Overview of Monitoring Requirements for Geologic Storage Projects

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OVERVIEW OF MONITORING REQUIREMENTS FOR GEOLOGIC STORAGE PROJECTS

Background to the Study

Much attention has been given to estimating the costs of capturing and storing CO_2 in geological formations as these costs are expected to dominate future CO_2 capture and storage (CCS) projects. The effective monitoring of underground reservoirs used to store CO_2 will be an essential part of such projects. This activity could continue long after capture and injection of CO_2 has ceased. The cost of monitoring has been the subject of some debate, so this report was commissioned to examine in more detail the monitoring technologies which would be available, assess their relative attractiveness and estimate the overall cost of monitoring. The contract for this study was awarded to Lawrence Berkeley National Laboratory (LBNL) of the USA.

Approach adopted

LBNL was asked to provide an overview of all monitoring technologies which might be applicable either now or in the future including an indication of their approximate cost. They were also asked to formulate a framework for monitoring throughout the lifetime of typical CO_2 storage projects and to select appropriate monitoring for the various phases in order to be able to arrive at estimates of the probable cost in use. In order to evaluate the range of costs for different types of project, LBNL was asked to propose scenarios for injection for both EOR and deep aquifer storage and to consider how costs would differ between onshore and offshore situations. Where possible, evaluations were to be based on knowledge from real reservoirs and the report thus contains many references to specific formations.

The standard economic analysis used for IEAGHG studies uses a discount rate of 10% which means that costs towards the end of a long term activity such as CO_2 geologic storage would be heavily discounted. An approach using lower discount rates is advocated by some for this type of "inter-generational" situation. LBNL was asked to consider using this alternative approach to discounting for any very long term cost commitments in their analysis.

Results and Discussion

Project phases

The framework for monitoring presented in this report suggests four main phases for a typical CO_2 storage project:

- Pre-operational
- Operational
- Closure
- Post injection

When setting up the framework LBNL proposed to place emphasis on high quality monitoring early in the project so that uncertainties and any need for very long term monitoring would be minimised. To achieve this it would be an aim of a typical storage project to reach a complete and final closure of storage reservoirs no more than a few decades after ceasing injection. Whilst a few decades is short in terms of the timescale for storage it spans more than a generation which should be long enough to reach at least a technical consensus on the integrity of a site. This approach would avoid any significant need for long term monitoring thereafter although this cannot be ruled out for some sites.

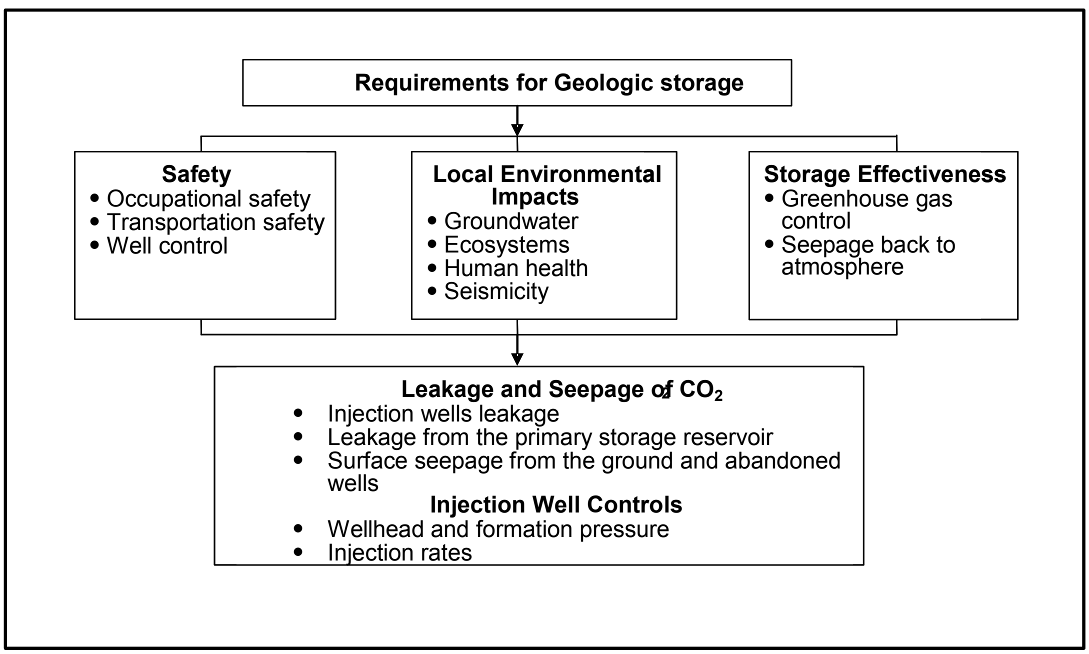
Consideration was given to frameworks in which monitoring would occur in the post injection phase. However, this was found to be difficult to formulate because of the great uncertainty about which problems were to be addressed by the monitoring. Furthermore the discounted costs of such long term activities would be heavily affected by the discount rate which was chosen although, even when intergenerational rates of only 1 or 2% per year were used. Expenditures so far in the future do not contribute much to the overall cost leading to the conclusion that the basing the assessment on costs in the first few decades of the project was sufficient.

Requirements for geologic storage

There are three main requirements of a CO_2 storage project which need to be satisfied:

- It has to be safe
- It has to have acceptable environmental impact
- It has to retain the CO_2 in the reservoir in order to be effective as a mitigation technique.

These basic requirements are illustrated in more detail in the diagram below which was used as the framework from which to explore the role and reasons for monitoring activities. Items in the lower box may relate to each of these three requirements



Reasons for monitoring

The report identified 14 main reasons for monitoring during the four phases of a storage project and in which phases they are expected to be required. There are a number of reasons why monitoring will always be required in certain phases, for example to determine baseline conditions, or to track the plume of CO_2. Other monitoring will only be needed if triggered by circumstances or events, such as detection of a leak, unexpected micro-seismic events or ground movement. The type of monitoring needed in particular circumstances is indicated in table T.1. Note that the baseline survey encompasses most of the requirements prior to actual injection. Where there are specific concerns about existing surface gas fluxes, microseismic activity and behaviour of other underground resources these will need to be included in the baseline and this possibility is indicated in the table.

Table T.1 Monitoring requirements – circumstances under which monitoring would be required

Monitoring purpose	Project phase			
	Pre-Operation	Operational	Closure	Post-injection
Establish baseline conditions from which the impacts of CO_2 storage can be assessed	YES			
Ensure effective injection controls		YES		
Detect the location of the CO_2 plume		YES	YES	G
Assess the integrity of shut-in, plugged or abandoned wells	YES	A	B	B
Identify and confirm storage efficiency and processes	YES	YES		
Model calibration and confirmation of performance		YES	YES	
Detect and quantify surface seepage	F	A	B	B
Assess environmental, health and safety impacts of leakage		A	B	B
Monitoring micro-seismicity associated with CO_2 injection	F	C		
Monitoring to design and evaluate remediation efforts		A	A	
Provide assurance and accounting for monetary transactions		YES	YES	
Evaluate interactions with other geological resources	F	D	D	D
Settling of legal disputes for example due to leaks, seismic events, ground movement		A,C or E	A,C or E	A,C or E
Assuring the public where visibility and transparency is of prime importance	YES	YES	YES	H

Key
A - If Leakage detected
B - If leakage not stopped
C - If micro-seismicity detected
D - If interactions are possible
E - If ground movement is detected
F – To establish baseline
G – If future plume movement remains uncertain
H – If public concerns remain

Methods of monitoring

Below is a list of all the types of monitoring or measurement which could be applied to a geologic storage project for CO_2. An in-depth review of each of these techniques is contained in the main report. From this it is concluded that seismic methods are the most accurate but also the most expensive way of following the fate of CO_2 after it has been injected into a geological formation. Other geophysical techniques such as gravity, surface tilt and well-to-well electric resistance measurements have a significantly lower resolution. The sensitivity limits for these techniques are explored in the report. The prospects for these being improved to match that of seismic are slim. However they offer good prospects for combination with seismic methods which could both enhance overall resolution and reduce costs. In particular the ability to distinguish between CO_2 and other reservoir fluids by using combined methods could be an important breakthrough akin to the (still pressing) need in oil and gas exploration to distinguish between oil and gas.

Types of monitoring technique considered

- Wellhead Pressure
- Formation Pressure
- Injection and Production Rate
- Well Logs
- Fluid and Gas Composition
- Seismic Monitoring
- Electrical and Electromagnetic Monitoring
- Gravity Monitoring
- Land Surface Deformation
- Tilt Measurements
- Airborne or Satellite Imaging
- Soil Gas and Vadose Zone Monitoring
- Surface Flux Monitoring
- Atmospheric CO2 Concentration
- Micro Seismicity

Cost of monitoring methods

The report tabulates the basic cost of deploying and operating each of the monitoring methods. This information is then used to estimate what the overall costs for monitoring some typical projects would be.

Application of monitoring techniques

The report presents an analysis of the monitoring methods, showing which would be applicable for each of the various reasons for monitoring. Some techniques have definite application whilst some may have only a possible application. Table T.2 shows in outline which methods are applicable distinguishing between where a method is definitely applicable and where it is only possibly applicable. One of the purposes of the analysis was to arrive at a systematic definition of complete monitoring systems for cost estimating purposes. This work has been done assuming extensive use of CO_2 Capture and Storage (CCS). For the first generation of storage projects much more extensive monitoring may be deployed, for example to demonstrate conclusively the safety and environmental impact of the projects, and also to develop, calibrate and understand the monitoring methods.

Table T.2 Application of monitoring techniques

Monitoring purpose	Wellhead Pressure	Formation Pressure	Injection and Production Rate	Well Logs	Fluid and Gas Composition	Seismic Monitoring	Electrical and Electromagnetic Monitoring	Gravity Monitoring	Land Surface Deformation	Tilt Measurements	Airborne or Satellite Imaging	Soil Gas and Vadose Zone Monitoring	Surface Flux Monitoring	Atmospheric CO2 Concentration	Micro Seismicity
Establish Baseline Conditions	Y		Y	Y	Y	Y	P	P	P		P	P	P		P
Ensure Effective Injection Controls	Y	Y	Y	Y											P
Detect Location of the CO2 Plume	P	Y		P	P	Y	P	P	P	P					P
Assess Integrity of Shut-in, Plugged or Abandoned wells	P			Y	P	P					P	P	P	P	
Identify and Confirm Storage Efficiency and Processes	Y	Y		Y	P	Y	P								
Model Calibration and Performance Confirmation	Y	Y	P	Y	P	Y	P	P							
Detect and Quantify Surface Seepage											P	Y	Y	Y	
Assess Environmental, Health and Safety Impacts of Leakage					Y	Y	P	P	P	P	P	Y	P	P	P
Record Micro-Seismicity Associated with CO2 Injection									P	P					Y
Design and Evaluate Remediation Efforts	P			P	P	Y	P				P	P	P	P	
Provide Assurance and Accounting for Monetary Transactions	Y	Y				P									
Evaluate Interactions or Impacts with Other Geological Resources	P	P			Y	Y	P								
Settle Legal Disputes Due to Leaks, Seismic Events, or Ground Movement	P			P	P	Y	P		P	P	P	P	P	P	P
Assure the Public Where Visibility and Transparency is of Prime Importance	Y	Y		P	Y	Y	P	P	P	P	P	P	P	P	P

Y Yes - Likely to be used **P** Possible uses

Definition of complete monitoring systems

In order to estimate the overall costs of monitoring, a set of scenarios was developed for typical onshore CO_2 storage projects. The basis of the scenarios is capture of CO_2 from a 1000MW coal fired power plant and its storage in a dedicated reservoir nearby. It is emphasised again that the scenario assumes that geologic storage has become a common activity. CO_2 is captured at the rate of 8.6 million tonnes/yr for a period of 30 years so that approximately 258 million tonnes is eventually stored. Scenarios with three different storage reservoirs are considered. One uses a depleted oil reservoir for the purpose of Enhanced Oil Recovery. The other two consider storage in a deep saline aquifer in one case where the CO_2 plume does not spread significantly and in the other where it migrates over a wider area.

For each of these three cases a package of monitoring methods was developed along with a timetable for their use. The analysis of reasons for monitoring and applicability of methods was used as the basis for formulating the monitoring programmes for the typical storage projects described in the scenarios. Full details of what is in the packages are to be found in the main report.

Overall cost of monitoring

The costs of monitoring in $ per tonne of CO_2-stored for three different onshore scenarios described above have been calculated (see table T.3). Two levels of monitoring were considered, a basic package and an enhanced package. The basic level is considered to be adequate for widespread use whilst the enhanced package is designed to provide an additional level of certainty. This might for example be appropriate in environmentally sensitive or more heavily populated areas. The monitoring costs per tonne injected are tabulated below. These are based on IEAGHG standard economic criteria i.e. discount rate of 10%.

Table T.3 Cost of monitoring (onshore)

	Spreading plume Saline aquifer	Contained plume Saline Aquifer	EOR
Cost $/ton basic monitoring	0.053	0.047	0.049
Cost $/ton enhanced monitoring	0.076	0.069	0.085

The costs for offshore have not been developed in the same detail although the report does indicate how the main expense, seismic survey is expected to increase relative to the assumptions made for the onshore situation. None of the surface leakage methods and only some of the surface-based monitoring methods, such as tilt measurements, could be done sub-sea in the same way as they are on land, and in most cases would not be relevant. Their omission would thus slightly compensate for the increased expense of offshore seismic which can be 2-3 times the cost of onshore acquisition.

No monitoring in the post injection phase was planned in the costing calculations although it may be required if monitoring during the closure phase reveals a need, for example if ongoing micro-seismic events, surface movement or plume migration is detected. Monitoring techniques are expected to be sufficiently sensitive to detect this need should it arise. Any such long term monitoring would employ a selection of techniques considerably less costly than seismic survey but it is difficult to evaluate what the costs might be for the following reasons: the frequency with which storage sites might need longer term monitoring is not known although, if it is not low, the acceptability of geological storage would probably be in question. The degree of localisation and the effect of remedial measures is also uncertain. Simple analysis shows that if leakage were significant it would also be limited in duration, indeed the larger the leak the shorter the time for which monitoring would be required and the greater the incentive to adopt remedial action, such as transferring the stored CO_2 to another site.

It is suggested that the costs of such long term monitoring be assessed in economic terms using an appropriate intergenerational discount rate of say 1 or 2% per year. A rough analysis of possible costs is given an appendix to this overview. Extra costs for the long term monitoring for example by deploying CO_2 surface flux measurements at a number of points are only a fraction of the total monitoring costs and are likely to be far lower than the cost of lost emission credits or the cost of transferring some of the CO_2 to another reservoir.

Expert Reviewers' Comments

The draft report was reviewed by several experts. The reviewers felt that the report was comprehensive and very few technical points were raised. It was pointed out that the study does not address monitoring of CO_2 stored in coal seams or the movement of water displaced by the injected CO_2 in oil fields or aquifers. The assumption that injection into aquifers can be controlled to prevent fracturing of the cap-rock was questioned by one reviewer. Any injection into some aquifers might cause "overpressure" and the report should not be taken to conclude that such fracturing can always be avoided. Likewise the previous history of containment by an oil or gas reservoir does not necessarily mean that the cap-rock can be assumed to have integrity up to the original reservoir pressure. It could be subject to weakening by chemical effects or the rock mechanics associated with re-pressurisation by CO_2. Whilst the latter are important points their main effect would be to reduce reservoir capacity and suitability. They were not felt to have significant effect on the estimating of monitoring costs for the typical project scenarios considered in this report.

Major Conclusions

The unit cost of monitoring of CO_2 storage per ton of CO_2 stored is small compared to the costs of capture, compression, transport and injection. The extra cost of more comprehensive monitoring is also small, suggesting that in the context of assuring public confidence there is little to be saved by economising on monitoring programmes.

The mainstay and major cost of monitoring is seismic and this is unlikely to alter. Some other techniques have potential to work in combination with seismic to increase resolution and certainty about the location and amount of CO_2 stored. They may also help to reduce overall cost.

The need for long term post injection monitoring is not clear but it should not be needed for the majority of sites if these are carefully selected. A rough analysis indicates that, if such monitoring is required, the additional unit costs would be small.

Recommendations

It would be useful if those conducting monitoring projects could formulate some common practices for monitoring. This should preferably be on a functional rather than a prescriptive basis which would make it easier for international adoption.

Further work on integrating seismic with other measurement techniques should be encouraged with a view both to reducing the overall costs of monitoring and to enhancing the resolution and certainty with which CO_2 can be tracked in the subsurface.

Further work to address monitoring of CO_2 in coal seams and to map the movement of displaced water is also recommended.

APPENDIX

Costs of long term monitoring

Scenarios for long term monitoring

If a major leak develops, remediation or even blow-down of the reservoir may be required with associated costs far outweighing that of any additional monitoring. Consideration of such a scenario is outside the scope of this study. Another scenario is one in which a lesser leak occurs which requires long term monitoring until it subsides but does not require remediation. Extra costs would then be incurred for monitoring and these could be considerable if they accumulate over a long period of time. The scenario used for the estimation of monitoring costs in the main report is based on an injection period of 30 years. Should any leakage occur from the reservoir, the rate of leakage will affect the length of time over which monitoring would be extended. As the basis for an example calculation, we will look at the case of extending the monitoring over 100 and 1000 years.

There are three main reasons why on-going leak monitoring might be required:

- Safety – Because seepages to surface could pose risks particularly in buildings
- Environment – Because high CO_2 fluxes could have effects on flora and fauna
- Accounting – Because loss of CO_2 from storage negates emission credits

For safety and environmental purposes, it would be essential to monitor where and in what concentrations CO_2 was being lost and also the effect that seepages were having on the local environment. The absolute amounts would not be important other than as an indication of how long the leakage might persist. For accounting purposes it would only necessary to measure the cumulative losses, presuming that CO_2 emissions remain under some form of control so far in the future. Precise measurement of losses is likely to be difficult.

Unless such a leak was highly localized it is unlikely to pose much of a threat. The maximum extent of long term monitoring required will thus depend on the rate of leakage since the smaller the leak the less the area which can be significantly affected. The following examples are illustrative of the magnitude of costs which might be incurred if simple surface flux monitoring was needed over an extended period. These costs are additional to those for the basic monitoring of the first three phases of typical projects.

Discounted costs for long term monitoring

Case 1 Additional monitoring at 10 sites for surface flux for extra 1000 years

Set up costs	\$60 000 per site
Operating costs	\$15 000 per site per year (both as estimated in the main report)
Tonnes of CO_2 in store	258 million
Undiscounted cost/tonne CO_2	\$0.0605/tonne
For intergenerational discount rate	2% p.a.
Discounted cost /tonne CO_2	\$0.0052/tonne
For intergenerational discount rate	1% p.a.
Discounted cost /tonne CO_2	\$0.0081/tonne

Case 2 Additional monitoring at 10 sites for surface flux for extra 100 years

Set up costs	$60 000 per site
Operating costs	$15 000 per site per year (both as estimated in the report)
Tonnes of CO_2 in store	258 million
Undiscounted cost/tonne CO_2	$0.0081/tonne
For intergenerational discount rate	2% p.a
Discounted cost /tonne CO_2	$0.0048/tonne
For intergenerational discount rate	1% p.a
Discounted cost /tonne CO_2	$0.006/tonne

These results show that the ongoing monitoring at this level would be small compared with the main monitoring costs for the project. The effect of discounting at even 2% over 1000 years would be to reduce the Net Present Value (NPV) to just 5% of the undiscounted value. The above gives some guidance as to the cost if long term monitoring is required at a CO_2 storage site.

OVERVIEW OF MONITORING TECHNIQUES AND PROTOCOLS FOR GEOLOGIC STORAGE PROJECTS

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Chapter 1. Introduction

This paper was prepared for the International Energy Agency Greenhouse Gas R&D Programme (IEA GHG) to provide an overview of monitoring techniques for geologic storage of CO_2. The study surveys the techniques available and the economics of deploying them. It also considers the range of applications for which monitoring will be required including verification of quantities stored, routine management of geological storage operations, short and long term monitoring for reservoir and seal integrity, leaks or CO_2 migration and accounting for CO_2 which has been traded. The study also provides general guidance on selection of techniques and identifies technology gaps.

1.1. Overview and Organization of the Report

The report is divided into four chapters that are described below.

Chapter 2. Purposes of Monitoring Geologic Storage Projects.

This chapter reviews the various purposes for CO_2 monitoring in connection with geological storage.

Chapter 3. Monitoring Techniques Currently Available.

This chapter reviews available information on existing geophysical and other techniques, which might be applicable to CO_2 monitoring in geological storage projects. An assessment is made of their status, and potential further development requirements. Where known, the accuracy and reliability are described. The applicability of each technique and where appropriate specific combinations of techniques for each category of storage reservoir are assessed and described. Finally, a matrix is developed showing which techniques are applicable for each of the purposes identified in Chapter 2.

Chapter 4. Evaluation of Monitoring Techniques for Specific Scenarios

Chapter 4 provides a site specific scenario that is used to evaluate the applicability of the monitoring techniques described in Chapter 3. This scenario is also compared to others with regard to the application of monitoring approaches.

Chapter 5. Selection of Monitoring Programs and Monitoring Costs

The costs of deploying and operating the various techniques are estimated on a stand-alone basis and converted to a cost range per tonne CO_2 stored. Key assumptions underlying the cost estimates such as reservoir size and depth are provided and any major cost dependencies are described. For each scenario a “package” of suitable monitoring techniques is proposed with a commentary on how the components were selected. The scenarios are based on a complete project lifecycle and thus consider monitoring requirements in each phase of a storage project. For each of the scenarios an estimate of the cost of deploying the preferred combination of monitoring techniques is made.

Chapter 6. Identification of Gaps and Further R&D Needs

Based on the information described in Chapters 2 through 5, current gaps in the availability of adequate monitoring techniques are assessed and R&D needs to fill these gaps are identified. In addition, for techniques that are already developed, we assess the likely improvements that can be anticipated as this technology matures.

1.2. Overview of Geologic Storage of CO_2

Storing industrially generated CO_2 in deep underground formations is being seriously considered as a method for reducing greenhouse gas emissions to the atmosphere (IPCC, 2003). Growing interest has lead to significant investment by governments and the private sector to develop this technology and to evaluate whether or not this approach to greenhouse gas control could be implemented safely and effectively.

At properly selected storage sites, safe and effective storage of CO_2 in deep geological reservoirs can be accomplished by a combination of physical and geochemical trapping as illustrated in Figure 1. Depleted oil and gas reservoirs, coal beds and deep salt water-filled formations (saline formations) are all being considered as potential storage options. Depleted oil and gas reservoirs are particularly suitable for this purpose as they have been shown by the test of time that they have – in the past – physically trapped buoyant fluids, such as oil, gas and CO_2. Storage in deep saline-filled formations is in principle the same as storage in oil or gas reservoirs, but the geologic seals that would retain the CO_2 in the intended storage formation need to be characterized and demonstrated to be suitable for long term storage. Without adequate caprocks (seals), geologic formations are not suitable for geologic storage of CO_2. Furthermore, for both depleted reservoirs and saline formations, it must also be demonstrated that storing CO_2 does not compromise the integrity of the geologic seals.

When CO_2 is first injected into a storage formation, a significant fraction (up to about 15%) may dissolve in the formation water. Over hundreds to thousands of years, even more, including possibly all of the CO_2, is expected to dissolve in the native formation fluids. Some of the dissolved CO_2 would react with and become part of the solid mineral matrix. Once dissolved or reacted to form minerals, CO_2 is no longer buoyant and consequently, will be trapped in the subsurface, even without the presence of a suitable geologic seal. Coal beds offer the potential for a different type of storage, where some fraction, including potentially all of the CO_2 becomes chemically bound (adsorbed) to the solid coal matrix. Complete adsorption onto the coal matrix requires effective contact between the CO_2 and the coal, which may be difficult given the low permeability of coal and tendency to hydrofracture during injection. If the CO_2 is not completely adsorbed to the coal matrix, low permeability seals, like those required in oil and gas reservoirs and saline formations, are required to retain the stored CO_2.

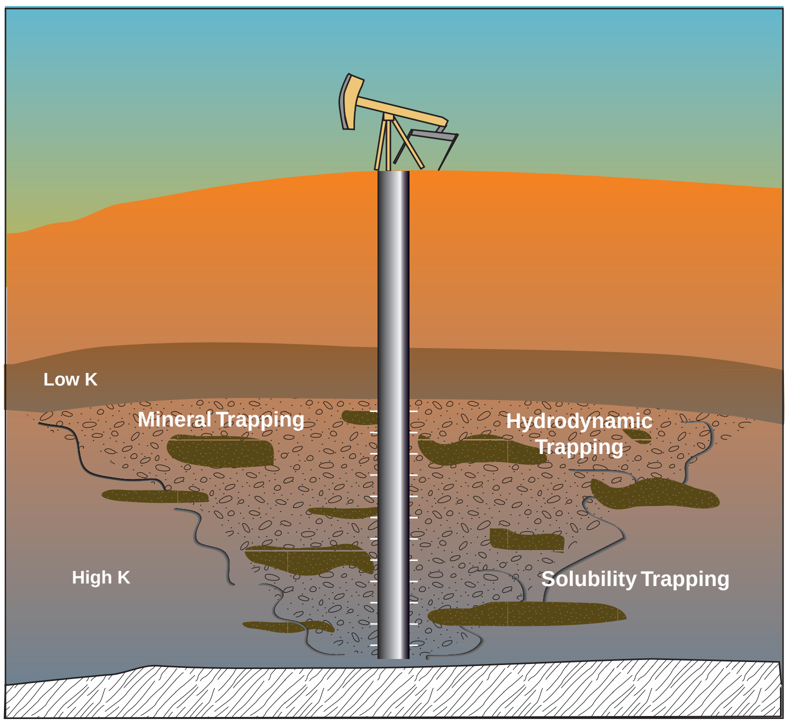


Figure 1. Schematic illustrating the concept of geologic storage of CO_2.

Chapter 2. Monitoring Geologic Storage Projects

Monitoring is essential for the successful implementation and public acceptance of geologic storage. Regulatory oversight bodies and prudent operators will require demonstration that the practice of geologic storage is safe, does not create significant adverse local environmental impacts and that it is effective as a greenhouse gas emission control technology. Monitoring will be the primary means by which it will be demonstrated that a project meets these requirements.

2.1. Purposes for Monitoring

The primary purpose of monitoring is to assure that (1) CO_2 storage is safe, (2) it does not create local environmental impacts such as groundwater contamination and (3) that it can effectively prevent CO_2 from being released into the atmosphere. Figure 2 illustrates these requirements and provides a framework for monitoring. As shown, while there are a broad range of safety and environmental issues that must be addressed to ensure safe and effective storage, the majority of the issues hinge on two primary factors, namely, (1) implementation of effective controls on injection well completion, injection rates, and wellhead and formation pressures, and (2) assurance that the CO_2 remains trapped and does not leak out of the intended storage reservoir(s). In addition to these two essential elements of monitoring strategy, there are many other parameters that can be used to optimize storage projects, deal with unintended leakage, and address regulatory, legal and social issues. These elements of a monitoring program are described in the following paragraphs.

