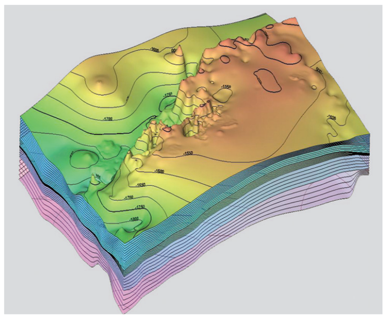

BEST PRACTICES for

Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations – 2012 Update

Second Edition

DOE/NETL-2012/1568

U.S. DEPARTMENT OF ENERGY

the ENERGY lab
NATIONAL ENERGY TECHNOLOGY LABORATORY

NETL

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Best Practices for Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations – 2012 Update

DOE/NETL-2012/1568

October 2012

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Table of Contents

List of Figures

List of Tables

List of Acronyms and Abbreviations

ADM	Archer Daniels Midland
AMA	Active Monitoring Area
AoR	Area of Review
AWWA	American Water Works Association
AZMI	Above-Zone Monitoring Interval
BLM	U.S. Bureau of Land Management
BNL	Brookhaven National Laboratory
bopd	Barrels of Oil Per Day
BPM	Best Practice Manual
BSCSP	Big Sky Carbon Sequestration Partnership
C/O	Carbon/Oxygen Ratio
Ca	Calcium
CASSM	Continuous Active Source Seismic Monitoring
CBL	Cement Bond Log
CBM	Coalbed Methane
CCP	Carbon Capture Project
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization, and Storage
CELLC	Chaparral Energy, LLC
CFR	Code of Federal Regulations
CH_4	Methane
C_2H_6	Ethane
C_3H_8	Propane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2CRC	Cooperative Research Centre for Greenhouse Gas Technologies
CODDA	Carbon Dioxide Detection by Differential Absorption
CRDS	Cavity Ring-Down Spectroscopy
CSEM	Controlled-Source Electromagnetic
CT	Computed Tomography
DCS	ADM's Distributed Control System
DIAL	Differential Absorption Light Detection and Ranging
DOE	U.S. Department of Energy
DTPS	Distributed Thermal Perturbation Sensor
DTS	Distributed Temperature Sensor
EC	Eddy Covariance
ECBM	Enhanced Coalbed Methane
EGL7	Ella G. Lees #7 Well
EGR	Enhanced Gas Recovery
EM	Electromagnetic
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
ER	Enhanced Recovery
ERCB	Energy Resources Conservation Board
ERT	Electrical Resistance Tomography
ET	Electrical Tomography
FE	Office of Fossil Energy
FEP	Features, Elements, or Processes
FMEA	Failure-Mode-and-Effects Analysis

FMI	Formation Micro-Imager
FWU	Farnsworth Unit
GHG	Greenhouse Gas
GLONASS	Russian Global Navigation Satellite System
GNSS	Global Navigation Satellite System
GPS	Global Position System
GS	Geologic Storage
GWIC	Montana Groundwater Information Center
H_2	Hydrogen
H_2S	Hydrogen Sulfide
He	Helium
HiVIT	High-Volume Injection Test
IBDP	Illinois Basin Decatur Project
ICET	Institute of Clean Energy Technology
IEA	International Energy Agency
INS	Inelastic Neutron Scattering
InSAR	Interferometric Synthetic Aperture Radar
IOGCC	Interstate Oil and Gas Compact Commission
IP	Induced Polarization
IPAC-CO_2	International Performance Assessment Center for Geologic Storage of Carbon Dioxide
IPCC	Intergovernmental Panel on Climate Change
IR	Infrared
IRGA	Infrared Gas Analyzer
ISO	International Organization for Standardization
IWR	Injection/Withdrawal Ratio
kT	Kilotonnes
LANL	Los Alamos National Laboratory
LBNL	Lawrence Berkeley National Laboratory
LIBS	Laser-Induced Breakdown Spectroscopy
LIDAR	Light Detection and Ranging
LLNL	Lawrence Livermore National Laboratory
MASTER	Moderate Resolution Imaging Spectroradiometer/Advanced Spaceborne Thermal Emission Reflection Radiometer
MEMS	Micro-Electromechanical System
Mg	Magnesium
MGSC	Midwest Geological Sequestration Consortium
MIT	Mechanical Integrity Test
MMA	Maximum Monitoring Area
Mn	Manganese
MRCSP	Midwest Regional Carbon Sequestration Partnership
MRV	Monitoring, Reporting, and Verification
MSU	Montana State University
MTRS	Multi-Tube Remote Sampler
MVA	Monitoring, Verification, and Accounting
N_2	Nitrogen
NaCl	Sodium Chloride
NDIR	Non-Dispersive Infrared
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NMOGCD	New Mexico Oil and Gas Conversation Division

NMSLO	New Mexico State Trust Lands Office
NRAP	National Risk Assessment Program
NRC	National Research Council
o-PDMCH	Orthoperfluorodimethylcyclohexane
O_2	Oxygen
ORNL	Oak Ridge National Laboratory
PCOR	Plains CO_2 Reduction Partnership
PEM	Planetary Emissions Management, Inc.
PFC	Perfluorocarbon
PFT	Perfluorocarbon Tracer
PISC	Post-Injection Site Care
PMCH	Perfluoromethylcyclohexane
PNC	Pulsed Neutron Capture
PNT	Pulsed Neutron Tools
ppm	Parts Per Million
psi	Pounds Per Square Inch
psia	Pounds Per Square Inch Absolute
psig	Pounds Per Square Inch Gauge
PSInSAR	Permanent Scatterer Interferometric Synthetic Aperture Radar
PTCH	Perfluorotrimethylcyclohexane
QASP	Quality Assurance and Surveillance Plan
R&D	Research and Development
RCSP	Regional Carbon Sequestration Partnership
RITE	Research Institute of Innovative Technology for the Earth
ROV	Remotely Operated Vehicle
RST	Reservoir Saturation Tool
SACROC	Scurry Area Canyon Reef Operators Committee
SAR	Synthetic Aperture Radar
SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
SF_6	Sulfur Hexafluoride
SHPO	State Historic Preservation Office
SJB	San Juan Basin
SP	Spontaneous Potential
STM	Surface Tilt Monitoring
SWP	Southwest Regional Partnership on Carbon Sequestration
TDS	Total Dissolved Solid
TOC	Total Organic Carbon
UAV	Unmanned Aerial Vehicle
UIC	Underground Injection Control Program
USDW	Underground Sources of Drinking Water
VERA	Vertical Electrical Resistivity Array
VSP	Vertical Seismic Profile
WVS	Wind-Vane Sampler
ZERT	Zero Emission Research and Technology Center

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DOE Contract #DE-FE0004002

Acknowledgments

This report was prepared by Leonardo Technologies, Inc. (LTI) for the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL). This work was completed under DOE NETL Contract Number DE-FE0004002. This work was performed under LTI Activity 300.02.01.

The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff and RCSP members, particularly:

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1 Introduction

This Best Practices Manual (BPM) is a technical guide to monitoring, verification, and accounting (MVA) of carbon dioxide (CO_2) stored in geologic formations. The information compiled here is intended to increase awareness of existing and emerging MVA techniques and, ultimately, to help ensure safe and permanent geologic storage (GS) of CO_2. The target audience for this BPM includes project developers, regulatory officials, national and state policymakers, and the general public. This document is an update of "Best Practices for Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations," which was published by the National Energy Technology Laboratory (NETL) in 2009. This update includes a significant number of new MVA technologies, a summary of new MVA regulations, and up-to-date results from recent field trials of MVA tools.

Carbon capture, utilization, and storage (CCUS) has been a topic of scientific investigation for more than 20 years, but has gained recognition over the last decade among environmental policymakers and the global scientific community as a feasible approach to reducing greenhouse gas (GHG) emissions (IPCC 2007, Presidential Task Force 2010). When the Intergovernmental Panel on Climate Change (IPCC) released its "Special Report on Carbon Capture and Storage" in 2005, they found no major technical or knowledge barriers to the adoption of geological storage of captured CO_2. However, the report also identified several key technology gaps, including MVA, where additional work would reduce uncertainty and facilitate informed decision making for large-scale deployment of CCUS.

Since its inception in 1997, the U.S. Department of Energy's (DOE) Carbon Storage Program, which is managed within the Office of Fossil Energy (FE) and implemented by NETL, has been advancing technologies to improve the effectiveness of CCUS and reduce its cost of implementation. DOE is committed to enabling widespread commercial deployment of CCUS by 2030, and a major component of this effort is the development of improved MVA technologies.

The Carbon Storage Program is comprised of three main elements: (1) Core R&D, (2) Infrastructure, and (3) Global Collaborations. All three program elements include development and testing of effective MVA technologies as a primary objective. The Core R&D element has a specific technology focus area aimed at developing new MVA technologies and systems through applied laboratory testing and pilot-scale field research. The program's Infrastructure element includes testing and validation of MVA technologies through the seven Regional Carbon Sequestration Partnerships (RCSPs). These partnerships are conducting field tests, engaging regional stakeholders, and investigating CO_2 storage and utilization in seven regions across the United States and Canada. Finally, the program's Global Collaborations element involves MVA field testing through participation in large-scale international GS demonstration projects. Research results from these three program elements will advance the Carbon Storage Program goal "to develop technologies to demonstrate that 99 percent of injected CO_2 remains in the injection zones."

The MVA plan for a storage project will have a broad scope, covering CO_2 storage conformance and containment, monitoring techniques for internal quality control, and verification and accounting for regulators and monetizing benefits of GS. MVA programs need to be flexible and site-specific to adapt to the inherent variability and heterogeneity of geologic systems. MVA plans also change in scope as a project progresses from the pre-injection phase to the post-injection phase. For all these reasons, MVA plans need to be tailored to site-specific geologic conditions and operational considerations. Some monitoring techniques are better suited to providing data specific to regulatory compliance, while other tools are better suited to reservoir management. Chapter 2 provides an overview of existing MVA technologies, along with a discussion of the maturity and suitability of various tools for field deployment in different situations. In addition, Chapter 2 provides practical guidelines for developing and executing an MVA plan.

MVA is an important part of making storage of CO_2 safe, effective, and permanent in all types of geologic formations. Monitoring technologies can be deployed for surface, near-surface, and subsurface applications, to ensure that injected CO_2 remains in the targeted formation, and that injection wells and preexisting wells are not prone to unintended CO_2 release. Since Federal and state GHG regulations and emission trading programs have been developed, monitoring has also gained importance as a means of accounting for the quantity of CO_2 that is injected and stored underground. The location of the injected CO_2 plume in the underground formation can also be determined, via monitoring, to satisfy operating requirements under the Environmental Protection Agency's (EPA) Underground Injection Control (UIC) Class VI and GHG Reporting Programs to ensure that potable groundwater and ecosystems are protected. In fields where CO_2 storage goes hand-in-hand with enhanced oil recovery (EOR), monitoring may be more challenging because of the presence of oil and gas in the formation. This added complexity needs to be considered when selecting monitoring methods that are best suited to fields where EOR is feasible. The portfolio of available monitoring technologies for all types of CO_2 storage situations is large and continues to grow. Chapter 3 provides an extensive discussion of existing and evolving monitoring tools, the information that each tool can provide, and its research and development (R&D) status.

Significant steps toward defining the regulatory framework for CCUS in the United States were taken in December 2010 when EPA released the UIC Class VI and GHG Reporting rules referenced above. EPA used the data and experience from the Core R&D Program, International Projects, and RCSP Program as a foundation for development of these regulations. Results from large- and small-scale GS projects will continue to contribute to support future GHG registries, incentives, or other policy instruments that may be deemed necessary in the future. A summary of new EPA regulations, with a focus on their monitoring requirements, is found in Chapter 4 of this BPM.

Finally, Appendices A through K present a wide range of examples from the field of monitoring activities being carried out by the RCSPs. Results and lessons learned from the RCSP Validation Phase and Development Phase field tests are presented and summarized.

2 Addressing the Objectives and Goals of Monitoring

As stated in the Introduction to this Best Practice Manual (BPM), one of the main goals of the U.S. Department of Energy's (DOE) Carbon Storage Program is to "develop technologies to demonstrate that 99 percent of injected carbon dioxide (CO_2) remains in the injection zones." To achieve this goal, DOE's National Energy Technology Laboratory (NETL) has dedicated significant effort to the development and testing of a broad spectrum of monitoring, verification, and accounting (MVA) technologies. A diverse portfolio of effective MVA tools is needed to meet the needs of individual injection projects and to support widespread commercial deployment of CCUS by 2030.

The Carbon Storage Program is comprised of three elements: (1) Core Research and Development (R&D), (2) Infrastructure, and (3) Global Collaborations. All three program elements include development and testing of effective MVA technologies as a primary objective. The Core R&D element has a specific technology focus area aimed at developing new MVA technologies and systems through applied laboratory and pilot-scale field research. The program's Infrastructure element includes testing and validation of MVA technologies through the seven RCSPs. Finally, the program's Global Collaborations element involves MVA field testing through participation in large-scale international GS demonstration projects.

Drawing upon results to-date from DOE's Storage Program, as well as from other international research efforts, this chapter provides an overview of existing MVA technologies; a discussion of the maturity or field readiness of these technologies; a discussion of the suitability of various monitoring tools to meet specific project needs for regulatory compliance and/or reservoir management; and guidelines for developing and executing an MVA plan.

More detailed information on existing MVA technologies, with extensive examples of tools that have been tested in the field, can be found in the "CO_2 Monitoring Techniques" chapter of this BPM.

2.1 Overview of Existing MVA Technologies

Carbon dioxide MVA technologies can be broken down into four main categories: (1) atmospheric monitoring tools, (2) near-surface monitoring tools, (3) subsurface monitoring tools, and (4) MVA data integration and analysis technologies. Atmospheric monitoring tools are used to measure CO_2 density and flux in the atmosphere above underground storage sites. Three types of tools that are used for tracking CO_2 in the atmosphere are optical CO_2 sensors, atmospheric CO_2 tracers, and eddy covariance (EC) flux measurement techniques.

Near-surface monitoring techniques are used to measure CO_2 and its manifestations in the near-surface region. This region extends from the top of the soil zone down to the shallow groundwater zone. Tools that measure CO_2 effects in the near-surface region include geochemical monitoring tools (in soil, vadose, and shallow groundwater zone), surface displacement monitoring tools, and ecosystem stress monitoring tools. Surface displacement and ecosystem stress monitoring are commonly measured with satellite-based, remote sensing tools. These tools are able to detect deformation of the land surface and vegetative stress resulting from increased concentrations or fluxes of CO_2 in the near-surface region.

Subsurface monitoring tools are used to detect and quantify CO_2 that has been injected into a geologic storage (GS) reservoir and to detect faults, fractures, and any seismic activity that may be present in the injection zone and adjacent confining zones. Subsurface monitoring tools include well logging tools, downhole monitoring tools, subsurface fluid sampling and tracer analysis, seismic-imaging methods, high-precision gravity methods, and electrical techniques.

Finally, MVA data integration and analysis technologies are used to integrate the wide variety of CO_2 monitoring data that are acquired. Tools used for MVA data integration and analysis include intelligent monitoring networks and advanced data integration and analysis software. Examples of all of these monitoring tools, technologies, and approaches are provided in the "CO_2 Monitoring Techniques" chapter of this BPM.

2.2 Field Readiness of CO_2 Monitoring Tools

Carbon dioxide monitoring tools are selected based in part on the specific needs of individual injection projects, but also on the field readiness of potentially useful technologies. A wide variety of MVA technologies have been developed for CO_2 monitoring at CCUS sites over the past decade, and some have been utilized successfully in large demonstration projects. Novel technologies continue to be designed and developed through focused R&D. Although these emerging technologies may have clear advantages over existing techniques, they are not likely to be adopted until they have undergone significant field testing. The reliability of an MVA technology is proportional to its maturity or field readiness, and, as a result, project planners are more likely to select the MVA approaches that have a proven track record.

The maturity or field readiness of MVA technologies can be broadly classified as: (1) development stage, (2) early demonstration stage, and (3) commercial stage. It should be noted that MVA is a rapidly evolving area of R&D, so many technologies currently in the early demonstration stage could move to the commercial stage within 5 to 10 years.

MVA Technologies in the Development Stage

This category represents the first step in the development of novel tools for effective CO_2 release detection and monitoring. Technologies in the development stage may include simple conceptual designs, proof-of-concept designs, or early prototypes undergoing laboratory testing or pilot-scale field testing. These technologies are typically validated using model simulations or pilot-scale testing under representative in-situ operating conditions.

Technologies still at the development stage are likely to require modifications and multiple pilot-scale field tests prior to being ready for systematic field deployment. Emerging CO_2 monitoring technologies, once they are fully tested, may offer considerable benefits over existing techniques. Benefits include significant reductions in cost, improved performance, and the ability to meet existing regulatory requirements that may be difficult for current technologies to meet.

MVA Technologies in the Early Demonstration Stage

This category includes: (1) validated prototypes that have been deployed in multiple stand-alone or integrated field demonstration pilots, under relevant conditions to monitor CO_2 storage performance and release; (2) technologies that have been deployed in commercial-scale operations, but not across a wide variety of geologic settings; and (3) commercially available monitoring techniques that are routinely used in the oil and gas industry, but are relatively untested for CCUS monitoring. The potential benefits of these techniques may include lower costs of deployment, higher sensitivity to CO_2, and higher accuracy or precision of measurements compared to established, commercial-stage techniques.

MVA Technologies in the Commercial Stage

MVA technologies in the commercial stage of development have been systematically tested and utilized in multiple commercial-scale injection sites across a wide variety of geologic settings and site conditions. Such technologies have also been successfully integrated with other technologies deployed at the commercial scale. Technologies in this category are considered to be mature in the GS context, and field testing results are typically published and readily available.

2.3 Applicability to Regulatory and Reservoir Management Needs

Certain CO_2 monitoring techniques are well-suited to meet a project's requirements for regulatory compliance, while other tools may be better suited to address the project's reservoir management needs. The right-hand side of Table 1 is intended to show which tools are applicable to regulatory compliance, and which tools are more readily applicable to reservoir management. For commercial-stage monitoring technologies, this determination is based on the types of data and information that are obtained. For technologies that are still in the development stage, this determination is based on the types of data and information that will be obtained when the tool or technique becomes mature and ready to deploy.

The current Federal regulatory framework for controlling CO_2 injection projects is found in the CFR, in:

1. CFR Title 40, Part 146, Underground Injection Control (UIC) Program.
2. CFR Title 40, Part 98, Mandatory Greenhouse Gas (GHG) Reporting Program.

The UIC Program regulates the injection of all fluids into the subsurface, and a UIC Class VI well rule was developed specifically for injection wells used for GS of CO_2. These regulations were developed to protect underground sources of drinking water (USDWs) and to ensure that no injection operations endanger USDWs or human health. Monitoring techniques that address well integrity, groundwater monitoring, subsurface plume tracking, long-term containment of the injected plume, and soil-gas and surface-air monitoring are all applicable to UIC Class VI Rule requirements.

The GHG Reporting Program is intended to complement the UIC Program, and its focus is on reporting and accounting for all CO_2 throughout the life of an injection project. Subpart RR of CFR Title 40, Part 98, covers injection of CO_2 for GS purposes, and Subpart UU covers injection of CO_2 for purposes of enhanced oil or gas recovery. The GHG reporting rules require that a surface and subsurface monitoring strategy be developed that includes development of a baseline of atmospheric CO_2 prior to injection, CO_2 mass balance calculations for the entire injection process, and identification of potential CO_2 releases. The GHG reporting requirements also include delineation and frequent updating of the monitoring area. Monitoring techniques that address delineation of monitoring areas, quantification of injected CO_2 for mass balance calculations, identification of potential release pathways, and identification of release risks and impacts are applicable to Subpart RR. Subpart UU requires reporting of information on flow rates of CO_2 received at the injection facility.

Chapter 3 of this BPM provides a more detailed discussion of these Federal regulations. The regulations do not mandate utilization of specific monitoring tools in order for a project to achieve regulatory compliance. Instead, the UIC and GHG reporting rules recommend that the choice of monitoring tools be made based on project- and site-specific conditions and needs.

Monitoring strategies are also driven by reservoir management needs, so this has been included in the far right-hand column of Table 1. MVA technologies may be used to support design and control of injection operations, to monitor plume injection and migration in the storage reservoir, and to optimize utilization of subsurface storage reservoirs. Techniques for reservoir management include subsurface pressure monitoring and plume tracking, surface displacement monitoring, and measuring the volume of CO_2 in the subsurface.

Table 1: Field Readiness and Applicability of Monitoring Tools

Monitoring Approach		Field Readiness of Technology	Techniques	Applicability of Technology: UIC Class VI Rule	Applicability of Technology: GHG Reporting Rule	Applicability of Technology: Reservoir Management
Atmospheric Monitoring	Optical Sensors	Commercial Stage	CRDS, NDIR-based CO_2 sensors	✓	✓	
Atmospheric Monitoring	Optical Sensors	Development Stage	DIAL/LIDAR	✓	✓	
Atmospheric Monitoring	Atmospheric Tracers	Early Demonstration Stage	Passive tracer sampling (flask, sorbent)	✓	✓	
Atmospheric Monitoring	Atmospheric Tracers	Development Stage	Multi-tube remote samplers, wind-vane samplers	✓	✓	
Atmospheric Monitoring	Eddy Covariance	Early Demonstration Stage	EC flux towers	✓	✓	
Near-Surface Monitoring	Geochemical Monitoring in the Soil and Vadose Zone	Commercial Stage	Flux accumulation chambers	✓	✓	
Near-Surface Monitoring	Geochemical Monitoring in the Soil and Vadose Zone	Early Demonstration Stage	Soil-gas tracer sampling, soil-carbon analysis	✓	✓	
Near-Surface Monitoring	Geochemical Monitoring in the Soil and Vadose Zone	Development Stage	Portable isotopic carbon analyzers, fiber optic sensors for soil-CO_2	✓	✓	
Near-Surface Monitoring	Geochemical Monitoring of Shallow Groundwater	Commercial Stage	Shallow-groundwater sampling, geochemical analyses	✓	✓	
Near-Surface Monitoring	Surface Displacement Monitoring	Early Demonstration Stage	Tiltmeters InSAR/PSInSAR, GPS	✓		✓
Near-Surface Monitoring	Ecosystem Stress Monitoring	Early Demonstration Stage	Hyperspectral, multi-spectral imaging of vegetative stress		✓	

Monitoring Approach		Field Readiness of Technology	Techniques	Applicability of Technology		
				UIC Class VI Rule	GHG Reporting Rule	Reservoir Management
Subsurface Monitoring	Well Logging Tools	Commercial Stage	Density, neutron porosity logs, pulsed neutron tools (PNT), acoustic logging, dual-induction logging	✓		✓
Subsurface Monitoring	Downhole Monitoring Tools	Commercial Stage	Downhole/wellhead pressure, temperature gauges, flow meters, sonic logging, oxygen-activation logs, radioactive tracer surveys, corrosion monitoring	✓	✓ See [1]	✓
Subsurface Monitoring	Downhole Monitoring Tools	Development Stage	Fiber-optic distributed temperature sensor (DTS) system, Distributed thermal perturbation sensor (DTPS)	✓	✓	✓
Subsurface Monitoring	Downhole Monitoring Tools	Development Stage	Cable-less ruggedized sensors for downhole P.T. corrosion	✓	✓	✓
Subsurface Monitoring	Seismic Methods	Commercial Stage	Time-lapse surface seismic (3-D, 2-D) Borehole seismic (vertical seismic profile [VSP])	✓	✓	✓
Subsurface Monitoring	Seismic Methods	Early Demonstration Stage	Cross-well seismic, passive (micro) seismic	✓	✓	✓
Subsurface Monitoring	Seismic Methods	Development Stage	Fiber-optic geophone technology for borehole seismic surveys, Cable-less data acquisition for multi-component, 3-D seismic data	✓	✓	✓
Subsurface Monitoring	Subsurface Fluid Sampling and Tracer Analysis	Commercial Stage	Wireline-based samplers	✓	✓	✓
Subsurface Monitoring	Subsurface Fluid Sampling and Tracer Analysis	Early Demonstration Stage	U-tube sampling, modified reservoir fluid sampling system, gas membrane sensor system	✓	✓	✓
Subsurface Monitoring	Gravity	Early Demonstration Stage	Remotely-operated vehicle-deployable-deep-ocean gravimeters (ROVDOG), borehole gravity measurements	✓		✓
Subsurface Monitoring	Electrical Techniques	Early Demonstration Stage	Cross-well electrical resistivity tomography (ERT), surface-downhole ERT	✓	✓	✓
Subsurface Monitoring	Electrical Techniques	Development Stage	Controlled-source electromagnetic (CSEM) surveys	✓	✓	✓
MVA Data Integration and Analysis Technologies	Intelligent Monitoring Networks	Commercial Stage	Remotely controlled downhole sensors and fluid control equipment	✓	✓	✓
MVA Data Integration and Analysis Technologies	Intelligent Monitoring Networks	Development Stage	Continuous and autonomous monitoring of CO_2 storage by pressure monitoring	✓	✓	✓
MVA Data Integration and Analysis Technologies	Advanced Data Integration and Analysis	Development Stage	Combining GPS, InSAR data with seismic and geochemical data Integrating seismic techniques with other geophysical tools (e.g., electromagnetic, gravity)	✓		✓

[1] Flow meters are also applicable to Subpart UU of the EPA GHG reporting rule.

Detection Versus Quantification of CO_2 Volumes

Detecting the ***presence*** of CO_2 and determining the ***quantity*** of CO_2 at a particular location represent distinct technical challenges. The need for CO_2 detection versus quantification should be considered in evaluating the suitability of individual monitoring techniques.

The ability of a particular tool to detect and/or quantify a CO_2 release to the atmosphere depends on the amount of CO_2 released, the type of release, and the release rate. Durucan (2010) suggests that low release rates (100 g CO_2/d, or 10^{-4} T/d or lower) may not be detected by most current technologies, whereas intermediate and higher rates can be detected and even quantified using some existing monitoring tools. A combination of atmospheric monitoring tools may be needed to accurately detect and quantify a CO_2 release. Carbon dioxide released into the atmosphere may be quantified using EC, optical sensors, atmospheric tracers, and isotopic analyses.

Shallow, near-surface CO_2 releases may be quantified using soil-CO_2 flux monitors supplemented by geochemical tracers, isotopic analyses, and ecosystem stress monitoring. Soil CO_2 fluxes, tracers, and isotopic measurements have been used successfully to measure CO_2 release at rates as low as 0.01 percent of the injected CO_2 (Korre et al., 2011).

