
Source: Bachu and Celia, 2006 (in press)

In addition, it is important to avoid geological settings with extensive natural fractures and non-sealing faults which can provide leakage pathways through otherwise low permeability rock. Moreover, areas with seismic, volcanic, or other natural geologic events that may compromise the security of the CO_2 storage reservoir should be avoided. Fortunately, each of these leakage pathway risks can be minimized through careful site assessment and evaluation. Finally, other potential beneficial factors include a storage reservoir being part of a regional geologic structure or system, enhancing the possibilities to dissipate pressure buildups due to high rate CO_2 injection, and a storage reservoir with a relatively small footprint (for example, thick reservoir rocks are better than thin reservoir rocks).

a) Leakage Through the Caprock. CO_2 can migrate through fissures in the caprock or, when permeability and pressure are sufficiently high, even directly through the caprock itself, Figure 2-11. In general, depleted oil and gas fields can make attractive storage sites because they have already demonstrated long-term caprock integrity. However, even depleted oil and gas field caprocks may be degraded by development and production with the stress threshold highly dependent on reservoir conditions (Zoback and Zinke, 2002). For example, the stress of depletion and subsequent re-pressurization with CO_2 can create fissures that may transmit CO_2 through the caprock.

Studies of naturally CO_2-charged geologic systems provide valuable analogs to predict which reservoirs may or may not be good CO_2 storage candidates (Shipton, et al., 2005). Large natural sub-surface accumulations of CO_2 can be found around the world, in a wide variety of geological settings. Many of these natural CO_2 accumulations, such as those in the Colorado Plateau of the Rocky Mountains in the U.S., are in geological settings comparable to settings selected for industrial CO_2 storage. Three of these fields – the Jackson, McElmo, and St. Johns Domes – have been extensively studied (Stevens, 2004). Together, these fields contain over 2.4 billion tons of CO_2 and have stored CO_2 for millions of years. In two of these fields, Jackson and McElmo, there is no evidence of CO_2 leakage to the overlying strata while some presence of CO_2 has been noted in the soil near and above the St. Johns Dome.

Figure 2-11. Threshold Displacement Pressure Versus Water Permeability



Important insights on caprock integrity have been gained from studying these naturally occurring CO_2 fields. For example, the 400-m thick salt and 1200-m thick shale caprock at the McElmo Dome field has provided an excellent seal that has contained CO_2 in the Leadville reservoir for approximately 60 million years. In contrast, the thin anhydrite seals at St. Johns Dome appear to be less effective due to a large bounding fault that reaches to surface, and the presence of groundwater across the fault.

b) Leakage Through Natural Faults and Fractures. Transmissive natural faults and fractures, caused by tectonic activity or loading and unloading of overburden, can provide leakage pathways when these faults and fractures are non-sealing (open). Human induced reactivation of faulting and fracturing can also occur, perhaps due to nearby mining, construction or similar activities, as is discussed in more detail below.

Recent work on "leaky" natural analogs - - such as in Italy or parts of the Colorado Plateau -- has demonstrated that faults can be conduits for CO_2 leakage (Allis, 2004). However, faults can also serve as effective seals. Fault geometry, stress regime, and fault juxtaposition with stratigraphy all are key elements establishing which faults are seals and which are leakage pathways (Pasala, et al., 2003). Also, the heterogeneity of subsurface formations suggests that the sealing capacity of faults could vary spatially, complicating assessments of the role of faults on storage integrity.

Extensive research has been performed on the propensity of faults to act as seals or, conversely, as conduits, particularly for hydrocarbon flow (Davies and Handschy, 2003). Recent research in the fields of hydrocarbon exploration and geologic storage has led to improved predictive concepts and tools by which to determine whether or not faults will act as seals. The mechanisms which generally allow a fault to act as a seal or a conduit include:

- Clay smear or gouge developed along the fault zone, particularly in poorly lithified shales, can inhibit fluid flow.

- Juxtaposition of low-permeability strata against a hydrocarbon reservoir can seal a fault. One factor contributing to the potential effectiveness of a fault in providing an effective seal is the relative proportion of sand to shale. One reported rule of thumb is if the proportion of sand to shale is greater that 0.5, the ability of the fault to provide an effective seal should be carefully evaluated (Durham, 2005).

- Pore pressure below a formation closure or parting pressure will keep rocks on both sides of a fault in close contact, inhibiting fluid flow.

- Obtaining core samples from faults zones can provide valuable information that will help determine their effectiveness at providing reservoirs seals, or in characterizing their propensity to leak. Information on clay content and cementation, petro-physical properties such as capillary entry pressures and permeability, and microstructures such as cataclasis or grain crushing within the fault zone can be obtained from core plug samples (Davies and Handschy, 2003).

c) Leakage Due to Subsequent Volcanic and Tectonic Activity. Seismic activity, tectonic uplift, recent volcanism and other processes could affect the integrity of CO_2 storage. Major documented releases of dangerous volumes of CO_2 have all come from areas with high levels of volcanic activity. Independent research suggests that these areas may not be appropriate for long-term geologic storage of CO_2.

d) Leakage Due to Unconfined Lateral Migration. An important but mostly overlooked CO_2 leakage pathway is the potential for lateral migration of CO_2 in "open-system" saline formations. Until the CO_2 is fully immobilized by the various trapping mechanisms discussed above, this buoyant fluid (or gas) will tend to migrate updip, primarily along a bounding rock strata or the caprock. In turn, the CO_2 in solution in the saline waters of the formation will also migrate, although this migration may take some time, and will be in the direction of aquifer flow, which can be either down or up-dip.

Three important containment mechanisms can help retard the lateral migration of CO_2 in a saline formation. First is the structure which would make the saline formation a "closed system" and would enable the CO_2 to accumulate, much as in a traditional oil or natural gas reservoir. The second is a stratigraphic barrier or sealing fault that would provide updip closure to the saline formation. The third is the complete solubility of the CO_2 in the saline water of the formation leading to density inversion. Laboratory work shows that water saturated with CO_2 is slightly more dense than unsaturated formation water. Over time and in favorable reservoir settings, the CO_2 saturated waters will invert (flow downwards) enabling the unsaturated CO_2 formation waters to become the bouyant fluid.

2. Human-Created Leakage Pathways. Five categories of human-created CO_2 leakage pathways may occur. Of these, the most likely, as demonstrated by the natural gas storage industry, is CO_2 leakage from improperly completed or abandoned wells. CO_2 injection operations may also create leaks, either by a failure in operations from reservoir overfill, or from injection-induced faulting. Finally, post-storage release of CO_2 could occur if wells were drilled without pre-knowledge of the CO_2 storage reservoir.

a) *Leakage from Improperly Completed or Abandoned Wells.* Petroleum fields (and to a lesser extent, saline formations) that are converted to CO_2 storage sites often contain abandoned wellbores from past decades of drilling that need to be located and properly sealed to prevent CO_2 leakage. The location and number of some of these open well bores may be initially unknown to the storage operator. Even seemingly harmless shallow well bores that do not penetrate the targeted storage reservoir could become hazards should CO_2 leak into overlying strata (Gunter, et al., 1998).

b) *Leakage During Injection Operations.* CO_2 may leak during injection operations due to equipment malfunction, corrosion, inappropriate operational procedures, or other factors. Leakage may occur anywhere within the CO_2 supply and injection system ranging from the hot tap at the main CO_2 pipeline, the distribution manifold and lines, the wellhead, and the tubing, casing, downhole packer assembly within the well.

c) *Leakage Due to Storage Reservoir Overfill.* Inaccurate mapping of the storage reservoir structure could also cause storage capacity to be overestimated and lead to excess injection of CO_2. One underground gas storage site in the Illinois Basin experienced leakage of natural gas due to overfill. In addition, one of the natural analogs - - St. Johns Dome in Arizona - - appears to leak along its edge, not because the caprock is impaired, but rather because the naturally generated CO_2 overfilled its structural storage containment capacity.

Sidebar 3 provides more detailed summary of the leakage that occurred at the Yaggy Gas Storage Field due to failure of well casing and the subsequently unconfined lateral migration of natural gas.

d) *Leakage from Injection-Induced Faulting.* Another set of potential risks relate to the large quantities of CO_2 that could be injected, and the potential production/withdrawal induced faulting that can result from this injection. The risks could include:

- Sheared injection wells and casing
- Hole instability during injection well drilling
- CO_2 leakage along new or reactivated fault planes
- Induced earthquakes and ground uplift/subsidence.

SIDEBAR 3. THE YAGGY GAS STORAGE LEAKAGE INCIDENT

One example of the potential risks associated with lateral gas migration due to improperly completed wells happened at the Yaggy Gas Storage field in Kansas.

On January 17, 2001 a natural gas leak at this field led to an explosion that destroyed two buildings in the town of Hutchinson, Kansas. The next day, another explosion occurred five kilometers (km) away at a mobile home park, killing two people. In total, an estimated four million cubic meters of natural gas leaked and migrated 10 km from an injection/withdrawal well.

Apparently, the leaked gas from a well in this underground salt cavern storage field (Figure 1) flowed up-dip to the town of Hutchinson. It reached the near-surface via a high-permeability fractured dolomite, and then reached the surface through abandoned brine wells (Figure 2).

Figure 1. Schematic of Gas Flow at the Yaggy Gas Storage Field Blowout

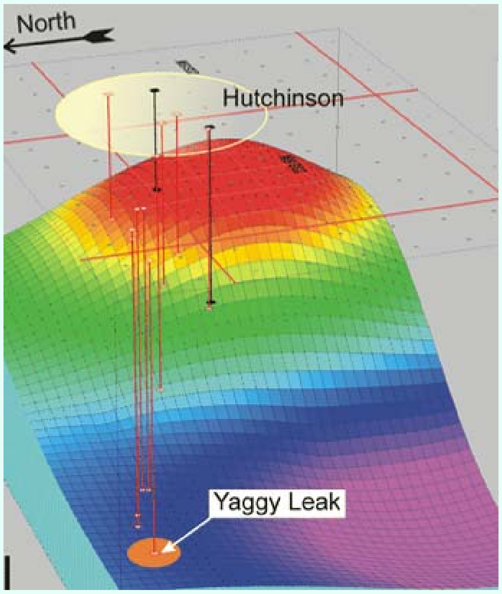
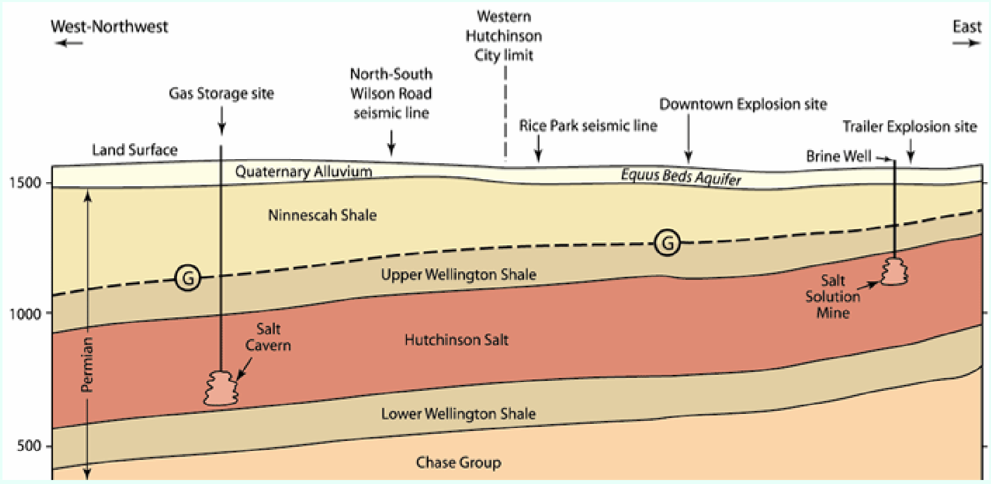


Figure 2. Schematic of the Geology and Wells Near the Yaggy Gas Storage Field



According to the post-incident investigation, a casing leak occurred in the S-1 storage well, just below top salt and 56 m above the top of the salt cavern. Salt dissolution caused flexure and fracturing in the overlying 8- meter thick dolomite, allowing a pathway for gas. These fracture apertures were opened by high-pressure gas injection.

The leaking S-1 well was plugged and abandoned, and a large scale remediation effort was undertaken. The theory is that the casing failed due to mill work conducted in this well eight years earlier (in 1993) weakening the pipe. This failure would have most likely been detected if minimal levels of monitoring were utilized.

Source: Nissen, 2004.

Another issue of concern would relate to the injection rates and pressures. Avoiding excess CO_2 injection pressure may seem obvious, but injection wells usually lose “injectivity” (i.e., plug up) over their life because of chemical deposition near the well bore, saturation of reservoir porosity, or other factors. Short-term injection spikes may occur due to pipeline or injection pressure anomalies. This may cause injection pressure to exceed the fracture gradient of the rock, creating a “frac” (i.e., man-made hydraulic fracture) in the reservoir that may cause CO_2 to leak outside the targeted storage zone. Low-permeability settings with low formation parting pressures are at particular risk of unintentional fracturing.

Sidebar 4 provides an example of CO2 leakage during operation and the remediation measures taken to address this problem.

Another study of a depleting reservoir in a Gulf of Mexico field showed where depletion stabilized the reservoir’s stresses and curtailed normal faulting. In this case, the initial stress and poroelastic condition favored active normal faulting, and the depletion stress path moved the reservoir away from the active faulting envelope (Chan and Zobeck, 2002). However, in this instance, if the converse occurred (e.g., if CO_2 was injected into the reservoir) the reservoir would revert back to its original state, potentially promoting additional faulting. This study also provides a method for predicting the potential for faulting as the reservoir stress changes due to depletion or injection.

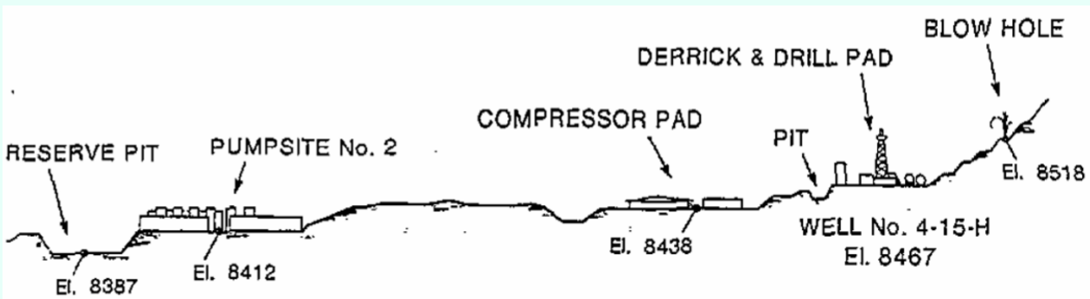
SIDEBAR 4. SHEEP MOUNTAIN CO_2 LEAKAGE INCIDENT

A well blowout occurred at the Sheep Mountain natural CO_2 field in Southern Colorado. This incident provides an example of CO_2 leakage and the remedial actions taken to control the situation.

The Sheep Mountain CO_2 field contains 110 million tons, or 2 trillion cubic feet (Tcf), of original CO_2 gas in place (OGIP). The CO_2 reserves are contained in the K Dakota sandstone reservoir at a depth of about 1 kilometer (about 3,300 feet). The field currently supplies about 3,000 tonnes/day (54 million cubic feet per day (MMcfd)) of CO_2 (down from 15,000 tonnes/day in 1987) for use in CO_2-EOR operations in the Permian Basin.

On March 17, 1982, a directional CO_2 production well at Sheep Mountain (Well 4-15-H) blew out during coring operations. The well flowed for 18 days at an estimated rate of 11,000 tonnes/day (200 MMcfd) of CO_2. Total emissions from the blowout were estimated at 190,000 tonnes, or 3.6 billion cubic feet (Bcf) of CO_2. The CO_2 vented out of surface rock fractures on the slope of a hill directly above the drill site. (Figure 1)

Figure 1. Flow Path of Sheep Mountain CO_2 Well Blowout



This well blowout occurred early in the Sheep Mountain field's life, when pressure in the field was still high, and the subsurface structure was poorly understood. The underground blowout apparently occurred at the base of surface casing (84 m), with the released CO_2 connecting with offset wells and surface fissures. The blowout was induced by reduction in mud weight to remove solids for improved coring.

The operator was initially unable to control the well by injecting overbalanced fluids (generally the simplest solution) because the small tubing size of the well (11.4-cm or 4.5-in) caused excessive frictional pressure losses. Instead, the well was finally controlled by use of dynamic control technology where the frictional pressure was reduced by adding friction reducers to the $CaCl_2$-brine fluid. Approximately 1,500 barrels of fluid were required to control the well. This mixture was injected through a snubbing unit at a rate of 570 cubic meters per hour down the production tubing. This well was then plugged and abandoned. Fortunately, no adverse environmental or health impacts occurred in this sparsely populated area.

The incident demonstrated that industry's well control techniques can be successfully applied to CO_2 production and (by analogy) injection.

Unlike the over-pressured Sheep Mountain field, some of the future CO_2 storage sites are likely to be depleted oil and gas fields, with lower risk of blowout during injection, and will have much more geological data. However, because saline formations are already, in general, at hydrostatic pressure, CO_2 injection will entail high pressure, calling for additional reservoir characterization and safety measures to assure safe options in these types of CO_2 storage reservoirs.

Source: Stevens, 2005.

The implications of production- and withdrawal-induced faulting for CO_2 remediation conclude that, once faulting has been induced, water injection or pressure maintenance programs may not cause faulting to stop. The subsidence at the nearby Ekofisk field was not quelled, nor even slowed, by water injection. In fact, in this case, water injection merely exacerbated fault plane slippage and subsidence. In general, there will be a need for conducting stress and poroelastic analysis to screen candidate storage reservoirs prior to CO_2 injection. Moreover, storage should be avoided in reservoirs where stress and pore pressure data indicate active faulting under original or depleted conditions, e.g., as indicated by well casing shear during development.

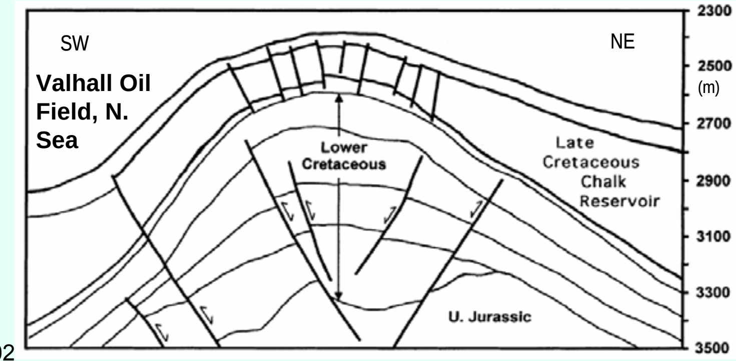
e) *Leakage Due to Post-Storage Disruption.* After the CO_2 storage site has been filled and successfully capped, it is still possible that future human activity may disrupt the field and cause CO_2 leakage. For example, future petroleum exploration or mining activity may penetrate the CO_2 zone.

Sidebar 5 provides an example where production and changes in operating pressure may create faulting.

SIDEBAR 5. EXAMPLE OF PRODUCTION RELATED FAULTING

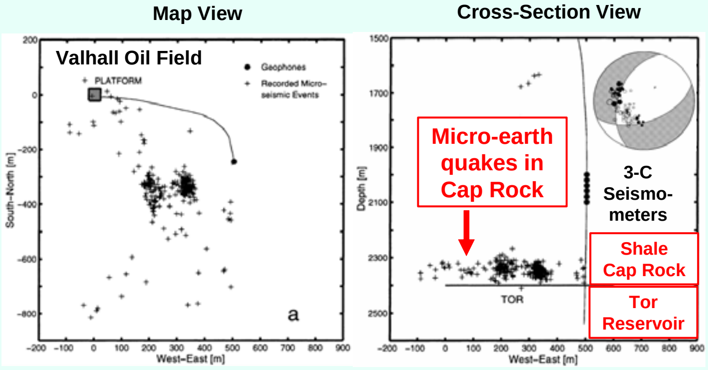
Under certain conditions, oil field production operations can induce faulting within a field. The initial reservoir study of the Valhall and Ekofisk oil fields in the North Sea showed that normal faulting existed on the crest of the structures in these two fields. Reservoir depletion appeared at Ekofisk to create faults on the flanks (Figure 1). Passive seismic monitoring at these fields measured micro-earthquakes which corroborated active normal faulting (Figure 2).

Figure 1. Nature of Production Related Induced Faulting – Valhall Oil Field, North Sea



Zoback & Zinke, 2002

Figure 2. Characterization of Seismic Events at Valhall Oil Field, North Sea



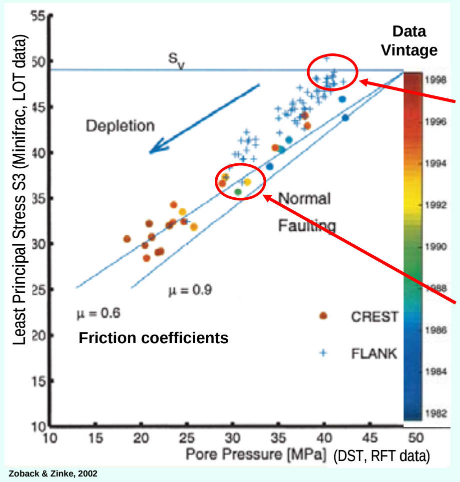
Zoback & Zinke, 2002

The production-related induced faulting at the Ekofisk Field was identified based on problems associated with sheared well casings, subsidence, and gas leakage through the caprock. The 15 years of reservoir depletion reduced the pore pressure in the reservoir (Figure 3).

Initially, stress on the crest was high enough to cause active normal faulting over geologic time, although these faults appeared to have sealed (approximately 30 to 40 MPa). Production operations caused the stress regime to cross into normal faulting regime (<30 MPa) as the reservoir was depleted.

Injection of water and the maintenance of pore pressure in the reservoir would have helped mitigate the induced faulting.

Figure 3. Least Principal Stresses vs. Pore Pressure for Tor Reservoir at Valhall Oil Field, North Sea



E. EXAMINATION OF RISKS FROM CO_2 LEAKAGE

Approaches for remediation for CO_2 leakage should be based, at least in part, on the risks this leakage can pose. Given the long history of industrial experience with handing and using CO_2, the health risks associated with CO_2 exposure are well understood. Humans can tolerate exposures of up to 1% CO_2 (10,000 ppm) with no adverse effects. Significant effects on respiratory rate and physical discomfort is experienced at concentrations approaching 3-5% CO_2, and death is imminent at concentrations greater than 30% for several minutes. These concentrations serve as the current basis for federal occupational safety and health set standards for CO_2 exposure in the workplace (Benson, et al., 2002).

In most instances, even where large releases of CO_2 have occurred, these releases have been quickly dispersed into the atmosphere, and have not resulted in any significant hazard. Significant risks do exist in situations where released CO_2 is not effectively dispersed, such as at Lake Nyos. However, these situations have been rare.

In addition to concerns about CO_2 exposure to human populations, potential ecosystem impacts need to be considered. Ecosystem impacts pertain to the effects of elevated CO_2 concentrations on the soil system (roots, insects, burrowing animals), or impacts on deep geological ecosystems. Soil system impacts relate to the physiology, ecology, and likely responses of animals, plants, and microorganisms at the surface and in subsoil ecosystems. They can also pertain to emerging risk considerations about impacts on subsurface microbial organisms.

Sidebar 6 provides a case study of a naturally leaky geologic CO_2 storage system and an examination of its long-term impact.

SIDEBAR 6. A NATURALLY LEAKY GEOLOGICAL CO_2 STORAGE SYSTEM

An in-depth study of leaky CO_2 reservoirs in the northern Paradox Basin, Utah (USA) provides valuable information on: (1) the subsurface CO_2 migration and flow system; (2) how CO_2 reacts with ground water and reservoir rocks in the subsurface; and (3) the effects on surface environments when CO_2 leaks to the surface. Insights from this "leaky system" for designing mitigation strategies will help establish more accurate risk assessment models and procedures.

1. *The CO_2 Migration and Flow System*. The natural CO_2 stems from clay-carbonate reactions in deeply buried Paleozoic source rocks in the Paradox Basin.

   As the CO_2 migrates upward through fractures related to the fault damage zone, it accumulates in a series of shallow sandstone groundwater reservoirs. As the accumulation of CO_2 builds, the CO_2 saturated water and free CO_2 escape into the atmosphere through a series of springs and geysers along the faults, Figure 1.

2. *Role of Abandoned Wells*. The natural leakage of CO_2 through the fault-related fractures has occurred for more than 150 years. The accumulation of carbonate minerals has been insufficient to seal these naturally occurring fractures. The subsequent drilling of oil, gas and water wells (now abandoned) provided pathways for more rapid transport of CO_2-charged groundwater to the surface. Most of the wellbore leakage is from abandoned oil and gas exploration wells and no record exists of the kind of cement or casing that was used in these wells.

3. *Effects of CO_2 on Subsurface Groundwater and Rocks***.** The groundwater in the vicinity of the CO_2 leaks is saline and slightly acid, with 14,000 to 21,000 mg TDS per liter and with pH values of 6.07 to 6.55. The water appears to be supersaturated with respect to carbonate phases resulting in carbonate precipitation.

4. *Effects of CO_2 Leaking to the Surface*. At the surface, the rapid degassing of CO_2-charged groundwater results in the formation of travertine mounds around the active springs. However, only about 10% of the leaked CO_2 appears to be trapped by travertine mineralization. The bulk of CO_2 escapes to the atmosphere.

   The study's principal investigators, that included participants from earth science departments at three universities (Utah State University, Trinity College and Saint Louis University), found "no evidence of adverse effects of this leakage on wildlife or humans."

   The CO_2 geyser and springs provide somewhat saline water for plants in the high desert environment. In addition, the initial observations showed that there was little or no impact on the local biological ecosystems, with no observed changes in plant growth around any of the leakage sites. The CO_2 effusion has resulted in no reported casualties even though the area is visited by locals and tourists.

SIDEBAR 6. (Cont'd)

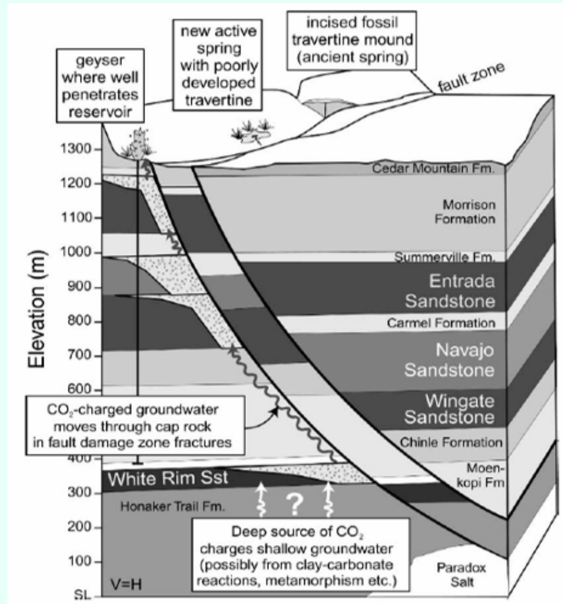
5. *Lessons Learned from "Leaky Systems" for Safe, Secure CO_2 Storage Site Selection.* A series of lessons can be learned from studying this naturally leaky CO_2-charged systems:

- Faults and fracture systems can pose a leakage risk to a geological storage site. As such, detailed structural characterization and an understanding of caprock integrity will be essential for any project.

- The presence of older wells and their relationship to the storage reservoir, as well as to the shallower leakage trapping reservoirs, must be clearly defined and, where necessary, remediated with modern well plugging and abandonment procedures.

- Ground water flow can transport CO_2 for considerable distance before the CO_2 reaches the surface. As such, a more complete understanding of the groundwater hydrology and flow paths would help define the transport of any CO_2 that may leak from a CO_2 storage site.

Figure 1. Schematic cross-section of a typical oil and gas field showing how faults can act as seals or barriers to movement.



Shipton et al., 2005

In addition, geologic CO_2 storage and leakage from reservoirs may lead to the dissolution of metal from minerals and the mobilization of these metals by the aqueous phase, along with the potential concentration of organic compounds in the supercritical CO_2, due to its solvent properties. Undesirable impacts could also arise from the displacement of saline fluids into shallower potable water zones by the injected CO_2. Initial research efforts are underway to understand the likelihood, rates and consequences of these processes, which should subsequently help guide appropriate approaches for remediation, if necessary.

One important category of risks is related to the health and safety of workers and, possibly, those that may live or work near a large CO_2 storage field or operation. These are risks associated with handling large volumes of CO_2. Fortunately, this is one area where we can take advantage of the long history of industrial experience in understanding and addressing potential operational risks associated with handling, injecting and storing large volumes of CO_2. As such, the risks are generally well understood, and primarily relate to the effects of CO_2 exposure, or the effects of CO_2 management at very high pressures and temperatures.

Operational risks are the primary risks addressed by analogous operations today, and occupational standards have been established to address these risks. Risks to local populations will also need to be addressed, with the primary concern being sensitive populations near the CO_2 storage site. Addressing these risks will generally involve implementing processes and procedures to minimize CO_2 releases, as well as CO_2 control and response procedures to deal with the risks should releases occur.

III. SITE SELECTION AND RESERVOIR SCREENING

A. INTRODUCTION

The dominant strategy for leak prevention and remediation is obviating the need for remediation in the first place, by selecting storage sites that have an extremely low risk of leakage over geologic time. In selecting geologically favorable, safe and secure storage sites, five considerations stand out:

- Caprock (Seal) Integrity. Does the proposed reservoir's caprock and bounding layer(s) have sufficient thickness, low permeability, and no faulting to serve as essentially a permanent seal for stored CO_2?

- Assured Natural Confinement. Does the proposed storage reservoir have a structural component or other mechanisms that would confine the updip migration of CO_2? Has the reservoir site been selected in areas or where tectonic activity would not potentially compromise storage confinement?

- Assured Wellbore Integrity. Are there any older producing or abandoned wells in the expected path of the CO_2 plume? To what extent have the wells been designed for safe, long-term operations involving CO_2 injection? Will the procedures for plugging and abandoning the CO_2 injection wells assure essentially no leakage?

- Sufficient Reservoir Storage Capacity. Will the proposed geological formation be able to store sufficient volumes of CO_2 without exceeding a "spill-point" or reaching an escape conduit?

- Sufficient Reservoir Injectivity Rate and Safe Pressures. Will the proposed geological formation accommodate sufficient rates of CO_2 injection and pressure without creating fracturing or other leakage pathways?

These five topics and their associated questions form the substance of the discussion in this chapter.

In addition to the geological criteria for preventing leakage, which are the primary site selection criteria that are the focus of this report, it is important to recognize that, in case there is leakage, surface/shallow subsurface characteristics, such as topography, presence of sensitive areas (nature reserves, etc.), population density, and presence of groundwater aquifers (used for drinking water supplies etc.), may also be of importance for the screening process.

B. KEY CO_2 STORAGE SITE AND SUITABILITY STEPS AND CONCERNS

When examining the sustainability of a geologic formation to store CO_2, the first step is gathering detailed geological and reservoir data, both local and regional. This will help provide the essential understanding of the expected long-term (100's to 1,000's of years) movement and storage of the injected CO_2 in the subsurface. When evaluating sites for their potential to store CO_2, in addition to calculating the volumetric size of the repository, it is also important to quantify the reservoir's trapping and storage mechanisms. As such, the quantification of a reservoir's ability to receive, maintain and store the CO_2 within the geologic unit provides the foundation for selecting a suitable site.

After the initial characterization of the storage site, it will be important to verify and, if needed, modify the initial assumptions on the location flow and storage of CO_2. This can be accomplished with available reservoir engineering methods (such as well testing and pressure measurements) during the injection of CO_2 and rigorous flow following the injection of CO_2. Technologies that help monitor the location and movement of CO_2 include modeling (Jazrawi, et al., 2004), time-lapse (4-D) seismic (Arts, et al., 2004), observation wells, soil (Norman, et al., 1992) and air sampling (Anderson and Farrar, 2001), and natural tracers (Hoefs, 1987), as further discussed in Chapter IV.

1. Evaluating Potential for CO_2 Migration and Leakage of CO_2. Loss of CO_2 from within a geologic storage site can occur in two primary ways - - lateral migration of the gas away from the injection site and vertical leakage toward the subsurface.

a) *Lateral Migration*. The lateral migration of CO_2 in a dipping geologic formation will generally be updip, until it reaches a confining structure. Should the migrated CO_2 encounter a setting with an inadequate caprock or a natural break in the overlying caprock before reaching a confining structure, the CO_2 can then escape (leak) vertically through the overlying formation. As such, it is important to not only develop a sound understanding of a reservoir's caprock in the vicinity of the injection site, but also (particularly for saline formations) the integrity of the caprock for the larger regional area.

In addition, the potential "spill" points of the reservoir, as well as the geologic closure of the storage reservoir, should be rigorously defined. It is important to note that lateral migration of CO_2 within saline reservoirs will occur without clear structural confinement through the normal dynamics of aquifer flow, while depleted oil and gas reservoirs generally have well defined structural closure.

b) *Vertical Leakage*. When considering vertical leakage of CO_2, there are two primary mechanisms: 1) seal failure; and 2) wellbore failure (Senior, et al., 2005).

- Failure of the seal can occur both naturally, through inherent flaws (faults and fractures) in the overlying caprock, and mechanically, through induced fracturing of the caprock during CO_2 injection. Therefore, considerable effort should be taken to ensure injection pressures, while sufficient to achieve efficient gas injection, will not promote induced fracturing. Finally, as CO_2 tends to rise due to density differences among the native reservoir fluids (water and oil), the permeability of the reservoir seal should be very low to preclude the permeation of CO_2 through the seal.

- Wellbore failure can occur in both the short- and long-term. In the near-term, poor or ineffective cementing of the well's casing strings, a problem that can be exacerbated with high CO_2 injection pressure, can create pathways for the gas to migrate vertically within the wellbore and into the overlying formation. Wellbore failure could allow the injected CO_2 to enter the potable water table as well as cause rapid release of CO_2 to the atmosphere. In the long-term, prolonged contact of the CO_2 with the wellbore cement and well casing may lead to degradation of the well completion and allow subsequent leakage and vertical migration through the wellbore.

2. Steps to Take to Minimize CO_2 Migration and Leakage. The potential for CO_2 migration and leakage need to be thoroughly addressed during the preliminarily screening of the reservoir and its caprock. The steps to take to minimize the potential for leakage will involve the following:

- Assessing the integrity of the caprock and any faulting and/or fracturing of reservoir seal and the overlying rock strata
- Evaluating the locations of structural closure and the gross storage volume contained within the structurally closed area
- Identifying the location and vertical penetration of all wells drilled in the vicinity of the potential CO_2 storage site
- Assembling key reservoir properties (thickness and porosity) for calculating net storage
- Assessing the reservoir's injectivity and safe operating pressure.

Each of these important site assessment steps are further discussed and developed in this Chapter.

C. SELECTING SAFE, SECURE AND FAVORABLE GEOLOGICAL SETTINGS

1. Assessing Caprock Integrity. Assessing the integrity of the caprock is one of the essential steps in site selection, especially when selecting a saline aquifer for CO_2 storage.

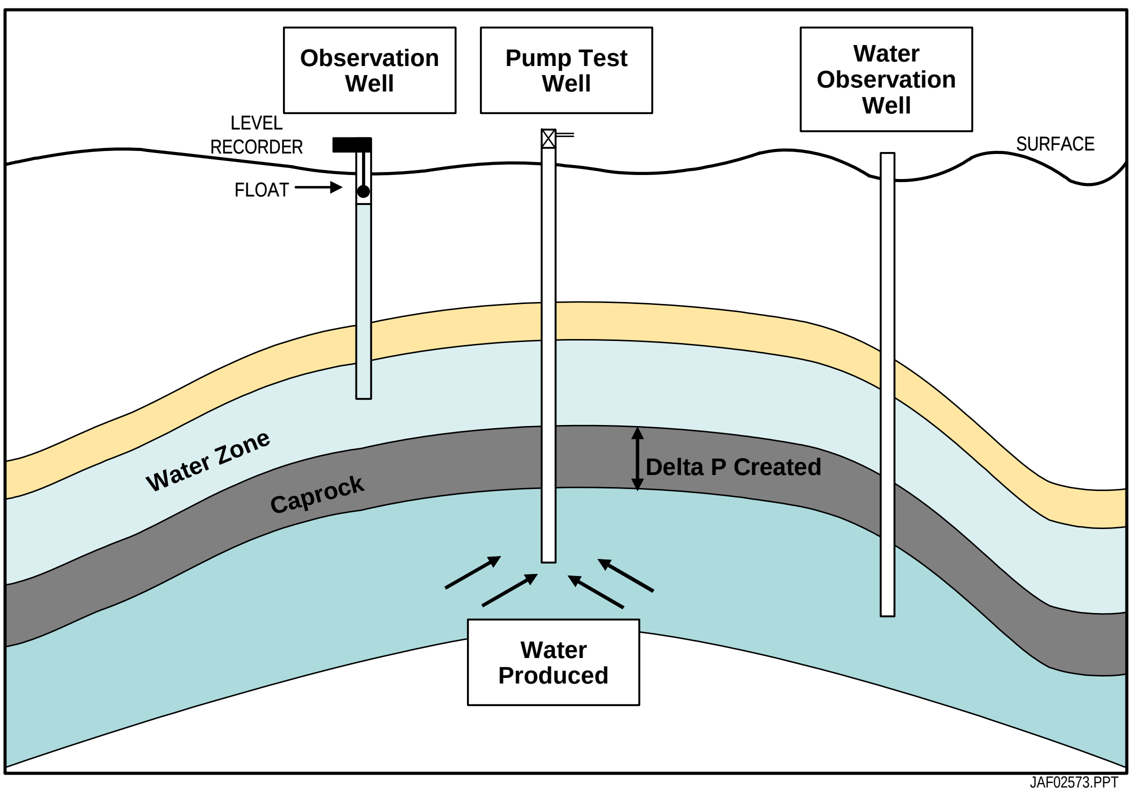
The first step is to develop a sound, overall understanding of the geological formations and particularly the regional extent of the caprock and the storage reservoir. This would be followed by undertaking a very detailed investigation of the geological formations at the storage site. Regional cross-sections are essential for understanding the regional extent of the caprock, as well as for identifying large anticlinal structures and other features that would contain and thus limit the movement of the injected CO_2.

Detailed log evaluations of the subsurface at and around the storage site will help place the local data into a regional context.

The second step is to take core samples of the caprock and test the samples for the threshold pressure of the caprock. This is particularly important for establishing the safe maximum bottomhole pressure during injection and storage of CO_2.

The third step is to conduct a series of permeability tests of the caprock involving water withdrawal from the zone below the caprock to create a pressure differential across the caprock. Any unexpected changes in pressure above the caprock would indicate the potential for faults or other paths of permeability whose presence would compromise the integrity of the caprock. Figure 3-1 illustrates the use of pump testing to assess the integrity of the caprock.

Figure 3-1. Pump Testing of a Potential CO_2 Storage Field to Assess the Integrity of the Caprock

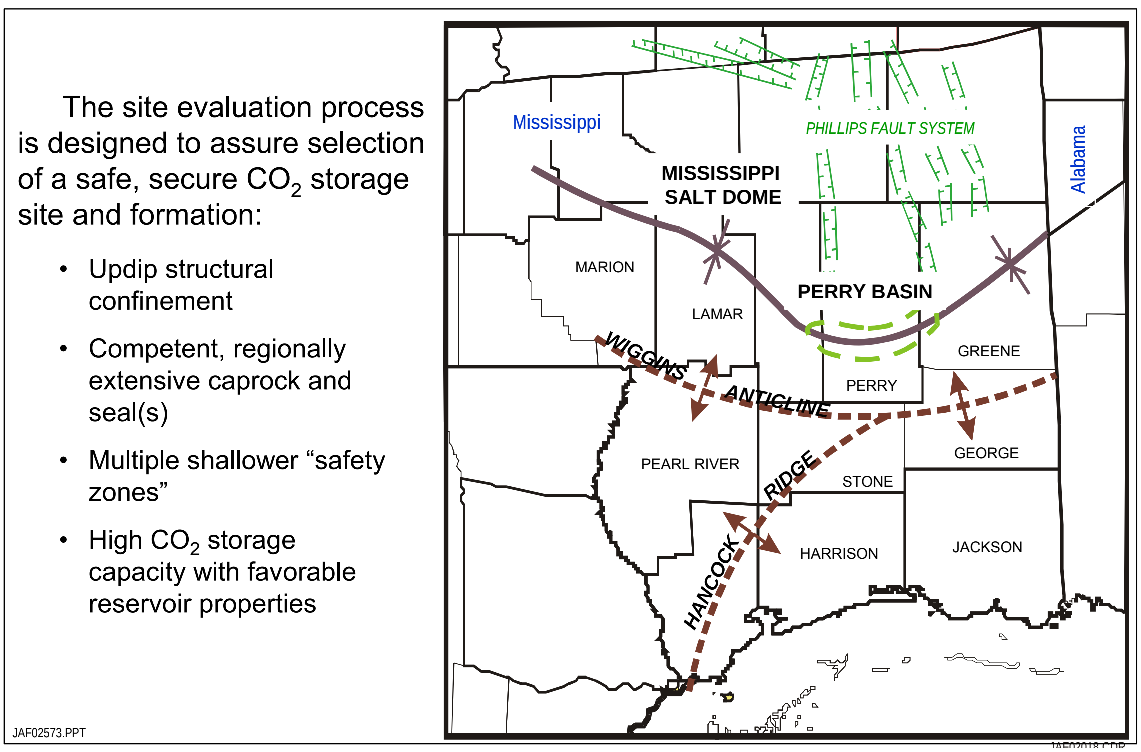


2. Assessing Structural Confinement. Structural confinement is a critical component for a safe, secure storage site. By definition, oil and natural gas fields have an established history of structural confinement. However, when assessing saline aquifers for secure CO_2 storage, structural confinement can often also be important to ensure storage integrity and certainty. The site assessment activity should look for two types of structural confinement:

- The first type of structural confinement is a distinct, classic anticline (dome) that would trap CO_2, much as the structures found over conventional oil and gas fields or used for establishing an aquifer-based natural gas storage field.

