Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO_2 Capture Project

Geologic Storage of Carbon Dioxide with Monitoring and Verification

Volume 2

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Geologic Storage of Carbon Dioxide with Monitoring and Verification

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Volume 2

ELSEVIER

2005

Amsterdam – Boston – Heidelberg – London – New York – Oxford
Paris – San Diego – San Francisco – Singapore – Sydney – Tokyo

ELSEVIER B.V.
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First edition 2005

Library of Congress Cataloging in Publication Data
A catalog record is available from the Library of Congress.

British Library Cataloguing in Publication Data
A catalogue record is available from the British Library.

ISBN: 0-08-044570-5 (2 volume set)

Volume 1: Chapters 8, 9, 13, 14, 16, 17, 18, 24 and 32 were written with support of the U.S. Department of Energy under Contract No. DE-FC26-01NT41145. The Government reserves for itself and others acting on its behalf a royalty-free, non-exclusive, irrevocable, worldwide license for Governmental purposes to publish, distribute, translate, duplicate, exhibit and perform these copyrighted papers. EU co-funded work appears in chapters 19, 20, 21, 22, 23, 33, 34, 35, 36 and 37. Norwegian Research Council (Klimatek) co-funded work appears in chapters 1, 5, 7, 10, 12, 15 and 32.

Volume 2: The Storage Preface, Storage Integrity Preface, Monitoring and Verification Preface, Risk Assessment Preface and Chapters 1, 4, 6, 8, 13, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33 were written with support of the U.S. Department of Energy under Contract No. DE-FC26-01NT41145. The Government reserves for itself and others acting on its behalf a royalty-free, non-exclusive, irrevocable, worldwide license for Governmental purposes to publish, distribute, translate, duplicate, exhibit and perform these copyrighted papers. Norwegian Research Council (Klimatek) co-funded work appears in chapters 9, 15 and 16.

♾ The paper used in this publication meets the requirements of ANSI/NISO Z39.48-1992 (Permanence of Paper).
Printed in The Netherlands.

Carbon Dioxide Capture for Storage in Deep Geologic Formations, Volume 2
D.C. Thomas and S.M. Benson (Eds.)

Chapter 2

TECHNICAL HIGHLIGHTS OF THE CCP RESEARCH PROGRAM ON GEOLOGICAL STORAGE OF CO_2

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ABSTRACT

This chapter provides an overview of the contents of this volume and the technical contributions of the CCP research team. Key results from 32 individual research projects are described. Contributions are discussed under four headings: storage integrity; storage optimization; monitoring; and risk assessment.

INTRODUCTION

The geological storage research program focused on four areas: storage integrity, storage optimization, monitoring and risk assessment. The following sections summarize progress in each of these areas.

STORAGE INTEGRITY

The storage "integrity" theme studies are directed towards better understanding elements of natural (reservoir and cap rocks, overburden, faults, etc.) and engineered (well materials) features that permit safe and effective geological storage of CO_2. Implications of an important industrial analog, natural gas storage, are also examined.

Assessment of Storage Integrity from Natural Geological Systems
Features of natural systems that are "effective" in accumulating and retaining large quantities of CO_2 are examined by Stevens (Chapter 3). Three large US CO_2 reservoirs were evaluated: (1) McElmo Dome, CO (30 Tcf at 2300 m; carbonate reservoir with thick halite cap rock), (2) Jackson Dome, MS (2 Tcf at 4700 m; sandstone with some carbonate reservoir with carbonate cap rock) and (3) St Johns, AZ (14 Tcf at 500 m; sandstone reservoir and anhydrite cap rock). Production and operations data were gathered for each of the sites. Key findings of the study are given below.

- CO_2 storage is a natural process that occurs where reliable reservoir seals such as thick evaporites or shales are present.
- Production of CO_2 from natural reservoirs provides insights for CO_2 storage.
- Efficient CO_2 storage operations will require specialized practices and technologies.

Recommendations include further analog studies focusing on classification of site suitability for storage, site characterization, modeling of injection process and monitoring.