Subsurface CO_2 plume migration and potential release from a deep, subsurface injection zone may be best monitored using high-resolution seismic imaging (Korre et al., 2011) and passive seismic monitoring. High-precision gravity measurements, surface deformation monitoring, downhole sensors (including pressure), and electrical techniques may be used to reduce uncertainties in seismic interpretations, as well as to help identify potential release pathways. In sites with favorable geology, 4-D surface seismic methods may be able to be used to verify the storage of a minimum of hundreds of kilotonnes (kT) of CO_2 in the subsurface and releases as small as a few kTs of CO_2 (Fabriol et al., 2011).

2.4 Monitoring Plan Design

Risk analysis, reservoir management, and monitoring design are all closely linked and form the basis of a successful CO_2 injection project. A project's MVA plan should have a broad scope, including CO_2 storage conformance and containment, monitoring techniques for internal quality control, and verification and accounting for regulators and monetizing benefits of GS (DNV, 2010a).

Typical MVA plans include components for meeting regulatory requirements, monitoring the CO_2 plume, monitoring water/brine behavior, detecting potential release pathways, and quantifying releases (EC, 2011). The monitoring plan also defines monitoring objectives, risk-based performance metrics, and resources allocated for monitoring activities. In addition, a comprehensive plan should include reviews of monitoring tools' effectiveness, stakeholder communications, procedures for documenting monitoring activities, and processes used to evaluate monitoring performance.

MVA plans may change in scope as a project progresses from the pre-injection phase to the post-injection phase. In the pre-injection phase, project risks are identified, monitoring plans are developed to mitigate these risks, and baseline monitoring data is obtained. During the injection phase, monitoring activities are focused on containment and storage performance. Monitoring techniques may need to be adapted and evaluated to ensure that they continue to be effective for meeting MVA goals. In the post-injection phase, monitoring activities are focused on long-term storage integrity and managing containment risk.

Risk-Based Monitoring Strategies

Each CO_2 injection project has its own set of priorities, risks, monitoring targets, and requirements for project success. A site-specific, risk-based monitoring plan is designed to mitigate negative impacts and reduce uncertainties by iterative application of monitoring and risk analysis (Figure 1). The European Commission guidance document on site characterization, CO_2 monitoring, and corrective measures notes that monitoring requirements depend on the outcome

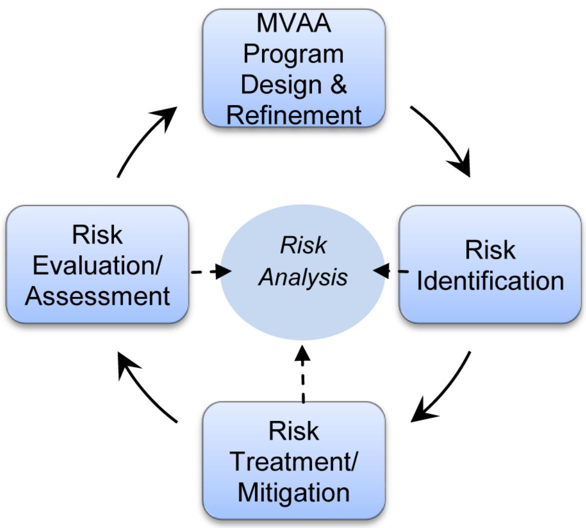


Figure 1: Iterative MVA and Risk Analysis. Adapted from DNV (2010a), IEAGHG (2009)

of the risk assessment and site-specific risks (EC, 2011). Identifying potential risks during initial site characterization, baseline, or subsequent monitoring operations allows targeted actions to mitigate risk impacts or to prevent their occurrence. Monitoring plans are, in turn, related to risk prevention and mitigation measures. For further details, the reader is referred to the International Energy Agency (IEA) GHG report on risk assessment guidelines and terminology (IEAGHG, 2009), the International Performance Assessment Center for Geologic Storage of Carbon Dioxide (IPAC-CO_2) draft standard on geologic CO_2 storage (CSA Z741, 2011), and the DOE/NETL BPM for Risk Analysis and Simulation (DOE/NETL, 2011y).

Workflow for Developing Site-Specific MVA Plans

The first stage in the workflow for the preparation of a site-specific MVA plan (Figure 2) is identification of risks based on available data, high-level project goals, performance targets, and regulations. Not all elements of this generic workflow may be components of each site's MVA design methodology. Rather, risk analysis and reservoir management would be tailored to site-specific needs to ensure successful project operation. Risk-source identification uses risk scenarios, which are aggregated from features, elements, or processes (FEPs) relevant to the specific site. Examples of FEPs of concern may be the presence of abandoned wells penetrating the injection zone and elevated injection pressures. Scenarios of higher concern form the basis for risk-mitigation actions and define monitoring targets.

Measurement techniques and safeguards for monitoring targets are identified in the next step. Each active safeguard has a sensor for parameter measurement, decision logic to respond to the measurement output, and a control response to mitigate risk and inform the project operator. In the next step, the selected monitoring techniques are screened and evaluated to identify the most cost-effective technique for a particular monitoring target. This can be accomplished by qualitative expert judgment or relative cost versus benefit studies, such as the Boston Square approach.

The fourth stage in the work flow is the preparation of base case and contingency monitoring and verification plans. The base case monitoring plan covers activities that follow a planned schedule, whereas the contingency plan monitoring activities only occur in the event of release detection. The verification plan ensures that actual storage performance is consistent with the predicted performance. Together, the monitoring and verification plans document the allocation of responsibilities for individual monitoring tasks and the effectiveness of monitoring techniques. Compliance of project performance with existing regulations is the focus of the reporting plan.

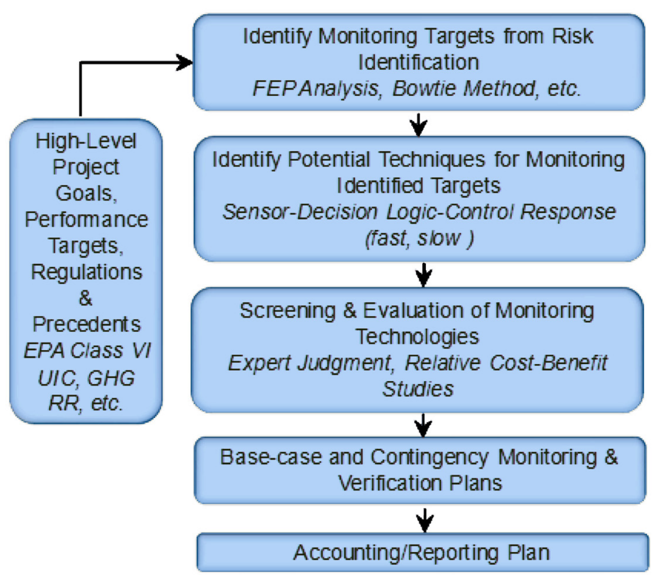
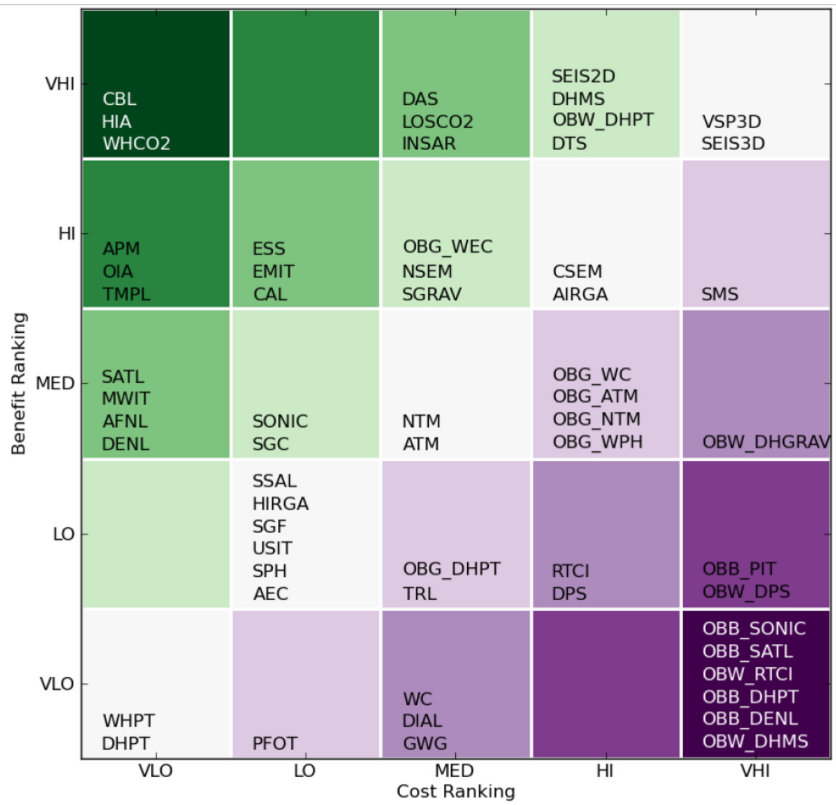


Figure 2: Workflow for the Preparation of a Risk-Based MVA Plan. Adapted from DNV (2010b)

Examples of Risk-Based MVA Plan Workflows

The "Bowtie Method" (Shell, 2010; DNV, 2010a) was used to identify and assess containment (release) and storage performance (conformance) risks in the Shell QUEST saline storage project. Containment risks were addressed in greater detail than conformance risks. Monitoring targets and four groups of monitoring tasks were identified, and monitoring technologies were ranked using expert opinions and lifecycle cost-benefit estimates (Figure 3), leading to base-case and contingency monitoring plans.



VALUE	TECHNOLOGY DESCRIPTION
4.0 WHCO2	Wellhead CO_2 detectors
3.9 HIA	Satellite or airborne hyperspectral image analysis
3.8 CBL	Cement bond logs
3.5 APM	Annulus pressure monitoring
3.3 OIA	Operational Integrity Assurance System
3.0 TMPL	Time-lapse temperature logging
2.8 INSAR	InSAR – Interferometric Synthetic Aperture Radar
2.2 MWIT	Mechanical well integrity pressure testing
1.7 SGRAV	Time-lapse surface microgravity
1.7 ESS	Ecosystem studies
1.6 DAS	Fibre-optic distributed acoustic sensing
1.6 CAL	Time-lapse multi-finger caliper
1.6 AFNL	Time-lapse annular flow noise logging
1.5 DENL	Time-lapse density logging
1.5 LOSCO2	Line-of-sight gas flux monitoring
1.3 SATL	Time-lapse saturation logging
1.2 EMIT	Time-lapse EM casing imaging
1.0 SONIC	Time-lapse sonic logging
1.0 SGC	Soil CO_2 gas concentration surveys
1.0 OBW_DHPT	Downhole pressure-temperature gauge using observation wells in WPGS
0.8 DTS	Fibre-optic distributed temperature sensing
0.8 SGF	Soil CO_2 gas flux surveys
0.7 NSEM	Magnetotelluric – natural source EM
0.7 ATM	Artificial tracer monitoring
0.7 SEIS2D	Time-lapse surface 2D seismic
0.6 DHMS	Down-hole microseismic monitoring
0.6 USIT	Time-lapse ultrasonic casing imaging

VALUE	TECHNOLOGY DESCRIPTION
0.5 OBG_WEC	Down-hole electrical conductivity monitoring using Observation wells in GWPZ
0.2 SPH	Soil pH surveys
0.2 SSAL	Soil salinity surveys
0.1 VSP3D	Time-lapse 3D vertical seismic profiling
0.0 WHPT	Wellhead pressure-temperature gauge
0.0 AIRGA	Airborne infrared laser gas analysis
-0.2 NTM	Natural isotope tracer monitoring
-0.2 CSEM	Time-lapse surface controlled source EM
-0.2 SEIS3D	Time-lapse surface 3D seismic
-0.2 DHPT	Downhole pressure-temperature gauge
-0.2 OBG_ATM	Artificial tracer monitoring using Observation wells in GWPZ
-0.4 AEC	Atmospheric eddy correlation
-0.4 OBG_WPH	Downhole pH monitoring using Observation wells in GWPZ
-0.6 HIRGA	Hand-held infrared gas analysers
-0.7 OBG_WC	Water chemistry monitoring using Observation wells in GWPZ
-0.9 SMS	Surface microseismic monitoring
-1.0 OBG_DHPT	Down-hole pressure-temperatur gauge using Observation wells in GWPZ
-1.1 TRL	Tracer injection & gamma logging

VALUE	TECHNOLOGY DESCRIPTION
-1.2 PFOT	Pressure fall-off test
-1.2 OBW_DHGRAV	Time-lapse down-hole microgravity using Observation wells in WPGS
-1.2 OBG_NTM	Natural isotope tracer monitoring using Observation wells in GWPZ
-1.7 DPS	Fibre-optic distributed pressure sensing
-2.0 RTCI	Real time casing imager
-2.3 GWG	Ground water gas analysis
-2.3 WC	Water chemistry monitoring
-2.4 DIAL	DIAL – Differential absorption LIDAR
-3.1 OBW_DPS	Fibre-optic distributed pressure sensing using Observation wells in WPGS
-3.2 OBB_PIT	Pressure interference testing using Observation wells in BCS
-3.3 OBB_DENL	Time-lapse density logging using Observation wells in BCS
-3.3 OBB_DHPT	Down-hole pressure-temperature gauge using Observation wells in BCS
-3.6 OBB_SONIC	Time-lapse sonic logging using Observation wells in BCS
-3.6 OBB_SATL	Time-lapse saturation logging using Observation well in BCS
-3.9 OBW_RTCI	Real time casing imager using Observation wells in WPGS
-4.6 OBW_DHMS	Down-hole microseismic monitoring using Observation wells in WPGS

Figure 3: Shell QUEST CCUS Project Cost-Benefit Ranking of Monitoring Technologies. (2010)
Technologies with higher ranking values are more beneficial and less costly. Lower ranking values are less beneficial and more costly.

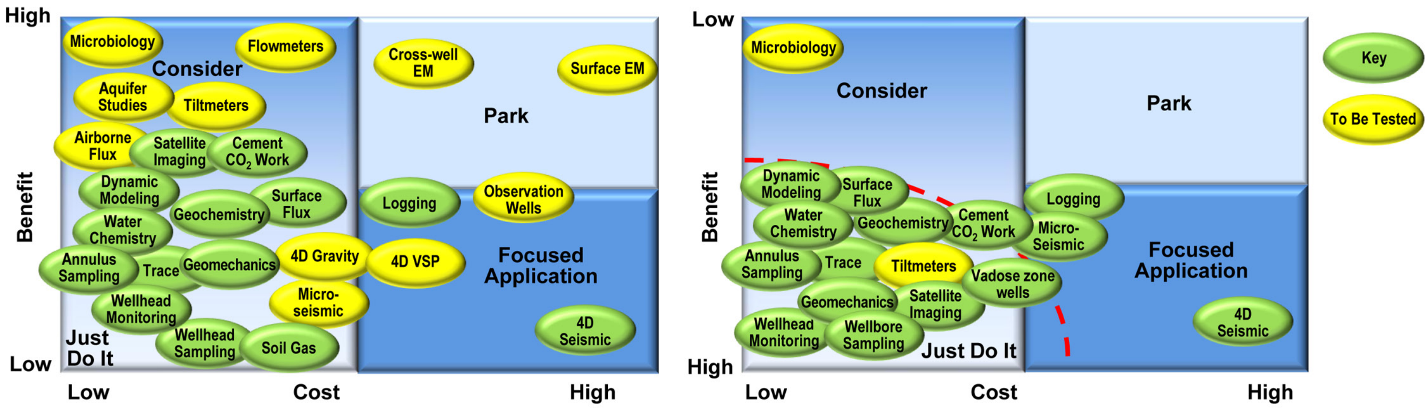


Figure 4: Boston Square Approach for Monitoring Technologies Evaluation at In Salah Before (Left) and After (Right) Their Evaluation. (Wright et al, 2010)

Another ranking methodology, the Boston Square approach, was applied to the In Salah storage project in Krechba, Algeria (Figure 4). In this approach, monitoring techniques are categorized as: (a) Just Do It, (b) Consider, (c) Park, and (d) Focused Application. The effectiveness of each monitoring tool was evaluated prior and subsequent to their deployment (Wright et al., GHGT-10). The red line in Figure 4, (Just Do It, Consider, and Park categories), represents cost-effective tools to satisfy regulatory requirements.

A third example of identification and evaluation of monitoring techniques is the IEAGHG monitoring selection tool (IEAGHG, 2010). The tool identifies suitable monitoring technologies based on site characteristics such as the depth of injection, type, quantity and duration of storage, land use at proposed site, project phase, and various monitoring objectives and targets (e.g., plume, seal, and migration monitoring, release quantification). Each monitoring technique is assigned a score corresponding to each of the selected monitoring aims, ranging from zero (not applicable) to four (strongly recommended).

CCUS monitoring plans can also be designed by identifying risk scenarios of concern and ranking them in a risk matrix (likelihood-severity scale) by semi-quantitative risk assessment methods. In this context, the CarbonWorkflow™ approach involves expert ranking of risks to project success using a common scale. Risks that are ranked above a certain tolerance threshold, and that might be mitigated with additional characterization or monitoring, are designated as monitoring targets and guide the design of the monitoring plan (Hnottavange-Telleen, 2011, personal communication).

A similar approach, used at the Fort Nelson CCUS project, integrated the International Organization for Standardization (ISO) 31000 risk management framework with risk management methods used by the project operator (Botnen et al., GHGT-10) for monitoring design. Failure-mode-and-effects analysis (FMEA) and FEP analysis were used to compile a risk register. Critical risks were identified using flow and release modeling and expert ranking of risk frequency and impacts. Monitoring targets were identified by breakdown of critical risks into causes, failure modes, and consequences. A list of technologies to monitor the critical risks specific to each phase of the project was developed as part of a preliminary MVA plan.

Scenario modeling determines if a particular monitoring technique can identify unexpected behavior of injected CO_2. Hypothetical-release scenarios are defined, revised, and evaluated using FEP analysis and systems modeling to calculate release impacts and changes in monitoring parameters. For example, offshore CO_2 storage site monitoring techniques were evaluated by modeling hypothetical well-, fault-, and caprock-release scenarios (Metcalfe et al., 2011). The hypothetical-release scenario modeling results indicate that reservoir and overburden characteristics strongly affect the choice of suitable monitoring strategies.

3 CO_2 Monitoring Techniques

A wide variety of tools and techniques are available for monitoring CO_2 and potential release risks at GS sites. These include tools designed for monitoring CO_2 and its effects in the atmosphere, in the near-surface region, and in the subsurface. This chapter presents basic information on existing monitoring tools, including a discussion of how each type of tool is used, what it measures, and its advantages and limitations. Examples are provided to illustrate lessons learned from field testing and utilization. Finally, current and ongoing research activities are introduced along with goals for improving existing tools and advancing the state-of-the-art in CO_2 monitoring.

Some CO_2 monitoring tools and techniques are tested and field-ready, while others are still being developed. Technologies such as reflection seismic imaging and well logging, for example, were established and tested by the petroleum industry over many decades, in situations with similarities to CO_2 storage projects. As a result, these methods have been readily adapted to CO_2 storage applications, and they have, in fact, been successfully demonstrated at commercial-scale CO_2 storage projects. Other techniques, such as the use of atmospheric tracers, are still at early stages of development and have been tested only in a laboratory or in pilot-scale field studies. Such tools are likely to become more widespread in the future for CO_2 MVA.

As large volumes of monitoring data are acquired using diverse monitoring approaches, a major challenge has been finding ways to streamline and optimize data processing and data integration. At the end of this chapter is a summary of new techniques and new software developed specifically for optimizing MVA data integration and analysis.

3.1 Monitoring of CO_2 in the Atmosphere

A number of monitoring techniques have been developed in recent years for detecting and quantifying atmospheric CO_2 emissions above injection sites, well heads, and abandoned well sites. These tools are intended to assure that CO_2 from underground storage is not released to the atmosphere. The three most common atmospheric monitoring techniques are: (1) the use of optical CO_2 sensors, (2) tracking of atmospheric tracers, and (3) EC flux measurement techniques (see Table 2).

Each technique listed in Table 2 has its benefits and its challenges. Optical sensors, for example, can provide continuous or intermittent measurement of CO_2 in a localized area, but they are not well-suited to monitoring over large areas. In addition, they are not able to differentiate between CO_2 released from storage and natural variations in ambient CO_2. Atmospheric tracers, while useful as a proxy for CO_2, may require the use of analytical equipment that is not typically available at CO_2 storage sites. The EC technique has the potential to be a powerful tool, because it can provide a time-averaged and spatially averaged data set over a large area. However, data processing is highly complex.

A description of each of these atmospheric monitoring techniques is provided below, along with a summary of lessons learned from the field and an introduction to current and ongoing research.

Table 2: Summary of Atmospheric Monitoring Techniques

Atmospheric Monitoring Techniques	
Monitoring Technique	**Description, Benefits, and Challenges**
Optical CO_2 Sensors	**Description:** Sensors for intermittent or continuous measurement of CO_2 in air. **Benefits:** Sensors can be relatively inexpensive and portable. **Challenges:** Difficult to distinguish release from natural variations in ambient-CO_2 emissions. Difficult to provide continuous measurements over large areas.
Atmospheric Tracers	**Description:** Natural and injected chemical compounds that are monitored in air to help detect CO_2 released to the atmosphere. **Benefits:** Used as a proxy for CO_2, when direct observation of a CO_2 release is not adequate. Also used to track potential CO_2 plumes. **Challenges:** In some cases, analytical equipment is not available onsite, and samples need to be analyzed offsite. Background/baseline levels must be established.
Eddy Covariance	**Description:** Flux measurement technique used to measure atmospheric CO_2 concentrations at a specified height above the ground surface. **Benefits:** Can provide continuous data, averaged over both time and space, over a large area (hundreds of meters to several kilometers). **Challenges:** Specialized equipment and robust data processing are required. Natural spatial and temporal variability in CO_2 flux may mask release signal.

Optical Sensors

Optical CO_2 sensors may be deployed aboveground to monitor release of CO_2 to the atmosphere. For health and safety applications, automated sensors are in some cases deployed to trigger alarms when CO_2 levels exceed a pre-determined safety threshold. Common optical sensors are based on infrared (IR) spectroscopy, cavity ring-down spectroscopy (CRDS), or light detection and ranging (LIDAR). Commercially available CO_2 detectors for health and safety monitoring use non-dispersive infrared (NDIR) spectroscopy. All of these sensors measure absorption of IR radiation along the path of a laser beam. Carbon dioxide concentration is computed based on the degree of absorption of particular wavelengths. Each sensor type differs in its resolution, its response to CO_2, and the level of sample conditioning and data processing required to produce meaningful results. Common problems with optical CO_2 sensors are: (1) cross-sensitivity to other gas species, such as water vapor and methane, and (2) temporal and thermal calibration drift. It may be possible to minimize these problems by collecting spatially separated, geo-referenced CO_2 gas concentration measurements at regular time intervals, using a ground-based or airborne vehicle. A limitation associated with these types of mobile surveys is that they require long-term land access to field sites that may span up to 100 square kilometers.

Lessons Learned from the Field: Optical Sensors

In 2009, optical sensors based on a mobile, open-path IR laser system were deployed at the In Salah CO_2 storage project in Algeria in order to monitor near-ground, atmospheric CO_2 near injection wells (Jones et al., 2010). Carbon dioxide concentrations were measured in the vicinity of two injection wells and in the region between an injection well and a plugged well. No anomalous CO_2 concentrations were detected in these areas. However, the open-path IR sensors were found to be unreliable in dusty, windy conditions. Airborne dust within the laser beam and dust settling on external optical surfaces made it difficult to separate the effects of dust from variations in atmospheric CO_2 content.

In 2006, 2007, and 2008, researchers from Montana State University (MSU) tested an above-ground, laser-based sensor at the Zero Emission Research and Technology Center (ZERT) facility in Montana during repeated controlled CO_2 release experiments (Humphries, 2008). The CO_2 Detection by Differential Absorption (CODDA) instrument uses a tunable distributed feedback laser that can identify water vapor and CO_2 absorption features based on their wavelengths. The sensor was set up for continuous measurement over the release pipe. Measurements made parallel to the release pipe registered a marked increase in CO_2 throughout the controlled release period. The results revealed a cyclic pattern in CO_2 levels at the site, with lower CO_2 during daylight hours and higher CO_2 at night, presumably due to diurnal effects of temperature, wind speed, and photosynthesis.

Optical sensors were also used at the Cooperative Research Centre for Greenhouse Gas Technologies (CO_2CRC) Otway site, in Australia, to monitor CO_2 over a period of more than three years, from 2007 to 2009 (Etheridge et al., 2010). At this site, CRDS- and NDIR-based instruments were deployed prior to injection to establish a baseline, and after injection to monitor potential release downwind of the injection site. No systematic increase in CO_2 was detected. However, CO_2 concentrations exhibited large variations, likely due to strong fluctuations in local ecosystem fluxes.

Researchers also tested a car-mounted CO_2 mini-logger at the Otway site. They concluded that measurements were needed at multiple, spatially separated sites, at different times of day, and during different seasons to establish a baseline that captures the natural fluctuations in the ecosystem CO_2 fluxes (de Vries and Bernardo, 2011). Once this baseline is known, the injected CO_2 component can be discerned. A mini-civil unmanned aerial vehicle (UAV) system was also tested at Otway to measure CO_2 concentrations in flight. Researchers found that such aerial surveys must fly low (approximately 20 m above the ground) to avoid the zone of CO_2 mixing and dispersion that occurs at higher elevations.

Current and Ongoing Research: Optical Sensors

DOE/NETL is currently working to advance the state-of-the-art in laser-based CO_2 sensors. The objective is to produce systems that are lightweight, compact, and readily deployable at GS sites. For example, NETL is providing funding for MSU to develop a compact, eye-safe, scanning differential absorption LIDAR (DIAL) CO_2 sensor. The instrument is designed to measure airborne CO_2 molecules along a horizontal path, using a tunable laser beam and a photo-detector (Figure 5). Airborne-pulsed LIDAR measurements have been used previously to measure aboveground CO_2 (e.g., Abshire et al., 2010), but such instruments weigh up to 190 kg. The DIAL instrument is designed to be lightweight and easily deployed by ground-based vehicles or small aircrafts.