- The second type of structural confinement is an updip closure, created by an arch or a major discontinuity. Figure 3-2 for Southern Mississippi in the United States shows how the Wiggins Arch and Hancock Ridge provide important updip and lateral closure for the saline formations in the area.

Figure 3-2. Structural Confinement Evaluation for Southern Mississippi, USA



The areal and vertical extent of structural close can be established using traditional oil and gas field logs, high resolution surface seismic, and rigorously constructed cross-sections of the region and local site. Of particular importance is to map the formation dip and examine the updip structures that would control the overall volume of CO_2 confinement and storage.

3. Assessing Wellbore Integrity. The initial step for wellbore integrity is to identify the location and vertical penetration of all wells drilled in the vicinity of the potential CO_2 storage site. State oil and gas boards, geological surveys and private well record archives are the first place to look for the locations and completion records for abandoned wells.

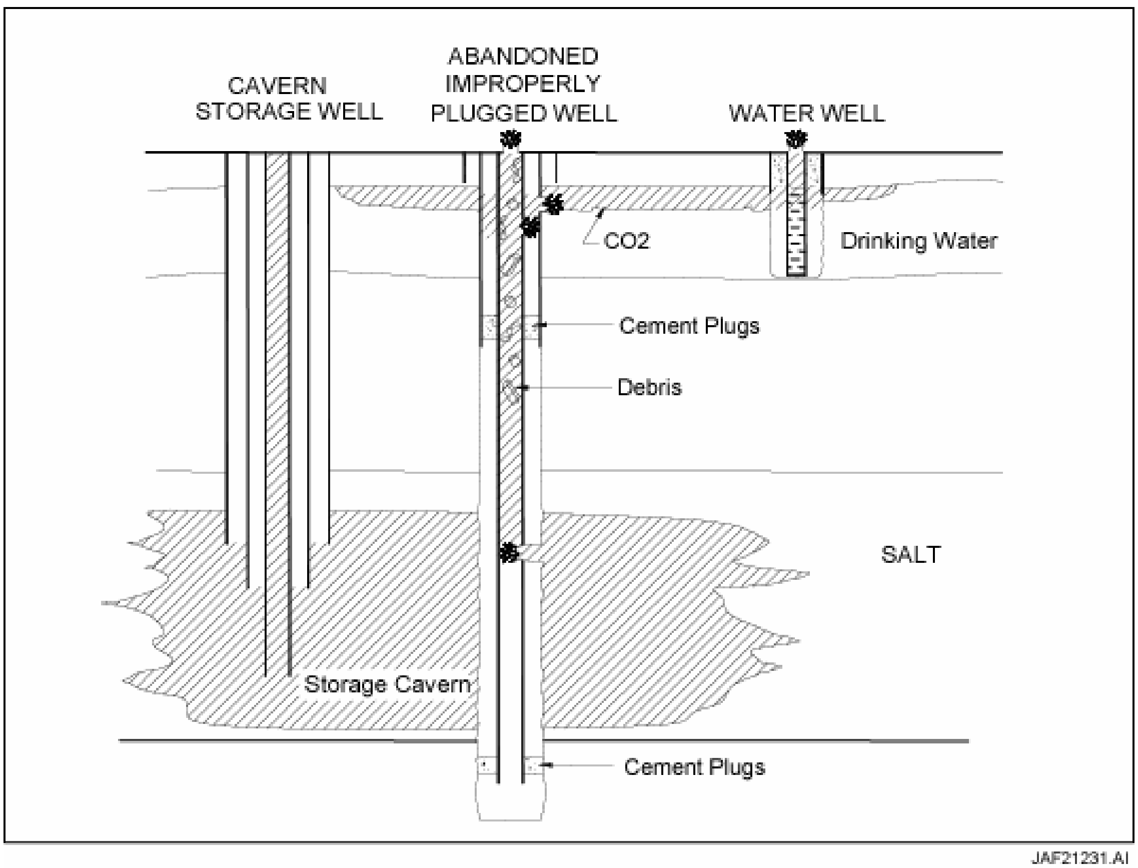
In some cases, particularly where the abandoned wells have been drilled some time ago and prior to more modern well recording and abandonment standards, it may be essential to independently locate the old, abandoned wellbores. New techniques, such as those being developed and tested by the U.S. DOE Carbon Sequestration Program provide one means by which to locate these older, poorly recorded wells that could create a CO_2 leakage pathway. More than likely, these independently identified wells will need to be properly recorded and re-plugged.

For wells whose locations are correctly identified in state or other records, and are (or will be) in the path of the CO_2 plume, it will be important to assess the completion methods that were used on the well, including:

- The extent and nature of well cementing (partial or fully to the surface), particularly for wells still in operation
- The specifics of the well casing, particularly across the interval of interest (if the casing is still in-place)
- The prior use of hydraulic fracturing (particularly in the interval of interest), to determine whether a hydraulic fracture may have created a leakage pathway though the caprock
- The actual well plugging and abandonment procedures that were recorded and used.

A properly plugged well should provide an adequate seal against fluid and CO_2 migration. However, as an example, the well depicted in Figure 3-3 was not properly plugged. The wellbore contains debris that may actually compromise the sealing qualities of drilling mud left in the tubing. CO_2 is depicted entering the central tubing, and exiting at the surface, and at a break. The CO_2 then migrates up the annulus between the tubing and the outer casing to a shallow porous and permeable aquifer. It then moves laterally and exits to the surface via a shallow well. While some aspects of Figure 3-3 are a worst-case situation, the figure depicts the concepts that CO_2 may migrate vertically by various paths within a single well, and laterally in porous zones to encounter another well.

Figure 3-3. CO_2 Migration in an Abandoned, Improperly Plugged Well.



In addition to undertaking direct observation of well integrity, it may be useful to conduct indirect observations, such as: (1) evaluating whether the surface areas around the plugged and abandoned wells indicate higher than normal concentrations of methane (for oil and gas wells); and, (2) whether there are indications of casing pressures (the presence of gas between the casing and the formation) for operating wells.

4. Assessing Favorable Storage Capacity. An ideal CO_2 storage site (or combination of closely located sites) would accommodate and accept CO_2 injection volumes for 30 to 50 years, equal to the CO_2 emissions from a plant (or combination of plants). For example, a single 500 MW coal-fired power plant, with annual CO_2 emissions of about 3 million tonnes (depending on the efficiency of the plant), will need on the order of 90 to 150 million tonnes of overall CO_2 storage capacity.

To provide some perspective on this capacity, we will translate this CO_2 storage requirement into oil and gas field terminology and benchmarks:

- Storing 100 million tonnes of CO_2 is equal in volume to a 1 billion barrels (original oil in-place and thus theoretical capacity) oil field (or collection of nearby fields).
- Only about 15% to 30% of this theoretical CO_2 storage capacity will be available following conventional oil recovery practices or be used under traditional CO_2-EOR activities.
- However, advanced CO_2-EOR and CO_2 storage designs could increase the usable storage capacity by several fold, as illustrated on Figure 3-4 and summarized in Table 3-1.
- As an example of advanced storage design, the CO_2-EOR and CO_2 storage project at the Weyburn oil field, with 1.4 billion barrels of original oil in-place, is planning to store 23 million tonnes of CO_2 during EOR, plus an additional 32 million tonnes of CO_2 as part of its CO_2 storage phase, over a period of about 55 years, Figure 3-5.

Table 3-1. Expanding CO_2 Storage: A Case Study

	"State of the Art" (millions)	"Next Generation" (millions)
CO_2 Storage (tonnes)	19	109
Storage Capacity Utilization	13%	76%
Oil Recovery (barrels)	64	180

Figure 3-4. Expanding CO_2 Storage: A Case Study

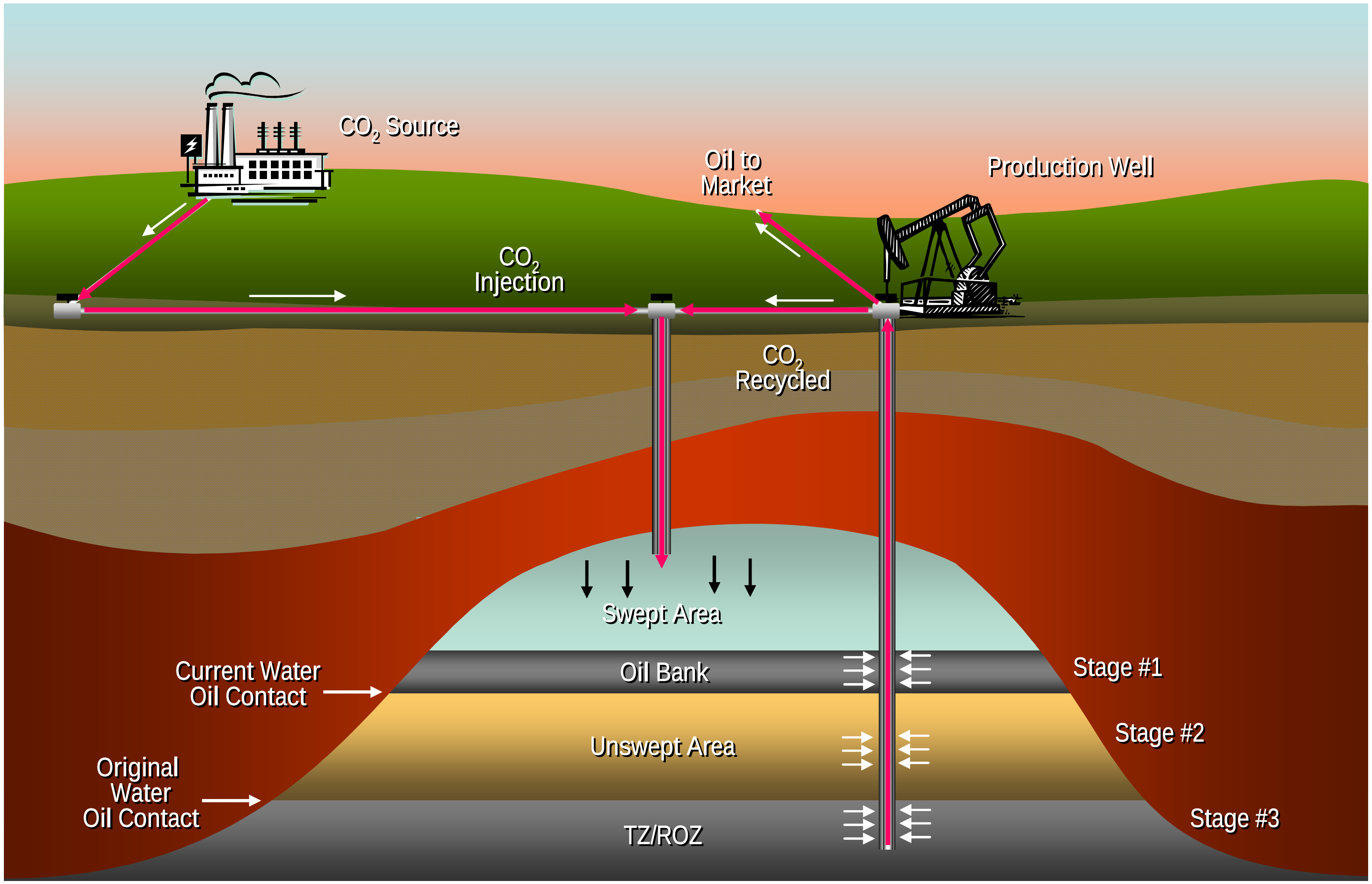
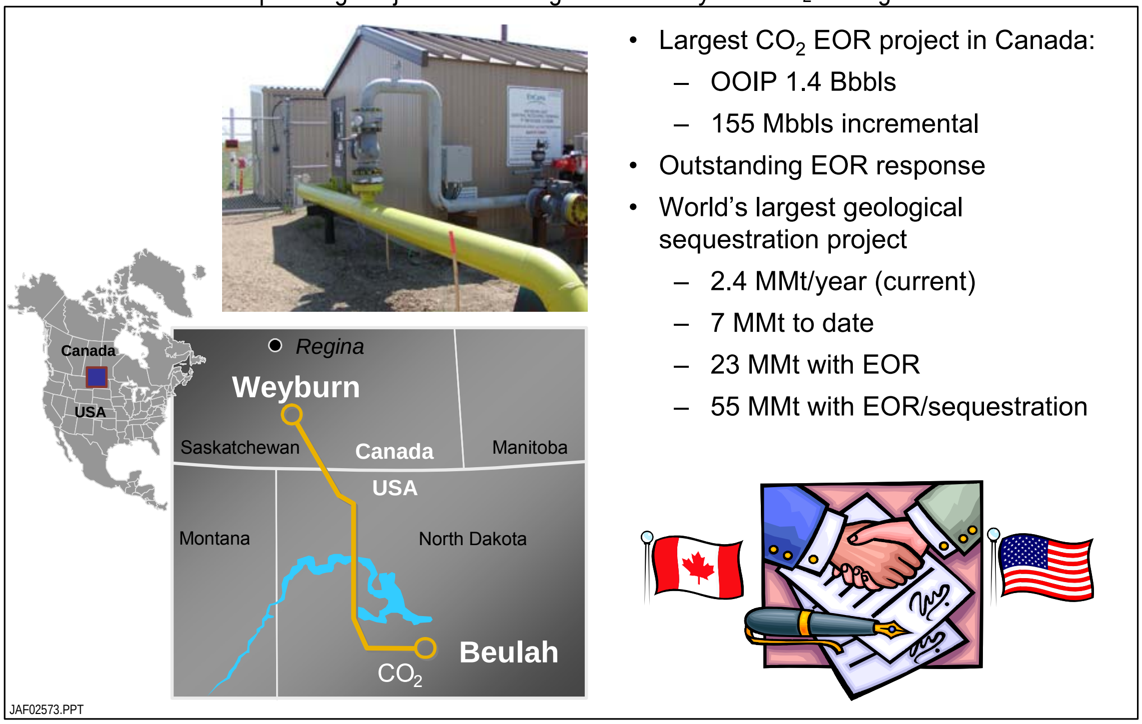


Figure 3-5. Weyburn Enhanced Oil Recovery Project.

An Operating Project Maximizing Oil Recovery and CO_2 Storage

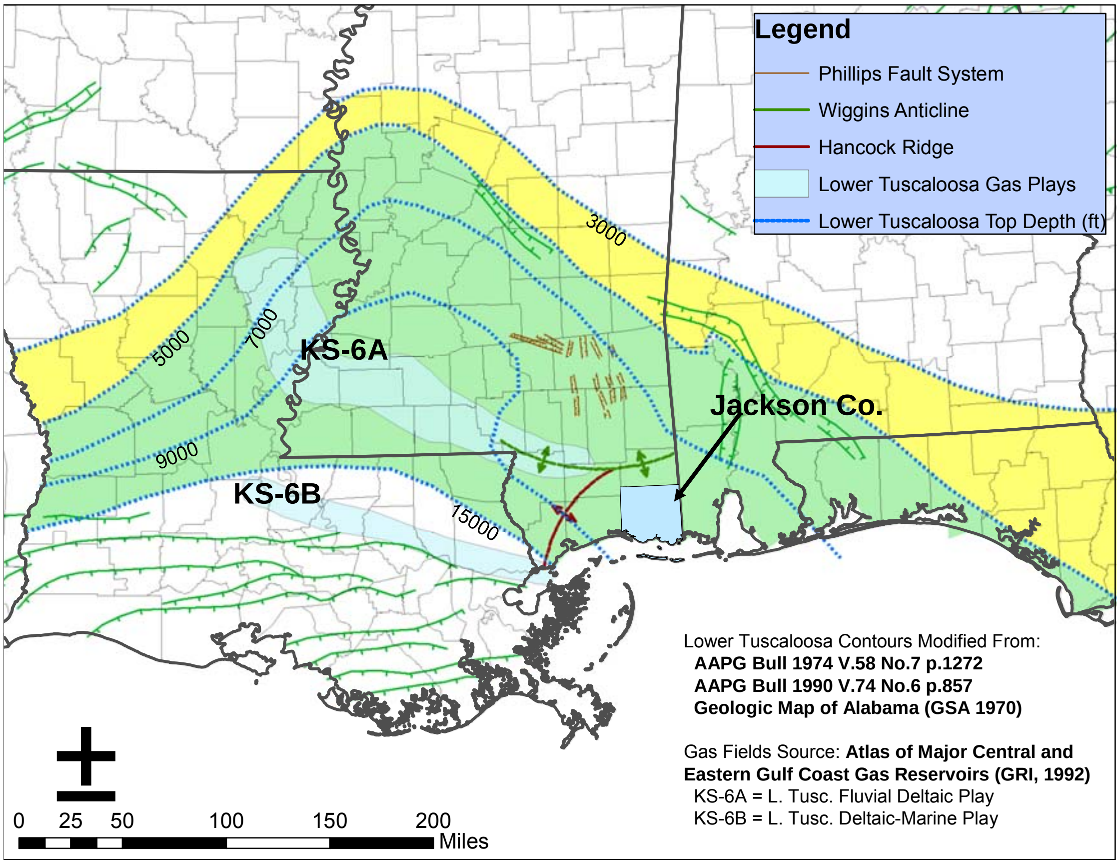


Saline formations can offer very high theoretical CO_2 storage capacity. For example, the Tuscaloosa Formation in Southern Mississippi offers several million tonnes of potential CO_2 storage capacity per square mile with up to 5 billion tonnes of CO_2 storage capacity in just one county (Jackson), Figure 3-6. Overlying and deeper saline formations could substantially increase this storage capacity.

However, only a moderate fraction of this storage capacity can be practically accessed using traditional well completion and CO_2 storage designs. Depending on the actual well design installed and the internal architecture of the saline formation, the practical storage fraction will range from a few percent to over 20 percent.

While "first-order" estimates of CO_2 storage capacity may be derived from using rules of thumb, full-scale reservoir simulation of CO_2 injection and storage will be required to establish a reliable value. Further discussion of modeling and calculating CO_2 storage volume is provided in Chapter IV.

Figure 3-6. Regional Extent of the Lower Tuscaloosa Massive Sand Unit



5. Assessing Reservoir Injectivity and Safe Operating Pressure. Once caprock integrity, structural confinement, wellbore integrity and storage capacity are addressed, assessing the reservoir's ability to safely accept CO_2 via injection is the next step in the evaluation process. The key reservoir parameters that control the injection rate of CO_2 are:

- reservoir permeability and relative permeability
- reservoir net thickness
- the current and the maximum safe reservoir pressure.

Many of the same tools and procedures for gathering information for establishing CO_2 storage discussed above will be used to collect geologic and reservoir data that will help define the CO_2 injectivity of the reservoir.

D. SITE SELECTION DATA SETS, TOOLS AND PROCEDURES

For purpose of efficiency, the geologic sites being evaluated for CO_2 storage would already have large existing regional and local data sets that could be used for screening the site and designing the storage container. However, these data sets will most likely need to be augmented by additional site specific geological data prior to drilling an expensive CO_2 injection well, particularly for deep saline formations that may have only regional geologic data available.

This section of Chapter III discusses the variety of site characterization tools and procedures that are available for undertaking the essential regional and local geological site assessment.

- ***Well Logging.*** Geophysical well logs are the "workhorse" of geological site characterization. They include resistivity, gamma ray, sonic velocity, and other downhole tools that can be used to evaluate the physical properties of the reservoir and caprock. Although some of the early exploration wells at a depleted oil and gas field may have logged the caprock, the later development wells will have generally logged only the reservoir. While commercial log libraries and state geological survey offices can be sources for past information and well logs, a new, comprehensive suite of well logs across the entire subsurface (from the top of the vadose zone to below the base of the storage formation) is highly recommended.

- ***Seismic.*** Seismic methods are a second, important tool for evaluating and monitoring geologic CO_2 storage sites (Hoversten, 2003). Surface and downhole 2D and 3D seismic data are useful in defining the basic structure of the storage field. Shear-wave seismic can help locate natural fracturing. 4D (time lapse) seismic can be used to monitor CO_2 movement, including leakage and migration of the CO_2 outside the confining structure. Cross-well seismic tomography is a more costly but also a higher resolution tool for tracking the location of the CO_2 plume between offset wells. The seismic tool(s) chosen will be site-specific, depending on data sets available, surface and sub-surface considerations, and budget. An important role of seismic will be to establish the potential for future CO_2 leakage through any faults and fractures that may exist in the area.

- ***Core Data.*** A field operator often takes cores from the petroleum reservoir, but generally not of the caprock itself. Core data is an important complement to well logging particularly for calibrating well logs. Core data also provides a wealth of information on the storage reservoir's porosity, permeability, fluid composition, and geochemistry. Many states have well-established core libraries or depositories to which industry has contributed their previously taken core samples. In settings where very limited or only old core data is available, new core samples, particularly of the caprock, will be most valuable.

- ***Regional Geologic Mapping.*** A geologic information system (GIS) provides an efficient and powerful way to comprehensively evaluate geological data to define the regional reservoir structure and caprock integrity. This step will be valuable for locating formation pinchouts, four-way closures, sealing caprocks, and other features that would minimize the risk of CO_2 migration and leakage. Likewise, a GIS can help identify geologic features such as leaky faults, facies changes in otherwise permeable sandstones or carbonates, structural saddles, and other geological hazards. A thorough vertical and horizontal regional mapping of the CO_2 storage area is essential for sound site selection.

- ***Well Integrity Assessments.*** The status and condition of all wells that penetrate the caprock and the reservoir at the storage site should be evaluated. Cement logs can help establish integrity of the current cement sheath. The location and status of abandoned wells need to be documented, measured, recorded and replugged, where necessary.

- ***Augmented Caprock Core.*** Whole core or less expensive sidewall cores may be gathered from a well drilled through the caprock of a CO_2 storage site, providing information on vertical permeability and the geochemistry of the crucial CO_2 – caprock interface. Efforts are underway to core the caprock at several natural CO_2 fields in the USA, which would be the first such attempt, and, when available, would provide valuable information on changes in caprock integrity with time. Detailed analysis of the core could show that the security of the CO_2 – caprock interface can be reinforced by chemical alterations and mineral precipitation.

- ***Augment Seismic.*** Additional new seismic acquisitions tuned for caprock characteristics rather than simply the storage reservoir could be taken. In addition, sequential VSP profiles could be run in offset observation wells to track the flow of the CO_2 in the reservoir.

- ***Isotope Geochemistry.*** Isotope geochemistry, particularly of stable carbon and noble gases, can be a powerful and low-cost tool for monitoring reservoir architecture, fluid flow, and leakage (Ballentine, et al., 2000).

E. EXAMINATION OF NATURAL AND INDUSTRIAL ANALOGS

Another source of data, valuable for understanding the risk of CO_2 leakage, are naturally occurring CO_2 deposits, underground gas storage sites, and CO_2 floods for enhanced oil recovery.

- ***Natural CO_2 Fields:*** The best engineered CO_2 storage site may well be a fully depleted natural CO_2 field (such as McElmo Dome). However, few such sites exist near anthropogenic CO_2 sources. Still, a well-defined natural CO_2 field could be evaluated as a predictive analog for a nearby depleted oil and gas field with similar reservoir and caprock geology. In addition, the geologic criteria extracted from natural analogs could be used to define screening criteria for CO_2 storage sites.

- ***Underground Gas Storage:*** Over 500 gas storage facilities have been developed worldwide in depleted oil fields and gas fields. Additional gas storage fields have been developed in aquifers, often in the same geological settings (such as the Mt. Simon Sandstone) that are candidates for CO_2 storage. Their experience with respect to leakage and other operational issues germane to CO_2 storage, investigated by Perry (2003), provides a valuable source of relevant information.

- ***EOR Projects:*** There has been more than three decades of CO_2 injection and monitoring experience in the oil fields of the Permian Basin, Rocky Mountains, and other areas. A particularly valuable study that has begun to examine industry's experience is the comprehensive study of CO_2-EOR projects performed by Grigg (2002).

Sidebar 7 to this report provides, in summary, the lessons learned from gas storage aquifers for CO_2 storage and site selection.

F. EVALUATING DEPLETED AND NEAR-DEPLETED OIL AND GAS FIELDS FOR CO_2 STORAGE

1. Geologic Screening Criteria. The primary screening criteria for selecting depleted oil and gas fields for CO_2 storage are: reservoir depth, maximum safe CO_2 injection pressure and bottom hole temperature (to enable CO_2 to be stored in a super critical phase); the presence of a competent seal (generally available in oil and gas reservoirs that have held natural gas for millions of years); sufficient net pay, porosity and area to provide a significantly large volume of storage capacity; and, the absence of seal penetrating faults that may become reactivated by geologic stress, either changes in natural stress or stress induced by the injection of CO_2.

In addition, the reservoir properties that would be most favorable for storing CO_2 would include: low current reservoir pressure; absence of a strong bottom water drive; high permeability; and a competent well infrastructure. Depleting oil and gas reservoirs (as opposed to a fully depleted, abandoned reservoir) will be more favorable because a quality infrastructure may still be in place, and ongoing CO_2 injection and gas production at the site may be more publicly acceptable.

SIDEBAR 7. LESSONS LEARNED FROM GAS STORAGE OPERATIONS FOR SITE SELECTION

A review of natural gas storage sets forth the following geological conditions essential for successful, safe storage:

- An impermeable caprock
- Rigorous mapping and remediation of all old abandoned wells
- An anticline with sufficient and clearly defined structural closure
- A porous and permeable reservoir with sufficient pore volume and depth to provide storage capacity.
- A sufficiently deep reservoir to provide safe distance from sources of potable water.

Caprock Leakage. All noted incidents of caprock leakage were associated with aquifer-based natural gas storage. Aquifer storage accounts for a relatively small (13%) of the natural gas storage installations in the United States, as shown below:

Type of Storage Site	Number of Sites	% of Total	Incidents of Caprock Leakage
Oil and Gas Fields	529	83.5%	-
Aquifers	80	12.6%	5
Salt Caverns/ Other	25	3.9%	-
TOTAL	**634**	**100.0%**	**5**

Each of these five incidents of caprock leakage occurred prior to 1980.

Abandoned Oil and Gas Wells. Natural gas storage operators give particular attention to evaluating the presence of abandoned oil and gas wells that could compromise the integrity of the gas storage site.

In spite of the potential problems with older wells, and the large number of depleted oil and gas fields being used for underground natural gas storage, only one incident of gas leakage is reported due to an old, improperly plugged well.

- In the 1970's, natural gas was detected as leaking from abandoned oil and gas wells in the West Montebello, California (USA) gas storage field.
- The leaked natural gas was trapped and thus accumulated in a shallower zone and did not reach the surface.
- The problem wells were plugged and the natural gas in the shallower zones may eventually be produced.

Structural Closure for Aquifer Storage. Gas storage operators spend considerable effort to select closed aquifer systems, with structural closure provided by dome-like formations sealed with an impermeable caprock. Natural gas (like CO_2) is buoyant, less dense than the water in an aquifer and will remain in the dome, preventing horizontal and lateral migration.

When selecting an aquifer with structural closure, it is important to establish the "spill point", the lowermost position of the dome that would prevent natural gas from spilling out and escaping structural confinement. The lack of proper definition and observance of the "spill point" led to one example of gas leakage.

In 1992, a salt cavern gas storage field in Benham, Texas (USA) was overfilled. Natural gas entered into an adjoining brine pit and then formed a low-lying cloud several hundred yards long. The released natural gas exploded, killing three people, injuring 21 people and causing $9 million (U.S.) of damage.

Source: Perry, 2003.

Oil and natural gas reservoir production can be classified into two types: (1) depletion drive, and (2) water drive.

- Under depletion drive, oil and natural gas flow out of the wells under their own pressure and oil/gas recovery is a function of the pressure decline. As such, depletion drive reservoirs with their low pressures at depletion and the small volumes of residual oil and gas are ideal formations for CO_2 storage.
- Under water drive, the water in underlying formations enters the reservoir as the oil and natural gas is produced, replacing the pressure decrease from production. Water drive reservoirs fill with water as the oil and gas is removed, limiting recovery of a portion of the oil and gas in the reservoir, filling the pore space with an incompressible fluid, and maintaining a higher reservoir pressure at depletion.

2. Identifying "Value Added" CO_2-EOR and CO_2 Storage Candidates. In some settings the potential for joint operations involving CO_2 storage and enhanced oil recovery (EOR) may be favorable, providing revenues to offset some or all of the costs of CO_2 storage.

Five prominent screening criteria can be used to identify the initial group of reservoirs technically favorable for joint EOR and storage of CO_2. These are: reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil composition. These values can be used to establish the minimum miscibility pressure for conducting miscible CO_2-EOR and for selecting reservoirs that would be amenable to this oil recovery process. Reservoirs not meeting the miscibility pressure standard can be considered for immiscible CO_2-EOR.

Additional screening criteria for selecting favorable depleted and depleting oil fields for joint CO_2-EOR and CO_2 storage are provided in Table 3-2.

Table 3-2. Screening Criteria for Joint CO_2-EOR and CO_2 Storage

Property Name	Relates To	Positive Indicators	Cautionary Indicators
Reservoir Properties			
$S_o Ø$	Oil Storage Capacity	≥ 0.05	< 0.05 Consider filling reservoir voidage if capacity is large
Kh (m^3)	Flow within the Reservoir	≥ 10^{-14} – 10^{-13}	< 10^{-14} If kh is less, consider whether injectivity will be sufficient
Seals	Permanence of CO_2 Storage	Adequate characterization of caprock, minimal formation damage	Areas prone to fault slippage
Oil Properties			
P (°API, kg/m^3)	Oil Density	> 22	< 22
μ (mPa s)	Oil Viscosity	< 10	>10
	Composition	High concentration of C_5 to C_{12}	Significant levels of aromatics

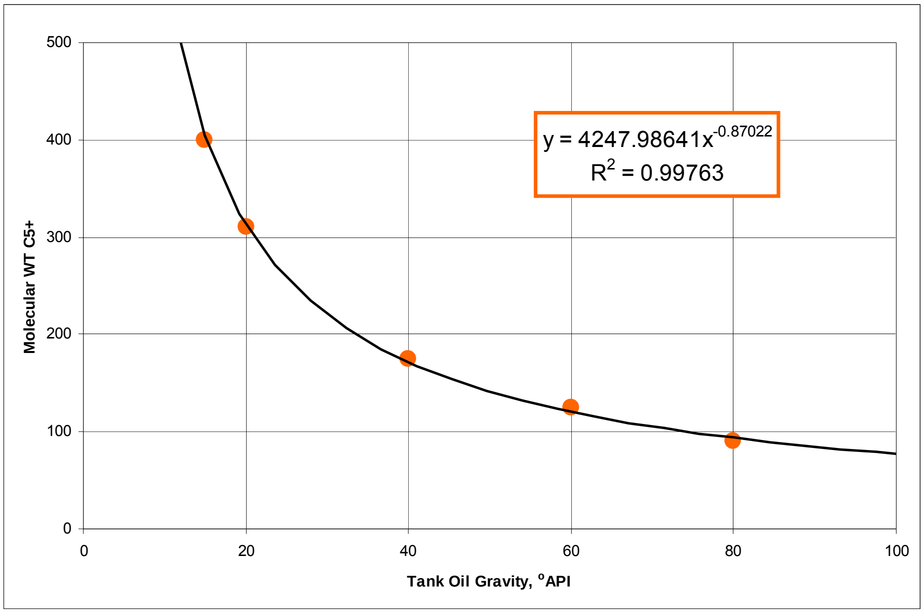
S_o = oil saturation, ø = porosity, Kh = permeability-thickness product
°API – degrees API gravity, μ = viscosity
Source: Advanced Resources International, 2004

a) `*Meeting the Depth and "Light Oil" Criteria*. The preliminary screening step involves selecting the deeper oil reservoirs that have sufficiently high oil gravity. A minimum reservoir depth of 3,000 feet, at the mid-point of the reservoir, may be used to ensure the reservoir could accommodate high pressure CO_2 injection. However, under other favorable conditions, such as a low temperature and high oil gravity, this strict depth limit may be relaxed. A minimum oil gravity of 20^o API may be used to ensure that the first group of reservoirs selected have an oil that has sufficient mobility and may have favorable oil composition for miscibility.

b) *Meeting the Miscibility Criteria*. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and oil composition, is to determine whether the reservoir would hold sufficient pressure to attain miscibility. Where temperature and oil composition data are missing, correlations can be used to estimate these data.

If not available, the temperature of the reservoir can be estimated from the thermal gradient in the basin. Similarly the molecular weight of the pentanes and heavier fraction of the oil can be estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure 3-7.

Figure 3-7. Correlation of MW C5+ to Tank Oil Gravity



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To determine the minimum miscibility pressure (MMP) for any given reservoir, one can use the Cronquist correlation or type curves. The Conquist formulation determines MMP based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil, without considering the mole percent of methane. (Most depleted oil reservoirs have produced the bulk of their methane during primary and secondary recovery.) The Cronquist correlation is set forth below and provides a reliable "first order" estimate for minimum miscibility pressure:

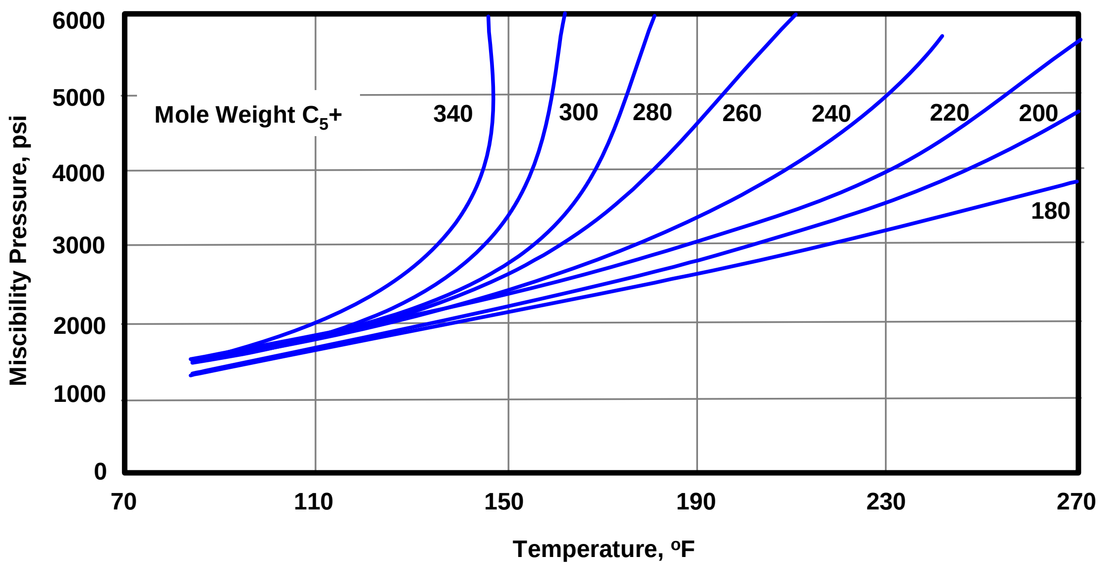
$$MMP = 15.988^* (0.744206+0.0011038^*MW\ C5+)$$

Where: T is Temperature in °F, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

The type curves for estimating minimum miscibility, provided on Figure 3-8, have been developed by Mungan (1981) and have been used for twenty five years. They also provide a reasonable "first order" estimate.

Figure 3-8. Estimating CO_2 Minimum Miscibility Pressure

Correlation for CO_2 Minimum Pressure as a Function of Temperature
(Mungan, N., Carbon Dioxide Flooding Fundamentals, 1981)



Ultimately, particularly when the safe maximum reservoir pressure is close to the minimum miscibility pressure estimated by the equation or the type curve, a more thorough laboratory investigation of the miscibility pressure of the reservoir's oil is warranted.

c) *Meeting the Pressure Criteria*. Once the minimum miscibility pressure (MMP) for a given reservoir is calculated, the next step is to compare it to the maximum allowable pressure. The maximum pressure is determined from the reservoir's fracture gradient, with an allowance for safety, and/or the regulatory allowed injection pressure. If the minimum miscibility pressure is below the maximum safe injection pressure, the reservoir is classified as a miscible flood candidate. Oil reservoirs that do not screen positively for miscible CO_2-EOR may be selected for consideration for immiscible CO_2-EOR or for regular storage of CO_2.

d) *Estimating Oil Recovery*. A critical step for evaluating the site is estimating the volume of oil that would be recovered using CO_2-EOR. A variety of methods may be used to provide an initial estimate of oil recovery. One reasonably rigorous method for providing a preliminary estimate is to utilize CO_2-PROPHET to calculate incremental oil produced using CO_2-EOR. CO_2-PROPHET was developed by the Texaco Exploration and Production Technology Department as part of a U.S. Department of Energy cost-share research program ("Post Waterflood CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir"; DOE Contract No. DE-FC22-93BC14960).

Once a first order estimate of oil recovery has been established using CO_2-PROPHET, a more rigorous evaluation needs to be undertaken using a full-scale compositional simulator to provide more confident, finer-grain estimates for oil recovery, CO_2 injection rates, water production, and well requirements and other key evaluation data.

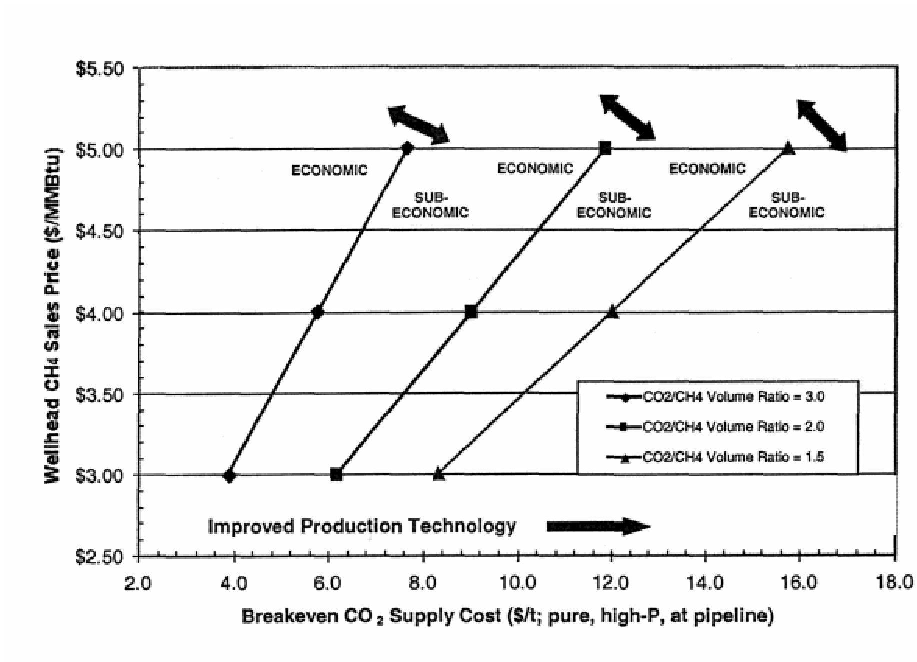
CO_2-PROPHET is available in the public domain, and generates streamlines for fluid flow between injection and production wells, and performs oil displacement and recovery calculations along the established streamlines. (A finite difference routine is used for oil displacement calculations.)

e) *Meeting the Economic Threshold*. In general, an oil field needs to be sufficiently large and offer promise of efficient use of the injected CO_2 to be selected for CO_2-EOR on a stand-alone economic basis. Credits or requirements for storing CO_2 would significantly change these economic criteria.

3. Identifying "Value-Added" Enhanced Gas Recovery (EGR) and CO_2 Storage Candidates. In some cases, it may be feasible to inject CO_2 for the joint purpose of storing CO_2 and enhancing gas recovery. Here CO_2 would be injected into a depleted or depleting natural gas reservoir at locations some distance from production wells. The CO_2 would displace the remaining methane in the reservoir toward production wells and create a pressure differential, thereby accelerating methane production and constraining water entry into the reservoir. The density and viscosity difference between CO_2 and methane would tend to limit the degree to which the two gases will intermingle and mix. The dense CO_2 would be injected at the bottom of the reservoir, while methane would be produced from the top. When CO_2 is injected in the lower portion of the reservoir, it tends to fill the reservoir, from the bottom as methane is produced form higher in the reservoir.

Work by Oldenburg, et al. (2004) provides an economic analysis of EGR. The key variables are the wellhead price for natural gas and the costs of (or credits for) storing CO_2. Figure 3-9 provides a breakeven cost analysis for a sample depleting natural gas field in California.

Figure 3-9. Economic Analysis of Enhanced Oil Recovery



There may also be benefits from CO_2 injection beyond additional gas production for reservoirs still under production. Injecting CO_2 can help maintain reservoir pressure, and thereby reduce water entry. The injected CO_2 may also prevent land subsidence, a problem in some fields.

G. EVALUATING SALINE FORMATIONS FOR CO_2 STORAGE

1. Geologic Screening Criteria. The primary CO_2 storage site selection criteria for saline formations are: sufficient depth (to assure that the CO_2 is in a highly compressed dense phase); sufficient reservoir thickness and porosity (to provide high local storage capacity); adequate permeability (to limit the number and location of CO_2 injection wells); and the presence of a competent caprock (to provide a safe, secure seal for the formation).