The study by Shipton et al. (Chapter 4) on leaking natural CO_2 reservoirs systems focuses on CO_2-charged geysers from Western Colorado Plateau (East Central Utah). A three-dimensional (3D) model for CO_2 sources, travel paths and fate in the subsurface was developed by integrating multiple geologic data sets. Compositional and isotopic data suggest that CO_2 originates from clay–carbonate reactions at 100–200 °C (1.0–1.5 km in Upper Paleozoic or Triassic strata), migrates to a sequence of shallow, stacked reservoirs (300–500 m) with shale cap rocks and escapes to the surface through fractures associated with faults.

Features and distribution of travertine deposits in the area indicate that the system has been leaking since before historical times. Anthropogenic activity, such as drilling through faults, has created additional leakage pathways to the surface and appears to have altered the location and episodicity of CO_2-charged eruptions in the area. No untoward ecological or human health effects attributed to CO_2 release to the surface have been recorded. The study demonstrates the utility of constructing 3D geological and fluid history models to assess the suitability of geologic systems for CO_2 storage.

The Next Generation Capture and Storage (NGCAS) project comprised a multi-scale, integrated assessment of the Forties Field (UK North Sea) for CO_2 storage (Cawley et al., Chapter 5). The study workflow moved from 2D basin scale hydrogeology models to 3D fluid flow simulation around the field to reservoir simulation of CO_2 – water simulations interactions (e.g., diffusion). Risk evaluation applied a series of sensitivity tests that took data uncertainties into account. It was found that the potential for CO_2 escape via geological pathways by various mechanisms (diffusion and advective flow through cap rock, dissolution and transport if CO_2 into the underlying aquifer) is low due to the quality and thickness of the cap rock and overburden and the very slow, compaction driven natural fluid velocity in the reservoir and surrounding are. Although the geologic features of the Forties Field combine to comprise an excellent venue for CO_2 storage, the risks associated with well leakage and seepage need to be examined in detail.

Streit et al. (Chapter 6) reviews the methods used to predict and monitor geomechanical effects of CO_2 injection. Increases in formation fluid pressure due to CO_2 injection decrease the effective rock stress thereby increasing the likelihood of fault reactivation or rock failure. Assessment of the geomechanical stability of reservoir rocks and top seals and faults requires predictions of in situ stresses, fault geometries and rock frictional strength. Commercial tools exist to predict the maximum sustainable fluid pressure for rocks and faults (e.g. FAST™ or TrapTester™). Fault stability is also predicted by mapping fault geometry and constructing fault-failure plots. In assessing the suitability of a CO_2 storage site in a depleted oil or gas field, it is necessary to analyze for the effects of both depletion (from production) and recharging (from injection). Stress–seismic velocity relationships are used to detect poroelastic changes in rocks due to fluid injection. Recent development of new waveforms and data processing techniques may improve the accuracy of seismic techniques used for detecting stress changes. Installation of downhole seismic monitoring instruments may provide rapid, early detection of faulting or fracturing induced by effective stress changes.

Changes in geophysical attributes and mineral stability with CO_2 injection are the subject of the experimental study by Schütt et al. (Chapter 7). Using a triaxial cell and autoclaves to reproduce reservoir PT conditions, supercritical CO_2 was injected into rock samples to assess how suitable existing geophysical models are for predicting rock mechanical changes and whether or not mineral dissolution occurs. Seismic data show that both the bulk and shear modulus depend on the CO_2 saturation and differential pressure. The Gassmann model underestimates the fluid substitution effect that reflects the modulus dispersion between the static (Gassmann) and ultrasonic (laboratory) regimes. The dependence of shear modulus on fluid composition is not predicted by the Gassmann model. The higher pressure sensitivity of the shear modulus, compared to the bulk modulus, may permit discrimination of pressure and saturation effects through simultaneous use of compressional and shear waves. Seismic wave attenuation may be used to infer saturation. The experiments corroborate numerical models that predict fluid-front instabilities. Improvements in the standard models using these data may enhance seismic monitoring techniques. The geochemical results suggest that major elements essential for rock stability and minor elements of importance to water quality are mobilized by CO_2 injection.