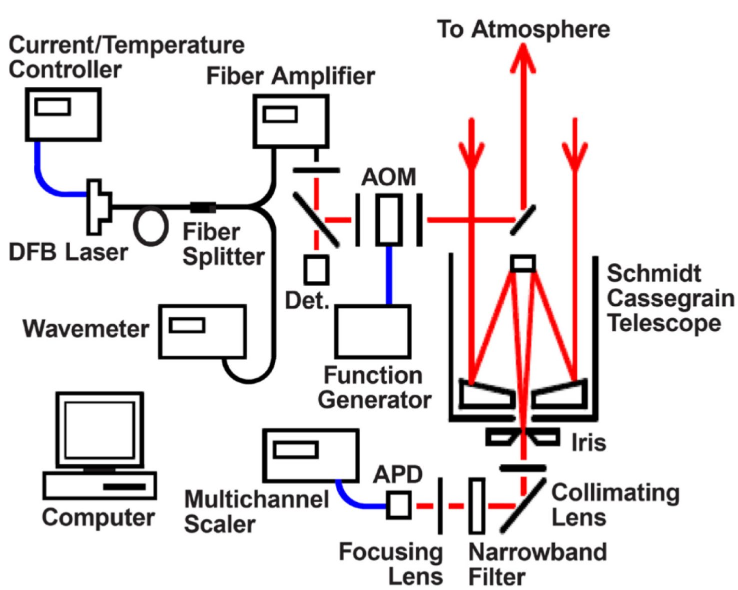


Figure 5: Schematic of the CO_2-DIAL Instrument for Monitoring CO_2 Number Densities.

Atmospheric Tracers

Natural and introduced tracers in the atmosphere can also be used for monitoring possible CO_2 release from GS reservoirs. Natural tracers are chemical compounds that are associated with CO_2 in the subsurface, near-surface, or atmosphere. These include methane (CH_4), radon, noble gases, and isotopes of CO_2. Introduced tracers, such as sulfur hexafluoride (SF_6) and perfluorocarbon tracer (PFT), are chemical compounds that may be injected into a geologic reservoir along with the CO_2 in order to give the injected CO_2 a unique fingerprint that can be recognized in aboveground emissions.

One challenge in using atmospheric tracers is that they may disperse in the air at different rates than CO_2. Certain tracers disperse more quickly than CO_2, which can result in a background buildup of tracer concentrations beyond the extent of the actual CO_2 plume in the air. Such differences in atmospheric dispersion effects between CO_2 and the tracer need to be understood in order to properly interpret atmospheric tracer data.

Lessons Learned from the Field: Atmospheric Tracers

Monitoring of CO_2 using atmospheric tracers was tested at the CO_2CRC Otway project in 2007 and 2009. The goal of the testing was to assess the practical field application of tracer gases, including CH_4, SF_6, and the CO_2 isotope $\delta^{13}CO_2$, for identification of potential CO_2 releases from underground storage during the drilling of an injection well in 2007, and later during a scheduled gas venting experiment in 2009. During the drilling phase of the experiment, researchers collected flask samples of the tracer gases and were able to identify a CO_2 plume, but its isotopic signature indicated it was sourced from the exhaust streams of the drill rig and generators. During the gas venting phase of this experiment, researchers observed marked increases in CH_4 and SF_6 tracers above stable background levels. Carbon dioxide levels were also measured during the venting experiment, but any increase in CO_2 flux was masked by variations in ecosystem-sourced CO_2 and atmospheric dispersion. These results indicate that tracers may play an important role in detecting CO_2 release in cases where ambient CO_2 fluctuations make direct detection problematic.

Flask sampling of tracer gases was also used to investigate unusually high nocturnal-CO_2 concentrations at the Otway monitoring station. Isotopic analyses of the tracer gases, together with flux measurements and air trajectory data, indicated that ecosystem respiration was the likely source of these anomalously high CO_2 levels. This test showed that atmospheric tracer analyses may be used to correctly identify the source of an elevated CO_2 reading that might otherwise be interpreted as a storage release. Additional discussion of tracer measurements and their utility in release detection is provided in the near-surface monitoring techniques section.

In 2010, NETL researchers conducted atmospheric PFT sampling during controlled CO_2 release experiments at the ZERT facility to develop an autonomous monitoring, sampling, and control system for tracer measurements (Pekney et al., 2011). A multi-tube remote sampler (MTRS) system, consisting of carousels of sealed sorbent tubes, was deployed with a mobile-tethered balloon, positioned 1 to 30 m above ground, to sample the PFT co-injected with CO_2. Additionally, wind-vane sampler (WVS) systems were placed 2 and 800 meters from the CO_2 release zone to sample the air at various elevations above ground. Mock-unmanned-aerial system monitoring was also carried out by circling the MTRS system over the CO_2 release zone (Figure 6).

The MTRS and WVS systems were controlled wirelessly by a ground-based transmitter-receiver system to sequentially expose the sorbent tubes and record exact global positioning system (GPS) locations for each sample. The mock-unmanned-aerial system trials yielded good correlation between wind-rose data and measured PFT concentration data. A far-field background-buildup of tracer concentrations was observed at the tower 800 m from the CO_2 release.

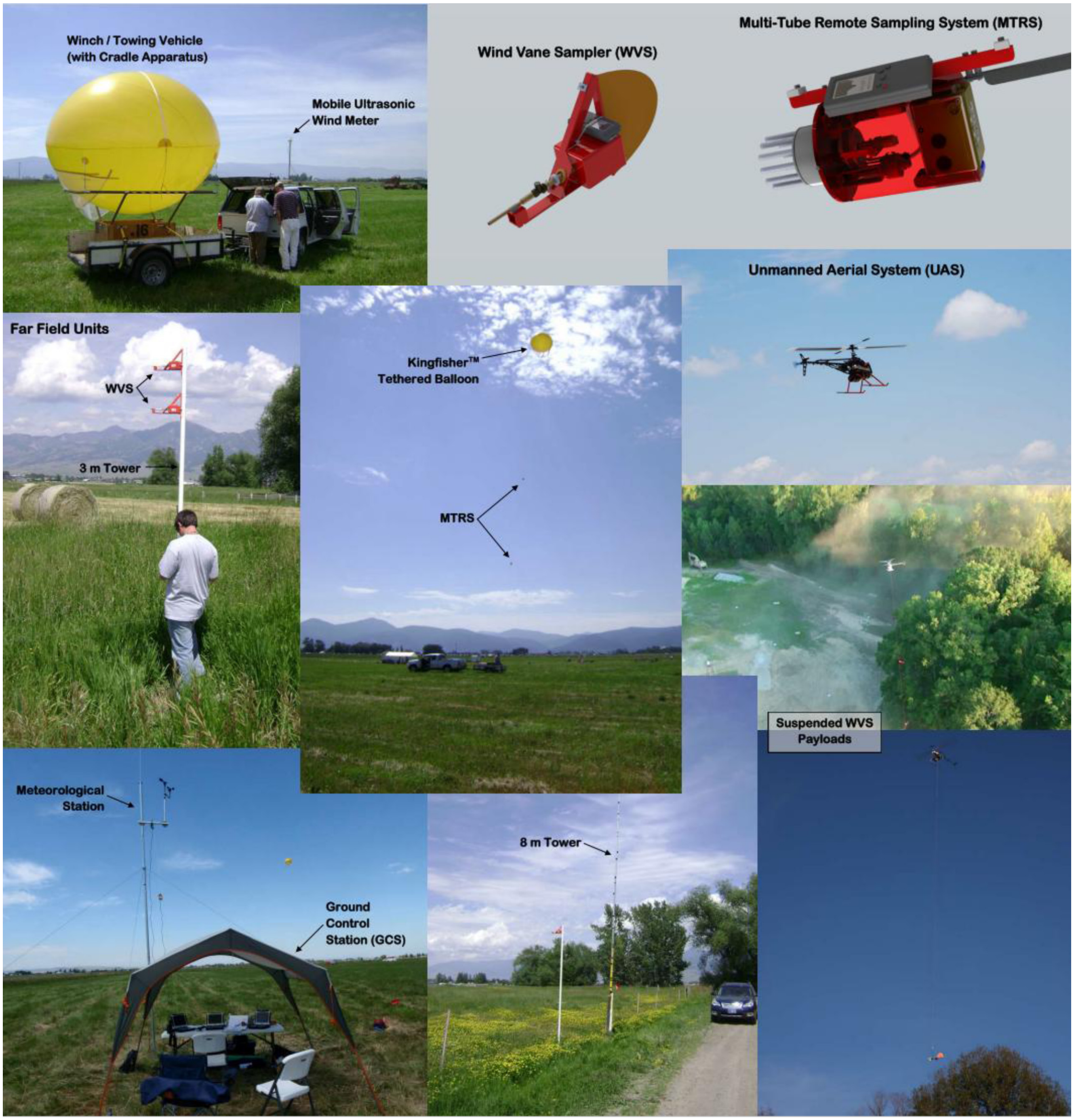


Figure 6: MTRS and WVS Systems for Atmospheric PFT Tracer Monitoring. (Pekney et al., 2011)

Current and Ongoing Research: Atmospheric Tracers

Current research on atmospheric tracers is aimed at developing novel tracer chemicals and tracer detection systems that may serve as an early warning system to signal CO_2 release from GS. Recent studies indicate potential problems with some existing tracer chemicals, including: (1) tracer chemicals that are soluble in petroleum cannot be used as a conservative tracer in oil and gas reservoir settings; and (2) tracers that interact with water or rock may be delayed in their arrival at atmospheric monitoring sites (Watson and Sullivan, 2012). Novel atmospheric tracers and tracer detection systems must overcome these challenges.

Eddy Covariance Technique

The EC technique (also known as eddy correlation and eddy flux) has become a popular tool for evaluating net CO_2 exchange from terrestrial ecosystems to the atmosphere, and in recent years it has been tested for its potential ability to detect CO_2 releases from underground storage reservoirs. Instruments mounted on towers above the land surface are used to measure CO_2 gas concentration, vertical wind speed, relative humidity, and temperature. Carbon dioxide flux is then calculated from these field measurements based on the covariance of CO_2 concentration and instantaneous vertical wind velocity above or below their mean values. Depending on the height of the towers, the resulting CO_2 flux estimates provide a spatial average for an area of up to several square kilometers. Data can be integrated over the time period of interest, which may be several days to a year or more.

The EC technique has some advantages over other atmospheric CO_2 monitoring techniques. The instruments are able to provide continuous measurements over extended time periods, the data can provide a spatial average over a large area, and the environmental impacts of installing the instrument towers are relatively minor. On the other hand, the EC technique requires robust data processing, and natural variability in ecosystem CO_2 fluxes may, in some situations, mask a release signal. As with other CO_2 monitoring techniques, a baseline must be established prior to injection so that the temporal and spatial variability in background CO_2 is known. In addition, EC flux data may be supplemented by soil-gas CO_2 flux data and tracer analyses to enhance release detection capabilities.

Lessons Learned from the Field: Eddy Covariance

An EC flux tower was deployed at the CO_2CRC Otway project in 2007, several months prior to CO_2 injection in 2008. A baseline was established for the site, which showed high background CO_2 concentrations and high natural variability in land-to-air CO_2 fluxes. EC flux data did not show evidence of CO_2 releases during a scheduled CO_2 venting from an observation well, but this may have been due to the high background CO_2 concentrations and high natural variability in ecosystem CO_2 fluxes at Otway. Etheridge et al. (2010) note that dry periods may be the best time to detect CO_2 releases in future tests, because this is when natural variations in CO_2 flux are lowest. Data from the flux tower were also used to model ecosystem CO_2 fluxes and atmospheric dispersion at the Otway site.

Lewicki and Hilley (2009) demonstrated the use of EC measurements and ecosystem-CO_2 exchange models to identify the location and magnitude of surface CO_2 releases at the ZERT facility (Figure 7). During the controlled release experiment in 2008, CO_2 fluxes were measured over a period of 29 days using the EC technique. Carbon dioxide flux from the controlled release was isolated by subtracting the fluxes corresponding to a model for net-CO_2 exchange. A least-squares inversion of the measured CO_2 fluxes and the corresponding modeled footprint functions recovered the location, length, and magnitude of the surface CO_2 flux release signal. EC measurements were found to be useful at the ZERT facility for non-invasive detection of CO_2 releases.

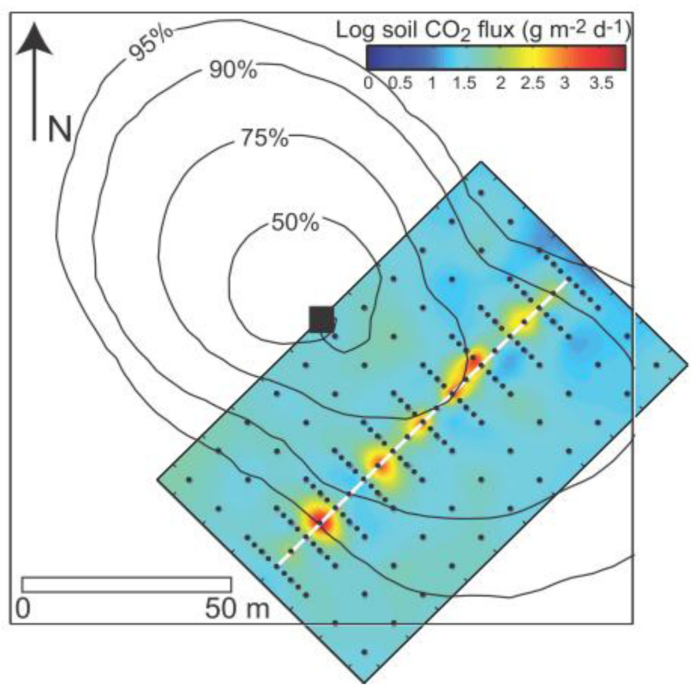


Figure 7: Map of Log Soil CO_2 Flux, Interpolated Based on Measurements Made at the Black Dots on July 25, 2008. (Lewicki & Hilley, 2009)

(The white line and black square show locations of surface trace of CO_2 release well and EC station, respectively. Mean EC flux 50, 75, 90, and 95 percent source area isopleths are shown for the CO_2 release time.)

Current and Ongoing Research: Eddy Covariance

EC has the potential to provide automated CO_2 flux measurements over large areas. Current research in EC techniques is aimed at obtaining quantifiable CO_2 emissions values from EC flux data. Lewicki et al. (2011) are conducting inverse modeling, based on EC flux data and soil-CO_2 flux measurements, to simulate land-to-air CO_2 flux and release rates for potential use at CCUS sites. Preliminary testing of the technique at Mammoth Mountain in California showed moderate to good agreement between land-to-air CO_2 flux rates predicted by the model and observed EC and soil-CO_2 flux measurements.

3.2 Near-Surface Monitoring Techniques

This section provides a summary of near-surface monitoring techniques, including geochemical monitoring in the soil and vadose zone, geochemical monitoring of near-surface groundwater, surface displacement monitoring, and ecosystem stress monitoring. The purpose of these monitoring approaches is to detect near-surface manifestations of CO_2 released from GS. Each near-surface monitoring technique is summarized in Table 3 and discussed in greater detail below.

Table 3: Summary of Near-Surface Monitoring Techniques

Near-Surface Monitoring	
Monitoring Technique	**Description, Benefits, and Challenges**
Geochemical Monitoring in the Soil and Vadose Zone	DESCRIPTION: Sampling of soil gas for CO_2, natural chemical tracers, and introduced tracers. Measurements are made with sensors inserted into the soil and/or with opaque flux accumulation chambers placed on the soil surface. BENEFITS: Soil-gas measurements detect elevated CO_2 concentrations above background levels and provide indications of releases. Tracers aid in identification of native vs. injected CO_2. Opaque flux chambers can quickly and accurately measure local CO_2 fluxes from soil to air. CHALLENGES: Significant effort for null result. Relatively late detection of release. Considerable effort is required to avoid cross-contamination of tracer samples. Flux chambers provide measurements for a limited area.
Geochemical Monitoring of Shallow Groundwater	DESCRIPTION: Geochemical sampling of shallow groundwater above CO_2 injection zone to demonstrate integrity of freshwater formations. Chemical analyses may include pH, alkalinity, electrical conductivity, carbon, hydrogen, oxygen, and tracers. BENEFITS: Mature technology, samples collected with shallow monitoring wells. Early detection may be possible. CHALLENGES: Significant effort for null result. Carbon isotopes are difficult to interpret due to complex dynamics of carbonate dissolution in shallow formations.
Surface Displacement Monitoring **(Includes Remote Sensing)**	DESCRIPTION: Monitor surface deformation caused by reservoir pressure changes associated with CO_2 injection. Measurements made with satellite-based radar (SAR/InSAR) and surface- and subsurface-based tiltmeters and GPS instruments. Data allow modeling of injection-induced fracturing and volumetric change in the reservoir. BENEFITS: Highly precise measurements over a large area (100 km x 100 km) can be used to track pressure changes in the subsurface associated with plume migration. Tiltmeter technology is mature, and has been used successfully for monitoring steam/water injection and hydraulic fracturing in oil and gas fields. GPS measurements complement InSAR and tiltmeter data. CHALLENGES: InSAR methods work well in locations with level terrain, minimal vegetation, and minimal land use, but must be modified for complex terrain/varied conditions. Tiltmeters and GPS measurements require surface/subsurface access and remote data collection.
Ecosystem Stress Monitoring **(Includes Remote Sensing)**	DESCRIPTION: Satellite imagery, aerial photography, and spectral imagery are used to measure vegetative stress resulting from elevated CO_2 in soil or air. BENEFITS: Imaging techniques can cover large areas. Vegetative stress is proportional to soil CO_2 levels and proximity to CO_2 release. CHALLENGES: Detection only possible after sustained CO_2 emissions have occurred. Shorter duration release may not be detectable. Natural variations in site conditions make it difficult to establish reliable baseline. Changes not related to CO_2 release can lead to false positives.

Geochemical monitoring in the soil and vadose zone involves direct sampling of CO_2 and its reaction products, as well as sampling for tracers that were injected into underground storage along with the CO_2. Geochemical monitoring of near-surface groundwater involves installation of shallow monitoring wells for measuring potential changes in groundwater chemistry related to CO_2 injection. Such geochemical sampling techniques provide valuable direct measurements of CO_2 and associated tracers, but characterizing a large area requires many individual data collection points.

Surface displacement measurements are designed to detect uplift of the land surface that may have been caused by CO_2 injection, and ecosystem stress monitoring is aimed at mapping vegetative stress that may have resulted from elevated CO_2 levels near the soil/atmosphere interface. Remote sensing data can provide highly precise surface displacement measurements and indications of vegetative stress over a large area. However, the data are difficult to interpret where site conditions are complex.

Geochemical Monitoring in the Soil and Vadose Zone

Geochemical monitoring in the soil and vadose zone, which extends from the top of the land surface down to the water table, includes measurement of CO_2, natural tracers, and introduced tracers. First, a pre-injection baseline of soil-gas concentrations is established. Post-injection measurements are then used to detect soil-gas increases that could be related to CO_2 release from GS.

Soil-gas sampling is carried out using soil-gas sensors and capillary adsorbent tubes inserted in the upper 10 m or so of the soil zone and with opaque flux accumulation chambers placed at discrete locations on the ground. Gas concentrations and the isotopic composition of the captured gas are measured using infrared gas analyzers (IRGAs), gas chromatography, and/or mass spectrometry.

Flux accumulation chambers consist of an opaque, open-bottom chamber placed on the soil surface and designed to collect gas emanating from soil pores. Monitoring a large area requires installation of flux accumulation chambers at multiple sampling locations. Captured soil gas is circulated through the accumulation chamber to an IRGA, and the rate of change of CO_2 concentration within the chamber is used to calculate the local flux of CO_2 from land to air.

Natural chemical tracers – including isotopes of carbon, oxygen, hydrogen, nitrogen, and sulfur, as well as noble gases helium, krypton, neon, and argon – may be measured to differentiate between native CO_2 and injected CO_2. In some cases, the isotopic composition of the injected CO_2 may be readily identifiable and therefore attributable to possible migration. In other cases, further analysis of the isotopic ratios in the collected soil gas is needed to distinguish injected CO_2 from native CO_2.

Carbon dioxide monitoring of soil gas may also include measurement of introduced tracer chemicals, such as PFTs. Introduced tracers may be injected with the CO_2 and then monitored in the soil gas. The occurrence of some tracer chemicals is so low in natural systems that detection and attribution can be achieved at a parts-per-billion resolution level. Tracer and isotope sampling may be conducted in conjunction with near-surface soil-gas analyses, or as a separate component of near-surface monitoring activities.

Lessons Learned from the Field: Geochemical Monitoring in the Soil and Vadose Zone

The Southeast Regional Carbon Sequestration Partnership (SECARB) High-Volume Injection Test (HiVIT) was initiated in 2008 in the depleted Cranfield Oilfield of western Mississippi. Researchers installed a semi-permanent soil-gas well to collect gas samples from depths of 5 to 15 feet to test for possible CO_2 release related to injection. Carbon dioxide, CH_4, oxygen (O_2), and nitrogen (N_2) were measured in real-time using a gas chromatograph; stable isotopes, noble gases, light hydrocarbons, and tracer gases (including PFTs and SF_6) were also analyzed. The results indicated that CH_4 in the soil was likely from a native, thermogenic source, and that the CO_2 was generated by microbial oxidation of the CH_4 (Romanak et al., 2010a). The study demonstrated that hydrocarbons and stable isotopes may be useful for tracking migration of fluids from deep reservoirs to the soil and vadose zone, and for distinguishing native gases from injected gases.

The Midwest Geological Sequestration Consortium (MGSC) Sugar Creek CO_2-EOR injection pilot was initiated in the Sugar Creek Oilfield, in Kentucky, in 2009, and soil CO_2 monitoring was put into place to test the extent of an actual, unplanned release. The release was visually sighted and appeared to emanate from a pipeline buried at a depth of approximately 1 m below ground. Soil CO_2 flux measurements were made with an array of accumulation chambers spread out on a radial grid centered on the surface expression of the release. Soil CO_2 flux data clearly registered release from the pipeline; however, CO_2 concentrations exceeded the operating ranges of the monitoring instruments, which complicated the quantification of CO_2 flux (Wimmer et al., 2010).

Soil-gas measurements have also been carried out as part of the IEAGHG Weyburn CO_2 Monitoring and Storage Project in Saskatchewan, Canada, where CO_2 injection began in 2000 and continues to the present day. Researchers measured CO_2 and radon concentrations, CO_2 flux, and $CH_4/(C_2H_6+C_3H_8)$ ratios above the injection site using a steel probe, IR gas analyzer, and laboratory analysis of collected gas samples (Riding and Rochelle, 2005). All soil-gas measurements were found to be in the normal range for the site, and no evidence was found for escape of injected CO_2 from the storage reservoir.

Soil-gas concentrations were measured as part of a monitoring program at the In Salah storage project in 2004 and 2009 (Jones et al., 2010). In-situ gas concentrations (CO_2, CH_4, O_2, carbon monoxide [CO], and hydrogen sulfide [H_2S]) were measured using a soil-gas probe and electrochemical or IR detectors, and CO_2 fluxes were measured with accumulation chambers. Slightly elevated levels of CO_2 flux and concentration, suggesting a release, were observed near one of the observation wells. That release was confirmed by direct observation of CO_2 emanating out of the wellbore, and the well was subsequently sealed and abandoned.

An underground, laser-based CO_2 monitoring instrument was tested at the ZERT facility, in Montana, during the 30-day controlled CO_2 release experiment that took place in 2008 (Barr et al., 2011). The instrument is comprised of fiber-optic cables that deliver laser output to three underground sensors. Carbon dioxide enters the sensors via gas permeable membranes, and each sensor transmits a spectrum of wavelengths measured; the transmission spectra are then used to calculate CO_2 concentrations. During the ZERT controlled release experiment, this instrument measured a marked increase in CO_2 concentration after initiation of CO_2 injection. Researchers found that it took approximately 40 hours for the injected CO_2 to spread 1 meter laterally from the release pipe.

Also at the ZERT facility, small amounts of tracer-spiked CO_2 were injected just below the soil zone, via vertical and horizontal wells (NETL website). Surface CO_2 flux and tracer measurements were obtained, using capillary adsorbent tube sampling and gas chromatographic analysis, to track the movement of the CO_2 in the shallow subsurface. The results provided valuable constraints for modeling CO_2 movement in the soil and vadose zone at ZERT.

Soil-CO_2 concentrations were measured at the CO_2CRC Otway project, using a direct-push soil-gas probe and laboratory analysis of the collected gases (Schacht et al., 2010). Soil-CO_2 concentrations varied over three orders of magnitude during the initial baseline and subsequent assurance monitoring surveys. A combination of CO_2 and helium (He) concentrations, as well as carbon isotope analyses, was used to determine that the source of soil-CO_2 fluctuations was natural decomposition of organic matter at the site. This was confirmed by radiocarbon dating of selected samples.

Current and Ongoing Research: Geochemical Monitoring in the Soil and Vadose Zone

DOE/NETL is currently sponsoring research efforts to develop cost-effective, field-deployable soil-CO_2 monitoring technologies for identifying release of injected CO_2 from the soil and vadose zone. Examples include non-destructive soil-carbon analyzers; new instruments for measuring tracers and isotopes; and scalable, low-cost fiber-optic arrays.

Brookhaven National Laboratory (BNL) is developing a unique instrument for non-invasive, in-situ, quantitative soil analysis of carbon and other elements in a variety of conditions. The instrument is based on gamma-ray spectroscopy, in which fast neutrons undergo inelastic neutron scattering (INS) and thermal neutron capture by interacting with soil elements. The INS system yielded reliable results when compared with standard soil-CO_2 measurement techniques. The INS system is capable of time-lapse or continuous monitoring of soil carbon over large areas.

In another study, NETL is partnering with the University of Wyoming to conduct a systematic survey of discrete radon isotope and CO_2 flux measurements in soil gases at field sites to identify deep-CO_2 flows and areas of fast soil-gas transport. NETL is also supporting researchers at the University of Miami who plan to use portable CRDS to analyze the concentration and carbon isotope ratios in soil-gas and air samples using fixed or vehicle-installed spectrometers. The results will be used to assess CO_2 concentrations and isotopic variations at a CO_2 injection site.

In addition, NETL is partnering with Planetary Emissions Management, Inc. (PEM) and others to develop and test a novel, field-ready carbon isotope analyzer for near-surface release monitoring (NETL website)[2]. This is a significant advance over current techniques for radiocarbon analysis, such as accelerator mass spectrometry, which require specialized facilities and are not field-deployable. The PEM analyzer has the capability to measure isotopic ratios on site. A spatial array of such analyzers could be an effective means of monitoring and verifying release of injected fossil fuel CO_2.