Like for other geological CO_2 storage sites, the most favorable saline aquifer sites would contain some geologic structure to help trap the CO_2 and would not be in highly faulted or fractured settings that would limit the aquifer area or that may compromise the reservoir seal.

In addition, it is important to establish the direction and rate of flow of the saline waters in the aquifer, map the surface exist points for the displaced water (if applicable), and define the nature of the geologic strata above the target CO_2 storage formation.

Key reservoir properties need to be assembled to calculate both theoretical and practical CO_2 storage capacity, as discussed previously. In addition, as further set forth below, these reservoir properties can also be used to calculate the daily and annual volumes of CO_2 that may be injected into the aquifer by one or more CO_2 injection wells.

2. Site Selection Procedures. Considerable geologic and reservoir study needs to accompany CO_2 storage assessments for saline aquifers. For example, there is need for:

- Structure contour, depth and gross interval isopach maps for each of the overlying reservoir seals
- Pressure, temperature and CO_2 phase diagrams for each CO_2 storage formation
- Geologic cross-sections to illustrate and define the characteristics of the key CO_2 storage reservoirs

- Sufficient assembly of data to enable a realistic estimate for each of the key CO_2 storage mechanisms, including estimating CO_2 in solution in the reservoirs' brines, CO_2 trapped in the reservoirs' pore space, and free CO_2 contained at the top of the reservoir's boundary layer(s).

In evaluating the storage site, it will be valuable to recognize that the extent of CO_2 trapping will vary according to the reservoir's pore structure and rock characteristics. Additional data collection and laboratory work will be required to reliably define this mechanism. In addition, structure and stratigraphy will enhance CO_2 storage volume and, over time, enable the CO_2 to go into solution via density inversion and flow.

Understanding and defining the reservoir boundaries are essential for estimating storage capacity in saline aquifers. Mapping of saline aquifer structure is essential for defining fractures that will help immobilize CO_2 movement.

In addition, there is a need to estimate CO_2 injectivity. CO_2 injectivity is controlled by permeability, net reservoir thickness, and pressure differential. The "pseudo pressure" flow equation used to calculate the CO_2 injection rate shows that for the particular reservoir conditions set forth in Table 3-3, about 18 MMcfd could be injected into a structurally unconfined reservoir.

Table 3-3. Calculating CO_2 Injectivity for a Saline Aquifer

$$q_{sc} = \frac{(\Psi_2 - \Psi_1)kh}{\gamma T P_t}$$

Where:	q_{sc} = CO_2 injection rate (MMscfd)	**(result) 18**
	Ψ_2 = maximum pseudo pressure (E+6psia^2/cp)*	190
	Ψ_1 = current pseudo pressure (E+6psia^2/cp)*	301
	k = permeability (md)	16
	h = thickness (ft)	100
	γ = constant	1.422×10^6
	T = temperature (ºR = ºF + 460º)	574
	P_t = 1/2(ln t_D+0.80907)*	11.6
	t_D = dimensionless time	

*Note: Standard reservoir engineering equations are used to generate the pseudo pressure values as a function of reservoir pressure, temperature, gas compressibility and the gas deviation factor.

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IV. MODELING CO_2 FLOW AND MONITORING CO_2 LEAKAGE

This chapter addresses two closely linked topics, modeling and monitoring. These two topics, when properly coordinated, can help avoid leakage of CO_2 and, should leakage occur, quickly establish its source and degree of risk.

A. MODELING CO_2 FLOW

The goals of a comprehensive CO_2 storage reservoir model are: (1) to predict how the CO_2 plume will flow and become physically trapped in the short-term; and (2) to understand the effects of chemical reactions (and other mechanisms) that will immobilize the CO_2 over the longer term. The basic capability to model fluid transport and, to some extent, chemical reactions within geologic reservoirs already exists. These models are currently used to manage secondary and tertiary oil recovery and to examine the long-term fate of underground hazardous waste disposal. Activities are underway to adapt these models to help plan, manage, and monitor geologic CO_2 storage.

The first step in modeling is characterizing in detail the CO_2 storage formation, using data from regional geologic assessments, well bore measurements, seismic surveys, and fluid samples. By including probabilistic data and assumptions, these models can be used to develop a range of possible CO_2 transport and reaction scenarios. The output from these models can be used to communicate the security of CO_2 storage to the public and regulating agencies. In addition, these models can be valuable for setting priorities for the monitoring and remediation strategies for geological CO_2 storage sites.

1. Phases of Reservoir Modeling. Reservoir modeling is an ongoing process and the models themselves will need to be updated as new information is gathered. We have set forth four key phases for the reservoir modeling process:

- The first phase of reservoir modeling needs to occur during the site selection phase, even though only regional data may be available by which to populate and constrain the model, and a significant range of uncertainty will exist with regard to the first phase modeling results.

- The second phase of reservoir modeling should occur after new information is obtained from the drilling of the first well or wells - - be they reservoir delineation wells, the initial set of observation and monitoring wells, or the CO_2 injection wells. At this point, considerably more detailed and local reservoir data will be available, particularly on the internal architecture of the CO_2 storage reservoir. With benefit of additional data, the range of uncertainty on modeling results will narrow.

- The third phase of reservoir modeling should occur after CO_2 has been injected for some period of time and the arrival of CO_2 is measured and/or detected in the near-by observation well or set of observation wells. At this point, valuable information is now available on the nature of CO_2 flow, the efficiency of the various CO_2 trapping mechanisms, and the progress of the CO_2 plume, providing greater confidence and certainty on modeling results.

- The final phase of reservoir modeling involves periodically revising the model based on post-injection observations of the CO_2 plume as well as observed changes in chemical reactions and the composition of the reservoir fluids.

The major CO_2 storage field tests, particularly at Sleipner and Weyburn, have gained significant insights by following this multiple-phase approach to reservoir modeling. Figure 4-1 shows the potential predictive capabilities of the models used in the Weyburn Field study (Jazrawi, et al., 2004).

Two additional reservoir simulation studies, undertaken as part of planning new CO_2 storage tests, further illustrate the value of reservoir modeling. Figure 4-2 shows how the modeling of CO_2 flow and trapping in two very distinct saline formations can enable the CO_2 storage operator understand the likely path of the CO_2 plume and craft an effective CO_2 injection and monitoring plan (GCEP, 2004). Figures 4-3 and 4-4 show the CO_2 flow and CO_2 saturation from running a 100-year reservoir model of CO_2 injection into a saline formation.

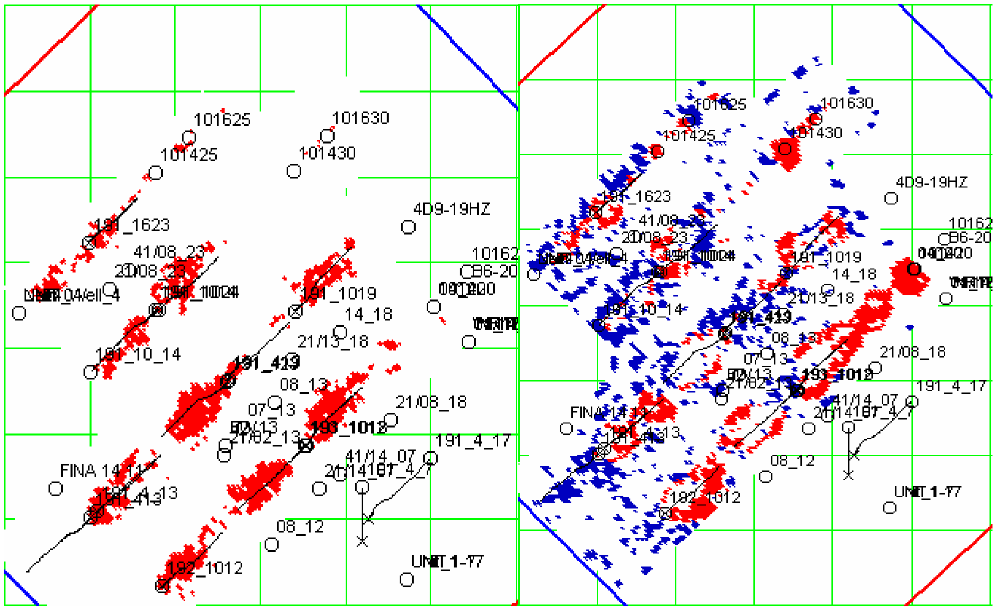

Figure 4-1. Comparison of Reservoir Simulation Versus Time-Lapse Seismic. Results are shown for the 9-pattern Phase-1A area of the Weyburn enhanced oil recovery field. Grid cells where both the seismic and simulator indicate increased CO_2 saturation are shown in red.

Source: Jazrawi, et al., 2004

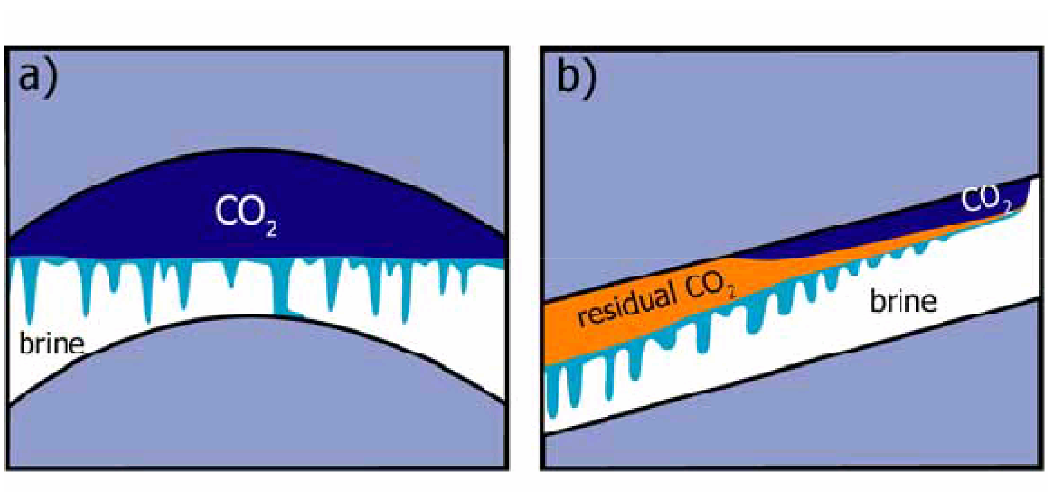

Figure 4-2. Schematic of CO_2 Dissolution in Two Aquifers. The mobile CO_2 gas phase is dark blue, the dissolved aqueous CO_2 is light blue, and the residual CO_2 is orange. In aquifer A, CO_2 gas is held under a structural trap. Dissolution of CO_2 into the brine and subsequent CO_2 saturated brine inversion reduces the CO_2 gas phase volume. In aquifer B, the CO_2 gas phase migrates along the top of a sloping aquifer, leaving behind a region of residual CO_2 trapped in the pore space and dissolved in brine.

Source: GCEP, 2004

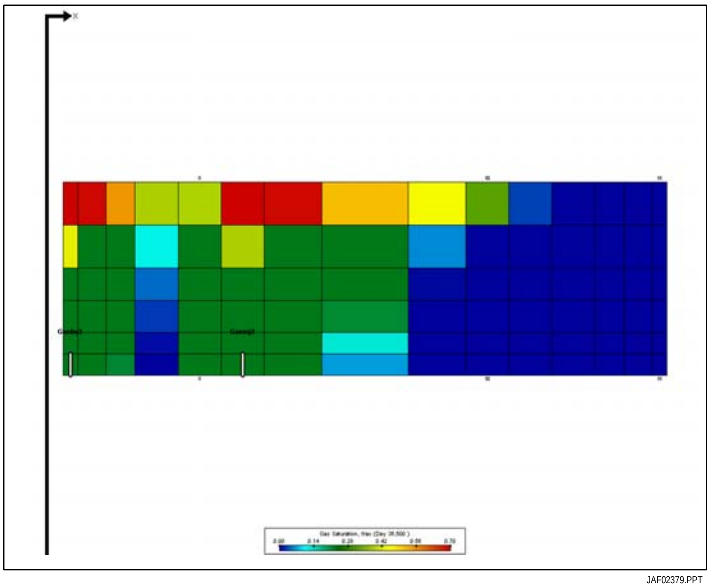

Figure 4-3. CO_2 Saturation and Concentration in a Saline Reservoir (Cross-Section, at 100 Years). CO_2 injection is on the left side of the grid.
Source: Advanced Resources, 2006

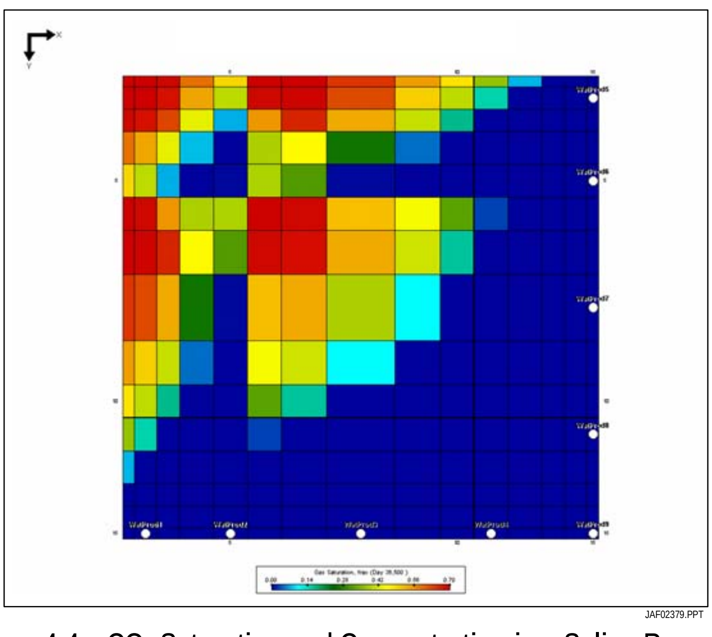

Figure 4-4. CO_2 Saturation and Concentration in a Saline Reservoir (Top Layer, at 100 Years). CO_2 Injection is in the NW corner of the Grid.
Source: Advanced Resources International, 2006

2. Available Reservoir Modeling Tools. A number of reservoir simulation tools, each with particular areas of strength and emphasis, are available for planning and managing CO_2 storage projects. On one end of the scale is COMET3, a general purpose, "user friendly" reservoir simulator that can evaluate CO_2 storage in all types of reservoirs. It is particularly suited for use in fractured reservoirs and for evaluating storage of CO_2 in coal seams or organic shale. At the other end of the scale are ECLIPSE and GEM, compositional reservoir simulators, particularly suited for complex modeling problems and storage of CO_2 with miscible-flooding.

In addition, a series of special purpose, research supportive reservoir models have been developed by research institutes, such as SIMEDII, SIMUSCOPP, TOUGH2, and UTCOMP. Table 4-1 contains a list of seven commercially available reservoir simulators capable of assessing CO_2 injectivity, capacity and flow as part of CO_2 storage (Law, et al., 2002; Pruess, et al., 2004).

Table 4-1. Reservoir Modeling Tools for Geologic Storage of CO_2

Name	Application	Organization
COMET3	• General purpose reservoir simulator with additional features for CO_2 storage modeling • Capable of handling fractured reservoirs, sorption-based gas storage (3 gas components) and two phases	Advanced Resources International, Inc. (ARI)
ECLIPSE	• Black oil simulator with additional features for CO_2 storage modeling • Capable of handling two gas components	Schlumberger GeoQuest
GEM	• Compositional simulator with additional features for CO_2 storage modeling • Capable of handling 3 or more gas components	Computer Modeling Group (CMG)
SIMED II	• Compositional simulator with additional features for CO_2 storage modeling • Capable of handling 3 or more gas components	CSIRO
SIMUSCOPP	• General purpose reservoir simulator • Capable of assessing environmental impact at geologic storage sites for CO_2 and other acid gases	IFP (Institute Francais du Petrole)
TOUGH2	• General purpose reservoir simulator with special gas module	Lawrence Berkeley National Laboratory (LBNL)
UTCOMP	• Compositional miscible-flood simulator with CO_2 solubility in brine formations	Center for Petroleum and Geosystems Eng. – UT

3. Estimating CO_2 Storage Capacity Using Modeling

a) Saline Formations. Estimating the CO_2 storage capacity of a deep saline formation is a relatively complex undertaking, requiring considerable baseline geologic data on the characteristics of the reservoir, as well as an in-depth understanding of the dynamics of water and CO_2 flow through the reservoir.

To accurately estimate CO_2 storage capacity in an aquifer, one needs to fully account for the main storage functions present in the reservoir, namely: (1) the solubility of CO_2 in the reservoir's saline water; (2) the trapped CO_2 in the pore space; and (3) the extent of free CO_2 and its distribution, generally along the confining layers of the reservoirs. Of particular importance is the characterization of the vertical heterogeneity of the reservoir and the selection of an injection well pattern that optimizes the long-term storage of CO_2 in the aquifer.

Sidebar 8. Illustrative Example of Estimating CO_2 Storage Capacity in a Saline Formation. This example shows that even with rigorously established CO_2 injection designs, only a small fraction, in this case 12%, of the theoretical CO_2 storage volume can be practically stored in a saline formation.

(1) *Calculating Storage Capacity*. The illustrative example in Sidebar 8 provides some guidelines and "rules of thumb" for estimating CO_2 storage capacity in saline aquifers and for performing certain of the key capacity calculations. The guidelines and "rules of thumb" are based on experiences gained from conducting a series of COMET3 reservoir simulation runs of CO_2 storage and flow:

- The first step involves setting forth the basic data for the storage reservoir.
- The second step involves defining the operating conditions for the CO_2 injection and storage project.
- The third step involves calculating overall storage capacity as well as the capacity provided by each of the three key storage mechanisms.

SIDEBAR 8. ILLUSTRATED EXAMPLE OF ESTIMATING CO_2 STORAGE CAPACITY IN A SALINE FORMATION

Basic Data.

- Reservoir properties:
  - 5,000 feet of depth
  - Slightly under-pressured
  - Porosity of 10%, for 90 feet of net sand
  - Temperature of 114° F
  - Salinity of water of 30,000 ppm
  - Vertical/horizontal permeability of 0.02

Operating Conditions.

- Assume an unbounded aquifer system
- Inject CO_2 into the aquifer for 25 years
  - 1.3 MMcfd per year
  - 25,000 tons per year
  - 11.9 Bcf/0.63 million tons, total
- Shut in the aquifer for 75 years
- Examine distribution of CO_2 and its concentration, at end of 100 years

The example calculation of CO_2 storage capacity, starting with estimating overall reservoir pore volume and ending with CO_2 storage by individual storage mechanisms, is set forth in Figures 1 through 4.

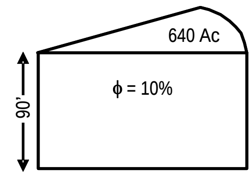

Figure 1

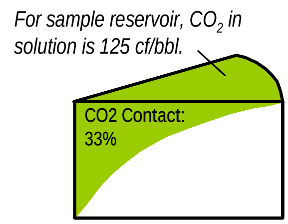

Figure 2

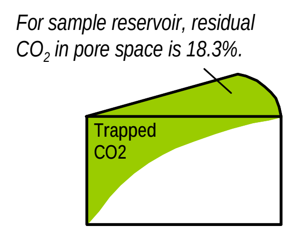

Figure 3

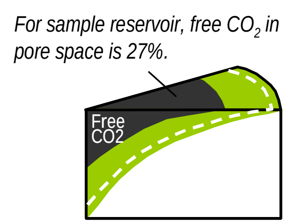

Figure 4

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1. Establish Reservoir Pore Volume. (Figure 1)

Pore volume = Area * Thickness * Porosity
= 640 Acres * 90 feet * 0.1 = 5,760 AF

Unit conversion (5,760 AF * 7758 B/AF) = 44.7 MMB reservoir pore volume

If all of the reservoir pore volume were filled with supercritical CO_2 (2.26 Mcf/barrel at 2,000 psi and 114°F), the reservoir would hold 101 Bcf, or 5.3 million metric tons CO_2.

Theoretical storage volume = 44.7 MMB * 2.26 Mcf/B = 101 Bcf
= 5.3 million metric tons

SIDEBAR 8. ILLUSTRATED EXAMPLE OF ESTIMATING CO_2 STORAGE CAPACITY IN A SALINE FORMATION (Cont'd)

2. Estimate CO_2 Contacted Pore Volume. Based on ARI's modeling of the example saline aquifer, only 33% of the reservoir comes in contact with injected CO_2. This is due to CO_2's buoyancy in a brine formation and its strong tendency to flow upwards. Figure 2 shows the shape of the CO_2 plume as the CO_2 travels upward and horizontal until it reaches the caprock.

3. Calculate CO_2 in Solution. The CO_2 dissolution mechanism provides storage in the portion of the reservoir in contact with CO_2, Figure 3. At 2,000 psi and 30,000 ppm TDS, 1 barrel of brine holds 125 cubic feet CO_2.

CO_2 in solution = total pore vol. * CO_2 contact * solution capacity in brine
= 44.7 MMB * 33% * 125 cf/bbl
= 1.8 Bcf (0.10 million mt CO_2)

4. Calculate CO_2 Trapped in Pore Space. The CO_2 trapping in pore space varies according to the nature of the reservoir's rock. In the portion of the reservoir contacted with CO_2, the amount of CO_2 trapped varies from a few percent to 23 percent, for an average of 18.3%.

CO_2 trapped in pore space = total pore vol. * CO_2 contact * CO_2 trapping factor * CO_2 volume factor
= 44.7 MMB * 33% * 0.183 * 2.26 Mcf/B
= 6.1 Bcf (0.32 million mt CO_2)

5. Calculate CO_2 in Free Phase. CO_2 that is not dissolved or trapped in pore space will remain as free phase CO_2 along the upper sealing boundary of the storage formation:

Free phase CO_2 = total CO_2 injected - CO_2 in solution - CO_2 trapped
= 11.9 Bcf – 1.8 Bcf – 6.1 Bcf
= 4.0 Bcf (0.21 million mt CO_2)

Figure 4 shows the free phase CO_2 within the contacted portion of the reservoir.

The table to the right shows the amount of CO_2 stored by the various mechanisms. The overall CO_2 storage in one square mile of area is 0.63 million metric tons. This is equal to 12% of the theoretical pore space volume of 5.3 million metric tons of CO_2.

CO_2 Storage Mechanisms	**Bcf**	**Million Metric Tons**
CO_2 in solution	1.8	0.10
Trapped Pore Space CO_2	6.1	0.32
Free CO_2	4.0	0.21
Total	11.9	0.63

(2) *Gaining Insights On Storage Capacity*. While the overall CO_2 storage capacity and role of each of the three storage mechanisms are only valid for the basic data and operating conditions of the sample saline aquifer, the example serves to illustrate the relative role of each CO_2 storage mechanism. In addition, the example begins to define the overall extent of the CO_2 storage requirements as well as the areal extent of the free and mobile CO_2 phase in the saline aquifer.

b) Oil Fields. Oil fields, involving a combination of CO_2-EOR and CO_2 sequestration, will likely be the most prominent initial geologic formations where CO_2 is stored. A "first-order", minimum estimate of CO_2 storage capacity in depleted oil fields can be estimated from the following equation, in terms of Mcf of CO_2:

CO_2 Storage Capacity = Area (acres) * Net Pay (feet) * Porosity * 7758 barrels/acre-foot * A (pore space, filled with mobile fluid, assume 0.7) * E (effective reservoir contact, assume 0.5) * 2 Mcf/barrel.

Note: The conversion factor of 2 Mcf/barrel of pore space may range from 1.5 to 2.5, depending on actual reservoir conditions. Mcf of CO_2 can be converted to metric tons of CO_2 by the factor 18.9 Mcf of CO_2 equals 1 ton of CO_2.

More precise estimates of CO_2 storage capacity in depleted oil reservoirs can be obtained by performing a reservoir simulation that incorporates the reservoir boundaries and allowable pressure buildup in the reservoir.

Increasing CO_2 storage (while optimizing oil recovery) is a goal worth pursuing and may be achieved by the following strategies:

1. Use well completions that reduce the adverse effects of preferential flow of injected CO_2 through high permeability zones, particularly toward the top of the reservoir. For example, should high permeability intervals be toward the top of the reservoir, the strategy would be to inject CO_2 at the base of the reservoir, enabling the CO_2 to vertically contact as much of the reservoir area as possible.

2. Optimize gas and water injection (timing, injection rates) to minimize CO_2 cycling and maximize CO_2 storage. While injection of water can impede preferential CO_2 flow through high-permeability pathways in a reservoir, thus improving the distribution of CO_2 throughout the reservoir, water can also block reservoir pore volume that otherwise would be available for or accessible by CO_2.

3. Consider injecting a portion of the CO_2 into the underlying aquifer, where present.

4. Consider using a gravity-stable CO_2 flooding design in reservoir settings where this approach appears feasible.

5. Undertake reservoir repressurization after the end of oil production.

One action to enhance CO_2 storage capacity would be to use partial completions in both injection and production wells or use horizontal wells to better distribute the injected CO_2. Because of gravity effects, completing injection wells low in the formation rather than over the entire reservoir column improves the contact of the CO_2 with a greater portion of the reservoir's volume. Production wells completed low in the formation also delay break-through of the CO_2.

CO_2-EOR operations often include water as well as CO_2 injection. This process is called WAG (water alternating gas) injection. In one version of WAG, alternate slugs of water and CO_2 are injected. In another version, CO_2 is injected continuously until significant CO_2 breakthrough. At CO_2 breakthrough, WAG injection is started. The benefits of WAG injection are several. First, gravity forces cause the water and CO_2 to sweep different portions of the pore space - - CO_2 generally gravitates to the top of the reservoir, while water contacts the lower portion. In addition, the presence of water reduces the mobility of the CO_2, thereby reducing CO_2 breakthrough. Further, sequencing of CO_2 and water injection across a large field offers significant opportunities for increased gas storage.

CO_2 could also be injected into an aquifer below the oil field instead of only into the oil zone. CO_2 injection into the aquifer may displace oil trapped in the transition zone between the water filled and the oil filled pore space, increasing oil recovery.

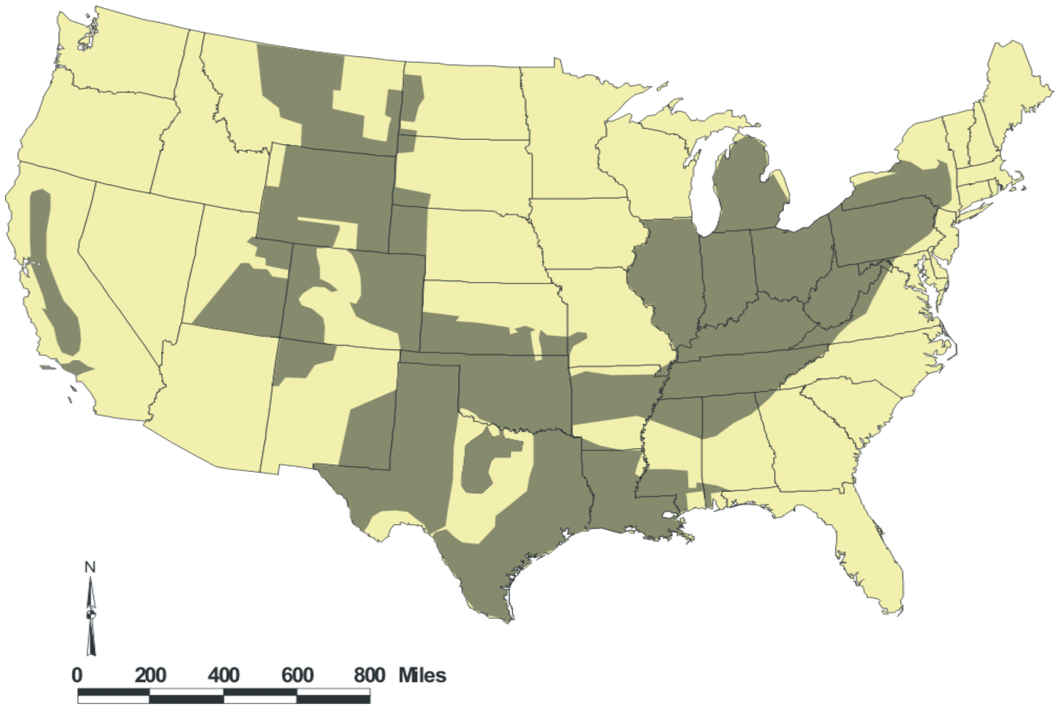
Finally, it is possible to continue CO_2 injection after oil production ceases. Further pressurizing the reservoir, provided that the reservoir seals are not damaged, allows substantial additional increase in storage.

c) Depleted Natural Gas Fields. Depleted natural gas fields, at or below 2,500 feet of depth, can also provide a favorable option for CO_2 storage. In general, these fields have been well characterized from prior well drilling and logging, may contain available distribution facilities and injection wells for CO_2, and should provide considerable assurance of long-term containment for the CO_2. In some cases, the injection of CO_2 provides the potential for enhancing and/or accelerating recovery of the natural gas still remaining in the natural gas field (Oldenberg, et al., 2001).

In the process of producing and depleting a natural gas field, the pressure is reduced considerably, unless a strong water drive maintains a portion of the reservoir's pressure. As a result, both the CO_2 storage capacity and the CO_2 injectivity in pressure depleted natural gas fields can be favorable. The great majority of the 600 domestic natural gas storage sites are in depleted natural gas reservoirs, confirming that depleted natural gas fields could be excellent candidates for CO_2 storage.

A vast number of natural gas fields and reservoirs exist across the U.S., as shown on Figure 4-5. Many of these gas fields are at or near the end of their economically productive life, particularly the very mature natural gas fields in the Appalachian and Mid-Continent basins. The U.S. DOE/NETL natural gas data base, GASIS, tabulates nearly 20,000 gas reservoirs in 21 gas producing states (GASIS, 1999). This data base provides an excellent starting point for selecting depleted natural gas fields for geologic storage of CO_2.

Figure 4-5. Locations of Depleted Gas Reservoirs



Source: Dahowski, R.T. et al., A CO2 Storage Supply Curve for North America, 2004 DRAFT

JAF02379.PPT

The CO_2 storage mechanisms in depleted natural gas fields are similar to those in depleted oil fields with a few notable differences: (1) depleted gas fields will generally be at a lower pressure than depleted oil fields, because pressure maintenance, critical for maximizing recovery in oil fields, is not generally practiced in gas fields; and (2) depleted gas fields will contain less water in the reservoir and thus will generally have higher storage capacity than a comparable size oil field. This is because water injection, important for maximizing recovery in oil fields, is not practiced in gas fields.

As such, the primary CO_2 storage mechanisms in depleted gas fields is the compressibility of the CO_2 in the available pore spaces of the reservoir, where CO_2 compressibility is a function of pressure and temperature. Typically, one barrel of available reservoir pore space can contain 2 Mcf of CO_2, with a range of 1.5 Mcf to 2.5 Mcf of CO_2 per barrel of available pore space, depending on reservoir temperature and pressure conditions. A "first-order", minimum estimate of CO_2 storage capacity in depleted natural gas fields can be estimated from the following equation, in terms of Mcf of CO_2:

Area (acres) * Net Pay (feet) * Porosity * 7758 barrels/acre-foot * 2 Mcf/barrel * A (available pore space, assume 0.7) * E (effective reservoir contact, assume 0.8) * PL (pressure limit of the confined depleted gas reservoir, need to calculate from pressure, temperature and volume equation).

Note: The conversion factor 2 Mcf/barrel of pore space may range from 1.5 to 2.5, depending on actual reservoir conditions. Mcf of CO2 can be converted to metric tons of CO2 by the factor 18.9 Mcf of CO2 equals 1 ton of CO2.

More precise estimates of CO_2 storage capacity in depleted natural gas reservoirs can be obtained by performing a reservoir simulation that incorporates the reservoir boundaries and allowable pressure buildup in the reservoir.

4. Probabilistic Storage Capacity Injectivity and Flow Modeling. As additional reservoir information is gathered, it will become possible to provide more sophisticated modeling of CO_2 storage capacity, injectivity and flow. This more rigorous use of the full distribution of geological and reservoir properties will enable the operator to better understand and communicate the likely range of outcomes at the selected storage site. Use of probabilistic modeling also helps establish the value of gathering additional data that could help narrow the expected range of estimates for CO_2 storage capacity, injectivity and likely flow paths.

5. Wellbore Integrity Modeling. High priority is being given to better understanding wellbore integrity in CO_2 storage. As such, numerous efforts are underway to understand wellbore-based leakage mechanisms, the causes of well failure and the potential risks associated with wellbore leakage. Wellbore leakage modeling may also be a primary interest of regulatory authorities for understanding and addressing wellbore integrity concerns.

Currently one, two, and three-dimensional wellbore models are under development to simulate the processes observed in the laboratory and the field. For example, researchers at the University of Alberta have developed a comprehensive methodology for assessing the transport properties of wellbores used for the geologic storage of CO_2 (Chalaturnyk and Moreno, 2004). This methodology identifies a variety of possible failure mechanisms and systematically represents these mechanisms and the interactions among them analytically. The methodology is sufficiently flexible to allow new mechanisms to be added, allows for properties to change over time, incorporates assumptions for missing data, and enables addition of new data as these become available.

The initial research by the University of Alberta, which is consistent with work by Princeton University, indicates that the two most critical points of wellbore leakage in CO_2 storage include the annuli between the cement and the well casing and the interval between the cement and the reservoir rock. Of particular concern is the subsequent dissolution of cement by CO_2 interactions in both of these cement filled spaces.

Research is also underway by the Carbon Mitigation Institute (CMI) at Princeton University to develop analytical and semi-analytical solutions for estimating the probability distribution for leakage rates through abandoned wells (Nordbotten, et al., 2005). These techniques are being applied in the Alberta Basin, using a study area with a large number of existing wellbores (Celia, et al., 2006).

6. Geomechanical Modeling of CO_2 Injection. The injection of CO_2, particularly in hydrostatic saline formations, requires that the formation pressure be exceeded as the injected fluid needs to displace or compress the fluid in the storage reservoir.

Geomechanical modeling is used to help ensure that the injection of CO_2 avoids damaging the reservoir or fault seals of the CO_2 storage site. Geomechanical modeling is used to predict the evolution of effective stresses in rocks and faults and the maximum sustainable fluid pressure that can be safely used during CO_2 injection. The geomechanical models used for estimating fault and rock stability rely on Mohr-Columb criteria, where effective stress is defined as total stress minus the pore-fluid pressure, and the classic Mohr circle is used to predict rock failure.

Pressure-depletion scenarios can have a significant impact on effective stress, causing damage to reservoir seals and fault seals. However, it is not clear whether fluid injection will have significant effects on total stress at reservoir scale. New work on combining geomechanical modeling (particularly the poro-elastic behavior of the reservoir) and injection-related pore pressure/stress coupling, and application of geophysical monitoring (to be discussed in the next section of this Chapter) would provide improved means for controlling the geomechanical effects of CO_2 storage.

The assessments of fault stability and maximum sustainable fluid pressures for CO_2 injection require information on in situ stress, fault geometries and rock strength. Drilling data and induced micro-fracturing can be used to establish in situ stress; fault geometry can be determined from a depth-converted 3D seismic survey; and rock strength (including the strength of the reservoir rock, the caprock and faults) can be established from laboratory tests.

Geochemical Modeling. The purpose of geochemical modeling is to better understand the expected reactions between the injected CO_2 (including the CO_2 in solution with reservoir brines) and the in-place reservoir minerals (in the storage formation and the caprock). Modeling of the interaction of CO_2 and the minerals in the storage formation will help establish the long-term CO_2 storage and trapping offered by mineralization. Modeling of the interaction of CO_2 and the caprock will help establish the extent to which this interaction will improve or weaken the sealing ability of the caprock. (Laboratory and analytical studies conducted to date appear to indicate that CO_2 interaction with the caprock tends to lower caprock permeability, although much more work and geologic variability are required to establish more conclusive results.)

B. MONITORING OF CO_2 LEAKAGE

Monitoring in a geologic CO_2 storage project helps to determine the location of the injected CO_2 and, most importantly, to detect leaks or other deterioration of storage integrity. Monitoring, in turn, is also essential for remediation of CO_2 leakage, as discussed in the next chapter, enabling one to rapidly respond to CO_2 leakage in the event that such leakage should occur (NETL, 2004).

1. Value of Monitoring. Three most important reasons exists for monitoring at CO_2 storage projects: (1) assessing the performance of the CO_2 injection and storage process by tracking the subsurface movement and immobilization of the injected CO_2; (2) providing an “early warning” system should CO_2 seepage or leakage occur; and, (3) providing information, particularly for meeting public and regulatory concerns, that no adverse actions are occurring or likely to occur in the storage reservoir.

In addition, as discussed previously, monitoring serves an important role in helping verify and calibrate the performance of the reservoir and wellbore models used to assess long-term CO_2 movement and storage integrity, particularly after CO_2 injection operations have ceased. Monitoring and modeling of long-term performance will also be important for obtaining permits and gaining public acceptance.

Monitoring is aimed at helping to avoid and, should it occur, to quickly provide information on the local, as well as the global, risks related to leakage of stored CO_2. Of particular concern are rapid releases, leading to local health and the environment risks, including CO_2 accumulation in buildings or low-lying areas, damage to plants, and contamination of underground drinking water. Monitoring can help avoid and better respond to these risks. Monitoring can also help assess the global risk that a particular storage site will be ineffective due to slow but persistent leakage of CO_2.

For the most part, all of the monitoring techniques currently being considered are adaptations from other -- albeit similar -- applications. Much can be learned from the monitoring efforts used by CO_2-EOR projects and particularly by the gas storage industry (Benson, et al., 2002).

- In CO_2-EOR projects, the principal method used to monitor CO_2 movement in the reservoir has been the direct observation of the composition of the produced fluids (Grigg, 2002). Increased use is being made of seismic methods, particularly in pilot tests and experimental projects, including cross-well tomography, surface 3-D and 4-D seismic, and vertical seismic profiling, as shown on Figure 4-6.

- Much more extensive use of monitoring is common in the natural gas storage industry that tends to extensively rely on a series of special purpose observation wells, as shown on Figure 4-7.

Benson (2004) identifies a number of important purposes that the monitoring system will need to serve:

- Monitoring to ensure effective CO_2 injection controls

- Monitoring to detect the location of the injected CO_2 plume

- Monitoring of the integrity of shut-in, plugged, or abandoned wells
- Monitoring to identify and confirm CO_2 storage efficiency and processes
- Monitoring to detect and quantify any CO_2 surface seepage.

A suite of monitoring technologies will need to be employed to achieve these objectives, providing complimentary information and planned redundancy. In addition, a variety of monitoring approaches will be required depending on the leakage pathways and risks that are of concern. Figure 4-8 provides an illustration of the various targets for monitoring and the approaches for conducting the monitoring.

Two general categories of monitoring will need to be installed at a CO_2 storage site (Chalaturnyk and Gunter, 2005).

a) Comprehensive Leakage Monitoring and Safety Assurance. Carbon dioxide is a commodity useful in a wide variety of applications. In addition to its importance for enhancing oil recovery, CO_2 is used in manufacturing carbonates and urea. Dry ice (solid CO_2) is used as a refrigerant. CO_2 is also used in carbonated beverages and in fire extinguishers. Supporting this large CO_2 industry is a vast infrastructure for storing, delivering, and processing CO_2. For example, CO_2 injection operations in West Texas are supported by over 2,200 miles of high pressure (1,500 – 2,000 psi) pipelines. Eight major CO_2 processing plants dry, separate and compress produced CO_2 to prepare it for reinjection (Melzer, 2004).

All of these systems and facilities have worker safety procedures and protections, such as CO_2 sensors near injection wells and other equipment to detect leakage and ensure worker safety. An immediate objective of such monitoring is to protect human health by alerting project operators of dangerous CO_2 concentrations.

Figure 4-6. Using Surface, Vertical Seismic Profiling (VSP) and Crosswell Seismic for Monitoring CO_2 Storage.