Johnson et al. (Chapter 8) used reactive transport geochemical and distinct element geomechanical models to infer long-term effects of CO_2 injection on cap rocks. It was shown that CO_2 influx-triggered mineral dissolution and precipitation reactions in typical shale cap rocks reduce microfracture apertures whereas pressure and effective stress evolution initially increase and then slowly decrease them. For a given shale composition, the extent of geochemical alteration (to reduce permeability) appears nearly independent of key reservoir properties (permeability and lateral continuity) and CO_2 influx parameters (rate, focality and duration). In contrast, the extent of geomechanical degradation (to increase permeability) is highly dependent on the reservoir and influx parameters as they control the magnitude of pressure perturbation. One implication of this study is that natural CO_2 accumulations, which have not been subjected to large stress changes, may not be good analogues for man-made CO_2 storage reservoirs. Stress changes that could threaten the security of a CO_2 storage project can be avoided by appropriate reservoir selection (e.g. large, unconfined) and adhering to safe operation parameters (e.g. injection rate).

Storage Integrity of Engineered Systems

In the survey of the natural gas storage industry operational experience in North America and Europe, Perry (Chapter 9) draws important parallels to a future CO_2 storage industry. Through operation of $\sim$600 natural gas storage facilities in North America and Europe over the past 90 years, only nine gas migration incidents are recorded (all in the US). These include three cap rock failures, five wellbore failures and one case of poor reservoir selection. The review of natural gas storage technologies with possible implications for CO_2 storage includes the following.

- *Field integrity determination*. This involves selecting a structure that has a competent seal and structurally adequate closure. Broadly structured sites are favored because those with tight structuring have often developed faults and fractures. Pump testing of structures to ensure cap rock integrity is often performed. A modified pump test may be feasible for CO_2 cap rock testing.
- *Monitoring and leak detection*. This involves monitoring via observation wells for occurrence of gas above and lateral to the structure. Similar approaches may be used for CO_2 storage although gas migration may not be as readily detected.
- *Response to leakage*. Leak mitigation measures for natural gas leaks include shallow gas recycle, aquifer pressure control and cap rock sealing. For CO_2 storage, the former approaches are relevant but the latter approach needs further development.

Based on experience from the natural gas storage industry, the CO_2 sequestration industry should investigate the "science of observation wells," integration of existing technologies for locating and sealing leak, and methods to test field integrity. Claims that gas will never be found outside of the containment area should not be made.

The well integrity issue, particularly as it relates to cement stability, is addressed by Scherer et al. (Chapter 10). Well leakage scenarios are defined, and modeling of the potential number of wells expected to be exposed to a plume of injected CO_2 are tested. Degradation of annular and casing plug cements through poor construction, age or acid attack provides multiple pathways for CO_2 leakage with potential impacts on shallower resources and surface ecosystems. In the high well density Viking Formation (Alberta Basin), a modest CO_2 injection plume of 5 km radius is expected to contact an average of 240 wells. Rates and mechanisms of cement attack by carbonated water are tested experimentally and by simulation of subsurface conditions. Experiments with cements (class H with 0, 6 and 12% bentonite) included exposure of slices of sandstone and limestone cores with cement cores to static carbonated water (3% NaCl) at a range of temperature and pH. Post-exposure, the samples were analyzed for compositional (chemical, mineralization), structural (porosity, cracks) and hardness changes. Cured cement cylinders were exposed to carbonated water to test changes in permeability. Cement pastes were tested to determine the rate of leaching and permeability. The experiments demonstrated that carbonated water attack on cements is rapid. The reaction rim showed increases in porosity, and extensive removal of Ca and changes in Fe redox state (II to III) were noted. Preliminary simulations of plume delivery rate and attendant changes in water composition and pH indicated that the rate of acid attack on cements is most intense with the arrival of the plume but eventually stabilizes to a lower rate. Acid attack on cement is most severe when fresh carbonated water is continually delivered to the exposed cement. The study highlights the need to develop well leakage, cement stability and fluid flow scenarios prior to CO_2 injection in high well density areas.

The storage integrity studies contribute useful protocols for site assessment and considerations for operating and monitoring planning. The natural and industrial analogs are reassuring in terms of safety and provide practical operations and intervention information. The issue of well integrity is increasingly recognized as critical, probably more so than geological systems' integrity.

STORAGE OPTIMIZATION

The storage optimization studies are aimed at realizing operational efficiencies or cost savings that might make CO_2 storage a technical and economic success.