Soil-CO_2 flux measurements and vadose-zone gas monitoring are also components of the monitoring program in MGSC's Illinois Basin Decatur Project (IBDP). Researchers at MSU are developing a low-cost, fiber-optic sensor array for CO_2 detection in the near-subsurface. Monitoring soil-CO_2 over a large area currently involves using networks of solid-state IR sensors. The fiber-optic sensor arrays being developed at MSU are easily deployed over large surface areas for soil-CO_2 detection (Figure 8).

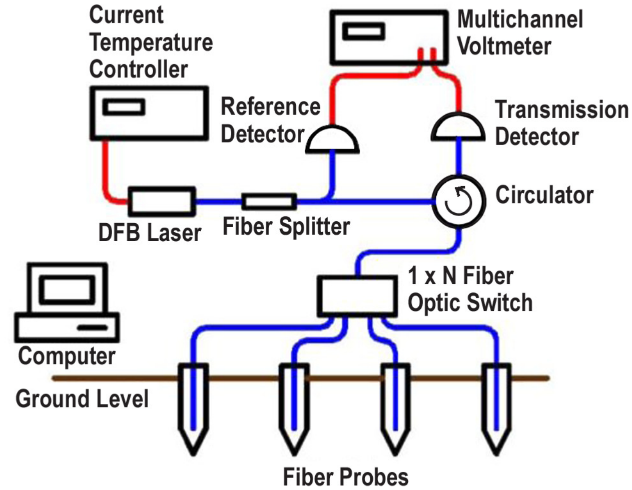


Figure 8: Schematic of a Proposed 1 x 4 Fiber Sensor Array for Soil-CO_2 Detection. (Repasky et al., 2012)

Geochemical Monitoring of Shallow Groundwater

Geochemical monitoring of shallow groundwater is carried out for purposes similar to near-surface soil-gas sampling – to provide assurance that injected CO_2 has not been released to near-surface formations. Shallow groundwater sampling is designed to demonstrate the integrity of freshwater formations that overlie the CO_2 injection zone. The interaction of CO_2 with shallow groundwater may lead to mobilization of reactive and hazardous metal cations, a decrease in pH and alkalinity, and elevated electrical conductivity.

Typical shallow groundwater monitoring wells are less than 100 meters deep, though deeper wells may be required in locations where potable water sources occur at greater depths. Geochemical measurements may include pH, alkalinity (both lowered by dissolution of CO_2), electrical conductivity, and various cation (e.g., Na^+, Ca^{2+}, Mg^{2+}, Fe^{2+}, Fe^{3+}) and anion (e.g., HCO_3^-, CO_3^{2-}, Cl^-, SO_4^{2-}) compositions. In addition, C, H, and O isotopic analyses may be carried out, dissolved inorganic carbon may be measured, and other anion and tracer analyses may be conducted.

[2] http://www.netl.doe.gov/publications/factsheets/project/Project666.pdf.

Lessons Learned from the Field: Geochemical Monitoring of Shallow Groundwater

Shallow groundwater monitoring conducted at the Scurry Area Canyon Reef Operators Committee (SACROC) oilfield in Texas, where CO_2-EOR has been conducted for more than 35 years, indicates that carbon isotopes may have limited use for identifying the source of CO_2 in shallow groundwater systems (Romanak et al., 2010b). A site-specific context is necessary to understand the complex dynamics of carbonate dissolution in shallow groundwater formations. Influential factors may include mixing of groundwater with underlying saline waters, leaching of historically produced brine and other liquids into freshwater formations from unlined surface pits, temporal geochemical variations related to pumping and local irrigation practices, and site-specific geochemical reactions that affect shallow groundwater chemistry (Romanak et al., 2008).

Shallow groundwater monitoring at the CO_2CRC Otway site was initiated in June 2006, nearly two years prior to the onset of CO_2 injection at the site. A baseline was established by monitoring seasonal water levels and bi-annual groundwater chemistry in a shallow formation that lies approximately 2,000 meters above the CO_2 injection reservoir (Hortle et al., 2010). Pre-injection baseline measurements, when compared with injection and post-injection monitoring results, indicate no significant fluctuations in the shallow formation chemistry as a result of CO_2 injection.

Multiple shallow groundwater sampling programs have been conducted as part of the IEAGHG Weyburn-Midale CO_2 storage and monitoring project to test the integrity of the Weyburn CO_2 storage reservoir over time (Rostron and Whittaker, 2010). Water chemistry data have been collected from shallow groundwater monitoring wells since 2000, when CO_2 injection began. The results indicate that the background shallow water chemistry is highly variable, with dissolved solids ranging from 300 to 2,000 mg/L. However, no significant, long-term increase in CO_2 or HCO_3 has been detected in over the 12-year sampling period.

Groundwater monitoring was conducted during the 2008 CO_2 release detection testing at the ZERT field site in Montana. Carbon dioxide was injected through perforated pipe buried approximately 2 m below the surface for a one-month period during the summer of 2008. Water samples were collected from 10 monitoring wells installed 1 to 6 m from the injection pipe (Kharaka et al., 2009, Apps et al., 2010). A decrease in pH, increase in total alkalinity, increase in electrical conductance, and major increases in calcium (Ca), iron (Fe), magnesium (Mg), and manganese (Mn) were observed following CO_2 injection (Figure 9).

Current and Ongoing Projects: Geochemical Monitoring of Shallow Groundwater

Current research on shallow groundwater monitoring is aimed at using chemical parameters as indicators for CO_2 release into overlying formations. Developing such techniques is essential for meeting U.S. Environmental Protection Agency (EPA) monitoring requirements and gaining broader public acceptance of GS of CO_2. Little and Jackson (2010) indicated that Mn, Fe, and Ca levels and pH could be used as markers for CO_2 releases into near-surface formations.

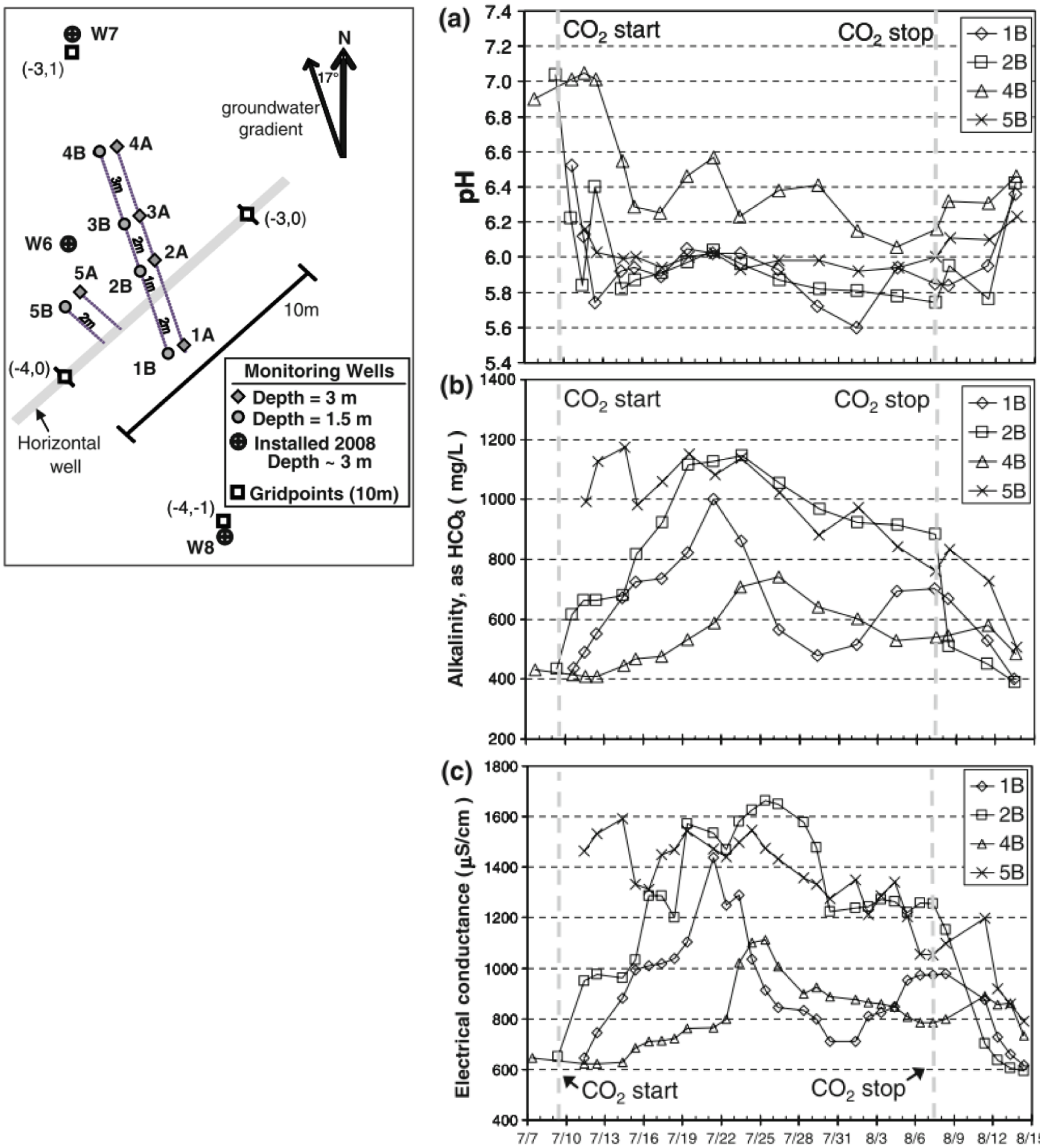


Figure 9: Groundwater pH, Alkalinity, and Electrical Conductance Values Measured at the ZERT Site; Monitoring Well Configuration is Also Shown. (Kharaka et al., 2009)

Surface Displacement Monitoring

Injection of CO_2 into a geologic formation causes an increase in the pressure within the reservoir, which may result in small displacements of the ground surface above the reservoir. Highly precise surface displacement measurements, including data acquired with Interferometric Synthetic Aperture Radar (InSAR), tiltmeters, and global navigation satellite systems (GNSS), can be used to monitor this deformation. Surface displacement data can be inverted to show the areal distribution, or footprint, of pressure changes in the subsurface. This footprint includes the CO_2 plume plus a region in the brine beyond the plume where pressures have been changed due to injection operations. Detailed analysis of surface displacement data can be used to determine if CO_2 is migrating through existing fractures. Analysis of surface deformation data is optimized by use of a geomechanical model, which has the ability to correlate surface displacements with CO_2 injection and movement in the storage reservoir.

SAR/InSAR: This satellite-based technique measures millimeter-scale displacements of the Earth's surface by recording microwaves as they are reflected off of permanent, solid features on the ground. The amount of surface displacement due to CO_2 injection is typically small; uplift related to CO_2 injection at the In Salah storage site, for example, is approximately 3 to 5 mm per year. Large areas, up to 10,000 km^2, can be imaged in a time-lapse manner to evaluate surface displacement occurring over a given time period. The frequency of the time-lapse monitoring depends on how often the satellite passes over the area of interest; Permanent Scatterer InSAR (PSInSAR) has an accuracy of up to 1 mm/year for long-term monitoring (Ringrose et al., 2009). InSAR methods work well in locations with level terrain, minimal vegetation, and minimal land use, and require adaptive techniques, such as the installation of permanent reflectors, when these conditions are not met.

Tiltmeters: A tiltmeter is an instrument that operates like a carpenter's level and is able to measure extremely small (one part in a billion) changes in strain, either at the Earth's surface or at depth. Tiltmeters are commonly deployed to monitor oil field operations, including water flooding, CO_2 flooding, and hydraulic fracturing. Measurements are typically collected remotely via radio or satellite. A widespread array of tiltmeters may be required to accurately measure surface deformation associated with CO_2 injection and movement in the subsurface.

GNSS: GNSS allows the precise determination of a location anywhere on or above the Earth's surface. Both the U.S. GPS and the Russian Global Navigation Satellite System (GLONASS) are currently available for commercial applications. Efficient receivers, combined with enhanced signal processing techniques, allow remote, continuous operation of GPS stations with accuracies of 1.5 mm or less. A Surface Tilt Monitoring (STM) array can measure relative changes in elevation with sub-millimeter accuracy over a large area, whereas high-precision GPS measurements provide absolute elevation changes with millimeter-scale accuracy for the region of interest. GPS measurements are typically employed to complement long-term tiltmeter and InSAR monitoring surveys.

Surface deformation monitoring techniques require permitting and site access for equipment installation in the field (Hamling et al., 2011). Shallow boreholes are required for installation of tiltmeters, InSAR corner reflectors, and GPS instruments. The long-term reliability of tiltmeters can be affected by drift, which can be mitigated by calibration to other displacement measurements and advanced data processing methods.

Lessons Learned from the Field: Surface Displacement Monitoring

InSAR, tiltmeter, and GPS measurements were utilized to monitor surface displacement associated with plume migration, caprock integrity, and changes in reservoir pressure at the In Salah storage site during and after CO_2 injection (Figure 10). PSInSAR monitoring revealed surface uplift over all three CO_2 injection wells, with corresponding subsidence observed in the gas production area (Ringrose et al., 2009. Forward- and inverse-geomechanical modeling (Rutqvist et al., 2010) indicated that the surface uplift pattern was consistent with upward propagation of subsurface reservoir pressures. The surface displacement pattern provided an indirect image of the CO_2 plume migrating through an existing fracture network, as anticipated. InSAR data collected in 2006 and 2007 suggested that CO_2 was migrating quickly in the direction of an unplugged, abandoned well, which was subsequently plugged and decommissioned. Rutqvist et al. (2010) note that relatively hard sediments and bare rock at the project site contributed to the success of the InSAR method at In Salah.

From 2008 to 2009, GPS and tiltmeter stations were used to monitor possible surface deformation caused by CO_2 injection at the Southwest Regional Partnership on Carbon Sequestration's (SWP) San Juan Basin CO_2-enhanced coalbed methane (ECBM) Phase II pilot in New Mexico (ARI, 2010). Surface tiltmeters were installed in shallow boreholes (40 feet deep) eight weeks prior to the start of CO_2 injection in order to establish a regional baseline (Figure 11). Two GPS stations were integrated with an STM array to constrain absolute changes in elevation and confirm long-term deformation measurements. GPS data, collected continuously, indicated no significant cumulative change in elevation during the injection

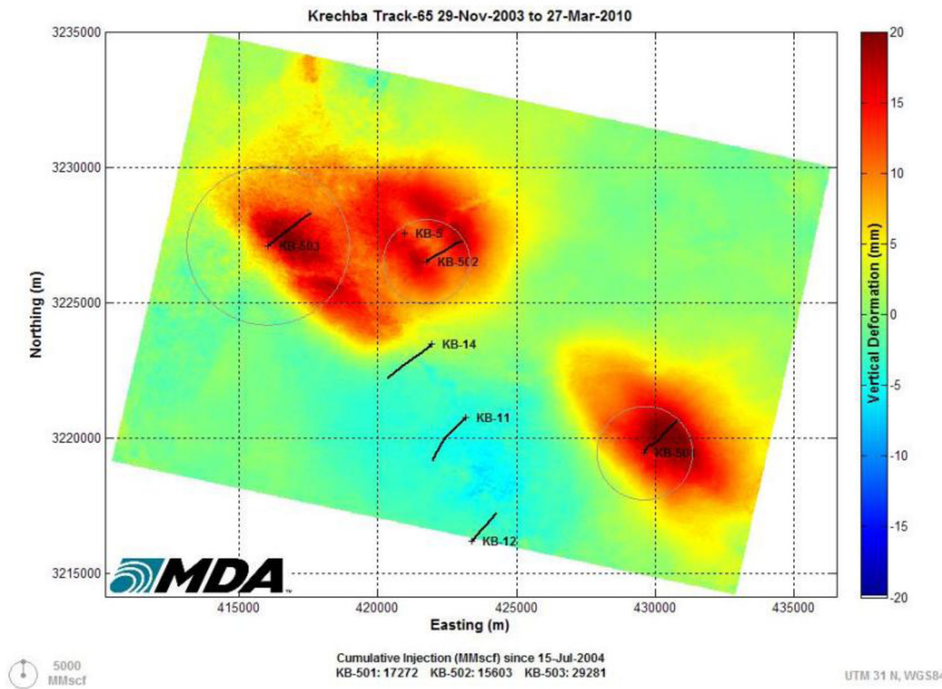


Figure 10: Satellite Image of Cumulative Surface Deformation at Krechba (In Salah) Due to CO_2 Injection. (Mathieson et al., 2010)

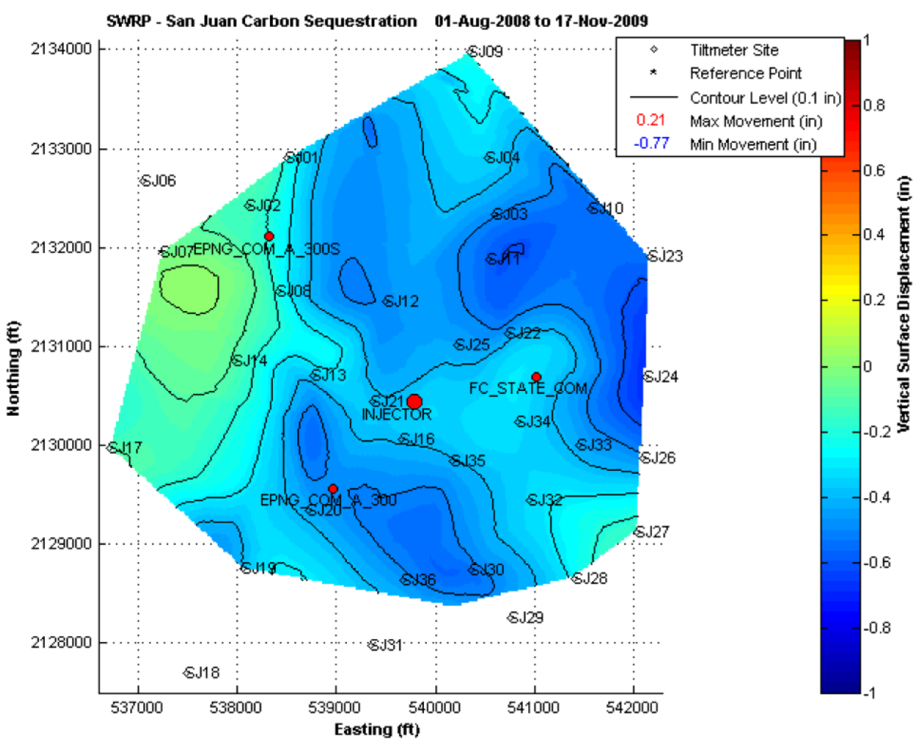


Figure 11: Cumulative Surface Deformation at the SWP Pump Canyon Phase II Injection Site from August 1, 2008, to November 17, 2009, Indicating Net Subsidence in the Field. (Advanced Resources International, Inc., 2010)

period. STM data indicated net subsidence, likely caused by production in nearby wells, which exceeded the volume of CO_2 injected. Surface uplift measured during the post-injection monitoring phase (October to November 2009) was limited to the periphery of the STM array. Surface tilt measurements were used, via inverse modeling, to compute the volumetric strain in the reservoir.

Current and Ongoing Research: Surface Displacement Monitoring

Current research goals for surface displacement monitoring include verifying caprock integrity and measuring changes in reservoir pressure during and after CO_2 injection. Several of the National Laboratories have planned surface displacement monitoring projects at existing CO_2 injection sites. Lawrence Berkeley National Laboratory (LBNL) is planning to utilize 3-D InSAR and SqueeSAR for surface displacement monitoring at the In Salah CO_2 injection site. In addition, Lawrence Livermore National Laboratory (LLNL) is planning to use InSAR measurements to track mechanical deformation associated with CO_2 injection at Snøhvit.

PSInSAR is also being employed at the MGSC Decatur project. An InSAR survey was acquired for the central Illinois Decatur site during the spring of 2010, and current activities include the use of an array of engineered reflectors to optimize displacement signal detection in a vegetated environment. This is the first attempt to use InSAR to monitor CO_2 injection at a vegetated site with variable land uses.

Ecosystem Stress Monitoring

Plants are susceptible to stress caused by elevated levels of CO_2 in the soil, and measurements of vegetative stress can be used as an independent indicator of possible CO_2 release from the subsurface. Vegetative stress can be measured by aerial photography, satellite imagery, and spectral imagery. Initial surveys are required to establish baseline conditions, including seasonal changes that take place at a particular site, as well as natural variations in temperature, humidity, and light and nutrient availability at the site. Once the baseline is established, anomalous vegetative stress may be observed.

Hyperspectral imaging collects and processes radiation across a broad portion of the electromagnetic (EM) spectrum, typically including wavelengths from 400 to 900 nanometers. This includes the high absorbance region in the visible spectrum associated with chlorophyll absorbance, and high reflectance in the near-IR region that is typical of spongy leaf tissues. Spectral imaging has the ability to detect changes in light reflectance and absorption that occur in vegetation that is struggling. Multispectral imaging may be simpler and less costly, and it affords continuous daytime operation in both clear and cloudy weather (Rouse et al., 2010). Whereas hyperspectral imaging collects a continuous spectrum of wavelengths, multispectral imaging collects discrete spectral bands. Spectral imaging sensors may be airborne, satellite-mounted, or handheld.

Lessons Learned from the Field: Ecosystem Stress Monitoring

Pickles and Cover (2005) proposed the use of satellite- or airborne-based spectral imaging to assess vegetative stress over a large area. Remote sensing techniques were tested in central Italy in 2005 to detect CO_2 emanating from natural seeps at the Latera caldera (Bateson et al., 2008). Hyperspectral imaging, multispectral imaging, LIDAR, orthophoto, and high-resolution photographic data were all acquired during two airborne surveys over an area with known CO_2 gas venting. These imaging methods were successful in locating some, but not all of the major gas vents. The researchers concluded that different remote sensing techniques work best in different conditions, depending on the amount of vegetation and steepness of topography at the site, and depending on the season and time of day during which the data are collected. In all cases, complementary soil-gas geochemical data were required to interpret the remote sensing results in terms of CO_2 concentrations and flux rates.

Researchers at the MGSC Phase II Sugar Creek site in Kentucky tested several monitoring techniques, including aerial hyperspectral imaging, during a real, short-duration CO_2 release from a buried pipeline (Wimmer et al., 2010). Hyperspectral imaging was found to be ineffective at locating the release; longer duration releases may be more readily identified by hyperspectral methods because of cumulative effects of CO_2 on vegetation.

DOE's Core R&D Program carried out a controlled release experiment at the Naval Petroleum Reserve Site #3 in Wyoming in 2006. Aerial hyperspectral imagery was acquired using Moderate Resolution Imaging Spectroradiometer/Advanced Spaceborne Thermal Emission Reflection Radiometer (MASTER) technology. Data analysis demonstrated that MASTER could identify major CO_2 and CH_4 surface seeps.

Spectral imaging was also used to detect vegetative stress related to CO_2 release at the ZERT facility in Montana. Pure CO_2 gas was released at a flow rate of 300 kg/day for 29 days from a 100-m long horizontal injection well buried 1 to 2.5 m underground. The vegetation at the ZERT site began to show visible signs of stress within four days of CO_2 injection, with various plant species responding differently to CO_2 stress (Male et al., 2010). Vegetative stress was detectable with field spectrometers and airborne-based hyperspectral imaging, and a correlation was found between the degree of spectral reflectance measured from vegetation and the concentration of soil CO_2 measured in the vicinity of the release well (Figure 12). Similar results were obtained when a platform-mounted multispectral imager was used to detect changes in reflectance spectra of vegetation (Rouse et al., 2010). In addition, the time-dependent band reflectance values and the normalized difference vegetation index, a measure of the extent of healthy vegetation, showed a significant correlation with the proximity to the CO_2 well. In summary, sustained releases of significant CO_2 flux are detectable with hyperspectral and multispectral imaging techniques, and the vegetative stress indicators have been found to be proportional to soil CO_2 levels and proximity to the CO_2 release.

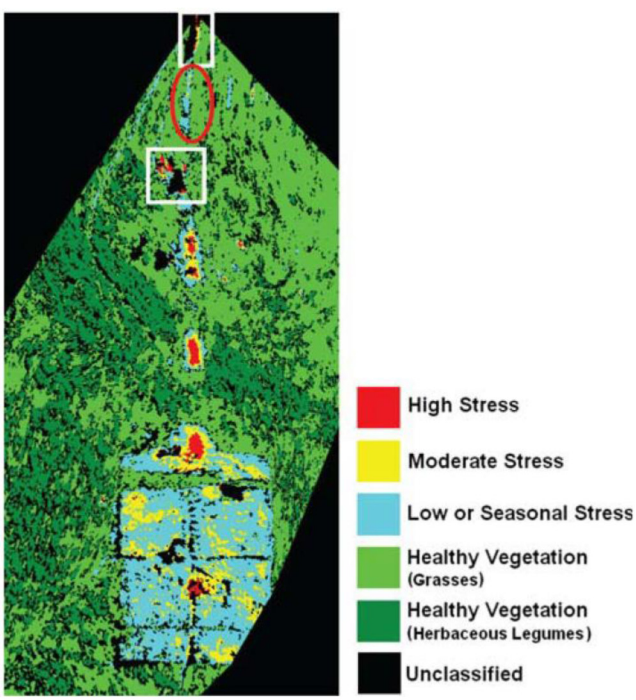


Figure 12: Aerial Hyperspectral Imagery Collected at the ZERT Facility 27 Days After CO_2 Injection, 2008. (Male et al., 2010)

Current and Ongoing Research: Ecosystem Stress Monitoring

Current research in ecosystem stress monitoring is aimed at developing improved satellite- and aircraft-based imaging techniques for detection of vegetative stress; tailoring existing ecosystem stress imaging approaches to handle a wide variety of site conditions; calibrating vegetative stress imagery to quantitative soil-gas data; and reducing the cost of data acquisition and processing. Researchers at MSU continue work to develop a low-cost system for multispectral vegetation imaging and detection of CO_2 gas release (Hogan et al., 2012).

3.3 Subsurface Monitoring

Subsurface monitoring is a key element of CO_2 storage programs. The objectives are to track the movement of an injected CO_2 plume in a deep geologic formation; to define the lateral extent and boundaries of the plume; to track associated pressure changes in the reservoir; and to demonstrate long-term stability of the CO_2 plume. Most techniques and tools used for subsurface monitoring are also used to characterize the geologic framework and rock and fluid properties of the storage reservoir.