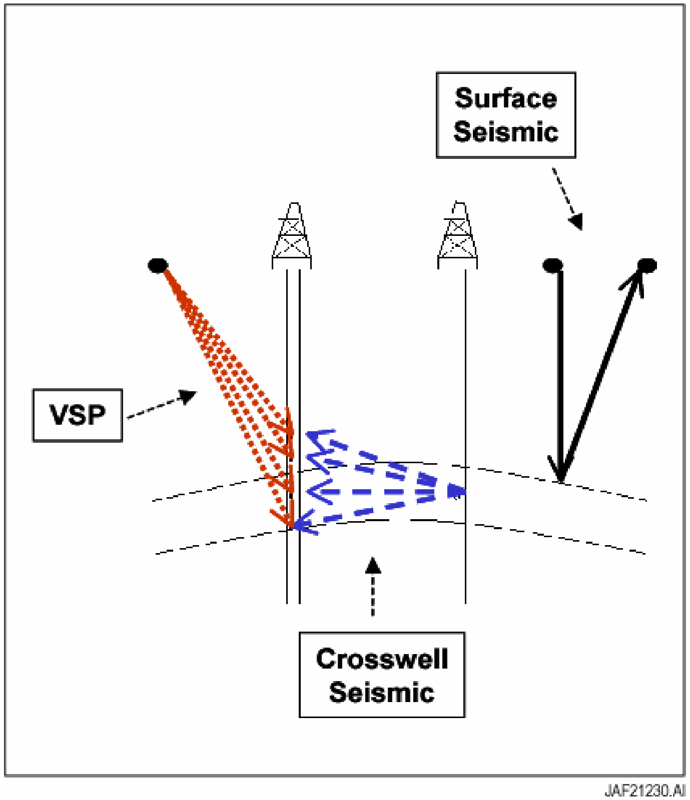
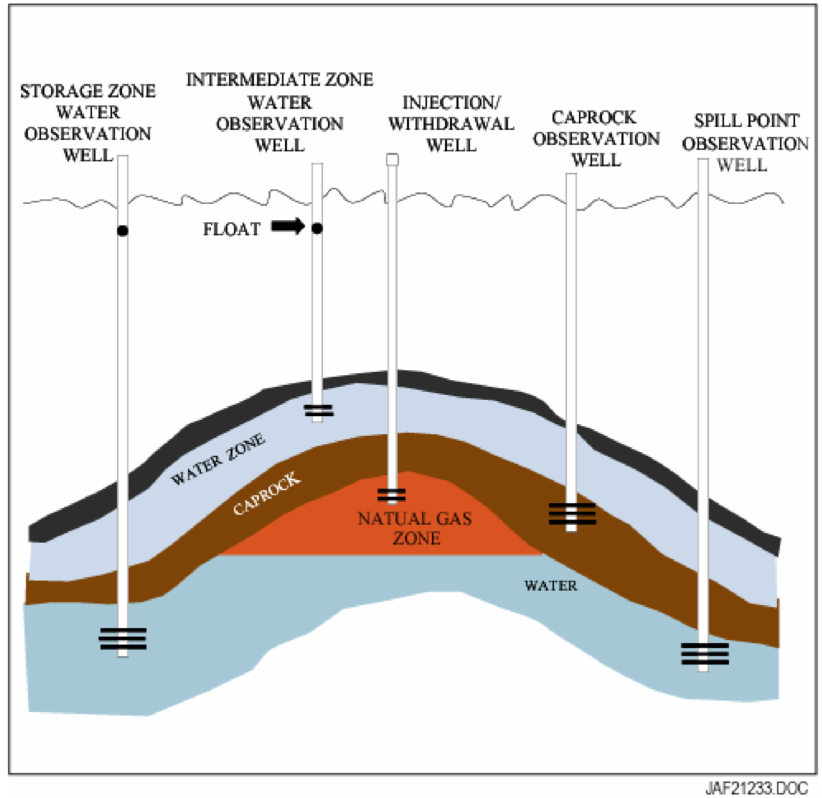
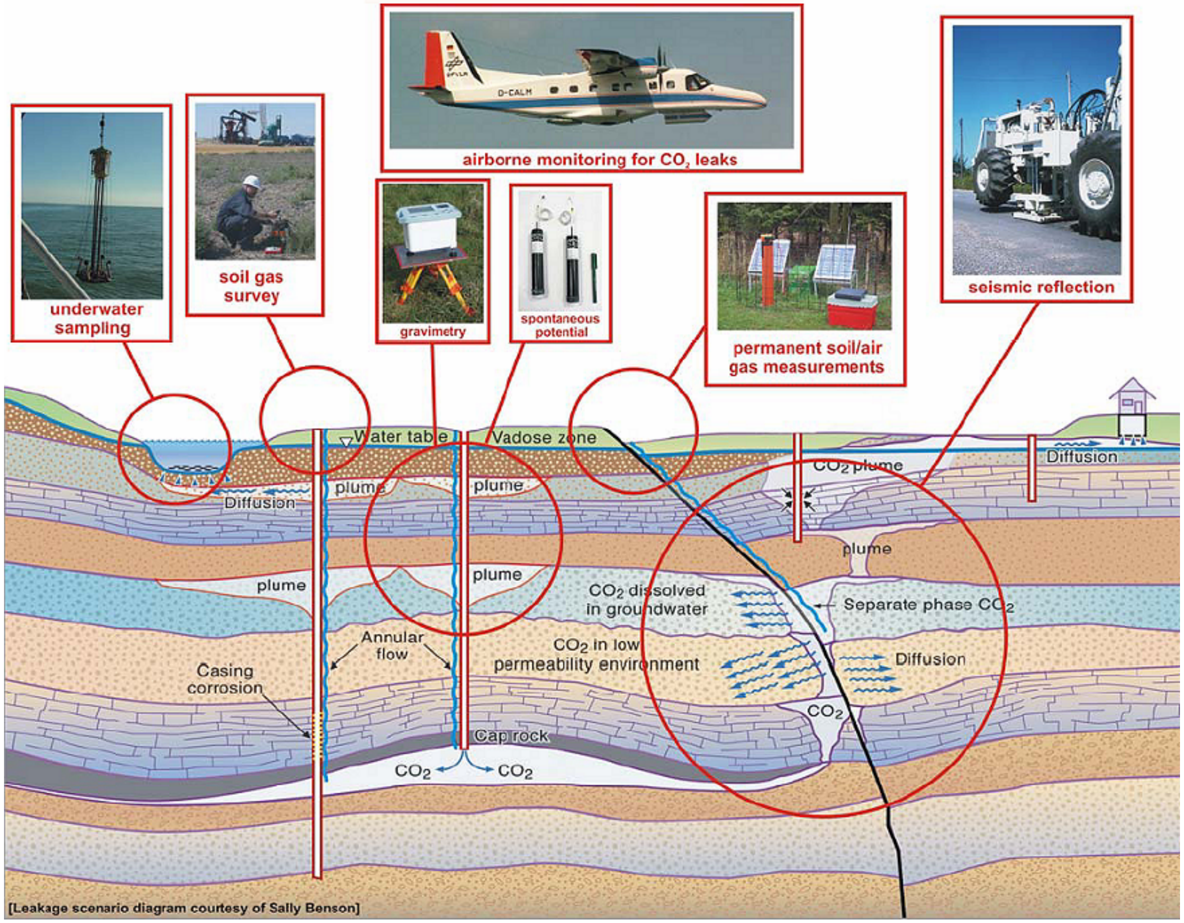


Figure 4-7. Locating Observation Wells for Monitoring Storage.



Modified from Underground Storage of Gases, University of Michigan Engineering Summery Conference, 1978.

Figure 4-8. Various Monitoring Approaches for Various Leakage Pathways



Courtesy British Geological Service

Source: Heidug, 2006

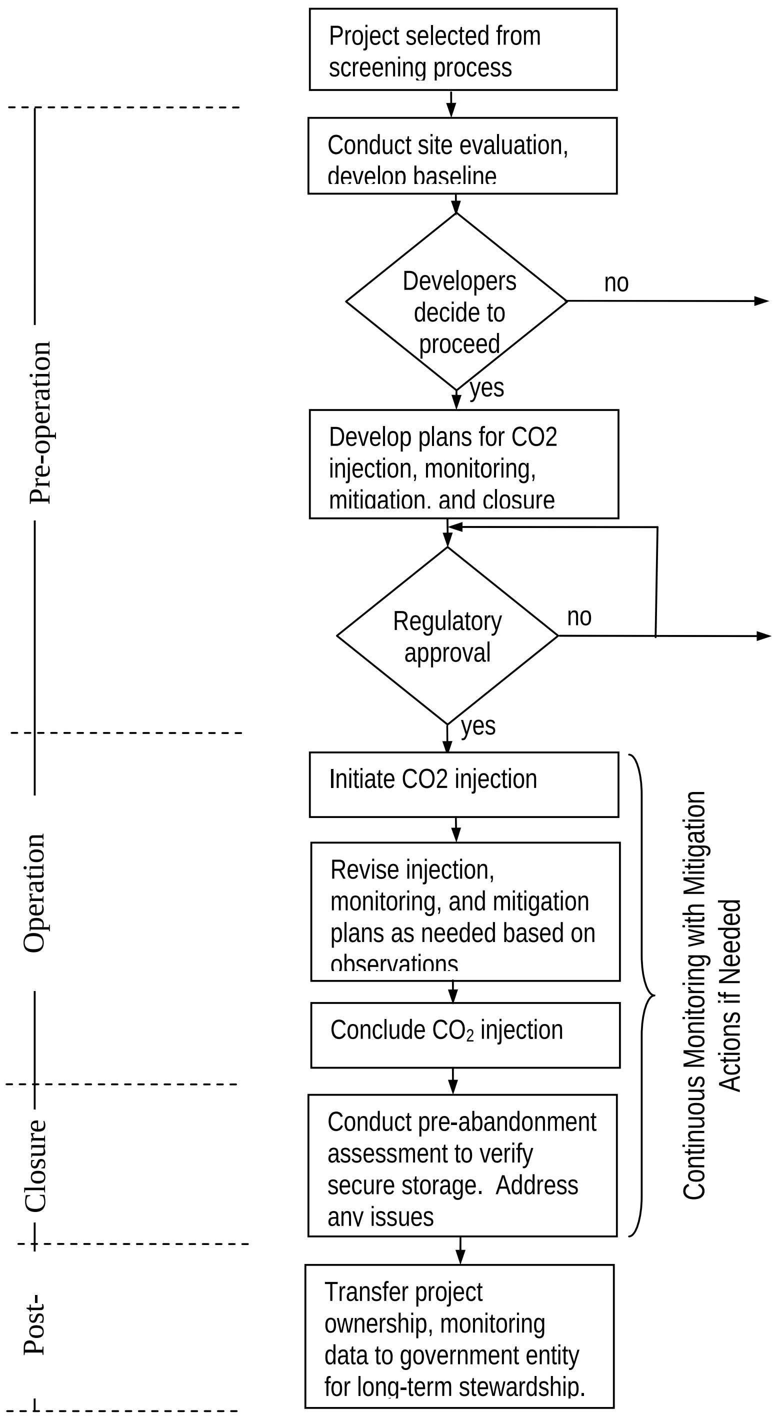
b) Comprehensive Seepage Monitoring and Storage Assurance. Seepage monitoring serves as a backstop for leakage monitoring, and also offers direct protection of ecosystems and human health. Key to this monitoring is the availability of high quality data on baseline conditions. All such monitoring faces the problem of filtering out the natural CO_2 concentrations and fluxes, which change with atmospheric conditions, temperature, soil moisture, and intensity of sunlight.

2. Phases of Reservoir Monitoring. All CO_2 storage projects will likely require a detailed monitoring plan. The actual monitoring plans for each project will need to be based on the characteristics of the storage reservoir, including its development history (if it is a depleted oil and gas reservoir). Four distinct monitoring phases should be considered in the life-cycle of a geologic CO_2 storage project (Benson, 2004). The four phases are:

- Pre-operation phase - - as the base-line conditions are established, the geologic setting is defined and the storage design is formulated, the specific role of the monitoring systems for providing information and reducing risks needs to be set in-place;
- Operation phase - - during the 30 to 50 years time period when CO_2 will be injected into the storage reservoir, an active program of monitoring and feedback will need to be in operation;
- Closure phase - - after injection has stopped, passive but still ongoing monitoring will be used to demonstrate that the storage project is performing as expected and that it is safe to discontinue further monitoring;
- Post-closure phase - - after some time period following the closing of the project, monitoring may no longer be required except in the event of leakage, legal disputes, or other matters that may require new information about the status of the storage project.

Figure 4-9 shows the phases of a CO_2 storage project and how monitoring activities are integral throughout.

Figure 4-9. Role of Monitoring During Four Phases of a Geologic CO_2 Storage Project



3. Wellbore Integrity Monitoring. Leaking wellbores will, most likely, be a high concern for safe, secure CO_2 storage. During operations, monitoring of injection and production rates can provide the first source of information of where wellbore leakage may be occurring, followed closely by monitoring of wellbore and formation pressures and temperatures. Fluid sampling, vertical seismic profiling (VSP), and cross well seismic are other techniques for monitoring of leakage from wellbores. These techniques are most applicable during injection operations.

For prevention of future CO_2 leakage from wells, mechanical integrity tests (MI) are the most common means of demonstrating that the CO_2 injection wells have integrity. Although relatively simple in theory, a wide variety of methods could be used for conducting MI tests (MITs), with the applicability a function of the reservoir setting, type of well, location, specific regulatory requirements, and fluids injected. The types of MIT tests that could be considered include: annulus pressure tests (SAPT), annulus monitoring tests (SAMT), radioactive tracer surveys (RTS), water-brine interface tests (W-BIT), "Ada" pressure tests, water in annulus tests (WIAT), single point resistivity test (SPRT), dual completion monitoring tests (DCMT), temperature logs, noise logs, oxygen activation method tests, downhole cameras and visualization tools, and the use of cementing records including cement bond logs and casing inspection logs.

Cement quality and bonding is usually evaluated using sonic and ultrasonic tools, while ultrasonic tools combined with electromagnetic sensing or caliper measurements (Mulders, 2006) provides a means to evaluate casing conditions. (For a more detailed description these varies techniques for testing mechanical integrity of injection wells, see http://www.epa.gov/region5/water/uic/r5guid/r5_05.htm#A).

In the case of CO_2 injection wells, diagnosis of potential leakage of CO_2 from the wellbore is not always easy, and each technique has its unique applicability and each has its strengths and weaknesses (Vrignaud, 2006). For example, cased hole logging is good for tubing, but can only assess production casing during workovers when tubing is removed. Temperature logs help identify hot spots due to flow from deeper formations, while noise logs provide a signature of flow behind pipe.

Looking forward, the CO_2 Capture Project is currently conducting a well “autopsy” and “prognosis” study for use on a decommissioned well that has been used for CO_2 injection for 20 to 30 years. This study is intended to provide quantitative information on well stability during injection, to be extrapolated to provide a realistic prognosis for long term stability and integrity. It is anticipated that this work will provide insights into well design and materials, along with appropriate methods and regulatory criteria for well abandonment, intervention, and remediation (Imbus, 2006).

4. Monitoring and Controlling Geomechanical Effects of CO_2 Injection. The reactivation of pre-existing faults will result in the generation of micro-seismic events which can be monitored with geophysical instruments such as an array of geophones. The purpose of monitoring will be to establish the location of fault-reactivation and the advancement of fluid pressure during CO_2 injection. If the micro-seismic events are detected in the overlying caprock, close monitoring of caprock integrity will be essential.

The monitoring for CO_2-induced micro-seismic events will help detect accidental over-pressuring of the CO_2 storage formation, allowing real-time adjustment of the injection pressure. Passive seismic monitoring will also provide a means to minimize the potential for damage from inadvertent overestimation of maximum sustainable fluid pressures.

Finally, periodic monitoring should be conducted to test for pore pressure/stress coupling during CO_2 injection by performing leak-off tests and hydraulic-fracturing tests to determine the total horizontal stress. However, it is not clear whether the poro-elastic behavior of the reservoir rock during CO_2 injection would significantly affect either effective or total stress on a reservoir scale.

5. Overview of Monitoring Approaches. A number of monitoring approaches are available to help monitor the efficacy of CO_2 storage. The applicability of the various methods will depend, in large part, on the specific storage situation, formation, and site and reservoir characteristics. In addition, and perhaps most importantly, the choice of method will depend not only on its applicability, but also on its cost to implement. Finally, it is quite likely that a combination and/or sequence of approaches will be required over the life of a storage project.

Some monitoring approaches are classified as "indirect" since they infer the presence of CO_2. For example, seismic techniques are based on interpreting sound waves to infer information. In contrast, "direct" monitoring technologies entail the actual measurements of CO_2. Indirect methods can be highly accurate and efficient for monitoring relatively large areas. Direct methods can serve as a useful back stop in the event that something unusual or unexpected happens. Table 4-2 presents monitoring options for a range of potential issues.

Sidebar 9 provides three CO_2 storage monitoring case studies that discuss alternative approaches being used for monitoring at these fields sites.

6. Discussion of Monitoring Technologies.

a). Use of Wellbores for Monitoring CO_2 Storage. Properly designed observation and pressure monitoring wells can provide an important source for information on CO_2 storage project performance.

(1) Observation Wells. Observation wells are drilled within a storage formation some distance from an injection well, and are used to directly measure temperature, pressure, and fluid composition at a specific location. Observation wells are a relatively expensive monitoring option, but provide invaluable data that can be used to "ground truth" both seismic interpretation and reservoir models.

Observation wells can also be drilled into either nearby or overlying formations into which CO_2 is being stored. Fluids can be periodically drawn from the wells and tested for CO_2 contamination. CO_2 seepage through the cap rock can be detected long before any CO_2 would reach the surface. If CO_2 is detected, the observation well can be converted to a CO_2 recovery well.

Table 4-2. Monitoring Approaches for Geologic CO_2 Storage	
Target for Monitoring	Current Monitoring Approaches
CO_2 Plume Location	• Two and three dimensional time-lapse seismic reflection surveys • Vertical seismic profiling and cross wellbore seismic surveys • Electrical and electromagnetic surveys • Satellite imagery of land surface deformation • Satellite imagery of vegetation changes • Gravity measures • Reservoir pressure monitoring • Wellhead and formation fluid sampling • Natural and introduced tracers • Geochemical changes identified in observation or production wells
Early warning of storage reservoir failure	• Two and three dimensional time-lapse seismic reflection surveys • Vertical seismic profiling and cross wellbore seismic surveys • Satellite imagery of land surface deformation • Injection well and reservoir pressure monitoring • Pressure and geochemical monitoring in overlying formations • Microseismicity or passive seismic monitoring
CO_2 concentrations and fluxes at the ground surface	• Real time infrared based detectors for CO_2 concentrations • Air sampling and analysis using gas chromospectrometry • Eddy flux towers • Monitoring for natural and introduced tracers • Hyperspectral imagery
Injection well condition, flow rates and pressures	• Borehole logs, including casing integrity logs and radiotracer logs • Wellhead and formation pressure gauges • Wellbore annulus pressure measurements • Well integrity tests • Orifice or other differential flow meters • Surface CO_2 measures near injector points and high risk areas
Solubility and mineral trapping	• Formation fluid sampling using wellhead or deep well concentrations of CO_2 • Major ion chemistry and isotopes • Monitoring for natural and introduced tracers
Leakage up faults and fractures	• Two and three dimensional time-lapse seismic reflection surveys • Vertical seismic profiling and cross wellbore seismic surveys • Electrical and electromagnetic surveys • Satellite imagery of land surface deformation • Reservoir and aquifer pressure monitoring • Microseismicity or passive seismic monitoring • Groundwater and vadose zone sampling • Vegetation changes
Groundwater quality	• Groundwater sampling and geochemical analysis of monitoring wells • Natural and introduced tracers

Source: Chalaturnyk and Gunter, 2004

SIDEBAR 9. CO_2 STORAGE MONITORING CASE STUDIES

This Sidebar summarizes the monitoring activities underway at three significant CO_2 storage projects - - Weyburn, Sleipner and Frio.

1. IEA GHG Weyburn CO_2 Monitoring and Storage Project

The Weyburn CO_2-EOR and Sequestration Project, led by Encana, is located in southeastern Saskatchewan near the U.S. border with North Dakota. The CO_2 source is from a coal gasification demonstration facility in North Dakota and the CO_2 is transported 204 miles to the Weyburn field, where it is injected into an oilfield to enhance recovery.

The project utilizes advanced 4-D seismic, reservoir simulation and other methods to better understand the behavior of injected CO_2 in the subsurface.

Extensive simulation and monitoring studies (funded through the IEA GHG Programme) are being conducted to assess the fate and transport of the injected CO_2, the quantities of CO_2 stored in the reservoir, and the time expected for the CO_2 to remain sequestered in the reservoir. Results to date indicate:

- Soil gas levels over the CO_2 injection area are normal; with no evidence for escape of injected CO_2 from depth
- Monitoring methods deployed clearly show physical and chemical effects associated with CO_2 injection
- Geochemical processes observed show good spatial correlation in areas with the highest CO_2 injection volumes. These processes include CO_2 dissolution into the reservoir brine, reservoir carbonate mineral dissolution, and an increase in total dissolved solids in reservoir brine
- Good results are obtained from using 4D seismic, with results demonstrating no evidence of CO_2 escape, zones of possible enhanced flow (perhaps due to fractures), and volume estimates accurate to $\pm$ 20%. These results are also contributing to improved simulations.

Source: White, 2004

2. Sleipner/ Saline Aquifer CO_2 Storage (SACS) Project (http://www.ieagreen.org.uk/sacshome.htm)

The Saline Aquifer CO_2 Storage (SACS) at Sleipner project is the world's first commercial-scale CO_2 storage project. Natural gas produced from the Sleipner West field contains about 9% CO_2, which must be reduced to 2.5% before the gas can be sold. CO_2 is separated from the produced gas stream by two absorption columns. The separated CO_2 is then injected into a large, deep saline reservoir, the Utsira formation, 800 meters below the bed of the North Sea. Statoil operates the Sleipner field on behalf of a group of partners, and has implemented several programs to monitor the storage of CO_2 in this unique facility.

The first phase of the SACS monitoring project was completed in December 1999, with the results reported to the European Commission. Since 1996, nearly 1 million tonnes per year of CO_2 has been injected into the reservoir. In the summer of 1999, a seismic survey of the reservoir was completed, with the initial results clearly identifying the position of the injected CO_2 within the Utsira reservoir.

SIDEBAR 9. CO_2 STORAGE MONITORING CASE STUDIES (Cont'd)

3. Frio Brine Pilot Experiment (Hovorka, 2006)
From October 4–14, 2004, the Frio Brine Pilot injected 1,600 tons of CO_2 into a high permeability brine-bearing sandstone of the Frio Formation beneath the Gulf Coast of Texas, USA.

The Frio Brine Pilot experiment is funded by the Department of Energy (DOE) National Energy Technology Laboratory (NETL) and led by the Bureau of Economic Geology (BEG) at the Jackson School of Geosciences, The University of Texas at Austin. Major technical support was provided by GEO-SEQ, a national lab consortium led by Lawrence Berkeley National Lab (LBNL). The project had four major objectives:

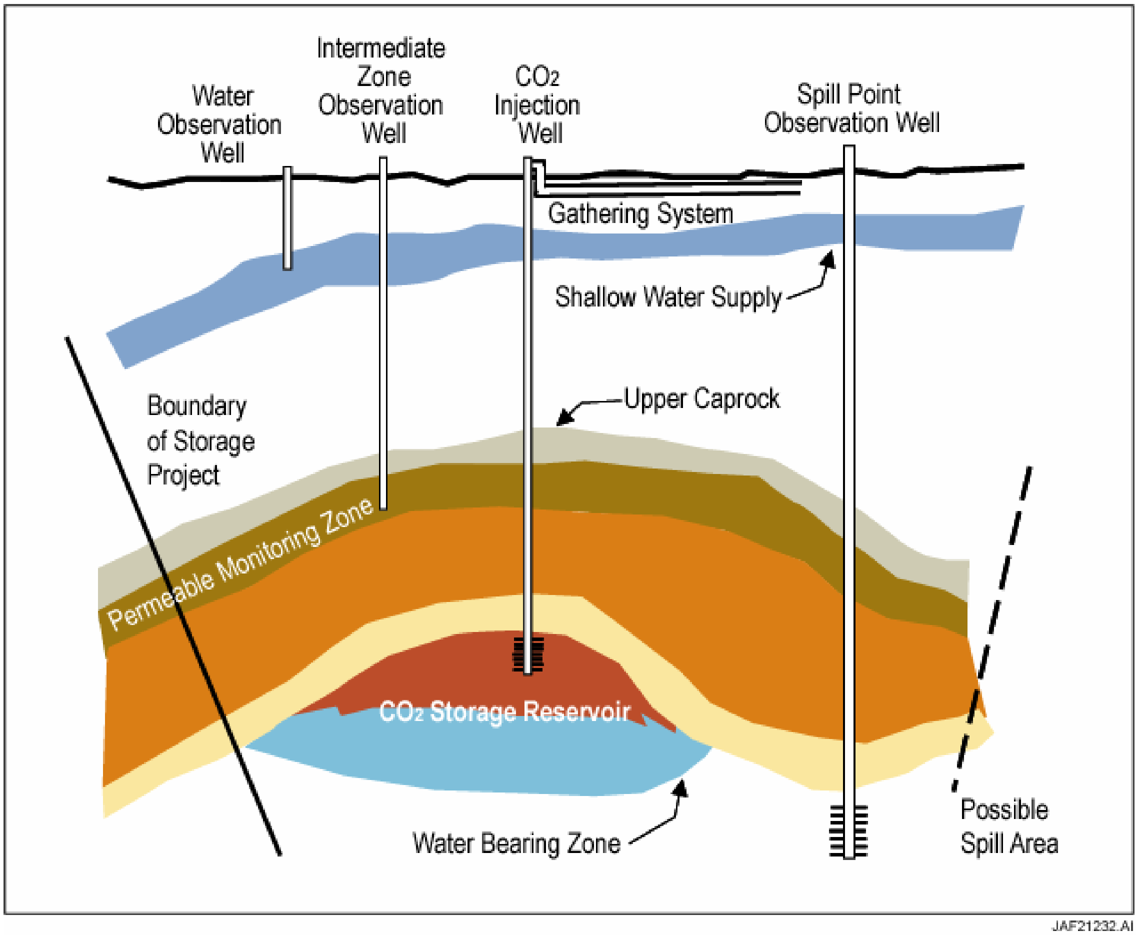
- Demonstrate to the public and other stakeholders that CO_2 can be injected into a brine formation without adverse health, safety, or environmental effects
- Measure subsurface distribution of injected CO_2 using diverse monitoring technologies
- Test the validity of conceptual, hydrologic, and geochemical models
- Develop experience necessary for development of larger-scale CO_2 injection experiments.

Diverse monitoring technologies were tested in both the injection zone and in the shallow near-surface environment. The monitoring results were used to better refine and calibrate the models developed for this reservoir. In general, both geochemical and geophysical monitoring techniques were successfully demonstrated, showing that significant volumes of CO_2 are being stored by dissolution and two-phase trapping in this deep saline aquifer.

Observation wells have been required for some natural gas storage and hazardous waste disposal applications, depending on the risks at a particular site and the discretion of the regulating entity. An overarching theme for observation wells is that they should not compromise the integrity of the CO_2 storage repository.

Figure 4-10 and Table 4-3 set forth four types of observation wells that may be valuable for monitoring at a CO_2 storage site.

Figure 4-10. Monitoring in Natural Gas Storage Fields



Modified after Katz, D.L, and K.H. Coats, *Underground Storage of Fluids*, Ulrich's Books, 1968.

Table 4-3. Alternative Observation Well Options for Monitoring CO_2 Storage

Types of Monitoring Wells	Primary Usage
Injection Well	One or more of the original CO_2 injection wells would remain shut-in for constant measurement of reservoir pressure.
Water Observation Wells	Water observation wells would be drilled to monitor water pressure in the storage interval outside the CO_2 plume.
Spill Point Observation Well	Observation wells could be strategically located to monitor the structural spill point or most likely point for CO_2 leakage out of the structure.
Intermediate Zone Observation Well	Intermediate zone observation wells, located above the storage reservoir caprock, would be used to monitor pressure changes that could be caused by leaks due to lack of well bore integrity or caprock integrity.

(2) Pressure Monitoring Wells. Pressure monitoring wells have been suggested by some researchers as an alternative to seismic and other indirect methods. However, some question whether such pressure transient methods have the sensitivity necessary to detect leakage from a large storage reservoir, and if applied, how many monitoring wells would be required. Preliminary work seems to indicate that in some reservoir settings, such pressure monitoring wells could be effective, though considerably more work is required to further verify their applicability (Benson, 2006).

b). Use of Geophysical Methods for Monitoring CO_2 Storage. A variety of seismic monitoring methods can be incorporated into a CO_2 storage monitoring system.

(1) Seismic Methods. A number of geophysical monitoring approaches and technologies are available to help monitor the efficacy of CO_2 storage, ranging from borehole based seismic to electromagnetic techniques. Seismic technology is currently the workhorse technology for oil and gas exploration, and it will likely be the workhorse for the monitoring of geologic storage of CO_2 as well. However, extensively using seismic methods will be costly.

Fundamentally, seismic technology involves “shooting” the ground (using either an explosion or a large weight) and listening to sound reflections. Different types of rock reflect sound differently and seismic practitioners are able to develop detailed pictures of underground rock formations based on these reflections. Notably, rocks that are saturated with gas or a highly compressible fluid, as opposed to brine, leave a distinctive “bright spot” on a seismic read-out enabling CO_2 to be “observed”.

Historically, a seismic test would consist of one point where the ground was being “shot” and a single line of “receivers” spaced apart with the shooting point in the middle. With the advent of fast computers in the 1970s, seismic tests can now be conducted with a second line of receivers perpendicular to the first and so create a three-dimensional view of the rock. The latest development, and one that is highly useful for CO_2 storage, is time-lapse seismic in which 3D snapshots of a formation are taken over several months and years and the changes observed. This technique is sometimes referred to as 4D seismic, with time being the fourth dimension.

Seismic imaging enables developers to track the progress of the CO_2 plume as it flows up through the storage formation, rises against the caprock, and expands laterally along the caprock. Figure 4-11, from Weyburn, shows a distinctive CO_2 signature (Jazrawi, 2004). This is not surprising given the large difference between the density, viscosity, and compressibility of supercritical CO_2 versus brine. This test provides confidence in the ability of seismic technology to track the CO_2 front, though accurate estimation of CO_2 volume remains a challenge.

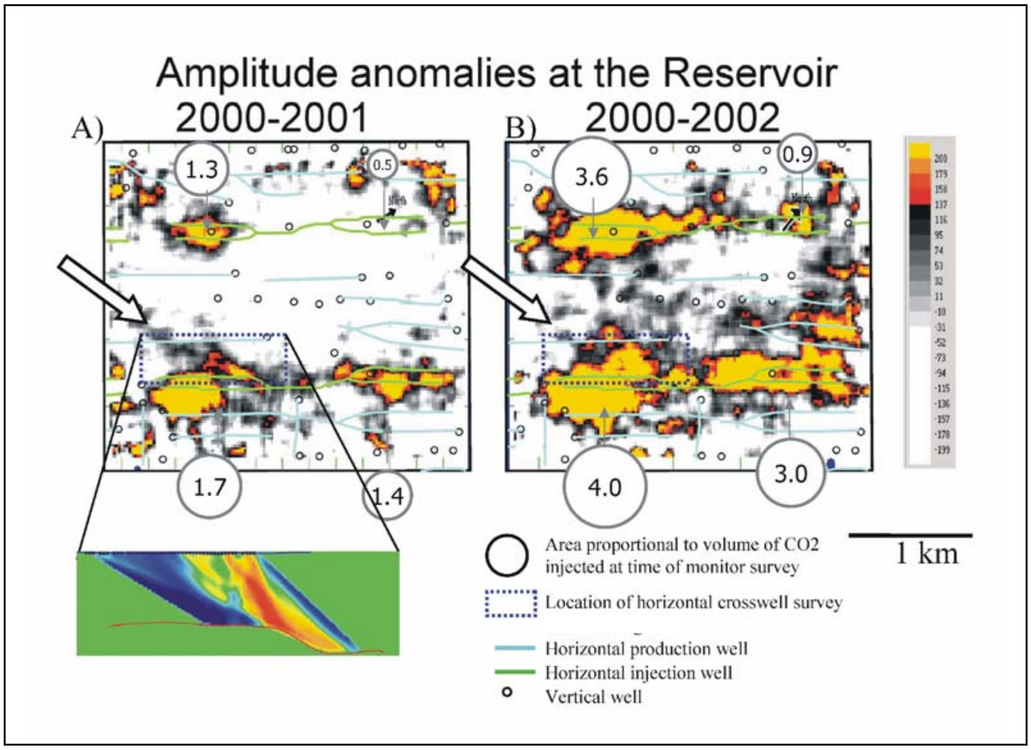


Figure 4-11. P-Wave Amplitude Difference Maps for a) baseline minus 2001 survey, and b) baseline minus 2002 survey, determined from the 3D P-wave surface seismic data within a 4-pattern subregion of the Phase-1A area. A horizontal crosswell survey is shown in an expanded panel in A.

Scientific progress on 4D seismic is moving forward, and high-resolution, time-lapse seismic appears to have considerable promise in most settings. For example, an evaluation of 4D seismic data from Sleipner has shown that both the location of CO_2 in the reservoir and the mechanism through which it is stored can be deduced (Arts, et al., 2004). This is significant as storage via dissolution and pore space trapping is much more stable than "free" supercritical CO_2.

(2) Electrical and Electromagnetic Methods. Electromagnetic methods rely on changes in the electrical conductivity and dielectric properties of fluids caused by different composition. As such, a decrease in brine-saturated fluids should be detectable when CO_2 is injected, increasing CO_2 concentration in the fluid.

(3) Gravitational Methods. Gravitational methods, such as surface and downhole gravity surveys, detect changes in bulk density as a function of changes in density of subsurface fluids and may provide a lower cost geophysical method for tracking CO_2.

(4) Deformation Methods. Minor displacement of the Earth's surface can occur with changes in the pore pressure of a subsurface formation. In a closed storage reservoir, such a change would be caused by the injection of CO_2. This deformation can be monitoring by technologies such surface tiltmeters and perhaps other approaches.

c) Use of Geochemical Methods for Monitoring CO_2 Storage. The carbon associated with the injected CO_2 will have a distinct isotopic composition relative to that in the reservoir fluids. This enables geochemical methods to identify the CO_2 front through fluid sampling. Artificial tracers can also be used to monitor CO_2 movement in a reservoir.

(1) *Measuring CO_2 in Soil*. Soil monitoring has the advantage of being a direct observation, but it has the disadvantages that some leakage pathways may bypass the soil and go directly into the air. Improved technologies to both measure CO_2 fluxes through the soil and to predict soil fluxes from air measurements are being developed.

Even relatively modest CO_2 leakages can cause high CO_2 fluxes and concentrations in the overlying shallow subsurface (Oldenburg and Unger, 2003). A monitoring program for elevated CO_2 in soil may consist of either a sampling and testing program or the operation of a network of accumulation chambers (Norman, et al., 1992). For example, an accumulation chamber (AC) with an open bottom (cm^2 scale) can be placed either directly on the soil surface or on a collar installed on the ground surface. A sample of air is circulated through the AC and the infrared gas analyzer (IRGA). The rate of change of CO_2 concentration in the chamber is used to derive the flux of CO_2 across the ground surface at the point of measurement.

Increased CO_2 in the soil has a negative effect on plant life. The general health of plants and density of different plant species in the area above a geologic storage site can be used as a proxy for monitoring abnormally high CO_2 flux. Importantly, plant health and species modification spatial patterns accumulate over time and so plant surveying methods can pick up on small quantities of leaked CO_2 that would otherwise be hard or impossible to detect by direct observation.

(2) *Measuring CO_2 in Groundwater*. Groundwater monitoring focuses on one of the primary focal points of concern associated with potential CO_2 leakage from a storage reservoir. Groundwater monitoring equipment consists of pumps and a wide variety of possible instruments that can tap into the water table to measure CO_2 concentrations in water. Critical is understanding the amount of free gaseous CO_2 that may be leaking into groundwater, and establishing how much is dissolved in the groundwater. CO_2 instruments to measure dissolved CO_2 include a submerged probe that is covered by a thin organic membrane. When the probe is submerged, CO_2 diffuses through the membrane at a rate proportional to its partial pressure, which is a function of the concentration of the dissolved CO_2.

(3) *Measuring CO_2 in Air*. A variety of techniques exist to measure CO_2 in air. Point detectors for monitoring CO_2 concentrations could be placed strategically at high risk locations, for example at abandoned well locations. Satellite and laser-based analyzers are being developed and have the potential to screen an area as large as several square miles at relatively low cost. Also being developed are methods to precisely quantify the variations in baseline CO_2 concentrations. One such approach is eddy covariance where a tower-based laser spectrometry is used to establish CO_2 flux near the surface (Anderson and Farrar, 2001; Baldocchi, et al., 1996). The detection limits and accuracy of remote/aerial detection methods remains uncertain and needs to be further confirmed.

(4) *Using Tracers*. Tracers are a topic that cross-cut all direct CO_2 monitoring technologies. Natural tracers can enable practitioners to identify the source of detected CO_2. For example, leaking natural source CO_2 will have a carbon-14 signal that is distinct from atmospheric and most biogenic respiration sources (Hoefs, 1987). Other naturally occurring tracers include carbon-13, stable isotopes of O, H, C, S, and N, and noble gases. While there is an extra expense in

testing a sample of CO_2 for natural tracers, such an analysis can provide definitive information in a situation where the flux measurements indicate a possible leak.

Another approach is to inject a minute amount of an artificial tracer (e.g., perfluorocarbons, PFTs) with the CO_2 to be stored. Generally, by design, the artificial tracers are easy to detect at low levels. Also, one can vary the amount of tracer or change tracers during CO_2 injection to gain detailed information about the CO_2 flow paths. At present, such approaches are primarily aimed at gaining scientific understanding, and may not be a part of a monitoring program for a commercial demonstration.

V. REMEDIATION OPTIONS FOR CO_2 LEAKAGE

All CO_2 storage projects will be designed and conducted with the goal and expectation that no CO_2 will leak from the containment formation. But, unexpected things can and do happen. Therefore, this Chapter discusses remediation actions designed to address the highest likelihood CO_2 leakage events. This will accomplish two purposes: (1) the monitoring and pre-preparation actions associated with remediation will enable quick action to be taken once evidence of a leak or other problems are observed; and (2) the pre-established documentation of expected risks will provide an established understanding of the potential impacts of particular leakage events, which will greatly help guide the appropriate remediation efforts.

Much can be learned from past efforts to remediate oil and gas reservoirs and gas storage reservoirs that have leaked. A portion of this past learning has also been incorporated into this Chapter, Remediation Options for CO_2 Leakage.

A. RESERVOIR ASPECTS OF REMEDIATION

The remediation actions, should leakage occur, will depend, to a considerable extent, on the type of reservoir in which the CO_2 is stored, as discussed below.

1. Depleted Oil and Gas Fields. CO_2 stored in this class of structurally confined reservoirs will most likely be the most effectively contained and easiest to monitor, offering the best chance of successful remediation.

Once leakage has been detected, the first step would be to measure, as possible, the extent and nature of the leakage, which will help guide the method and pace of remediation. For example, if leakage merely transports CO_2 into a securely sealed, secondary storage reservoir, remediation may not be needed. On the other hand, if the CO_2 leak is detected at the surface, prompt action will be essential.

Initial steps for remediating minor leakage in wellbores may involve injecting mud, cement, or conformance-enhancing polymers to seal off the suspected leakage source. Should these steps fail or should leakage be worryingly rapid, a more radical approach may involve producing CO_2 back up the injection wells to the surface, then reinjecting the CO_2 into a more secure stratigraphic zone or reservoir within the field, or even transporting it to another site, preferably without venting. Contingency plans to deal with leakage will be needed for each CO_2 storage site in an oil and gas formation, so that remediation action can be taken promptly should leakage occur.

However, it is important to recognize that, as a remediation measure, extraction (or production) and transportation of the injected CO_2 without venting, while recommended, can be a complicated, time-consuming, and costly process. In particular, considering the very large volumes of CO_2 being stored, transporting and injecting it at another site may take years of design and construction. One or more production wells will be needed, and a pipeline may be needed if the leakage is at a different location from where the leakage is occurring. While the new storage operation is being put in place, venting may be unavoidable.

2. Saline Formations. CO_2 stored in saline formations, particularly those lacking structural closure, will be much more challenging to access and recover should remediation be necessary. Over time, CO_2 injected into a saline formation becomes increasingly dispersed due to the regional hydrologic flow.

Like that for other settings, the first step will involve, to the extent possible, determining the location, nature, and extent of the leak. Wellbore leaks in saline aquifers can be addressed in a manner similar to that in oil or gas reservoirs. In cases where the leakage has been caught early and the risks posed are low, the most prudent option may be to just stop injection in the location near the leakage and allow the reservoir to stabilize. However, this will only work if the CO_2 leakage is driven mainly by a lateral pressure differential away from the injection well, and not by CO_2 buoyancy, or a significant pressure differential in the vertical direction.

If the CO_2 leaked is significant, it may be necessary to produce the CO_2 from the reservoir near where the leak occurred, and reinject the CO_2 elsewhere in a more suitable location in the saline formation or in an alternative geologic structure, as described for depleted oil and gas reservoirs above.

Contingency plans to deal with leakage events, should they occur, will also need to be developed for each storage project injecting into a saline aquifer.

In general, regardless of the type of geologic storage formation, other than plugging the source of the leak (such as in a wellbore or fracture), if possible, there are three basic mechanisms to stop leakage from the reservoir:

- Reduce the pressure in the storage formation
- Increase the pressure in the formation into which the leakage is occurring
- Intercept the CO_2 plume and extract the CO_2 from the reservoir before it leaks such that it poses undue risks, and, if possible, reinject in another formation.

These scenarios and actions are discussed in more detail in the paragraphs below.

B. CLASSIFICATION OF CO_2 LEAKAGE SCENARIO

A number of authors have set forth potential sub-surface leak scenarios around which CO_2 storage remediation can be structured. For example, Espie (2005) summarizes three main sub-surface leak events, as follows:

- Seal failure (capillary failure, faults and fractures)
- Bypassing of trap (spillage, aquifer migration)
- Wellbore failure.

A more detailed categorization of potential CO_2 escape mechanisms has been set forth by the Australian CO2CRC, as displayed in Figure 5-1. In addition, the CO2CRC has, in a very brief form, matched each potential escape mechanism with a potential remediation measure. In addition, Perry (2005) offers a series of conceptual mitigation steps that apply in the case of a leak in an aquifer gas storage field. In general, these conceptual steps would apply, perhaps with some modification, to any type of geologic storage, including CO_2 storage. These steps are summarized as follows:

1. When a leak is first observed or reported, the geographic area of the leak should be surveyed for homes, farms, businesses, etc., that could be

impacted or endangered. State and local officials should be notified as necessary and/or required.

2. Injection into the storage reservoir, at least in the vicinity of the leak, should be halted immediately.

3. An investigation into the source of the leak should begin immediately.

    - Other wellbores, if they exist, should be checked for anomalous pressures.