Industry CO_2 Injection Experience

Grigg (Chapter 11) surveyed the performance of Permian Basin (West Texas, Southeast New Mexico) CO_2 EOR operations over the past 30 years to assess what can be learned from the projects and where further research is needed. Data from operator surveys and the literature were tabulated by reservoir/seal type, performance issues such as injectivity, oil response and gas breakthrough and containment. There is significant industry experience in the safe separation, compression, transportation and injection of CO_2. In general, for well-characterized reservoirs in which previous operation problems were noted (e.g. during water flood), CO_2 behavior is consistent with reservoir simulations. In the short term (compared to geological time), behavior is consistent with predictions from reservoir simulations. In the short time that CO_2 has been injected into reservoirs, seals are maintaining their integrity and CO_2 is retained in the injection formation. The Permian Basin CO_2 EOR survey is a valuable "lessons-learned" exercise for CO_2 storage efforts given the extensive and unique collective experience of such operations.

Injection of acid gas (CO_2 and H_2S) from natural gas processing has been practiced without incident for 15 years at over 40 sites in the Alberta Basin of western Canada. Bachu and Haug (Chapter 12) describe the wide range of acid gas compositions injected, reservoir characteristics and operating conditions involved. Site selection criteria, including proximity to source, confinement of gas, effect of the gas on reservoir rock, protection of energy, mineral and groundwater resources, equity interests, wellbore integrity and public safety are outlined. Well completions, testing, operations and abandonment regulatory requirements have been established to ensure safe storage. The acid gas injection experience is encouraging for the prospects of safe and secure CO_2 storage as the presence of H_2S in the former poses a much greater hazard. The remaining issues include long-term containment and the applicability to larger scale operations.

Simulation of CO_2 Injection Performance in Coal Beds

Coal bed storage of CO_2 offers an economic offset from expected enhanced coal bed methane (ECBM) recovery. In the case study of a Colorado Plateau gas field (Tiffany) currently under N_2 flood, Wo and Liang (Chapter 14) outline considerations for the success of CO_2 ECBM in terms of reservoir performance and the potential for seepage. History matching of the N_2 injection shows that coal/CO_2 contact is limited. N_2 injection has caused coal fracturing and the development of preferred gas pathways from the injection to production wells. Methane seepage has already been noted in the San Juan Basin area. A representative seepage model for the Fruitland coal simulated conditions under which outcrop seepage of CO_2 and methane can be expected. Placement of injection wells within 2 miles of an outcrop could result in seepage of injected and mobilized gases.

Cost Reduction

Heggum et al. (Chapter 15) focused on designing safe and cost-effective systems and operational parameters for the compression and transportation of CO_2 under various conditions (e.g. offshore versus onshore, distance, presence of cooling water, CO_2 impurities). The principal goal of the study is to assess the utility of inexpensive carbon steel in settings, such as offshore Norway (hydrated, cool) as opposed to the better-known US situation (dehydrated, onshore). Based on water solubility in supercritical CO_2 experiments it is suggested that the proposed dehydration specification for LNG (50 ppm) might easily be relaxed to 600 ppm (the existing US Kinder-Morgan specification). Thermodynamic calculations of free water precipitation from supercritical CO_2 indicate that the specification might be further relaxed to 1300 ppm.

The Seiersten and Kongshaug (Chapter 16) study provided experimental results for CO_2 corrosivity to carbon steel. Experimental data obtained at higher pressure (up to 50 bar) showed that corrosion rates in CO_2 systems containing water and those containing water and MEG inhibitor are considerably lower than that predicted by existing corrosion models, particularly at low temperatures typical for subsea pipelines in northern waters. The study provides the basis for operational constraints for CO_2 transport in inexpensive carbon steel pipelines which may improve the economics of CO_2 storage offshore.

The study by Sass et al. (Chapter 17) on CO_2 impurities' tradeoffs serves as a link between storage studies and those examining transportation and capture. The substantial cost-saving potential in CO_2 capture of delivering CO_2 contaminated with impurities such as SO_x, NO_x and others (e.g. N_2, O_2, hydrocarbons, Hg) is balanced with potential operational complications and damage to surface facilities such as compressors, pipelines and injection systems. Absorption and regeneration characteristics of amines and other solvents used for CO_2 capture are adversely affected by acid gas impurities. Compression of gas mixtures may be complicated by the presence of higher boiling constituents, which may limit the ability to achieve adequate interstage cooling and damage compressors and related processing equipment. Materials used in separation, compression and transmission are subject to corrosion by carbonic, sulfuric, nitric and nitrous acids. Although corrosion mechanisms and their effects are fairly well understood, further work needs to be done on phase behavior of gas mixtures and their effects on compression and piping. Once the likely gas composition ranges from the capture process are defined, experiments and thermodynamic modeling can proceed to better predict possible adverse effects of impure gas streams and approaches devised to prevent them.