Deep subsurface monitoring is carried out using an extensive range of tools, including well logging tools, wellbore monitoring tools, subsurface fluid sampling and tracer analysis, seismic methods, and gravity and electrical techniques. These tools and techniques are summarized in Table 4 and described in greater detail below. Subsurface monitoring programs may use a combination of these tools, depending on the specific geologic conditions and challenges at a given CO_2 storage site.

Table 4: Summary of Subsurface Monitoring Techniques

Subsurface Monitoring	
Monitoring Technique	**Description, Benefits, and Challenges**
Well Logging Tools	**Description**: Mature technology used to monitor the wellbore and near-wellbore environment. Logs include porosity, density, acoustic, optical, gamma ray, resistivity imaging, borehole diameter logging, and pulsed neutron capture. **Benefits**: Easily deployed technology used to detect wellbore release and changes in near-wellbore fluid or formation composition. **Challenges**: Area of investigation limited to near the wellbore. Sensitivity of tool to fluid change may vary. Some tools are not sensitive to dissolved or mineralized CO_2. Workover fluids may affect log results.
Downhole Monitoring Tools	**Description**: Technology used to monitor CO_2 injection, reservoir conditions, wellbore conditions, CO_2 breakthrough at observation wells; also used to differentiate between CO_2 and brine. **Benefits**: Indirect and direct measurements of CO_2 transport. Pressure sensors useful for monitoring wellbore mechanical integrity and detecting CO_2 releases. Downhole temperature monitoring data could be used as inputs for history-matching simulation models. Flow meters monitor fluid flow conditions throughout the injection site. **Challenges**: Sensors need to have little drift over a long time span. Sensors and meters require specific calibrations to conform to regulations.
Subsurface Fluid Sampling and Tracer Analysis	**Description**: Technology used to monitor changes in the composition of fluids at observation wells and for characterizing CO_2 transport, reactions, dissolution, and subsurface dispersion. **Benefits**: Provides information on fluid geochemistry, CO_2 transport properties, and CO_2 saturation to estimate mass balances and distribution of CO_2 in the subsurface. **Challenges**: Cannot image CO_2 migration and release directly. Only near-well fluids are measured.
Seismic Methods	**Description**: Reflection seismic uses acoustic properties of geologic formations and pore fluids to image geologic layers and plume migration in the subsurface. Passive seismic detects microseismic events in the subsurface and can provide information on fluid movement in a formation.
	Benefits: Reflection seismic is useful for time-lapse monitoring of a CO_2 plume, and possibly for out-of-zone CO_2 migration indicating a release. Borehole seismic (crosswell, VSP) surveys can provide high-resolution imaging of the plume near the wellbore. Passive seismic can be used to detect natural and induced seismicity, to map faults and fractures in the injection zone and adjacent horizons, and to track the migration of the fluid pressure front during and after injection.
	Challenges: Geologic complexity and a noisy recording environment can degrade or attenuate surface seismic data. Two-dimensional seismic surveys may not detect out-of-plane migration of CO_2. Borehole seismic methods require a wellbore for monitoring, and careful planning is required to integrate these with other surveys. Microseismic monitoring detects fracturing and faulting events that may result from CO_2 injection, but a comprehensive knowledge of reservoir geomechanical properties is needed to properly interpret these events.
Gravity	**Description**: Use of gravity to monitor changes in density of fluid resulting from injection of CO_2. **Benefits**: Fluid density changes due to CO_2 releases or CO_2 dissolution can be detected, unlike seismic methods, which do not identify dissolved CO_2. **Challenges**: Limited detection and resolution unless gravimeters are located just above reservoir, which significantly increases cost. Noise and gravity variations (tides, drift) need to be eliminated to interpret gravity anomalies due to CO_2.
Electrical Techniques	**Description**: Based on the resistivity contrast between injected CO_2 and more conductive brine. Technology used in the oil and gas industry to detect hydrocarbons. Electrical tomography (ET) images spatial distribution of resistivity in reservoir by measuring potential differences or induced electromagnetic fields. Controlled-source electromagnetic (CSEM) surveys measure induced electrical and magnetic fields.
	Benefits: Electrical techniques provide resistivity distribution in the subsurface, which can be interpreted to estimate CO_2 saturation distribution. Data resolution is dependent on electrode spacing for ERT techniques. Crosswell ERT is more sensitive to changes in near-wellbore resistivity. Surface-downhole ERT and CSEM measurements increase the lateral extent and provide data on CO_2 plume tracking. ERT and CSEM do not interfere with other subsurface monitoring techniques operating within the well casing (e.g., wireline logging, borehole seismic). **Challenges**: May not detect contrast between CO_2 and hydrocarbons. ET requires non-conductive well casings and multiple monitoring wells.

Many subsurface monitoring techniques were originally designed for oil and gas exploration and development, and have been recently adapted for use in CO_2 storage fields. Some technologies, such as well logging and reflection seismic imaging, have reached a highly sophisticated level due to many decades of utilization in the petroleum industry. A focus of many current R&D activities has been to adapt these methods to the specific requirements of CO_2 injection, storage, and long-term monitoring. Note that some of these subsurface monitoring technologies are available commercially and are being utilized in injection projects to identify formation characteristics and track CO_2 migration.

Subsurface monitoring requires development of a reliable baseline prior to injection. Fortunately, many of the techniques used for subsurface monitoring are also used to characterize the storage site and the properties of the storage reservoir and confining layers prior to injection. These measurements typically become part of the baseline for measurements made after CO_2 injection begins.

Note that many subsurface monitoring techniques do not directly detect CO_2; rather, they detect changes in some other property, such as seismic velocity or electrical resistivity, which may then be interpreted to provide relevant information about CO_2. This requires extensive data processing and analysis. Forward-modeling studies are often used to design an injection and monitoring program, and inverse-modeling studies are typically employed to analyze the collected data.

Well Logging Tools

Well logging technology is highly advanced, owing to decades of utilization in oil and gas exploration and production. In recent years, many well logging tools have been applied to subsurface monitoring of CO_2 in fields where CO_2 storage and/or CO_2-EOR operations are underway. Well logging consists of lowering instruments into a wellbore and collecting data on the physical and chemical properties of a reservoir interval and its pore fluids. Most well logging tools are conveyed into the wellbore via wireline, coiled tubing, or drill pipe. Typical wireline logging tools include pulsed neutron tools (PNTs), density, acoustic, optical, gamma ray, resistivity, and borehole diameter logging tools. Metal casing interferes with some wireline measurements, so in conventional operations wireline logging is carried out before casing is installed (i.e., in openhole conditions). Well logging performed after metal casing is installed is referred to as cased-hole logging.

A number of standard well logging tools are used to characterize the lithology, mineralogy, porosity, fluid saturation, and structural complexity of reservoir formations at CO_2 storage fields prior to injection. The following logging tools have shown promise for measuring and quantifying CO_2 in pore fluids during and after injection.

PNT: PNTs have become useful tools for estimating CO_2 saturation in the injection reservoir. PNTs emit neutrons into the formation and measure the ability of the reservoir rock and its pore fluids to absorb or capture the neutrons. A detector measures decay times of thermal neutrons to estimate fluid saturations; it can also measure gamma rays emitted by inelastic neutron scattering to estimate carbon/oxygen (C/O) ratios. PNTs are sensitive to changes in reservoir fluid composition and can distinguish between brine, oil, and CO_2. In CO_2 monitoring, PNTs can be used to quantify CO_2 saturation in strategically placed wellbores, to detect the arrival of a CO_2 plume front, and to detect out-of-zone migration of CO_2. PNT logging is conducted in time-lapse mode to record changes in reservoir fluids before, during, and after CO_2 injection. PNT measurements are not sensitive to CO_2 dissolved in water.

Acoustic Logging Tools: Acoustic logging tools are used to measure compressional wave velocity, shear wave velocity, and acoustic wave transit times, all of which depend on the lithology and fluid content of the formation. Sonic logging tools are wireline-based and measure interval transit times for compressional waves travelling through a formation. Sonic logs can be used to monitor changes in pore fluid composition as a CO_2 plume moves past a wellbore, because the velocity contrast between water and CO_2 is strong.

Dual Induction Logging Tools: Dual induction logging is a type of resistivity logging that uses EM induction principles to measure the resistivity of a formation. The resistivity of a formation and its fluids is usually measured using a four-electrode configuration. Dual induction logging requires electrically conducting fluid (mud or water) in the wells. Dual induction logging is useful for CO_2 monitoring applications because of the large resistivity contrast between CO_2 and water. Resistivity readings are affected by borehole diameter, bed thickness, and borehole fluids.

Lessons Learned from the Field: Well Logging Tools

Time-lapse monitoring with a wireline-deployed PNT was carried out at the CO_2SINK site in Ketzin, Germany, beginning in 2007, to measure CO_2 saturation at an observation well located 50 m from an injection well (Vu-Hoang et al., 2009). Prior to CO_2 injection, pulsed neutron logs were acquired in the observation well to establish a baseline. Several weeks later, additional logs were acquired in this well to measure post-injection CO_2 saturation in two sandy intervals targeted for injection. After injection, CO_2 saturation was found to increase to 60 percent in the upper sand interval, while it remained negligible in the lower sand. The research team concluded that CO_2 breakthrough favored the upper sand, possibly due to upward migration via fractures that connect the two zones at the injection well.

At the Nagaoka pilot CO_2 injection site in Japan, several logging tools were used for post-injection, time-lapse monitoring of CO_2 from 2005 to 2010. The tools were deployed in observation wells located 40 to 120 m from the injection well, and CO_2 arrival was successfully measured by three independent logging methods. Sonic log measurements showed a drastic decrease in P-wave velocity; neutron porosity measurements showed an increase in CO_2 saturation; and dual induction logging registered a marked increase in resistivity (Mito and Xue, 2010). All of these changes are consistent with CO_2 replacing formation water, as the injected CO_2 plume advanced to the observation wells. The researchers found that P-wave velocity is a better indicator of CO_2 saturation at values below 20 percent CO_2 saturation, while resistivity is more reliable above 20 percent saturation.

Six time-lapse PNT surveys were conducted at the DOE Frio pilot site in Texas from late 2004 to early 2005 (Muller et al., 2007, Hovorka and Daley, 2010). Repeat measurements were made to establish a baseline, monitor injection, monitor post-injection, and monitor post-well completion changes in CO_2 saturation. The results showed CO_2 saturation of up to 65 percent in the injection interval, with injected fluid confined to porous and permeable zones in the Frio sandstone (Figure 13). Time-lapse PNT surveys were also carried out at the SECARB Phase III HiVIT area in Cranfield, Mississippi. The resulting near-wellbore saturation profile was consistent with saturation patterns determined from crosswell ERT (Hovorka et al., 2010).

The Schlumberger Reservoir Saturation Tool (RST) was tested at the Plains CO_2 Reduction (PCOR) Partnership's Northwest McGregor Huff 'n' Puff site in North Dakota. The tool was deployed in the 2,450-m deep Mission Canyon carbonate reservoir (Sorensen et al., 2010a). Time-lapse monitoring was achieved by logging the injection well in three stages: (1) prior to injection to establish a baseline; (2) 72 hours after injection, when the concentration of CO_2 was at its maximum; and (3) 129 days after the well was brought back into production. The results indicate that the CO_2 plume migrated vertically from the perforated zone until it encountered an impermeable anhydrite bed, and a portion of the gas migrated and remained at levels below the perforated zone. These results are consistent with dynamic simulation models which incorporated a fracture network in the geologic model.

Current and Ongoing Research: Well Logging Tools

In recent years, logging tools and services have been customized for monitoring CO_2 in the subsurface, and these products and services are now being offered by commercial vendors. Service companies can now recommend specific logging packages based on prior experience with CO_2 injection projects. For example, the Ohio River Valley CO_2 Storage Project has contracted a third-party to perform logging services for continuous monitoring of an injected CO_2 plume in the subsurface.

Downhole Monitoring Tools

Downhole monitoring tools may be used to monitor wellbore conditions, in-situ reservoir conditions, and CO_2 injection. Specific tools may be installed to differentiate between CO_2 and brine, to detect CO_2 breakthrough at observation wells, and to monitor wellbore conditions and wellbore integrity. For injection wells, wellbore conditions must be monitored in order

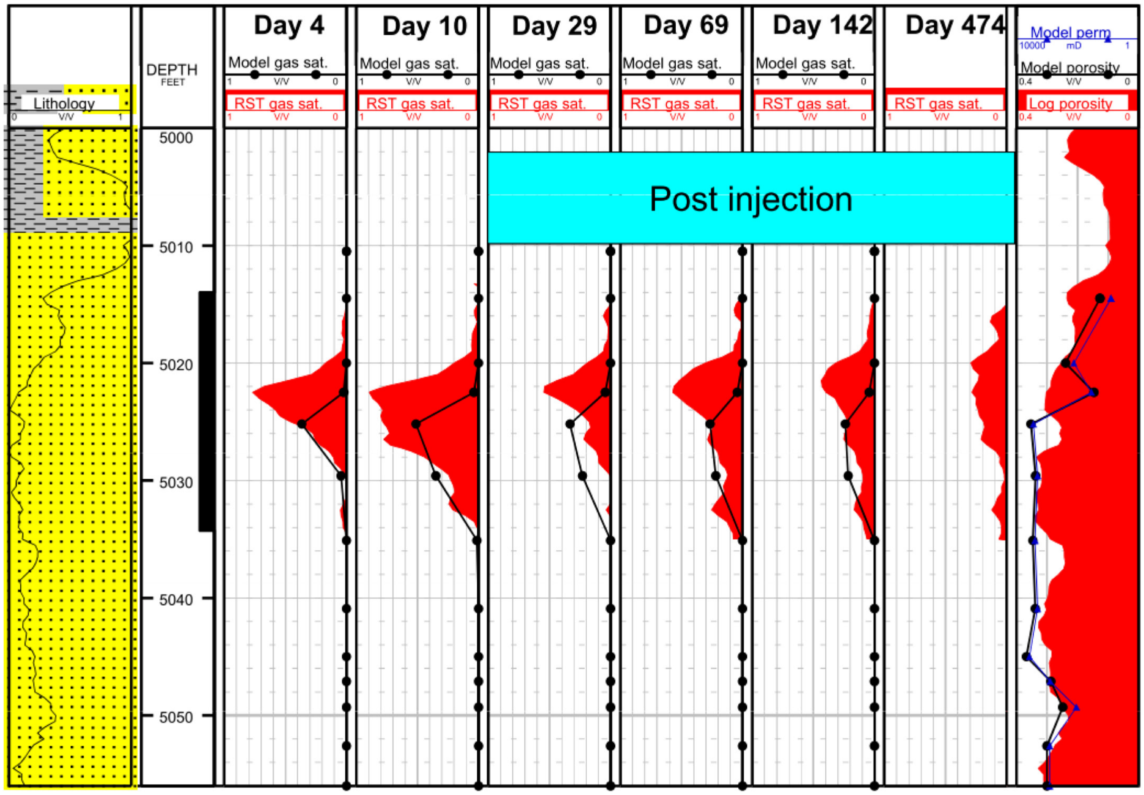


Figure 13: Saturation Logging (RST) at Observation Well (Frio) Indicating Matches to Simulation Model. (Hovorka and Daley, 2010)

to meet EPA standards for proper and safe injection of CO_2. External mechanical integrity tests (MITs) are performed to test the integrity of the seals between the cement, the casing, and the injection formation, while internal MITs are used to test the integrity of the casing itself. The most common wellbore monitoring tools used for CO_2 injection projects are described below.

Sonic Logging Tools: Sonic logging tools are used in cased-hole conditions to carry out external MITs. External MITs are used to test the integrity of the seals between cement, casing, and the formation, and to identify possible fractures caused by pressure, stress, or fluid invasion.

Oxygen-Activation Logs and Temperature Logs: These tools are also used to assess external mechanical integrity of the wellbore. Oxygen-activation logs are able to measure the direction and velocity of water movement around the casing. If water is detected moving outside of the casing, this may signal a loss of external mechanical integrity. Temperature logs can be used to identify fluid temperature fluctuations that may indicate a poorly sealed wellbore.

Radioactive Tracer Survey: Radioactive tracers can be used to monitor internal mechanical integrity during injection. A radioactive tracer is released within the casing, and the subsequent gamma ray response is measured through a series of sondes. This log is then compared to a baseline gamma ray log (without tracer) in order to identify any anomalies. Differences between the logs may indicate potential fluid movement and internal casing releases.

Downhole Temperature and Pressure Sensors: Pressure and temperature sensors located in the injection zone can be used to monitor CO_2 injection, differentiate between CO_2 and brine, and detect the arrival of CO_2 at monitoring wells. Subsurface temperature and pressure are indirect indicators of CO_2 transport because the injected CO_2 is typically at a lower temperature and higher pressure compared to the fluids in the formation. Pressure monitoring may also be used to check the internal mechanical integrity of the wellbore. Out-of-zone monitoring may be useful for detecting CO_2 release through sealing formations. Downhole pressures and temperatures can also be used as inputs for history-matching simulation models to better predict the migration of injected CO_2. Pressure and temperature transducers may be located within the wellbore, or they may be cemented with the casing.

Distributed Temperature Sensor Systems: Distributed Temperature Sensor (DTS) systems measure temperature profiles along the length of a wellbore. DTSs are based on fiber-optic technology and have CO_2 monitoring applications similar to those for temperature and pressure sensors. DTS systems can operate at depths up to 15,000 m and can incorporate distributed, point-acoustic, or pressure sensors (Hamling et al., 2011). Any reduction in light transmission caused by absorption or impurities in the optical fiber may lead to measurement errors in DTS systems. Mechanical and chemical exposure can reduce their service life (Jasskelainen, 2009).

Distributed Thermal Perturbation Sensor: Distributed Thermal Perturbation Sensors (DTPSs) are used to estimate the CO_2 saturation in the injection zone by measuring the thermal conductivity of the formation (Freifeld et al., 2009). An increase in CO_2 saturation and a decrease in the brine saturation results in a decrease of the bulk thermal conductivity. DTPS measurements involve installation of an electrical heater with the DTS fiber-optic cables. The heater is energized for a set time period, providing a source of heat along the wellbore. Temperature decay curves after the heater is turned off are inverted to provide estimates of formation thermal conductivity, and thereby CO_2 saturation.

Flow Meters: Flow meters can be installed to directly measure the rate and volume of transported and injected CO_2 at multiple locations. The most commonly used types of flow meters are differential pressure meters, velocity meters, and mass meters. Both differential pressure and velocity meters require additional real-time fluid data to determine rate and volume, while mass meters may not need further information. Current permit requirements demand continuous CO_2 flow monitoring at multiple locations; therefore, placement and cost may also determine the type of meter used.

Corrosion Monitoring: Corrosion monitoring must be performed in order to prevent potential failures within the injection system. The most common monitoring techniques are corrosion coupon analysis and corrosion loops. Corrosion coupon analysis consists of exposing a removable piece of casing or tubing material (coupon) to the corrosive fluid environment for a predetermined amount of time. The coupon is then removed and analyzed for any corrosion effects, such as weight loss, chemical reaction, discoloration, or visible pitting. A corrosion loop can also be installed within the injection system. This consists of a removable loop of tubing installed parallel to the CO_2 tubing flow. The loop is of a smaller diameter and a proportionally smaller amount of CO_2 is passed through it. When the CO_2 flow through the loop is shut off, the pipe is removed and examined for signs of corrosion.

Lessons Learned from the Field: Downhole Monitoring Tools

At the CO_2SINK project in Ketzin, Germany, downhole pressure and temperature were monitored for approximately 16 months, starting when injection was initiated in June 2008. A pressure sensor was installed in the injection well at the end of the injection tubing string. This sensor operated as a fiber-optic gauge for measuring wellbore pressure and temperature in the injection zone. Pressure measurements were used to monitor changes in reservoir pressure that resulted from CO_2 injection. The pressure history was also used to constrain CO_2 transport models (Pamukcu et al., 2010). By August 2009, the bottom-hole pressure in the injection well stabilized, indicating normal reservoir behavior.

At the Ketzin site, the injection well and two observation wells also have permanently installed fiber-optic sensor cables for distributed temperature sensing. The cables were permanently installed behind the casing, allowing access to the entire length of the wellbore, even during technical operations (Giese et al., 2009). The evolution of temperature in the injection zone, the arrival of CO_2, and the evolution of two-phase P/T conditions were monitored periodically during 2008 and 2009. It was found that strong transient-temperature effects from injection caused a distortion of the inverted thermal conductivity profiles. Further data processing is in progress (Martens et al., 2010).

Pressure monitoring has also been used for CO_2 release detection at the Zama acid gas CO_2-EOR CCUS project in Alberta, Canada. The reservoir in this project is in a producing oil field that stands to benefit from CO_2-EOR (Smith et al., 2010). Bottom-hole pressures in the injection/production zone and the overlying Slave Point Formation were monitored from 2006 to 2009. The results indicate a small increase in pressure in the overlying formation. However, further data are needed to determine the cause of this pressure increase. Bottom-hole pressures and temperatures were also monitored at the DOE Frio test pilot in Texas from 2004 to 2006; at the Midwest Regional Carbon Sequestration Partnership (MRCSP) Phase II Cincinnati Arch, Duke Energy East Bend Generating Station, in Kentucky in September 2009; and at the Nagaoka pilot project in Japan from 2003 to 2008. Results indicate that pressure monitoring may be useful as a non-invasive, cost-effective element of an MVA program.

Current and Ongoing Research: Downhole Monitoring Tools

Downhole pressures and temperatures have been measured in the injection well at the Snøhvit field in the Barents Sea, offshore Norway, since 2008 (Eiken et al., 2010). The operation has been characterized by frequent injection stops due to intermittent availability of the onshore CO_2 source. This has resulted in a cycle of pressure build-ups and fall-offs. Eiken et al. note that a long-term pressure increase for more than 2.5 years likely indicates that the effective permeability of the injection formation may be lower than initially estimated from injection well data.

Bottom-hole pressures and temperatures are also being monitored at the SECARB Phase III Cranfield, Mississippi, project. A pressure increase in the injection zone was measured from July to October 2008. Comparatively little pressure change was observed in the monitoring zone, indicating no vertical or lateral CO_2 release. It was noted that any potential release could be detected using multiple wells (Meckel et al., 2008). Casing-deployed, above-zone pressure measurements and DTSs are also being used to monitor in-zone CO_2 retention at the site (Hovorka et al., 2010).

Subsurface Fluid Sampling and Tracer Analysis

Subsurface fluid sampling involves the collection of liquid or gas samples via wells that penetrate a geologic zone of interest. For subsurface CO_2 monitoring, the zone of interest is usually the injection reservoir or the overlying formation. Subsurface samples can provide information on physical and geochemical changes taking place in the reservoir due to CO_2 plume migration. Samples provide the ground-truth data on fluid chemistry, CO_2 transport properties, and CO_2 saturation that are used to constrain reservoir simulation models.

Subsurface tracer monitoring differs in some respects from near-surface and atmospheric monitoring. Near-surface tracer monitoring is primarily aimed at identifying CO_2 releases, whereas subsurface tracer monitoring is also used to track the migration of the CO_2 plume and assess the phase partitioning of CO_2 in the reservoir. Different tracers may be used for subsurface monitoring than for near-surface monitoring to avoid the overlap of release signals from different geologic horizons.

Sampling of subsurface fluids is non-trivial, because fluid mixtures such as CO_2, brine, and hydrocarbons density-separate in the wellbore, temperature and solubility relationships change, and dissolved gases degas from the liquid phase. Preserving samples at in-situ temperature and pressure conditions is a major challenge in subsurface fluid sampling. Specialized downhole sampler systems, including wireline-deployed Kuster flow-through samplers and Modular Formation Dynamics Testers, can retrieve and maintain samples at in-situ pressure conditions.

A device developed with DOE funding, called a U-tube (Freifeld et al, 2005) (Figure 14), enables sampling of fluids at more closely spaced intervals compared to what can be achieved with wireline sampling methods. The U-tube is a double length of high-pressure stainless steel tubing with a check valve that is initially open to the reservoir. The open valve allows formation fluid to flow into the sample leg of the U-tube, driven by the fluid pressure in the reservoir. High-pressure nitrogen gas is then applied to the drive leg of the U-tube, causing the check valve to close and forcing the fluid out of the sample leg and into an evacuated sample chamber at the surface. The sample, which may include free gas and gases coming out of solution, is then pumped through gas analyzers to measure the gas composition in the field (Freifeld et al., 2005).

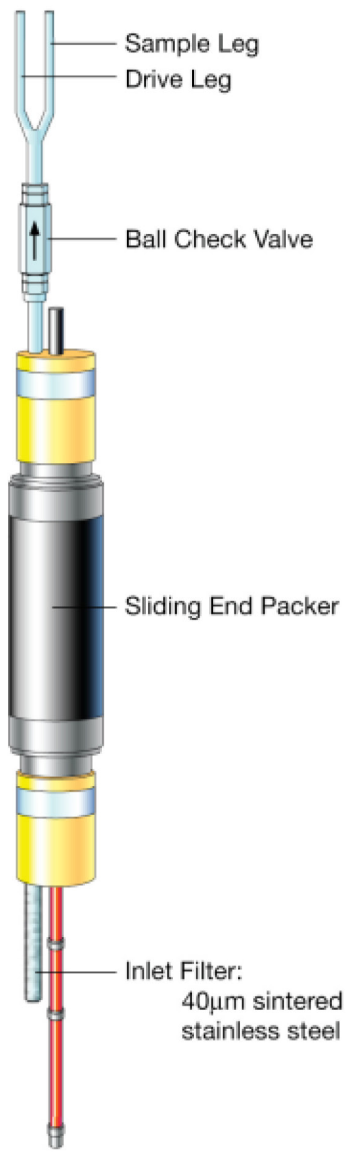


Figure 14: U-Tube Downhole Assembly Detail. (Freifeld et al., 2005)

Lessons Learned from the Field: Subsurface Fluid Sampling and Tracer Analysis

U-tube sampling was first tested in 2004 during the injection phase of the Frio brine pilot (Freifeld et al., 2009). Wireline-based Kuster samplers were also employed. Properties such as alkalinity and pH were measured in the field, and real-time fluid gas compositions were measured using a mass spectrometer. Additional samples were collected for laboratory analysis of major and minor elements and injected isotope tracers (Kharaka, Y., et al., 2006, Hovorka and Daley, 2010). Researchers found that pH, alkalinity, and gas compositions were highly effective parameters to track the CO_2 plume. Isotopic laboratory analyses of brine and CO_2 samples were also useful for tracking the migration of CO_2. The isotopic results indicated the transformation of a brine-dominated system to one in which supercritical CO_2 comprises approximately 50 percent of the fluid volume 6 months post-injection, which is consistent with CO_2 saturations inferred from wireline pulsed neutron logs. The study successfully demonstrated a method to collect frequent, high-quality, minimally altered samples of two-phase fluids during CO_2 injection (Freifeld et al., 2005).