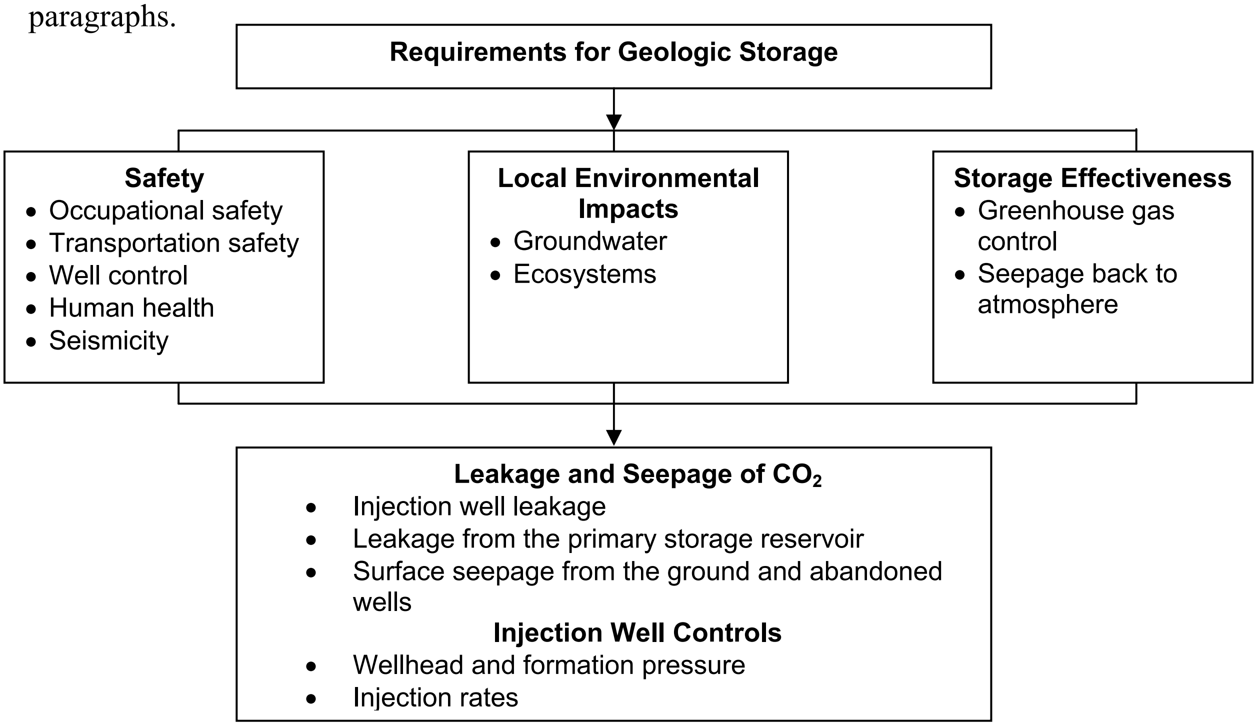


Figure 2. Schematic showing requirements for safe and effective geologic storage of CO_2.

2.1.1. Establishing Baseline Conditions from Which the Impacts of CO_2 Storage Can Be Assessed

Carbon dioxide is ubiquitous in the environment. It is everywhere in the air, water, and soils around us. CO_2 concentrations in these media can vary on daily, seasonal or longer time frames depending on the sources, sinks and long-term processes affecting CO_2 concentrations. Centuries of observation and monitoring data have also shown that the earth system is very heterogeneous, varying from place to place across the land surface and with depth. Moreover, many of the parameters that can be used to monitor a storage project are not uniquely and directly indicative of the presence of CO_2, but instead, it is the changes in these parameters over time can be used to detect and track migration of CO_2 and its reaction products.

For these reasons it is important to have a well-defined baseline that includes not only the average value of these parameters, but also how they vary in space and time before the project begins. This "time-lapse" approach is the foundation for monitoring CO_2 storage projects and having a well-defined baseline is critical to its success. Without an adequate baseline it may not be possible to separate storage-related changes in the environment from the natural spatial and temporal variations in the monitoring parameters. For most storage projects, the monitoring baseline will be obtained during the pre-injection characterization phase of a storage project. This is particularly important for geologic storage projects in deep saline aquifers, which have less prior data than depleted oil and gas fields.

2.1.2. Monitoring to Ensure Effective Injection Controls

Measurements are needed for ensuring and documenting effective injection well controls, specifically, for monitoring the condition of the injection well, measuring injection rates, wellhead pressures and formation pressures. While injection operations are practiced safely all over the world, experience has shown that leakage from the injection well itself, due to improper completion or deterioration of the casings, packers or cement is one of the most significant failure modes for injection projects (Benson et al., 2002a). Therefore to avoid the consequences of unintended leakage, periodic inspections to assure the integrity of the injection well are needed. Routine inspection practices and monitoring approaches have been developed for other applications and can be adopted easily for inspecting CO_2 injection wells. In addition, experience has shown that over pressuring the injection well due to injecting at too high rates or plugging of the injection well can create hydraulic fractures in the storage formation or cap rock that can lead to leakage. The degree to which over pressuring can be tolerated before fracturing occurs varies from one geologic setting to another, but site specific studies can be used to identify appropriate constraints. The conditions under which fracturing occurs are conceptually well understood and testing procedures have been developed to identify site-specific injection pressure limits. Injection into gas storage reservoirs and many other injection applications require continuous monitoring of wellhead pressures and injection rates to stay below the maximum injection pressure and avoid this problem (Benson et al., 2002a).

2.1.3. Monitoring to Detect the Location of the CO_2 Plume and Leakage from the Storage Formation

Measurements are needed for tracking the location of the plume of CO_2, either as a supercritical fluid or as a gas in the subsurface. This is the principal method for assuring that the CO_2 remains in the storage reservoir. It is also the method by which leakage and leakage pathways can be detected. In Chapter 3, many methods for tracking migration of the plume, either alone or in combination are described. Many of these have already been used in CO_2 Enhanced Oil Recovery Projects such as the Weyburn Project in Saskatchewan and the CO_2 storage project at Sleipner Vest in the North Sea.

2.1.4. Monitoring to Assess the Integrity of Shut-in, Plugged or Abandoned wells

Experience from natural gas storage and injection of liquid wastes into deep geological formations has shown that shut in, plugged or abandoned wells that are ineffectively sealed are the most probable leakage pathways (Benson et al., 2002a). Therefore, at storage sites with old and abandoned wells, methods are needed to monitor and verify that these wells are not providing a pathway for leakage between the deep and shallow subsurface. Pre-injection testing should be completed before a CO_2 storage project is initiated if the locations of the abandoned wells are known. In some cases, historical record-keeping has been poor, and the location of these wells only becomes apparent when they begin to leak.

2.1.5. Monitoring to Identify and Confirm Storage Efficiency and Processes

Geologic storage uses four processes to keep CO_2 from returning from the atmosphere – (1) physical trapping (sometimes called hydrodynamic trapping) below a low permeability cap rock, (2) residual gas trapping, (3) dissolution into the in situ reservoir fluids (solubility and ionic trapping) and (4) conversion to minerals that become part of the reservoir itself (mineral trapping) (Gunter et al., 2003). The dominance of these mechanisms changes over time, with an evolution from physical trapping and residual gas trapping, to solubility trapping and finally, mineral trapping. The time scale over which this evolution occurs and the degree to which it occurs is very site specific, and depends on the type of formation used for storage and the fluids in the formation. In many cases, physical trapping may be the most important and in this case, monitoring how completely the storage volume is filled may be needed to design, guide and evaluate the project. In other cases, solubility trapping may be very large and in fact, over time the entire plume may dissolve in the reservoir fluids. In this case, monitoring how quickly and effectively dissolution is taking place will be needed to confirm that the storage project is performing as designed. Similarly, though less probable, in other projects it may be necessary to monitor the progress of mineral trapping.

2.1.6. Monitoring for Model Calibration and Performance Confirmation – Comparing Model Predictions to Monitoring

One of the most important purposes of monitoring is to confirm that the project is performing as expected from predictive models. Specifically, confirming that the CO_2 plume is migrating as expected, that the storage reservoir is being filled as expected, and that the reservoir pressure is increasing as expected can all be used to validate that the storage project is performing as anticipated. This is particularly valuable in the early stages of a project when there is the opportunity to alter the project or if it is not performing adequately, to abandon the storage site altogether. Moreover, monitoring data collected early in the project is often used to refine and calibrate the predictive model further. The refined model then forms the basis for predicting the longer-term performance of the project. This approach was successfully applied in the Sleipner Project, where the first set of monitoring data significantly changed the conceptual model of the storage project and allowed for a much better understanding of the influence of the fine-scale reservoir heterogeneity (Chadwich, et al., 2002; Van Der Meer et al., 2002; Lindeberg et al., 2002; Zweigel at al., 2000).

Comparing model predictions with monitoring data is the key to model calibration and performance confirmation. While this is simple in principle, unless the linkage between the model results and monitoring data is considered during the design of the monitoring program, the data needed for model calibration and performance confirmation may not be available. Issues such as which parameters should be monitored, timing of measurements, spatial scale and resolution of measurements, and location of monitoring points all needed to be considered.

2.1.7. Monitoring to Detect and Quantify Surface Seepage

If there is evidence that significant leakage has occurred from the primary storage formation and CO_2 has migrated to the land surface or ocean floor, methods for detecting the location of seepage and monitoring the concentration and flux of CO_2 may be needed. Monitoring to detect and quantify seepage will be different depending whether the storage site is on-shore or off-shore. For on-shore storage sites, seepage monitoring is likely to require a combination of soil gas CO_2 concentration measurements, CO_2 concentrations in air, and surface flux measurements using eddy flux towers or flux chambers. Off-shore, detecting and monitoring seepage to the ocean floor may require a combination of measurements, including ocean water chemistry, detection of hydrate formation and other as yet to be determined techniques.

2.1.8. Monitoring to Assess Environmental, Health and Safety Impacts of Leakage

If significant leakage occurs, monitoring will be needed to assess the consequent environmental impacts. Potential impacts include:

- groundwater contamination, either from the CO_2 itself, from geochemical interactions between CO_2 and the geological formation (e.g. dissolution of metals or trace elements such as arsenic and lead), or from hydrocarbon gases and H_2S that are carried along with the leaking CO_2;
- ecosystem damage to flora and fauna associated with elevated concentrations of CO_2 in soil gas, acidification of soil water, and mobilization of metals and trace elements; and
- the unlikely, but possible, human health impacts caused by exposure to elevated CO_2 concentrations in low lying areas, enclosed spaces or under stagnant atmosphere conditions. Atmospheric CO_2 concentrations in excess of 3% are known to have physiological impacts to humans. Simulation studies have shown that atmospheric mixing is very effective at dispersing CO_2 which seeps to the surface through the vadose zone (Oldenburg et al, 2003). However, leakage through abandoned wells or other man-made structures may conceivably create localized areas with high concentrations of CO_2. In this case, monitoring would be needed detect, quantify and remediate the human health hazards.

2.1.9. Monitoring Micro-Seismicity Associated with CO_2 Injection

While it is not expected that induced seismicity will be a significant problem at CO_2 storage sites, under certain conditions, such as when the injection pressure is too high or the temperature of the injected fluid is much colder than the reservoir, injection is known to cause seismic events created by microfracturing the reservoir rock or by small movement along existing fracture surfaces. Examples of induced seismicity have been documented in oil and gas production, natural gas storage sites, waste injection sites and dams. Most of these events are far below the level that can be detected by humans and cause no harm. However, there have been notable exceptions such as at the Rocky Mountain Arsenal in Colorado, where a 5.3 magnitude earthquake is believed to been induced by waste injection. Monitoring for the detection of microseismic events may be required or desirable to demonstrate the natural seismicity of a region and how it is affected by CO_2 injection. If CO_2 injection induced micro-seismicity is detected, ongoing monitoring may be required.

2.1.10. Monitoring to Design and Evaluate Remediation Efforts

If leakage occurs, it will probably be necessary to implement remediation measures to stop the leakage or minimize its environmental, health and safety impacts. Designing and evaluating the effectiveness of remediation may require additional monitoring. For example, accurately locating and characterizing the source of the leak may require more detailed information than is required to track migration of the CO_2 plume. Higher resolution methods for detecting and quantifying the presence of CO_2 may be required. After the remediation plan is designed and implemented, additional monitoring would be required to evaluate whether the remediation plan was successful and if further action is needed.

2.1.11. Monitoring to Provide Assurance and Accounting for Monetary Transactions and Validation of Emission Reductions

Validating or certifying transactions for financial purposes such as carbon credit trading, emission taxes or emission reduction treaties or incentives will require accepted protocols for assuring that CO_2 has been effectively stored underground. The protocols have not yet been developed but will likely be based on a combination of the above-mentioned monitoring activities. At a minimum, CO_2 injection rates must be monitored. Whether or not additional monitoring is required should be determined by the type of geological reservoir into which the CO_2 is injected. For example, in a CO_2 EOR project, it may be sufficient to only monitor both how much CO_2 is injected underground, and how much is returned to the surface with the produced oil. In contrast, for storage in saline formations, where the caprock may not be as well characterized as for oil and gas reservoirs, or an oil-field penetrated by many abandoned wells, it may be desirable to monitor the location of the CO_2 plume to assure that it remains underground. Over time, monitoring protocols for these and other situations will be developed.

2.1.12. Monitoring to Evaluate Interactions with or Impacts on Other Geological Resources

In the event that a storage project is located in the vicinity of producing oil and gas fields, coal mines or other geological resources it may be necessary to demonstrate that the storage project is not harmful to or interfering with these activities. Likewise, if there are multiple storage projects in the same area it may be necessary to demonstrate that each is accessing only the allocated storage space and not encroaching on the other project. At a minimum this would require tracking subsurface migration of the injected CO_2. In addition, it may be desirable to tag the CO_2 with a tracer that could uniquely identify its origin and thus distinguish one “operator” CO_2 from another.

2.1.13. Monitoring to Settle Legal Disputes Due to Leaks, Seismic Events, or Ground Movement

Legal disputes arising from alleged damage to ecosystems, groundwater resources, production of oil and gas resources, or other claims of harm to life or property will require information to support or defend those claims. In this event, having an adequate baseline against which the claims can be judged will be important. In addition, ongoing monitoring data to demonstrate the impacts of the project will be required. For example, proving claims of structural damage due to an injection-induced seismic event would require a pre-project baseline of regional seismicity and ideally, ongoing monitoring showing the location and magnitude of subsequent events. Similarly, proving or disproving claims of groundwater damage would require baseline information about water quality, water-table elevation, and subsequent monitoring data that could demonstrate whether or not any significant changes had taken place, and whether or not it could be demonstrated that the changes could be attributed to the CO_2 storage project. In almost every case, having accurate and timely information on the location of the injected CO_2 will be needed to support or defend such claims. Additional data, specifically related to the nature of the claims will also be required.

2.1.14. Monitoring to Assure the Public Where Visibility and Transparency is of Prime Importance

Knowing that monitoring approaches are available could provide greater assurance to the public that geologic storage projects can be safe and effective. This will be particularly important as the first large scale projects are implemented. In addition, a storage project located near a large population center may require more monitoring than one in a remotely located area to assure the local population that they are safe.

2.2. Phases of Monitoring Geologic Storage Projects

Every geologic storage project will go through a series of phases which constitute the life-cycle of the project. During each of these phases, monitoring will serve different purposes. For this report, we suggest that there are four distinct phases of life-cycle of a geologic storage project. A similar, but not identical discussion of the life-cycle of a storage project can be found in Keith and Wilson (2002). In addition, as protocols for monitoring have yet to be established, we take the liberty of proposing a conceptual framework for determining when and how long monitoring will be required.

- **Pre-operation Phase**. During this phase of the project, the geology of the site is characterized; the environmental, health and safety risks are identified; abandoned wells are located and assessed; base-line conditions are established; small-scale injection tests may be conducted to understand and help optimize storage processes and injection operations; the injection operation is defined; monitoring plans are developed; environmental and operational permits are obtained; injection wells are drilled; and surface facilities are constructed.
- **Operation Phase**. During this phase of the project, which is expected to take place over a 30 to 50 year time period, CO_2 will be injected into the reservoir; surface facilities and injection rates will be monitored; the location of the plume will be tracked; and other monitoring activities will be conducted as required by the regulatory permit.
- **Closure Phase**. The closure phase of the project begins when CO_2 injection has stopped. The purpose of this phase is two-fold. First, surface facilities will be removed and the injection wells plugged and abandoned if they are no longer required for monitoring. Second, it will be used as a confirmatory period to

demonstrate that the storage project is performing as expected and that it is safe to decrease or discontinue further monitoring. The duration of the closure phase will vary, depending on a number of factors such as the type of storage project, the regulatory requirements, and the degree to which the project performed as expected. Conceivably the closure phase could last from several decades up to several centuries. For example, the closure phase for storage in a depleted gas field with very few abandoned wells may be relatively short because there is a high degree of assurance that the CO_2 will remain trapped in the gas reservoir and the risk of leakage up abandoned wells is low. A limited monitoring program, over several decades may be sufficient to demonstrate that the CO_2 will remain safely underground and that monitoring is no longer required. On the other hand, a storage project in a very large saline formation, where the CO_2 may continue to migrate even after injection has stopped, may require hundreds of years to demonstrate that the project is performing as expected and that CO_2 is safely contained. At the end of the closure phase and if CO_2 is retained as expected in the storage reservoir, monitoring may no longer be required. Regulatory agencies would determine if and when a project had come to closure and could be transitioned to the post-closure monitoring phase.

- **Post-Closure Phase**. At the end of the closure phase, a complete set of records about the location and status of the CO_2 plume and abandoned wells would be turned over the regulatory authorities who would maintain a permanent archive of this information. It is proposed here that monitoring will no longer be required except in the event of monitoring ongoing leakage, legal disputes or other matters that may require new information about the status of the storage project. This perhaps optimistic proposal is predicated on gaining experience and using appropriate technology to ensure that abandoned wells do not present an unacceptable risk of creating a pathway for CO_2 leakage back to the surface. In Chapter 5, where the cost of monitoring is discussed, we also examine scenarios where on-going monitoring is required, even during the post-closure phase.

The purposes for monitoring are different during each of these phases. Table 1 provides suggestions for the purposes of monitoring over the life-cycle of a storage project. For example, during the Pre-Operational Phase, the primary purposes for monitoring are to obtain baseline data, assess the integrity of shut-in, plugged or abandoned wells, and identify and confirm storage efficiency and processes. During the Operational-Phase, the most important purposes include ensuring injection well integrity, tracking migration of the CO_2 plume, confirming that the storage projects is operating as expected, providing assurance where credits or monetary transaction are involved, and assuring the public that the project is safe and effective. During the Closure Phase, monitoring must demonstrate that the storage project continues to be safe and effective, and that it is performing as expected. The regulators and the public must be assured that the project will continue to perform before monitoring can cease and transition into the Post-Closure Phase. During the Post-Closure Phase, monitoring would only be required if the site is leaking or to monitor other ongoing environmental impacts. Should legal disputes arise, additional monitoring may also be required in the Post-Closure Phase.

2.3. The Value of a Tailored and Dynamic Approach to Monitoring

Monitoring for CO_2 storage projects should be tailored to the specific conditions and risks at the storage site. For example, if the storage project is in a depleted oil reservoir with a well-defined cap rock and storage trap, the most likely pathway for leakage is the injection well itself or perhaps, abandoned wells from former reservoir operations (Benson et al., 2002a). In this case, the monitoring program should focus on detecting leakage from injection well, locating any abandoned wells in the area and ensuring they are not leaking CO_2 to the land surface or shallow aquifers. On the other hand, if a project is in a formation where the cap rock is less well defined or lacks a local structural or stratigraphic trap, the monitoring program should focus on tracking migration of the plume and ensuring that is does not leak through discontinuities in the cap rock. Likewise, a storage project relying on solubility or mineral trapping for secure storage would need to demonstrate that the geochemical interactions were effective and progressing as predicted. One can also imagine that the extent of land surface monitoring would depend on the size of the local population. If a project were located in an urban area, extra precautions would be put in place to assure the public that the storage project was not causing a safety or human health hazard.

The value of taking a tailored approach to monitoring is two-fold. First, the monitoring program focuses on the largest risks and impacts. Second, since monitoring may be expensive, a tailored approach will enable the most cost effective use of monitoring resources. Having said this however, it is likely that there will be a minimum set of monitoring requirements that will be based on experience and regulations from related activities such as natural gas storage, CO_2 enhanced oil recovery and disposal of industrial wastes in deep geologic formations (Benson et al, 2002a; Wilson et al., 2002).

The design and implementation of a monitoring program should also be dynamic – in the sense that the biggest risks should continually be reassessed and the monitoring program re-directed to address those risks. Risk assessment should be an ongoing process throughout the life-cycle of a storage project, taking advantage of new information obtained from the monitoring program. The dynamic process of continually improving the risk assessment and refining the monitoring program is the key to a cost-effective and protective monitoring program.

Monitoring Purpose	Pre-Operation Phase	Operational Phase	Closure Phase	Post-Closure Phase
Establishing baseline conditions from which the impacts of CO_2 storage can be assessed	Yes			
Ensure effective injection controls		Yes		
Detect the location of the CO_2 plume		Yes	Yes	If movement remains uncertain
Assessing the integrity of shut-in, plugged or abandoned wells	Yes	Yes	Yes	If leakage not stopped
Identify and confirm storage efficiency and processes	Yes	Yes		
Model calibration and performance confirmation – comparing model predictions to monitoring data		Yes	Yes	
Detect and quantify surface seepage	c	If leakage detected	If leakage not stopped	If leakage not stopped
Assess environmental, health and safety impacts of leakage		If leakage detected	If leakage not stopped	If leakage not stopped
Monitoring micro-seismicity associated with CO_2 injection	To establish baseline	If micro-seismicity detected		
Monitoring to design and evaluate remediation efforts		If leakage detected	If leakage detected	
Provide assurance and accounting where monetary transactions are involved such as with carbon trading and emission tax or emission reduction incentives		Yes	Yes	
Evaluating interactions or impacts with other geological resources: for example nearby water, coal, oil & gas, mineral reserves or other geological waste disposal operations.	To establish baseline	If interactions are possible	If interactions are possible	If interactions are possible
Settling of legal disputes for example due to leaks, seismic events, ground movement		If leakage, seismicity or ground movement detected	If leakage, seismicity or ground movement detected	If leakage, seismicity or ground movement detected
Assuring the public where visibility and transparency is of prime importance	Yes	Yes	Yes	If public concerns remain

Table 1. Summary of the purposes for monitoring during the phases of a storage project.

Chapter 3. Overview of Currently Available Monitoring Techniques

Measurement technology applicable for monitoring geologic storage of CO_2 is available from a variety of other applications, including the oil and gas industry, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, food preservation and beverage industries, fire suppression and ecosystem research (Benson et al., 2002a; 2002b). In the following chapter we introduce these techniques and describe their applicability for monitoring CO_2 storage projects. This overview is not intended to provide a comprehensive description of all the available techniques. Instead, only brief descriptions are provided for the most well established techniques such as pressure and flowrate measurements are provided. More comprehensive descriptions are provided for the most promising techniques such as seismic imaging and developing techniques such as Self-Potential. At the end of this chapter, we present a matrix which shows how these techniques can be applied for the purposes identified in Chapter 2.

3.1 CO_2 Flow Rates, Injection and Formation Pressures

Measurements of CO_2 injection rates are a common oil field practice and instruments are available from commercial manufacturers. Measurements are made using gauges that are part of the surface facilities, either at the injection wellhead or near distribution manifolds. Typical systems use orifice meters or other differential producing devices that relate the pressure drop across the device to the flow rate. Real-time and continuous monitoring is provided by signals that are electronically transmitted to a control center. Recent enhancements in the basic technology are now available that allow for accurate measurements and injection control for CO_2, even under varying pressure and temperature conditions (Wright and Majek, 1998).

Measurements of injection pressure at the surface and in the formation are also routine. Wellhead pressure gauges are installed on most injection wells through orifices in the surface piping near the wellhead. Downhole pressure measurements are not made as part of daily operations, but are used for injection well testing or under special circumstances where measurements of surface pressure do not provide reliable information about the pressure in the formation. A wide variety of pressure sensors, including piezo-electric transducers, strain gauges, diaphragms and capacitance gauges are available and suitable for monitoring CO_2 injection pressures either at the wellhead or in the formation. Real-time and continuous data is available and typically transmitted to a central control room. Surface pressure gauges are often connected to shut-off values that will stop or curtail injection if the pressure exceeds an unsafe threshold. A relatively recent innovation, fiber optic pressure and temperatures sensors have been developed and many manufacturers now sell these products. Fiber optic cables are lowered into the wells, connected to the sensors and provide real-time formation pressure measurements. These new systems are expected to provide even more reliable measurements and well control (Brown and Hartog, 2002).

The current state of the art is adequate to meet the needs for monitoring CO_2 injection rates, wellhead and formation pressures.

3.2. Direct Measurement Methods for CO_2 Detection

Direct measurements of CO_2 in air, water or soils may be required as part of the monitoring program. For example, CO_2 concentrations in the air near the injection wells or abandoned wells may be monitored as a precaution to ensure worker and public safety at the storage site. In addition, nearby groundwater monitoring wells may be monitored periodically to ensure that the CO_2 storage project is not harming groundwater quality. If there is an indication that CO_2 has leaked from the primary storage reservoir and migrated to the surface, vadose zone and soil gas CO_2 concentrations may be monitored (e.g. Strutt et al., 2002).

Even in the event that the storage project poses no safety or environmental concerns, direct measurement of CO_2 concentrations and CO_2 reaction products may be wanted to assess the extent of solubility and mineral trapping. In addition, in some cases it may be desirable to have a method to uniquely identify and trace the movement of injected CO_2 from one part of the storage formation to another.

3.2.1. CO_2 Sensors for Measurement of CO_2 in Air

Continuous sensors for monitoring CO_2 are used in a wide variety of applications, including CO_2 demand-controlled HVAC (Heating, Ventilation and Air Conditioning) systems, greenhouses, combustion emissions measurement, and the monitoring of environments in which carbon dioxide is a significant hazard (such as breweries). Such devices rely on Infrared (IR) detection principles and are referred to as infrared gas analyzers (IRGA). IRGAs are small and portable and commonly used in occupational settings. Most use nondispersive infrared (NDIR) or Fourier Transform infrared (FTIR) detectors. Both methods depend upon light attenuation by CO_2 at a specific wavelength, usually 4.26 μm. For extra assurance and validation of real-time monitoring data, NIOSH (National Institute for Occupational Safety and Health), OSHA (Occupational Safety and Health Administration), and the U. S. EPA (Environmental Protection Agency) use periodic gas sampling bags and gas chromatography for measuring CO_2 concentrations. Mass spectrometry is the most accurate method for measuring CO_2 concentration, but it is also the least portable. Electrochemical solid-state CO_2 detectors exist, but they are not cost effective at this time (e.g. Tamura et al. 2001).

Common field applications in environmental science include the measurement of CO_2 concentrations in soil air, flux from soils, and ecosystem-scale carbon dynamics. Diffuse soil flux measurements are made using simple IR analyzers (Oskarsson et al. 1999). The

USGS measures CO_2 flux on Mammoth Mountain using LI-COR detectors, named after the company that makes them (LI-COR 2001, Sorey et al. 1996, USGS 2001, 1999). Biogeochemists studying ecosystem scale carbon cycling use CO_2 detectors on 2–5 meter-tall towers in concert with wind and temperature data to reconstruct average CO_2 flux over large areas. These eddy flux correlation measurements (ECOR) assume thorough atmospheric mixing.

CO_2 leaks may also be located by detecting leakage of other gases. For example, it is well established that radon (Ball et al.1991) and helium are good pathfinders for gas migration from depth, exploiting fractures and faults to make their way to the surface. Helium has an almost constant concentration in the soil gas environment (5.24 ppm) and thus any increase from this value must be due to a geological input.

Remote sensing of CO_2 releases to the atmosphere by satellites is also possible, but because of the long path length through the atmosphere over which it is measured and because of the inherent variability of atmospheric CO_2, the detection sensitivity will not be sufficient unless leakage rates are very high. The total amount of CO_2 integrated by a satellite through the depth of the entire atmosphere is large. Infrared detectors measure average CO_2 concentration over a given path length, so a diffuse or low-level leak viewed through the atmosphere by satellite would be undetectable. In contrast, SO_2 and integrated total atmospheric CO_2 are routinely measured (Lopez-Puertas and Taylor 1989). Geologists use airborne instrumentation called COSPEC to measure the amount of SO_2 in eruption plumes, but it is not directly relevant to monitoring for surface leaks of CO_2 over large areas. A plane carries a spectrometer through the plume and measures the attenuation of solar ultraviolet light relative to an internal standard. Carbon dioxide released from volcanoes is measured either directly in the plume by a separate IR detector, or calculated from SO_2 measurements and direct ground sampling of the SO_2/CO_2 ratio for a given volcano or event (Hobbs et al. 1991, Mori and Notsu 1997, USGS 2001). Remote-sensing techniques currently under investigation for CO_2 detection are LIDAR (light detection and range-finding) a scanning airborne laser, and DIAL (differential absorption lidar) that looks at reflections from multiple lasers at different frequencies (Hobbs et al. 1991, Menzies et al. 2001).