    - Well logs may be run in suspect wells.

4. In the case of a suspected caprock leak, the local geology should be reviewed for the most likely area of CO_2 accumulation above the storage zone. (Ideally, this characterization should have been done as part of the site selection process, and should be readily available.) These secondary CO_2 accumulation settings will generally consist of permeable, porous formation above the storage formation, with some type of impermeable caprock overlaying it.[3]

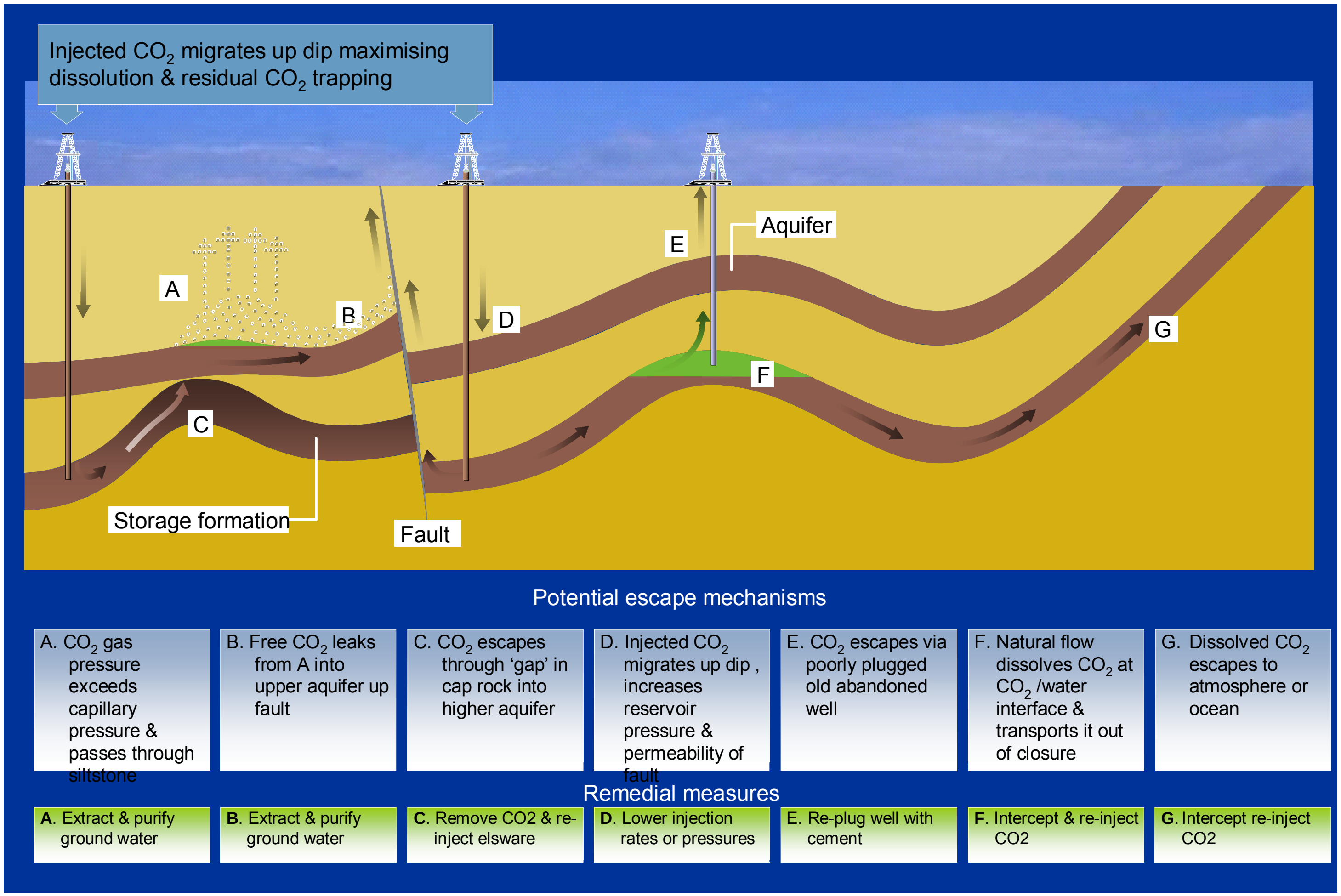
5. Once the shallow geology is reviewed, a study should be conducted integrating all information on hand, such as the surface location of the CO_2 leak in relation to structural high points in shallow zones.

6. Based on this information, one or more wells may need to be drilled in the shallower zones to locate and recover any CO_2 migrating to those zones.

7. This process may need to be repeated and modified if the first wells do not locate the migrating CO_2, or if the CO_2 has migrated to multiple horizons.

[3] A good description of this process for geological investigation, as it applies to gas storage reservoirs, is provided in Katz and Coats (1968)

Figure 5-1. Overview of Potential CO_2 Escape Mechanism and Associated Remediation Measures



Source: Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC).

8. Alternatively, the leak, depending on circumstances, may also be controlled by lowering the pressure in the storage zone, or by creating a hydraulic barrier by increasing the pressure upstream from the leak

9. The final mitigation step is to either plug the leak, if located, or reconfigure that storage operation to reduce the likelihood of future leakage.

Sidebar 10 summarizes four CO_2 leakage scenarios and the remediation options available to mitigate and address these problems.

SIDEBAR 10. REMEDIATION OPTIONS FOR CO_2 LEAKAGE FROM GEOLOGICAL STORAGE PROJECTS (Modified from Benson and Hepple (2005).

Scenario	**Remediation Options**
1. Leakage through caprock	• Lower injection pressure by injecting at a lower rate or through more wells; • Lower pressure by removing water or other fluids from the storage reservoir; • Intersect the leakage with extraction wells in the vicinity of the leak; • Create a hydraulic barrier by increasing pressure upstream of the leak; • Stop CO_2 injection and produce the CO_2 from the storage reservoir and reinject it into a more suitable storage structure.
2. Leakage Out of Confining Structure	• Injection into the storage reservoir should be halted immediately. • Begin investigation into the source of the leak immediately; check wellbores for anomalous pressures, run well logs on suspect wells • Review local geology for the most likely area of CO_2 accumulation above the storage zone. Integrate all information on hand, such as the surface location of leak in relation to structural high points in shallow zones. • Based on this information, drill in the shallower zones to locate and recover any migrating CO_2, or control by lowering the pressure in the storage zone, or by creating an hydraulic barrier by increasing the pressure upstream from the leak • The mitigation step is to either plug the leak, if located, or reconfigure the CO_2 storage operation to prevent further leakage.
3. Leakage due to lack of well integrity	• Repair leaking injection wells with standard oil and gas field well recompletion techniques; • Repair leaking injection wells by squeezing cement behind the well casing to plug leaks behind the casing; • Plug and abandon injection wells that cannot be repaired by any method, including the two main methods listed above;
4. Leakage due to well blow out	• Remediate injection or abandoned well blow-outs with standard techniques to 'kill' a well such as injecting a heavy mud into the well casing. • If the wellhead is not accessible, a nearby well can be drilled to intercept the casing below the ground surface and 'kill' the well by pumping mud down the interception well.

In most cases, the geologic and engineering effort, analysis, and time associated with such mitigation would be comparable to, and may often exceed, that associated with site selection, project design, and construction and development. Inevitably, attempts to save money and time on the front end site selection and project design phase would likely result in losses, perhaps several times over, in the geologic, engineering and development effort undertaken to remediate problems that may result from inadequate work up front.

This Chapter will use the seven part categorization of potential CO_2 leakage mechanisms set forth in Figure 5-1 and develop, in more depth, the set of remediation measures the could be used to address, mitigate and correct a CO_2 leakage problem.

1. CO_2 Leakage Due to Seal Failure. The first four leakage mechanisms, shown as A, B, C and D in Figure 5-1, involve leakage of CO_2 through the caprock, either due to excess gas pressure, CO_2 buoyancy, and/or the presence of a permeable (non-sealing) fault or fracture. The appropriate remediation plans and actions will need to take into consideration the specific seepage pathway of the leaked CO_2. In some cases, it may be that the leaked CO_2 will be passively dissipated or contained in upper, secondary storage formations and no action needs to be taken. However, in most cases, remediating this problem will be required, involving the following steps:

a) *Locating and Sealing Leaks in the CO_2 Storage Reservoir Caprock.* The first step would be to locate the source of the leak. The likely pathways could be natural or induced faults or fractures located near a steeply dipping flank of a confining structure. A variety of tests could be used to locate, as closely as possible, the source of the leak, including:

- Undergound pressure and flow monitoring
- Tracer surveys
- Subsurface injection and production tests
- Seismic surveys and analyses.

The first three may require new wells and access to the subsurface, and likely a period of time to conduct conclusive monitoring.

Technologies for locating CO_2 leaks should be a subject of future R&D. For example, the above noted techniques were used to attempt to locate a leak in a Midwestern Mt. Simon aquifer gas storage field with inconclusive results.

b) *Locating and Remediating the Accumulation of Leaked CO_2*. More likely, if the CO_2 has leaked through the caprock, portions of it could accumulate in, shallower strata. An investigation of the local geology surrounding the leak, as well as the use of advanced seismic techniques, could indicate which of the strata might be storing portions of the leaked CO_2. A likely secondary storage or accumulation might exist in the structural high points of shallower formations overlain by competent caprock.

It is again important to note that an investigation of the geology around the leak, as recommended, may require new wells to be drilled, which may, perhaps, increase the risk of future leakage.

Having identified the formations holding the leaked and stored CO_2, the next step would be to drill a series of shallow wells into the strata holding the leaked CO_2 to capture and remove the accumulated CO_2. This action will also serve to lower the pressure in the zone, helping mitigate CO_2 movement to the surface.

c). *Other Actions to Mitigate and Further Remediate Caprock Leakage.* To reduce the rate of CO_2 leakage through the caprock, faults or fractures, several steps could be taken, as follows:

- The pressure in the storage reservoir could be lowered by withdrawing water or CO_2 from the storage reservoir.
- The pressure in the strata above the storage reservoir could be increased by injecting water into the strata.

Both of these steps would lower the driving pressure between the storage reservoir and the overlying strata, reducing (or eliminating, at least temporarily) the rate of CO_2 leakage if this driving pressure is the primary contributor to the extent and nature of the leakage.

Assuming that the location of the leak has been established, the remediation approach would be to attempt to seal the leak by drilling a nearby well and injecting foam, time setting gels, or cements; or using other sealing substances to close the leakage pathway (Perry, 2005). However, while theoretically possible, this caprock remediation technique has yet to be accomplished in actual practice.

d) *Abandoning the Leaking CO_2 Storage Reservoir*. Should the above three approaches for remediating CO_2 leakage through a caprock not be successful, the final alternative would be to deplete and abandon the initially selected CO_2 storage reservoir and store the CO_2 in an alternative, more secure location.

2. Leakage Out of the Confining Structure. The next two leakage mechanisms, shown as F and G in Figure 5-1, involve leakage of CO_2 out of the confining structure. As discussed in more depth in Chapter III: Leakage Pathways, the "leakage" (movement) of CO_2 out of a confining structure may de due to: (1) natural hydrodynamics of a saline formation that transports dissolved CO_2 out of a closure; or (2) excess injection of CO_2 past the confining "spill point" of the formation. Once the CO_2 has escaped its confining structure, the horizontal leakage of CO_2 can readily turn vertical and escape through a permeable pathway or an outcrop to the atmosphere.

Obviously, proper site selection and project design, with appropriate precautions taken for geologic and operational uncertainties, should ensure that leakage outside of the confining structure does not occur. In addition, proper monitoring and reservoir modeling during injection operations should also play a key role in ensuring that leakage outside of the confining structure does not happen. However, if such overfilling does occur during injection operations, and some of the stored CO_2 leaks out from the formation, injection should cease immediately, and the remediation steps described above for leakage through caprock should be implemented.

3. Leakage Due to Lack of Well Integrity. The third leakage mechanism, shown as E in Figure 5-1, involves leakage of CO_2 from loss of well integrity. This may be due to: (1) a poorly designed and constructed CO_2 injection well; (2) an unanticipated well failure, such as a parted casing; or (3) a poorly plugged old, abandoned well.

The natural gas production and storage industry has well-developed capabilities for repairing small leaks in injection wells. These include replacing the tubing or re-cementing the well. Casing leaks can be stopped by injecting heavy mud into the well. If the leaking well is not accessible, a nearby well can be drilled to intercept the casing below ground and stop the leak.

Of particular concern is CO_2 leakage through poorly plugged and abandoned wells. A number of states have programs that address this topic because, in addition to serving as potential CO_2 leakage pathways, poorly plugged wells may cause other potential problems, such as contamination of groundwater and leakage of hydrocarbons into the atmosphere.

Sidebar 10 presents information from the Indiana Department of Natural Resources that addresses the topic of "Orphaned and Abandoned Wells in Indiana."

a) *Insuring Wellbore Integrity*. Of all of the possible leakage pathways from a geologic storage reservoir, leakage through operating injection and production wells and through improperly abandoned wells are the most likely. In general, based on current knowledge and practice, wellbore integrity is a greater concern than the geologic integrity of the reservoir. This is because considerable attention is being given to finding storage areas with a competent seal and a confining structure.

However, restoration of well integrity if a wellbore does leak is a more challenging topic. Leakage can occur though the wellbore, through the annulus between the well tubing and casing, or on the outside of the casing. Figure 5-2 provides a schematic diagram of a wellbore showing potential CO_2 leakage pathways.

In addition, similar to production and injection wells, it is important to recognize that improperly documented or poorly completed CO_2 injection wells could represent an operational liability; affecting injection rates, reservoir pressurization, and/or production. Consequently, during operations, wellbore leakage problems will generally be recognized relatively quickly, allowing them to be quickly addressed by the operator.

SIDEBAR 10. ORPHANED AND ABANDONED WELLS IN INDIANA

How many oil and gas wells are there in Indiana? There have been more than 70,000 oil and gas wells drilled in Indiana. Many were drilled during the original "gas boom" in east central Indiana that began in the 1890's. About 5,000 wells are in use today. While Indiana had well plugging standards as early as 1893, many methods used to abandon wells prior to 1947 do not meet modern standards.

Why does a well need to be plugged?
When no longer used for production of oil or gas, a well is required to be plugged to ensure that:

- it does not cause or contribute to the contamination of ground or surface water;
- it does not allow oil, gas, or water to discharge onto the ground or into the air;
- all oil, gas, and water are confined in their original formations; and
- the well does not pose a hazard to public health or safety or interfere with agricultural or other uses of the land after the well is no longer in active use.

Who is responsible for plugging the well?
Indiana law requires a well to be plugged by the owner or operator whenever it is no longer used for oil or gas production. In addition to plugging it, the operator is required to remove all equipment used in the production of the well and restore the site to a suitable condition.

How is a well plugged? After all of the tubing and other equipment in the well is removed, the well is plugged with Portland Cement. The cement plug is placed in the well across all zones that had produced oil or gas and also from below the base of the deepest fresh groundwater zone to the top of the well to ensure that all fresh groundwater zones are protected with a solid column of cement.

How will I know if I have an abandoned well on my property? Unless the well casing, wellhead, or surface production equipment is still present, it can be difficult to determine whether an abandoned oil or gas well is on your property. Many of these wells have been found buried under buildings, driveways, as well as streets and highways. Some signs that may indicate an abandoned well are:

- areas of distressed vegetation;
- areas where the ground has settled or caved in from a collapsed wellbore;
- oily or salty water seeps;
- the odor of natural gas or crude oil; or
- a water well contaminated with saltwater, crude oil, or natural gas.

How many orphaned or abandoned wells are there in Indiana? The number of inventoried orphaned or abandoned wells as of July, 2006, was 1,323. This list is continually updated as new wells are added and as wells are either plugged or returned to production by other operators.

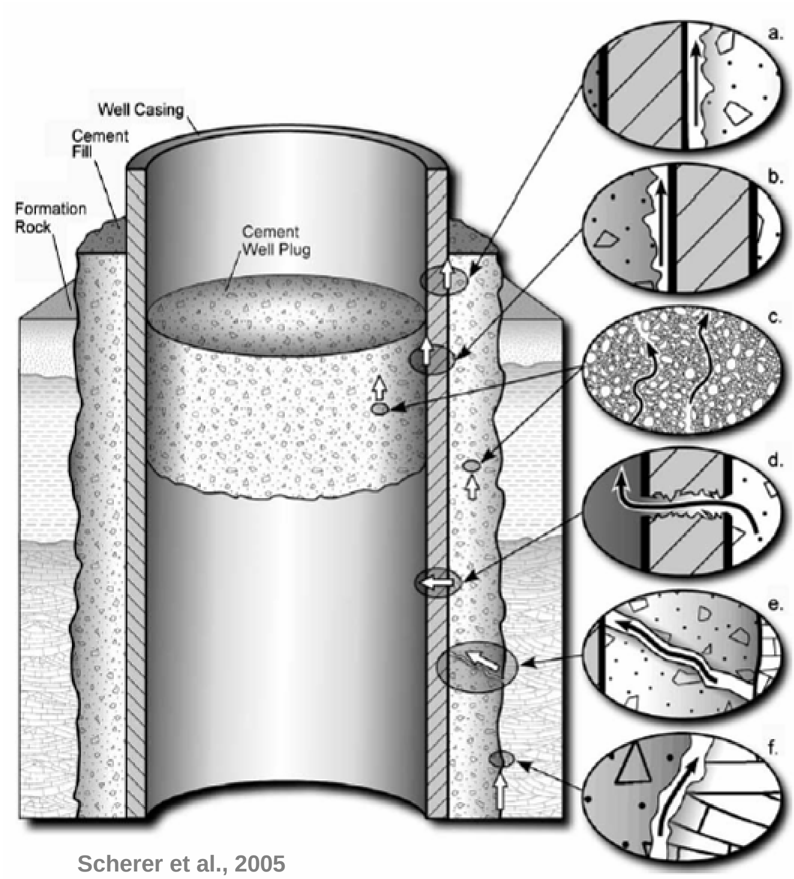
What are the procedures for plugging an orphaned or abandoned well? By law a representative from the Division of Oil and Gas must witness oil or gas well plugging operations. In addition to safety and environmental concerns previously mentioned, cutting the casing off from an abandoned well and covering it with soil or other material is an unacceptable method of plugging which can create substantial risks to public health or safety and result in the contamination of groundwater.

Never attempt to remove abandoned equipment or abandon a well without first notifying the Division of Oil and Gas and seeing that the work is performed by an experienced well plugging contractor.

Source: Indiana Department of Natural Resources, Orphaned & Abandoned Well Program www.dnr.IN.gov/dnroil

Appendix 1 to this report provides the "Casing, Cementing, Drilling and Completion Requirements for Onshore Wells", as set forth in Rule 3.13 of the Texas Administrative Code and as administered by the Railroad Commission of Texas, Oil and Gas Division.

Figure 5-2. Schematic Diagram of Wellbore Showing Leakage Pathways



b) *Identifying Leakage in Wellbores*. Leakage through wellbores can occur in two main ways:

- Through loss of wellbore integrity. This mechanism is more likely to result from slower processes related to the age of the well and the materials used in its completion and/or plugging.
- Through well blowouts: Though relatively rare, notable case studies have demonstrated the significant impacts should well blowouts release large amounts of CO_2. This would most likely occur as a result of poor completion practices. Because of higher safety danger of CO_2 well blowouts, this topic is discussed in more depth in a separate section of this Chapter.

The larger focus of concern is the long-term integrity of wellbores in the presence of stored CO_2 in a geologic reservoir, particularly in storage fields that are no longer in operation. Factors affecting overall wellbore integrity and the potential for leakage include the drilling and completion practices used, the technical competence of the company that drilled and completed the well, the quality and integrity of the materials used, and the age and operational history of the well. Of particular concern are older operating and abandoned wells that may not have been plugged to more recent standards – newer wells are generally drilled and completed to higher specifications designed to reduce the potential for leakage.

c) *Addressing Wellbore Integrity Concerns*. Addressing concerns associated with wellbore integrity in CO_2 storage projects involves the following:

- Characterizing the location and condition of old wells, including production, injection and abandoned wells.
- Selecting CO_2 storage sites where the impacts of wellbore leakage from existing, abandoned, and new wells are minimal and/or manageable.
- Understanding leakage and corrosion mechanisms in wellbores, along with effectively modeling these processes in field conditions, by developing techniques to better understand and model the mechanisms contributing to wellbore integrity problems.
- Evaluating the reactivity of well construction materials to CO_2, and selecting materials that can withstand exposure to CO_2 over sufficiently long periods to minimize the effects of corrosion.
- Developing and implementing effective, low-cost techniques for monitoring wellbores for leakage, to identify in the early stages of injection the likely wellbore integrity problems.
- Developing and implementing well completion practices and configurations to reduce the potential for wellbore leakage of CO_2 in operating wells, including well design, materials, and construction.

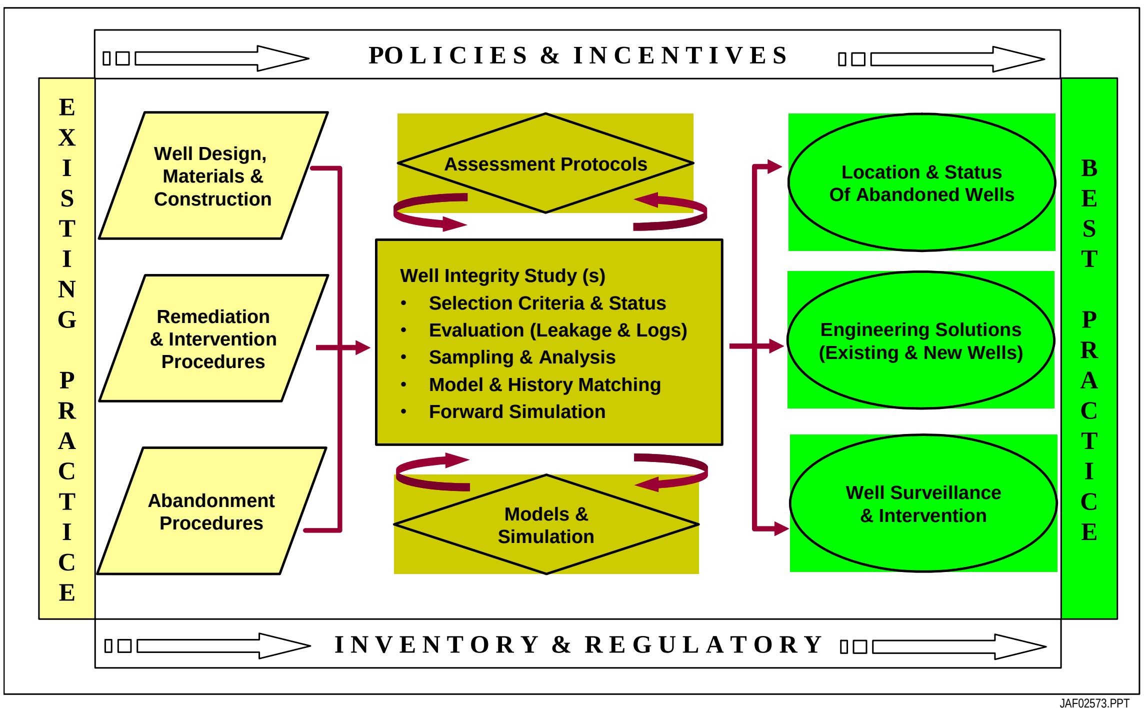
- Developing and implementing effective, low-cost techniques for monitoring wellbores for leakage.

- Developing and implementing well plugging procedures to reduce the potential for wellbore leakage in abandoned wells.

- Intervening and mitigating any problems once identified, through plugging practices and other wellbore leakage remediation actions.

Such a multi-phased approach is illustrated schematically in Figure 5-3. Each of the various aspects associated with addressing the issue of ensuring wellbore integrity is discussed in the following sections.

Figure 5-3. Comprehensive Well Integrity Program



Source: Imbus and Stark, 2006

d) *Locating and Characterizing Existing and Abandoned Wells*. In many regions of the world, such as the United States and Canada, existing fields may contain hundreds of wells that have been abandoned, or that are currently idle. In the U.S., as many as two million wells have been drilled to produce oil and natural gas, with over one million wells drilled in Texas alone. Likewise, in the Alberta Basin in Canada, nearly 400,000 wells have been drilled to date. Additional wells are used in gas storage operations, and for injecting (predominantly liquid) wastes and acid gases.

Locating and characterizing the condition of these wells is a formidable task. The experience from an exercise to develop a database of wellbores just at the Weyburn oil field alone shows that even in an area that has good public records there are lots of gaps (Princeton, 2004). In many areas of the world, extensive well completion records will not have been kept or have been lost. More importantly, well completion and abandonment approaches, technologies, and regulatory requirements have evolved and improved over times – implying wells drilled and/or abandoned many years ago most likely do not meet today's standards.

Currently, in most established oil and gas producing areas, applicants for injection well permits are required to conduct an "area of review", or AOR, as part of the permit application process. The objective of an AOR is to identify any potential conduits for the flow of injected fluids from the proposed well out of the intended formation, and remediate any conduits to flow that could exist. Within the AOR, the permit applicant must identify and determine the age and condition of any existing and/or abandoned wells.

In the United States, the AOR, while varying somewhat from state-to-state, is generally defined as ¼ mile (about 0.4 kilometers) for saltwater injection wells, and 2.5 miles (about 4 kilometers) for hazardous waste injection wells. Sometimes, the AOR is determined by formula based on reservoir conditions.

Similar procedures will need to be applied to CO_2 storage wells as well. However, traditional approaches assume that the injectant is liquid, usually saline brine. In the case of CO_2 storage, the buoyancy of the CO_2 adds another dimension to be considered in establishing an appropriate AOR for CO_2 storage. This may imply the need for establishing an AOR requirement based on both reservoir conditions and the likely volume of CO_2 to be injected. This will help assure that the potential "zone of endangering influence", or ZEI, is not larger than the applied for AOR (Nicot, et al., 2004).

Other mechanisms could also be used to locate and characterize previously drilled wells. For example, research is underway to use high resolution magnetic (Xia, et al., 2003), soil gas surveys[4], and/or other techniques to locate abandoned wells. No matter the method for locating and characterizing abandoned wells, and wells that may pose a risk of leakage will need to be remediated. In general, these wells will need to be re-plugged using state-of-the-art techniques designed to be resistant to CO_2-laden fluids (see discussion below).

Developing national databases of plugged and abandoned wells might be considered, but this will not be an easy task. Moreover, in addition to a historical record of past drilling, some type of regulatory body would need to maintain records of all future wells drilled. Ideally, these databases should contain details on the well locations and the processes and materials used for plugging and abandoning these wells. Issues to consider include establishing responsibility for developing such a database and for implementing remediation measures, once the reservoirs have been abandoned and after injection operations have ceased.

e) *Well Completion and Plugging Practices*. The integrity of wellbores over hundreds or thousands of years will be one of the primary considerations in establishing the "permanence" of geologic storage. Therefore, it is important that operational procedures and regulatory mechanisms are established to ensure minimal leakage of stored CO_2 from both operating and plugged and abandoned wells.

[4] http://www.microseeps.com/html/carbon_seq_latest.html

Current requirements for injection wells in the United States and elsewhere, including those for gas and water injection in oil recovery operations, gas injection for storage, and waste disposal, have resulted in a good history of performance. In fact, EPA states that "…When wells are properly sited, constructed, and operated, underground injection is an effective and environmentally safe method to dispose of wastes."[5] The record of performance in the current applications of CO_2 injection for enhanced oil recovery has also been exemplary (Grigg, 2002). The same standards should apply to CO_2 storage.

The issue of wellbore integrity as it relates to CO_2 storage has been explored extensively in several recent workshops sponsored by IEA GHG.[6] These workshops have investigated the cases where failures have occurred, to understand why they occurred, and have begun to develop approaches to minimize such occurrences in the future. Work to date has focused on the development and testing of well materials that are resistant to the effects of CO_2.

In general, wellbore leakage problems are identified by sustained casing pressure (SCP), or excessive pressure in the annulus of the wellbore, indicating a failure in the pressure envelope of the well. This can be caused by leaks in packers, tubing and/or casing failure, cement degradation (including at the interface of the reservoir and the casing), wellhead leaks, and potential fractures and faults intersecting the wellbore.

Specific standards are established for injection wells used in oil and gas recovery operations, which also include CO_2 injection wells for enhanced oil recovery.[7] Moreover, based on over 30 years of experience, current CO_2 operators have, by necessity, developed well design and completion standards for CO_2 injection wells to minimize corrosion and wellbore leakage. These designs utilize corrosion resistant cements, casing, tubulars and packers, as well as preferred methods for stimulating CO_2 injection wells to enhance injectivity.

Some of the more important features of the most recently established well completions designs are described below.

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[5] http://www.epa.gov/safewater/uic/whatis.html
[6] http://www.co2captureandstorage.info/networks/wellbore.htm
[7] http://www.epa.gov/region5/water/uic/r5guid/r5_05.htm#A

(1) Well Cements. Leakage due to well cement failure appears to be the most common mechanism for wellbore failure (Chalaturnyk, 2006). In particular, traditional Portland cements used in well drilling and plugging operations are known to degrade in the presence of CO_2, especially if water is also present. The process involves carbonation of the primary cement constituents, where Portlandite and calcium silicate hydrates are converted into carbonate minerals such as aragonite, calcite and vaterite. This degradation results in a loss of density and strength, and an increase in porosity of the cement. Efforts to date show that, at least under laboratory conditions, this degradation can occur quite rapidly. However, the degradation process is quite complex, and further work to understand the processes involved is required.

Limited field investigations have shown that cement degradation also occurs in the field, but has not been a major problem. Cement has not been a particular problem in the West Texas CO_2-EOR projects, some of which have been underway for 30 years. Cement failure was not the cause of the blowout at the Sheep Mountain CO_2 field, discussed elsewhere in this report (Christopher, 2006). In some field studies, CO_2 pathways appear along the casing-cement and cement formation interfaces (Figure 5-2, above), though the amount of CO_2 that would leak along these interfaces is not clear. Moreover, the degree and rate of the reaction may not necessarily be comparable in the laboratory and the field. Important factors believed to control this rate include water saturation and relative humidity, the age of the cement, and the ratio of water to cement.

Collaborative efforts are underway by researchers with the Carbon Mitigation Initiative (CMI) at Princeton University, in collaboration with the DOE's Rocky Mountain Oilfield Test Center (RMOTC) at the Teapot Dome field in Wyoming. CMI will acquire samples of cement from old wells, attempt to recreate the cement/formation interface to replicate existing properties, and seek to better understand the properties and failure mechanisms in old cemented wells.

Research by the CO_2 Capture Project is attempting to characterize the responsiveness of Portland cement to extended CO_2 exposure, with the goal of developing a comprehensive, systematic understanding of degradation mechanisms and rates, and the development of specifications for new cements and sealants applicable to CO_2 storage applications (Imbus and Christopher, 2004). Moreover, this work is attempting to understand how cement composition, additives, water chemistry, and the conditions of curing impact this process.

In addition, both academic and industry researchers are conducting novel experiments to assess the potential for cement failure in wells (Barlet-Gouedard, et al., 2004). These experiments are focusing on the factors impacting well cement degradation, and on the physical and chemical changes that occur at the interface where the well cement and reservoir rock meet. This work is looking at the impact of carbonate brines and high pressures on potential corrosivity and wellbore failure. Early geochemical experiments have shown that pressure has only minimal effects on mineral dissolution in deep aquifers.

Moreover, this work is looking at alternative cements and sealants applicable to CO_2 storage applications. These could potentially include calcium phosphate cements, which appear not to be affected by exposure to CO_2, or other non-reactive cements under development by service companies. In this regard, some standard methods for testing cements for application in CO_2 storage projects will probably be necessary.

(2) Casing and Tubulars. CO_2 resistant casing and tubulars are also critical to minimizing leakage from CO_2 storage wells. Combinations of corrosion and/or erosion mechanisms seem to cause an increase in the rate of metal loss compared to the summation of separate mechanisms (Mulders, 2006). To minimize corrosion in production tubing, most operations are utilizing specialized stainless steel tubulars set to high standards (such as API 5CT), much of which is plastic or poly-lined. In addition, corrosion resistant connectors, packers, wellheads, and rings are being used at current operations to minimize corrosion to CO_2 (Larkin, 2006).

(3) Alternative Well Designs and Configurations. To minimize the potential for leakage, industry groups have developed guidelines and standards, such as recent standards on flow prevention and remediation through practices aimed at isolation of potential flow zones (Sweatman, 2006). Moreover, alternative designs and well configurations are being considered to minimize risk even when wellbore leakage occurs.

(4) Well Plugging and Abandonment Practices. While regulatory standards and industry guidelines for well plugging are well established and common,[8] new standards for CO_2 storage wells will probably need to be established. These standards are likely to evolve over time as new knowledge on corrosion resistant materials and plugging practices improves.

4. Leakage Due to Well Blowout. Well blowouts for wells in CO_2 storage are essentially no different that those associated with wells in natural gas production operations (in particular those from gas fields containing relatively high concentrations of CO_2) or associated with natural gas storage operations. The lessons learned from previous well blowouts have formed the regulatory requirements and industry practices, such as standards and recommended procedures published by the American Petroleum Institute and the UK Offshore Operators Association.

Appendix 2 to this report sets forth the Texas Administrative Code Rule 3.20 for "Notification of Fire Breaks, Leaks and Blowouts". Appendix 3 provides State of Utah regulation for "Reporting of Undesirable Oil and Gas Events."

One particularly important distinction for CO_2 relative to natural gas storage is the fact that CO_2 is generally injected, and will likely be stored, in a supercritical state. Should pressure control be lost in the reservoir, like that from a blowout, the phase change from a supercritical fluid to a vapor results in significant and rapid expansion of the CO_2, a process that can be extreme and violent. Because of the rapid expansion in pressure, flow rates for CO_2 in this situation, especially if through small openings, can reach sonic velocities.

In addition, this expansion can lead to rapid cooling of the wellbore and fluid streams. In some cases, solid dry ice particles can form quickly in the wellbore and surface equipment, can create a "cloud" around the well reducing visibility, and may be forced out of the well as pea-to-marble sized projectiles at very high velocities.

[8] See, for example, UK Offshore Operators Association, Well Operations Subcommittee on Permanent Well Abandonment, *Guidelines for the Suspension and Abandonment of Wells*, Issue 1, July 2001

Preventative measures for reducing the probability for CO_2 storage well blowouts, are essentially the same as those for other types of well blowouts. These include (Skinner, 2003):

- Regular wellbore integrity surveys on existing wells
- Use of blow out prevention equipment (BOPE), especially during workover operations, along with regular inspection and maintenance
- Installation of additional BOPE on suspect or high-risk wells and use of annular BOPE
- Extensive crew awareness and well control training
- Proactive blowout contingency and emergency response planning and training for operator personnel.

Even though it is unlikely in the case of a CO_2 storage operation, such operations should have in place emergency management tools, contingency plans, and appropriately trained personnel in place should a CO_2 well blowout occur. Blowout contingency plans (BCPs) are common in conventional oil and gas production operations, especially on offshore platforms.

In general, BCPs can either be general or specific. General plans are strategy manuals without specific well or site information that outlines how a particular operator will respond to blowouts. These guidelines are used as a training guides or workbooks. Specific plans expand upon general plans and offer specific guidance in particular areas and blowout scenarios, including a complete intervention process.

According to well blowout advisors John Wright Co., effective BCPs should include the following:[9]

- Emergency blowout task force (BTF) management, including organization and job descriptions; mobilization priorities; initial procedures and instructions; pre-qualification of critical equipment, personnel, contractors and suppliers; data

[9] http://www.jwco.com/technical-litterature/p01.htm; and http://www.jwco.com/technical-litterature/p04.htm

acquisition needs for site survey and files; safety, documentation and audits; emergency classifications, risks and consequences

- General intervention strategies for relief well or surface control
- Blowout scenarios that define and classify critical wells and structures based on subjective risk assessment by local management and advisors
- Specific intervention strategies that identify relief well and surface needs for hypothetical blowouts on critical structures and exploration wells
- Logistics and support information that, in detail, describe source equipment, material and services requirements based on scenarios and local capabilities
- Drilling and completion procedure audits that review and critique well plans and risks, summarizing possible corrective measures, anticipated geology and reservoir conditions
- Blowout prevention and well control inspections of ongoing drilling operations, listing results and recommended corrective actions
- An Appendix that includes items useful if a blowout occurs (such as wind data, surface topography maps, local water sources, etc.).

C. CO_2 LEAKAGE WELL REMEDIATION PROCEDURES

Thus far, this chapter has discussed in detail four classifications of potential CO_2 leakage - - through the caprock, out of a confining structure, due to loss of well integrity and well blowout. In addition, the chapter has set forth, in general, how to remediate these CO_2 leakage events. Assuming that a competent, secure CO_2 storage site has been selected, the loss of well integrity and blowouts will represent the greatest risk of CO_2 leakage. As such, this section will concentrate on practices associated with remediating well integrity and well blowouts by presenting standard well service and repair procedures and guidelines should a CO_2 leak occur.

1. Overview of Existing Mechanical Integrity and Monitoring Procedures. The loss of a well's mechanical integrity (MI) can lead to internal CO_2 leaks in the casing, tubing, or packer, and external leaks allowing fluid movement behind the casing and/or cement into underground sources of drinking water (USDW). A major portion of each state's underground injection control (UIC) program centers on the mitigation of fluid movement into USDWs. The UIC program sets forth steps for automated data collection, annual or multi-annual tests to ensure well integrity, and efforts for early detection of leakage.

UIC Class I wells, for example, which inject hazardous or other municipal waste, are required to demonstrate the mechanical integrity of each injection well, which is defined as the absence of any significant leaks in the casing, tubing, or packer of a well and the absence of significant fluid movement into a USDW through vertical channels adjacent to the well bore[10]. Testing is typically performed by pressuring the casing or tubing strings and monitoring pressure for a stated duration to ensure no pressure leaking-off.

During the injection phase, subsequent monitoring efforts will generally include:

- An analysis of injected fluids
- Continuous monitoring of injection pressure, flow rate, and volume
- Demonstration of mechanical integrity once every five years
- Placement of a sufficient number of monitoring wells to assess any migration of fluids into a USDW.

If monitoring indicates leakage into a USDW, then preventive actions must be taken. These actions will include additional monitoring and reporting requirements; prompt corrective action; or permit termination and well closure[11]

2. Identifying Fugitive Emissions or Fluids. Should the mechanical integrity testing (MIT) or leakage monitoring protocols indicate fugitive movement of the injectant, several methods are available to aid in pinpointing the location of the leak.

[10] Underground Injection Control Program. Code of Federal Regulations, Part 146, Title 40, 40CFR146; www.gpoaccess.gov.

[11] Underground Injection Control Program. Code of Federal Regulations, Part 144, Title 40, 40CFR144; www.gpoaccess.gov.

These methods can also provide insights into the best method of remediation. Some of these are highlighted below and may be used with one another for improved accuracy.

- Monitoring wells – These will generally indicate external leakage away from the injection well and may indicate injectant movement outside of the containment reservoir through a poor cement sheath, a fault or fracture in the reservoir seal, or injection past the reservoir spill point.

- Loss of annular pressure - Most injection wells are required to inject through packer-set tubing, with annular brine at higher pressure than the injection operation. The UIC permit also requires continuous monitoring of this annular pressure. As such, this monitoring technique is perhaps the first indicator of a potential leak and can be identified by a loss of pressure at the surface. This will generally indicate a leak has occurred in the packer, tubing or casing and will not provide a definitive location of the leak.

- Increase of pressure – In abandoned wells or monitoring wells, the location where pressure is increasing (external versus internal production string) will be a key indicator of what corrective action will be necessary to repair the well. Should the increase in pressure be annular, grouting or a cement bond log followed up with squeezing may be necessary to seal the well. Internal pressure increases may be indicative of a failed cement abandonment plug or a leaky casing.

- Pressure testing – Through the use of a retrievable plug or inflatable packer, the tubing and/or casing can be pressure tested, much like the MIT, to ensure that pressure integrity is maintained. This method provides an overall look at the entire tubular section and will indicate which aspect of the completion is leaking.

- Downhole video camera – This tool can provides visual evidence, linked to depth and orientation measurements, of the leaking location.

- Noise Log – An acoustic log is able to "listen" to the sound within the casing string. It can provide the depth where fluid is entering or leaving the wellbore, if leakage is due to a casing failure.

- Temperature log – This log indicates fluid movement via temperature shifts from a baseline. Cooling or warming of the borehole environment may indicate fugitive fluid movement.

- Radioactive tracers – Various tracers exist that can be tracked via downhole geophysical tools to indicate the fugitive movement path of the injectant.

- Cement bond log – If the fugitive movement appears to be external to the well completion, the use of a cement bond log, or the acoustic imager, can help determine whether the injection well's cement sheath is still maintaining a quality bond between the steel casing and reservoir face.

3. Remediating Fugitive Emissions and Fluids. Once the leakage is determined to be internal or external to the injection well, remediation plans can be put forth to correct the issue. From a mechanical integrity standpoint for the injection well, there are several corrective actions that can be used to address the leak(s). The method(s) employed will stem from the results of the above procedures to determine the location and nature of the leak and may include the following:

- Wellhead repair – The wellhead should be the first item checked prior to any in-depth leak detection investigation. Wellhead equipment, including valves, flanges, etc., can be easily inspected due to their above ground location.