Subsurface geochemical monitoring at In Salah began in 2004 and has focused on downhole gas measurements and production monitoring. Different PFTs were used to tag the CO_2 injected in each of three injection wells, so that any CO_2 detected may be differentiated from native CO_2 and traced back to its source. Tracer sampling was used to confirm that a small release from an unplugged well intersecting the water-saturated portion of the injection zone came from the CO_2 injected at an adjacent well (Ringrose et al., 2009). The releasing well has since been plugged and abandoned.

A Gas Membrane Sensor system was developed for real-time, in-situ measurement of CO_2 and other gases at the CO_2SINK Ketzin pilot site (Giese et al., 2009). Gas membrane sensors were successfully tested at the site to detect the arrival of CO_2 at two monitoring wells after the injection of CO_2 in 2008 (Martens et al., 2010). Increasing concentrations of He, hydrogen (H_2), CH_4, and N_2 were observed at the observation well following CO_2 injection (Giese et al., 2009). The Gas Membrane Sensor in one observation well was replaced by stainless steel riser tubing installed in the injection zone, and the system detected the arrival of injected krypton tracer after injection of additional CO_2 (Martens et al., 2010).

Subsurface fluid sampling at the SECARB Cranfield Phase III project (HiVIT) was conducted, starting in 2009, to monitor changes associated with CO_2 injection. The aim of the sampling program was to observe geochemical changes that occur as reservoir fluids evolve from a single-phase brine to a two-phase CO_2-brine system (Thordsen et al., 2010, Hovorka et al., 2010). Researchers utilized U-tube and Kuster sampling to recover fluids and introduced tracers such as PFTs, noble gases, and SF_6 (Hovorka et al., 2010). Results suggested only minimal water-rock interaction in the reservoir, contrasting sharply with results from the Frio pilot. The relatively minor chemical changes at Cranfield were attributed to the use of fiberglass-lined casing and non-corrosive well components; the predominance of slow-reacting host rocks; and the advance of CO_2, primarily in high-permeability, carbonate-poor, non-reactive, iron chlorite-coated sandstone zones (Lu and others, 2012).

A coiled tubing system was used to collect pressurized-fluid samples from observation and injection wells in the PCOR Partnership's Northwest McGregor Huff 'n' Puff Phase II test. Sampling began in June 2009, prior to injection, and continued for four months post-injection. Compositions of the samples were analyzed, and the results from the injection well were used as input parameters for geochemical modeling. Other field data collected included conductivity, pH, temperature, total dissolved solids (TDSs), salinity, gas concentrations, and oil parameters. The data from the observation well were used for history-matching. The results indicate displacement of the H_2S gas by CO_2 around the wellbore, an increase in the TDS as a result of mineral dissolution, and a further pH decrease due to CO_2 dissolution.

Current and Ongoing Research: Subsurface Fluid Sampling and Tracer Analysis

A long-term fluid sampling and geochemical analysis program has been operational at the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project for more than 10 years. Geochemical samples were obtained prior to injection, which was initiated in 2000, to establish a baseline. Since then, post-injection samples have been collected periodically from more than 40 wells that penetrate the 1,500-m deep Midale injection zone (Whittaker, 2010, Wilson and Monea, 2004, Emberley et al., 2004). Samples of produced brines were analyzed in detail, and certain geochemical parameters were found to signal incipient CO_2 breakthrough at monitoring wells. In addition, geochemical sampling results over the first phase of the project indicate dissolution of carbonate minerals in the reservoir. Geochemical monitoring results from the second phase of the project are currently being integrated with experimental and modeling studies to establish a better understanding of brine-CO_2 reactions at all scales.

Subsurface fluid sampling has been carried out as part of the monitoring effort at the CO_2CRC Otway Project since injection began in 2008, using an observation well that penetrates the Warre-C injection formation. U-tube samples have been collected from the gas cap and in the zone below the gas-water contact (Sharma et al., 2010, Underschultz et al., 2009). The sampling program was designed to track CO_2 arrival at the observation well and to provide data on the filling of a depleted-gas reservoir. Other objectives were to measure partitioning of CO_2 between the existing gas and water phases and to monitor changes in formation water chemistry. Tracers were injected with the supercritical mixture of CO_2 and CH_4 over specified time periods. Geochemical changes indicated movement of the CO_2 plume through the reservoir, with local geochemical reactions occurring near the supercritical CO_2 front. Geochemical sampling and isotopic gas analyses were used to track the path of the CO_2 plume and to validate and refine reservoir models. Post-injection monitoring is in progress at the site.

A novel third-party fluid sampling system is currently being used at the IBDP. This system involves water sampling equipment that has been modified to withstand CO_2-rich environments found in an injection reservoir. The modifications to the standard water sampling equipment include strengthening of the instrument shell and the use of more durable materials for internal components and O-rings to prevent CO_2 corrosion and pitting. The result is a system capable of collecting fluid samples from harsh CO_2 environments at depths down to approximately 2,400 m. This system provides downhole data on CO_2 concentration and quality, as well as in-situ reservoir pressure and temperature.

NETL researchers are developing a miniature, ruggedized, remotely operated laser system for Laser-Induced Breakdown Spectroscopy (LIBS) analysis (Jain et al., 2011, Figure 15). LIBS can be applied for real-time elemental and isotopic analyses of solid, liquid, and gas samples. It represents a significant advance over conventional techniques, such as mass spectrometry, because it provides rapid and direct chemical characterization without extensive sample preparation procedures. Current research efforts are focused on the development of a high-pressure, high-temperature laser system for groundwater monitoring, CO_2 release detection, in-situ tracer detection, and isotope measurements.

Deep reservoirs have low quantities of ^{14}C, so this isotope can serve as an effective tracer to track geochemical reaction processes and estimate CO_2 inventories. NETL is supporting efforts to develop ^{14}C-tracer technology at the CarbFix CO_2 GS site in Iceland. The project will test ^{14}C-tracer technology for quantitative monitoring of injected CO_2. Fluid and core sampling will be performed as part of the monitoring activities. The ^{14}C counts should be directly proportional to the amount of anthropogenic carbon in the reservoir. In addition, $^{14}CO_2$ will be tested as a reactive tracer to evaluate the extent of CO_2 trapping in basaltic rocks. Additional tracers (SF_6, SF_5, CF_3) will be used to characterize CO_2 dispersion in basalt.

DOE/NETL is also supporting Oak Ridge National Laboratory (ORNL) in developing and testing geochemistry-based techniques to monitor and assess CO_2-injection operations and improve large-scale CO_2 storage. The project has provided baseline gas chemistry and gas and brine isotope chemistry for the Frio I and Frio II pilot studies. Results indicate that CO_2 tracking is feasible using a combination of geochemical and PFT tracers.

Seismic Methods

Seismic technologies have benefited from many decades of development, testing, and optimization for the petroleum industry. As a result, these technologies are highly advanced and have become indispensable for reservoir characterization, and in some cases reservoir fluid monitoring, in producing oil and gas fields. In just the past 12 years, certain seismic imaging techniques and approaches have been carried over and tested successfully for CO_2 monitoring at injection fields. The challenge is to optimize existing seismic technologies to meet the specific needs of CO_2 injection projects.

Seismic monitoring strategies include surface seismic, borehole seismic, and passive seismic techniques (Figure 16). Surface seismic surveys utilize surface sources to generate downward-propagating elastic waves. These waves travel downward into the earth and are reflected back to the Earth's surface at layer boundaries due to changes in acoustic impedance properties of the rock medium. The reflected waves are recorded by ground motion sensors or geophones, and these arrivals are used to develop an image of subsurface geologic structure.

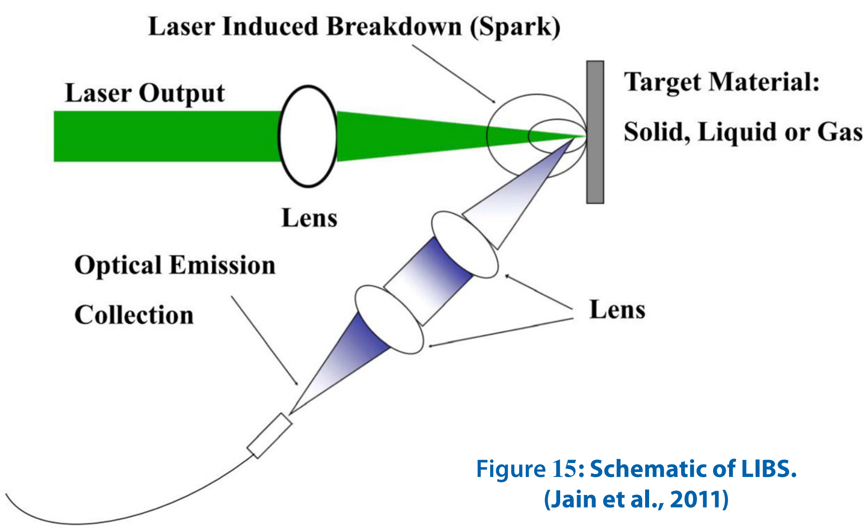


Figure 15: Schematic of LIBS. (Jain et al., 2011)

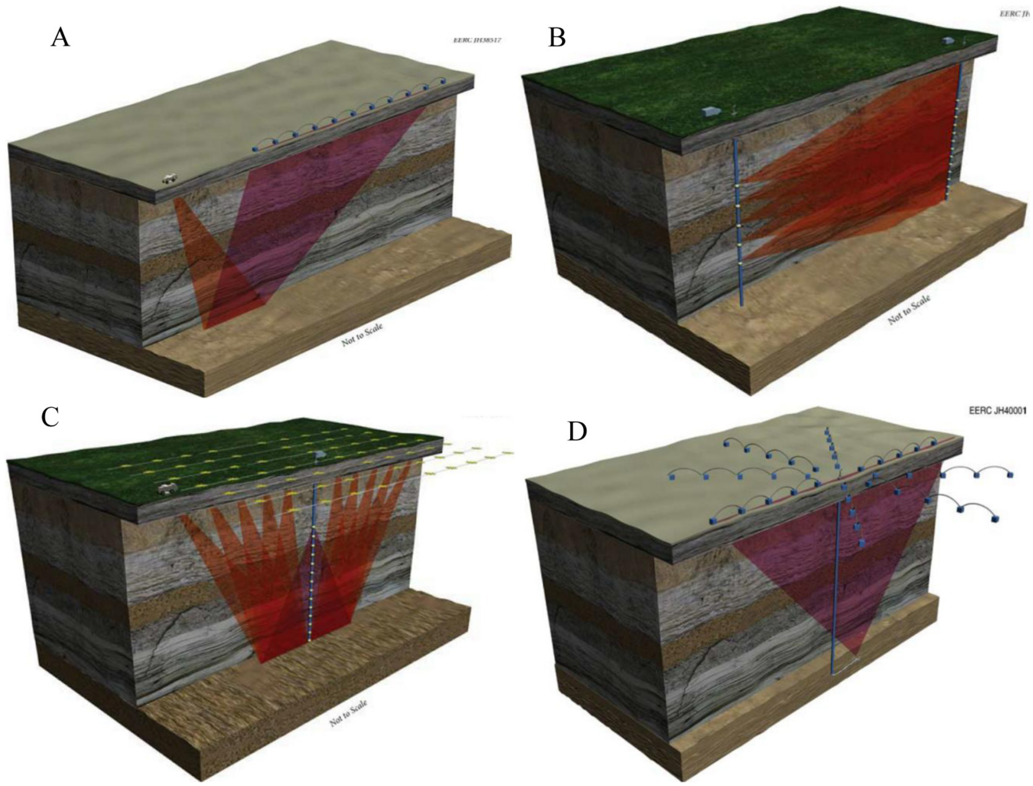


Figure 16: Schematics of Various Seismic Monitoring Techniques: (A) 2-D Surface Seismic, (B) Crosswell Seismic, (C) 3-D VSP, (D) Surface-Based Microseismic. (Hamling et al., 2011)

A seismic reflection survey can be used for site characterization, and repeat surveys can provide time-lapse monitoring of the migration of a CO_2 plume in the subsurface. Surface seismic data generally have lower spatial resolution than borehole seismic data (Monea et al., 2008). The spatial resolution of a particular surface seismic survey depends on the depth to the target, the frequency content of the source, spacing of sources and receivers, subsurface geologic complexity, and many other site-specific factors (Hamling et al., 2011). Certain geologic features, noise from heavy equipment, or related operations can degrade or attenuate surface seismic data. Two-dimensional seismic surveys may not detect out-of-plane migration of CO_2 and features not directly underlying the geophone line

Borehole seismic techniques follow the same principles as surface seismic, but in borehole seismic surveys the receivers, sources, or both are placed in a well (Schlumberger, 2011a). Borehole seismic includes vertical seismic profiling (VSP) and crosswell seismic. VSPs are generally conducted with the seismic source at the land surface and the receiver array placed in a wellbore (Schlumberger, 2011b, Hamling et al., 2011). An array with many closely spaced receivers can produce a high-resolution image in the vicinity of the wellbore (300 to 600 m away). Borehole seismic methods require a wellbore for monitoring, and careful planning is required to coordinate these with other surveys.

- Time-lapse VSPs can be used to detect changes in reservoir properties such as fluid pressure changes caused by injection or production activities (Daley et al., 2007). Walk-away VSPs can be used to calibrate surface seismic data and to monitor the CO_2 plume as it migrates away from the injection well.
- Crosswell seismic is a borehole seismic approach that uses a seismic source located in one well and a receiver array located in an adjacent well. The travel times for each source-receiver pair can be used to create a network of overlapping ray paths, and these are used to make a velocity map (or tomogram) between the wells. Crosswell surveys require wellbore access, and careful planning is required in order to coordinate survey activities with other monitoring activities.

Passive seismic monitoring is a tool used to map microseismic events (microearthquakes) in the subsurface. It has been used in the petroleum and geothermal industries to monitor microseismicity that results from pressure changes and geomechanical deformation in the reservoir. In GS applications, microseismic monitoring is useful for evaluating the natural seismicity that may be present in a target reservoir and for detecting induced seismicity resulting from injection.

Passive seismic monitoring prior to injection can be used to establish a baseline of background seismicity and to map faults and fracture networks that may be present in the reservoir and in adjacent strata. Pre-injection microseismicity monitoring may be coupled with stress mapping, which relies on borehole breakout data, drilling-induced fractures, and available focal mechanism solutions, to determine the state of stress of the reservoir prior to injection.

Passive seismic monitoring during and after injection can be used to detect and locate induced seismic events resulting from CO_2 injection. Induced seismic events may occur if fluid injected into the reservoir raises the pore pressure in the injection zone such that it exceeds the frictional resistance on faults and fractures and triggers fault slippage. Recording background and induced microseismic events can lead to a better understanding of (1) potential seismic risk in a CO_2 injection site, (2) geomechanical properties of the reservoir, and (3) more accurate mapping of the fluid pressure front representing the advance of the injected CO_2 plume.

Passive seismic surveys are carried out using geophones installed near the surface or in a wellbore. These geophones are capable of detecting extremely small microseismic events (between -4 and -1 on the moment-magnitude scale). However, natural seismic attenuation in the crust limits the range of monitoring of such small events to less than 800 m away from the detectors in most situations.

Because no seismic sources are needed, passive seismic monitoring is well-suited to environmentally sensitive areas. A precise knowledge of the geomechanical properties of the reservoir, extensive forward modeling, and predictive simulation work is needed to correctly interpret passive seismic data.

Use of passive seismic surveys as described herein is well aligned with recent recommendations made by the National Research Council (NRC; NRC, 2012). NRC recommends that high-quality seismic data be collected and analyzed in order to detect potential induced seismic events at CO_2 injection sites and to identify key data types and a data collection protocol. Additionally, NRC recommends gathering microseismic data to better define preexisting fracture systems in and adjacent to an injection reservoir. NRC also recommends that research be carried out to clarify the relationship between injection rate, injection pressure, and microseismic event size. Finally, NRC encourages research that addresses gaps in current knowledge and instrumentation for microseismic monitoring.

Lessons Learned from the Field: Seismic Methods

Seismic monitoring of CO_2 in the subsurface was first demonstrated as a viable method at the Sleipner CO_2 injection site in the central North Sea off the coast of Norway (Eiken et al., 2011). Carbon dioxide injection began at Sleipner in 1996, and a time-lapse seismic program was initiated there in 1999. Six repeat 3-D seismic surveys were acquired from 1999 to 2008, to image the distribution and movement of the CO_2 plume in the Utsira Formation, following successive injection stages. The Utsira reservoir is a thick, unconsolidated, structurally simple, high-porosity sandstone that lies approximately 700 m below the seafloor at the Sleipner site. In the 3-D seismic data obtained at Sleipner, the CO_2 plume stands out as a mappable, highly reflective body with clearly delineated boundaries. Time-lapse seismic difference maps show an increase in seismic amplitudes and a steady expansion of the plume from 1999 to 2008, as 12 million tons of CO_2 were injected into the reservoir (Figure 17). The sum of the seismic amplitudes was observed to track linearly with the cumulative volume of injected CO_2. However, Eiken et al. (2011) note that quantitative estimation of CO_2 from the seismic data is challenging. No release of CO_2 into overlying units has been detected, but the threshold for release detection at Sleipner is on the order of 1 kT of CO_2.

Time-lapse 3-D seismic surveys were also acquired at the Weyburn-Midale CO_2 storage and monitoring project, where CO_2 injection began in 2000. Repeat, co-located seismic surveys were acquired from 2000 to 2007 to track long-term migration of injected CO_2 through the Midale formation (White, 2010, Verdon et al., 2010).

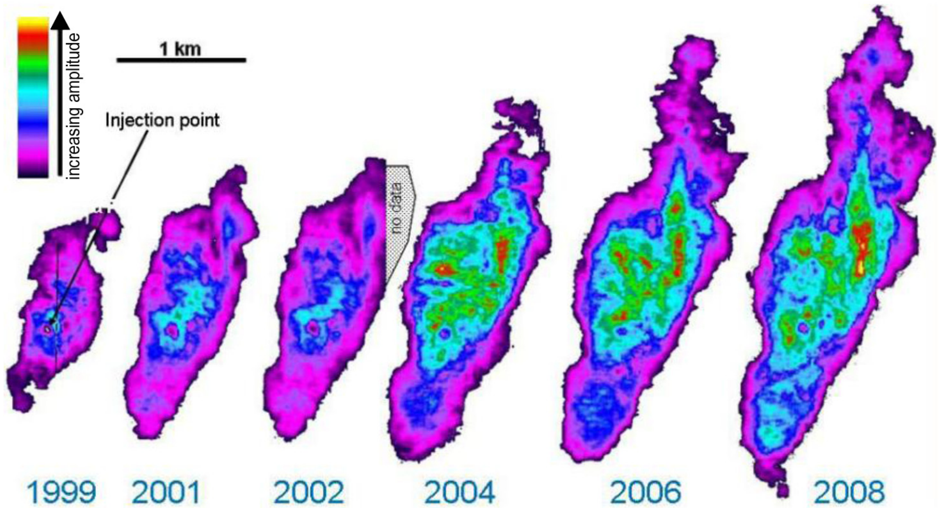


Figure 17: Time-Lapse Seismic Difference Amplitude Maps at Sleipner. (Eiken et al., 2010)

Seismic attribute maps were used to define the lateral extent of the CO_2 plume and to detect potential release into overlying units. An analysis of interval travel times in the strata above the reservoir did not indicate any significant out-of-zone CO_2 migration. Seismic amplitude-versus-offset-and-azimuth analyses were used to map variations in the structure of the overlying strata. The results helped locate regions where the caprock may be vertically fractured and warrant future monitoring activities. Seismic inversion techniques are also being developed to enable estimation of CO_2 saturation from the Weyburn-Midale time-lapse data.

At the CO_2CRC Otway site, time-lapse surface and borehole seismic methods were combined to monitor CO_2 in the injection horizon, approximately 2 km below the surface (Urosevic et al., 2010). Pre-injection surface seismic and VSP surveys were acquired in 2007 and 2008 to establish a baseline. Post-injection 3-D surface seismic surveys were acquired in 2009, after injection of 33 kT of CO_2, and again in 2010, after injection of an additional 32 kT; a post-injection VSP survey was also acquired in 2010. The surface seismic and VSP data showed excellent repeatability, owing to the use of closely spaced shots and receivers and high-quality data processing. However, seismic difference sections, which are designed to accentuate time-lapse changes related to CO_2 injection, showed only subtle amplitude increases in the injection zone, suggesting that this method of CO_2 monitoring may not be useful at this site. In fact, rock physics modeling indicates that even prolonged injection of CO_2 may not produce strong differences in the time-lapse seismic signal at Otway, in part because of the depth of the reservoir horizon.

The remote location of the In Salah CO_2 storage site has made it difficult to acquire multiple time-lapse datasets. Only two repeat 3-D seismic surveys have been acquired to date—one in 1997, prior to CO_2 injection, and the other in 2009, after injection. Time-lapse processing has been difficult due to limitations in the quality of the 1997 baseline survey. However, changes related to pressure effects were detected at the reservoir level in the vicinity of one of the injection wells. The 2009 survey, when processed separately, provided high-quality images of the injection horizon and overlying units. In combination with satellite data, these images have proved helpful for guiding ongoing monitoring and injection activities at In Salah (Mathieson et al., GHGT-10).

In 2009, 4-D seismic data were acquired at the Snøhvit CO_2 injection site in the Barents Sea, offshore Norway, after the injection of approximately 500 kT CO_2 into a sandstone reservoir located 2,400 m below the seafloor. Seismic amplitude maps revealed marked anomalies related to the presence of CO_2 and pressurized water, with amplitudes decreasing systematically away from the injection well (Eiken et al., 2010). The seismic results also suggest that only a portion of the injection formation may be receiving most of the CO_2, and that lateral heterogeneities may create barriers that reduce effective permeability.

Multiple surface and borehole seismic surveys were acquired at the Ketzin CO_2SINK project site in Germany (Lüth et al., 2010, Arts et al., 2010), beginning with a pre-injection, 3-D surface seismic baseline acquired in 2005. The injection horizon at this site is a 650-m deep sandstone formation formerly used for natural gas storage. In 2008, CO_2 injection into this reservoir was initiated, and a repeat 3-D survey was acquired in 2009, as cumulative injection reached 25,000 tons of CO_2. Amplitude analysis of the time-lapse data revealed a clustering of positive amplitudes around the injection well, with an asymmetric spread outward from the well suggesting anisotropic migration of CO_2 near the top of the injection formation (Lüth et al., 2010).

Borehole surveys, including walk-away VSP and crosswell seismic, were also acquired at Ketzin. Walk-away VSP data were successful in resolving the base and top of the injection formation in the vicinity of the injection well. VSP data also revealed a bright reflection corresponding to CO_2 in the uppermost layer of the injection formation. Crosswell tomography showed subtle changes in seismic wave attenuation after the injection of 19,000 tons of CO_2.

Seismic methods have also been tested in a number of Regional Carbon Sequestration Partnership (RCSP) pilot-injection projects. A baseline VSP survey was conducted at the MRCSP Cincinnati Arch Phase II site in 2006, and crosswell seismic surveys were conducted at the MRCSP Michigan Basin Phase II site in 2009. At the Frio II test site near Houston, Texas, researchers tested a continuous active seismic monitoring system, starting in 2006, for observing CO_2 plume migration in real time. In this system, the source and receiver strings were left in the wells, and continuous monitoring data were integrated with reservoir models for better estimates of CO_2 plume extent and distribution in the reservoir (Daley et al., 2007, Daley et al., 2011).

In 2009, repeat VSP monitoring was tested to track a small-volume CO_2 plume in a deep carbonate reservoir at the PCOR Partnership's Huff 'n' Puff pilot in the Northwest McGregor oil field (Sorensen et al., 2010a). The pre-injection VSP study was useful for reservoir characterization, but the results of the time-lapse VSP study performed 143 days after injection did not provide conclusive evidence for the detection of CO_2 in this reservoir.

Microseismic events were also monitored at the SWP Phase II CO_2-EOR pilot project in the Aneth oil field in Utah starting in 2008. Researchers are studying the relationship between the frequency of microseismic events and the cumulative volume of CO_2 and water injected into the Aneth reservoir. Double-difference seismic tomography was used to precisely locate microearthquakes and thereby delineate reservoir structure. Events recorded over a three-month period in 2008 defined a northwest-southeast trending fracture system on the margins of the injection reservoir (Zhou et al., 2010). This research supports NRC's recent recommendation to collect field data that will provide a better understanding of native fracture networks and the relationship between CO_2 injection and microseismic events (NRC, 2012).

Current and Ongoing Research: Seismic Methods

Current DOE seismic monitoring efforts are focused on developing: (1) advanced receivers and receiver arrays, (2) advanced 4-D strategies and technologies, (3) improved borehole imaging capabilities for next generation monitoring of CO_2 in the subsurface, (4) improved microseismic monitoring techniques, and (5) rock physics models and seismic data integration strategies.

Microseismic monitoring is being carried out at the In Salah storage site in order to monitor background seismicity and possible induced seismicity. A borehole array was installed in 2009 containing 48 three-component sensors. Since that time, more than 1,000 events have been recorded. The relationship between CO_2 injection and seismicity is being studied, but the data quality and accuracy of the event location are not good enough to draw firm conclusions at this time. An extended monitoring network is under consideration for the future. Two important lessons learned from this study are: (1) it would have been beneficial to install the microseismic monitoring array and establish a baseline of background seismicity prior to the initiation of CO_2 injection at the site, and (2) an extended monitoring network is needed to improve the accuracy of microseismic event location (T. M. Daley, pers. comm., 2012). These results are in line with NRC's recent recommendations to identify key types of microseismic data to be collected and to establish data collection protocols (NRC, 2012).