In summary, occupational safety monitoring of CO_2 is well established. On the other hand, while some promising technologies are under development for environmental monitoring and leak detection, carbon dioxide measurement and monitoring approaches on the temporal and space scales that are relevant to geologic storage could be improved with additional R&D.

3.2.2. CO_2 and Geochemical Monitoring for Groundwater and Vadose Zone Impacts

Groundwater quality is usually measured by collecting groundwater samples and analyzing them to determine pH, Eh and chemical composition. Groundwater samples can be collected either directly from the formation using a downhole sampler or from the wellhead if the well from which the sample is collected is pumped. Downhole samples are considerably more costly, but have the advantage that they are more representative of the formation fluids because they are not depressurized as they flow up the well. Methods for collecting downhole and wellhead fluids samples are well developed and geochemical sampling is conducted on a routine basis.

Fluid samples from the vadose zone (region between the water table and the ground surface) can be collected by installing porous-cup samplers that operate under vacuum to extract water under unsaturated conditions. Likewise, gas samples can be collected from the vadose zone using soil-gas samplers. Once collected, these liquid samples can be analyzed with the same techniques used for monitoring groundwater composition. Gas samples can be analyzed using conventional techniques such as mass spectrometry.

Potential groundwater impacts from CO_2 storage projects fall into two categories: (1) impacts caused by migration of CO_2 into groundwater aquifers and (2) impacts caused by displacement and migration of saline water into fresh-water aquifers. Impacts from both of these causes can be detected by analyzing the composition of the groundwater for major ions (e.g. Na, K, Ca, Mg, Mn, Cl, Si, HCO_3^- and SO_4) pH, alkalinity, stable isotopes (e.g. ^{13}C, ^{14}C, ^{18}O, ^{2}H), and gases, including hydrocarbon gases, CO_2 and its associated isotopes (Gunter et al., 1998; 2001). In addition, if CO_2 has migrated into the groundwater, samples should be analyzed for trace elements such as arsenic and lead, which are mobilized by acidic water. Standard analytical methods are available to monitor all of these parameters, including the possibility of continuous real-time monitoring for some of the geochemical parameters. For routine monitoring, it is not necessary to monitor all of the parameters listed above. A limited subset that is tailored to the local hydrogeologic setting should be sufficient. However, a comprehensive baseline should be established prior to the beginning of the project.

Natural tracers (isotopes of C, O, H and noble gases associated with the injected CO_2) and introduced tracers (noble gases, SF_6 and perfluorocarbons) also may provide insight about the groundwater impacts of CO_2 storage projects (Emberly et al., 2002; Blencoe et al., 2001; Cole, 2000; Kennedy and Torgersen, 2001). Natural tracers such as C and O isotopes may be able to link changes in groundwater quality directly to the stored CO_2 by "fingerprinting" the CO_2, thus distinguishing storage-induced changes from changes in groundwater quality caused by other factors. Introduced tracers such as perfluorocarbons that can be detected at very low concentrations (10^{-12}) may also be useful for determining whether or not CO_2 has leaked from the storage reservoir and is responsible for changes in groundwater quality. Tracers may also provide the opportunity to uniquely identify the source of CO_2 and in essence, answer the question "Whose CO_2 is it?"

3.3. Indirect Methods for Locating CO_2 Plumes in the Subsurface

Indirect measurements for detecting CO_2 in the subsurface provide methods for tracking migration of the CO_2 plume in locations where there are no monitoring wells, or for providing higher resolution monitoring in between wells or behind the cased portion of a well. Such indirect methods fall into five categories, namely: well logs; water quality measurements; geophysical monitoring methods such as seismic, electromagnetic, and gravity; land surface deformation using tiltmeters, plane or satellite-based geo-spatial data; and satellite-based imaging technologies such as hyperspectral and IR imaging.

The utility of these indirect methods is determined by (1) their threshold for detection of the presence of CO_2, (2) the extent to which the signal is uniquely related to the presence of CO_2 (e.g. distinguish the effects of a pressure increase from the presence of CO_2) and the (3) the degree of quantification that is possible (e.g. what is the fraction of the pore volume occupied by CO_2).

To date, three-dimensional (3-D) seismic reflection surveys have been used to monitor, with excellent success, migration of the CO_2 plume injection in the Utsira Formation in Statoil's Sleipner Vest CO_2 storage project (Korbul and Kaddour, 1995; Arts et al., 2000; 2002; Eiken et al., 2000; Torp and Gale, 2002). The success of this project bodes well for the ability of indirect methods to track plume migration in the subsurface. However, 3-D seismic reflection surveys may not always be so successful; costs for these surveys are high compared to other available monitoring methods, and in some cases, the spatial resolution or the detection threshold may not be adequate. Therefore, additional methods for plume detection are being evaluated.

3.3.1. Well Logs

One of the most common methods for evaluating geologic formations is the use of well logs. Logs are run by lowering an instrument into the well and taking a profile of one or more physical properties along the length of the well. Many types of well logs are available and can measure a variety of parameters - from the condition of the well, to the composition of pore fluids, and mineralogy of the formation. Commonly run well logs include formation resistivity, neutron, acoustic, gamma ray, self potential and temperature logs. These well logs, run and interpreted singly or in combination, provide invaluable information about the subsurface environment. Well logging is a mature technology that has been highly developed, both in terms of the instruments and the interpretation, for the petroleum industry. All of these techniques are directly applicable for monitoring CO_2 storage projects.

Well logs will be particularly helpful for geologic storage projects in four ways, namely (1) initial geologic characterization of the storage site, including the thickness and properties of the storage formation and seal; (2) developing a baseline for parameters such as formation resistivity, seismic velocities and mineralogical composition of the formation; (3) for identifying the initial salinity and hydrocarbon content of the formation, including a baseline against which future changes can be detected; and (4) for assessing the integrity of injection, monitoring or other wells within the footprint of the storage project. Application of these techniques is well-developed for monitoring injection wells in natural gas storage projects and for disposal of industrial wastes in deep geologic formations. Periodic measurements are required by the regulatory agencies to ensure that the well itself does not provide a leakage pathways. Several logs are routinely used for this purpose, including temperature, noise, casing integrity and radioactive tracer logs (Benson et al., 2002a).

Time-lapse imaging of physical properties related to the distribution of CO_2 in the reservoir can also be useful for monitoring the progress of a geologic storage project. For example, sonic logs could be used to monitor changes in the compressional wave velocity, which is in turn related to the density and compressible of the pore fluids, and hence, CO_2 saturation. Formation resitivity and neutron logs are also diagnostic of changes in pore fluid composition. While these methods are undoubtedly useful for providing qualitative information, the extent to which time-lapse imaging can provide a quantitative measure of the CO_2 distribution still needs to be demonstrated and evaluated.

3.3.2. Water Quality Measurements

Geochemical methods are also useful for understanding the reactions taking place between CO_2 and the reservoir fluids and minerals (Gunter et al., 1998; 2001). Similar to groundwater sampling, fluid and gas samples can be collected either directly from the formation using a downhole sampler or from the wellhead if the well from which the sample is collected is pumped. Once collected, samples can be analyzed for major ions (e.g. Na, K, Ca, Mg, Mn, Cl, Si, $HCO_3^-$and SO_4) pH, alkalinity, stable isotopes (e.g. ^{13}C, ^{14}C, ^{18}O, ^{2}H), and gases, including hydrocarbon gases, CO_2 and its associated isotopes (Gunter et al., 1998; 2001). While it is comparatively straightforward to measure the parameters listed above, interpreting these measurements to infer information about geochemical reactions is much more challenging. In particular, little attention has been given to understanding the impact of mineral/CO_2 interactions on enhanced oil recovery. Only recently, and as a result of recent interest in geologic storage of CO_2, has a great deal of attention been paid to understanding reactions between CO_2 and deep geologic formations shortly after CO_2 is introduced into the environment (Bachu and Gunter, 1994; Czernichowski et al., 1996; Johnson et al., 2001; Knauss et al., 2001). Much remains to be learned about the kinetics of mineral/CO_2 interactions and how monitoring data can be used to predict the extent and rate of mineral and solubility trapping. Studies of natural CO_2 reservoirs are being used to learn more about the kinetics and extent of these reactions and will he helpful for designing monitoring programs for assessing geochemical reactions.

3.3.3. Geophysical Monitoring Methods: Seismic, Electromagnetic and Gravity

It is natural to consider geophysical techniques for monitoring of geologic storage because of the large body of experience in their application in the petroleum industry. Three primary candidates for geophysical monitoring include seismic, electromagnetic and gravity techniques. Gravity methods sense changes in density; electrical methods primarily respond to changes in resistivity, and seismic methods depend on both density and elasticity. These physical properties are known for CO_2, typical reservoir fluids, and their mixtures (Batzle and Wang, 1992; Magee and Howley, 1994, NIST, 1992) so assessments can be made of expected changes in geophysical properties. CO_2 is resistive, so electrical methods are good candidates for saline formations because a large contrast in electrical resistivity will be present. For most of the depth interval of interest for storage, CO_2 is less dense and more compressible than water or oil, so gravity and seismic methods are candidate methods for saline water or oil bearing formations. At shallow depths (less than 800 m), CO_2 has gas-like properties so none of the geophysical methods are good candidates for monitoring CO_2 within a shallow dry natural gas reservoir. Even in this case, however, since saline formations are commonly found above gas reservoirs, geophysical methods would still be candidates for detection of leaks. Research continues to refine the information available on the influence of varying CO_2 saturations on seismic and electrical properties (e.g. Hoversten and Myer, 2000; Myer, 2001; Xue et al., 2002; Hill et al., 2002).

Among geophysical techniques, seismic methods are by far the most highly developed. The most likely mode of application will be time-lapse, in which the difference between surveys at different times would be used to evaluate the movement of CO_2. As mentioned above, this technique has been used very effectively for monitoring CO_2 movement in the Utsira Formation (see discussion below). Though time-lapse imaging is becoming more common, it is a much less mature technology than exploration geophysics.

All of the geophysical methods described here continue to improve with the development of new technology. In particular, crosswell seismic and electromagnetic (EM) technology has developed over the past two decades to provide high spatial resolution images of the seismic velocities (V_P and V_S) and electrical resistivity of the interwell region. The output from cross-well surveys is still most commonly a cross section of velocity, electrical resistivity or the time-lapse change of these parameters, which is then interpreted to detect changes in the parameter of interest (e.g. temperature, CO_2 saturation, etc.). Cross-well surveys will be most useful for assessing how effectively the pore space in the storage formation is being used, for assessing sweep efficiency in EOR projects and for validating high-resolution performance prediction models. In addition, the high-resolution techniques may be useful for providing more detailed information about leaks, once they have been located by other methods which provide broader spatial coverage.

One of the limitations of all these techniques is the difficulty in quantifying the amount of CO_2 that is present. For example, the presence of only a small amount of CO_2 creates large changes in the seismic velocity and compressibility of the rock (Arts et al., 2002). However, as the pore space is filled with a larger fraction of CO_2, little additional change occurs. Hoversten et al. (2002) have developed methods to quantify the saturation of CO_2 in the pore space by combining electrical and seismic imaging measurements. To predict quantitatively the location and amount of CO_2 in the crosswell image plane, the change of P-wave velocity (V_P) is decomposed into the part that can be predicted by the estimated changes in water saturation and pressure and the part predictable by a change in CO_2 content. Using this procedure, Hoversten et al. (2002) demonstrated that by combining seismically derived changes in compressional and shear velocity with EM-derived changes in electrical resistivity, estimates of pressure change, water saturation change, and CO_2 gas/oil ratio can be made in a complex reservoir containing oil, water, hydrocarbon gas, and injected CO_2. While knowledge of the saturation of CO_2 may not be required as part of a routine monitoring program, it will be very useful for calibrating and confirming reservoir simulations.

The resolution of potential field methods like gravity and electrical methods (essentially all geophysical methods other than seismic) is not formally defined. It is generally recognized that the resolution of these methods is much less than that of seismic. More importantly, the vertical resolution of the potential methods is very poor, particularly if the spacing of monitoring locations is sparse. Good vertical resolution is essential for detecting leaks from storage reservoirs.

Finally, all of the methods described above can be deployed in a number of ways, depending on the resolution and spatial coverage needed. For example, seismic data can be obtained in 2 or 3-dimensions where the seismic source and receiver are located at the ground surface. Alternatively, higher resolution data can be obtained from vertical seismic profiling where receivers are located along the length of a wellbore. Even higher resolution data can be obtained by locating the source and receivers in wellbores and imaging between them. Successful images of CO_2 migration during EOR have been obtained using cross-well seismic imaging (Wang et al., 1998). Similar configurations are applicable to electromagnetic techniques, including EM and electrical resistivity methods. Recent efforts are developing electrical resistance tomography, a simple approach that uses the wells themselves as electrodes, as a low-cost, low-resolution method for tracking CO_2 movement within a wellfield. A pilot test of this technology is underway at the Vacuum Field in New Mexico (Newmark et al., 2002).

The applicability of geophysical techniques depends, first, on the magnitude of the change in the measured geophysical property produced by CO_2, and second, on the inherent resolution of the technique. Finally, the applicability also depends on the configuration in which the measurement is deployed. Each of the methods is described below, along with information about their applicability and sensitivity. Real-world examples are used to illustrate the methods when possible. Techniques that are well developed are described briefly. For those that are less well developed, more detailed information is provided.

3.3.3.1. Seismic Monitoring

Seismic imaging, the most widely used geophysical technique today, makes use of the propagation of sound energy in the earth. This technique uses man made or natural sources of acoustic energy to image the interior of the earth. Seismic acoustic energy can be generated and received on the land surface, in the oceans or down boreholes. This technology has formed the core of geophysical exploration for the petroleum industry over the second half of the twentieth century.

Seismic methods cover several frequency ranges and bandwidths: the higher the frequency and bandwidth, the greater the resolution. However, higher frequency waves propagate over shorter distances, so the optimal frequency and bandwidth must be selected for the particular application. Surface seismic methods produce energy from 10 Hz to about 100 Hz. Crosswell seismic methods using rotary sources produce energy in the 100 Hz to 500 Hz range and using piezoelectric sources, in the 1 to 2 KHz range. Borehole seismic methods produce energy in the 10 KHz range. CO_2 plumes as thin as 2 to 15 m thick may be detected using surface seismic methods. Wavelengths of high frequency borehole-deployed methods are much shorter, implying high resolution, but scattering and intrinsic attenuation limit the distance over which an interpretable signal will travel. High frequency borehole methods can penetrate only a few tens of meters into typical sedimentary rock.

Statoil's CO_2 Injection Project in the North Sea provides an outstanding example of the applicability of seismic methods for monitoring CO_2 migration in the subsurface. Carbon dioxide is injected into the Utsira Sand, a Mio-Pliocene sandstone reservoir about 150-200 m thick, at a depth of 800–1,000 m, overlain by more than 100 m of shale. A seismic line beneath the Sleipner injection facility showing the Utsira formation is shown in Figure 3 with a cartoon illustrating the relation between the petroleum bearing sediments and the Utsira shown in Figure 4. The overlying shale sequence has a very low permeability and is expected to provide an effective seal to the injected CO_2. Injection started in 1996 and is planed to last 20 years at annual rates of approximately 1 million tonnes CO_2 injected per year.

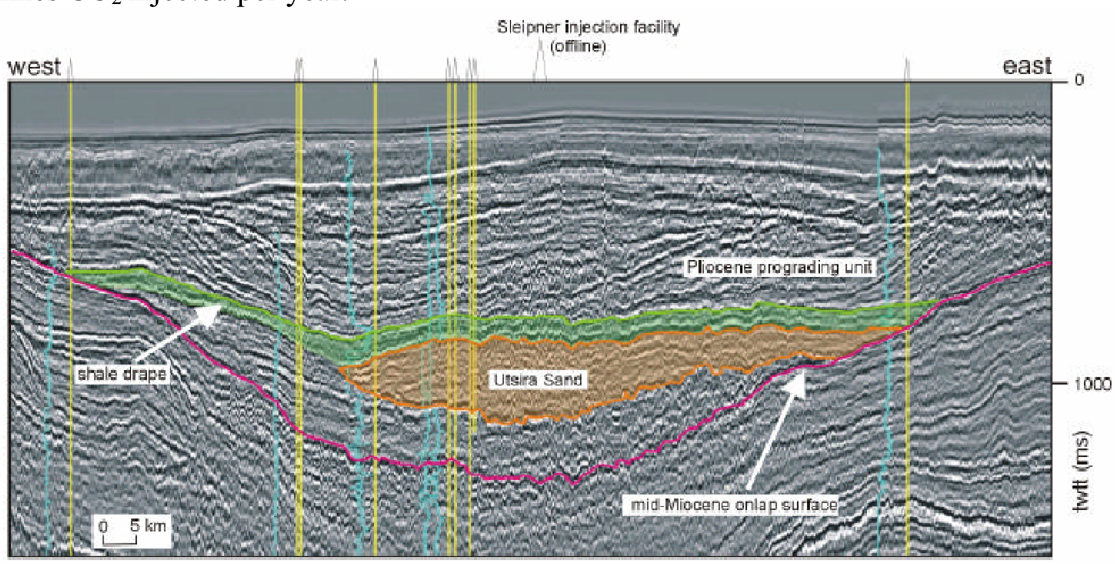


Figure 3. Regional seismic line through the Utsira Sand Formation (after Chadwick et al., 2000).

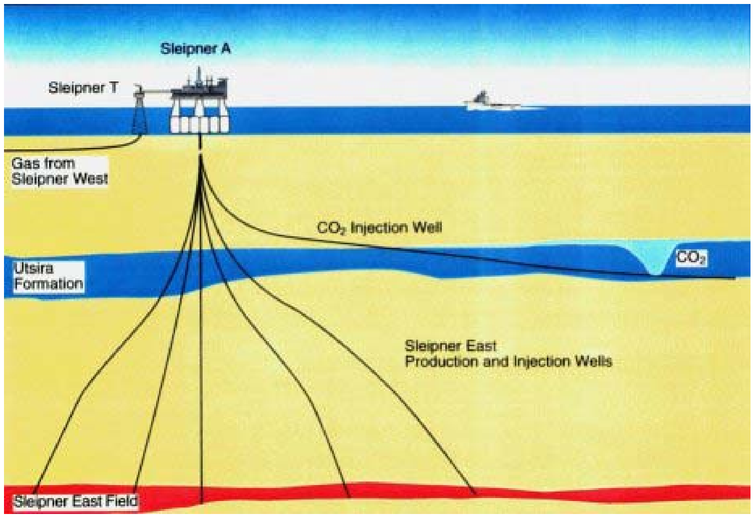


Figure 4. A sketch of Sleipner Field production (after Arts et al., 2000).

As part of the Saline Aquifer CO_2 Storage (SACS) project, time-lapse 3D seismic surveying has been used to successfully monitor the CO_2 movement. A seismic time-lapse survey was acquired in early October 1999, 3 years after CO_2 injection began. A comparison between the seismic data from 1994 and 1999 is shown in Figure 5. The time-lapse data show the occurrence of 'anomalies', very strong amplitudes, most likely caused by CO_2, in several layers within the Utsira Sand. The survey showed that as expected, the injected CO_2 has migrated upwards towards the top of the reservoir. With CO_2 stored underneath, the shale layers that trap CO_2 within the storage formation are illuminated and can be identified on the seismic data as amplitude anomalies, despite the thicknesses of the accumulations being below the limit of seismic resolution. The enhanced reflectivity is caused by the high compressibility of the CO_2 and by the constructive tuning effects of the top and bottom reflections at the CO_2 accumulations. The effect of the density is less important since the CO_2 is in a supercritical rather than a gaseous state at the reservoir pressure and temperature conditions. The thicknesses of the accumulations can be estimated quantitatively using the seismic amplitude information and assuming a tuning relationship. Because seismic waves travel more slowly through CO_2-saturated rock than through water-saturated rock, a "velocity push-down effect" beneath the CO_2 plume can be observed on the seismic data (Arts, 2002).

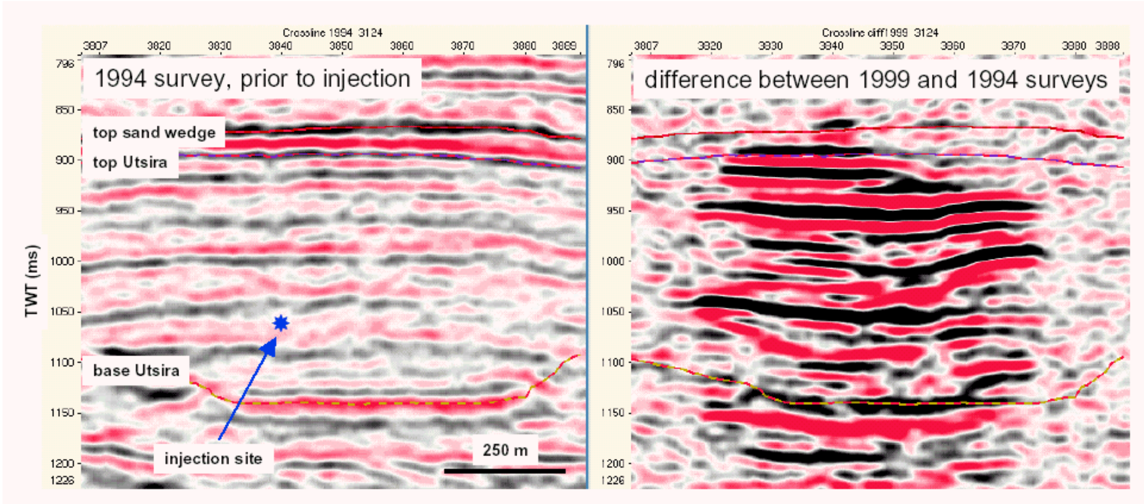


Figure 5. Seismic section for 1994 survey, and difference between 1999 and 1994 surveys (after Zweigel et al., 2001).

A third survey was conducted in 2001. Strong negative reflections (black peaks) are observed for at least nine depth levels both on the 1999- and the 2001 time-lapse surveys (Figure 6). The consistency between the CO_2 levels of both surveys is striking. In general the 2001 CO_2 levels have a larger lateral extent and have been "pushed down" slightly with respect to the 1999 CO_2 levels. This can be easily explained considering that more injected CO_2 causes more velocity pushdown. The two shallowest CO_2 reflections correspond to accumulations at the top of the sand wedge and the top of the Utsira Sand. By 1999 the CO_2 had reached the top of the sand wedge and since then has spread laterally at this level. The other seven interpreted levels are caused by CO_2 accumulated below the thin intra-reservoir shale layers. A prominent vertical feature that can be clearly distinguished is characterized by localized pushdown and much decreased reflection amplitudes. This is interpreted as a "chimney" of CO_2, situated approximately above the injection point and forming a major vertical migration path, which conducts CO_2 almost directly to the top of the reservoir.

The successful application of time-lapse seismic imaging at Sleipner Vest demonstrates that this is a powerful technique for tracking migration of CO_2 within the storage reservoir. The question then becomes, can time-lapse imaging be used to detect leakage through the cap rock and into shallower strata?

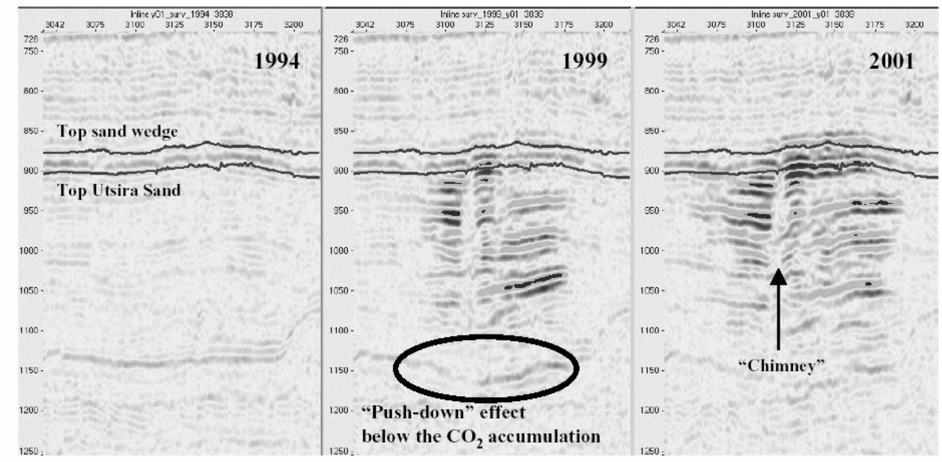


Figure 6. The seismic inline (of the 1994, 1999 and 2001 survey) through the injection point (after Arts et al., 2000).

Detecting small amounts of CO_2 that may have escaped from the primary storage reservoir is one of the most important monitoring needs. The size of a region containing CO_2 must also be sufficient to generate an interpretable geophysical signal. A relevant concept is resolution, which, in geophysics, is defined as the ability to distinguish separate features. For seismic methods, resolution is usually discussed in the context of reflection processing, and expressed in terms of the size of the feature compared to the seismic wavelength. Seismic resolution has been addressed by Widess 1973, Hilterman, 1976, Sheriff 1997, Neidell and Poggiagliolmi 1977, Mechel and Narth 1977, and others. Vertical resolution relates to bed thickness and the critical resolution thickness is about $^1/_8$ wavelength. For thinner beds, separate reflections from the top and bottom cannot be identified. Lateral resolution is related to Fresnel zone size. When the lateral dimension is less than one Fresnel zone, reflected amplitudes are a function of size, in addition to property contrasts. Myer et al (2002) studied the resolution of surface seismic for detecting subsurface volumes containing CO_2 and concluded that, at depth, a plume as small as 10,000 to 20,000 tonnes of CO_2 may be detectable but would be difficult to resolve its precise location and CO_2 saturation. Under typical circumstances, plumes containing this amount of mass are expected to be on the order of 200 m in diameter and 10's of meters thick.

3.3.3.2. Electrical and Electromagnetic Methods

Electrical and electromagnetic (EM) geophysical techniques use the propagation of electrical and/or EM fields within the earth as a means to infer the electrical structure of the earth. The distinction between electrical and EM techniques is made based on the frequency at which energy is generated. In general 'electrical' refers to zero or very low frequency methods where no EM induction occurs. EM techniques, in contrast to electrical techniques, operate at frequencies where the time-varying EM source fields produce induction in the earth, thus generating secondary electric and magnetic fields which carry information about the electrical structure where they were generated. These techniques play a central role in mining applications of geophysics because they are sensitive to the electrical resistivity structure of the earth, and mining targets (ore bodies) are very good electrical conductors. In recent years electrical and EM techniques have been increasingly used in petroleum exploration in areas where seismic methods do not provide the necessary information. The EM applications as developed in the petroleum context are the most applicable to the task of CO_2 monitoring.

In addition to traditional electrical and EM methods, Self-Potential (SP) methods may also be useful for monitoring plume migration. Fluid flow within a porous medium can produce an electrical potential due to the separation of ions across flow boundaries. This phenomenon is the basis of the SP method. SP has been used in geothermal exploration (i.e. Corwin and Hoower, 1979), in earthquake studies (i.e. Fitterman, 1978; Corwin and Morrison, 1977), and in engineering applications (i.e. Ogilvy et al, 1969; Bogoslovsky and Ogilvy, 1973, Fitterman, 1983).