Bryant and Lake (Chapter 18) examined the possible subsurface implications of injecting CO_2 with impurities (e.g. SO_x, NO_x) into a saline formation (dissolution/precipitation affecting injectivity) and for CO_2 EOR. It was found that injecting CO_2 with impurities is unlikely to degrade injectivity even in the worst case scenario. Increased acidity from the nitric or sulfuric acid might even improve injectivity (temporarily). Impurities in CO_2 EOR injection are unlikely to affect performance as there is a tradeoff between lowering MMP and increasing the mobility ratio. The study suggests that CO_2 impurities (particularly, soluble species such as SO_x and NO_x) are not of particular concern in aquifer injectivity or EOR performance. Other gases such as N_2, however, would present operational difficulties and degrade performance.

The optimization studies provide direct industry analogs for safe and effective CO_2 injection. Simulations of CO_2 behavior in the subsurface document the rates and mechanisms of CO_2 immobilization. Reducing costs of CO_2 transportation and storage may become critical determinants in implementing CO_2 storage projects.

MONITORING

The monitoring studies were intended to examine the efficacy of a wide range of techniques, commercially available and under development, applied remotely, near the surface or in the subsurface.

Arts and Winthaegen (Chapter 19) conducted a broad survey of geophysical and geochemical monitoring techniques for the purpose of recommending "optimal" techniques for various CO_2 storage venues. Monitoring well technologies include pressure and temperature sensors, electrical resistivity, TDT, microseismic, VSP, crosswell seismic and fluid sampling. Surface geophysical methods include 4D seismic, subbottom profiling and sonar (marine), gravity, electromagnetics (EM), gravity, InSAR and tiltmeters. Geochemical monitoring includes groundwater sampling, tracer surveys, atmospheric detection and geobotanical hyperspectral remote sensing. The applicability of the various monitoring techniques was matched to specific features, events and processes (FEPs) such as those related to seal, casing/cement or well failure. The study provides a useful assessment of available technologies to monitor CO_2 leakage in a variety of settings and potential failure modes.

Atmospheric

In addition to surveying the state of the art in atmospheric monitoring systems, Shuler and Tang (Chapter 20) evaluate in detail the capability of various ground-based instruments to detect CO_2 leakage. The target detectable leak rate of 1% over 100 years (0.01%/year) was used as a base case. The detectability of leaks of this magnitude depends on the amount of leakage with time (flux), size of the affected area, mode of leakage (diffuse or point source) and atmospheric conditions. Currently available instruments can detect if the atmospheric CO_2 concentrations increase 10 ppm over background. Nomograms are used to predict the "excess" CO_2 present in the atmosphere for a given situation. Open path instruments (laser spectrometers) may be a cost-effective means of detecting small CO_2 leakage over a field-sized area (a few km^2). A spreadsheet application produced for the study permits matching of analytical instruments suitable for detecting CO_2 under various leakage scenarios.

The "eddy covariance" (micrometeorological perturbation) method, a technology used to establish baseline CO_2 flux from plant photosynthesis and respiration cycles, was evaluated for its applicability to CO_2 leak detection at the field scale by Miles et al. (Chapter 21). The technology is based on laser spectrometers mounted on towers (~ 10 m) that could be set up in an array at the field scale. This technology has been widely applied and is considered reliable and robust. Its applicability and expense should be compared with similar ground-based detection, given field size and the type and magnitude of CO_2 leakage.

The "hyperspectral geobotanical" remote sensing study by Pickles and Cover (Chapter 22) uses aerial data acquisition and processing to indirectly detect CO_2 leakage through CO_2 effects on plants and soils. Case studies include a satellite survey of the Mammoth Lakes, CA area where substantial volcanogenic leakage is known to have caused tree kills, and an aerial survey of Rangely Field, CO where low CO_2 leakage due to EOR operations is postulated. Hyperspectral images of Mammoth Lake and Rangely correlated well with ground-based CO_2 measurements and observations of vegetation effects. The Rangely Field surveys included pre- and post-rain images that showed marked differences in the (sparse) vegetation patterns but no obvious indications of CO_2 leakage. Detection of CO_2 leakage at Rangely Field will require further development and be mindful of the results of an independent Colorado School of Mines soil gas survey that showed little to no CO_2 leakage from the EOR operation (however, a possibly significant methane flux was detected). Additional processing and interpretation might reveal soil changes due to long-term CO_2 leakage and the location of hidden faults.