DOE/NETL is providing support to Paulsson Inc., to develop a fiber-optic/micro-electromechanical system (MEMS)-based borehole receiver system for active and passive seismic applications. The receivers would have a low-noise floor, high sensitivity, extreme robustness, and reliability, enabling significantly improved data repeatability compared to current analog and MEMS geophones. A prototype fiber-optic/MEMS receiver array will be built and tested at a CO_2 storage site. This receiver system is an example of a technology that addresses the need for improved instrumentation for microseismic monitoring (NRC, 2012).

DOE/NETL is also supporting research at the University of Texas at Austin to develop and deploy a novel, cable-less seismic data acquisition system. The system will be used to acquire multi-component 3-D seismic data for monitoring CO_2 injected into saline formations. This system is designed to overcome the problems associated with cable-based data acquisition systems, including the size, weight, manpower demands, and repair costs.

Passive seismic monitoring has been used at the Weyburn-Midale Monitoring and Storage Project since 2003 in order to track mechanical deformation associated with CO_2 injection. This effort supports NRC's recommendation to "collect, categorize, and evaluate data on potential induced seismic events in the field," and to "conduct research that might clarify the in situ links among injection rate, pressure, and event size" (NRC, 2012). Researchers have found that microseismic events are more frequent during periods of rapid CO_2 injection, and event locations tend to correlate with areas of high CO_2 saturation. The overall rate of microseismicity at the site has been low, with approximately 100 events recorded from 2003 to 2008. Nearly all of these events occurred prior to 2006, during the early stages of CO_2 injection. This pattern indicates little or no ongoing mechanical deformation of the reservoir. Coupled fluid flow and geomechanical modeling has shown that microseismicity immediately above the reservoir was likely due to stress-arching effects, not upward escape of CO_2 (White, 2010). The acquired passive seismic data were also used to infer the permeability anisotropy of the injected formation (Verdon, 2012).

Multiple seismic techniques are being tested at the SECARB Phase III test in Cranfield, Mississippi, where injection of CO_2 began in 2008. Time-lapse 3-D surface seismic imaging is being utilized to map the extent of the injected CO_2 plume; time-lapse VSP is being employed for improved vertical resolution in the injection zone; continuous active source seismic monitoring and crosswell seismic tomography are being used to detect the timing of CO_2 movement in the reservoir; and passive seismic monitoring is being tested for its ability to track injection-related mechanical deformation in the reservoir. This is another example of a passive seismic monitoring effort that addresses NRC's recommendation to collect field data that can identify potential induced seismic events associated with CO_2 injection (NRC, 2012).

MGSC's IBDP Phase III is also utilizing passive seismic monitoring to record microseismic events that may be related to CO_2 injection in the reservoir. The research team has installed a geophone array in a dedicated monitoring well for continuous recording of events that exceed a specified magnitude threshold.

DOE/NETL is supporting research at Stanford University to develop rock physics models that incorporate CO_2 dissolution, rock chemical changes, and pore-pressure changes for long-term, quantitative seismic monitoring of CO_2 in the subsurface. Current rock physics models used to correlate CO_2 saturation with seismic data are based on assumptions that may not be realistic for medium- to long-term CO_2 monitoring applications.

DOE/NETL is supporting research at Virginia Tech to establish data collection and processing requirements for double-difference waveform inversion and tomography. This technique will allow quantitative mapping of stored CO_2 as a function of time. Waveform inversion of seismic data, followed by the subtraction of images inverted from the baseline and time-lapse seismic data sets, provides quantitative estimates of changes in subsurface density and elastic properties. However, independent inversions of baseline and time-lapse seismic data sets lead to noisy images. This limitation can be overcome by double-difference waveform inversion and tomography, which has the potential to generate less-noisy and higher-resolution images of changes in reservoir density and elastic properties.

DOE/NETL is supporting two research efforts on inverting multi-component seismic data to monitor injected CO_2. First, a methodology to invert 3-D multi-component seismic waveforms and thereby estimate the post-injection distribution of CO_2 is being developed by researchers at the University of Wyoming. The inversion methodology is being developed by comparing and calibrating formation properties modeled from flow model-derived synthetic-seismic responses to post-injection CO_2 saturations within the formation. Second, rock physics models that correlate compressional- (P), and shear- (S) seismic wave attributes to rock/fluid properties for improved MVA are being developed at the University of Texas at Austin. Cable-less conventional and multi-component seismic data would be acquired, processed, and interpreted using a rock physics model to better detect features such as releasing seals, fluid-flow paths, high- and low-gas saturation zones, and any permeability barriers.

DOE/NETL is also partnering with West Virginia University to conduct research focused on identifying reservoir faults and fractures using 3-D seismic data. Seismic attribute analysis and waveform model regression have been used to map fractures, lithofacies, and reservoir properties. The results can be used to evaluate and model reservoir flow pathways, caprock integrity, CO_2 storage capacity, and retention permanency in CO_2 storage reservoirs.

Gravity Methods

High-precision gravity measurements can be used to detect changes in density caused by CO_2 injection into a subsurface reservoir. This is due to the fact that CO_2 is less dense than the formation water or oil that it displaces in the reservoir. A change in the vertical gravity gradient may also indicate a change in reservoir pressure (Kerr, 2003). Time-lapse gravity surveys may be used to track the migration and distribution of CO_2 in the subsurface, although the resolution of gravity surveys is much lower than that of seismic surveys. The resolution of a gravity survey can be improved if gravimeters are placed in a wellbore in close proximity to the reservoir of interest. Carbon dioxide detection thresholds are site-specific, but, as a general rule, deeper reservoirs are less suitable for gravity monitoring.

Lessons Learned from the Field: Gravity Methods

Time-lapse seafloor gravity measurements were made over the Sleipner injection site in 2002, 2005, and 2009 to monitor the evolution of stored CO_2 in the 800-m deep Utsira formation (Alnes et al., 2010). Highly precise gravity measurements were obtained using a remotely operated vehicle (ROV), which made repeat visits to 30 benchmark stations on the seafloor. The time-lapse data showed good repeatability between surveys. The results of the time-lapse gravity surveys revealed a significant reduction in gravity over the CO_2 plume from 2002 to 2009 (Figure 18), reflecting the displacement of denser formation water in the Utsira reservoir with less dense CO_2 during and after injection. Repeat gravity measurements at Sleipner were also used to estimate the density of the supercritical CO_2 in the reservoir.

Seafloor gravity measurements were also used to constrain the extent of CO_2 dissolution in the injection reservoir at Sleipner. Carbon dioxide injected into deep saline formations can stay in the supercritical phase, dissolve in brine, or react to form solid mineral phases. Carbon dioxide monitoring requires an accounting of CO_2 in supercritical, liquid, and solid phases. The CO_2 density estimated from gravity surveys indicated that the rate of CO_2 dissolution in the brine is less than 1.8 percent per year. This result demonstrates the usefulness of gravity measurements for CO_2 monitoring. The rate of CO_2 dissolution in brine cannot be detected with time-lapse seismic data, but it was reliably estimated using high-precision gravity surveys.

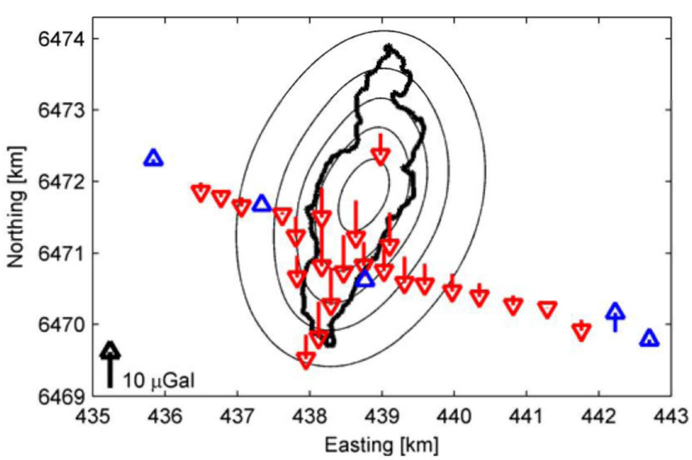


Figure 18: Map of Observed Gravity Changes at Sleipner (2002-2009), Indicating Lowered Gravity Due to CO_2 (Red Arrows). (Alnes et al., 2010)

Current and Ongoing Research: Gravity Methods

High-precision gravity surveys are likely to continue to be useful for identifying density and pressure changes in the subsurface resulting from CO_2 injection. Such surveys may also gain importance for monitoring dissolution rates of CO_2 in the injection reservoir. For improved efficacy of gravity monitoring in deep formations, development and deployment of wellbore-based gravimeters may be necessary.

Researchers from Japan are developing a highly sensitive, superconductive gravimeter for use in gravity monitoring surveys. The goal is to deploy these instruments at CO_2 injection sites for continuous monitoring of gravity perturbations. One system is currently being field tested at SWP's CO_2 injection field in Utah.

Electrical Methods

Electrical methods can be used to detect the conductivity contrast between CO_2 (less conductive) and saline water (more conductive) in a geologic formation. Specific electrical techniques that have been used to monitor CO_2 are primarily electrical tomography (ET), including electrical resistance tomography (ERT) and EM tomography, and controlled-source electromagnetic (CSEM) surveys.

ET can provide a 3-D image of the resistivity distribution of the injection reservoir. In time-lapse mode, this method can be used to map the spatial extent of an undissolved CO_2 plume in a saline formation to monitor changes in reservoir fluid saturation and to track plume migration. Dissolved CO_2 has little effect on water/brine resistivity (Fleury and Deschamps, 2008). Two standard types of ET are ERT, where the potential difference across two electrodes caused by injected current is measured, and EM tomography, which is based on EM induction principles.

In ERT, electrodes are used to measure the pattern of resistivity in the subsurface. These electrodes can be mounted on the exterior of non-conductive well casing, forming a vertical electrical resistivity array (VERA). This method does not interfere with subsurface monitoring techniques operating within the well casing, such as wireline induction logging (Carrigan et al., 2009). ERT may be performed in crosswell or surface-to-downhole configuration, depending on the desired scale of resistivity imaging. ET requires non-conductive well casings and multiple monitoring wells for best results.

CSEM surveys are also used, mainly in offshore environments, to study variations in the conductivity of the subsurface. Marine CSEM surveys involve towing a high-powered EM source close to the sea floor, and measuring the transmitted fields using widely spaced receivers that are anchored onto the sea floor (Mehta et al., 2005, Pratt, 2006). Low-frequency CSEM monitoring is sensitive to thin resistive layers, and it may provide a suitable tool for large-scale injection monitoring. CSEM surveys have been used successfully to detect hydrocarbons in offshore environments.

Lessons Learned from the Field: Electrical Methods

Several electrical techniques were tested at the CO_2SINK project site in Ketzin, Germany, from 2007 to 2010 to monitor CO_2 injection and plume migration. Crosswell electrical measurements were obtained from a VERA, and surface-to-downhole measurements were obtained using an injection well and two observation wells (Kießling et al., 2010; Schmidt-Hattenberger et al., 2010). Time-lapse, crosswell ERT results indicated a significant resistivity increase in the injection zone of 200 percent over baseline values. The bulk CO_2 saturation was estimated at 50 percent in the injection zone, which lies at an approximate depth of 635 m (Figure 19). Data resolution was on the order of the electrode separation distance (10 m) in the vertical array, so that small-scale fingering and zones of low-CO_2 saturation were not detected. Surface-to-downhole ERT data collected at the depth of the injection zone using 16 non-permanent electric dipoles, located 800 m and 1,500 m from each well, indicated preferential migration of CO_2 along the predominant structural trend of the formation.

In addition to the surface-to-downhole and crosswell ERT surveys, a CSEM survey was also conducted at Ketzin (Streich et al., 2011). Currents varying in frequency from 1/64 to 64 Hz were injected, and the induced horizontal electric and three-component magnetic fields were recorded by 39 surface receivers. Initial data analysis suggested that lower-frequency source signals could be traced over distances of approximately 10 km, indicating the potential to monitor CO_2 plume migration over a large area.

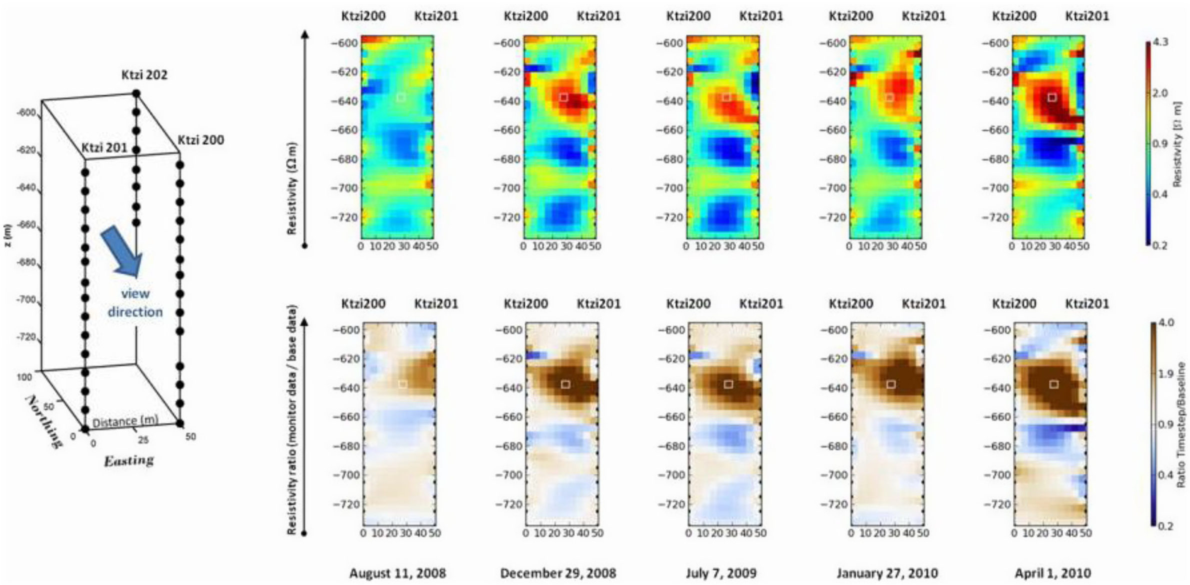


Figure 19: Crosswell Configuration and Time-Lapse Monitoring Results, Indicating Absolute Resistivity Distribution Along Two Observation Wells and Changes in Resistivity Over Base Data at Ketzin. (Schmidt-Hattenberger et al., 2010)

A trial offshore CSEM survey was carried out at Sleipner in 2008, but no clear signal from the CO_2 plume was detected (Eiken et al., 2010). This may have been due to a combination of pipeline noise and insufficient resistivity contrast between the CO_2 plume and adjacent reservoir areas.

Current and Ongoing Research: Electrical Methods

Crosswell ERT measurements are being obtained at the SECARB Cranfield Phase III Early Test site to monitor the resistivity of the subsurface, where CO_2 is injected beneath the oil-water contact. Electrodes were installed in a vertical array in two monitoring wells. The electrode array is mounted outside of the well casing and is cemented in-place (Carrigan et al., 2009). Time-lapse results over a two-month period indicate two resistive masses, likely corresponding to migrating CO_2 plumes (Figure 20). Researchers have also identified a conductive mass, possibly a plume of workover fluids, located in the area between the two observation wells (Romanak, 2010).

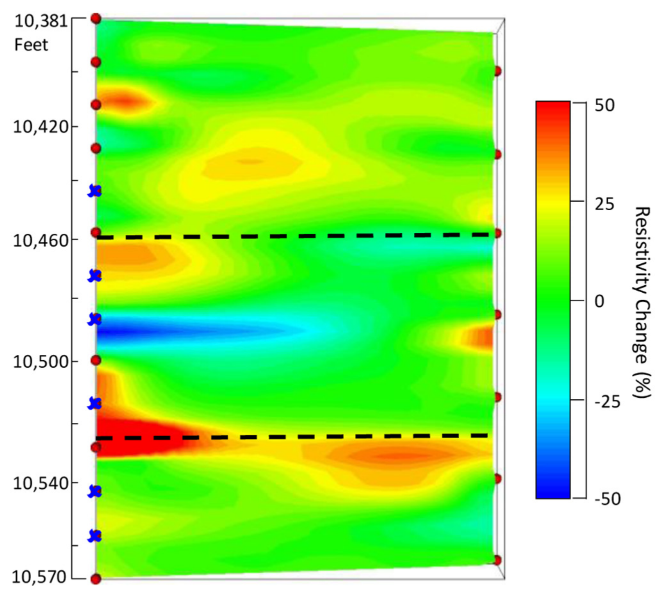


Figure 20: Percent Change of Resistivity Between Monitor Data on February 5, 2010, and the Baseline on December 1, 2009, Obtained by Conventional ERT Data Processing Methods. (Yang et al., Submitted Manuscript)

(Round dots are electrodes in the borehole. Electrodes marked by an "X" were removed before the inversion. Two horizontal dashed lines are the boundaries of the reservoir layer.)

In an effort to develop a method that is less expensive than 3-D seismic surveys for monitoring onshore CO_2 injections, researchers at LBNL are modeling CSEM surveys using a vertical electric dipole source installed in a well beneath the CO_2 plume. This source configuration is used because buoyancy-driven CO_2 plumes, which are electrically resistive compared to brine and shale caprocks, tend to form a relatively thin, flat-lying shape beneath a caprock. EM sources that generate vertical electric fields (E_z) in this region can provide a detectable response using magnetic (B-field) and electric (E-field) sensors located on the surface (Figure 21) or in a borehole. Baseline and time-lapse surveys would be used to detect the undissolved CO_2 plume distribution during and after injection.

3.4 MVA Data Integration and Analysis Technologies

Throughout this chapter, numerous tools and technologies used to collect CO_2 monitoring data in the atmosphere, the near-surface zone, and the subsurface have been discussed. There are also a number of cross-cutting technologies being developed to better integrate and analyze the wide variety of monitoring data that are acquired. These data integration and analysis technologies include computer-based intelligent monitoring networks and advanced data integration and analysis software tools.

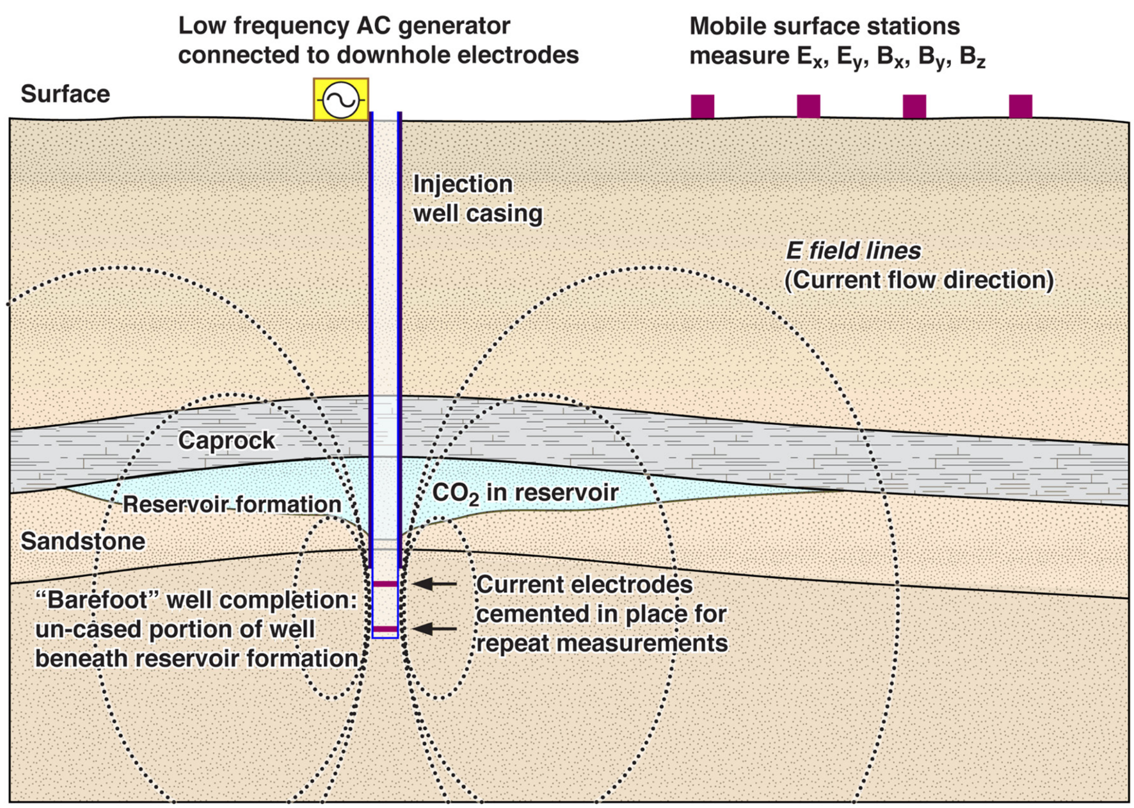


Figure 21: Survey Configuration for Time-Lapse CSEM Monitoring of Onshore CO_2 Injections. (Beyer et al., 2012)

Intelligent Monitoring Networks

Intelligent monitoring networks are automated, computer-based systems that gather field information from injection and monitoring equipment, evaluate GS conditions, and recommend appropriate actions. Systematic data collection, analysis, and modeling are key components of these systems. Intelligent monitoring networks are designed to show that site performance meets pre-defined objectives and to ensure that release of CO_2 is promptly identified and mitigated.

An intelligent monitoring network may combine data from CO_2 monitoring wells, surface monitoring sensors, subsurface monitoring tools, and injection equipment. The data are compiled in real time in a database that is updated continuously. The intelligent monitoring network may also compare field data to available models and historical field data. Measurements that lie outside normal operational limits or historical trends are flagged as potential risks.

In some cases, an intelligent monitoring network may determine the cause of an anomaly and proceed to rectify the problem. If a CO_2 transport line registers an increase in pressure, for example, the monitoring network may decrease the flow rate or utilize a bypass line. The system may also recommend action items based on analysis of the field data. For example, if a surface sensor shows increased levels of CO_2, the system may recommend further investigation in the vicinity of the sensor and specify potential release pathways present in the area. This information will aid field operators in promptly locating and identifying a release.

The selection of sensors and methods employed in a monitoring network is site-specific and requires testing, planning, and scheduling within the project plan. Conditions that may affect the selection of monitoring network components include site access, surface geography, type and complexity of storage formation, and size of the monitoring area. Project developers may perform a risk assessment of the site in order to determine the appropriate techniques required to monitor and mitigate risks.

Smart-well technology may be utilized to provide real-time well data to a monitoring network. Smart wells contain permanent, downhole sensors and flow equipment that allow for continuous monitoring and regulation of fluid flow, formation pressure, and formation temperature in the injection formation. Smart wells have been used in the oil and gas industry for more than 10 years, and the technology can be readily adapted for use in a CO_2 monitoring network.

Some smart wells contain remotely actuated packers, which allow for in-situ fluid control and selective zone production in multi-zone wells. The proximity of these sensors to the injection horizon minimizes response times and provides valuable in-situ information that is not obtainable with indirect monitoring methods. Smart-well technology can also respond to sudden changes in wellhead pressure and production rates, and it can be useful for controlling unstable wells.

Lessons Learned from the Field: Intelligent Monitoring Networks

The value of intelligent monitoring networks is reflected by the fact that they are increasingly utilized in CO_2 monitoring projects. The IBDP was one of the first projects to include a comprehensive network of monitoring technologies within its project plans. Techniques including 2-D geophysical surveys, EC measurements, shallow groundwater monitoring, and computer simulations have been used at every phase of the project in order to accurately record baseline, injection, and post-injection conditions. These methods have been combined in real time using a state-of-the-art intelligent monitoring network. The network compiles measurements from all field sensors and compares these measurements to historical data. A fast interpretation loop, implemented within the control and data acquisition system at IBDP, monitors the sensor diagnostics, ensures proper data acquisition, and provides fast interpretation to generate real-time alerts based on pre-defined thresholds. Field operators may interact with individual sensors to determine the best ways to mitigate risk (Picard et al., 2011).

Advanced seismic and gravimetric monitoring are the primary components of the intelligent monitoring network used at the Sleipner CO_2 deep offshore storage project in the North Sea. Several time-lapse 3-D seismic surveys have been conducted throughout the life of the project to monitor and study the distribution of the CO_2 plume. Other related technologies used at Sleipner include high-resolution 2-D seismic and seabed imaging. These data, along with advanced modeling and simulation tools, are being used to determine storage performance and identify any CO_2 containment risks.

Current and Ongoing Research: Intelligent Monitoring Networks

Recent DOE/NETL research has focused on efficient risk assessment and innovative intelligent monitoring methodologies. To this end, ZERT and MSU are developing technologies that reduce the uncertainties associated with risk assessments and monitoring data. ZERT personnel are also working with scientists at Los Alamos National Laboratory (LANL) to develop monitoring technologies to fill the gaps found in current risk assessments.

The SACROC CO_2-EOR Project in Texas has incorporated smart-well technology in its CO_2 monitoring strategy. Remotely controlled downhole sensors and fluid control equipment monitor and control the distribution of injected CO_2 into targeted stratigraphic zones. This allows the project to lower its CO_2 injection volume while maintaining adequate oil production levels.

In addition, DOE/NETL is working with West Virginia University to develop intelligent monitoring software for continuous and autonomous monitoring of CO_2 storage in geologic formations. The software will help the operator to recognize patterns in real-time data obtained from multiple permanent downhole gauges. Changes in reservoir pressure, recorded at multiple gauges, will be analyzed and used to identify the location of potential CO_2 releases and to estimate approximate release rates.

Advanced Data Integration and Analysis Software

In addition to intelligent monitoring networks, scientists are developing advanced software tools to perform specific MVA data integration and analysis tasks. These tools include data processing software as well as data integration and visualization software.

A number of Core R&D projects supported by NETL/DOE are focused on improved processing and interpretation of CO_2 monitoring data, processing data from a variety of monitoring methods, and development of cost-effective time-lapse seismic monitoring techniques. In addition, projects are underway to develop graphical user interfaces to aid in the design of site-specific monitoring plans. These graphical user interfaces may also help to facilitate data interpretation, integration, and fluid flow simulations.

Current and Ongoing Research: Advanced Data Integration and Analysis Software

NETL is partnering with the University of Miami to develop a low-cost, data integration methodology for long-term monitoring of CO_2 in the subsurface. Geodetic data, including GPS and InSAR data, will be combined with seismic reflection data and geochemical data using a straightforward series of algorithms. The plan is to demonstrate this methodology at a DOE CO_2 storage test site. The project includes development of training modules on how to integrate GPS and InSAR data, analytical and numerical modeling results, and geochemical modeling results to evaluate ground deformation, poroelastic rock behavior, and effects of long-term geochemical reactions in CO_2 storage reservoirs.