The measurement of the SP generated electric fields is relatively simple and low cost. Field measurement requires only monitoring the background electric field while moving over the surface measuring the potential difference between the measurement site and a reference electrode. Field operations typically require only a single individual with only a few minutes required per measurement. The ease of the measurement coupled with the fact that the data is generated directly by the flow phenomena suggests a potential technique for low-cost, low-resolution monitoring. As the SP method is not as well developed as the other methods described above, and because the sensitivity has not been established for monitoring CO_2 migration, the following paragraphs provide a case study regarding the applicability to monitoring CO_2 migration in a saline formation. The gradient of the electric potential (electric field) produced at a flow boundary by the SP is given by:

$$\nabla \phi = L \frac{\Gamma \mu}{k \sigma} \tag{1}$$

where L is the so called 'coupling coefficient'
Γ is the primary fluid flux, related to the pressure gradient by Darcy's Law
k is solution dielectric constant
σ is the bulk conductivity (1/resistivity) of the rock
μ is the fluid viscosity

Laboratory studies have been conducted to measure the SP due to CO_2 injection in Berea sandstone (Lang Stone, Columbus, Ohio). The fundamental finding of this work as it relates to the SP method as a potential monitoring tool is contained in Figure 7, where the coupling coefficient (L from equation (1)) as a function of time in the flow injection experiment is plotted. When liquid CO_2 was applied to the sample, the water in the sample pore space was displaced, while reacting with the CO_2 to form carbonic acid. The coupling coefficient evolved over time in response to the mixing and displacing of the pore water. Figure 7 shows the coupling coefficient evolution of both tests for the 20 minutes following CO_2 injection.

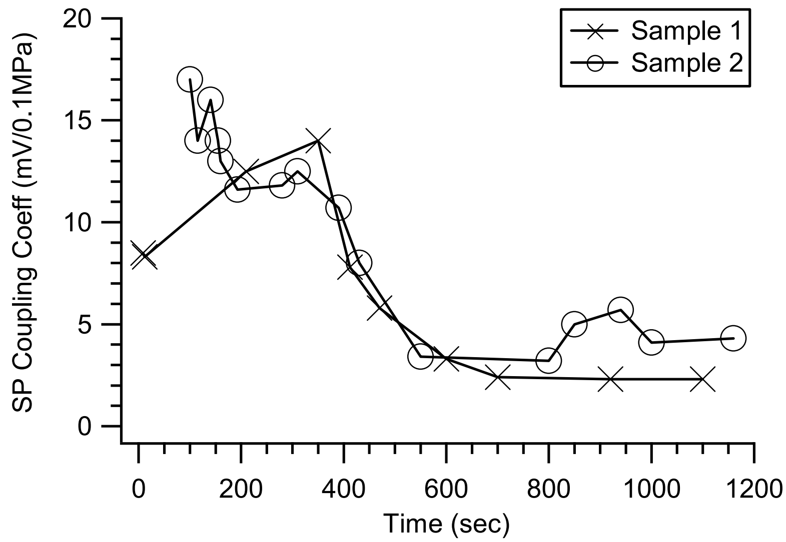


Figure 7. Coupling coefficients as a function of time for the first 20 minutes of CO_2 injection for samples 1 and 2. Coupling coefficient values were steady for times greater than 700 seconds, and remained steady throughout the remaining testing time.

The coupling coefficient, which scales the magnitude of the observed SP response, is largest at the CO_2 front where mixing with the in-situ water occurs. Behind the front where most of the water has been swept L decreases to near 4 mV/atm. In most CO_2 storage settings the in-situ fluid will be highly conductive saline with L approximately 0 so that the CO_2 – saline contrast will be large and potentially offer a means of monitoring the advance of the CO_2 front.

In order to determine the magnitude of the SP response a 2D numerical model based on the geology of the Frio Formation, Texas, was created. The Frio Formation is a widespread saline formation (with a number of oil reservoirs) that has many desirable attributes for geologic storage (Hovorka et al., 2001). The model consists of a 10 m thick sand unit at a depth of 1,500 m embedded in shale. The resistivity of the sand unit is 2 Ohm-m, while the resistivity of surrounding shale is 1 Ohm-m. The flow rate of CO_2 is 350 kg per second; the viscosity of CO_2 is 0.073 x 10^{-3} Pascal-seconds and the density of CO_2 is 788 kg/m^3 at a temperature of 70° C and a pressure of 30 MPa. The model is shown in Figure 8a. The 2D algorithm developed by Sill (1983) was used. This algorithm assumes the fluid sources to be a line perpendicular to the geologic variation at steady state conditions (constant flow of a single phase fluid).

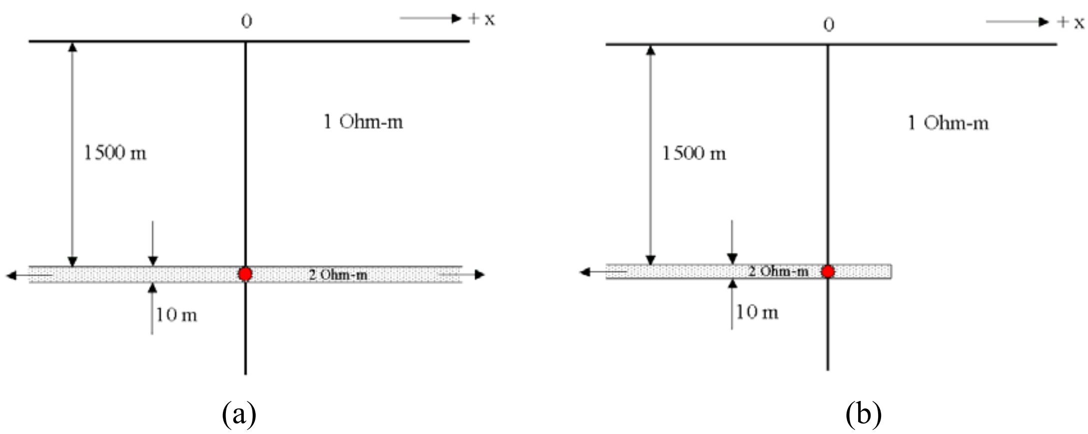


Figure 8. (a) Continuous layer model simulating the Liberty Field geology - 10 m thick sand layer at a depth of 1,500 m. (b) Layer truncated at +300m in x.

The model shown in Figure 8b has the same parameters as the model in Figure 8a, except that the sand layer is terminated at +300 m. Comparison of results from these two models give an indication the ability of the SP surface measurements to resolve lateral variations in the subsurface flow of CO_2. The largest effect of the layer truncation is an increase of the pressure gradient by reducing the flow volume within the layer thus increasing the magnitude of the SP observed at the surface. The truncation of the layer also introduces an asymmetry in the surface SP response (red curve in Figure 9). The response is 10 mV higher on the truncated side than on the continuous side. The ability to differentiate this spatial variation in the signal will depend on the background noise level in the electric fields on the surface.

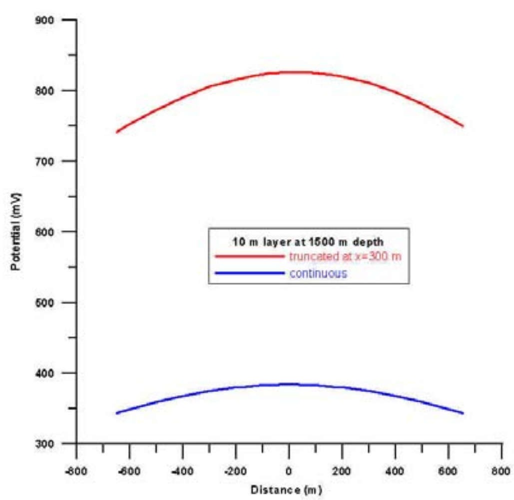


Figure 9. Surface SP response for models shown in Figure 8. Blue curve is for continuous layer; red curve is for the truncated layer. There is a 5% lateral variation in the SP response of the truncated layer.

These initial laboratory measurements and numerical model studies suggest that SP may provide a very low cost monitoring technique. However, further numerical code development and field testing are required before this technique can be considered as a viable option for storage monitoring.

3.3.3.3. Gravity

The gravity method makes use of the gravitational attraction of the mass of the rocks that make up the earth. In particular spatial changes in rock density produce spatial changes in the gravitational field measured at some distance from the mass. Gravity is most commonly used as a surface or marine based measurement, but can be made in boreholes as well. Measured gravity data is used in conjunction with numerical modeling to infer the density distribution that best fits the observed data. The inferred density can then be used to further infer the fluid saturations within the rock due to the different densities of the fluids present. As applied to CO_2 storage monitoring, gravity measurements show a reduction in the gravitational attraction over regions of a formation containing CO_2 when compared to the formation filled with saline water, because CO_2 is less dense than saline water.

In order to set some limits on the size and depths of CO_2 plumes that can be detected and resolved by surface gravity measurements, a simple wedge model is used to represent a vertically migrating buoyant CO_2 plume. In this model the rock parameters from the Frio Formation were also used. The surrounding shale has a density of 2,240 kg/m^3 with an embedded saline water saturated sand layer having 20% porosity resulting in a density of 2,280 kg/m^3. The 3D wedge of CO_2 saturated sand was considered to be 100% saturated with CO_2, which resulted in a density of 2,200 kg/m^3 for the wedge. The two models cover a reasonable range of the most likely depths for CO_2 storage.

Figure 10 shows three surface response curves of the vertical component of the gravity field for the top of the wedge at a depth of 2,000 m. The radius of the wedge is 240 m. This radius represents one seismic Fresnel zone, and thus a target which would be easily imaged on surface seismic data. The volume of CO_2 contained in the 100 m thick wedge represents 41 days production from a 1,000 MW coal fired power plant. The simulation was run for 100, 50 and 30 m thick wedges. Repeated land gravity measurements have been reported (Brown, 2003) with a standard deviation near 5 micro-gals (μGal), and recent repeat marine measurements at Sleipner have been reported to have a standard deviation of 3 μGal. Manufacturer's literature suggests instrument accuracy approaching 1 μGal (Micro-g http://www.microgsolutions.com /hardware.htm). It is reasonable to set the standard deviation of repeat measurements as the detection threshold. The wedge model representing 41 days production produces a peak signal just over 1 μGal, suggesting that this represents a lower detection limit for plumes at 2 km depth.

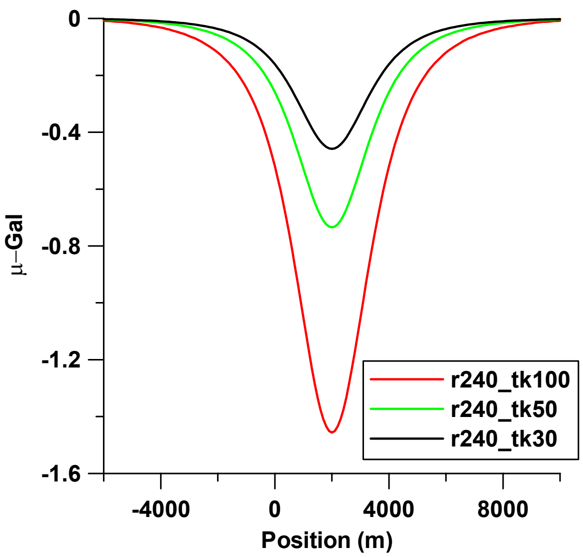


Figure 10. Surface vertical component of gravity measured over a 3D wedge at a depth of 2,000 m. The wedge radius is 240 m with thickness of 100, 50 and 30 m. The wedge with thickness of 100 m contains the equivalent amount of CO_2 produced by a 1,000 MW US coal fired power plant in 41 days.

A second set of models with the wedge at 1,000 m depth were run, their responses are shown in Figure 11. With the CO_2 plume at 1,000 m the 100 m thick volume would be detectable.

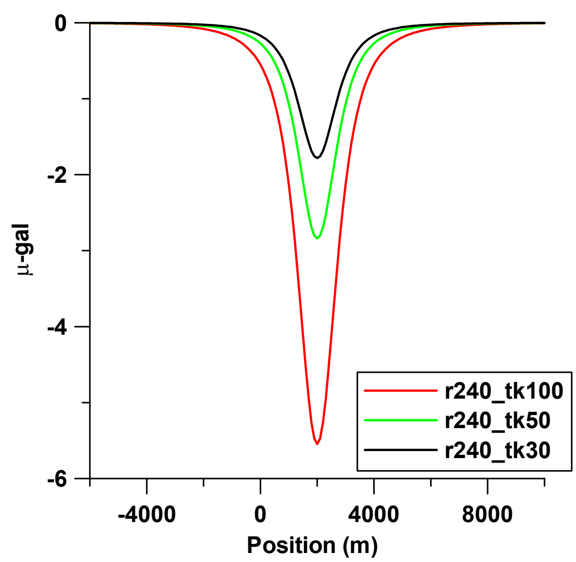


Figure 11. Surface vertical component of gravity measured over a 3D wedge at a depth of 1,000 m. The wedge radius is 240 m with thickness of 100, 50 and 30 m.

Model calculations indicate that gravity monitoring is feasible for storage with the sensitivity to the effected formation volume over large, planer injection projects falling off approximately as the inverse of the depth to the storage formation.

3.3.4. Land-surface Deformation, Satellite and Airplane-Based Monitoring

Recent advances in satellite imaging provide new opportunities for using land surface deformation and spectral images to indirectly map migration of CO_2. Ground surface deformation can be measured by satellite and airborne interferometric synthetic aperture radar (InSAR) systems (Zebker, 2000, Fialko and Simons, 2000). Tiltmeters placed on the ground surface can measure changes in tilt of a few nano-radians (Wright et. al., 1998). Taken separately or together these measurements can be inverted to provide a low-resolution image of subsurface pressure changes. While these technologies are new and have not yet been applied for monitoring CO_2 storage projects, they have been used in a variety of other applications, including reservoir monitoring (Vasco et al., 2001) and groundwater investigations (Hoffman et al., 2001, Vasco et al., 2001). Satellite spectral imaging has been used to detect CO_2 induced tree kills from volcanic outgassing at Mammoth Mountain, California (Martini et al., 1999; 2000). Maturation of these technologies may provide a useful and comparatively inexpensive method for monitoring migration of CO_2 in the subsurface and for ecosystem monitoring.

3.3.4.1. Tilt Measurements

Numerical modeling work done in preparation for the DOE GeoSeq CO_2 field test in the Liberty Field, Texas (scheduled for spring of 2004) provides an illustration of the application of surface deformation as a monitoring tool. The planned test is quite small, injecting a total of 3,000 tonnes of CO_2 over a 15-20 day period. The injection target is a 12 m thick sand at a depth of 1,500 m. The target sand lies in a fault block which has sealing faults on three sides and is open to flow on the fourth. The presence of the sealing faults acts to confine pressure build up to the fault block, thus increasing the magnitude of the surface deformation.

As CO_2 injection proceeds there is an associated pressure build up in the storage unit. This pressure increase translates into stress changes that propagate to the surface and manifest themselves as surface deformation. Figure 12 shows the depth-averaged change in pressure (left panel) within a 15 m thick sand unit at a depth of 1,500 m from the flow simulation model of the Liberty field project as well as the inversion (right panel) of the resulting synthetic surface tilt data (Vasco et al., 1998, 2001). The surface tilt is shown in Figure 13. The response is dominated by the fact that the injection occurs in a bounded fault block, thus amplifying the surface tilt above the injection point. The inverted pressure distribution has captured the large-scale pressure increase trending from southwest to northeast across the center of the section.

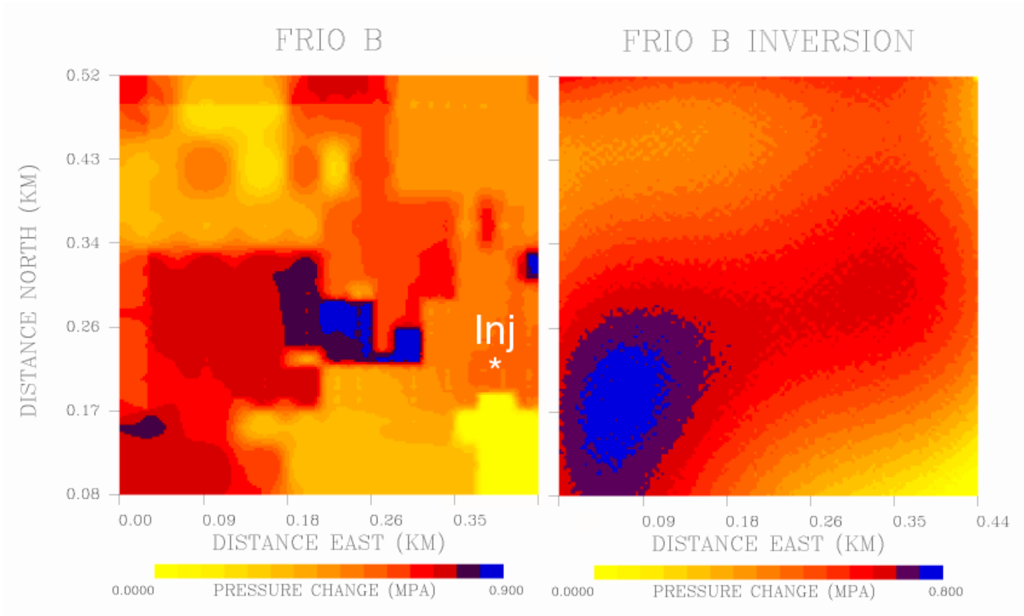


Figure 12. Left panel: Simulated depth-averaged pressure buildup in Frio B sand after 30 days of CO_2 injection. Right Panel: Inversion for pressure change from synthetic surface tilt measurements. The section shown is bounded by faults on left, right and top and is open to the bottom. CO_2 concentration and maximum local pressure increase are centered on the injection well but permeability variations within the unit cause the maximum depth-averaged pressure increase to be offset from the injection well.

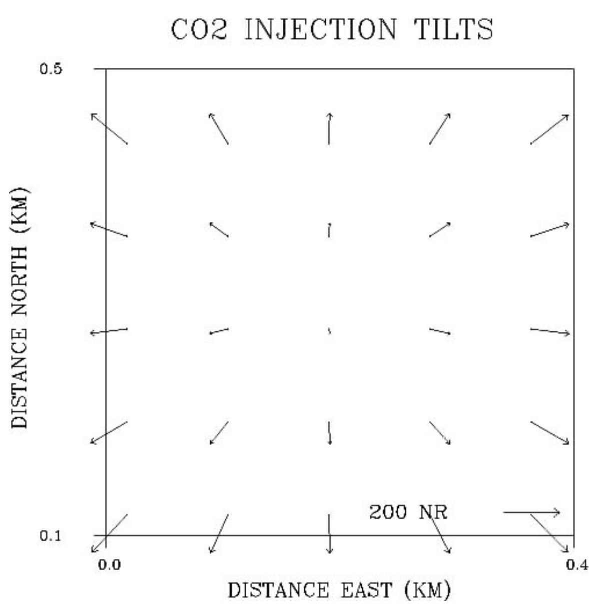


Figure 13. Surface tilt calculated for the pressure change shown in the left panel of Figure 12 and rock properties representative of the Liberty Field geology. Vectors show the orientation and magnitude of the tilt. The center of the bulge over the maximum pressure is flat and has little tilt. The bounding faults truncate the pressure field and are seen as locations of maximum tilt.

The calculated tilt values are easily observable in the field, since it is possible to achieve an accuracy of 1 nano-radian in field tilt measurements. While the limited spatial extent of this model with the presence of bounding faults (increasing the pressure buildup) dominate the response, it is clear that these measurements can be made in the field and detect the pressure changes associated with the injection of a small amount of CO_2.

While in some cases tilt may provide useful information for monitoring CO_2 storage projects, it is important to also point out the limitations in these measurements. For example, they do not directly detect CO2 migration, instead, they detect regions of pressure change. These changes result as much or more from displacement of water or oil as they do movement of CO_2. In addition, in areas where the land surface freezes annually, differential heave associated with freezing and thawing the ground surface may obscure the signal associated with pressure changes in the deep sub-surface. So, this technique, like all monitoring techniques should be evaluated based on site specific considerations, before it is deployed for monitoring a CO_2 storage project.

3.4. Summary of Costs for Individual Measurement Methods

Table 2 below provides cost estimates for each of the monitoring technologies. These cost estimates are presented on the basis of a single measurement or survey. In Chapter 5, we present the costs for monitoring packages that include periodic suites of measurements, on a per tonne of CO_2 basis.

Technique	Costs
Wellhead Pressure	\$4,500/\$5,500 without/with remote transmission (http://www.pioneerps.com)
Formation Pressure	open hole, depth 5,000 ft, 20 tests, Texas: \$10,450, Alaska: \$32,800 (http://www.reeves-wireline.com)
Injection and Production Rate	Production well: Gas/water separator w/meters: \$35,000 (cheaper version: \$15,000), remote monitoring with satellite feed \$4,500; Injection well: gas meter: \$4,500,remote monitoring with satellite feed \$4,500, continuous gas analysis: \$50,000, it's cheaper if only periodic analysis is used (J. Robinson, Alberta Reseach Council)
Well Logs	Basic Combo (caliper, gamma ray, neutron, resistivity): \$29,600; Sonic DeltaT Long-Spacing: \$8,910; UltraSonic Cement/ Casing Imager: \$13,500; Dipole Sonic Imager: \$12,328; Combinable Magnetic Resonance: \$19,849; RST (Saturation Tool): \$17,238 (Schlumberger)
Fluid and Gas Composition	Complete compositional analysis of gas samples: \$100/sample; ^{14}C analysis of gas component by AMS: \$650/component (http://www.isotechlabs.com); isotopes in CO_2 sample: \$30; isotopes in water sample: \$50-\$100 (M. Conrad, LBL); Chromatograph +RTU: \$30,000 (G. Wright, ExxonMobil)
Seismic Monitoring	\$10-25 k / km^2 acquisition + \$800-1,000/km^2 processing (SACS and W. King (ChevronTexaco) and seismic contracting company)
Electrical and Electromagnetic Monitoring	\$1,000/site (\$200/site) (M. Hoversten, LBNL)
Gravity Monitoring	\$1,000/site (\$200/site) (J.Hare, ZongeEnginnering and T. Niebauer, Micro-g)
Land Surface Deformation	InSAR: \$10,000/image (http://www.npagroup.com)
Tilt Measurements	downhole: existing well, 5 days, \$94K acquisition + \$37K interpretation (array of 12 tools) (Pinnacle Technologies)
	surface:(\$45-60K construction + \$15k/day analysis)/20-30 stations (Pinnacle Technologies)
Airborne or Satelite Imaging	\$70K for 300-500 km^2 for hyperspectral imaging; \$20-40K for satelite imaging; if seasonal view -> 3 times/year; mobilization: \$30K; baseline imaging will take 3 years; interpretation: 3* (\$96K+\$300K) = \$1,188K (W. Pickles, LLNL)
Soil Gas and Vadose Zone Monitoring	Vadose zone: \$40k (http://www.sandia.gov/ Subsurface/factshts/ert/vzms.pdf)
Surface Flux Monitoring	\$35k equipment + \$25k installation + 10k interpretation/year + 5k maintenance/year (M. Fischer, LBNL)
Atmospheric CO_2 Concentration	1ppm: < \$10k, 0.1 ppm: \$120k (M. Torn, LBNL)
Micro Seismicity	10 stations: \$400k + \$50-75k/year (E.Majer, LBNL)

Table 2. Cost estimates for stand-alone monitoring technologies.

3.5. Matrix of Monitoring Purposes and Measurement Methods

The measurement methods described above can be used alone or in combination to satisfy all of the monitoring purposes described in Chapter 2. In Table 3 we provide a matrix showing how the measurements describe in Chapter 3 can meet the various purposes for monitoring described in Chapter 2. For each purpose, we identify which measurement techniques are likely to be used (indicated by “Y”) and which techniques could possibly be used (indicated by “P”).

For example, during the Pre-operational phase of the project it will be necessary to measure a suite of parameters to characterize the site and establish a baseline set of environmental parameters (see Table 3). Establishing a baseline will require measuring the storage formation pressure, wellhead pressure, pressure in formations above the storage unit. It will also be necessary to measure the geothermal gradient and temperature in the storage formation. Wells logs will be required to locate and evaluate the lithology and structure of the storage formation, cap rock and overlying hydrocarbon or groundwater resources. Well logs may also be used to measure saturation of hydrocarbons in the storage formation and salinity of the formation fluids and overlying units. Samples of formation fluids and, in some cases, fluid samples from overlying units will be used to assess the nature and extent of geochemical interactions expected between CO_2 and the formation fluids. Surface seismic measurements will be used to determine the large-scale structure of the storage formation, cap rock and overlying units. Faults will be looked for and identified using surface seismic or higher resolution borehole to surface to borehole–to–borehole methods. In addition to the methods just mentioned, depending on the site and nature of the project, other geophysical methods such as gravity and electromagnetics may be used to further refine the geological description of the site. Land surface topography may be determined to establish a baseline against which future surface deformation could be monitored. Airplane or satellite based spectral imaging may be used to document the characteristics and health of the ecosystem over the footprint of the storage project. Soil gas composition and CO_2 flux measurements may be obtained to establish a seasonal baseline of biogenic CO_2 concentrations and fluxes. Depending on the natural background of seismicity and potential for induced seismicity, a baseline level of microseismic events may be measured. The suite of measurements will be determined by site specific considerations, driven by the local, regional and federal regulations; site specific risks; and the extent of characterization data already available at the site. For example, in a mature hydrocarbon producing field, much if not all of the above data will already be available. On the other hand, for a storage project in a saline formation where the cap rock is poorly defined, a considerable effort may be required to characterize the site and developed a project baseline.

Ensuring effective injection well controls to avoid fracturing the formation and preventing leakage around the wellbore will require routine monitoring of several parameters (see Table 3). Wellhead pressures must be measured. Formation pressure must be measured directly or calculated from the wellhead pressure. Injection rates must be monitored. Well logs that document the integrity of the injection well may be required periodically by the regulatory agencies and desirable even if not required. Periodic pressure testing of the casing and annulus may also be required. Experience from natural gas storage projects and liquid waste disposal projects has demonstrated that maintaining well integrity is one of the most important elements of having a safe and effective storage project. The measurements described here are employed successfully at many hundreds of projects around the world.

Tracking the location of the injected CO_2 may or may not be required to operate a storage project. For example, for storage projects in depleted gas fields, deep coal beds or even depleted oil reservoirs, it may not be necessary to track where the CO_2 goes as it fills up the formation. In saline formations, if much less is known about the cap rock, and how effectively it will trap the CO_2, tracking migration of the plume is more likely to be required, at least during the early stages of the project. In addition, oil reservoirs undergoing CO_2 EOR are likely to benefit from the data obtained by knowing how the CO_2 is migrating through the formation. In fact, it is in existing CO_2 EOR projects where high-resolution imaging is being pioneered to help optimize oil recovery. Three-dimensional, time-lapse seismic imaging is almost certainly going to be the most useful method for tracking migration of CO_2 in the subsurface. It can be conducted over a large footprint and does not require the presence of wells. It provides excellent vertical and horizontal resolution of the plume and can detect relatively small quantities (approximately 10,000 tonnes; Myer, et al., 2002) of CO_2. This can provide early warning in the event that a storage project begins to leak. Having said this however, methods such as pressure transient monitoring of the formation pressure, resistivity and neutron logs, fluid composition monitoring, electromagnetic geophysics, gravity, land surface deformation and tilt measurements may provide additional information that can be used to supplement seismic surveys. Over time, as these methods are refined and tested, their value may increase even further, reducing the requirements for repeated 3-D seismic surveys. At present, it is unlikely that any other these other methods will have sufficient resolution to replace the need for seismic surveys.

As shown in Table 3, there is at least one, and often multiple methods that can be used to satisfy the monitoring requirements identified in Chapter 2. The applicability of the methods is highly site specific. Measurements that are effective at one site may not be successful at another. Site specific risks may dictate that multiple approaches to monitoring may be required, while at another site, a minimal set of measurements may be all that is needed. In Chapter 4 we present a site-specific example that illustrates the contribution that each of these techniques could make to monitor a specific CO_2 storage project.