- Packer replacement – Should annular pressure be lost or waning, and the casing and tubing strings are shown to hold pressure, it is most likely the packer sealing element that has failed. Since the tubing string and packers are retrievable, this can be a very simple repair involving the removal of the existing tubing injection string and swapping the potentially leaky packer for a new one. Most packers are mechanically set, generally involving rotation or the application of force to initiate inflation, so most well completion units are able to pull and reset these packers. A packer that has begun to leak over time should be replaced and not reset, as a new leak may develop in the future.

- Tubing repair – If the leak is in the tubing, a completion unit can be mobilized to pull the injection string and readily replace the faulty tubing joint. The string can then be run back into the well and pressure tested to ensure integrity. It is important to visually inspect all tubing joints as they are run out of and into the well. If a tubing joint appears excessively worn at the connections, replacement of this tubing joint may eliminate future leaks.

- Squeeze cementing – A leaky casing string can be restored to high-pressure injection operations by forcing the cement slurry by pressure to specified points in a well to provide seals at the points of squeeze. Once the leak location is detected, the area of the leak is perforated and then isolated by a packed tubing string to direct cement flow during pumping. This operation will generally use a low pressure "push" to force the cement into the perforations to mitigate fracturing. This method is the industry standard corrective measure for a loss of casing integrity.

- Patching casing – A new alternative to squeeze cementing is the use of expandable casing patches to restore casing integrity. The application of a casing patch involves positioning the setting tool at depth and hydraulically "inflating" the tool. The exterior of this tool contains the expandable patch which continues to deform as the inner pressure increases until it reaches the internal diameter of the casing string, whereupon it creates a seal across the leaky area. (*See* ***Appendix 4*** *for State of Kansas procedure for internal casing repair.)*

- Repairing damaged or collapsed casing – If the casing is found to be collapsed or deformed due to external pressure, the well can be temporarily or sometimes permanently restored to previous use through the use of a swage. A swage (shown in Figure 5-4) is a repair device that acts like a circular wedge to push back damaged casing and install liners. The lower end is tapered to fit into reduced diameter pipe, then hydraulic power is used to open the jaws of the swage and push casing back to about the original diameter. The pressure exerted by the swage can be as great as 50 tons per square inch.[12] (See Appendix 4)

[12] http://www.welenco.com/well_repair.htm

- Plugging a well – Each State will have unique requirements for permanent well abandonment that may include deployment of cement plugs across USDWs, active hydrocarbon production zones and/or across open perforations as well as cement squeezes into non-cemented, cased holes across USDWs (See **Appendices 5, 6 and 7** of this report for Texas, Utah and Washington State regulations regarding well plugging and abandonment). State-to-State variations are primarily due to regional geology and drilling development. The height of the cement plug will vary for each application, but it generally is on the order of 100 feet per plug. States may also require a section of casing (up to ten feet from surface) to be removed from the site with the wellhead equipment.

Figure 5-4. A Typical Large Diameter Swage

4. Remediating a Leaking Abandoned Well. In the event a previously abandoned well is found to be leaking, a series of steps can be employed to restore the well for temporary use, remediate the leak, and re-abandon the well. They include:

1. Inform the relevant oversight agency that a leak has been detected in an abandoned well.

2. Review all available well data records, including well completion, abandonment and geophysical logs to assess the current disposition of the well.

3. Formulate a detailed plan for well intervention and remediation and file a copy with the lead regulatory agency.

4. Set up a drilling rig above the location of the leaking well and drill the reclaimed soil above the abandoned well, enabling the intersection of the abandoned completion string. This may require the drilling of a cement plug at the surface.

5. Use swages and/or overshots to help make secure connections between new casing and the abandoned casing strings. These may include (from largest to smallest in diameter) surface, intermediate and production casing strings.

6. Measure pressures within each connected casing string to ascertain from where the leak is originating and proceed with the appropriate remediation plan.

    - If the leak is occurring within the production casing string, the previous abandonment or the casing string itself may be leaking. Remediation efforts here might require the drilling out of the original plugs and determining whether the leak was through the plug or through a leaky casing string

        - For a casing leak, remediate by “killing” the well (loading with a heavy brine to stop inflow) and either installing a casing patch or squeeze cementing

        - For a poor abandonment plug, re-plug the well according to state regulations (see **Appendix 8** of this report for Colorado regulations regarding re-abandonment)

    - If the leak is external to the production string, the leak may be moving through the cement sheath or between the cement sheath and the rock behind it. Locate the leak by drilling out the cement plug, “killing” the well, and running a ultra-sonic cement bond log to determine where the cement channels or areas of poor bonding exist. Remediate the well by squeezing channeled cement in areas of poor bonding

Alternatively, if the injectant has been radioactively traced, 3-dimensional tracer logs can be lowered into the well to show the path of the fugitive injectant. Remediate by squeeze cementing

7. Re-plug the well according to state regulations (see **Appendix 8** of this report for Colorado regulations regarding re-abandonment).

5. Modifications to Remediation Practices to Account for CO_2. Carbon dioxide in combination with water can form carbonic acid, which is corrosive to standard oilfield tubulars as well as cements. Items of concern when used with CO_2 are:

- Permanent and Retrievable Packers – Packers employed in CO_2 environments should be refitted with stainless steel elements, where appropriate, and fit-for use inflation elements. Storage project operators should clearly state the intended use of the packer in a CO_2-rich environment to the vendor.

- Casing and Tubular goods – To mitigate corrosion and extend tubular life the use of fiberglass-lined or stainless steel casing and tubular strings are often employed where CO_2 is present. In the injection well, the CO_2 will be most likely “dried” before injection. For wells that the CO_2 and water plumes will intersect, proper corrective actions or replacement of downhole tubulars may be required. Similarly, all casing repairs employing casing patches may need to consider the use of CO_2 resistant materials.

- Cement – The oilfield service industry recognizes the adverse effects carbonic acid can have on standard oilfield cements, and is working hard to bring state-of-the-art cements to the market for use with CO_2. One such cement is Schlumberger’s CemCrete™ product. It is a low water-use cement that was specifically designed to reduce the development of microannuli within the cement sheath. When employed in a CO_2-rich environment, this type of cement is more resistant to CO_2 invasion due to the cement's low porosity.

D. REMEDIATING THE ASSOCIATED IMPACTS OF CO_2 LEAKAGE

The scope of work set forth for this study requested that our examination of remediation be limited to the geological storage formations. For completeness, however, we briefly introduce, in this last section of Chapter V, the efforts involved with remediating the impacts of CO_2 leakage. Table 5-1, modified from Benson and Hepple (2005) and the text below set forth these additional remediation options.

Table 5-1. Options for Remediating the Impacts of CO_2 Leakage Projects (Modified from Benson and Hepple, 2005).

Remediating accumulation of CO_2 in groundwater	• Accumulations of CO_2 in groundwater can be removed by drilling wells that • intersect the accumulations and extracting the CO_2; • Residual CO_2 that is trapped as an immobile gas phase can be removed by dissolving it in water and extracting it as a dissolved phase using groundwater extraction wells; • CO_2 that has dissolved in the shallow groundwater could be removed, if needed, by pumping to the surface and aerating it to remove the CO_2; • For metals or other trace contaminants that have been mobilized by acidification of the groundwater, 'pump-and-treat' methods can be used to remove these contaminants. Alternatively, hydraulic barriers can be created to immobilize and contain the contaminants by appropriately placed injection and extraction wells.
Remediating leakage into the vadose zone and CO_2 accumulation in soil gas	• CO_2 can be extracted from the vadose zone and soil gas by standard vapor extraction techniques from horizontal or vertical wells; • Fluxes from the vadose zone to the ground surface could be decreased or stopped by caps or gas vapour barriers. Pumping below the cap or vapour barrier could be used to deplete the accumulation of CO_2 in the vadose zone; • Since CO_2 is a dense gas, it could be collected in subsurface trenches. Accumulated gas could be pumped from the trenches and released to the atmosphere or reinjected back underground; • Passive remediation techniques that rely only on diffusion and 'barometric pumping' could be used to slowly deplete one-time releases of CO_2 into the vadose zone; • Acidification of the soils from contact with CO_2 could be remediated by irrigation and drainage. Alternatively, agricultural supplements such as lime could be used to neutralize the soil;
Remediating large releases of CO_2 in near-surface atmosphere	• For releases inside a building or confined space, large fans could be used to rapidly dilute CO_2 to safe levels; • For large releases spread out over a large area, dilution from natural atmospheric mixing (wind) will be the only practical method for diluting the CO_2; • For ongoing leakage in established areas, risks of exposure to high concentrations of CO_2 in confined spaces (e.g. cellar around a wellhead) or during periods of very low wind, fans could be used to keep the rate of air circulation high enough to ensure adequate dilution.
Remediating accumulation of CO_2 in indoor environments	• Slow releases into structures can be eliminated by using techniques that have been developed for controlling release of radon and volatile organic compounds into buildings. The two primary methods for managing indoor releases are basement/substructure venting or pressurization. Both would have the effect of diluting the CO_2 before it enters the indoor environment

1. Remediating Accumulation of CO_2 in Groundwater. CO_2 contamination of groundwater can be remediated by the "pump and treat" method. Water is pumped to the surface and aerated to flash the CO_2. The water can then be either pumped back underground or used. CO_2 migrating to a drinking water reservoir will likely leach some amount of minerals along the way and transport them into the water. Treatment for such constituents is more involved and expensive, but could be accomplished with the "pump and treat" approach.

2. Remediating the CO_2 Leakage into Vadose Zone. The Lawrence Berkeley National Laboratory (LBNL) looked at vadose zone remediation of CO_2, based on the similarity of CO_2 transport to the transport of other common vadose zone contaminants. LBNL assumed that soil vapor extraction (SVE) technology could be used for removing CO_2 from soil. Several soil remediation scenarios were examined with the TOUGH2 numerical simulator. The results indicated that large amounts of CO_2 could be removed from the vadose zone using SVE technology. In addition, design enhancements to improve process efficiency were identified (Zhang, et al., 2004).

3. Extracting CO_2 from Near-Surface Accumulations. Horizontal pinnate (leaf-vein pattern) drilling, which has been commercially developed for coalbed methane development, can provide a useful method for accessing CO_2 in near-surface reservoirs and accumulation zones (von Shoenfeldt, et al., 2004).

4. Remediating Surface Accumulations of CO_2. If CO_2 were to migrate up through the soil and into populated areas, there is a danger of CO_2 collecting in basements and low-lying areas and creating an asphyxiation hazard. Mitigation efforts could include fans and CO_2 detectors. In addition, shallow wells could be drilled to intercept and vent the migrating CO_2.

VI. STRATEGIES FOR LEAKAGE PREVENTION AND REMEDIATION

A. OVERVIEW OF THE LEAK PREVENTION AND REMEDIATION STRATEGY

A comprehensive strategy for leak prevention and remediation would contain five main elements: (1) obviating the need for remediation of CO_2 leakage in the first place by selecting favorable storage sites with extremely low risks of leakage; (2) placing considerable emphasis on well integrity, including identifying and properly plugging, where necessary, previously drilled wells; rigorously designing the newly drilled CO_2 injection (and observation) wells so they remain secure during the injection and operating life of the well; and, properly plugging and abandoning the CO_2 injection and observation wells so that they remain secure for “a thousand years”; (3) conducting a phased series of short- and long-term reservoir modeling efforts to establish the flow and trapping of the CO_2 plume; (4) installing a reliable and comprehensive CO_2 plume location and “early warning” leak detection monitoring; and (5) preparing and updating, as necessary, a “ready-to-use” set of procedures and responses for remediating CO_2 leakage should it occur.

B. THE FIVE-PART STRATEGY

This five-part leak prevention and remediation strategy for CO_2 storage is further discussed and developed below.

1. Selecting Favorable Storage Sites With Low Risks of CO_2 Leakage. No other single aspect of a leak prevention and remediation strategy is more important than selecting a safe, secure site in the first place. Chapter II of this report reviews the potential CO_2 leakage pathways that would need to be fully addressed for evaluating the favorability of a storage site. Chapter III of this report provides an extensive discussion of the tools and procedures for helping select a safe, secure CO_2 storage site.

2. Placing Emphasis on Well Integrity. There are three key priorities for ensuring long-term well integrity at a CO_2 storage site.

- The first is identifying the older, abandoned wells in the vicinity of the proposed CO_2 storage site and replugging these wells, where necessary. Using CO_2 resistant cements for plugging these previously abandoned wells and rigorously documenting their locations are two important steps.

- The second priority is designing and installing the CO_2 injection wells so that they will resist loss of cement integrity and corrosion of casing from the acidic CO_2 and water mixture. Chapter V of this report discusses preferred well design and completion practices for CO_2 storage wells

- The third priority is properly closing the CO_2 storage site, including plugging all CO_2 injection and observation wells to promote long-term storage integrity. Chapter V of this report also contains discussion on well plugging and abandonment procedures for CO_2 storage wells.

3. Conducting a Phased Series of Reservoir Simulation-Based Modeling to Track and Project the Location of the CO_2 Plume. Based on experiences to date, we recommend multiple stages of reservoir simulation for supporting leak prevention and remediation efforts in CO_2 storage. The first stage of reservoir simulation and modeling would be undertaken during the initial site selection process. The purpose here is to assemble the available reservoir data, often extrapolated from a regional data set, to establish the injectivity and storage capacity of the site, as well as to project the anticipated movement and location of the CO_2 plume.

The second stage of reservoir simulation modeling would be undertaken after the CO_2 injection and observation wells have been drilled and more site specific geological and reservoir data have been collected. Of particular importance will be the modeling of the internal architecture of the storage formation, including the nature and extent of any shale breaks that might serve as baffles for promoting increased CO_2 contact with the reservoir. Also important would be incorporating into the reservoir model the newly collected data on relative permeability to better estimate CO_2 injectivity and the pore-space (capillary) trapping mechanisms essential for long-term immobilization of the CO_2 plume.

The third stage of reservoir simulation, which would involve repeated runs, would be initiated once the CO_2 monitoring systems provide new information on the flow direction and location of the CO_2 plume. Of particular value is incorporating seismic data and results from subsurface observation wells for calibrating the reservoir model. This third stage of reservoir simulation, often repeated, would be used to project the long-term (1,000 year) trapping and immobilization of the CO_2 plume.

Chapter IV of this report provides additional discussion on the role of reservoir modeling for supporting safe CO_2 storage.

4. Installing and Maintaining a Comprehensive Monitoring System for the CO_2 Storage Site. The overall CO_2 monitoring system will need to be designed to serve several purposes. First and foremost, the CO_2 monitoring system will need to serve as an "early warning system" of any impending CO_2 leakage. For this, there is need for downhole pressure data, CO_2-sensitive logging tools, and near-surface CO_2 detection systems to identify any leakage through or around the reservoir seal. In addition, a variety of pressure monitors and cement bond logs will need to be used for assuring wellbore integrity.

Second, the CO_2 monitoring system will need to provide on-going information on the movement and immobilization of the CO_2 plume. Seismic methods, both surface and downhole, real-time information from offset observation wells, plus regional surface-based leak detection and sub-surface monitoring techniques would be used to augment this information.

Chapter IV of this report provides additional discussion on installing a comprehensive MMV system for monitoring CO_2 storage.

5. Establishing a "Ready-to-Use" Contingency Plan/Strategy for Remediation. The remaining discussion in Chapter VI sets forth a response and mitigation strategy once a leak in the CO_2 storage field has been detected. The procedures and options associated with the response and mitigation strategy are outlined in Chapter V.

C. COSTS OF LEAK PREVENTION AND REMEDIATON

Inevitably, the costs of remediation will impact the overall costs for CO_2 storage in geologic reservoirs. As such, the remediation strategy needs to be considered in the context of the overall CO_2 storage project. The likelihood of needing remediation will be greatly reduced if a rigorous geologic and engineering analysis is performed up front as part of overall site selection and storage project design.

As described in the previous chapter, if a leak occurs, the geologic and engineering effort for remediating the leak can at times be comparable to, and may exceed, that associated with original CO_2 storage site selection, project design and implementation. Therefore, attempts to save money on the front-end site selection, project design and planning phases could result in even higher expenses for remediating problems that could have been avoided by more thorough up-front work. For example, if the causes of a CO_2 leak cannot be remediated, the CO_2 storage site may have to be terminated with the CO_2 transferred to an alternative site. In this extreme case, the entire investment in the initial CO_2 storage project will have been lost.

Two additional costs could also be incurred from leakage of CO_2, assuming significant vertical migration of the CO_2. First would be the cost for remediating the impacts of CO_2 accumulation in the potable water and vadoze zone. The second would be the loss of any CO_2 credits for storing CO_2. Even a modest CO_2 leak involving 25,000 tons of CO_2 (one day of CO_2 emissions from the example power plant) would result in a loss of $1 million (assuming a CO_2 credit of $40 per tonne, in U.S. dollars).

The costs associated with the various activities for both preventing leaks and for remediating them after they occur are summarized below. *(All costs are reported as U.S. dollars.)*

1. Leak Prevention Costs. Three important activities - - rigorous site selection, on-going monitoring, and periodic testing for well integrity - - are at the heart of CO_2 leak prevention.

a) Costs for Rigorous Site Selection and Project Design. The major components of a rigorously selected, installed and operated CO_2 storage facility are outlined in Table 6-1. The costs include a comprehensive geological assessment, multiple-phases of reservoir modeling, and a variety of supportive activities. The front-end costs would also include the drilling of reservoir characterization wells which would, subsequently, be converted to long-term observation and monitoring wells.

Table 6-1. Major Components of Site Selection and Project Design

Project Definition and Design
• Initial Geologic and Reservoir Characterization • Test Site Design and Plan • Reservoir Modeling/Simulation • Comprehensive MMV Protocols • Remediation Strategy and Procedures • Regulatory/Permitting Activities
Detailed Site and Reservoir Characterization
• MMV Baseline Studies • Observation, Characterization and Monitoring Well(s) • Seismic Survey(s) • Well Tests
Continuing Activities
• Updated Geologic/Reservoir Model • Operational Monitoring System

The costs for site selection and project design could range from $5,000,000 to $20,000,000 per site. The largest single cost item will be the cost of drilling and testing the reservoir characterization and observation wells. Other significant costs will involve establishing the regional geological framework, conducting reservoir modeling of the expected flow and trapping of the CO_2 plume, and testing the integrity of the reservoir caprock. Seismic, while an essential part of site characterization and selection, is not included in these costs as this cost component is included in the monitoring system, as discussed below. The actual costs will depend on the type and depth of the project (e.g., oil and gas field, deep saline aquifer), the amount of CO_2 to be stored, the conditions at the surface overlying the storage formation (industrial, suburban, farmland, etc.), and, perhaps, most important, the regulatory and permitting requirements imposed on the project.

For the illustrative example, we assume the need to drill 6 observation wells costing $2.5 million each, plus $3 million for the remaining aspects of rigorous site selection and project design.

The overall costs for site selection and project design will be combined with the other leak prevention and leak remediation costs (as discussed below) and then converted to a cost per tonne of stored CO_2, using an illustrative example of storing CO_2 in a deep, saline formation.

b) Costs for Project Monitoring and Leak Detection. The costs for implementing monitoring and leak detection protocols for geologic storage of CO_2 have been modified from the original study by Benson, et al., (2005).

This study set forth two monitoring scenarios (a “basic monitoring package” and an “enhanced monitoring package”) to evaluate the applicability and costs of conducting monitoring over the life-cycle of a CO_2 storage project. The monitoring systems were designed for three types of projects: (1) an enhanced oil recovery project followed by CO_2 storage; (2) a storage project in a saline aquifer with a high residual gas saturation (RGS), where the CO_2 plume does not move significantly after CO_2 injection stops; and (3) a storage project in a saline aquifer with low residual gas saturation (RGS), where the CO_2 plume keeps moving for a considerable amount of time after injection stops, Table 6-2.

In our remediation study, we have selected the saline aquifer with high RGS and the “enhanced monitoring package” in the illustrative example. However, we reduced the closure monitoring phase in the example to 20 years, from the 50 years set forth in Table 6-2, modified some other costs, and worked to ensure no significant duplication of effort (such as for the seismic survey). As a result, our modified costs for monitoring and leak detection are estimated at $62.5 million. (See discussion in illustrative example, below.)

Table 6-2. Costs of Alternative Monitoring Strategies

Cost Component	Estimated Monitoring Costs (Million Dollars)					
	EOR		Saline Aquifer			
			Low RGS [(2)]		High RGS [(2)]	
	Basic Package	Enhanced Package	Basic Package	Enhanced Package	Basic Package	Enhanced Package
Pre-Operational Monitoring						
Well Logs	\$0.0	\$0.0	\$1.1	\$1.1	\$1.1	\$1.1
Wellhead Pressure	\$0.0	\$0.0	\$0.1	\$0.1	\$0.1	\$0.1
Formation Pressure	\$0.0	\$0.0	\$0.3	\$0.3	\$0.3	\$0.3
Injection and Production Rate Testing	\$0.0	\$0.0	\$0.6	\$0.6	\$0.6	\$0.6
Seismic Survey	\$0.0	\$0.0	\$3.8	\$3.8	\$2.4	\$2.4
Microseismicity (Baseline)	\$0.5	\$0.5	\$0.5	\$0.7	\$0.5	\$0.7
Gravity Survey (Baseline)	\$0.0	\$0.4	\$0.0	\$0.2	\$0.0	\$0.2
Electromagnetic Survey (Baseline)	\$0.0	\$0.4	\$0.0	\$0.2	\$0.0	\$0.4
Atmospheric CO2 Monitoring (Baseline)	\$0.3	\$0.6	\$0.1	\$0.2	\$0.1	\$0.2
CO2 Flux Monitoring	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Pressure/Water Quality in Upper Formation	\$0.0	\$1.0	\$0.0	\$1.0	\$0.0	\$1.0
Subtotal	\$0.8	\$2.9	\$6.5	\$8.2	\$5.1	\$7.0
Management (@15%)	\$0.1	\$0.4	\$1.0	\$1.2	\$0.8	\$1.1
Subtotal	\$0.9	\$3.3	\$7.5	\$9.4	\$5.9	\$8.1
Operational Monitoring						
Well Logs	\$0.0	\$13.2	\$0.0	\$6.0	\$0.0	\$6.0
Wellhead Pressure	\$1.5	\$1.5	\$1.7	\$1.7	\$1.7	\$1.7
Injection and Production Rates	\$6.5	\$6.5	\$3.4	\$3.4	\$3.4	\$3.4
Wellhead Atmospheric CO2 Monitoring	\$2.5	\$2.5	\$1.8	\$1.8	\$1.8	\$1.8
Microseismicity	\$3.7	\$3.7	\$3.7	\$3.7	\$3.7	\$3.7
Seismic Survey	\$16.0	\$16.0	\$9.5	\$9.5	\$9.5	\$9.5
Gravity Survey	\$0.0	\$1.4	\$0.0	\$0.9	\$0.0	\$0.9
Electromagnetic Survey	\$0.0	\$1.4	\$0.0	\$0.9	\$0.0	\$0.9
Continuous CO2 Flux Monitoring (10 stations)	\$0.0	\$4.8	\$0.0	\$4.8	\$0.0	\$4.8
Pressure/Water Quality in Upper Formation	\$0.0	\$0.6	\$0.0	\$0.6	\$0.0	\$0.6
Subtotal	\$30.2	\$51.6	\$20.1	\$33.3	\$20.1	\$33.3
Management (@15%)	\$4.5	\$7.7	\$3.0	\$5.0	\$3.0	\$5.0
Subtotal	\$34.7	\$59.3	\$23.1	\$38.3	\$23.1	\$38.3
Closure Monitoring						
Seismic Survey	\$7.9	\$7.9	\$16.0	\$16.0	\$12.0	\$12.0
Gravity Survey	\$0.0	\$0.7	\$0.0	\$1.5	\$0.0	\$1.1
Electromagnetic Survey	\$0.0	\$0.7	\$0.0	\$1.5	\$0.0	\$1.1
Continuous CO2 Flux Monitoring (10 stations)	\$0.0	\$3.2	\$0.0	\$8.0	\$0.0	\$8.0
Pressure/Water Quality in Upper Formation	\$0.0	\$0.4	\$0.0	\$1.0	\$0.0	\$1.0
Wellhead Pressure Monitoring (1)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Subtotal	\$7.9	\$12.9	\$16.0	\$28.0	\$12.0	\$23.2
Management (@15%)	\$1.2	\$1.9	\$2.4	\$4.2	\$1.8	\$3.5
Subtotal	\$9.1	\$14.8	\$18.4	\$32.2	\$13.8	\$26.7
TOTAL	\$45	\$78	\$49	\$80	\$43	\$73

Notes: (1) Conducted for 5 years, after which the wells are abandoned; (2) RGS – Residual gas saturation

Source: Benson, et al., 2005.

c) Costs for Wellbore Integrity Monitoring. Wellbore integrity monitoring and logging costs will be a function of the depth of the well, the condition of the well, and the number and types of logs required. Based on cost quotes received by Advanced Resources for conducting ultrasonic cement bond logging (including rig time), the costs for monitoring well integrity are estimated as follows:

Well Depth	Well Integrity Logging Costs	
	Per Log	Total *
5,000 feet	$120,000	$12 million
7,500 feet	$150,000	$15 million
10,000 feet	$180,000	$18 million

*Total assumes 10 CO_2 injection wells and 10 logging runs in 50 years, for a total of 100 logging runs.

We assume that, for the most part, the costs for a more comprehensive set of wellbore integrity logs, essential for providing up-to-date information on the condition of the CO_2 injection wells, are not included in the costs for project monitoring and leak detection set forth in Table 6-2.

2. Leak Remediation Costs. Depending on the nature of the CO_2 leakage problem being addressed, the costs of leak remediation can vary widely. Set forth below are estimated costs for solving four types of problems - - locating the source(s) of the CO_2 leak, plugging old wells, remediating active CO_2 injection wells, and remediating a leak in the caprock.

a) Costs for Locating Source(s) of CO_2 Leaks. Assuming a rigorous site selection process (as discussed above), the most likely source for CO_2 leaks will be the wells themselves, either the older, abandoned wells or because of problems with newly drilled wells. Considerable expertise exists for identifying the source and reasons for CO_2 leaks in wells. As such, the well leak diagnostic procedures are relatively straightforward, with much of the essential information expected to be provided by the on-going project monitoring and leak detection program, discussed above.

Locating an old, abandoned well can be accomplished by numerous means, as set forth in Chapter V. The costs for locating a single well (or even a group of wells) will be modest, set at \$100,000 per survey (including interpretation), with significant economies of scale in multi-well situations. We assume, for the illustrative example purposes, a need to conduct ten such surveys in the 50 year life of the project.

For the CO_2 injection wells, a new set of logs (such as a cement bond log) or other diagnostic tools (such as a downhole wireline video camera or a spinner survey) may need to be run to more precisely identify the exact location and cause of the leak in the new injection well. Assuming two diagnostic logs costing \$200,000 (including rig time) plus a diagnostic and management charge of \$100,000, the costs for a wellbore-based leak detection procedures would be on the order of \$300,000 per well. We assume 10 wellbore leaks need to be remediated during the 50 year life of the project.

The process and costs for locating geologically-based CO_2 leaks in a storage formation are much more challenging, as discussed in Chapter V. The costs will be a function of the size of the leakage area, the conditions at the surface overlying the storage formation (industrial, suburban, farmland, etc.), and, perhaps, most important, the requirements imposed by regulatory authorities.

Establishing the cause and source of the geologically-based CO_2 leak may require investigating a large area, with emphasis on areas of potential caprock weakness (such as faulted areas) and structural “spill points”. As such, a new large scale seismic survey covering 5 to 20 square miles may need to be conducted over the area where surface leakage has been detected. In addition, new leak detection wells (potentially horizontal wells) may need to be drilled and tested to more precisely locate the source for the CO_2 leak and, ultimately, capture the leaked CO_2 for reinjection.

For the illustrative example, we assume a 20 square mile seismic survey and a cost of \$100,000 per square mile for 3D seismic (including processing and interpretation). We also assume \$4 million for each horizontal leak detection well (including testing and subsequent operations).

b) Costs for Well Plugging. Well plugging costs will depend on whether the requirement is to plug a recently abandoned well, an old, previously plugged and abandoned well, or a well that was never plugged. Second, the costs will depend on what must be done to plug the well, with the range of possible requirements described in Chapter V. Third, costs will depend on the location of the well being plugged. For example, a well located in an easily accessible, remote location will have much different costs than a well in a difficult-to-access location or in a densely populated area.

Nonetheless, well plugging (in a typical 7,500 foot well) could cost as little as $20,000 and as high as $80,000. On average, most well plugging operations cost $50,000 per well, without considering the salvage value of the casing, if any. In the illustrative example, we assume the need to plug 20 old, abandoned wells leaking CO_2.

c) Costs for Well Remediation. Remedial cementing jobs, intended to repair a simple wellbore leak, would cost in the range of $30,000 to $50,000, on average, but could vary considerably depending on the nature of the leak and the condition of the wellbore. A more involved remediation, required when a substantial section of the well has leaks or damage, would require placing and cementing in place a smaller diameter liner inside the well casing. The costs of this remediation step is estimated at $100,000 per well.

In some cases, a leaky well cannot be repaired, and must be plugged. In this case, the costs would include plugging the leaking well and drilling a new replacement CO_2 injection well. The costs of drilling new wells depend on the depth of the well, with an average well cost of $1,000,000 (in 2003) for a 7,500 foot (2,300 meter) well. These costs can range from $500,000 for a shallow 5,000 foot (760 meter) well, to $5.5 million for a deep 15,000 foot (4,600 meter) well (API, 2005). However, well costs have increased by about 150% in the last three years, and now a 7,500 foot CO_2 injection well costs on the order of $2.5 million. The main cost components that have dramatically increased are rig fuel (diesel oil), tubulars (steel), and the day-rate for drilling rigs.

For the illustrative example, we assume one significant remediation for each of the CO_2 injection wells (10 remediations) and the need to re-drill one CO_2 injection well.

In the case of a well blow-out, an extremely rare event in natural gas storage operations, the operator may need to inject heavy fluids or even drill a directional well to intercept the damaged well. The costs can range from relatively moderate costs of well plugging to very high costs for drilling a costly directional well by which to access the blow-out and then converting this well (or drilling a new well) for CO_2 injection. Because of the unique circumstances and rare occurrence of this problem, we have not estimated these costs.

d) Costs for Remediation of Leaks in Caprock. The first step in mitigating a CO_2 leak in the caprock would be to stop CO_2 injection and to inject water into a formation above the caprock to create a positive pressure barrier, if possible. This would involve drilling and operating new water injection wells, with costs comparable to those set forth above.

To create a positive pressure barrier for mitigating the CO_2 leak would, we assume, involve the drilling and completing two horizontal water injection wells and installing a water source well and water injection facilities. We estimate the water source and injection facility costs at $2 million.

There are no documented cases of fully remediating a leak in a caprock, in either a CO_2 storage or a natural gas storage project. In general, performing such a remediation effort is speculative at best. Consequently, the costs associated with this remediation action are unknown and not estimated by this study. The development of possible approaches for remediating leaks in caprock remains an important area for future research.

3. Example Storage Case. To further illustrate the costs of remedation, we have selected a sample saline aquifer CO_2 storage site. (For consistency, we have constructed this illustrative CO_2 storage example to be relatively similar to the high RGS saline aquifer example set forth by Benson (2005)). The main assumptions are as follows:

- The storage site serves one 1,000 MW coal-fired power plant, with 8.6 million metric tons of annual CO_2 emissions. The site will operate for 50 years, with 30 years for CO_2 injection and 20 years for post-closure monitoring.

- An "enhanced" CO_2 monitoring system has been assumed to have been implemented, involving $7 million of pre-operational monitoring (integrated with site characterization), $33 million for operational monitoring (including continuous pressure and atmospheric monitoring and periodic seismic and other geophysical surveys), $10 million for post-closure monitoring and $12.5 million (25%) for G&A/management. As such, this $62.5 million monitoring strategy is consistent with a rigorous site selection program and is highly supportive of the diagnostic systems essential for identifying the sources for CO_2 leakage, should these occur.

- For consistency purposes, we also assume that the CO_2 storage site has 10 CO_2 injection wells, each capable of injecting 2,500 tonnes of CO_2 per day with a 94% operating factor. (This is a highly optimistic CO_2 injection assumption given the effects of two-phase relative permeability, interference among the 10 relatively closely spaced CO_2 injection wells, and the steadily increasing pressure in the saline formation.)

- The CO_2 plume extends radially and underlies an area of about 80 square miles (216 km^2) at the end of 50 years.

Based on this example, the overall costs for leak prevention and leak remediation (including the comprehensive monitoring effort) would be as shown in Table 6-3:

Table 6-3. Representative Costs for Leak Prevention and Remediation

	Activity	Mid-Range Costs (millions)	Comments
A. BASIC COSTS			
	1. Site Selection and Project Design	\$18.0	Includes 6 observation wells plus other site selection costs
	2. Monitoring and Leak Detection	\$62.5	Includes the comprehensive seismic program otherwise included in site selection
	3. Wellbore Integrity	\$15.0	Includes multiple periodic ultrasonic cement bond logs and well integrity tests in 10 CO_2 injection wells
	Sub-Total	\$95.5	
B. REMEDIATION COSTS (If Needed)			
	1. Locating Sources of CO2 Leaks		
	• Old, Abandoned Wells	\$1.0	Assumes 10 leaking, abandoned well surveys
	• New CO_2 Injection Wells	\$3.0	Assumes 10 sets of diagnostic logs
	• Caprock/Spill Point	\$10.0	Includes seismic and 2 horizontal leak detection wells
	2. Well Plugging	\$1.0	Includes plugging of 20 old wells
	3. Well Remediation	\$3.5	Includes 10 well remediations and drilling one new CO_2 injection well
	4. Caprock Leakage		
	• Pressure Boundary	\$10.0	Includes two horizontal water injection wells plus a water plant
	• Other Problems	Large	May need to abandon original storage site and build a new site
	Sub-Total	\$28.5+	
	TOTAL	\$124.0+	

The cost for a comprehensive CO_2 leak prevention, monitoring and remediation program estimated to be on the order of \$120 to \$130 million per site. Assuming the injection of 258 million tones of CO_2, the cost per tonne for these efforts would range from \$0.45 to \$0.50 per tonne. However, should the CO_2 leakage problems not be able to be remediated, the costs would become large and include establishing a new storage facility, transporting some or all of the CO_2 to the new facility, remediating the impacts of CO_2 losses to the potable water and vadoze zone, and losing the value of any CO_2 credits for the CO_2 lost to the atmosphere or other undesirable locations.

D. OBSERVATIONS AND RECOMMENDATIONS

1. Observations. Our work in conducting this study and preparing this report convinces us that, with a properly designed and rigorously implemented leakage prevention and remediation strategy, the use of geologic storage of CO_2 can be safe, secure and worthy of public acceptance.

Of particular note is the excellent reliability and safety record of the natural gas storage industry, the closest long-term analog for CO_2 storage. We have summarized this experience and performance record in the many "Sidebars" to this report.

Similarly, our review and summary of naturally stored CO_2, in places such as McElmo Dome and the Paradox Basin, provides a second set of valuable analogs that show: (1) under a favorable combination of caprock, structural confinement and well integrity conditions, CO_2 can be safely and securely stored for millions of years; and (2) even when nature has created leakage pathways for deep-earth generated CO_2, these leakage pathways, once understood and monitored, can be accommodated with practical and reasonable mitigation actions.

We observe that CO_2 leakage diagnosis and remediation, particularly remediation, has received much less attention and priority than this important topic deserves. For example:

- A search of the technical literature identifies very few technical reports or papers that concentrate on CO_2 leakage remediation. Generally, this topic, even when addressed, is given only "high level" and brief discussion in papers addressing geological CO_2 storage.
- We find only two in-depth studies of remediation experiences and "lessons learned" for the most analogous activity to CO_2 storage - - the natural gas storage industry. The work by Perry (2003) is most valuable and provides original data and investigation of this topic, including its relevance to CO_2 storage. The work by Woodhill (2005) mainly repeats the work by Perry and others on the gas storage experience and adds little original work to the body of knowledge.

We are pleased to observe, and duly applaud, that the U.S. DOE's *Carbon Sequestration Technology Roadmap and Program Plan for 2006* (U.S. DOE, 2006) contains a section on CO_2 leakage mitigation and remediation. The term MMV, which has traditionally stood for monitoring, *measurement* and verification, now refers to monitoring, *mitigation,* and verification in the DOE roadmap and program plan. For the mitigation topic, the program is investigating steps that can be taken, should CO_2 leakage occur, to arrest the flow of CO_2 and mitigate negative impacts. Examples of activities under consideration include lowering the pressure within the storage formation to reduce the driving force for CO_2 flow (including closing unintended fracturing or faulting); forming a "pressure plug" by increasing the pressure in the formation into which the CO_2 may be leaking; intercepting the leakage path; or plugging the region where leakage is occurring with low permeability materials, such as, for example, "controlled mineral carbonation" or "controlled formation of biofilms."

DOE's Carbon Sequestration Program is also performing research on various potential breakthrough concepts. One such concept with potential applicability to long-term CO_2 leakage mitigation is the examination of naturally occurring bacteria ("methanogens") that may have the ability to convert CO_2 into methane within geologic reservoirs (many natural gas fields have been created this way). Efforts are underway to develop technology for introducing such organisms into geologic CO_2 storage sites to harness their natural ability to generate future potentially producible natural gas resources. The activities associated with the initial phases of this work are to: (1) identify and define the biological requirements of bacterial consortia most appropriate for remediating geologic CO_2 sequestration sites, (2) assess the geochemical conditions required for successful application of methanogens in geological settings; and (3) screen known oil and gas reservoirs in the U.S. to quantify potential application of methanogens and to identify high-graded sites for further laboratory and field application.[13]

2. Recommendations. Clearly, this overview study and report on CO_2 leak prevention and remediation serves as merely a first step forward. Fruitful next steps would include the following:

[13] http://www.er.doe.gov/sbir/awards_abstracts/sbirsttr/cycle21/phase1/049.htm

a) Develop a "Best Practices" Remediation Manual. It would be most valuable to develop and maintain an up-to-date "Best Practices" Manual on CO_2 Leak Prevention and Remediation. Similar "best practices" efforts are underway on topics such as site assessment and selection and monitoring. Summaries of this work could be incorporated without duplication, into the Remediation Manual to provide a comprehensive strategy for CO_2 Leak Prevention and Remediation. As new insights on remediation are developed, these would need to be added to this "Best Practices" CO_2 Leak Prevention and Remediation Manual to keep it "evergreen".

b) Study Remediation in the Natural Gas Storage Industry. Given its value as the most relevant analog to CO_2 storage, we recommend undertaking additional studies of the remediation experiences, practices and "lessons learned" of the natural gas storage industry. Fruitful areas for exploration would be further detailed on leak source identification and the cost of remediation.

c) Invest in Research and Technology Development in Remediation for CO_2 Storage. Of high priority would be much more intensive investigations and field trials of procedures for identifying and then sealing a failure in the caprock. Equally valuable would be work on materials and procedures for greater well integrity, leading toward a "thousand year well."

d) Develop New Procedures and Technology for Locating and Assessing the Integrity of Abandoned Wells. Valuable work on this topic has been undertaken by the U.S. DOE/NETL, but much more needs to be done to develop cost-effective means for reliably locating and assessing the status of old, abandoned wells near a CO_2 storage site. As valuable would be the development of new procedures and technologies for securely plugging these old, abandoned wells.

e) Launch a Series of "Best Practice", Large-Scale Field Tests of CO_2 Storage. An important emphasis in these large-scale field tests would be testing and assessment procedures for selecting sites with caprock and wellbore integrity. Equal emphasis in these large-scale field tests would be on establishing and testing an integrating system involving CO_2 monitoring, CO_2 leak detection, and remediation. A valuable side benefit would be learning, much more reliably, the actual costs of installing such an integrated system.

f) Address Concerns on Lack of Structural Confinement in "Open System" Saline Formations. If the large "open system" saline formations are to become viewed as safe, secure sites for injecting CO_2, considerable new investigation and research is required. Of particular importance are the following research topics - - aquifer hydrodynamics, potentially for pore space and hysterisis trapping of CO_2 in alternative geological settings understanding the dynamics of CO_2 displacement of stored saline water, and identification of geologic features that would provide assurance of updip trapping of the CO_2 plume, among others.

* * * * * *

We have been pleased to conduct the study and prepare this report on a most important topic involving geological storage of CO_2 - - Remediation of Leakage from CO_2 Storage Reservoirs. We trust this initial work will stimulate additional, more intensive investigations and investments in technologies on CO_2 leakage detection and remediation.

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REMEDIATION OF LEAKAGE FROM CO_2 STORAGE RESERVOIRS

APPENDIX

IEA/CON/04/108

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Appendix 1.
Casing, Cementing, Drilling and Completion Requirements for Onshore Wells

Rule §3.13: Texas Administrative Code
Railroad Commission of Texas
Oil and Gas Division

Texas Administrative Code

TITLE 16 ECONOMIC REGULATION
PART 1 RAILROAD COMMISSION OF TEXAS
CHAPTER 3 OIL AND GAS DIVISION
RULE §3.13 Casing, Cementing, Drilling, and Completion Requirements
(a) General.

(1) The operator is responsible for compliance with this section during all operations at the well. It is the intent of all provisions of this section that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all potentially productive zones be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing. When the section does not detail specific methods to achieve these objectives, the responsible party shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology.

(2) Definitions. The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(A) Stand under pressure--To leave the hydrostatic column pressure in the well acting as the natural force without adding any external pump pressure. The provisions are complied with if a float collar is used and found to be holding at the completion of the cement job.

(B) Zone of critical cement--For surface casing strings shall be the bottom 20% of the casing string, but shall be no more than 1,000 feet nor less than 300 feet. The zone of critical cement extends to the land surface for surface casing strings of 300 feet or less.