Geophysical and Geochemical Techniques

The "novel geophysical" monitoring study conducted by Hoversten and Gasperikova (Chapter 23) evaluates the resolution and applicability of seismic and non-seismic geophysical techniques to detecting CO_2 leakage. The Schrader Bluff, Alaska and S. Liberty, Texas reservoirs were used to model the spatial resolution of various geophysical CO_2 detection techniques. The significant changes in water with increasing CO_2 saturation might be detectable using seismic amplitude and AVO analysis. Ground-based gravity modeling shows that resolution is insufficient but might be improved with permanent sensor emplacement coupled with surface deformation measurements. Borehole gravity instrumentation emplaced up to 1200 ft above the reservoir might be sufficient to directly map the areas of net density changes caused by injecting CO_2 into water. The electrical resistivity changes attending CO_2 dissolution in water are easily detectable using EM techniques. This technique is currently available, inexpensive compared to seismic and most applicable to CO_2/brine systems. The streaming potential (SP) method has been successfully modeled in 2D for the Liberty Field and experimental results show promise. Unlike the other techniques, however, further developments in instrumentation and interpretation are needed. The novel geophysical techniques show considerable technical promise for CO_2 performance and leakage modeling whether by adding value to time-lapse seismic data or by development of inexpensive non-seismic techniques.

The utility and cost of using noble gas additives to monitor CO_2 movement and leakage in subsurface were studied by Nimz and Hudson (Chapter 24). The West Texas Mabee Field was used as a model for the study. Among the factors considered in selecting noble gases are cost, availability, subsurface transport characteristics and "distinctiveness" relative to the atmosphere and noble gases native to the reservoir. The Xe "system" (10 isotopes) was considered to meet these criteria. Given the volume of CO_2 injected into the reservoir and the detectability limits of the Xe isotopes, it is calculated that it would cost $\sim$ \$0.18/tonne CO_2 stored to adopt this monitoring system for the Mabee field. Further work on the subsurface partitioning behavior of noble gases relative to CO_2 is a prerequisite of effectively applying this technique.

The monitoring studies have surveyed diverse techniques in various stages of development. Near-term application of ground-based techniques is feasible. Further development of other technologies is warranted as these techniques may not be universally applicable and considerable cost savings might result.

RISK ASSESSMENT

The risk assessment studies have evolved from earlier lessons-learned analyses of natural and industrial analogs to scenario development and modeling of specific elements of systems to whole system comprehensive methodologies.

HSE Analogs, Regulatory and Intervention/Remediation

Benson (Chapter 25) produced a comprehensive compendium of information relevant to CO_2 storage (directly or by analog) via experiences with deep well injection of industrial wastes, natural gas storage, geologic repositories for nuclear waste and other information. Human health and ecosystem responses to various levels of CO_2, which are the most immediate concerns associated with CO_2 capture, transportation, injection and leakage, are also addressed. The lessons learned are as follows.

1. There is an abundant base of experience to draw on that is relevant and suggests that CO_2 can be stored safely if storage sites are selected carefully and monitored (natural gas storage, deep injection of liquid and hazardous waste, enhanced oil recovery).
2. The human health effects of exposure to elevated concentrations of CO_2 are well understood and occupational safety regulations are in place for safe use (confined spaces, transportation, food additive, pipeline transportation). Ecosystem impacts of elevated CO_2 concentrations in soils are not as well understood and may need additional study.
3. The hazard presented by CO_2 depends more on the nature of the release rather than on the size of the release (volcanic eruptions, ecosystem fluxes, fire suppression, limnic releases).
4. Experience from industrial analogs predicts that the biggest risks from CO_2 storage will be from leakage from poor quality or aging injection wells, leakage up abandoned wells, leakage through poorly characterized cap rocks and result from inconsistent or inadequate monitoring that could have been used for early intervention.
5. Regulatory paradigms and approaches vary and none address all the issues that are important for CO_2 storage (leakage between geologic units, performance versus practice-based requirements, state versus federal regulatory oversight, short versus long-term monitoring).