Monitoring Purpose/Methods	Wellhead and Formation Pressure	Injection and Production Rate	Casing and Annulus Pressure Testing	Temperature	Well Logs	Fluid and Gas Composition	Seismic Geophysics	Electrical and Electromagnetic Geophysics	Gravity	Land Surface Deformation	Tilt Measurements	Airborne or Satelite Imaging	Soil Gas and Vadose Zone Monitoring	Surface Flux Monitoring	Atmospheric CO_2 Concentration	Micro Seismicity
Establishing baseline conditions	Y			Y	Y	Y	Y	P	P	P		P	P	P		Y
Ensure effective injection controls	Y	Y	Y	Y	Y											P
Detect the location of the CO_2 plume	P	Y			P	P	Y	P	P		P					P
Assessing the integrity of shut-in, plugged or abandoned wells	P				Y	P	P					P	P	P	P	
Identify and confirm storage efficiency and processes	Y	Y			Y	P	Y	P								
Model calibration and performance confirmation – comparing model predictions to monitoring data	Y	Y		P	Y	P	Y	P	P							
Detect and quantify surface seepage												P	Y	Y	Y	
Assess environmental, health and safety impacts of leakage						Y	Y	P	P	P	P	P	Y	P	P	P
Monitoring micro-seismicity associated with CO_2 injection										P	P					Y
Monitoring to design and evaluate remediation efforts	P				P	P	Y	P				P	P	P	P	
Provide assurance and accounting where monetary transactions are involved such as with carbon trading	Y	Y					P									
Evaluating interactions or impacts with other geological resources: e.g. water, coal, oil & gas, mineral reserves	P	P				Y	Y	P								
Settling of legal disputes for example due to leaks, seismic events, ground movement	P				P	P	Y	P		P	P	P	P	P	P	P
Assuring the public where visibility and transparency is of prime importance	Y	Y			P	Y	Y	P		P	P	P	P	P	P	P

Table 3. Monitoring approaches for geologic storage of CO_2. Y indicates that the method is likely to be used and P indicates that is may be possible to use. Measurement methods are described in the text in the Measurement Methods Section. Purposes for monitoring are described in Chapter 2.

Chapter 4. Evaluation of Monitoring Techniques for Specific Scenarios

This chapter provides an evaluation of the contribution that the geophysical monitoring techniques described in Chapter 3 can make to monitoring requirements described in Chapter 2. This analysis makes use of a realistic scenario for a combined enhance oil recovery (EOR) and CO_2 storage project. It is based on the Schrader Bluff oil field on the North Slope of Alaska. Where differences exist in the application of a technology between the petroleum reservoir and a saline formation we comment on the differences. Life cycle monitoring costs for this project and another hypothetical saline formation storage project are presented in Chapter 5. Life-cycle costs are presented on the basis of $ per tonne of CO_2 in today's currency.

4.1. Case Study for an On-shore EOR project – Schrader Bluff, Alaska

A joint industry project comprising BP, ChevronTexaco, Norsk Hydro, Shell, Statoil, and Suncor was formed with the goal of developing technologies to enable the cost effective CO_2 capture and storage. One site being considered is the Schrader Bluff reservoir on Alaska's North Slope (Figure 14). Preliminary evaluations show that a CO_2 based enhanced oil recovery could increase oil recovery by up to 50% over water flooding (Hill et al, 2000). A schematic geological cross-section through the Schrader Bluff Formation is shown in Figure 15.

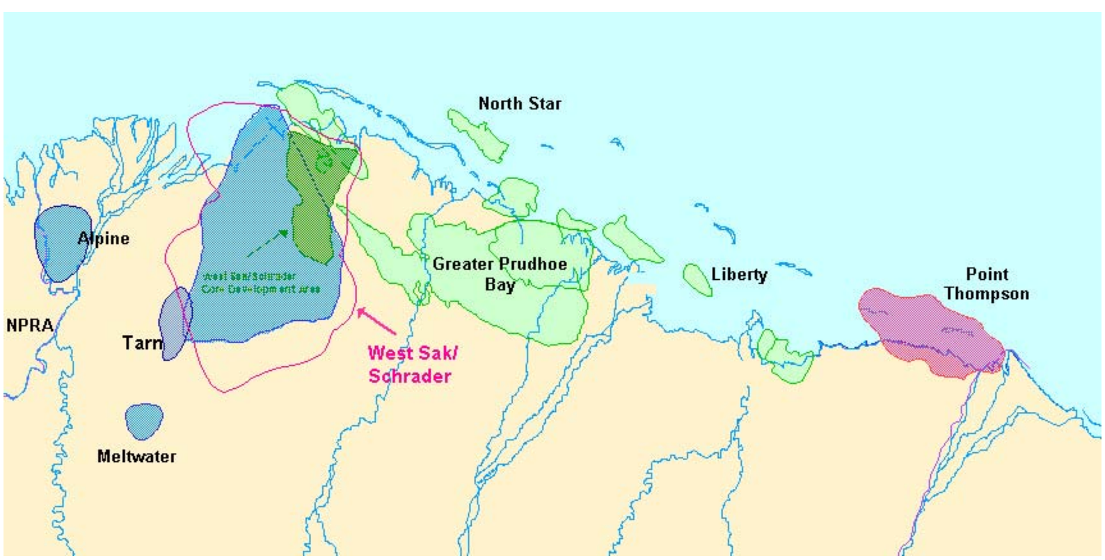


Figure 14. Location of Schrader Bluff reservoir on Alaska's North Slope.

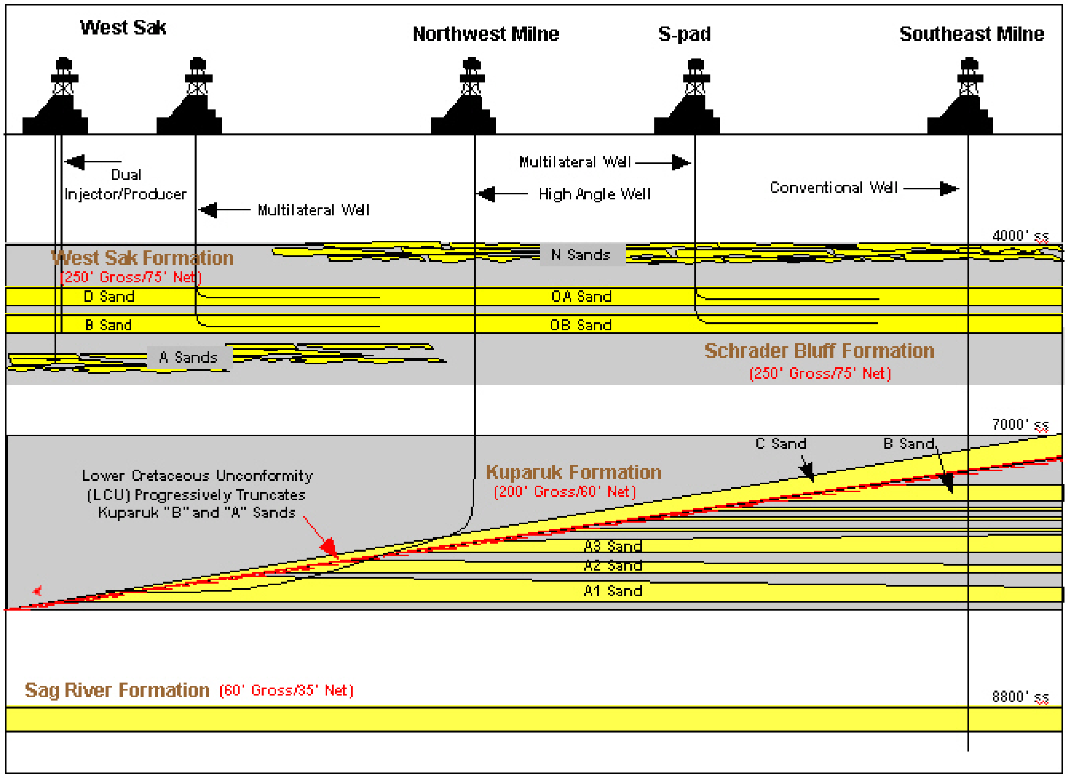


Figure 15. A schematic geological cross-section through the Schrader Bluff Formation.

In order to compare the spatial resolution and sensitivity of various geophysical techniques being considered for CO_2 storage monitoring a three-dimensional (3D) flow simulation model of the reservoir provided by BP was used in conjunction with rock-properties relations developed from log data to produce geophysical models from the flow simulations. The Schrader Bluff reservoir is a sandstone unit, between 25 and 30 m thick, at a depth of 1,100 – 1,400 m. Figure 16 shows a 3-D view of the portion of the reservoir under consideration for a CO_2 storage test. The reservoir unit gently dips to the east with major faulting running mainly north-south. Two faults with offsets in excess of 75 m cut the reservoir with several smaller sub-parallel faults present.

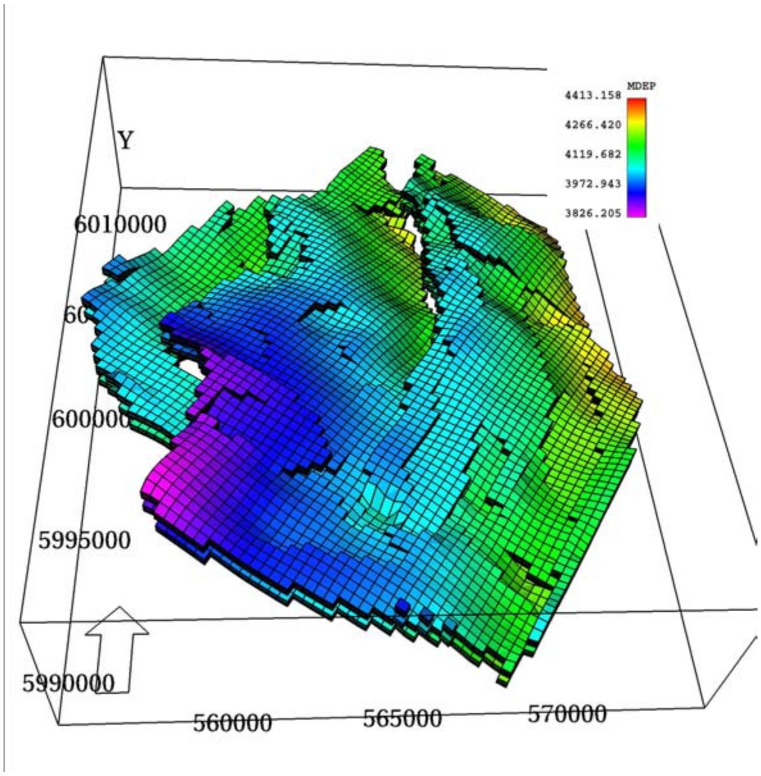


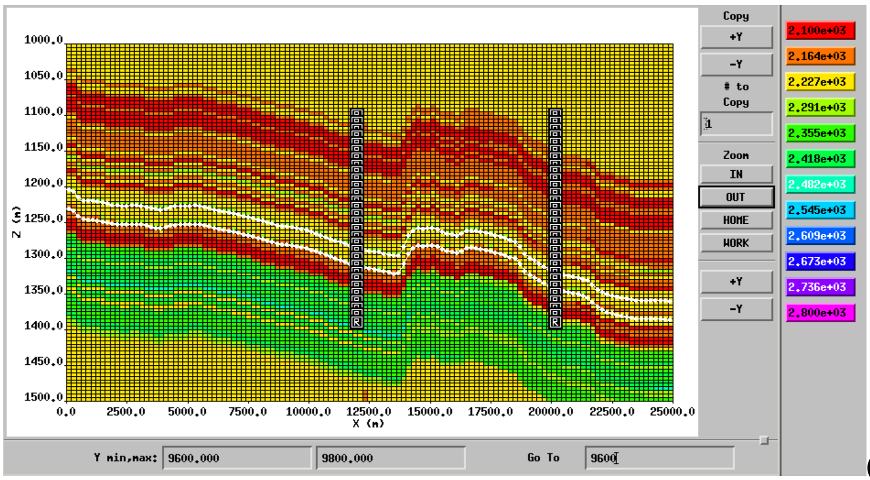
Figure 16. Three-dimensional view of the portion of the reservoir under consideration for CO_2 storage test at Schrader Bluff. Depths range between 3,800 and 4,400 feet (1,158 and 1,341 m) true vertical depth.

Rock properties models were developed from log data for the reservoir. These models relate reservoir parameters to geophysical parameters and are used to convert the flow simulation model parameters to geophysical parameters (V_P, V_S, density and electrical resistivity). A description of the rock-properties modeling process is given by Hoversten et al. (2003). Time-lapse snap shots of the reservoir at initial conditions and 5-year increments out to 2035 were used. A water alternating gas (WAG) injection strategy is considered which produces complicated spatial variations in both CO_2 and water saturation within the reservoir over time.

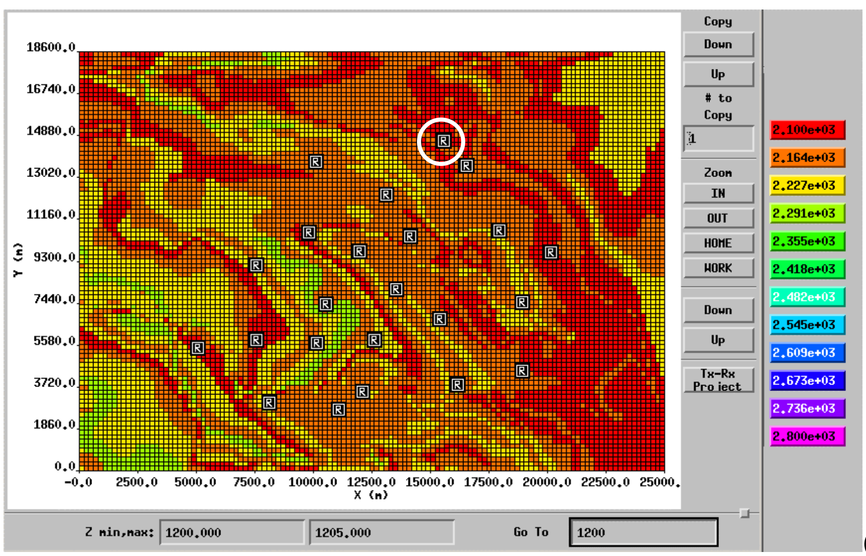
In the following sections we use simulations to calculate the sensitivity of various monitoring techniques for determining the location of CO_2 within the storage reservoir. In particular, we evaluate gravity, seismic, and EM measurements, which we believe to have the greatest potential for accurately tracking migration of the plume in the subsurface.

4.1.1. Gravity Measurements

A snapshot of the model at initial conditions, before CO_2 injection begins, is shown in Figure 17. Figure 17a is a cross-section of bulk density as a function of depth and horizontal distance between a pair of injection wells. In this figure, gravimeters are located in two wells roughly 8 km apart. The reservoir interval is outlined in white on Figure 17a. Figure 17b is a plan view of the density at initial conditions at a depth of 1,200 m with positions of 23 injecting wells taken from the reservoir simulation. The positions of the gravimeters are indicated by black squares. Spacing between the gravimeters in depth (z) is 10 m outside the reservoir and 5 m inside the reservoir. The white circle in the upper part of Figure 17b indicates a well for which borehole gravity responses are shown in Figure 23 and 24.



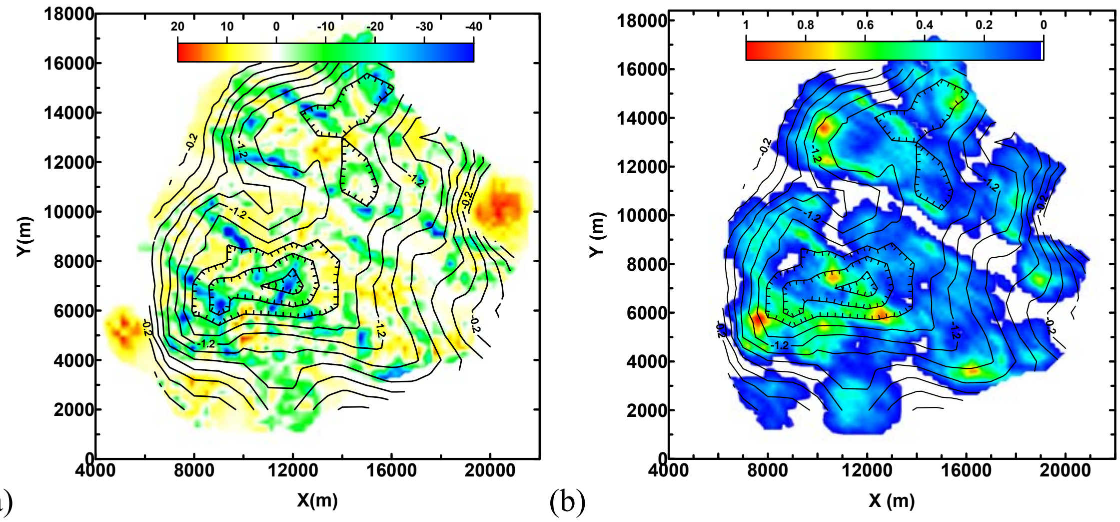
(a)



(b)

Figure 17. (a) Cross-section of a density field (kg/m^3) in the subsurface. (b) Plan view of a density (kg/m^3) field at a depth z = 1,200 m. The white circle indicates the well location used for borehole gravity calculations shown in Figures 23 and 24.

The surface gravity response was calculated on a grid of stations with 1 km spacing from 2,000 m to 22,000 m in x and from 2,000 m to 16,000 m in the y direction. In general since CO_2 is less dense (at reservoir conditions) than either oil or water, addition of CO_2 to the reservoir will cause a reduction in the measured gravitational attraction either at the surface or in a borehole.



(a) (b)

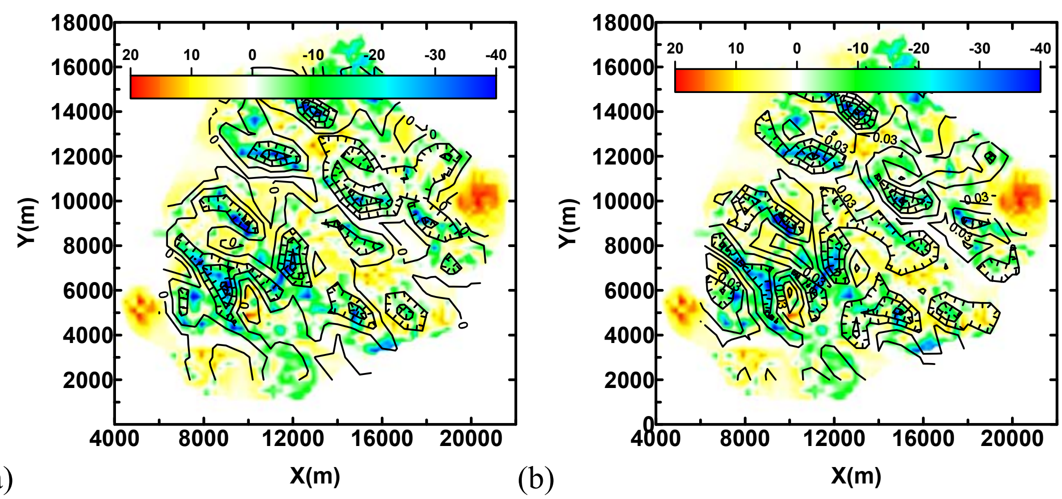
Figure 18. (a) Plan view of the net change in density (kg/m^3) within the reservoir. (b) Plan view of the net changes in CO_2 saturation within the reservoir. The change in Gz at the surface for the same time period is shown as black contours with hatch marks indicating decreasing Gz values.

The change in the vertical attraction of gravity (G_z) at the ground surface between 2020 and initial conditions is overlaid as black contours in Figure 18a on the net density changes within the reservoir. The peak-to-peak change in G_z is on the order of 2 μgal, which would be in the noise level of a field survey using current technology (Hare, 1999). The changes in the vertical gradient of gravity (dG_z/dz) between 20 years into CO_2 injection and initial conditions (not shown) are approximately 0.01 Eötvös units (EU), and also below the noise level of current instruments. The high spatial variations of the net density changes within the reservoir are expressed as a filtered response at the surface and only show the average changes on a larger scale. It should be noted that petroleum reservoirs in general, and this reservoir in particular, are thinner (30 m) than most saline formations considered for CO_2 storage (100–200 m). This difference means that while the calculated response for Schrader Bluff at the surface are below current technology repeatability, thicker saline formations at the same depths would produce measurable responses. This is the experience at the Sleipner CO_2 project (Eiken, 2003) for a gravity survey conducted in 2002 and not yet published. These results suggest future analysis to determine the maximum sensitivity of G_z and dG_z/dz that could be obtained by permanent emplacement of sensors with continuous monitoring coupled with surface deformation measurements to reduce noise levels.

Figure 18b shows the change in surface gravity G_z as black contours overlaid on the net change in CO_2 saturation within the reservoir. Because the density changes within the reservoir are caused by a combination of CO_2, water and oil saturation changes as the

WAG injection proceeds, there is not a one-to-one correlation in space between either the net change in density and the change in G_z or the net change in CO_2 saturation (S_{CO2}) and the change in G_z. There is correlation between the change in surface G_z and the net change in S_{CO2} on a large scale. For example, the largest changes in S_{CO2} occur in the south-west quadrant of the image (Figure 18b) where the largest change in G_z occurs. This scenario, injecting CO_2 into an oil reservoir with multiple fluid components, is a worst case for the use of gravity to directly map changes in S_{CO2}. In a CO_2 injection into a saline formation there would only be water and CO_2, in this case the net changes in density within the reservoir would directly correlate with the net changes in S_{CO2} as would the change in G_z at the surface.

Access to boreholes allows the gravity measurement to be made closer to the reservoir, thus strengthening the signal compared to observations made on the surface. Figure 19a shows the change in G_z (2020 – initial) at a depth of 1,200 m (just above the reservoir in this section of the field), while Figure 19b is a change in dG_z/dz at the same depth. In both figures, the data are calculated on the same grid of 1km by 1km site locations as on the surface. The color images in Figures 19a and 19b are the net density changes in the reservoir from Figure 18a. The changes in G_z and dG_z/dz respectively, correlate directly with the maximum density changes. The magnitude of the changes in both G_z and dG_z/dz is larger than for surface measurements, although only the change in G_z would be measurable in the boreholes with current commercial technology. It should be noted however that work on more sensitive borehole G_z and dG_z/dz meters is ongoing and has the potential to significantly lower the sensitivity of such devices in the near future (Thomsen et al, 2003).



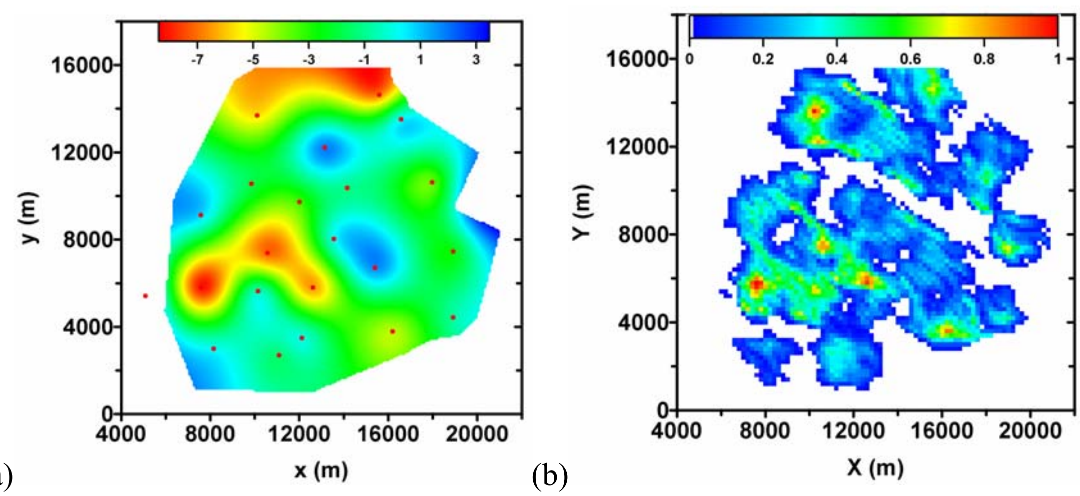
(a) (b)

Figure 19. (a) Plan view of the color coded net change in density within the reservoir (2020-initial). The change in G_z (μGal) at a depth of 1,200 m is overlaid as black contours. The peak-to-peak change in G_z is approximately 10 μGal. (b) The change in dG_z/dz (EU) at a depth of 1,200 m overlaid on the net change in density. The peak-to-peak change in dG_z/dz is approximately 0.25 EU.

While Figure 19 illustrated the potential resolution by measuring close to the reservoir, access though the existing injection wells would substantially reduce the data coverage.

Figure 20a shows a map of contoured changes in G_z measured only in the 23 boreholes at a depth of 1,200 m. Figure 20b is a net change of CO_2 saturation for comparison. Figure 20a was generated using a minimum curvature algorithm for data interpolation; however it is representative of the general features present in all of the other types of interpolation tested. In general, interpretation of the interpolated G_z changes from the boreholes would lead to an over estimate of the CO_2 saturation changes in the reservoir. This problem is particularly evident at the north end of the field where increased CO_2 saturation at two isolated wells produces an interpolated image that would be interpreted as increased CO_2 between the wells where none exists.

Borehole measurements would have to be used in conjunction with some form of surface measurement to guide the interpolation between wells. Alternatively, pressure testing between wells could provide estimates of spatial variations in permeability that could be used to condition, in a statistical sense, interpolation of the borehole gravity data. Many possibilities exist for combining the borehole data with other information in order to produce more accurate maps of change within the reservoir. This is an area where further work could be done.



(a) (b)

Figure 20. (a) Plan view of the change in G_z (μGal) at a depth of 1,200 m between 20 years into CO_2 injection and initial conditions using 23 wells indicated by red dots. (b) Plan view of the net change in S_{CO2} within the reservoir between 20 years into CO_2 injection and initial condition.

In addition to considering spatial variations in G_z and dG_z/dz on both the surface and at a constant depth within boreholes the response of G_z and dG_z/dz in vertical profiles down boreholes has been considered. Figure 21 is the change in S_w between 2020 and initial conditions along a vertical slice through the reservoir at an injection well indicated by a white circle in Figure 17b. Figure 22 shows the change in S_{CO2} between 2020 and initial conditions. At the top of the reservoir near the injection well, S_w decreases while S_{CO2} increases. At the bottom of the reservoir, both S_{CO2} and S_w increase slightly. G_z measured in the borehole, shown in Figure 23a, reflects this change by a decrease in the response at the top of the reservoir, and an increase in the response at the bottom. The change in G_z is ± 8 μGal. The reservoir interval is between 1,325 and 1,350 m at this location. The change in G_z between 2020 and initial conditions (Figure 23b) clearly identifies the position of the reservoir. The sign of the change reflects the changes in the local densities caused by the combined changes in all fluids (oil, water and CO_2). The reservoir is outlined by the shaded blue area.

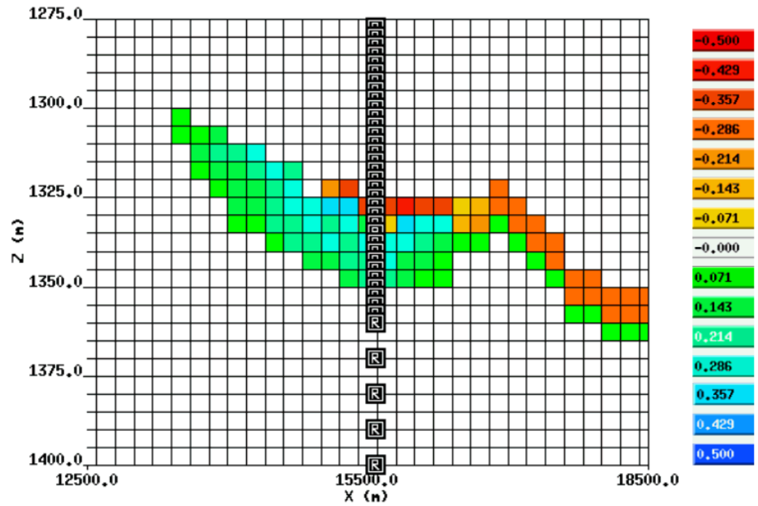


Figure 21. Change in S_w between 2020 and initial conditions. Greens and blues are an increase in S_w, yellows and reds are a decrease.