(C) Protection depth--Depth to which usable-quality water must be protected, as determined by the Texas Commission on Environmental Quality (TCEQ) or its successor agencies, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(D) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in commercial quantities in the area.

(b) Onshore and inland waters.

(1) General.

(A) All casing cemented in any well shall be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the well. For new pipe, the mill test pressure may be used to fulfill this requirement. As an alternative to hydrostatic testing, a full length electromagnet, ultrasonic, radiation thickness gauging, or magnetic particle inspection may be employed.

(B) Wellhead assemblies shall be used on wells to maintain surface control of the well. Each component of the wellhead shall have a pressure rating equal to or greater than the anticipated pressure to which that particular component might be exposed during the course of drilling, testing, or producing the well.

(C) A blowout preventer or control head and other connections to keep the well under control at all times shall be installed as soon as surface casing is set. This equipment shall be of such construction and capable of such operation as to satisfy any reasonable test which may be required by the commission or its duly accredited agent.

(D) When cementing any string of casing more than 200 feet long, before drilling the cement plug the operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the casing string by 0.2. The maximum test pressure required, however, unless otherwise ordered by the commission, need not exceed 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 10% or more from the original test pressure, the casing shall be condemned until the leak is corrected. A pressure test demonstrating less than a 10% pressure drop after 30 minutes is proof that the condition has been corrected.

(E) Wells drilling to formations where the expected reservoir pressure exceeds the weight of the drilling fluid column shall be equipped to divert any wellbore fluids away from the rig floor. All diverter systems shall be maintained in an effective working condition. No well shall continue drilling operations if a test or other information indicates the diverter system is unable to function or operate as designed.

(2) Surface casing.

(A) Amount required.

(i) An operator shall set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the TCEQ. Before drilling any well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable field rules, an operator shall obtain a letter from the TCEQ stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the commission.

(ii) Any well drilled to a total depth of 1,000 feet or less below the ground surface may be drilled without setting surface casing provided no shallow gas sands or abnormally high pressures are known to exist at depths shallower than 1,000 feet below the ground surface; and further, provided that production casing is cemented from the shoe to the ground surface by the pump and plug method.

(B) Cementing. Cementing shall be by the pump and plug method. Sufficient cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement does not circulate to ground surface or the bottom of the cellar, the operator or his representative shall obtain the approval of the district director for the procedures to be used to perform additional cementing operations, if needed, to cement surface casing from the top of the cement to the ground surface.

(C) Cement quality.

(i) Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.

(ii) An operator may use cement with volume extenders above the zone of critical cement to cement the casing from that point to the ground surface, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed.

(iii) In addition to the minimum compressive strength of the cement, the API free water separation shall average no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B.

(iv) The commission may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area.

(D) Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures adopted by the American Petroleum Institute, as published in the current API RP 10B. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished the commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure.

(i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement.

(ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.

(E) Cementing report. Upon completion of the well, a cementing report must be filed with the commission furnishing complete data concerning the cementing of surface casing in the well as specified on a form furnished by the commission. The operator of the well or his duly authorized agent having personal knowledge of the facts, and representatives of the cementing company performing the cementing job, must sign the form attesting to compliance with the cementing requirements of the commission.

(F) Centralizers. Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers shall meet API spec 10D specifications. In deviated holes, the operator shall provide additional centralization.

(G) Alternative surface casing programs.

(i) An alternative method of fresh water protection may be approved upon written application to the appropriate district director. The operator shall state the reason (economics, well control, etc.) for the alternative fresh water protection method and outline the alternate program for casing and cementing through the protection depth for strata containing usable-quality water. Alternative programs for setting more than specified amounts of surface casing for well control purposes may be requested on a field or area basis. Alternative programs for setting less than specified amounts of surface casing will be authorized on an individual well basis only. The district director may approve, modify, or reject the proposed program. If the proposal is modified or rejected, the operator may request a review by the director of field operations. If the proposal is not approved administratively, the operator may request a public hearing. An operator shall obtain approval of any alternative program before commencing operations.

(ii) Any alternate casing program shall require the first string of casing set through the protection depth to be cemented in a manner that will effectively prevent the migration of any fluid to or from any stratum exposed to the wellbore outside this string of casing. The casing shall be cemented from the shoe to ground surface in a single stage, if feasible, or by a multi-stage process with the stage tool set at least 50 feet below the protection depth.

(iii) Any alternate casing program shall include pumping sufficient cement to fill the annular space from the shoe or multi-stage tool to the ground surface. If cement is not circulated to the ground surface or the bottom of the cellar, the operator shall run a temperature survey or cement bond log. The appropriate district office shall be notified prior to running the required temperature survey or bond log. After the top of cement outside the casing is determined, the operator or his representative shall contact the appropriate district director and obtain approval for the procedures to be used to perform any required additional cementing operations. Upon completion of the well, a cementing report shall be filed with the commission on the prescribed form.

(iv) Before parallel (nonconcentric) strings of pipe are cemented in a well, surface or intermediate casing must be set and cemented through the protection depth.

(3) Intermediate casing.

(A) Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet above the shoe. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented from the shoe up to a point at least 600 feet above the top of the shallowest productive horizon or to a point at least 200 feet above the shoe of the next shallower casing string that was set and cemented in the well.

(B) Alternate method. In the event the distance from the casing shoe to the top of the shallowest productive horizon make cementing, as specified above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such possible productive horizons and prevent fluid migration to or from such strata within the wellbore.

(4) Production casing.

(A) Cementing method. The producing string of casing shall be cemented by the pump and plug method, or another method approved by the commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 feet above the shoe. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such possibly productive horizons by one of the methods specified for intermediate casing in paragraph (3) of this subsection.

(B) Isolation of associated gas zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact.

(5) Tubing and storm choke requirements.

(A) Tubing requirements for oil wells. All flowing oil wells shall be equipped with and produced through tubing. When tubing is run inside casing in any flowing oil well, the bottom of the tubing shall be at a point not higher than 100 feet above the top of the producing interval nor more than 50 feet above the top of a line, if one is used. In a multiple zone structure, however, when an operator elects to equip a well in such a manner that small through-the-tubing type tools may be used to perforate, complete, plug back, or recomplete without the necessity of removing the installed tubing, the bottom of the tubing may be set at a distance up to, but not exceeding, 1,000 feet above the top of the perforated or open-hole interval actually open for production into the wellbore. In no case shall tubing be set at a depth of less than 70% of the distance from the surface of the ground to the top of the interval actually open to production.

(B) Storm choke. All flowing oil, gas, and geothermal resource wells located in bays, estuaries, lakes, rivers, or streams must be equipped with a storm choke or similar safety device installed in the tubing a minimum of 100 feet below the mud line.

(c) Texas offshore casing, cementing, drilling, and completion requirements.

(1) Casing. The casing program shall include at least three strings of pipe, in addition to such drive pipe as the operator may desire, which shall be set in accordance with the following program.

(A) Conductor casing. A string of new pipe, or reconditioned pipe with substantially the same characteristics as new pipe, shall be set and cemented at a depth of not less than 300 feet TVD (true vertical depth) nor more than 800 feet TVD below the mud line. Sufficient cement shall be used to fill the annular space back of the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations.

(B) Surface casing. All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi) or reconditioned pipe that has been tested to an equal pressure. Sufficient cement shall be used to fill the annular space behind the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Surface casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations. In all cases, surface casing shall be set prior to drilling below 3,500 feet TVD. Minimum depths for surface casing are as follows.

(i) Surface Casing Depth Table.

Proposed Total Vertical Depth of Well	**Surface**
to 7,000 feet	25% of proposed total depth of well
7,000-10,000 feet	2,000 feet
10,000 and below	2,500 feet

(ii) Casing test. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling plug or initiating tests. Casing shall be tested by pump pressure to at least 1,000 psi. If, at the end of 30 minutes, the pressure shows a drop of 100 psi or more, the casing shall be condemned until the leak is corrected. A pressure test demonstrating a drop of less than 100 psi after 30 minutes is proof that the condition has been corrected.

(C) Production casing or oil string. The production casing or oil string shall be new or reconditioned pipe with a mill test of at least 2,000 psi that has been tested to an equal pressure and after cementing shall be tested by pump pressure to at least 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 150 psi or more, the casing shall be condemned. After corrective operations, the casing shall again be tested in the same manner. Cementing shall be by the pump and plug method. Sufficient cement shall be used to fill the calculated annular space above the shoe to protect any prospective producing horizons and to a depth that isolates abnormal pressure from normal pressure (0.465 gradient). A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating tests.

(2) Blowout preventers.

(A) Before drilling below the conductor casing, the operator shall install at least one remotely controlled blowout preventer with a mechanism for automatically diverting the drilling fluid to the mud system when the blowout preventer is activated.

(B) After setting and cementing the surface casing, a minimum of two remotely controlled hydraulic ram-type blowout preventers (one equipped with blind rams and one with pipe rams), valves, and manifolds for circulating drilling fluid shall be installed for the purpose of controlling the well at all times. The ram-type blowout preventers, valves, and manifolds shall be tested to 100% of rated working pressure, and the annular-type blowout preventer shall be tested to 1,000 psi at the time of installation. During drilling and completion operations, the ram-type blowout preventers shall be tested by closing at least once each trip, and the annular-type preventer shall be tested by closing on drill pipe once each week.

(3) Kelly cock. During drilling, the well shall be fitted with an upper kelly cock in proper working order to close in the drill string below hose and swivel, when necessary for well control. A lower kelly safety valve shall be installed so that it can be run through the blowout preventer. When needed for well control, the operator shall maintain at all times on the rig floor safety valves to include:

(A) full-opening valve of similar design as the lower kelly safety valves; and

(B) inside blowout preventer valve with wrenches, handling tools, and necessary subs for all drilling pipe sizes in use.

(4) Mud program. The characteristics, use, and testing of drilling mud and conduct of related drilling procedures shall be designed to prevent the blowout of any well. Adequate supplies of mud of sufficient weight and other acceptable characteristics shall be maintained. Mud tests shall be made frequently. Adequate mud testing equipment shall be kept on the drilling platform at all times. The hole shall be kept full of mud at all times. When pulling drill pipe, the mud volume required to fill the hole each time shall be measured to assure that it corresponds with the displacement of pipe pulled. A derrick floor recording mud pit level indicator shall be installed and operative at all times. A careful watch for swabbing action shall be maintained when pulling out of hole. Mud-gas separation equipment shall be installed and operated.

(5) Casinghead.

(A) Requirement. All wells shall be equipped with casingheads of sufficient rated working pressure, with adequate connections and valves available, to permit pumping mud-laden fluid between any two strings of casing at the surface.

(B) Casinghead test procedure. Any well showing sustained pressure on the casinghead, or leaking gas or oil between the surface casing and the oil string, shall be tested in the following manner. The well shall be killed with water or mud and pump pressure applied. Should the pressure gauge on the casinghead reflect the applied pressure, the casing shall be condemned.

After corrective measures have been taken, the casing shall be tested in the same manner. This method shall be used when the origin of the pressure cannot be determined otherwise.

(6) Christmas tree. All completed wells shall be equipped with Christmas tree fittings and wellhead connections with a rated working pressure equal to, or greater than, the surface shut-in pressure of the well. The tubing shall be equipped with a master valve, but two master valves shall be used on all wells with surface pressures in excess of 5,000 psi. All wellhead connections shall be assembled and tested prior to installation by a fluid pressure equal to the test pressure of the fitting employed.

(7) Storm choke and safety valve. A storm choke or similar safety device shall be installed in the tubing of all completed flowing wells to a minimum of 100 feet below the mud line. Such wells shall have the tubing-casing annulus sealed below the mud line. A safety valve shall be installed at the wellhead downstream of the wing valve. All oil, gas, and geothermal resource gathering lines shall have check valves at their connections to the wellhead.

(8) Pipeline shut-off valve. All gathering pipelines designed to transport oil, gas, condensate, or other oil or geothermal resource field fluids from a well or platform shall be equipped with automatically controlled shut-off valves at critical points in the pipeline system. Other safety equipment must be in full working order as a safeguard against spillage from pipeline ruptures.

(9) Training. Effective January 1, 1981, all tool pushers, drilling superintendents, and operators' representatives (when the operator is in control of the drilling) shall be required to furnish certification of satisfactory completion of a USGS-approved school on well control equipment and techniques. The certification shall be renewed every two years by attending a USGS-approved refresher course. These training requirements apply to all drilling operations on lands which underlie fresh or marine waters in Texas.

Source Note: The provisions of this §3.13 adopted to be effective January 1, 1976; amended to be effective April 8, 1980, 5 TexReg 1152; amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective January 1, 1983, 7 TexReg 3982; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective January 11, 1991, 16 TexReg 39; amended to be effective August 13, 1991, 16 TexReg 4153; amended to be effective August 25, 2003, 28 TexReg 6816

Appendix 2.
Notification of Fire Breaks, Leaks and Blow-outs

Rule §3.20: Texas Administrative Code
Railroad Commission of Texas
Oil and Gas Division

Texas Administrative Code

TITLE 16 ECONOMIC REGULATION
PART 1 RAILROAD COMMISSION OF TEXAS
CHAPTER 3 OIL AND GAS DIVISION
RULE §3.20 Notification of Fire Breaks, Leaks, or Blow-outs

(a) General requirements.

(1) Operators shall give immediate notice of a fire, leak, spill, or break to the appropriate commission district office by telephone or telegraph. Such notice shall be followed by a letter giving the full description of the event, and it shall include the volume of crude oil, gas, geothermal resources, other well liquids, or associated products lost.

(2) All operators of any oil wells, gas wells, geothermal wells, pipelines receiving tanks, storage tanks, or receiving and storage receptacles into which crude oil, gas, or geothermal resources are produced, received, stored, or through which oil, gas, or geothermal resources are piped or transported, shall immediately notify the commission by letter, giving full details concerning all fires which occur at oil wells, gas wells, geothermal wells, tanks, or receptacles owned, operated, or controlled by them or on their property, and all such persons shall immediately report all tanks or receptacles struck by lightning and any other fire which destroys crude oil, natural gas, or geothermal resources, or any of them, and shall immediately report by letter any breaks or leaks in or from tanks or other receptacles and pipelines from which oil, gas, or geothermal resources are escaping or have escaped. In all such reports of fires, breaks, leaks, or escapes, or other accidents of this nature, the location of the well, tank, receptacle, or line break shall be given by county, survey, and property, so that the exact location thereof can be readily located on the ground. Such report shall likewise specify what steps have been taken or are in progress to remedy the situation reported and shall detail the quantity (estimated, if no accurate measurement can be obtained, in which case the report shall show that the same is an estimate) of oil, gas, or geothermal resources, lost, destroyed, or permitted to escape. In case any tank or receptacle is permitted to run over, the escape thus occurring shall be reported as in the case of a leak. (Reference Order Number 20-60,399, effective 9-24-70.)

(b) The report hereby required as to oil losses shall be necessary only in case such oil loss exceeds five barrels in the aggregate.

(c) Any operation with respect to the pickup of pipeline break oil shall be done subject to the following provisions. The provisions hereafter set out shall not apply to the picking up and the returning of pipeline break oil to the pipeline from which it escaped either at the place of the pipeline break, or at the nearest pipeline station to the break where facilities are available to return such oil to the pipeline; provided, that such operations are conducted by the pipeline operator at the time of the pipeline break and its repair; provided, further, that such authority as is herein granted for the picking up of pipeline break oil shall not relieve the operator of such pipeline of notifying the commission of such pipeline break, and the furnishing to the commission of the information required by the provisions set out in subsection (a) of this section for reporting such pipeline breaks.

(1) Any person desiring to pick up, reclaim, or salvage pipeline break oil, other than as provided in this subsection, shall obtain in writing a permit before commencing operations. All applications for permits to pick up, reclaim, or salvage such oil shall be made in writing under oath to the district office.

(2) Applications to pick up, reclaim, or salvage pipeline break oil shall state the location of such oil, the location of the break in the pipeline causing the leakage of such oil, the name of the pipeline, the owner thereof, and the date of the break.

(3) Pipeline break oil that is not returned to the pipeline from which it escaped shall be offered to the applicant to reclaim by the operator of such pipeline but shall be charged to such pipeline stock account.

Source Note: The provisions of this §3.20 adopted to be effective January 1, 1976.

Appendix 3.
Reporting of Undesirable Oil and Gas Events

Rule 649-3-32: Division of Oil, Gas and Mining
Department of Natural Resources
State of Utah

UTAH OIL and GAS

Division of Oil, Gas and Mining - State of Utah - Department of Natural Resources

Definition of Major Event

- **Leaks, breaks or spills which result in the discharge of more than 100 barrels of liquid.**
- **Equipment failures or accidents which result in the flaring, venting, or wasting of more than 500 Mcf of gas.**
- **Any fire which consumes the volumes shown above.**
- **Any spill, venting, or fire, regardless of the volume involved, which occurs in a sensitive area stipulated on the approval notice of the initial APD for a well, e.g., parks, recreation sites, wildlife refuges, lakes, reservoirs, streams, urban or suburban areas.**
- **Each accident which involves a fatal injury.**
- **Each blowout; loss of control of a well.**

R649-3-32. Reporting of Undesirable Events.

1. The division shall be notified of all fires, leaks, breaks, spills, blowouts, and other undesirable events occurring at any oil or gas drilling, producing, or transportation facility, or at any injection or disposal facility.

2. Immediate notification shall be required for all major undesirable events as outlined in R649-3-32-5.

2.1. Immediate notification shall mean a verbal report submitted to the division as soon as practical but within a maximum of 24 hours after discovery of an undesirable event.

2.2. A complete written report of the incident shall also be submitted to the division within five days following the conclusion of an undesirable event.

2.3. The requirements for written reports are specified in R649-3-32-4.

3. Subsequent notification shall be required for all minor undesirable events as outlined in R649-3-32-6.

3.1. Subsequent notification shall mean a complete written report of the incident submitted to the division within five days following the conclusion of an undesirable event.

3.2. The requirements for written reports are specified in R649-3-32-4.

4. Complete written reports of undesirable events may be submitted on Form 9, Sundry Notice and Report on Wells. The report shall include:

4.1. The date and time of occurrence and, if immediate notification was required, the date and time the occurrence was reported to the Division.

4.2. The location where the incident occurred described by section, township, range, and county.

4.3. The specific nature and cause of the incident.

4.4. A description of the resultant damage.

4.5. The action taken, the length of time required for control or containment of the incident, and the length of time required for subsequent cleanup.

4.6. An estimate of the volumes discharged and the volumes not recovered.

4.7. The cause of death if any fatal injuries occurred.

5. Major undesirable events include the following:

5.1. Leaks, breaks or spills of oil, salt water or oil field wastes that result in the discharge of more than 100 barrels of liquid, that are not fully contained on location by a wall, berm, or dike.

5.2. Equipment failures or other accidents that result in the flaring, venting, or wasting of more than 500 Mcf of gas.

5.3. Any fire that consumes the volumes of liquid or gas specified in R649-3-32-5.1 and R649-3-32-5.2.

5.4. Any spill, venting, or fire, regardless of the volume involved, that occurs in a sensitive area stipulated on the approval notice of the initial APD for a well, e.g., parks, recreation sites, wildlife refuges, lakes, reservoirs, streams, urban or suburban areas.

5.5. Each accident that involves a fatal injury.

5.6. Each blowout, loss of control of a well.

6. Minor undesirable events include the following:

6.1. Leaks, breaks or spills or oil, salt water, or oil field wastes that result in the discharge of more than ten barrels of liquid and are not considered major events in R649-3-32-5.

6.2 Equipment failures or other accidents that result in the flaring, venting or wasting of more than 50 Mcf of gas and are not considered major events in R649-3-32-5.

6.3. Any fire that consumes the volumes of liquid or specified in R649-3-32-6.1 and R649-3-32-6.2.
6.4. Each accident involving a major or life-threatening injury.

Appendix 4.
Procedure for Internal Casing Repair

Procedure #: UICLPG-12
Kansas Department Of Health & Environment
State of Kansas

KANSAS DEPARTMENT OF HEALTH & ENVIRONMENT

PROCEDURE FOR INTERNAL CASING REPAIR

Procedure #: UICLPG-12

Narrative:

The operator shall submit a plan for casing repair to the Kansas Department of Health and Environment (KDHE) prior to repairing any casing in any underground hydrocarbon storage well. The operator shall not commence any repair operations until the plan is approved by KDHE.

The casing shall be repaired in a manner that will ensure the integrity of the well is maintained.

The plan for casing repair shall include the following information:

- A schematic of the well configuration, including casing size and weight
- The condition of the well, including any restrictions in the casing, hole deviation, and condition of the cement
- The external and internal pressure rating of the casing patch
- A description of the leak, including the depth, type, size, diameter, length, and width
- A description of the method and equipment used to locate the leak
- A description of the hole preparation before running the casing patch
- A description of the casing patch and installation method
- A description of safety precautions to be used while running the casing patch and the procedure to be used if the casing patch becomes stuck
- A description of the method to be used to pressure test the casing patch.

Procedure:

1. Depressure the cavern by removing all product that can feasibly be removed. Describe the procedure for removing product from the cavern, including any product trapped behind the casing.
2. Fill the cavern with brine.

3. Remove all tubing string(s) from the well.
4. Conduct a casing evaluation to determine the condition of the entire casing string. The operator should determine the following:
    a. The type of leak
    b. The internal diameter of the casing to determine if it is oversized
    c. The position of the hold down.
    d. The location of the leak.
5. Additionally, a gamma ray log shall be run to correlate the depth of the leak and the patch position.
6. Initiate any hole preparations and procedures required for the type of leak identified and approved by KDHE for repair.
7. Run a casing scraper to clean the casing in the patch area.
8. Make a gage or drift run to identify any restrictions in the casing. Describe tentative procedures for removing any restrictions.
9. Run a casing caliper log if the internal diameter of the casing is not known or is questionable. Determine the amount of reduction to the inside diameter of the casing after the patch is applied.
10. Determine the pressure requirements for the patch and confirm that the patch is designed for the size and weight of the casing. Refer to any charts provided by the patch manufacturer.
11. Follow manufacturer’s recommended safety precautions while running the patch.
12. When setting the patch, overlap the leak by 6 to 8 feet on each end. When patching corroded casing, cover the full joint of casing with a 6 to 8 foot overlap at each end.
13. Pressure test the patch. Allow the patch to set at lest 24 hours before testing. Do not exceed differential pressure ratings provided by the manufacturer.
14. Submit a casing repair report, including description of field work, to KDHE.

Appendix 5.
Well Plugging

Rule §3.14: Texas Administrative Code
Railroad Commission of Texas
Oil and Gas Division

Texas Administrative Code

TITLE 16 ECONOMIC REGULATION
PART 1 RAILROAD COMMISSION OF TEXAS
CHAPTER 3 OIL AND GAS DIVISION
RULE §3.14 Plugging

(a) Definitions and application to plug.

(1) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(A) Active operation--Regular and continuing activities related to the production of oil and gas for which the operator has all necessary permits. In the case of a well that has been inactive for 12 consecutive months or longer and that is not permitted as a disposal or injection well, the well remains inactive for purposes of this section, regardless of any minimal activity, until the well has reported production of at least 10 barrels of oil for oil wells or 100 mcf of gas for gas wells each month for at least three consecutive months.

(B) Approved cementer--A cementing company, service company, or operator approved by the Commission to mix and pump cement for the purpose of plugging a well in accordance with the provisions of this section. The term shall also apply to a cementing company, service company, or operator authorized by the Commission to use an alternate material other than cement to plug a well.

(C) Delinquent inactive well--An unplugged well that has had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months and for which, after notice and opportunity for hearing, the Commission has not extended the plugging deadline.

(D) Funnel viscosity--Viscosity as measured by the Marsh funnel, based on the number of seconds required for 1,000 cubic centimeters of fluid to flow through the funnel.

(E) Good faith claim--A factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate.

(F) Groundwater conservation district--Any district or authority created under §52, Article III, or §59, Article XVI, Texas Constitution, that has the authority to regulate the spacing of water wells, the production from water wells, or both.

(G) Operator designation form--A certificate of compliance and transportation authority or an application to drill, deepen, recomplete, plug back, or reenter which has been completed, signed and filed with the Commission.

(H) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in producible quantities in the vicinity of an unplugged well.

(I) Related piping--The surface piping and subsurface piping that is less than three feet beneath the ground surface between pieces of equipment located at any collection or treatment facility. Such piping would include piping between and among headers, manifolds, separators, storage tanks, gun barrels, heater treaters, dehydrators, and any other equipment located at a collection or treatment facility. The term is not intended to refer to lines, such as flowlines, gathering lines, and injection lines that lead up to and away from any such collection or treatment facility.

(J) Reported production--Production of oil or gas, excluding production attributable to well tests, accurately reported to the Commission on a monthly producer's report.

(K) To serve notice on the surface owner or resident--To hand deliver a written notice identifying the well or wells to be plugged and the projected date the well or wells will be plugged to the surface owner, or resident if the owner is absent, at least three days prior to the day of plugging or to mail the notice by first class mail, postage pre-paid, to the last known address of the surface owner or resident at least seven days prior to the day of plugging.

(L) Unbonded operator--An operator that has a current and active organization report on file with the Commission that filed a nonrefundable annual fee as financial security prior to September 1, 2004, and is not required by §3.78 of this title (relating to Fees and Financial Security Requirements) to file an individual performance bond, blanket performance bond, letter of credit, or cash deposit as its financial security until the first date for annual renewal of the operator's organization report after September 1, 2004.

(M) Usable quality water strata--All strata determined by the Texas Commission on Environmental Quality or its successor agencies to contain usable quality water.

(N) Written notice--Notice actually received by the intended recipient in tangible or retrievable form, including notice set out on paper and hand-delivered, facsimile transmissions, and electronic mail transmissions.

(2) The operator shall give the Commission notice of its intention to plug any well or wells drilled for oil, gas, or geothermal resources or for any other purpose over which the Commission has jurisdiction, except those specifically addressed in §3.100(e)(1) of this title (relating to Seismic Holes and Core Holes) (Statewide Rule 100), prior to plugging. The operator shall deliver or transmit the written notice to the district office on the appropriate form.

(3) The operator shall cause the notice of its intention to plug to be delivered to the district office at least five days prior to the beginning of plugging operations. The notice shall set out the proposed plugging procedure as well as the complete casing record. The operator shall not commence the work of plugging the well or wells until the proposed procedure has been approved by the district director or the director's delegate. The operator shall not initiate approved plugging operations before the date set out in the notification for the beginning of plugging operations unless authorized by the district director or the director's delegate. The operator shall notify the district office at least four hours before commencing plugging operations and proceed with the work as approved. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices

when a workover or drilling rig is already at work on location, and ready to commence plugging operations. Operations shall not be suspended prior to plugging the well unless the hole is cased and casing is cemented in place in compliance with Commission rules. The Commission's approval of a notice of intent to plug and abandon a well shall not relieve an operator of the requirement to comply with subsection (b)(2) of this section, nor does such approval constitute an extension of time to comply with subsection (b)(2) of this section.

(4) The surface owner and the operator may file an application to condition an abandoned well located on the surface owner's tract for usable quality water production operations. The application shall be made on the form prescribed by the Commission, the Application of Landowner to Condition an Abandoned Well for Fresh Water Production.

(A) Standard for Commission Approval. Before the Commission will consider approval of an application:

(i) the surface owner shall assume responsibility for plugging the well and obligate himself, his heirs, successors, and assignees to complete the plugging operations;

(ii) the operator responsible for plugging the well shall place all cement plugs required by this rule up to the base of the usable quality water strata; and

(iii) the surface owner shall submit:

(I) a signed statement attesting to the fact that:

(-a-) there is no groundwater conservation district for the area in which the well is located; or

(-b-) there is a groundwater conservation district for the area where the well is located, but the groundwater conservation district does not require that the well be permitted or registered; or

(-c-) the surface owner has registered the well with the groundwater conservation district for the area where the well is located; or

(II) a copy of the permit from the groundwater conservation district for the area where the well is located.

(B) The duty of the operator to properly plug ends only when:

(i) the operator has properly plugged the well in accordance with Commission requirements up to the base of the usable quality water stratum;

(ii) the surface owner has registered the well with, or has obtained a permit for the well from, the groundwater conservation district, if applicable; and

(iii) the Commission has approved the application of surface owner to condition an abandoned well for fresh water production.

(5) The operator of a well shall serve notice on the surface owner of the well site tract, or the resident if the owner is absent, before the scheduled date for beginning the plugging operations. A representative of the surface owner may be present to witness the plugging of the well. Plugging shall not be delayed because of the lack of actual notice to the surface owner or resident if the operator has served notice as required by this paragraph. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location and ready to commence plugging operations.

(b) Commencement of plugging operations, extensions, and testing.

(1) The operator shall complete and file in the district office a duly verified plugging record, in duplicate, on the appropriate form within 30 days after plugging operations are completed. A cementing report made by the party cementing the well shall be attached to, or made a part of, the plugging report. If the well the operator is plugging is a dry hole, an electric log status report shall be filed with the plugging record.

(2) Plugging operations on each dry or inactive well shall be commenced within a period of one year after drilling or operations cease and shall proceed with due diligence until completed. Plugging operations on delinquent inactive wells shall be commenced immediately unless the well is restored to active operation. For good cause, a reasonable extension of time in which to start the plugging operations may be granted pursuant to the following procedures.

(A) Plugging of inactive wells operated by unbonded operators. During the interim period between September 1, 2004, and the first date for annual renewal of an unbonded operator's organization report after September 1, 2004, the Commission or its delegate may administratively grant an extension of up to one year of the deadline for plugging an inactive well that is operated by an unbonded operator if the following criteria are met:

(i) The well and associated facilities are in compliance with all other laws and Commission rules;

(ii) The operator's organization report is current and active;

(iii) The operator has, and upon request provides evidence of, a good faith claim to a continuing right to operate the well; and

(iv) The operator has tested the well in accordance with the provisions of paragraph (3) of this subsection and files with its application proof of either:

(I) a fluid level test conducted within 90 days prior to the application for a plugging extension demonstrating that any fluid in the wellbore is at least 250 feet below the base of the deepest usable quality water stratum; or,

(II) a hydraulic pressure test conducted during the period the well has been inactive and not more than four years prior to the date of application demonstrating the mechanical integrity of the well.

(B) Plugging of inactive wells operated by bonded operators. An operator that maintains valid, Commission-approved financial security in the form of an individual performance bond, blanket performance bond, letter of credit, or cash deposit as provided in §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78) will be granted a one-year plugging extension for each well it operates that has been inactive for 12 months or more at the time its annual organizational report is approved by the Commission if the following criteria are met:

(i) The well and associated facilities are in compliance with all laws and Commission rules; and,

(ii) The operator has, and upon request provides evidence of, a good faith claim to a continuing right to operate the well.

(C) Revocation or denial of plugging extension.

(i) The Commission or its delegate may revoke a plugging extension if the operator of the well that is the subject of the extension fails to maintain the well and all associated facilities in compliance with Commission rules; fails to maintain a current and accurate organizational report on file with the Commission; fails to provide the Commission, upon request, with evidence of a continuing good faith claim to operate the well; or fails to obtain or maintain financial security as required by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78).

(ii) If the Commission or its delegate declines to grant or continue a plugging extension or revokes a previously granted extension, the operator shall either return the well to active operation or, within 30 days, plug the well or request a hearing on the matter.

(3) The operator of any well more than 25 years old that becomes inactive and subject to the provisions of this subsection or the operator of any well for which a plugging extension is sought under the terms of subparagraph (A) of paragraph (2) of this subsection shall plug the well or successfully conduct a fluid level or hydraulic pressure test establishing that the well does not pose a potential threat of harm to natural resources, including surface and subsurface water, oil and gas.

(A) In general, a fluid level test is a sufficient test for purposes of this paragraph. The operator shall give the district office written notice specifying the date and approximate time it intends to conduct the fluid level test at least 48 hours prior to conducting the test; however, upon a showing of undue hardship, the district director or the director's delegate may grant a written waiver or reduction of the notice requirement for a specific well test. The director or the director's delegate may require alternate methods of testing if necessary to ensure the well does not pose a potential threat of harm to natural resources. Alternate methods of testing may be approved by the director or the director's delegate by written application and upon a showing that such a test will provide information sufficient to determine that the well does not pose a threat to natural resources.

(B) No test other than a fluid level test shall be acceptable without prior approval from the district director or the director's delegate. The district director or the director's delegate shall be notified at least 48 hours before any test other than a fluid level test is conducted. Mechanical integrity test results shall be filed with the district office and fluid level test results shall be filed with the Commission in Austin. Test results shall be filed on a Commission-approved form, within 30 days of the completion of the test. Upon request, the operator shall file the actual test data for any mechanical integrity or fluid level test that it has conducted.

(C) Notwithstanding the provisions of subparagraph (B) of this paragraph, a hydraulic pressure test may be conducted without prior approval from the district director or the director's delegate, provided that the operator gives the district office written notice specifying the date and approximate time for the test at least 48 hours prior to the time the test will be conducted, the production casing is tested to a depth of at least 250 feet below the base of usable quality water strata, or 100 feet below the top of cement behind the production casing, whichever is deeper, and the minimum test pressure is greater than or equal to 250 psig for a period of at least 30 minutes.

(D) If the operator performs a hydraulic pressure test in accordance with the provisions of subparagraph (C) of this paragraph, the well shall be exempt from further testing for five years from the date of the test, except to the extent that the Commission or its delegate may require the operator to perform testing more frequently to ensure that the well does not pose a threat of harm to natural resources. The Commission or its delegate may approve less frequent well tests under this paragraph upon written request and for good cause shown provided that less frequent testing will not increase the threat of harm to natural resources.

(E) A well subject to the testing requirements of this paragraph shall not be returned to active operation unless a fluid level test of the well has been performed within 12 months prior to the return to activity or a mechanical integrity test of the well has been performed within 60 months prior to the return to activity.

(4) The Commission may plug or replug any dry or inactive well as follows:

(A) After notice and hearing, if the well is causing or is likely to cause the pollution of surface or subsurface water or if oil, gas, or other formation fluid is leaking from the well, and:

(i) Neither the operator nor any other entity responsible for plugging the well can be found; or

(ii) Neither the operator nor any other entity responsible for plugging the well has assets with which to plug the well.

(B) Without a hearing if the well is a delinquent inactive well and:

(i) the Commission has sent notice of its intention to plug the well as required by §89.043(c) of the Texas Natural Resources Code; and

(ii) the operator did not request a hearing within the period (not less than 10 days after receipt) specified in the notice.

(C) Without notice or hearing, if:

(i) The Commission has issued a final order requiring that the operator plug the well and the order has not been complied with; or

(ii) The well poses an immediate threat of pollution of surface or subsurface waters or of injury to the public health and the operator has failed to timely remediate the problem.

(5) The Commission may seek reimbursement from the operator and any other entity responsible for plugging the well for state funds expended pursuant to paragraph (4) of this subsection.

(c) Designated operator responsible for proper plugging.

(1) The entity designated as the operator of a well specifically identified on the most recent Commission-approved operator designation form filed on or after September 1, 1997, is responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning plugging of wells.

(2) As to any well for which the most recent Commission-approved operator designation form was filed prior to September 1, 1997, the entity designated as operator on that form is presumed to be the entity responsible for the physical operation and control of the well and to be the entity responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning plugging of wells. The presumption of responsibility may be rebutted only at a hearing called for the purpose of determining plugging responsibility.

(d) General plugging requirements.

(1) Wells shall be plugged to insure that all formations bearing usable quality water, oil, gas, or geothermal resources are protected. All cementing operations during plugging shall be performed under the direct supervision of the operator or his authorized representative, who shall not be an employee of the service or cementing company hired to plug the well. Direct supervision means supervision at the well site during the plugging operations. The operator and the cementer are both responsible for complying with the general plugging requirements of this subsection and for plugging the well in conformity with the procedure set forth in the approved notice of intention to plug and abandon for the well being plugged. The operator and cementer may each be assessed administrative penalties for failure to comply with the general plugging requirements of this subsection or for failure to plug the well in conformity with the approved notice of intention to plug and abandon the well.

(2) Cement plugs shall be set to isolate each productive horizon and usable quality water strata. Plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Texas Commission on Environmental Quality or its successor agencies. The operator shall verify the placement of the plug required at the base of the deepest usable quality water stratum by tagging with tubing or drill pipe or by an alternate method approved by the district director or the district director's delegate.

(3) Cement plugs shall be placed by the circulation or squeeze method through tubing or drill pipe. Cement plugs shall be placed by other methods only upon written request with the written approval of the district director or the director's delegate.

(4) All cement for plugging shall be an approved API oil well cement without volume extenders and shall be mixed in accordance with API standards. Slurry weights shall be reported on the cementing report. The district director or the director's delegate may require that specific cement compositions be used in special situations; for example, when high temperature, salt section, or highly corrosive sections are present. An operator shall request approval to use alternate materials, other than API oil well cement without volume extenders, to plug a well by filing with the director or the director's delegate a written request providing all pertinent information to support the use of the proposed alternate material and plugging method. The director or the director's delegate shall determine whether such a request warrants approval, after considering factors which include but are not limited to whether or not the well to be plugged was used as an injection or disposal well; the well's history; the well's current bottom hole pressure; the presence of highly pressurized formations intersected by the wellbore; the method by which the alternative material will be placed in the wellbore; and the compressive strength and other performance specifications of the alternative material to be used. The director or the director's delegate shall approve such a request only if the proposed alternate material and plugging method will ensure that the well does not pose a potential threat of harm to natural resources.

(5) Operators shall use only cementers approved by the director or the director's delegate, except when plugging is conducted in accordance with subparagraph (B)(ii) of this paragraph or paragraph (6) of this subsection. Cementing companies, service companies, or operators may apply for designation as approved cementers. Approval will be granted on a showing by the applicant of the ability to mix and pump cement or other alternate materials as approved by the director or the director's delegate in compliance with this rule. An approved cementer is authorized to conduct plugging operations in accordance with Commission rules in each Commission district.

(A) A cementing company, service company, or operator seeking designation as an approved cementer shall file a request in writing with the district director of the district in which it proposes to conduct its initial plugging operations. The request shall contain the following information:

(i) the name of the organization as shown on its most recent approved organizational report;

(ii) a list of qualifications including personnel who will supervise mixing and pumping operations;

(iii) length of time the organization has been in the business of cementing oil and gas wells;

(iv) an inventory of the type of equipment to be used to mix and pump cement or other alternate materials as approved by the director or the director's delegate; and

(v) a statement certifying that the organization will comply with all Commission rules.

(B) No request for designation as an approved cementer will be approved until after the district director or the director's delegate has:

(i) inspected all equipment to be used for mixing and pumping cement or other alternate materials as approved by the director or the director's delegate; and

(ii) witnessed at least one plugging operation to determine if the cementing company, service company, or operator can properly mix and pump cement or other alternate materials as approved by the director or the director's delegate according to the specifications required by this rule.

(C) The district director or the director's delegate shall file a letter with the director or the director's delegate recommending that the application to be designated as an approved cementer be approved or denied. If the district director or the director's delegate does not recommend approval, or the director or the director's delegate denies the application, the applicant may request a hearing on its application.

(D) Designation as an approved cementer may be suspended or revoked for violations of Commission rules. The designation may be revoked or suspended administratively by the director or the director's delegate for violations of Commission rules if:

(i) the cementer has been given written notice by personal service or by registered or certified mail informing the cementer of the proposed action, the facts or conduct alleged to warrant the proposed action, and of its right to request a hearing within 10 days to demonstrate compliance with Commission rules and all requirements for retention of designation as an approved cementer; and

(ii) the cementer did not file a written request for a hearing within 10 days of receipt of the notice.

(6) An operator may request administrative authority to plug its own wells without being an approved cementer. An operator seeking such authority shall file a written request with the district director and demonstrate its ability to mix and pump cement or other alternate materials as approved by the director or the director's delegate in compliance with this subsection. The district director or the director's delegate shall determine whether such a request warrants approval. If the district director or the director's delegate refuses to administratively approve this request, the operator may request a hearing on its request.

(7) The district director or the director's delegate may require additional cement plugs to cover and contain any productive horizon or to separate any water stratum from any other water stratum if the water qualities or hydrostatic pressures differ sufficiently to justify separation. The tagging and/or pressure testing of any such plugs, or any other plugs, and respotting may be required if necessary to ensure that the well does not pose a potential threat of harm to natural resources.

(8) For onshore or inland wells, a 10-foot cement plug shall be placed in the top of the well, and casing shall be cut off three feet below the ground surface.

(9) Mud-laden fluid of at least 9-1/2 pounds per gallon with a minimum funnel viscosity of 40 seconds shall be placed in all portions of the well not filled with cement or other alternate material as approved by the director or the director's delegate. The hole shall be in static condition at the time the cement plugs are placed. The district director or the director's delegate may grant exceptions to the requirements of this paragraph if a deviation from the prescribed minimums for fluid weight or viscosity will insure that the well does not pose a potential threat of harm to natural resources. An operator shall request approval to use alternate fluid other than mud-laden fluid by filing with the district director a written request providing all pertinent information to support the use of the proposed alternate fluid. The district director or the director's delegate shall determine whether such a request warrants approval, and shall approve such a request only if the proposed alternate fluid will insure that the well does not pose a potential threat of harm to natural resources.

(10) Non-drillable material that would hamper or prevent reentry of a well shall not be placed in any wellbore during plugging operations, except in the case of a well plugged and abandoned under the provisions of §3.35 or §4.614(b) of this title (relating to Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned (Statewide Rule 35); and Authorized Disposal Methods, respectively). Pipe and unretrievable junk shall not be cemented in the hole during plugging operations without prior approval by the district director or the director's delegate.