Recommendations for risk management approaches include development of a single set of consistent regulations, identification and investigation of the effectiveness of multi-barrier concepts, development of well completion, abandonment procedures and methods and of a risk management strategy that couples monitoring requirements with performance confirmation. Risk mitigation and remediation methods should also be developed. The lessons-learned study was an early SMV contribution that guided selection of subsequent risk assessment projects.

Hepple (Chapter 26) surveys data on human health impacts and ecosystem effects from exposure to elevated CO_2 concentrations. CO_2 is ubiquitous in the environment and an essential part of all living things. Humans can tolerate up to 1% concentration without suffering adverse effects. Exposure to concentrations of 3% begins to have acute, but reversible, physiological effects. Concentrations of greater than 10% can lead to death. Regulatory guidelines have been established for the safe use of CO_2. Ecosystem impacts due to high soil gas CO_2 concentrations are not well understood and more information on potential impacts may be needed.

The evolution and status of US federal and state laws and regulations to protect underground sources of drinking water from industrial and municipal wastes and their likely applicability to CO_2 storage are discussed by Apps (Chapter 27). Application of Type I well standards may be used for CO_2 injection. Under the Type I classification, CO_2 injection could be classified as non-hazardous, unless impurities such as H_2S and Hg are present. The buoyant character of supercritical CO_2 in the subsurface, however, would present a containment risk that is not addressed by current Type I well regulations governing disposal of hazardous waste. A new category of injection well, designed specifically for CO_2 storage projects may be desirable to ensure safe and effective storage, while facilitating the application of this technology.

Early detection and remediation of CO_2 leakage from storage sites is an understudied topic that Benson and Hepple (Chapter 28) address. The objective of this scoping study was to identify (1) monitoring approaches for early detection of CO_2 leakage, (2) remediation options that could be used to eliminate or manage risks after leakage has been detected and (3) additional information and R&D necessary to develop new remediation approaches. Scenarios for CO_2 leakage from storage sites include damaged injection wells, over-pressured reservoirs and accumulation in groundwater. The consequences of leakage include groundwater and surface water contamination by acidification and toxic element mobilization, vadose zone accumulation and surface releases. Remediation options applicable to leaking CO_2 storage projects are available from natural gas storage, oil and gas production, groundwater remediation and soil gas/vadose zone clean-up experience. HSE concerns become relevant not only for large leaks but also for chronic small leaks that may cause CO_2 to accumulate in structures. The study establishes a framework from which CO_2 leakage scenarios can be developed for specific storage sites and outlines technologies needed to manage such leaks and lessen their consequences. A site-specific plan that includes such contingencies will be essential for acceptance of CO_2 storage by NGOs, regulators and the public.

A coupled modeling framework has been developed by Oldenburg and Unger (Chapter 29) to simulate CO_2 leakage and seepage in the subsurface and atmosphere for risk characterization. The coupled model framework is built on the integral finite difference multi-phase and multi-component reservoir simulator (TOUGH2), and models CO_2 and air in both subsurface and atmospheric surface layer regions simultaneously. The model is demonstrated for a coupled subsurface–surface layer system and shows that seeping CO_2 can reflux into the subsurface as a dissolved component in infiltrating rainwater. Whereas CO_2 concentrations in the subsurface might be high, surface layer winds act to reduce CO_2 concentrations via dilution to low levels for the fluxes investigated (e.g. the Rio Vista, CA area which is characterized by strong persistent winds). High CO_2 levels persisting in the vadose zone, however, are a threat to ecosystems and for humans occupying poorly ventilated, low lying structures. The coupled subsurface–surface leakage and seepage modeling framework is likely to attract the attention of stakeholders in proposed CO_2 storage projects as the behavior of CO_2 at the surface is of the most immediate concern.

Onstott (Chapter 30) assessed potential impacts of CO_2 injection on subsurface organisms. The deep biosphere extends to $\sim$3.5 km with decreasing number of organisms with depth. These organisms are primarily methanogens, sulfur and iron reducers, and fermentative anaerobes. Genetic testing (16S rDNA) suggests that only about one-third of these subsurface organisms have been identified. By defining microbial assemblages and determining "microbial power" (free energy of redox reactions and availability of nutrients), a forward model is used to predict the impact of CO_2 injection on microbes in different environments (reservoir lithologies, ground water types) over three reservoir temperatures and constrained pCO_2 and pH/Eh. Fe (III) reducers and fermentative anaerobes are not favored by the presence of CO_2 but there is an increase in methanogenesis and acetogenesis. In general, the impact on microorganism's growth in carbonate systems is expected to be most significant.