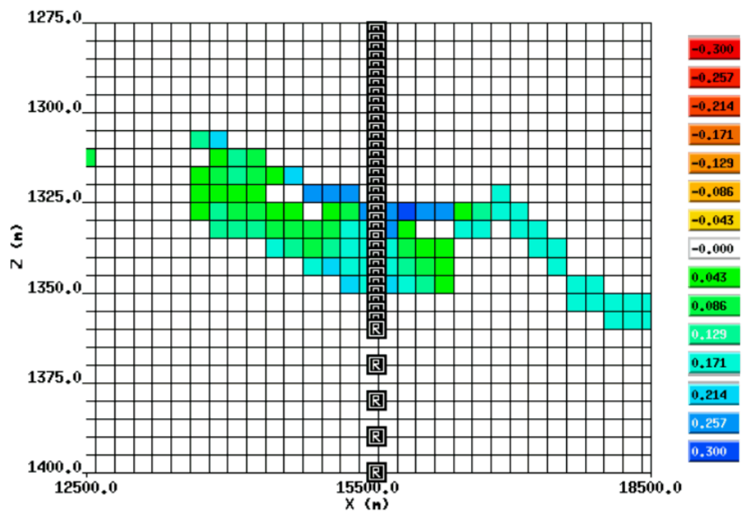
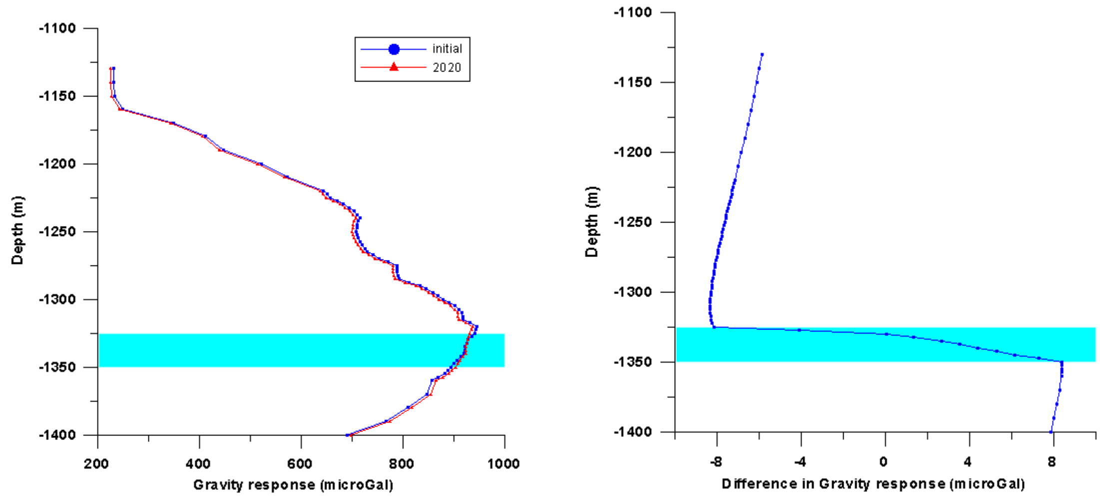


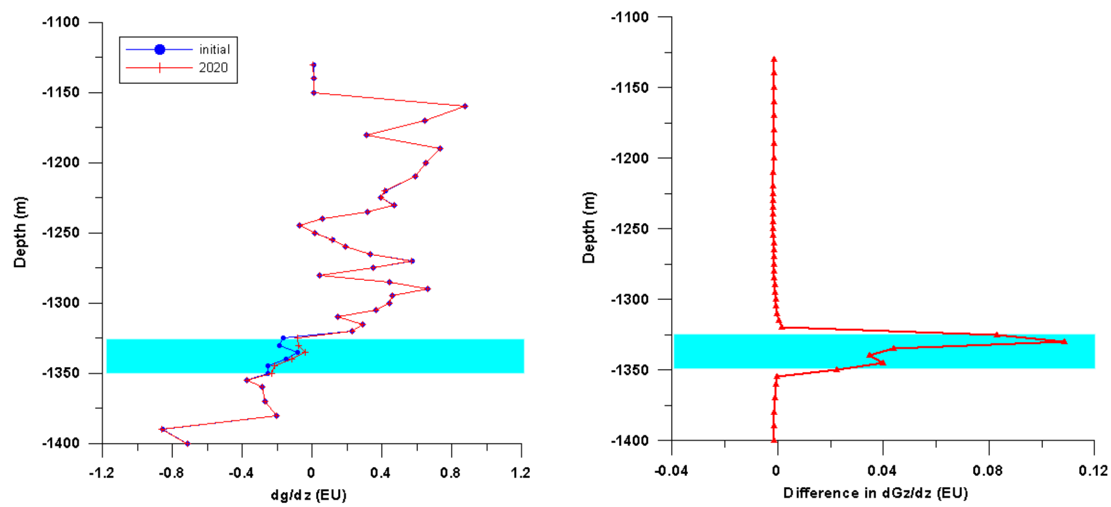
Figure 22. Change in S_{CO2} between 2020 and initial conditions. Greens and blues are an increase in S_{CO2}, yellows and reds are a decrease.



(a) (b)

Figure 23. (a) Borehole G_z for initial conditions (dark blue line) and 2020 (red line), (b) Change in G_z between 2020 and initial conditions. The reservoir interval is indicated by the light blue area.

The vertical gradient response (dG_z/dz) is shown in Figure 24a, and the change between 2020 and initial conditions is shown in Figure 24b. The change in the response is about 0.1 EU, which is not measurable with current technology.



(a) (b)

Figure 24. (a) Borehole vertical gradient response (dG_z/dz) for initial conditions (dark blue line) and 2020 (red line). (b) Change in dG_z/dz between 2020 and initial conditions. The reservoir interval is indicated by the light blue area.

Popta et al. (1990) showed that a geological structure with a sufficient density contrast can be detected by borehole gravity measurements if the observation well is not farther away than one or two times the thickness of the zone of density contrast. Figure 25 shows a CO_2 wedge of 250 m radius and density of 2,260 kg/m^3 (representing 20% CO_2

saturation in 20% porosity) inside a 100 m thick sand layer with a density of 2,285 kg/m^3 at the depth of 1 km. The background density is 2,160 kg/m^3. The borehole gravity response as a function of distance from the right edge of the wedge is shown in Figure 26a. The maximum response at the edge of the CO_2 wedge is 10 μGal (due to 1% change in density). This responses decreases with distance away from the wedge. 50 m away from the wedge the response is 6 μGal, 100 m away response decreases to 4.4 μGal, and 200 m away it is down to 2.5 μGal. The borehole vertical gradient response for the same model is shown in Figure 26b. The response changes from 7 EU at the edge of the CO_2 wedge to 1 EU 50 m away from the edge.

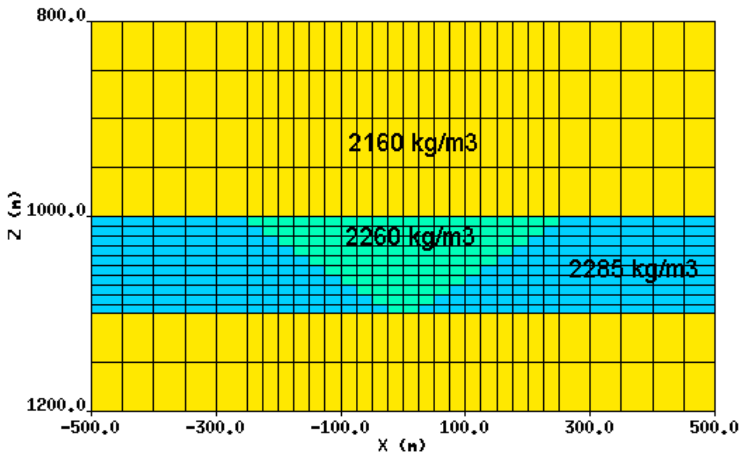
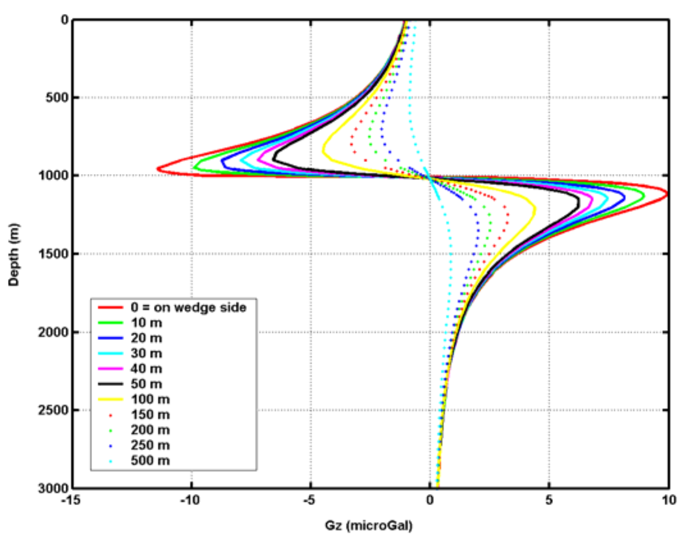
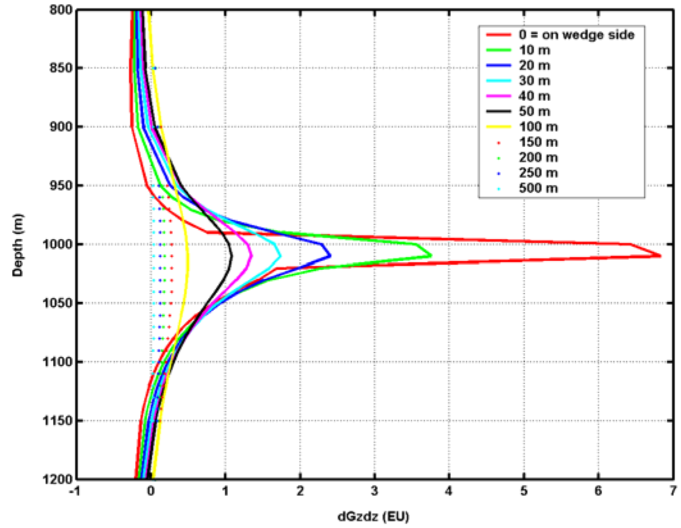


Figure 25. CO_2 wedge model.



(a)



(b)

Figure 26. (a) Borehole gravity response of the model in Figure 25 as a function of distance from the wedge edge. (b) Borehole vertical gradient gravity response of the model in Figure 25 as a function of distance from the wedge edge.

Current borehole gravimeter technology has a repeatability of around 5 μGal for G_z. So with current technology the borehole measurements are sensitive to approximately one anomalous density zone thickness away from the zone.

4.1.2. Seismic Measurements

The flow simulation models for Schrader Bluff have been converted to acoustic velocity, shear velocity and density. A simulated seismic line has been calculated running approximately N45°E across the reservoir. The elastic response to a 50 Hz Ricker wavelet was calculated. The general increase in S_{CO2} in portions of the reservoir near injection wells produces an approximately 20% decrease in seismic velocity as shown in Figure 27 (change in P-wave velocity between 2020 and 2005). The S_{CO2} and S_w changes are shown in Figures 28 and 29 respectively. The seismic pressure responses, for a single shot located at 7,500 m (covering the area of the reservoir with maximum change in S_{CO2}) on the 2D profile, for 2005 and 2020 are shown in Figure 30 with the difference shown in Figure 31. There is a significant class 3 type AVO effect as S_{CO2} increases in the reservoir.

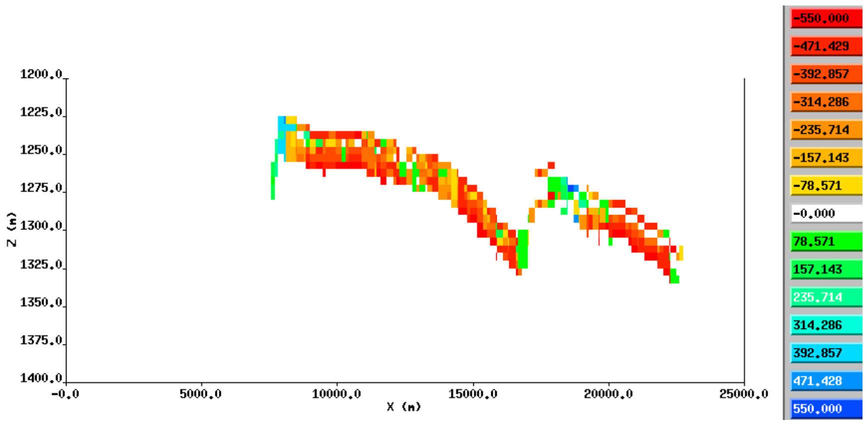


Figure 27. Change in the acoustic velocity (Vp) between 2020 and 2005 along a 2D profile extracted from the 3D model volume. The profile runs N45°E across the 3D model. Note the significant decrease in acoustic velocity associated with the increase in S_{CO2} (Figure 28).

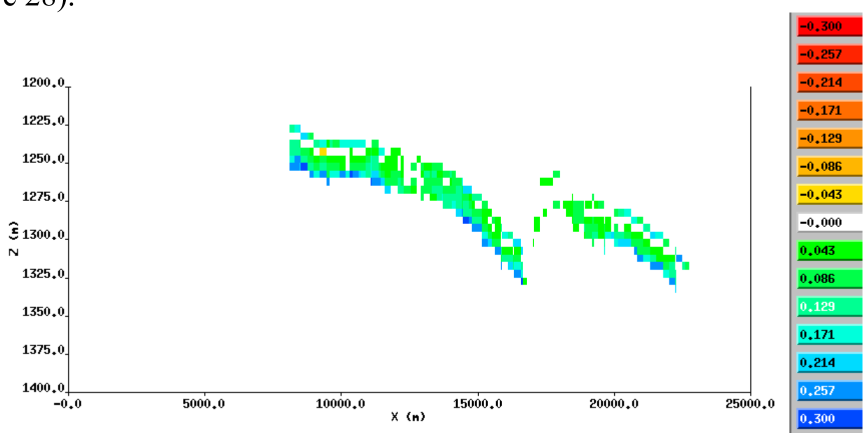


Figure 28. Change in the S_{CO2} between 2020 and 2005.

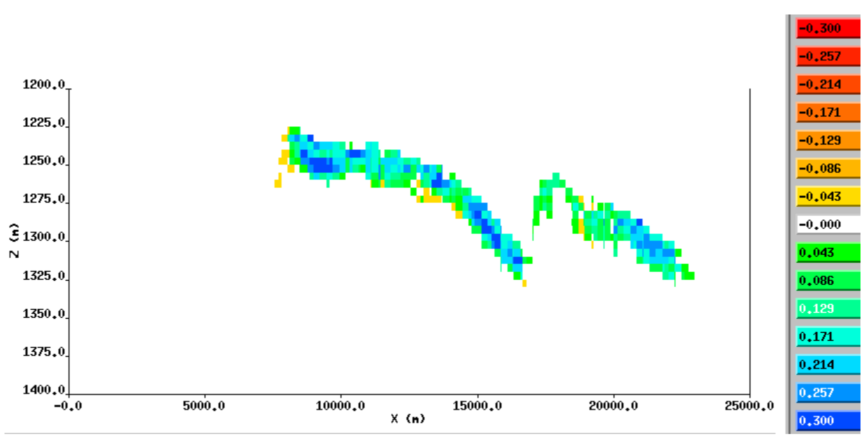


Figure 29. Change in S_w between 2020 and 2005.

Figure 30. Seismic pressure response (shot gather) for 2005 and 2020.

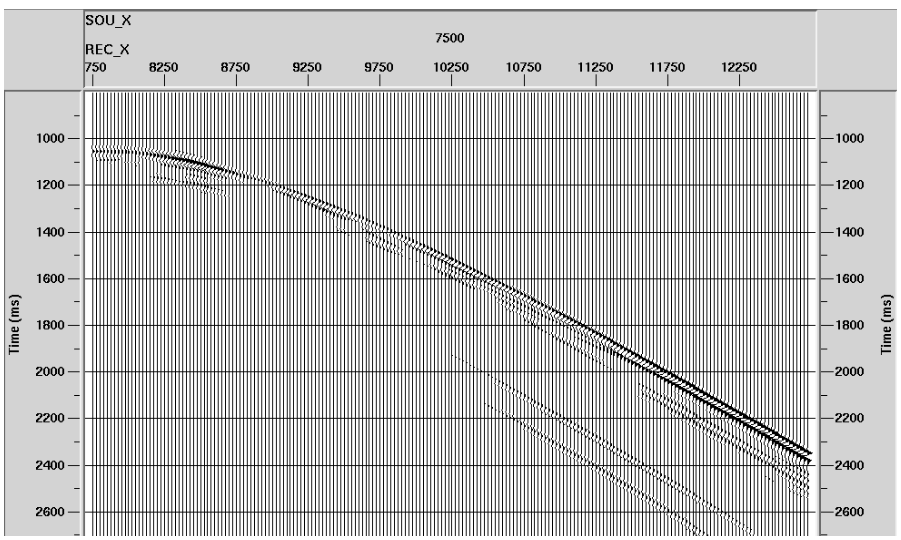


Figure 31. Change in pressure response (shot gather) between 2020 and 2005. Note amplitude change and AVO effects associated with S_w and S_{CO2} changes in the reservoir.

The pressure response was sorted to CDP gathers, NMO corrected and stacked to produce the sections for 2005 and 2020 shown in Figure 32. The red line is a constant time horizon within the reservoir for reference. The 30 m reservoir interval is not uniform and is comprised of 5 m thick substrata, each of which has reflection coefficients at their top and base that vary with S_{CO2}. These sub-strata are all below the seismic tuning thickness. This produces a seismic response without a clear top and base reflector. There is a significant increase in S_{CO2} to the right of CDP 8412.5 producing the large change in the stacked sections shown in Figure32.

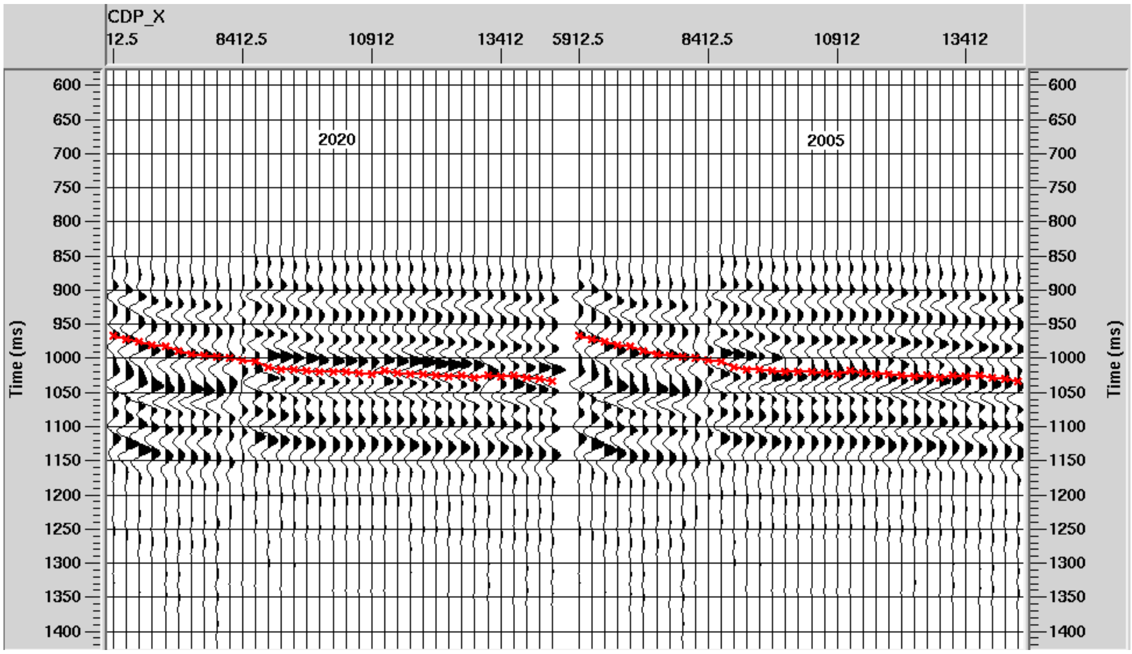


Figure 32. Stacked section for 2005 and 2020.

The change in the stacked sections between 2020 and 2005 is shown in Figure 33. Below the areas of major change in the reservoir (to the right of CDP 8412.5) the decrease in the velocity of the reservoir produces a time shift in the 2020 seismic responses below the reservoir, resulting in the events around 1,100 ms that do not reflect CO_2 saturation changes at this depth, only the time shift from CO_2 above.

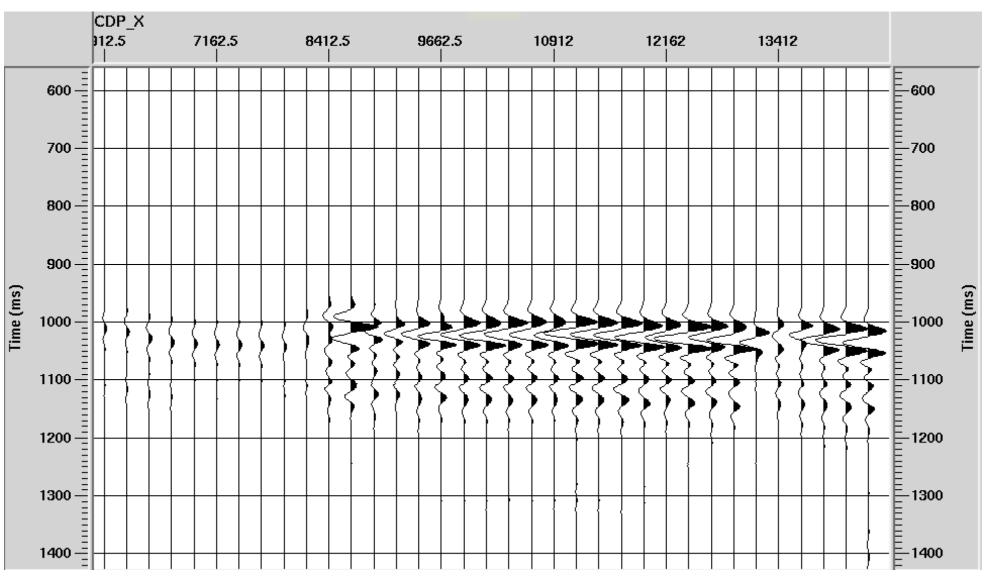


Figure 33. Change in the stacked sections between 2020 and 2005 (2020-2005).

There is a large, and easily measurable, change in the stacked trace amplitude associated with the reservoir caused by the changes in S_w and S_{CO2}. In addition, there is a change in the AVO effects as seen in Figure 31. Both amplitude and AVO can be exploited to make quantitative estimates of saturation changes under certain conditions. Forward calculations using the Zoeppritz equation for both the 2005 and 2020 models provide insight into the AVO dependence on model parameters. The forward modeling creates a synthetic seismic gather from a given set of elastic parameters V_P, V_S and density as a function of depth. The full Zoeppritz equation is used to compute the acoustic to acoustic (pp) reflection coefficient Rpp(θ) for each angle and at each layer boundary. Synthetic seismic CDP gathers are calculated by convolving the angle dependent reflection coefficients with a 50 Hz Ricker wavelet. The convolution model assumes plane-wave propagation across the boundaries of horizontally homogeneous layers, and takes no account of the effects of geometrical divergence, inelastic absorption, wavelet dispersion, transmission losses, mode conversions and multiple reflections.

The change in V_P, V_S, and density within the reservoir (between 1250 and 1275 m) is shown in Figure 34.

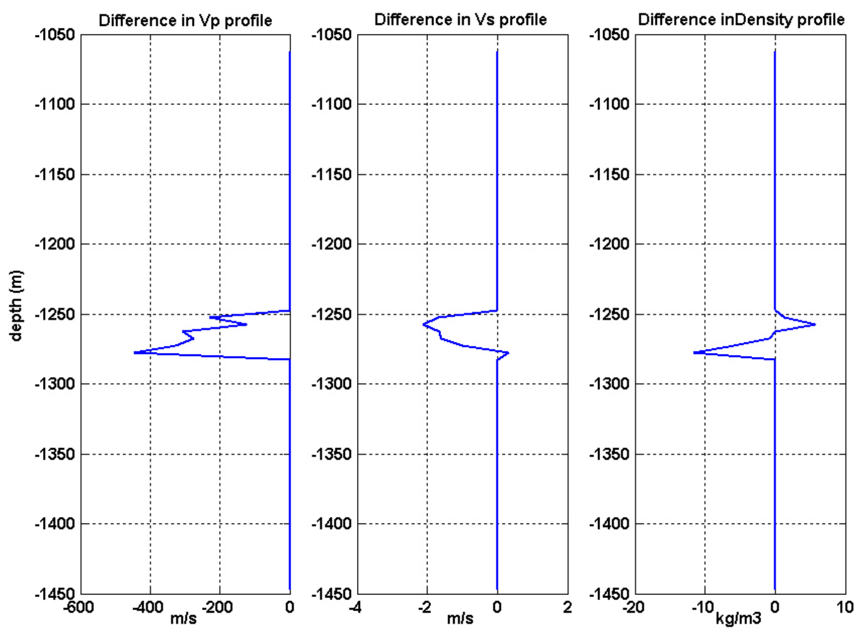
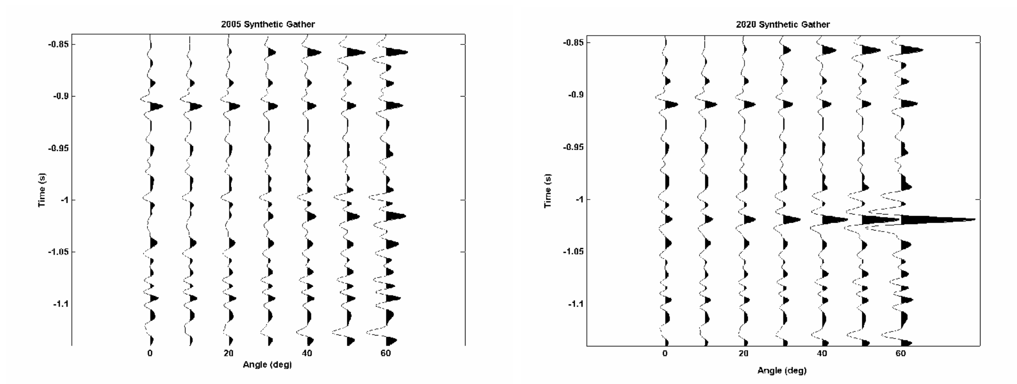


Figure 34. Difference in V_P, V_S, and density profiles between 2020 and 2005 for the Schrader Bluff model at the center of maximum CO_2 saturation increase.

The synthetic CDP gathers as a function of angle are shown in Figures 35a and 35b for 2005 and 2020 respectively. The change in reflection amplitude between 2020 and initial conditions is shown in Figure 36. The AVO response of the composite reflections from the reservoir interval shows increasing negative amplitude with offset, a typical Class 3 gas response. The negative trough (associated with the top of the reservoir) increases its magnitude with offset and is followed by an increasing peak amplitude with offset.



(a) (b)

Figure 35. Synthetic gather for (a) 2005 and (b) 2020.

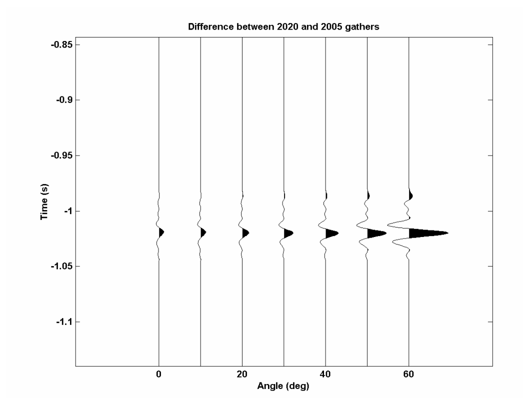


Figure 36. Difference between 2020 and 2005 gathers.