(11) All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(12) The operator shall fill the rathole, mouse hole, and cellar, and shall empty all tanks, vessels, related piping and flowlines that will not be actively used in the continuing operation of the lease within 120 days after plugging work is completed. Within the same 120 day period, the operator shall remove all such tanks, vessels, and related piping, remove all loose junk and trash from the location, and contour the location to discourage pooling of surface water at or around the facility site. The operator shall close all pits in accordance with the provisions of §3.8 of this title (relating to Water Protection (Statewide Rule 8)). The district director or the director's delegate may grant a reasonable extension of time of not more than an additional 120 days for the removal of tanks, vessels and related piping.

(e) Plugging requirements for wells with surface casing.

(1) When insufficient surface casing is set to protect all usable quality water strata and such usable quality water strata are exposed to the wellbore when production or intermediate casing is pulled from the well or as a result of such casing not being run, a cement plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and 50 feet below the base of the deepest usable quality water stratum. This plug shall be evidenced by tagging with tubing or drill pipe. The plug shall be respotted if it has not been properly placed. In addition, a cement plug shall be set across the shoe of the surface casing. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and below the shoe.

(2) When sufficient surface casing has been set to protect all usable quality water strata, a cement plug shall be placed across the shoe of the surface casing. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above the shoe and at least 50 feet below the shoe.

(3) If surface casing has been set deeper than 200 feet below the base of the deepest usable quality water stratum, an additional cement plug shall be placed inside the surface casing across the base of the deepest usable quality water stratum. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest usable quality water stratum.

(4) Plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Texas Commission on Environmental Quality or its successor agencies.

(f) Plugging requirements for wells with intermediate casing.

(1) For wells in which the intermediate casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum, but extend no less than 50 feet above and below the base of the deepest usable quality water stratum.

(2) For wells in which intermediate casing is not cemented through all usable quality water strata and all productive horizons, and if the casing will not be pulled, the intermediate casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(3) Additionally, plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Texas Commission on Environmental Quality or its successor agencies.

(g) Plugging requirements for wells with production casing.

(1) For wells in which the production casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum and across any multi-stage cementing tool. This plug shall be a

minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest usable quality water stratum.

(2) For wells in which the production casing has not been cemented through all usable quality water strata and all productive horizons and if the casing will not be pulled, the production casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(3) The district director or the director's delegate may approve a cast iron bridge plug to be placed immediately above each perforated interval, provided at least 20 feet of cement is placed on top of each bridge plug. A bridge plug shall not be set in any well at a depth where the pressure or temperature exceeds the ratings recommended by the bridge plug manufacturer.

(4) Additionally, plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Texas Commission on Environmental Quality or its successor agencies.

(h) Plugging requirements for well with screen or liner.

(1) If practical, the screen or liner shall be removed from the well.

(2) If the screen or liner is not removed, a cement plug in accordance with subsection (d)(11) of this section shall be placed at the top of the screen or liner.

(i) Plugging requirements for wells without production casing and open-hole completions.

(1) Any productive horizon or any formation in which a pressure or formation water problem is known to exist shall be isolated by cement plugs centered at the top and bottom of the formation. Each cement plug shall have sufficient slurry volume to fill a calculated height as specified in subsection (d)(11) of this section.

(2) If the gross thickness of any such formation is less than 100 feet, the tubing or drill pipe shall be suspended 50 feet below the base of the formation. Sufficient slurry volume shall be pumped to fill the calculated height from the bottom of the tubing or drill pipe up to a point at least 50 feet above the top of the formation, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(j) The district director or the director's delegate shall review and approve the notification of intention to plug in a manner so as to accomplish the purposes of this section. The district director or the director's delegate may approve, modify, or reject the operator's notification of intention to plug. If the proposal is modified or rejected, the operator may request a review by the director or the director's delegate. If the proposal is not administratively approved, the operator may request a hearing on the matter. After hearing, the examiner shall recommend final action by the Commission.

(k) Plugging horizontal drainhole wells. All plugs in horizontal drainhole wells shall be set in accordance with subsection (d)(11) of this section. The productive horizon isolation plug shall be set from a depth 50 feet below the top of the productive horizon to a depth either 50 feet above the top of the productive horizon, or 50 feet above the production casing shoe if the production casing is set above the top of the productive horizon. If the production casing shoe is set below the top of the productive horizon, then the productive horizon isolation plug shall be set from a depth 50 feet below the production casing shoe to a depth that is 50 feet above the top of the productive horizon. In accordance with subsection (d)(7) of this section, the Commission or its delegate may require additional plugs.

Source Note: The provisions of this §3.14 adopted to be effective January 1, 1976; amended to be effective February 29, 1980, 5 TexReg 499; amended to be effective January 1, 1983, 7 TexReg 3989; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective September 8, 1986, 11 TexReg 3792; amended to be effective November 9, 1987, 12 TexReg 3959; amended to be effective May 9, 1988, 13 TexReg 2026; amended to be effective March 1, 1992, 17 TexReg 1227; amended to be effective September 1, 1992, 17 TexReg 5283; amended to be effective September 20, 1995, 20 TexReg 6931; amended to be effective September 14, 1998, 23 TexReg 9300; amended to be effective December 28, 1999,24TexReg11711;amendedto be effective July 10, 2000, 25 TexReg 6487; amended to be effective November 1, 2000, 25 TexReg 9924; amended to be effective January 9, 2002, 27 TexReg 139; amended to be effective July 28, 2003, 28 TexReg 5853; amended to be effective December 3, 2003, 28 TexReg 10747; amended to be effective September 1, 2004, 29 TexReg 8271

Appendix 6.
Plugging and Abandonment of Wells

Rule 649-3-24: Division of Oil, Gas and Mining
Department of Natural Resources
State of Utah

UT Administrative Code
R649-3-24. Plugging and Abandonment of Wells.

1. Before operations are commenced to plug and abandon any well the owner or operator shall submit a notice of intent to plug and abandon to the division for its approval.

1.1. The notice shall be submitted on Form DOGM-9, Sundry Notice and Report on Wells.

1.2. A legible copy of a similar report and form filed with the appropriate federal agency may be used in lieu of the forms prescribed by the board.

1.3. In cases of emergency the operator may obtain verbal or telegraphic approval to plug and abandon.

1.4. Within five days after receiving verbal or telegraphic approval, the operator shall submit a written notice of intent to plug and abandon on Form 9.

2. Both verbal and written notice of intent to plug and abandon a well shall contain the following information:

2.1. The location of the well described by section, township, range, and county.

2.2. The status of the well, whether drilling, producing, injecting or inactive.

2.3. A description of the well bore configuration indicating depth, casing strings, cement tops if known, and hole size.

2.4. The tops of known geologic markers or formations.

2.5. The plugging program approved by the appropriate federal agency if the well is located on federal or Indian land.

2.6. An indication of when plugging operations will commence.

3. A dry or abandoned well must be plugged so that oil, gas, water, or other substance will not migrate through the well bore from one formation to another.

3.1. Unless a different method and procedure is approved by the division, the method and procedure for plugging the well shall be as follows:

3.2. The bottom of the hole shall be filled to, or a bridge shall be placed at, the top of each producing formation open to the well bore, and a cement plug not less than 100 feet in length shall be placed immediately above each producing formation open to the well bore.

3.3. A solid cement plug shall be placed from 50 feet below a fresh water zone to 50 feet above the fresh water zone, or a 100 foot cement plug shall be centered across the base of the fresh water zone and a 100 foot plug shall be centered across the top of the fresh water zone.

3.4. At least ten sacks of cement shall be placed at the surface in a manner completely plugging the entire hole. If more than one string of casing remains at the surface, all annuli shall be so cemented.

3.5. The interval between plugs shall be filled with noncorrosive fluid of adequate density to prevent migration of formation water into or through the well bore.

3.6. The hole shall be plugged up to the base of the surface string with noncorrosive fluid of adequate density to prevent migration of formation water into or through the well bore, at which point a plug of not less than 50 feet of cement shall be placed.

3.7. Any perforated interval shall be plugged with cement and any open hole porosity zone shall be adequately isolated to prevent migration of fluids.

3.8. A cement plug not less than 100 feet in length shall be centered across the casing stub if any casing is cut and pulled, a second plug of the same length shall be centered across the casing shoe of the next larger casing.

4. An alternative method of plugging, required under a federal or Indian lease, will be accepted by the division.

5. Within 30 days after the plugging of any well has been accomplished, the owner or operator shall file a subsequent report of plugging with the division. The report shall give a detailed account of the following items:

5.1. The manner in which the plugging work was carried out, including the nature and quantities of materials used in plugging and the location, nature, and extent by depths, of the plugs.

5.2. Records of any tests or measurements made.

5.3. The amount, size, and location, by depths of any casing left in the well.

5.4. A statement of the volume of mud fluid used.

5.5. A complete report of the method used and the results obtained, if an attempt was made to part any casing.

6. Upon application to and approval by the division, and following assumption of liability for the well by the surface owner, a well or other exploratory hole that may safely be used as a fresh water well need not be filled above the required sealing plugs set below the fresh water formation. The owner of the surface of the land affected may assume liability for any well capable of conversion to a water well by sending a letter assuming such liability to the division and by filing an application with and obtaining approval for appropriation of underground water from the Division of Water Rights.

7. Unless otherwise approved by the division, all abandoned wells shall be marked with a permanent monument showing the well number, location, and name of the lease. The monument shall consist of a portion of pipe not less than four inches in diameter and not less than ten feet in length, of which four feet shall be above the ground level and the remainder shall be securely embedded in cement. The top of the pipe must be permanently sealed.

8. If any casing is to be pulled after a well has been abandoned, a notice of intent to pull casing must be filed with the division and its approval obtained before the work is commenced.

8.1. The notice shall include full details of the contemplated work. If a log of the well has not already been filed with the division, the notice shall be accompanied by a copy of the log showing all casing seats as well as all water strata and oil and gas shows.

8.2. Where the well has been abandoned and liability has been terminated with respect to the bond previously furnished under R649-3-1, a $10,000 plugging bond shall be filed with the division by the applicant.

Appendix 7.
Procedures for Well Plugging

WAC 344-12-131
Washington State Legislature

Well Plugging
Washington State Legislature
WAC 344-12-131

Procedure for Well Plugging.
Each abandoned well drilled for the discovery of oil or gas or for any other purpose related to the exploration including seismic and core holes or production of oil and gas shall be plugged by or on behalf of the owner, operator, or producer who is in charge of the well or wells and responsible therefore. In general, cement plugs will be placed across specified intervals to protect oil and gas zones, to prevent degradation of potentially usable waters, and to protect surface conditions. Subject to approval of the supervisor, cement may be mixed with or replaced by other substances with adequate physical properties. The owner shall submit the proposed method and procedure for plugging to the supervisor on Form-3 (Notice of intention to abandon and plug well). Unless otherwise approved by the supervisor the method and procedure shall be as follows:

(1) Hole fluid. Drilling fluid having the proper weight and consistency to prevent movement of other fluids into the wellbore shall be placed in all intervals not plugged with cement, and shall be surface poured into all open annuli where required.

(2) Plugging by bailer. Placing of a cement plug by bailer shall not be permitted at a depth greater than 3,000 feet (914 meters). Water is the only permissible hole fluid in which a cement plug shall be placed by bailer.

(3) Surface pours. A surface cement-pour shall be permitted in an empty hole with a diameter of not less than 5 inches (12.7 centimeters). Depth limitations shall be determined on an individual well basis by the supervisor.

(4) Blowout prevention equipment. Blowout prevention equipment may be required during plugging and abandonment operations. Any blowout prevention equipment and inspection requirements deemed necessary by the supervisor shall appear on the approval issued by the supervisor.

(5) Junk in hole. Diligent effort shall be made to recover junk when such junk may prevent proper abandonment either in open hole or inside casing. In the event that junk cannot be removed from the hole and freshwater-saltwater contacts or oil or gas zones penetrated below cannot therefore be properly abandoned, cement shall be down-squeezed through or past the junk or a 100-foot (30-meter) cement plug shall be placed on top of the junk.

(6) A cement plug not less than 25 feet (7.6 meters) shall be placed in the hole and all annuli at the surface. All well casing shall be cut off at least 5 feet (1.5 meters) below the surface of the ground.

(7) Open hole.

(a) A cement plug shall be placed to extend from the total depth or at least 100 feet (30 meters) below the bottom of each oil or gas zone, whichever is less, to at least 100 feet (30 meters) above the top of each zone.

(b) A minimum 200-foot (61-meter) cement plug shall be placed across all underground source of drinking water-saltwater interfaces.

(c) An interface plug may be placed wholly within a thick shale if such shale separates the freshwater sands from the brackish or saltwater sands.

(d) The hole may be filled between plugs up to the base of the surface string, if this reaches below the freshwater zone, with approved heavy mud.

(8) Cased hole.

(a) All perforations shall be plugged with cement, and the plug shall extend 100 feet (30 meters) above the top of a landed liner, the uppermost perforations, the casing cementing point, or water shut-off holes, whichever is highest.

(b) If there is cement behind the casing across the underground source of drinking water-saltwater interface, a 100-foot (30-meter) cement plug shall be placed inside the casing across the interface.

(c) If the top of the cement behind the casing is below the top of the highest saltwater sands, squeeze-cementing shall be required through perforations to protect the underground source of drinking water. In addition, a 100-foot (30-meter) cement plug shall be placed inside the casing across the underground source of drinking water-saltwater interface. Notwithstanding other provisions of this section, the supervisor may approve a cavity shot followed by cementing operations at the base of the underground source of drinking water sands. The cavity shall be filled with cement and capped with a cement plug extending 100 feet (30 meters) above the cavity shot.

(9) Special requirements.

(a) Where geologic or ground water conditions dictate, special plugging procedures shall be required to prevent contamination of potentially usable waters by downward percolation of poor quality waters, and to separate water zones of varying quality, or varying hydrostatic pressure, and to isolate dry permeable strata that are brought into hydraulic continuity with ground water aquifers.

(b) The supervisor may set forth other plugging and abandonment requirements or may establish field rules for the plugging and abandonment of wells. Such cases include, but are limited to:

(i) The plugging of a high-pressure saltwater zone.

(ii) Perforating and squeeze-cementing previously uncemented casing within and above a hydrocarbon zone.

(10) In all holes open below the casing shoe, a cement plug shall extend from at least 50 feet (15 meters) below to at least 50 feet (15 meters) above the shoe of any cemented casing. If the hole cannot be cleaned out to 50 feet (15 meters) below the shoe, a 100-foot (30-meter) cement plug shall be placed as deep as possible.

(11) A steel plate at least one-quarter inch (0.64 centimeter) thick shall be welded to the top of the surface string of casing. The steel plate shall bear the drilling permit number and date of abandonment.

(12) Within thirty days after plugging of any well, the owner, operator, or producer responsible therefor who plugged or caused to be plugged the well shall file with the supervisor an affidavit on Form-4 (report on results of plugging well) setting forth in detail the method used in plugging the well.

(13) Inspection of plugging and abandonment operations. All plugging and abandonment operations shall be witnessed and approved as deemed necessary by the supervisor.

Appendix 8.
Requirements for Re-Abandonment of Previously Plugged and Abandoned Wells

Colorado Oil and Gas Conservation Commission

Colorado Oil and Gas Conservation Commission Policy
For Plugged and Abandoned Wells
Encountered By Surface Development Projects

WHEREAS, Colorado is experiencing rapid surface development along the Front Range corridor, as well as in other areas of the state. Housing and commercial developments in these areas have the potential to encounter previously plugged and abandoned oil and gas wells that interfere with earth moving operations. When these activities encounter previously plugged and abandoned wells, it may be necessary to cut the casing below grade and re-abandon them.

WHEREAS, Re-abandonment operations on previously plugged and abandoned wells are considered by the Colorado Oil and Gas Conservation Commission ("COGCC") to be "oil and gas operations" as defined in the Oil and Gas Conservation Act and in the COGCC Rules and Regulations, and may be required to be conducted by a registered operator who has provided financial assurance to ensure that the wells are properly plugged and abandoned.

NOW THEREFORE, The following are the requirements for re-abandonment operations when any oil or gas well is to be modified because of encroaching surface development:

REQUIREMENTS FOR THE RE-ABANDONMENT OF PREVIOUSLY PLUGGED AND ABANDONED WELLS:

The following are required whenever the wellbore of a previously plugged and abandoned well is modified and re-abandoned because of encroaching surface development:

(1) The surface developer or its designee that will conduct the re-abandonment operation shall be properly registered as an operator with the COGCC in accordance with Rule 302.

(2) The operator shall provide the COGCC with adequate financial assurance for the plugging and abandonment of the well(s) in accordance with Rule 706.

(3) A Change of Operator, Form 10 shall be submitted which shall indicate that the surface developer or its designee that will conduct the re-abandonment operation is the new operator of the well(s).

(4) The operator shall submit a Sundry Notice, Form 4 that includes a detailed description of the proposed re-abandonment operations. Approval of the Sundry Notice, Form 4 shall be obtained from the Director prior to commencement of operations.

(5) The operator shall provide a minimum seven (7) day written notice to the previous operator, if existing, of the intended re-abandonment operations and the date that such operations will commence. The operator shall confirm that this notice requirement has been completed or waived before the Director approves the Sundry Notice, Form 4.

(6) The operator shall provide verbal notice to the Director at least twenty-four (24) hours prior to the commencement of any operations to modify a wellbore or re-abandon a well.

(7) If during the re-entry of a previously plugged and abandoned well a surface cement plug is determined to be absent, then the operator shall determine the plugged back depth of the well and report such depth to the Director as soon as practicable. The Director may require remedial cementing operations consistent with the provisions for protecting aquifers and hydrocarbon bearing zones described in Rule 319. The operator shall obtain approval from the Director before proceeding with any further operations. If any cement or other plugging material is required to be placed in the well, the operator shall submit a Well Abandonment Report, Form 6 for approval from the Director prior to proceeding with any further operations. An additional Well Abandonment Report, Form 6, including third party Plugging Verification Reports, shall be required after the completion of the re-abandonment operations to provide documentation of the operations.

(8) The financial assurance required in (2) above shall not be released until the plugging operation can be verified through appropriate form submittals and the final reclamation threshold for release of financial assurance specified in Rule 1004.c. is met. If a variance to the 1000 Series Reclamation Rules is necessary for the surface lands where the re-abandoned well is located, the surface developer or its designee shall submit a Sundry Notice, Form 4 to request such variance. The variance request shall include a description of the planned surface use surrounding the re-abandoned well.

Remediation of Seepage from CO_2 Storage Formations

An understanding of remediation techniques is essential for the responsible operation and acceptance of CCS as a CO_2 mitigation option. However, remediation will only be necessary in the unlikely event that CO_2 migrates out of the storage formation and has the potential to reach the atmosphere or commercial resources. All CO_2 storage projects will be designed and operated with the aim and expectation of zero CO_2 seepage[1] and subsequent leakage[2], however the most likely possible seepage pathways must be identified and understood with plans in place for the unlikely event that seepage does occur.

There are three important aspects to properly understanding the remediation options for CO_2 seepage from a geological storage site. Firstly it must be understood how a CO_2 seepage event may occur, secondly it must be know how prevent each type of seepage event and how to remediate in the unlikely event that it does occur, and finally it is important to understand the financial costs associated with the prevention and remediation of CO_2 seepage.

The five-part strategy for seepage prevention and remediation

A comprehensive strategy for seepage prevention and remediation would contain five main elements:

1. *Selecting favorable storage sites with low risks of CO_2 seepage.* No other single aspect of a seepage prevention and remediation strategy is more important than selecting a safe, secure site in the first place.

2. *Placing emphasis on well integrity.* There are three key priorities for ensuring long-term well integrity at a CO_2 storage site, these are:
   - Identifying all old abandoned wells in the vicinity of the proposed CO_2 storage site. The location of the well should be documented and the well should be re-plugging if necessary using CO_2 resistant cements.
   - Designing and installing the CO_2 injection wells so that they will resist loss of cement integrity and corrosion of casing from the acidic CO_2 and water mixture.
   - Ensuring proper closure of the CO_2 storage site, including plugging all CO_2 injection and observation wells to promote long-term storage integrity.

3. *Conducting a phased series of formation simulation-based modeling to track and project the location of the CO_2 plume.* Multiple stages of formation simulation for supporting seepage prevention and remediation efforts in CO_2 storage should be used. The multi stage process should include:

[1] Seepage is defined as the movement of CO_2 out of the formation into the sub-surface.
[2] Leakage is defined as the movement of CO_2 from the sub-surface into the atmosphere.

- The initial site selection process to assemble the available formation data to establish the injectivity and storage capacity of the site, as well as to project the anticipated movement and location of the CO_2 plume.
- The collection of more site specific geological and formation data after the drilling of the injection and observation wells. This data can be used to model the internal architecture of the storage formation. Additional data on relative permeability can be used to better estimate CO_2 injectivity and the pore-space (capillary) trapping mechanisms.
- Repeat surveys after injection commences to provide information on the location and movement of the CO_2 plume. This includes incorporating seismic data and data from subsurface observation wells to help calibrate the formation model. This improving data set can then be used to project the long-term trapping and immobilization of the CO_2 plume.

4. *Installing and maintaining a comprehensive monitoring system for the CO_2 storage site.* The overall CO_2 monitoring system will need to be designed to serve several purposes. The CO_2 monitoring system will need to;
   - Serve as an early warning system of any impending CO_2 seepage event. This requires downhole pressure data, CO_2-sensitive logging tools, and near-surface CO_2 detection systems to identify any seepage through or around the formation seal. In addition, a variety of pressure monitors and cement bond logs will need to be used for assuring wellbore integrity.
   - Provide on-going information on the movement and immobilization of the CO_2 plume. Seismic methods, both surface and downhole, real-time information from offset observation wells, plus regional surface-based leak detection and sub-surface monitoring techniques would be used to augment this information.

5. *Establishing a "ready-to-use" contingency plan/strategy for remediation.* Operators should have a response plan ready in the event that seepage of CO_2 occurs from the storage formation. This plan should contain remediation options for all the most likely seepage scenarios.

Classification of a CO_2 seepage event

If seepage occurs the ease and method of remediation will depend largely on the type of formation used for storage and the nature of seepage event that has occurred.

CO_2 stored in structurally confined depleted oil and gas fields will be the most effectively contained and easiest to monitor, offering the best chance of successful remediation. CO_2 stored in saline formations, particularly those lacking structural closure, will be much more challenging to remediate should it be necessary, given the degree of dispersion of CO_2 under the caprock that will occur over time.

However, irrespective of the type of formation, if seepage occurs the first step is to assess the nature of the seepage event as this will dictate the method and pace of the remediation required. Below, a number of possible seepage mechanisms[3] are listed:

- *CO_2 seepage due to seal failure.* The first seepage mechanism involves CO_2 seeping through the caprock, either due to excessive gas pressure, or the presence of a permeable (non-sealing) fault or fracture.

- *Seepage out of the confining structure.* Seepage of CO_2 out of a confining structure will generally occur in two scenarios:
    - Through the natural hydrodynamic movement of dissolved CO_2 out of the defined formation,
    - Excess injection of CO_2 past the confining "spill point" of the formation.

- Proper site selection and project design, with appropriate precautions taken for geologic and operational uncertainties, as well as appropriate monitoring and formation modeling during injection operations should ensure that seepage outside of the confining structure does not occur.

- *Seepage due to lack of well integrity.* Seepage through operating or abandoned wellbores is the most likely seepage pathway for a CCS project surpassing concern over geological integrity which can be mitigated to a great extent through thorough site selection and characterization. There are a number of reasons why the integrity of a well may be compromised. Three possible options are a follows:
    - The well was poorly designed or constructed allowing gas migration up the well,
    - An unanticipated well failure, such as a parted casing,
    - When abandoned the well was inadequately plugged.

CO_2 seepage well remediation procedures

Assuming the CO_2 storage site is geologically stable and secure, the loss of well integrity and possible blowout during injection will represent the greatest risk of CO_2 seepage. Experience of remediation procedures for a well based CO_2 seepage event could be gained from the natural gas storage industry however it must be taken into consideration that CO_2 is generally injected in a supercritical state which means some additional thought must be given to the temperature, pressure and velocity of the leaking fluid. This section will concentrate on practices associated with remediating well integrity and well blowouts by presenting standard well service and repair procedures and guidelines should a CO_2 seep occur.

- *Mechanical integrity and monitoring procedures.* The loss of a well's mechanical integrity can lead to internal and external CO_2 seepages which can allow fluid

[3] The seepage mechanisms listed are not set out in any proposed order of occurrence or likelihood, they are merely listed for reference purposes

movement behind the casing and/or cement. This will result in a loss of stored CO_2 and could potentially damage other resources such as underground sources of drinking water.

Current injection guidelines in other industries[4] require an underground injection control program which sets forth steps for automated data collection, annual or multi-annual tests to ensure well integrity, and efforts for early detection of seepage. During the injection phase, subsequent monitoring efforts will generally include:

- An analysis of injected fluids,
- Continuous monitoring of injection pressure, flow rate, and volume,
- Demonstration of mechanical integrity once every five years,
- Placement of a sufficient number of monitoring wells to assess any migration of fluids out of the formation.

If monitoring indicates movement out of the formation, then preventive action must be taken. These actions will include additional monitoring and reporting requirements; prompt corrective action; or permit termination and well closure.

- *Identifying fugitive emissions or fluids.* Should there be any indication of CO_2 seepage; several methods are available to aid in pinpointing its location. These methods can also provide insights into the best method of remediation. Some of these are highlighted below:
  - Well Monitoring,
  - Pressure monitoring,
  - Downhole video camera ,
  - Noise Logs,
  - Temperature logs,
  - Radioactive tracers,
  - Cement bond logs.

- *Remediating fugitive emissions and fluids.* There are several corrective actions that can be used to address a seepage event due to loss of mechanical integrity in the injection well. The remediation method employed will be determined by identifying the type and location of the seepage involved and may include one or some of the following:
  - Wellhead repair,
  - Packer replacement,
  - Tubing repair,
  - Squeeze cementing,
  - Patching casing,
  - Repairing damaged or collapsed casing,
  - Plugging a well.

[4] Industries include oil and gas production, natural gas storage, etc.

- *Remediating a seeping abandoned well.* In the event a previously abandoned well is found to be seeping, a series of steps can be employed to restore the well for temporary use, remediate the seepage, and re-abandon the well. They include:
    - Review all available well data records,
    - Formulate a detailed plan for well intervention and remediation,
    - Set up a drilling rig above the location of the seeping well and drill the reclaimed soil above the abandoned well, enabling access to the well head,
    - If the seepage is occurring through the casing or well plug remediation efforts here might require the drilling out of the original plugs and determining the origin of the seepage event,
    - For a casing seep, remediation can be done by injecting a heavy brine to stop inflow ("killing" the well) and either installing a casing patch or squeeze cementing,
    - For a poor abandonment plug, re-plug the well according to best practice methods.

- *Modifications to remediation practices to account for CO_2.* CO_2 in combination with water can form carbonic acid, which is corrosive to standard well casings as well as cements. When working with CO_2 it must be ensured that all materials used are CO_2 resistant. Items of particular concern are, packers, casing and tubular goods, and the cement.

REMEDIATING THE SUBSURFACE IMPACTS OF CO_2 SEEPAGE

As well as stopping the seepage, it may be necessary to rectify any damage or potential damage resulting from any CO_2 that did leave the storage formation. Below are listed some potential options for remediating CO_2 effects on different parts of the sub-surface:

- *Accumulation of CO_2 in groundwater.* CO_2 contamination of groundwater can be remediated by the "pump and treat" method where the contaminated water is pumped to the surface and aerated to flash the CO_2. The water can then be either pumped back underground or used.

- *CO_2 seepage into vadose[5] zone.* This is an area of ongoing research however it is thought that large amounts of CO_2 could be removed from the vadose zone using soil vapor extraction technology.

- *CO_2 in near-surface accumulations.* Horizontal pinnate (leaf-vein pattern) drilling, which has been commercially developed for coalbed methane projects, can be used to access and extract CO_2 in near-surface formations and accumulation zones.

Costs of Seepage Prevention and Remediation

The costs of remediation will impact overall CO_2 storage costs therefore these need to be considered in the context of the overall CO_2 storage project. The likelihood of needing

[5] The vadose zone is the zone between surface and the water table.

remediation will be greatly reduced through rigorous site selection. If seepage occurs, the work required for remediation can at times be greater or equal to, that associated with original CO_2 storage site selection, project design and implementation.

Two additional costs could also be incurred from seepage of CO_2, assuming significant vertical migration of the CO_2. First would be the cost for remediating the impacts of CO_2 accumulation in the potable water and vadoze zone. The second would be the loss of any CO_2 credits for storing CO_2. A selection of costs associated with the prevention and remediation of seepage should it occur, is summarized below.

1. Seepage prevention costs

There are three main activities that are crucial to the prevention of a CO_2 seepage event, rigorous site selection, on-going monitoring, and periodic testing for well integrity.

Costs for rigorous site selection and project design

The major components of a rigorously selected, installed and operated CO_2 storage facility are outlined in below:

Major components of site selection and project design

Project definition and design
• Initial geologic and formation characterization • Test site design and plan • Formation modeling/simulation • Comprehensive MMV protocols • Remediation strategy and procedures • Regulatory/permitting activities
Detailed site and formation characterization
• MMV baseline studies • Observation, characterization and monitoring well(s) • Seismic survey(s) • Well tests
Continuing activities
• Updated geologic/formation model • Operational monitoring system

The costs for site selection and project design could range from $5,000,000 to $20,000,000 per site. The largest single cost item will be the cost of drilling and testing the formation characterization and observation wells. Other significant costs will involve establishing the regional geological framework, conducting formation modeling of the expected flow and trapping of the CO_2 plume, and testing the integrity of the formation caprock.

The actual costs will depend on the amount of existing data at the site as well as the type and depth of the project, the amount of CO_2 to be stored, the conditions at the surface overlying the storage formation and, perhaps, most important, the regulatory and permitting requirements imposed on the project.

Costs for project monitoring and seepage detection
The costs of project monitoring and seepage detection will depend heavily on the type of formation in question as well and the rigorousness of the monitoring package. Two scenarios are used to evaluate the applicability and costs of conducting monitoring over the life-cycle of a CO_2 storage project; these are:

1. The basic monitoring package,
2. The enhanced monitoring package.

These monitoring systems were then evaluated for three types of projects:

1. An enhanced oil recovery project followed by CO_2 storage,
2. A saline aquifer storage project with a high residual gas saturation (RGS), where the CO_2 plume does not move significantly after injection ,
3. A storage project in a saline aquifer with low residual gas saturation (RGS), where the CO_2 plume keeps moving for a considerable amount of time after injection.

The monitoring costs associated with the combination of each monitoring package with each project type are summarized below:

Costs of Monitoring Strategies						
Cost Component	Estimated Monitoring Costs (Million Dollars US)					
	EOR		Saline Aquifer			
			Low RGS		High RGS	
	Basic Package	Enhanced Package	Basic Package	Enhanced Package	Basic Package	Enhanced Package
Pre-Operational Monitoring	$0.9	$3.3	$7.5	$9.4	$5.9	$8.1
Operational Monitoring	$34.7	$59.3	$23.1	$38.3	$23.1	$38.3
Closure Monitoring	$9.1	$14.8	$18.4	$32.2	$13.8	$26.7
TOTAL	$45	$78	$49	$80	$43	$73

Costs for wellbore integrity monitoring
Wellbore integrity monitoring and logging costs will be a function of the depth of the well, the condition of the well, and the number and types of logs required. The costs for monitoring well integrity are estimated as follows:

Costs of Well Integrity Logging		
Well Depth	Well Integrity Logging Costs (Million dollars US)	
	Per Log	Total*
5,000 feet	$0.12	$12
7,500 feet	$0.15	$15
10,000 feet	$0.18	$18

* Total assumes 10 CO_2 injection wells and 10 logging runs in 50 years, for a total of 100 logging runs.

It is assumed that, for the most part, the costs for a more comprehensive set of wellbore integrity logs, essential for providing up-to-date information on the condition of the CO_2 injection wells, are not included in the costs for project monitoring and seepage detection outlined in the *Costs of Monitoring Strategies* table.

2. Seepage remediation costs

Depending on the nature of the CO_2 seepage event, the costs of remediation can vary significantly. The costs discussed below are estimates for locating the seepage source, plugging old wells, remediating active CO_2 injection wells, and remediating seepage in the caprock.

Costs for locating the source of CO_2 seepage

The cost of locating a seep will differ depending on source: abandoned well, injection well, or geological CO_2 seepage.

For abandoned wells, considerable expertise exists for identifying the source and reasons for CO_2 seepages. As such, the well seepage diagnostic procedures are relatively straightforward, with much of the essential information expected to be provided by the on-going project monitoring and seepage detection program. The costs for locating a single well (or even a group of wells) will be modest, set at $100,000 per survey (including interpretation), with significant economies of scale in multi-well situations.

For the CO_2 injection wells, a new set of logs or other diagnostic tools may be needed to more precisely identify the exact location and cause of the seepage in the new injection well. With two diagnostic logs costing $200,000 plus a diagnostic and management charge of $100,000, the costs for a wellbore-based seepage detection procedures would be on the order of $300,000 per well.

When locating geologically-based CO_2 seepages, the costs of will be a function of the size of the seepage area, the conditions at the surface overlying the storage formation (industrial, suburban, farmland, etc.), and, perhaps, most important, the requirements imposed by regulatory authorities. Establishing the cause and source of the geologically-based CO_2 seepage may require investigating a large area, with emphasis on areas of potential caprock weakness, faults/fissures, and structural “spill points”. As such, a new large scale seismic survey covering 5 to 20 square miles may need to be conducted over the area where surface leakage has been detected. In addition, new horizontal seepage detection wells may need to be drilled and tested to more precisely locate the source for the CO_2 seepage and, ultimately, capture the lost CO_2 for reinjection. 3D seismic survey including processing and interpretation may cost $100,000 per square mile with every new horizontal costing $4 million.

Costs for well plugging
Well plugging costs will depend on whether the requirement is to plug a recently abandoned well, an old, previously plugged and abandoned well, or a well that has never been plugged. The costs will also depend on what must be done to plug the well and on the location of the well being plugged.

It is estimated that the costs of plugging in a typical 7,500 foot well would be between $20,000 and $80,000. On average, most well plugging operations cost $50,000 per well, without considering the salvage value of the casing, if any.

Costs for well remediation
The cost of a simple wellbore seepage repair could vary considerably depending on the nature of the seepage and the condition of the wellbore but is estimated to be in the range of $30,000 to $50,000. If a more substantial section of the well is seeping or is damaged more involved remediation such as installing a smaller diameter liner inside the well casing may be required. The costs of this more involved remediation is estimated at $100,000 per well.

In some cases, a seeping well cannot be repaired, and must be plugged. In this case, the costs would include plugging the seeping well and drilling a new replacement CO_2 injection well. The costs of drilling new wells depend on the depth of the well; however an average depth well (7,500 foot) would be estimated to cost around $2.5 million. The cost of well construction has increased significantly recently so this estimate may rise.

Costs for remediation of seepages in caprock
The first step in mitigating CO_2 seepage in the caprock would be to stop CO_2 injection and, if possible, to inject water into a formation above the caprock to create a positive pressure barrier. Creating a positive pressure barrier above CO_2 seepage would involve drilling and completing two horizontal water injection wells and installing a water source well and water injection facilities. We estimate the water source and injection facility costs at $2 million.

There are no documented cases of fully remediating seepage in a caprock for either a CO_2 or natural gas storage project. In general, performing such a remediation effort is speculative. Consequently, the costs associated with this remediation action are unknown and have not estimated. The development of possible approaches for remediating seepages in caprock remains an important area for future research.

Example storage case
To further illustrate the costs of remedation, a scenario has been created around a saline aquifer CO_2 storage site. This scenario loosely follows the high residual gas saturation

(RGS) aquifer discussed in the *Costs for Project Monitoring and Seepage Detection* section of this report.

The main assumptions for the scenario are as follows:

- The storage site serves one 1,000 MW coal-fired power plant, with 8.6 million metric tons of annual CO_2 emissions,
- The site will operate for 50 years, with 30 years for CO_2 injection and 20 years for post-closure monitoring,
- The CO_2 storage site has 10 CO_2 injection wells, each capable of injecting 2,500 tonnes of CO_2 per day with a 94% operating factor,
- The CO_2 plume extends radially and underlies an area of about 80 square miles (216 km2) at the end of 50 years,
- An "enhanced" CO_2 monitoring system consistent with a rigorous site selection program and highly supportive of the diagnostic systems essential for identifying the sources for CO_2 seepage, should these occur. Costs associated with this monitoring programme are as follows:

Pre-operational monitoring (integrated with site characterization)	$7 million
Operational monitoring (including continuous pressure and atmospheric monitoring and periodic seismic and other geophysical surveys)	$33 million
Post-closure monitoring	$10 million
G&A/management	$12.5 million (25%)
Total	**$62.5 million**

Based on this example, the overall costs for seepage prevention and seepage remediation including the comprehensive monitoring programme are shown below:

Table 6-3. Representative costs for seepage prevention and remediation

	Activity	Mid-range costs (millions)	Comments
A. BASIC COSTS			
	1. Site selection and project design	\$18.0	Includes 6 observation wells plus other site selection costs
	2. Monitoring and seepage detection	\$62.5	Includes the comprehensive seismic program otherwise included in site selection
	3. Wellbore integrity	\$15.0	Includes multiple periodic ultrasonic cement bond logs and well integrity tests in 10 CO2 injection wells
	Sub-total	\$95.5	
B. REMEDIATION COSTS (If Needed)			
	1. Locating sources of CO_2 seepage		
	Old, abandoned wells	\$1.0	Assumes 10 seeping, abandoned well surveys
	New CO_2 injection wells	\$3.0	Assumes 10 sets of diagnostic logs
	Caprock/spill point	\$10.0	Includes seismic and 2 horizontal seepage detection wells
	2. Well plugging	\$1.0	Includes plugging of 20 old wells
	3. Well remediation	\$3.5	Includes remediation on 10 wells and drilling one new CO_2 injection well
	4. Caprock seepage		
	Pressure boundary	\$10.0	Includes two horizontal water injection wells plus a water plant
	Other problems	Large	May need to abandon original storage site and build a new site
	Sub-total	\$28.5+	
	TOTAL	\$124.0+	

The cost for a comprehensive CO_2 seepage prevention, monitoring and remediation program estimated to be on the order of \$120 to \$130 million per site. Assuming the injection of 258 million tones of CO_2, the cost per tonne for these efforts would range from \$0.45 to \$0.50 per tonne.

If the CO_2 seepage problems can not be rectified, which is only likely to occur if a fault is activated or if the site was poorly characterized initially, the remediation costs would become large. These costs would include establishing a new storage facility, transporting some or all of the CO_2 to the new facility, remediating the impacts of CO_2 losses to the potable water and vadose zone, and losing the value of any CO_2 credits for the CO_2 lost to the atmosphere or other undesirable locations.

Conclusions

The most important aspect of seepage prevention and remediation strategy is selecting a safe, secure storage site to begin with. Assuming that a secure CO_2 storage site has been selected, the loss of well integrity and blowouts will most likely represent the greatest risk of CO_2 seepage. In both cases there is experience in other industries for remediation.

In terms of cost, if seepage occurs, the work required for remediation can range from being relatively low to at times being greater or equal to, the costs associated with original CO_2 storage site selection, project design and implementation. However to put these costs in perspective, for a typical storage case the costs for site selection monitoring and remediation could range from $0.45 to $0.50 per tonne CO_2. Compared to the total cost of a CCS project ($35 -50/t CO_2) the additional cost for minimising seepage can be considered as low.

Recommendations

Following the completion of this study there are a number of recommendations for possible strategies to progress the understanding and development in the area of remediation as well as address some gaps in knowledge.

- Develop a “best practices” remediation manual. It would be most valuable to develop and maintain an up-to-date “Best Practices” Manual on CO_2 Seepage Prevention and Remediation similar being developed for site assessment and selection, and monitoring. This work could be used in the formation of remediation manuals to provide a comprehensive strategy for CO_2 seepage prevention and remediation.

- Study remediation in the natural gas storage industry. Given the similarities to CO_2 storage, researching the remediation experiences, practices and “lessons learned” of the natural gas storage industry could be useful for CO_2 storage.

- Invest in research and technology development in remediation for CO_2 storage. More intensive investigations and field trials of procedures for identifying and sealing failure in the caprock is a high priority. Equally valuable would be work on materials and procedures for greater well integrity.

- Develop new procedures and technology for locating and assessing the integrity of abandoned wells. More needs to be done to develop cost-effective means for reliably locating and assessing the status of old, abandoned wells near a CO_2 storage site. Also required is the development of new procedures and technologies for securely plugging these old, abandoned wells.

- Launch a series of "best practice" large-scale field tests of CO_2 storage. An important emphasis for field work should be the testing and assessment procedures for selecting sites with caprock and wellbore integrity. Equal emphasis should be on establishing and testing an integrating system involving CO_2 monitoring, CO_2 seepage detection, and remediation.

- Address concerns on lack of structural confinement in "open system" saline formations. If the large "open system" saline formations are to become viewed as safe, secure sites for injecting CO_2, considerable new investigation and research is required. In particular in the areas of:
    - Aquifer hydrodynamics,
    - Potential for pore space and hysterisis trapping of CO_2 in alternative geological settings
    - Understanding the dynamics of CO_2 displacement of stored saline water
    - Identification of geologic features that would provide assurance of updip trapping of the CO_2 plume