Risk Assessment Methodologies

A methodology for risk assessment was developed by Stenhouse et al. (Chapter 31) for the IEA Weyburn Monitoring and Storage Project to determine the long-term fate of CO_2 injected into the reservoir. An interdisciplinary effort involving geology, hydrogeology, geochemistry, geomechanics, reservoir modeling and wellbore technology was made to assess the potential for CO_2 migration, via natural and artificial pathways, from the reservoir to the environment. The core of the long-term assessment is the systems analysis approach which includes definitions, development of internal, external and inter-relating FEPs, construction of scenarios and description of how FEP–FEP interactions will be accommodated in the consequence analysis modeling undertaken for each scenario. The results of this in-progress study are expected to quantify the length of CO_2 containment in the system and potential consequences of containment loss.

Risk assessment has become a critical issue for advancing CO_2 transportation and storage. Although the behavior and HSE impacts of CO_2 leakage are understood, the challenge is to predict the likelihood and impact of such leakage at specific sites. Further research and development on intervention and remediation technologies are needed to assure avoidance of leaks and effectively treat those that might do occur.

Wo et al. (Chapter 32) have developed a mathematical model for probabilistic risk assessment for the Tiffany Field, CO which is presently under N_2 flood for ECBM production. The risk assessment methodology includes four major elements (hazard identification, event and failure quantification, predictive modeling, risk characterization) and the mathematical model includes six functional constituents (initiators, processes, failure modes, consequences, indicators and inference queries). To demonstrate the applicability of the methodology and model, a prototype application, capable of performing scenario and Monte Carlo simulations, was developed in Microsoft Access™. The geomechanical study revealed processes that lead to risks of developing leakage paths at each step of CO_2 storage in coal beds. It was found that risk of leakage is higher for old wells that were converted to injectors and that the most likely mechanism of leakage path formation is slip on preexisting discontinuities cross-cutting coal seams. Predictive quantitative modeling demonstrates that elevated pressure resulting from N_2 injection caused the coal fractures on the preferred permeability trends to expand and extend from injectors to producers. This could increase the risk of early gas (N_2 plus CO_2) breakthrough and under certain conditions the risk of CO_2 seepage from the outcrop is increased if CO_2 injection is placed within 2 miles of an outcrop. The importance of evaluating the effects of processes employed prior to CO_2 injection (e.g. coal bed depressurization and dewatering, N_2 injection) on CO_2 movement is highlighted. Further testing of the methodology on additional, candidate CO_2 storage venues and benchmarking with other risk assessment models will strengthen the application and make it more universally accepted by regulators and the public.

Wildenborg et al. (Chapter 33) have developed a comprehensive methodology for long-term safety assessment of underground CO_2 storage that is available for application. The three basic components of the methodology are: (1) scenario analysis, which includes a comprehensive inventory of risk factors or FEPs that are selected as appropriate to a given venue, (2) model development, which enables a quantitative safety assessment and (3) consequence analysis. A performance assessment (PA) model based on the large number of simulations with physical models comprised of multiple compartments has been developed. The PA model is capable of a statistical analysis that predicts CO_2 concentrations and fluxes in the biosphere, and therefore established whether or not they are likely to exceed acceptable levels. The methodology has been applied to a reference scenario (combined on- and offshore case, The Netherlands). The scenario was run without mitigation efforts and therefore represents a worst case scenario. The results showed that seepage of CO_2 to the biosphere would not occur in the 10,000 year timeframe simulated for all 1000 parameter realizations considered. Further development of the surface (hydrosphere and atmosphere) components and benchmarking with other risk assessment models will improve its reliability and acceptance by regulators, NGOs and the public.

CONCLUSION

The CCP geological storage program addressed many of the technical gaps evident at its inception. Future work should aim to integrate concepts, models and simulation into a comprehensive methodology for storage site assessment, process optimization, near- and long-term monitoring and verification strategies and credible risk assessment protocols.

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