4.1.2.1. Use of AVO in fluid saturation prediction

The AVO attributes of reflections from the reservoir can be used to estimate fluid saturations under certain circumstances. AVO data can be used to estimate the acoustic and shear impedance of the reservoir (Castagna et al., 1998). When used in a time-lapse sense, these data can provide estimates of the change in water saturation and pressure within the reservoir (Landro, 2001). The ability to predict changes in water saturation and pressure within a reservoir is illustrated in Figure 37. In Figure 37 the rock properties model derived for the North Sea sands of the Troll reservoir (Dvorkin and Nur, 1996) is used to calculate the changes in shear and acoustic impedance of the reservoir as the water saturation and pore pressure for two cases of oil saturation as CO_2 is introduced. The first case (open circles) has initial oil and water saturation of 50%, as CO_2 is introduced it replaces water. The second case has an initial oil saturation of 60% and 40% water, with CO_2 replacing water. In both cases S_{CO2} ranges from 0 to 30%. Each point in the figure represents a unique value of S_W and S_{CO2} with the oil saturation held fixed at either 50% or 60%. S_{CO2} values increase in increments of 0.015% from right to left on the figure, and pore pressure increases and decreases (indicated by arrows) from the reference pressure of 24.24 MPa by increments of 0.7 MPa.

Figure 37 illustrates three important points; 1) if the oil saturation is known the changes in shear and acoustic impedance of the reservoir can determine the change in pressure and CO_2 saturation, 2) the changes in the shear impedance required to make the estimates is quite small and would require extremely good shear data, 3) an uncertainty in the oil saturation level of 10% in this example has only a small effect on the estimated values of changes in S_{CO2} and almost no effect on the estimates of pressure change.

An uncertainty on the value of oil saturation has limited effects in these calculations because of the relative similarity of the bulk modulus and density of oil compared to water when either is compared to the properties of CO_2. The situation is significantly different if there is hydrocarbon gas (such as methane) in the reservoir. In this case (due to the extreme differences between the properties of methane and water) even a small uncertainty in the hydrocarbon gas saturation leads to very large uncertainties in the estimated values of pressure and CO_2 saturation changes, making this technique essentially unusable unless an independent estimate of water saturation or gas saturation can be obtained from other methods (Hoversten et al., 2003).

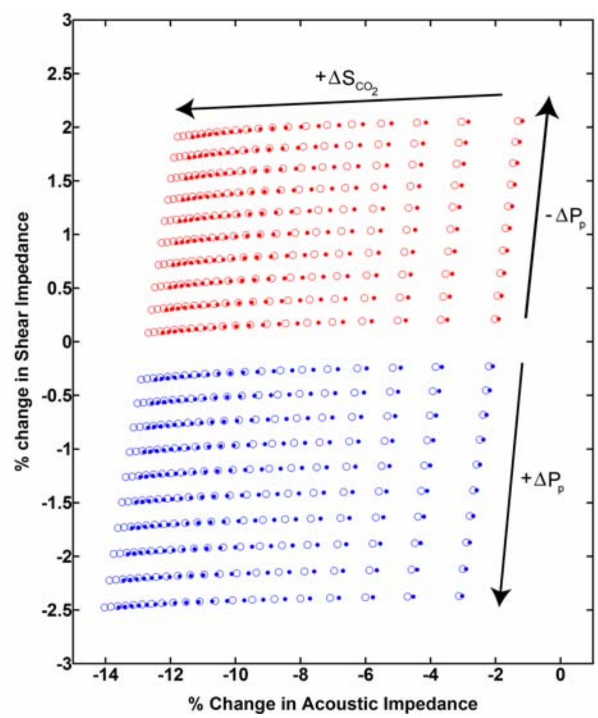


Figure 37. Each point represents a unique value of changes in pore pressure (ΔP_p) and CO_2 saturation (ΔS_{CO2}) as a function of changes in the shear and acoustic impedance of the reservoir. Open circles represent oil saturation of 50% with CO_2 replacing water. Filled dots represent oil saturation of 60% with CO_2 replacing water. Initial pore pressure is 25.24 MPa, initial S_{CO2} is 0%. S_{CO2} increments are 0.015 and pressure increments are 0.7 MPa.

While estimation of changes in fluid saturation using AVO is complicated by the multiple fluid components in oil or gas reservoir, the situation is simpler in a saline formation. For cases were CO_2 is injected into a saline formation there are only two fluid components (saline water and CO_2) and the added constraint that their saturations levels sum to one. In this case AVO information can more easily be used to estimate the level of CO_2 in the reservoir. The following example illustrates this process. An unconsolidated North Sea sand of the Troll reservoir (Dvorkin and Nur, 1996) that is encased in shale is assumed to contain 50% saline water and 50% CO_2 as the reference point for these calculations. Pressure and temperature are such that the CO_2 is in the liquid state. The values of CO_2 (and hence water) saturation and pore pressure are varied about this starting point and the acoustic and shear velocities as well as density are calculated.

The reflection coefficient at the top of the reservoir can be approximated (Shuey, 1985) by:

$$R(\theta) \approx A + B\sin^2(\theta) + C\sin^2(\theta)\tan^2(\theta) \tag{2}$$

where θ is the average of the reflection and transmission angle for a plane wave hitting the interface. The constants A and B are referred to as the intercept and slope respectively in the AVO literature. The constants A, B and C are functions of the velocity and density of the media on either side of the reflecting interface and are given by:

$$A = 1/2(\Delta V_p / \langle V_p \rangle + \Delta\rho / \langle \rho \rangle \tag{3}$$

$$B = 1/2(\Delta V_p / \langle V_p \rangle - 2(\langle V_s \rangle / \langle V_p \rangle)^2 (2\Delta V_s / \langle V_s \rangle + \Delta\rho / \langle \rho \rangle) \tag{4}$$

$$C = 1/2(\Delta V_p / \langle V_p \rangle \tag{5}$$

where ΔV_p is the change in acoustic velocity across the interface and $\langle V_p \rangle$ is the average acoustic velocity across the interface, ΔV_s , $\langle V_s \rangle$, $\Delta\rho$, and $\langle \rho \rangle$ are changes and averages for shear velocity and density respectively. If time lapse seismic data is acquired, and A and B are estimated from the AVO data and used to calculate ΔA and ΔB, the associated ΔS_{CO2} and ΔP_p can be estimated from model based calculations such as are illustrated in Figure 38.

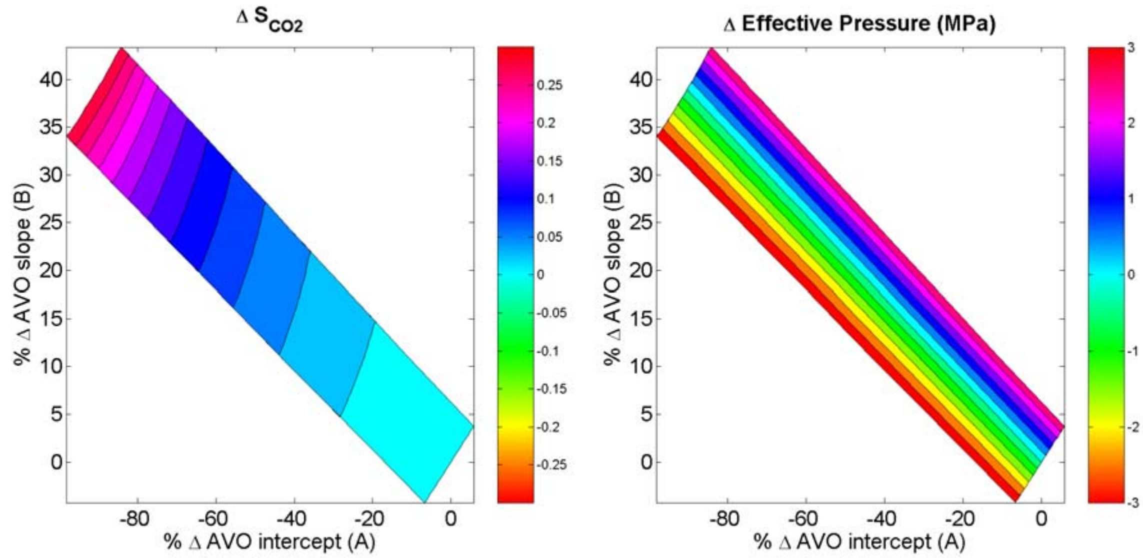


Figure 38. Contours of the change in CO_2 saturation (left panel) and effective pressure (lithostatic – pore pressure) (right panel) as function of the change in the AVO intercept (A) and slope (B) for an unconsolidated sand surrounded by shale.

This example illustrates a theoretical case without noise in the seismic data; in practice estimation of the "slope", B, is the most difficult. Extremely high signal to noise (S/N) seismic data would be required for accurate estimates of B and hence accurate estimates of pressure changes.

4.1.3. Electromagnetic Measurements

The electrical resistivity of reservoir rocks is highly sensitive to changes in water saturation. This can be seen from Archie's Law (Archie 1942), which has been demonstrated to accurately describe the electrical resistivity of sedimentary rocks as a function of water saturation, porosity, and pore fluid resistivity. Figure 39 shows the rock bulk resistivity (Ωm) as a function of gas saturation (1–water saturation) for a reservoir with saline water resistivity equivalent to sea water (ρ_{saline} = 0.33) with 25% porosity. All petroleum fluids (oil, condensate, and hydrocarbon gas) as well as CO_2 are electrically resistive, hence the relation shown in Figure 39 is appropriate for any combination of oil, hydrocarbon gas, condensate or CO_2.

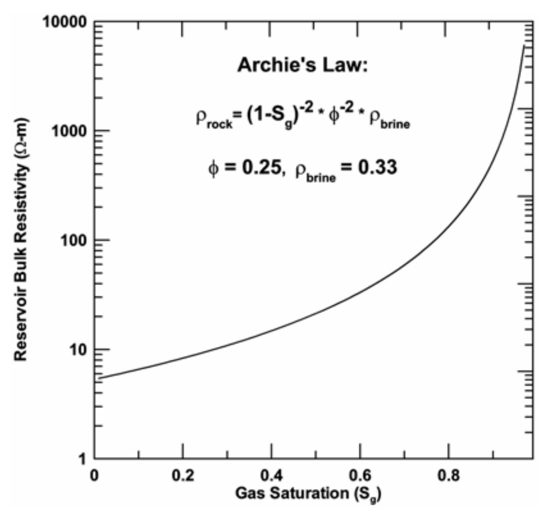


Figure 39. Reservoir bulk resistivity as a function of gas saturation (S_g). Porosity = 25%.

The bulk resistivity in Figure 39 is plotted on a log scale to span the large range of resistivity values as a function of the gas saturation (S_g). This high sensitivity to water saturation in a reservoir can be exploited by electromagnetic (EM) techniques where the response is a function of the earths electrical resistivity. Of all the possible combination of EM sources and measured EM fields one system combines both relative ease of deployment with high sensitivity to reservoirs of petroleum scale and depth. This technique uses a grounded electric dipole that is energized with an alternating current at a given frequency to produce time varying electric and magnetic fields that can be measured on the earth's surface. The electric dipole can consist of two steel electrodes (1 m^2 plates or sections of drill pipe) buried at a shallow depth (1-10 m) separated by 100 m and connected by cable to a low power generator (a portable 5,000 W generator is sufficient). The measured data would consist of the electric field at a given separation from the transmitter acquired on the surface or within the near surface.

To simulate such an EM system we have calculated the electric field on the surface of the Schrader Bluff model using 100 m electric dipoles operating at 1 Hz and measuring the resulting electric field at a separation of 2 km in-line with the transmitting dipole. Figure 40 shows the amplitude of the generated EM field at 2 km separation and 1 Hz together with the natural background electric field generated from worldwide thunderstorms and pulsations in the earth's ionosphere (the source field for the magnetotelluric method). The significance of Figure 40 is that the generated electric field for the Schrader Bluff model, using only a small portable generator (producing a 10 A current in the source dipole) is an order of magnitude above the background electric field (noise) at the operating frequency of 1 Hz. This means that synchronous detection of the signal combined with stacking can recover signal variations to better than 1 percent.

Figure 41 shows the net change in water saturation within the reservoir (vertically integrated ΔS_w) between 2020 and initial conditions. The change in the electric field amplitude for the same interval is overlaid as black contour lines, with peak-to-peak amplitude of 1.2%. There is a direct one-to-one correspondence with the change in S_w and the change in the electric field amplitude. While this signal level is low, it can be measured given the signal-to-noise ratio of the data (Figure 40). While this represents a potential low-cost monitoring technique it is better suited for CO_2 – saline water systems where there is a one-to-one correlation between the change in water saturation and the change in CO_2 saturation (since $S_w + S_{CO2} = 1$). In petroleum reservoir such as Schrader Bluff the presence of hydrocarbon as additional fluids eliminates the one-to-one correlation between changes in S_w and changes in S_{CO2}. This is illustrated in Figure 42 where the same changes in electric field amplitude are overlaid on the net change in the CO_2 saturation within the reservoir between 2020 and initial conditions. In this case we see that the correlation between changes in S_{CO2} and changes in the electric field amplitude are not as good as seen between changes in S_w and the electric field data.

This type of EM technique has not yet been employed as a monitoring tool within the petroleum industry. However, EM technology is currently the subject of a significant upsurge in industry interest. Several commercial contractors are now offering this technique as a survey tool, most notably, in the offshore environment where it is currently being used as an exploration tool (Ellingsrud et al. 2002). The equipment and service providers exist to apply this technique for monitoring in the future.

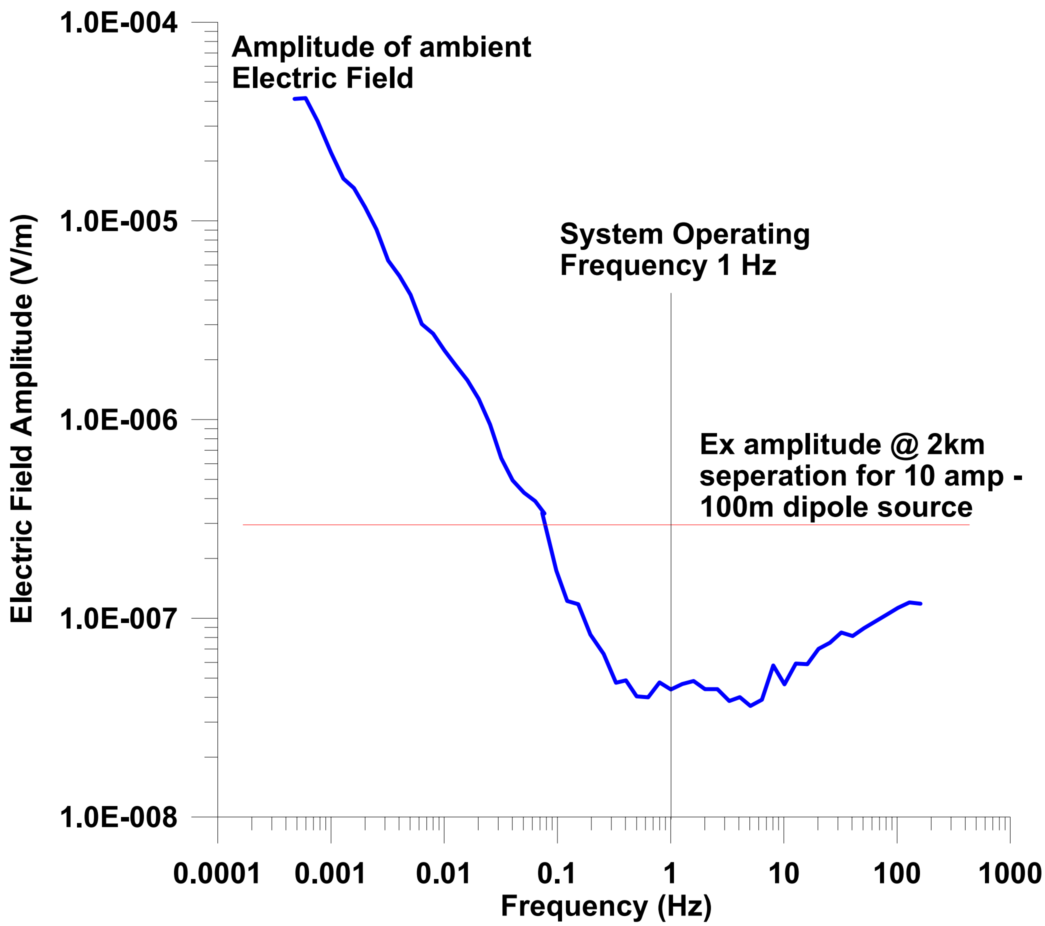


Figure 40. Amplitude of naturally occurring electric field (blue curve) as a function of frequency (Gasperikova et al. 2003), which would be considered noise to the electromagnetic system considered here for monitoring. The horizontal red line represents the signal amplitude at a source-receiver separation of 2 km at an operating frequency of 1 Hz for a 100 m electric dipole energized with 10 A of current.

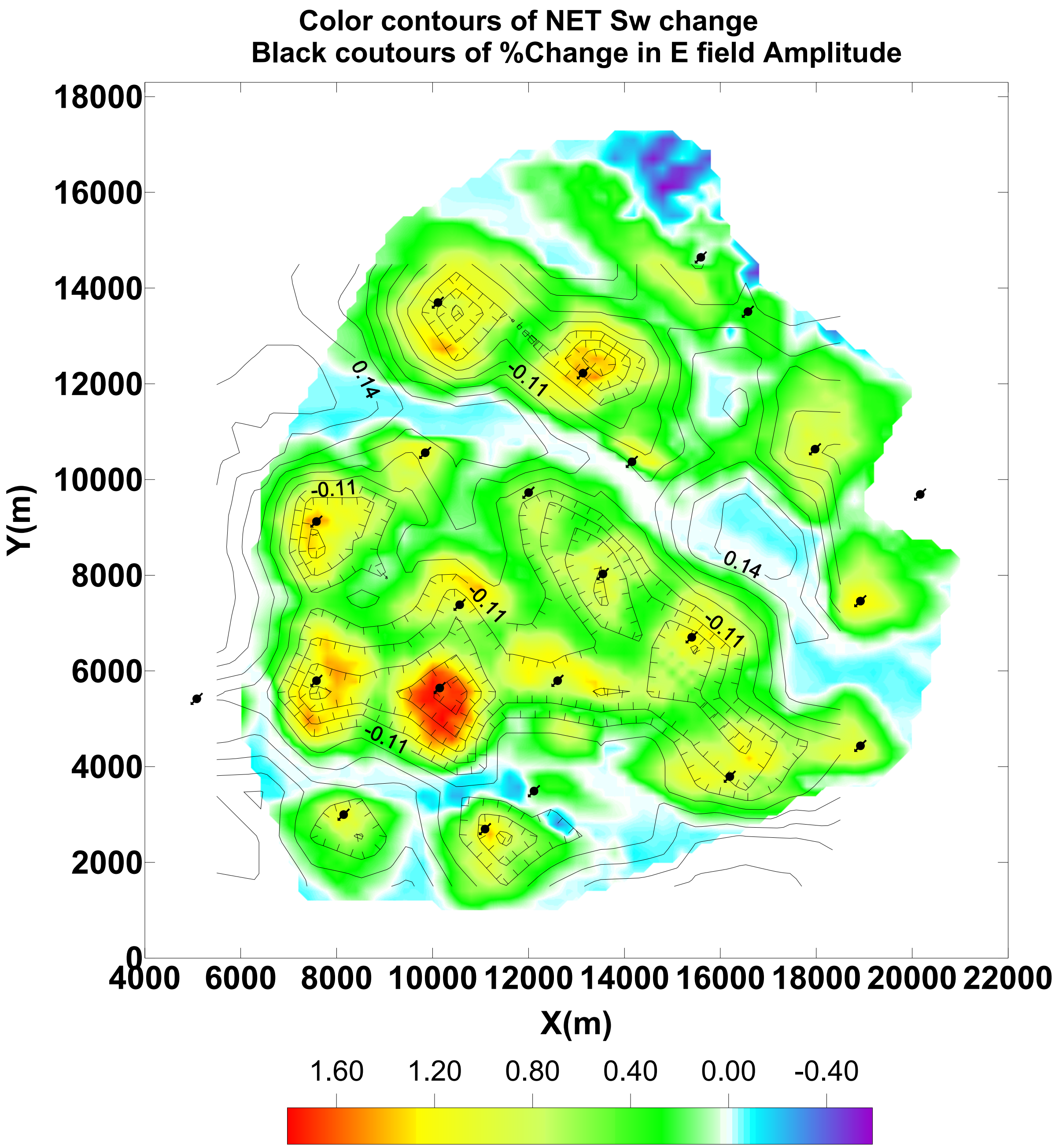


Figure 41. Color contours of the net change in water saturation over the vertical interval of the reservoir between 2020 and initial conditions. The change in the amplitude of the electric field from an electric dipole source at a separation of 2 km is overlaid as black contours. The peak-to-peak change is electric field amplitude is 1.2 %. Note the direct correlation between decreases in the electric field amplitude and increases in water saturation (decreased electric resistivity of the reservoir). Locations of injection wells are shown by black circles with arrows through them.

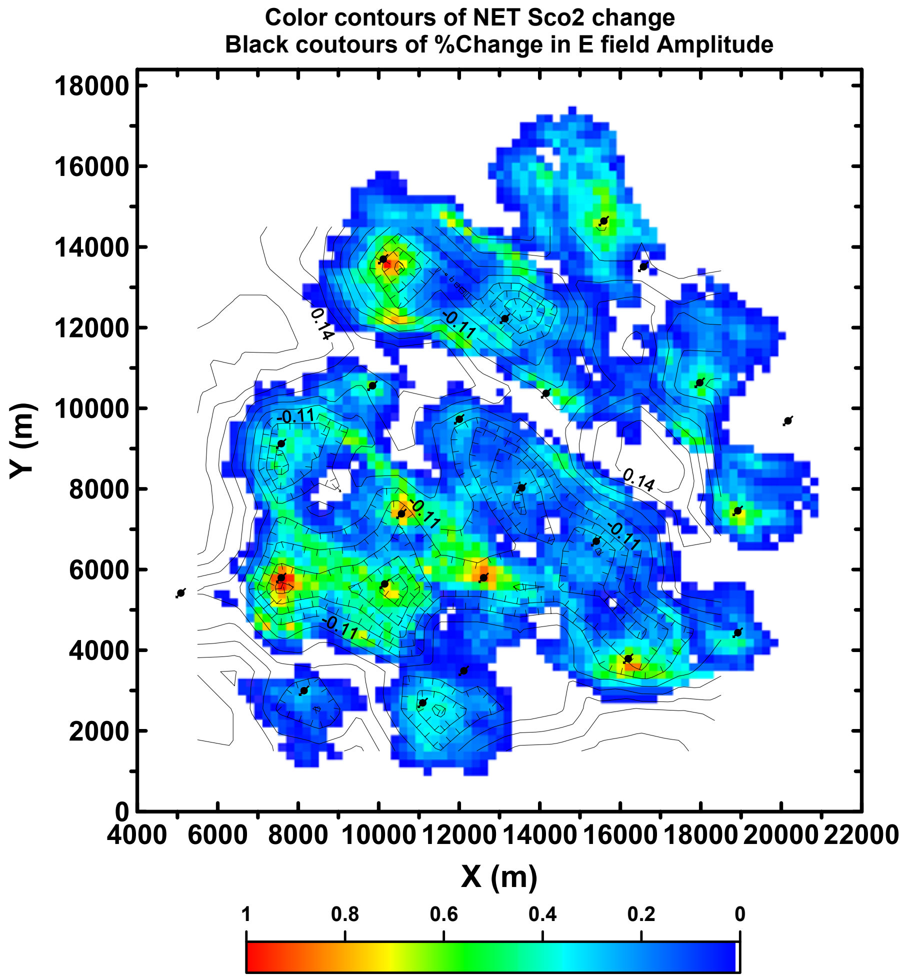


Figure 42. Color contours of the net change in CO_2 saturation (ΔS_{CO2}) over the vertical interval of the reservoir between 2020 and initial conditions. The change in the amplitude of the electric field from an electric dipole source at a separation of 2 km is overlaid as black contours. The peak-to-peak change is electric field amplitude is 1.2 %. Location of injection wells are shown by black circles with arrows through them.

4.2. Evaluation and Selection of Monitoring Techniques

On the basis of the examples presented in Chapters 3 and 4, we conclude that in order of overall value to the monitoring program, recommended geophysical techniques would be seismic, gravity, electromagnetic, surface deformation and SP. Seismic techniques are particularly valuable due to the high degree of spatial resolution, both within the storage formation, as well as in the overlying cap rock and strata. Not only can they provide high spatial resolution, they can detect small quantities of CO_2 (10,000's of tonnes) that may provide early warning that a storage project is failing. Due to inherent physical limits to the resolution of the other techniques, none is likely to provide an early warning that CO_2 has escaped from the storage reservoir and is migrating towards the land surface or sea floor.

Chapter 5. Selection of Monitoring Programs and Monitoring Costs

5.1. Scenarios for Estimating Monitoring Costs

The estimated life-cycle costs of monitoring geologic storage projects are presented here for two scenarios: a project modeled after the Schrader Bluff oil field described in Chapter 4 and CO_2 storage in a hypothetical saline formation. In order to put survey costs in perspective to other costs of storage, an estimate was made of the cost of monitoring of a hypothetical project for sequestering the CO_2 from a 1,000 MW coal-fired power plant with a 30-year lifetime. Such a plant, with current technology, would produce about 8.6 million tonnes of CO_2 per year.

It is important to recognize that these are both hypothetical scenarios and are presented for illustrative purposes only. However, both scenarios are possible and the monitoring packages presented here are also plausible. It is important however to point out that monitoring protocols are likely to vary from region to region, based on site-specific risks and applicable regulations. For each case, costs are estimated for the pre-injection, operational, closure and post-closure phases described in Chapter 2. Assumptions for the two scenarios are provided in Table 4.

For the saline formation scenario, two cases are considered: one for a low residual gas saturation (LRG) CO_2 plume that does not move after injection stops, and a high residual gas saturation (HRG) CO_2 plume which keeps moving after injection until after 80 years it stops moving and growing. The HRG plume is one in which the residual gas saturation is high (25%) and thus is easily trapped in the pore spaces of the storage formation. HRG plumes tend to be comparatively compact and retained in the vicinity of the injection wells. The LRG plume has a lower residual gas saturation (5%) and will migrate until it dissolves, becomes trapped in local features or the residual gas saturation is reached. This increases the footprint of the geophysical surveys, and hence increases the cost of monitoring. Using the parameters listed in Table 2, after 30 years the CO_2 plume will have an extent of 216 km^2 (note that we assume that LRG and the HRG plumes will be the same size during the operational phase of the project)[1]. During the closure phase we assume that the LRG plume will grow by 1% per year, thus, grow to have an eventual footprint of 348 km^2. For the oil-field, we assume that geophysical surveys are conducted over the entire reservoir area of 360 km^2 during the operational phase of the project.

We have also assumed that the closure phase will last significantly longer (50 years) for the saline formation scenario than for the oil field scenario (20 years). This is based on the presumption that the oil field has a well defined caprock, that the caprock has not been compromised during the operational phase of the project and thus leakage through the caprock is highly unlikely. In this case, the 20 year closure period would however

[1] Strictly speaking, the plume with low residual saturation is expected to grow more quickly during the operational phase, but this was not taken into consideration for this analysis.

provide the opportunity to confirm that the injection wells or other abandoned wells were not leaking. The longer closure period for the saline formation storage may be needed to demonstrate that the caprock is providing an effective seal for retaining the CO_2 in the storage formation. This will be particularly important in the case of the LRG plume where the footprint continues to grow during the closure period. Again, we reiterate that these are hypothetical scenarios, and not intended to prescribe the appropriate duration of the closure phase for a project. Site specific risks and local regulations will dictate the appropriate length and frequency of monitoring during all phases of a storage project.

For the scenarios presented here, geophysical surveys are used to monitor the plume location at 1, 2, 5, 10, 15, 20, 25 and 30 years during the operational phase of the project. During the closure phase, surveys are conducted every ten years.

<table>
<tr><th>Scenario Parameters</th><th>Oil-Field</th><th colspan="2">Saline Formation</th></tr>
<tr><td>Storage Scenario</td><td>CO_2 storage combined with enhanced oil recovery</td><td colspan="2">CO_2 storage in a saline formation</td></tr>
<tr><td>Number of Injection Wells</td><td>20 injection, 12 production wells distributed evenly over the foot print of the reservoir, based on the Schader Bluff scenario</td><td colspan="2">10 injection wells located within a 10 sq. km area, based on the injectivity of vertical wells in a Frio-like formation with a permeability of 0.5 Darcy</td></tr>
<tr><td>Reservoir Properties</td><td>25 m thick, areal extent of 360 km^2</td><td colspan="2">100 m thick, 20% porosity, capacity factor of 10%, density of CO_2 at reservoir conditions 800 kg/m^3</td></tr>
<tr><td>Operational Period</td><td>30 years</td><td colspan="2">30 years</td></tr>
<tr><td>Closure Period</td><td>20 years[2]</td><td colspan="2">50 years[3]</td></tr>
<tr><td>Post-Closure</td><td>0 years (assume no leakage from the storage formation)</td><td colspan="2">0 years (assume no leakage from the storage formation)</td></tr>
<tr><td>Mass of CO_2 Injected</td><td>258 million tonnes CO_2</td><td colspan="2">258 million tonnes CO_2</td></tr>
<tr><td>Frequency of Geophysical Monitoring</td><td>2, 5, 10, 15, 20, 30, 40 and 50 years</td><td colspan="2">1, 2, 5, 10, 15, 20, 25, 30, 40, 50, 60, 70 and 80 years</td></tr>
<tr><td>Project foot Print</td><td>360 km^2 (area of the oil reservoir)</td><td>HRG Plume: 19 km^2 after the first year, growing to 216 km^2 after 80 years</td><td>LRG Plume: 18 km^2 after the first year, growing to 348 km^2 after 80 years</td></tr>
</table>

Table 4. Parameters used for estimating the costs of storage for each of the scenarios.

[2] Note that the 20 year period was selected arbitrarily, not based on any specific data that would support that leakage from wells would or could be detected during this period. Over time, experience and technological advances in well sealing technology will provide better estimates of the time required to demonstrate that the wells will not provide a leakage pathway from the storage formation. The time required for the closure phase may be shorter or longer than the 20 year period used in this analysis.

[3] Note that the 50 year period was selected based on understanding of the behavior of LRG and HRG plumes from simulations of CO_2 storage in the Frio formation. As more storage projects are implemented, experience will provide greater understanding of the time required to demonstrate that the plume is safely and effectively stored. The appropriate duration for the closure phase should be project and site specific, and may be longer or shorter than the 50-year period used for this analysis.

5.2. Recommended Monitoring Packages

The monitoring packages recommended for a particular storage project will depend on site specific objectives. For each of the three scenarios presented here, two different monitoring packages are considered. The first package, which may become the most common over time, called the "basic monitoring package," is designed primarily to provide assurance that the CO_2 staying within intended the storage formation. The second monitoring package, called the "enhanced monitoring package," which may be more common in the early stages of storage development, would be one in which a detailed quantitative estimate of not only the spatial distribution of CO_2 is required but also estimates of CO_2 saturation within different parts of the storage formation. Table 5 lists the components of both monitoring packages.

Both monitoring packages include seismic imaging on a regular basis. Two or three-dimensional seismic imaging of the geologic structure of the proposed storage site will be needed during the pre-operational phase of the project. In the case of the EOR scenario, we assume that this survey has already been done and therefore, need not be done as part of the monitoring program. During operations, it will be used repeatedly to track migration of the plume and detect leakage from the storage formation. The frequency of the surveys should depend on a risk assessment, and for the cases illustrated here, the EOR scenario has surveys at 5, 10, 15 20 and 30 years during the operational phase of the project. In contrast, the saline formation scenarios have more frequent surveys because the storage integrity of the site may not be as well known. In this scenario, repeat seismic surveys are conducted at 1, 2, 5, 10, 15, 20, 25 and 30 years during the operations phase of the project. Obviously, over the course of the project it may be determined that this many surveys are not needed and therefore the program could be curtailed. In the closure phase, seismic surveys will be used to confirm that the CO_2 remains trapped within the storage formation. For the EOR scenario we hypothesize that a 20 year closure period, over which two seismic surveys are conducted, would be sufficient to provide assurance that the CO_2 is safely stored. For the saline formation scenarios, we assume that a longer period would be needed, up to 50 years, to gain the same level of confidence. Of course, actual requirements will be highly site specific and should be driven by the level and nature of the risks, unique features and regulatory concerns.

Both monitoring packages will also include injection rate measurements and wellhead pressure measurements. These are used to verify the quantity of CO_2 that is injected into the storage formation and to ensure that the injection pressure does not exceed a safe threshold. In addition, depending on the well construction, pressure measurements will also be made in the annulus between the injection tubing and the well casing in order to monitor the condition of the injection well. For the enhanced monitoring package, it may be desirable to maintain continuous wellhead pressure monitoring in some fraction of the wells that are not abandoned during the closure phase. Watching the rate at which the pressure changes will provide additional insight into a number of processes, namely, dissipation of the pressure increase by equilibration with the surrounding formations, continued dissolution of CO_2 into the saline water or oil, and potentially, leakage out of the storage reservoir through wells or weaknesses in the caprock.

In addition, both packages contain microseismicity monitoring to provide assurance that unsafe microseismic activity is not occurring. A similar philosophy underlies the recommendation that atmospheric CO_2 sensors are located at each injection well to ensure that it is not leaking. Obviously, sub-sea floor storage projects will not include atmospheric monitoring sensors.

Basic Monitoring Package	**Enhanced Monitoring Package**
Pre-Operational Monitoring Well Logs Wellhead Pressure Formation Pressure Injection and Production Rate Testing Seismic Survey Atmospheric CO_2 Monitoring	**Pre-Operational Monitoring** Well Logs Wellhead Pressure Formation Pressure Injection and Production Rate Testing Seismic Survey Gravity Survey Electromagnetic Survey Atmospheric CO_2 Monitoring CO_2 Flux Monitoring Pressure and water quality above the storage formation
Operational Monitoring Wellhead Pressure Injection and Production Rates Wellhead Atmospheric CO_2 Monitoring Microseismicity Seismic Surveys	**Operational Monitoring** Well Logs Wellhead Pressure Injection and Production Rates Wellhead Atmospheric CO_2 Monitoring Microseismicity Seismic Survey Gravity Survey Electromagnetic Survey Continuous CO_2 Flux Monitoring at 10 stations Pressure and water quality above the storage formation
Closure Monitoring Seismic Survey	**Closure Monitoring** Seismic Survey Gravity Survey Electromagnetic Survey Continuous CO_2 Flux monitoring at 10 stations Pressure and water quality above the storage formation Wellhead pressure monitoring for 5 years, after which time the wells will be abandoned

Table 5. Hypothetical components of the basic and enhanced monitoring packages.

For the enhanced monitoring package two additional geophysical monitoring techniques are recommended: gravity and electromagnetic measurements. In addition, periodic well logs are recommended to check the integrity of the injection wells and surface flux monitoring is recommended to provide a extra degree of assurance that the CO_2 is not leaking back into the atmosphere. Spatial and temporal changes in the gravity response can be used to obtain low resolution maps of lateral movement of CO_2 within a formation. Forward and inverse modeling of the gravity data can be constrained by the structural information provided by the seismic data. Gravity data, while having the ability to detect lateral changes associated with plume migration, have very limited ability to map vertical changes. Therefore, while adding to the information provided by seismic imaging, they can not be used to replace it. The second combination, seismic-electromagnetic, has two potential advantages; first the electromagnetic response is directly sensitive to changes in water saturation, and second the spatial resolution of electromagnetic data is superior to gravity data. The direct sensitivity to water saturation is potentially important if geophysics is to be used to quantitatively predict saturation levels in an oil/hydrocarbon gas/CO_2 system where the number of fluid components precludes doing so using seismic alone. In addition, collection of electromagnetic data using grounded electric dipole sources and measuring electric fields can be performed relatively inexpensively provided that a permanent installation of electrodes is done at the start of the project.

The enhanced monitoring package also includes monitoring pressure changes and water quality in a shallower permeable formation above the storage formation. Changes in pressure above the storage formation can be a sensitive indicator of leakage, although other factors such as groundwater pumping and seasonal changes in groundwater elevation may obscure storage-related pressure changes. Periodic water quality sampling can also be used to detect the presence of CO_2. However, siting the observation well at the optimal location for leak detection, based on changes in water quality, is problematic – and for this reason, observation wells are rarely required for liquid waste disposal projects in the U.S. (Benson et al., 2002a).

Other techniques, though not recommended as part of these two monitoring packages, include soil gas surveys, surface deformation, tilt and SP. Soil gas surveys will only be useful in the event that leakage it occurring. If leakage is detected based on seismic surveys, flux and soil gas surveys can be used to quantify leakage rates and environmental impacts. Surface deformation provides comparable spatial resolution to gravity data although the data acquisition is more expensive and numerical modeling of the responses is not as advanced as for gravity data. SP data provide even lower spatial resolution than either gravity or electromagnetic data but may be useful in certain circumstances. Of any of the geophysical technique considered here, SP data is by far the lowest cost alternative although at this stage its application has not been demonstrated and the numerical modeling capability to address complex systems in transient flow do not exist. SP will have to wait for further development before being considered for monitoring.

5.3. Monitoring Costs

For the oil-field storage scenario, we assume that these monitoring costs are only those over and above what would be done for the enhanced oil recovery operations.[4] Therefore,

[4] Note that in some cases depleted oil and gas fields will be used for storage without enhanced oil and gas recovery. In these cases, additional costs associated with measurements during the Pre-operational phase may be required. On the other hand, costs during the Operational phase may be less because measurement of the quantity of CO_2 produced along with the oil and gas will not be required.

we assume that it is not necessary to get baseline seismic data, well logs, wellhead pressure, reservoir pressure or well test data. It is also important to recognize that costs of geophysical surveys can vary widely depending on surface terrain and the complexity of the survey. For the electromagnetic and gravity surveys, we have two sets of costs, one based on Texas and one based on costs in Alaska. These may or may not span the range of costs and have been selected based on the availability of information. For this analysis we used the higher estimated costs typical of Alaska.

Tables 7 and 8 provide cost estimates for both the basic and enhanced monitoring packages for the three scenarios described above based on the cost data provided in Table 3. For the basic monitoring pack, at a discount rate of 10%, costs for each of the scenarios is approximately \$0.05/tonne of CO_2, depending on the scenario. The discounted costs for the enhanced monitoring package range from \$0.075 to \$0.09/tonne. While the overall costs are similar for each of the scenarios, there are some significant differences. First, for the EOR scenario there are more injection wells (22 versus 10 for the saline formation), so measurements that are needed for each well cost more overall. Second, for the EOR scenario, the seismic survey costs more because we assume that the entire oil-field, which occupies a large area, is surveyed on a periodic basis. In contrast, for the saline formation, we assume that early in the life of the project, the much smaller area that underlies the footprint of the plume is surveyed, thus lowering costs significantly. Finally, the cost for monitoring injection and production rates is much higher for the oil-field case because it is necessary to monitor how much CO_2 is coming back to the surface with the produced oil using a gas/oil separator. These higher costs during the operational phase for the EOR scenario are off-set by lower pre-operational phase costs, and because we assume that the post closure period will need to continue for 20 years, in comparison to 50 years for the saline formation scenario.

A comparison between the cost of the enhanced and basic monitoring packages shows that the additional information can be obtained at a premium of about \$0.027 to \$0.037 per tonne of CO_2. This may be a small incremental price to pay for the information afforded by these additional measurements. The benefits may very well outweigh the costs when looked at in this light. However, site specific considerations and risks would need to be considered before drawing such a conclusion.

It is important to reiterate that these three scenarios are just examples for illustrative purposes. In some cases, other factors, such as obtaining more groundwater chemistry data may be an important addition to the monitoring program. This may be particularly important for storage in saline formations. Likewise, in some scenarios, seismic surveys may not need to be repeated on such a frequent basis – and in this case, the cost of monitoring may decrease significantly. Nevertheless, this analysis shows that the cost of monitoring is likely to be less than a discounted cost of \$0.10 per tonne of CO_2 (undiscounted costs range from \$0.15 to \$0.30 per tonne), which is a very small part of the overall cost of capture and storage.

	Saline Formation (LRG)	**Saline Formation (HRG)**	**EOR Reservoir**
Pre-operational Monitoring			
Well logs	$1,064,250	$1,064,250	$0
Wellhead Pressure	$55,000	$55,000	$0
Formation Pressure	$328,000	$328,000	$0
Injection and Production Rate Testing	$550,000	$550,000	$0
Seismic Survey	$3,828,000	$2,387,000	$0
MicroSeismicity Baseline	$475,000	$475,000	$475,000
Baseline Atmospheric CO_2 Monitoring	$100,000	$100,000	$320,000
Management (15%)	$960,038	$743,888	$119,250
Sub-Total:	$7,360,288	$5,703,138	$914,250
Operational Monitoring			
Seismic Survey	$9,493,000	$9,493,000	$15,840,000
Wellhead Pressure	$1,665,000	$1,665,000	$1,500,000
Injection and Production Rates	$3,351,000	$3,351,000	$6,450,600
Wellhead Atmospheric CO_2 Concentration	$1,800,000	$1,800,000	$2,460,000
Micro Seismicity	$3,675,000	$3,675,000	$3,675,000
Management (15%)	$2,997,600	$2,997,600	$4,488,840
Sub-Total:	$22,981,600	$22,981,600	$34,414,440
Closure Monitoring			
Seismic Survey	$15,983,000	$11,935,000	$7,920,000
Management (15%)	$2,397,450	$1,790,250	$1,188,000
Sub-Total:	$18,380,450	$13,725,250	$9,108,000
Total Cost:	$48,722,338	$42,409,988	$44,436,690
Total Cost at a Discount Rate of 10%	$13,697,010	$12,023,781	$12,683,389
Metric tonnes of CO_2	2.58E+08	2.58E+08	2.58E+08
Total cost / CO_2 Tonne:	$0.189	$0.164	$0.172
Total discounted cost / CO_2 Tonne:	$0.053	$0.047	$0.049

Table 6. Cost estimates for the basic monitoring package for the three scenarios.

	Saline Formation (LRG)	Saline Formation (HRG)	EOR Reservoir
Pre-operational Monitoring			
Well logs	$1,064,250	$1,064,250	$0
Wellhead Pressure	$55,000	$55,000	$0
Formation Pressure	$328,000	$328,000	$0
Injection and Production Rate Testing	$550,000	$550,000	$0
Baseline Seismic Survey	$3,828,000	$2,387,000	$0
Baseline EM Survey	$225,000	$225,000	$360,000
Baeline Gravity Survey	$225,000	$360,000	$360,000
MicroSeismicity Baseline	$475,000	$475,000	$475,000
Baseline Atmospheric CO_2 Concentrations	$100,000	$100,000	$320,000
Baseline CO_2 Flux Monitoring	$700,000	$700,000	$700,000
Pressure and water quality above the storage formation[5]	$1,000,000	$1,000,000	$1,000,000
Management (15%)	$1,282,538	$1,066,388	$482,250
Sub-Total:	$9,832,788	$8,310,638	$3,697,250
Operational Monitoring			
Casing Integrity Logs	$6,000,000	$6,000,000	$13,200,000
Seismic Survey	$9,493,000	$9,493,000	$15,840,000
EM Surveys	$936,000	$936,000	$1,440,000
Gravity Surveys	$936,000	$936,000	$1,440,000
Wellhead Pressure	$1,665,000	$1,665,000	$1,500,000
Injection and Production Rates	$3,351,000	$3,351,000	$6,450,600
Wellhead Atmospheric CO_2 Concentration	$1,800,000	$1,800,000	$2,460,000
CO_2 Flux Monitoring	$4,800,000	$4,800,000	$4,800,000
Micro Seismicity	$3,675,000	$3,675,000	$3,675,000
Pressure and water quality above the storage formation[6]	$570,000	$570,000	$570,000
Management (15%)	$4,983,900	$4,983,900	$7,706,340
Sub-Total:	$38,209,900	$38,209,900	$59,081,940
Closure Monitoring			
Seismic Survey	$15,983,000	$11,935,000	$7,920,000
EM Surveys	$1,519,000	$1,125,000	$720,000
Gravity Surveys	$1,519,000	$1,125,000	$720,000
Wellhead Pressure	$277,500	$277,500	$250,000
CO_2 Flux Monitoring	$8,000,000	$8,000,000	$3,200,000
Pressure and water quality above the storage formation	$950,000	$950,000	$380,000
Management (15%)	$4,237,275	$3,511,875	$1,978,500
Sub-Total:	$32,485,775	$26,924,375	$15,168,500
Total Cost:	$80,528,463	$73,444,913	$77,947,690

[5] This includes the cost of drilling and completing a monitoring well above the storage formation at a cost of $950K. In addition, it includes the cost of installing a pressure transducer ($5K) and obtaining baseline water quality data ($45K).

[6] Cost estimate assumes continuous pressure measurements ($1K per year) and monthly water quality samples ($1500/month) for acquiring sample and chemical analysis).

Total Cost at a Discount Rate of 10%	$20,927,707	$19,250,724	$23,319,093
Metric tons of CO_2	2.58E+08	2.58E+08	2.58E+08
Total cost / CO_2 Ton:	$0.312	$0.284	$0.295
Total discounted cost / CO_2 Ton:	$0.081	$0.075	$0.090

Table 7. Cost estimates for the enhanced monitoring package for the three scenarios.

5.4. Implications and Considerations for Long Term Post-closure Monitoring

The approach used to calculate life-cycle monitoring costs for these scenarios assumed that no monitoring would be required during the post-closure phase. Certainly, if a storage project is known to leak, post-closure monitoring may be required. Moreover, since monitoring protocols have not been established, it may also be the case that some form of post-closure monitoring is required even in the event that leakage has not occurred. Therefore, it is worthwhile to consider the costs and other considerations associated with long term monitoring.

To assess the costs of long term monitoring, calculations were made over a 1000 year period for the basic monitoring package (e.g. periodic seismic surveys conducted every ten years). Not unexpectedly, with a discount rate of 10%, there is virtually no change in the cost of the monitoring because the present value of expenditures so far in the future is negligible. However, if an intergenerational discount rate of 1% is used after 30 years (Michael Haines, personal communication), then the discounted cost of the basic monitoring package increases from $0.053 to $0.059 for the saline aquifer scenario. Similar increases (e.g. 10%) are found for the other scenarios. This suggests that increased cost alone is not a major concern with regard to long term monitoring.

Perhaps what is of greater significance is the question about who will be responsible for long term monitoring, should it be needed. Is it the government as suggested by Keith and Wilson (2001)? Is the company who stored the CO_2? Or is it the field operator? Which institutions will be present and have the authority oversee the results of the monitoring programs? How will financial resources the set aside, reserved and made available for this purpose? Answering these questions and addressing these considerations will require thoughtful analysis and meaningful discussions among government policy makers, the private sector and other interested parties to come to agreement on the best approach. Such an analysis is beyond the scope of this study and should be the focus of future efforts.

5.5. Comparison between Onshore and Offshore Monitoring

While the focus of this study is on storage in onshore geological formations, many of the monitoring techniques, protocols and conclusions of this study are applicable to offshore formations. Of particular interest is the comparison between the cost of monitoring onshore and offshore. As illustrated by the examples described above, for the basic monitoring program the costs of the repeated 3-D seismic surveys constitute greater than 50% of the total cost. For these analyses we assumed that the seismic surveys cost \$10,000 per km^2. This is on the low end of the range of values reported for offshore seismic surveys (\$7000 to \$25,000 per km^2). Therefore, for the basic monitoring package it is probably reasonable to conclude that offshore monitoring costs would on average be somewhat higher than those reported here.

The additional costs for the enhanced monitoring package are due primarily to measurement of atmospheric CO_2 concentrations and land-surface fluxes. In an offshore setting, if CO_2 were to leak out of the storage formation and eventually migrate up to the sea floor, it would then enter the ocean bottom. There, depending on the temperature, pressure and flux, it may form CO_2-hydrates, dissolve in the seawater or bubble up to the sea surface and be released back into the atmosphere. Under each of these scenarios, different monitoring approaches would be needed. While it is beyond the scope of this report to develop monitoring protocols for these offshore scenarios, suffice it to say that some combination of water quality measurements, sea-floor topography and flux measurements would be needed monitor seafloor releases. Until specific monitoring protocols are developed, it is not possible to estimate costs for an enhanced monitoring package for offshore applications.

Chapter 6. Identification of Gaps and Further R&D needs

The foregoing chapters demonstrate that there are a number of methods that can be used to ensure that geologic storage of CO_2 can be safe and effective. These techniques are particularly well developed if they have been used in the exploration or production of oil and gas reservoirs. Examples include well logging methods, exploration seismology, wellhead and formation pressure monitoring, and injection rate monitoring. In addition, using these techniques repeatedly can produce time-lapse images that can be used to track migration of CO_2 in the subsurface and detect other changes related to the CO_2 storage project. However, improvements in these technologies, the development of new technologies and clarification of monitoring requirements will provide even greater assurance to the public that geologic storage can contribute significantly to greenhouse gas mitigation. Opportunities for improvement are described below.

6.1. Clarification of Monitoring Requirements

This study has suggested that there are four distinct phases in a storage project, each with its own monitoring purposes and requirements: the pre-operational phase; operational phase; closure phase; and a post-closure phase. There must be a general agreement that this approach, or an alternative one, is appropriate, in order to clarify monitoring requirements. Without a clearly defined set of monitoring requirements it is not possible to determine whether or not measurement techniques are satisfactory. Moreover, this information is needed for estimating monitoring costs. This is particularly important with regard to post-closure monitoring, which may be very costly if it must continue in perpetuity.

6.2. Enhancements to Seismic Monitoring Techniques

To date, the analysis of subsurface monitoring technologies has shown that seismic imaging is clearly the most advanced by several criteria. First, it has the highest spatial resolution; second, it is most sensitive to small amounts of CO_2 in the subsurface; and third, it has the most industrial application experience behind it. As a tool for mapping spatial variations in CO_2, it is the best technology available today. However, if seismic imaging technology is to be used to predict quantitative estimates of the amount of CO_2 present at a given location in the subsurface, several research issues must first be addressed.

One shortcoming of seismic technology is its inability to distinguish high from low CO_2 saturation, under conditions where CO_2 is in or near the gaseous phase, once a small amount of CO_2 is present in a formation. This is a well understood phenomenon and is recognized in the petroleum industry when seismic is used in hydrocarbon gas exploration. This would be important in leak detection monitoring, for example, where seismic reflections would show the presence of CO_2 in a formation above a leaking storage formation, but would not be able to provide information about the amount of CO_2

present. This can be addressed by combining the information from seismic with an electrical or electromagnetic technique which is directly sensitive to water saturation. Since in most cases the two fluids in a system will be water and CO_2, if water saturation can be determined then CO_2 saturation is also known. The combination of seismic and electromagnetic techniques is a current area of research for petroleum applications. This research could be augmented to include saline water - CO_2 systems.

A second area of research that is needed for the quantitative interpretation of seismic data is in the area of CO_2 behavior in the pore space of potential storage formations. In particular, does CO_2 uniformly fill the pore space (in which case the Gassmann model is appropriate for calculating rock properties used in interpreting seismic data) or does the CO_2 fill the pore space in a non-uniform manner as it interacts with the in situ pore fluids (in which case some form of a patchy saturation model is needed). Laboratory studies are needed to determine the nature of CO_2 saturation in a variety of potential storage rocks. In addition field tests at a large scale are needed to determine the magnitude of the effect on surface seismic data.

6.3. Enhancements to Gravity Monitoring Techniques

Both numerical modeling of Schrader Bluff in Alaska and field tests at the Sleipner site have indicated a potential for gravity measurements as a monitoring technique. In general the gravity response of saturation changes caused by CO_2 injection is right around the levels that are considered repeatable with current technology. Since the accuracy of the inferred CO_2 distributions from gravity measurements improves with the accuracy of the gravity data, research is needed into improved gravity measurement sensitivity. This will involve both improvements in gravity meters themselves as well as improvements in methodology and data processing.

A scoping study is needed to determine the costs and best practice to permanently instrument a storage site with gravity meters as well as surface tilt meters in order to maximize the removal of gravitational noise caused by surface deformation. This would involve both numerical modeling as well as field measurements. A permanent installation with advanced noise removal has the potential to be a cost effective monitoring technique, but requires demonstration.

In addition to mapping spatial variations of gravity and using this to infer the spatial movement of CO_2 in the subsurface, as demonstrated in Chapter 4, gravity data may also be used to get quantitative estimates of saturation changes in a formation through the use of inversion algorithms. Inversion produces a density model that fits the observed data subject to various constraints. Considerable effort has gone into the development of gravity inversion algorithms, but these have mainly been focused on structural problems (i.e. finding the base of salt structures in petroleum exploration). The potential exists to couple the structural information gained from seismic data with gravity data through an inverse algorithm to produce maps of the density change within a storage formation as CO_2 injection proceeds. The development of new, or the modification of existing, inversion algorithms, their testing and validation is a research task that should be undertaken if quantitative CO_2 saturation information is desired.

6.4. Enhancements to EM Monitoring Techniques

Electromagnetic (EM) data acquisition and interpretation capabilities are well advanced in the mining and petroleum industries. Limited numerical modeling of the use of EM as a monitoring tool (this report) indicates that it has the ability to map spatial variations in water saturation (and in a saline formation CO_2 saturation since $S_{CO2} + S_w = 1$) at least as well and possibly better than gravity. The hardware and field experience exist to acquire the data, numerical algorithms exist to model and invert the data. However, a demonstration field test is most likely required since this technology is not as well known and understood within the larger geophysical community as are seismic and gravity.

6.5. Enhancements to Techniques for Measuring Surface Fluxes

Today's techniques for locating and quantifying gas releases to the atmosphere rely on ground-based or airplane-based observations of gas composition. These techniques are labor intensive and are most successful when the location of the release is well known. For geologic storage of CO_2, leakage may occur anywhere within the footprint of the storage project. Since typical storage projects may be on the order of 100's of km^2, locating and quantifying leakage using today's technology could be a daunting challenge. In the future, ideally, remote sensing techniques could be used to reliably locate surface leakage, its quantity and/or leakage rates. Satellite-based earth observing platforms that would observe changes in the ecosystem (associated with CO_2 leaks) and repeatedly measure CO_2 concentrations could be used to locate and quantify leakage. This is a challenging problem because variability in natural CO_2 fluxes and the long path length over which satellite-based observing systems measure. However, perhaps a combination of land-based and satellite-based observations could be developed to address this opportunity.

6.6. Enhancements to Lower Costs of Monitoring Programs

Estimated costs for monitoring geologic storage over the full life-cycle of a project at a range from $0.05 to $0.10 per tonne of CO_2 (discounted at 10%/year, undiscounted cost range from $0.16 to $0.31 per tonne). While this is small in comparison to the cost of separation ($30 to $70 per tonne) or small even in comparison to long term goals for separation costs ($10 per tonne), it nevertheless may represent up to $50 to 80 M over the life cycle of a typical project. Reducing these costs or obtaining more and better quality information for the same cost is desirable.

For the basic monitoring package described here, repeated seismic surveys account for more than 50% of the total costs for a typical monitoring program. Therefore, finding ways to reduce the cost of seismic surveys or repeat them less often could considerably lower the overall cost of monitoring. For example, it may be possible to use time-lapse 3-D surveys during the early – confirmatory – stages of a project, but as time goes on, single lines over key features may be sufficient to demonstrate that the project is performing as expected. In addition, the use of less costly techniques such as gravity and EM to augment the seismic data may be another way to reduce the frequency of 3-D seismic surveys. However, the low resolution of these techniques may not make them sufficiently useful to reduce the frequency of seismic surveys. New ideas on lowering costs, either for individual technologies, or through combinations of technologies would be beneficial.

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