DOE/NETL is funding a project with Fusion Petroleum Technologies to develop software to perform 4-D seismic data processing and incorporate the results into reservoir modeling and simulation programs. The goal is a seamless CO_2 monitoring workflow that automatically integrates time-lapse seismic results with reservoir model simulations.

DOE/NETL is also supporting a project with Ohio State University to provide practical guidelines for the use of seismic monitoring techniques and other geophysical evaluation tools in CO_2 storage projects. A graphical user interface is being developed with modules for integrating and manipulating geologic, seismic, and EM data. The results will aid in decision making related to CO_2 injection planning and well placement. Further refinements are expected to lead to the application of the graphical user interface to data from the American Electric Power Mountaineer carbon storage site in West Virginia.

Finally, DOE/NETL is partnering with the University of Houston to provide training on advanced 3-D seismic processing methods that use elastic wavefield simulation and can be applied to CO_2 MVA. The project will address key challenges, including enhanced mapping of caprock integrity and potential release pathways and improved quantification of seismic results.

4. Review of EPA Permitting Requirements

In the U.S., regulations relevant to injection and storage of CO_2 in deep geologic formations are laid out in two EPA programs: (1) the UIC Program; and (2) the GHG Reporting Program. In this chapter, a summary of the salient elements of these programs is provided, along with links to the EPA webpages where more specific information can be found.

4.1 UIC Program

The UIC Program was developed in 1979 as an outgrowth of the Safe Drinking Water Act (SDWA). The SDWA included a mandate for EPA to develop Federal guidelines to control injection wells and injection activities, so that injection practices would not lead to contamination of USDWs. The UIC Program regulates the injection of all fluids, including liquids, gases, and semi-solids, into the subsurface. The UIC Program's primary mission is to protect USDWs and to ensure that no injection operations endanger USDWs or human health.

To this end, the UIC Program has established minimum standards for safe construction, operation, permitting, and closure of injection wells "that place fluids underground for storage or disposal." These standards are designed to ensure that injected fluids are not released from the wellbore or the targeted injection zone and do not endanger USDWs. Regulations specific to GS of CO_2 involve protection of USDWs from brine and CO_2 plume infiltration from the CO_2 injection process. UIC Program information, guidance documents, and compliance assistance are provided on the EPA website, at: **http://water.epa.gov/type/groundwater/uic/index.cfm**.

4.2 UIC Well Classes

During the 1980s, EPA's UIC Program established five well categories, or "classes," to manage particular risks associated with different types of injection wells. UIC Well Classes I through V were defined according to the types of fluids injected, the nature of injection activities, well design and construction, injection depth, and operating techniques employed. Wells in a particular UIC well class share similar design parameters and similar operating techniques, and they are therefore subject to a common set of safety standards and regulations.

In December 2010, EPA finalized a new well class—UIC Class VI—in order to ensure proper permitting and reporting of CO_2 injection wells in commercial-scale GS projects. The new Class VI regulations build on existing UIC regulatory components for key procedures including siting, construction, operation, monitoring and testing, and proper closure of injection wells. In addition to protecting USDWs, the new rules provide a regulatory framework to promote a consistent approach to permitting GS projects across the United States.

Injection wells are now classified according to the following six UIC well classes:

- Class I – Wells injecting hazardous, industrial, and municipal wastes below USDWs.
- Class II – Wells related to oil and gas production, mainly injecting brine and other fluids.
- Class III – Wells injecting fluids associated with solution mining of minerals, such as salt (sodium chloride [NaCl] and sulfur [S]).
- Class IV – Wells injecting hazardous or radioactive wastes into or above USDWs; generally only used for bio-remediation.
- Class V – Injection wells not included in Classes I through IV that are typically used as experimental technology wells.
- Class VI – Injection wells specific for the GS of CO_2 (finalized December 2010).

A detailed discussion of the six UIC well classes is available on EPA's UIC website, at: http://water.epa.gov/type/groundwater/uic/wells.cfm. The UIC Program also provides standards, technical assistance, and grants to state governments for regulating injection wells and protecting drinking water resources.

All injection wells are to be sited in geologically suitable areas, and a study is to be conducted to determine whether any conduits may be present that may provide a pathway for fluid movement to USDWs. Injection wells are to be constructed of materials that can withstand exposure to injected fluids, and testing throughout the injection period must be carried out to assure that each well remains in proper working order and that no unintended fluid release occurs. Finally, injection wells must be closed in a manner that prevents the well from inadvertently serving as a conduit for future fluid migration.

RCSP Validation Phase Project Injection Wells

Injection wells operated under the RCSP Validation Phase field projects were permitted under the UIC Program's original five well classes, because these permits were granted prior to the addition of the UIC Class VI. Most of the RCSP injection wells are therefore categorized as Class II or Class V. Note that future injection wells for GS projects will be permitted according to the recently finalized Class VI category. Table 5 provides a list of the current RCSP Validation Phase projects and indicates project location, injection formation, injection depth, injection volume, UIC well class, and UIC permitting entity.

Variations in RCSP well classifications reflect differences in project type, target formation characteristics, institutional architecture, primacy, and the local regulations of individual states or provinces within the context of overall Federal oversight. Almost 80 percent of the wells for RCSP Validation Phase projects were permitted by state agencies under the UIC Program, while 20 percent were permitted by Federal agencies. Future applications for all of the large-scale Development Phase UIC permits will be as Class V (experimental), or in some cases VI wells, if not determined to be experimental by EPA. Future Class V wells are expected to adopt many of the Class VI construction and operating requirements.

Table 5: Summary of RCSP Validation Phase Projects (Updated May 2012)

Project Name	Partnership	State	UIC Permit Class	Project Type	Basin Name	Injection Formation(s) (Reservoir)	Confining Formation(s) (Caprock)	Total Vertical Depth (ft)	Injection Depth (ft)	CO_2 Injected (tonnes total) April 2012
Sugar Creek Project	MGSC	Kentucky	Class II	EOR	Illinois Basin	Jackson Sandstone	Fraileys Shale	N/A	1,867–1,879	6,300
Mumford Hills Project	MGSC	Indiana	Class II	EOR	Illinois Basin	Clore Sandstone	Clore Shale	N/A	1,905–1,925	6,560
Loudon Single Well Huff 'n' Puff Project	MGSC	Illinois	None	HNP	Illinois Basin	Cypress & Mississippi Weiler SS	Cypress Shale	N/A	1,510–1,530	39
Tanquary Well Project	MGSC	Illinois	Class II	ECBM	Illinois Basin	Springfield Coal	Dykersburg Shale	960	896–902	91
Zama Acid Gas EOR, CO_2 Storage, and Monitoring Project	PCOR	Alberta, Canada	Directive 65 and Directive 51 (ECRB)	EOR	Zama Basin	Middle Devonian Keg River Formation	Muskeg Anhydrite	5,020	4,878	80,000 acid gas
Lignite CCS Project	PCOR	North Dakota	Class II	ECBM	Williston Basin	Lignite Seams in Ft. Union Formation	Clay/Mud layers within formation	1,246	1,100	80
NW McGregor EOR HNP Project	PCOR	North Dakota	Class II	EOR / HNP	Williston Basin	Mission Canyon Limestone	Charles Fm Tight Limestones and Anhydrites	10,147 (plugged to 8,150)	8,052	400
Plant Daniel Project	SECARB	Mississippi	Class V	Saline	Mississippi Interior Saly Basin	Massive Sand, Lower Tuscaloosa	Marine Tuscaloosa	9,720	8,520–8,720	2,740
Black Warrior Project	SECARB	Alabama	Class II	ECBM	Black Warrior	Pottsville Formation (coal zones)	Pottsville Fm (marine shale units)	3,510	1,000–2,500	252
Gulf Coast Stacked Storage Project	SECARB	Mississippi	Class II	EOR	Mississippi Interior Saly Basin	Tuscaloosa Formation	Upper Tuscaloosa, Eagle Ford Shale, Austin Chalk	10,500 +	10,300–10,500	627,744
Central Appalachian Basin Coal Test	SECARB	Virginia	Class II	ECBM	Appalachian	Pocahontas & Lee Formation	Norton Formation	2,534	1,600–1,700 (Lee) 2,100–2,300 (Pocahontas)	907
Pump Canyon CO_2- ECBM/ Sequestration Demonstration	SWP	New Mexico	Class II	ECBM	San Juan Basin	Fruitland Coal Formation	Kirtland Shale	3,153	~3,050	16,700
SACROC CO_2 Injection Project	SWP	Texas	Class II	EOR	Permian Basin	Horseshoe Atoll & Pennsylvanian Reef/Bank Play	Wolfcamp	~6,700	~6,600	86,000
Aneth EOR Sequestration Test	SWP	Utah	Class II	EOR	Paradox Basin	Desert Creek & Ismay Formation	Gothic Shale	~5,900	~5,800	630,000
Arizona Utilities CO_2 Storage Pilot	WESTCARB	Arizona	Class V	Saline	Holbrook Basin	Martin & Naco Formations	Supai Fm. evaporites, shale, mudstone	3,853	N/A - negligible permeability	None
Northern California Geologic Characterization	WESTCARB	California	None-Permitted under state O&G regulations by DOGGR	Geologic Characterization	Sacramento Basin (northern California Central Valley)	Domengine, Mokelumne River, H&T/Starkey SS	Nortonville, Capay, Meganos, H&T Shale, Starkey Shale	6,920	N/A	None
Appalachian Basin Geologic Test at R.E. Burger Power Plant: Fegenco Well	MRCSP	Ohio	Class V	Saline	Appalachian	Clinton SS / Salina Fm / Oriskany SS	Ohio Shale	8,384	5,000–7,500	50
Duke Energy - East Bend Well Site	MRCSP	Kentucky	Class V	Saline	Cincinnati Arch	Mt. Simon	Eau Claire	3,564	3,410–3,510	1,000
Michigan Basin Geologic Test	MRCSP	Michigan	Class V	Saline	Michigan Basin	Bass Islands Dolomite	Antrim Shale	5,800	3,400–3,500	60,000
Wallula Basalt Pilot Study	Big Sky	Washington	Class V	Basalt	Columbia River Basin	Interflow zones, Grande Ronde Basalt	Slack Canyon basalt, Umtanum basalt	4,110 (plugged to 2,910 ft)	2,716–2,910	None

4.3 UIC Class II Injection Wells Transitioning to UIC Class VI Wells

Permitted Class II EOR or enhanced gas recovery (EGR) wells "injecting CO_2 for the primary purpose of long-term storage into an oil or gas reservoir must obtain a Class VI permit when there is an increased risk to USDWs as compared to Class II operations" (U.S. Federal Register, 2010). If the owner/operator or the EPA Director determines that there is an increased risk to USDWs, the owner/operator must apply for and obtain a UIC Class VI permit. After transitioning from Class II to Class VI, the project may continue with enhanced recovery (ER) operations, but it must adhere to the more stringent monitoring requirements specified under a Class VI injection well permit. The EPA Director will make the determination between a "traditional Class II operation" and an "ER operation with Class VI classification" based on the following risk-based factors:

- Increase in reservoir pressure within the injection zone.
- Increase in CO_2 injection rates.
- Decrease in reservoir production rates.
- The distance between the injection zone and USDWs.
- The suitability of the Class II area of review (AoR) delineation.
- The quality of abandoned well plugs within the AoR.
- The owner's or operator's plan for recovery of CO_2 at the cessation of injection.
- The source and properties of injected CO_2.
- Any additional site-specific factors as determined by the Director.

Note that a single risk factor may not result in a determination that a Class II well should be re-permitted as a Class VI well. The classification of the well will depend on a study of all the risk factors. EPA encourages owners and operators to be proactive and assess their own ER wells using these risk-based factors in order to determine if they should be re-permitted as Class VI wells. Once a production well is re-permitted as a Class VI well, the project may continue ER operations with CO_2.

An EPA guidance document, titled "EPA Class II - Class VI Transition Guidance," is scheduled for release in 2012 and will provide regional directors and well owners and operators with further details on evaluating these factors and determining if a permit transition is necessary.

4.4 UIC Class VI Geologic Storage Wells

EPA, together with DOE'S R&D Program, evaluated the potential impacts of GS on health, safety, and the environment through several coordinated efforts. These analyses served as guidance for the development of the UIC Class VI well specification for GS projects. Additional guidance was provided by the Interstate Oil and Gas Compact Commission's (IOGCC) Task Force on Carbon Capture and Storage, which developed a legal and regulatory model framework for the GS of CO_2 that addressed the unique requirements of individual states. Members of the IOGCC Task Force include states with jurisdiction, experience, and expertise in the regulation of oil and natural gas wells (Class II), particularly in the injection of petroleum wastes and CO_2 for EOR. In addition, natural gas storage statutes provided relevant information for operational plans addressing public health and safety during injection. Although custody issues for long-term GS are not addressed in its report, IOGCC's work was the first step in considering appropriate regulatory requirements.

The EPA Class VI rule uses a combination of a fixed timeframe and a performance standard for well monitoring. EPA has established a post-injection site monitoring period of 50 years, with the UIC Program Director having discretion to change that period if appropriate. The default timeframe could be lengthened if potential for endangerment to USDWs still exists after 50 years, or if modeling and monitoring results demonstrate that the CO_2 plume and pressure front have not stabilized in this period. Conversely, the 50-year time period could be reduced if data on pressure, fluid movement, mineralization, and/or dissolution reactions indicate that movement of the plume and pressure front have ceased, and the injectate does not pose a risk to USDWs. This combination of fixed timeframe and performance standard emphasizes the importance of developing robust technologies for measurement and monitoring of CO_2 in deep geologic formations.

4.5 State and Regional Control of CO_2 Injection Wells

EPA encourages state and regional governments to seek primary enforcement responsibility or "primacy" for UIC well permitting, including UIC Class VI CO_2 injection wells. EPA asserts that state and regional entities are better equipped to address local concerns and handle geological assessments in their respective areas. State or regional primacy includes the right to approve permit applications and revisions, control over permitting decisions, and responsibility for oversight of injection wells. States may apply for this regulatory authority under Section 1422 of the SDWA.

EPA is currently accepting new applications for state control of UIC wells and program revisions to existing primacy agreements to include Class VI well permitting rights. States with no primacy agreements in place, or with primacy over Class II wells only, may choose to apply for primacy over all UIC well classes (I-VI) or over UIC Class VI wells only. Such states must hold an initial public hearing prior to submitting their application to EPA.

States that already have primacy over UIC well classes I-V may seek to add primacy for Class VI wells by applying for a program revision. States seeking this program revision are not required to hold an initial public hearing, because this requirement was fulfilled during their original application process.

Once the application is submitted and all required documents are received and approved, EPA will review and provide a public notice of the application. A 30-day opportunity for comments and public feedback will be provided by EPA, and a public hearing will be performed if strongly requested. During the review period, the state may continue to approve well permits within their authority and should forward all permit applications for Class VI wells to their regional EPA agency until their primacy application is approved and formally announced through the Federal Register. For specific details concerning UIC primacy and the application process, it is best to consult a regional EPA representative.

Wells utilized for GS projects that are currently approved through permits other than Class VI will need to be re-permitted through their UIC permitting authority. The timeframe for the re-permitting process will depend on proper approval of the UIC authority to handle UIC Class VI permits. As of January 2012, no state or regional government had been approved for primacy of Class VI wells. Once a state is approved for primacy, the well owner or operator will have up to one year to submit an application for re-permitting. EPA will continue to handle the UIC well permitting process for states that do not have permitting authority.

4.6 UIC Class VI Injection Well Requirements

The complete text of the new UIC Class VI regulations is found in the U.S. Federal Register, UIC Class VI Final Rule Document (U.S. Federal Register, 2010). The Class VI well rules are more stringent than the prior UIC regulations for Class I through Class V wells. The new regulations include: siting requirements, well design and construction guidelines, MITs, AoR determination, tracking plume location, and post-closure care. The following is a summary of the unique monitoring requirements introduced by EPA for UIC Class VI wells.

Under the new Class VI rules, well owners or operators are required to perform an initial site characterization study of each proposed injection site "to ensure that GS wells are sited in appropriate locations and inject into suitable formations" (U.S. Federal Register, 2010). Site characterization is to include a careful evaluation of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed site. This should include an evaluation of potential seismic risks and careful mapping of faults and fractures that may transect the confining zones and could make the site unsuitable for long-term containment. In addition, owners or operators must compile data on the porosity and fluid pressure of the injection formation, as well as extensive geochemical data on fluids in the injection zone, confining zones, overburden layers, and USDWs. The purpose of this information is to confirm adequate and stable storage capacity in the injection zone, to identify any potential release pathways or seismic risks, and to establish a baseline for subsequent monitoring studies.

Well construction procedures for Class VI wells require that surface casing for GS wells be set through the base of the lowermost USDW and cemented to the surface. The long-string casing must be cemented in place along its entire length. GS wells should also be constructed with a packer that is set opposite a cemented interval. Also, the use of corrosion-resistant materials that are compatible with the injectate and subsurface fluids is required.

Corrosion analysis of well components must be performed quarterly in order to determine loss of mass, thickness, cracking, or pitting. Corrosion monitoring methods may include: analyzing coupons (removable samples) of well construction material placed in contact with the CO_2 stream, routing of CO_2 stream through a test loop and further analyzing test loop material, or an alternative method approved by EPA.

Class VI wells used in GS projects are also required to have MITs performed at every stage of the project, including construction, injection, and well plugging. The internal mechanical integrity of the injection wells is to be tested at least once per year by monitoring injection pressure, flow rate, and injected volumes. The annular pressure and fluid volume must also be monitored to assure that no anomalies occur that may indicate an internal release.

Additionally, owners or operators of CO_2 GS wells are required to demonstrate the injection well's external mechanical integrity at least once annually. This is accomplished through the use of downhole geophysical logs or surveys designed to detect CO_2 release. Although EPA has identified several internal and external MIT methods that are acceptable for the fulfillment of these requirements, the EPA Director may approve alternative methods if required. The new rule also requires automatic downhole shut-off mechanisms in the event of a mechanical integrity loss. Finally, a pressure fall-off test must be performed at each injection well every five years to make sure the storage formation is responding as expected. This is an increase in testing frequency compared to other UIC well classes and is intended to protect USDWs.

EPA has identified five site-specific plans that must be approved and followed for UIC Class VI wells. These plans contain information necessary to warrant safe and controlled injection, monitoring, and long-term containment of CO_2. The plans include:

- AoR and Corrective Action Plan
- Testing and Monitoring Plan
- Injection Well Plugging Plan
- Post-Injection Site Care (PISC) and Site Closure Plan
- Emergency and Remedial Response Plan

The AoR and Corrective Action Plan for Class VI requires the determination of the AoR based on computational modeling of site conditions and injection regime. Delineation of the AoR must be based on potential plume migration and pressure propagation. Modeling should include site characterization data regarding the injection zone and confining system, taking into account geologic heterogeneities and potential migration pathways, including faults, fractures, and man-made conduits. The well owner or operator must re-evaluate the AoR periodically, as site conditions may change from the baseline state and directly impact the AoR. The timeframe for AoR re-evaluation must not exceed five years, and the proposed AoR must be approved by the Director. Additionally, the plan must include proposed corrective actions for identified release pathways that may pose a threat to CO_2 plume containment or threaten nearby USDWs.

The Testing and Monitoring Plan must include all potential release pathways and storage areas to be monitored, along with specific technologies and testing schedules chosen for monitoring at every stage of the MVA process. This document must also include a Quality Assurance and Surveillance Plan (QASP) validating that all monitoring equipment and methodologies are appropriate for their specific task. The Testing and Monitoring Plan should be reviewed and updated at least once every five years based on any changes to the AoR and/or monitoring efforts identified by the owner or operator and the reviewing EPA Director. This plan goes beyond previous UIC requirements by requiring ongoing monitoring throughout the project life.

EPA requires CO_2 GS projects to analyze the CO_2 source stream during injection in order to determine the chemical and physical characteristics of the injectate. The frequency of these analyses must be sufficient to provide representative data and must be approved by the EPA Director. Additionally, CO_2 injection parameters including injection pressure, rate, volume, annulus pressure, and annulus fluid volume must be continuously recorded and analyzed through a monitoring system to determine if the injection process is within standard operating limits. The monitoring system must also include descriptions of well safety equipment and formation data to aid in identification of potential CO_2 release or safety risks.

Owners or operators are required to track the subsurface extent of the CO_2 plume and pressure front using pressure gauges, geophysical techniques, or other downhole CO_2 detection tools. Table 6 is a summary of the requirements and recommendations for tracking the CO_2 plume and pressure front presented in the UIC Class VI rule.

Monitoring of groundwater geochemistry above the confining layer is also required and should include testing of salinity, pH, and aqueous and pure-phase CO_2 changes. Soil gas monitoring may also be required to complement underground sampling methods. The schedule for all groundwater geochemistry analyses is site-specific and must be approved by the EPA Director.

The owner or operator must also have an approved Injection Well Plugging Plan to ensure that all monitoring wells are properly plugged after injection. The plan should outline the materials and methods that will be used to plug the well, so that injection or formation fluids do not endanger a USDW. Additionally, approved PISC and Site Closure Plans are required. These plans should outline long-term monitoring and recording of formation pressures and the plume front. EPA has indicated a post-injection monitoring period of 50 years, but the EPA Director may lengthen or shorten the 50-year period if appropriate.

Finally, an Emergency and Remedial Response Plan must be approved. This plan should outline the procedures to be followed if injected CO_2 or formation fluids threaten to endanger USDWs during the life of the project. This plan may include third-party emergency contacts to be notified in such an event.

All five UIC Class VI plans are intended to be interdependent. A modification to one plan should be evaluated in terms of the action or response it may trigger in the other plans. All five plans should be updated in parallel, as new field data become available and CO_2 injection and storage efforts move forward.

Table 6: Summary of Class VI Requirements and Recommendations for Identifying Position of the CO_2 Plume and Associated Pressure Front

Technology	Description	Class VI Rule Requirement
Direct Pressure Monitoring	Measurement of in-situ fluid pressure using transducers placed within monitoring wells in the injection zone.	Required to track the presence or absence of elevated pressure within the injection zone.
Indirect Geophysical Monitoring	Seismic, electrical, gravity, or electromagnetic techniques.	Required to track the position of the CO_2 plume, unless the UIC Program Director determines that such methods are not appropriate.
Geochemical Monitoring for Carbon Dioxide	Use of monitoring wells in the injection zone to detect the presence or absence of CO_2.	Recommended to augment required CO_2 and pressure monitoring.
Computational Modeling	Incorporation of site data into comprehensive mathematical model of the site.	Computational modeling is required as a component of AoR delineation and re-evaluation.

Table 7 presents examples of various plan interactions that may result from potential field occurrences. EPA, in consultation with other Federal and state agencies, is currently studying specific requirements that should be included in the UIC Class VI plans to address the issue of induced seismicity. For further information concerning the structure, development, and evaluation of these plans, please consult EPA's "Draft Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance for Owners and Operators."

4.7 GHG Reporting Program for GS Projects

In December 2010, at the time that UIC Class VI well regulations were finalized, EPA also finalized regulations for "Mandatory Reporting of Greenhouse Gases for Injection and GS of Carbon Dioxide." These reporting requirements are meant to provide EPA with a consistent GHG activity record for all future GS projects. They also ensure that appropriate consideration is given

Table 7: Interaction of Class VI Injection Well Project Plans (EPA – Office of Water, 816-D-10-012, March 2011)

Plan	Changes Identified in Implementing the Plan	Potential Impacts on Other Plans
AoR and Corrective Action Plan	Revised modeling delineates a larger/ differently shaped AoR.	▪ Amend the AoR and Corrective Action Plan to address newly identified deficient wells. ▪ Add monitoring locations to the Testing and Monitoring Plan. ▪ Revise the Emergency and Remedial Response Plan if new resources/infrastructure are identified in the AOR.
Testing and Monitoring Plan	Groundwater monitoring indicates leaching/mobilization of toxic metals or organics.	▪ Adjust corrective action methods to address water quality changes. ▪ Adjust injection well plugging methods. ▪ Modify operational and post-injection groundwater monitoring.
	Monitoring detects impairment of a USDW.	▪ Implement the Emergency and Remedial Response Plan. ▪ Modify operational and post-injection groundwater monitoring.
	Monitoring indicates the C_O^2 plume is moving faster than predicted, or in a different direction.	▪ Adjust corrective action schedule; conduct more frequent AoR re-evaluations. ▪ Expand groundwater monitoring/pressure monitoring network.
	Pressures within the injection zone vary from modeled predictions.	▪ Adjust post-injection pressure monitoring. ▪ Re-evaluate AoR, considering current pressure data; revise AoR and Corrective Action Plan.
PISC and Site Closure Plan	Monitoring detects groundwater contamination and plume excursions.	▪ Implement the Emergency and Remedial Response Plan. ▪ Modify post-injection monitoring regime.
Emergency and Remedial Response Plan	An adverse event required implementation of emergency and remedial response plan.	▪ Revisit all plans to identify lessons learned.

to key monitoring elements of GS projects, including: identification of potential geological and equipment releases, adequate mass balance of CO_2 throughout the life of the project, development of a baseline of atmospheric CO_2, and a surface/subsurface monitoring strategy. These regulations are meant to complement the UIC Class VI well regulations. More information on EPA's GHG Reporting Program can be found at: **http://www.epa.gov/climatechange/emissions/ghgrulemaking.html**.

Specifics of GHG reporting requirements for GS projects are contained in Title 40, Part 98 of the CFR. The first set of requirements is meant to aid GS projects in proper reporting and accounting of all CO_2 throughout the many stages of the project (i.e., transportation, compression, injection, containment, etc). The document does not specify monitoring technologies or methods to be used, although it provides recommended monitoring approaches. It also outlines performance criteria that should be tracked by project supervisors in order to fulfill the GHG reporting requirements.

Any CO_2 release from the surface or from injection equipment must be recorded quarterly and reported yearly as part of the GHG reporting requirements. A mass balance of the entire injection process must be developed that identifies and quantifies all potential CO_2 sources, including:

- Mass of CO_2 received.
- Mass of CO_2 injected into the subsurface.
- Mass of CO_2 produced (relevant for projects that perform both long-term carbon storage and production through ER).
- Mass of CO_2 emitted by surface release.
- Mass of CO_2 equipment release and vented CO_2 emissions from surface equipment located between the injection flow meter and the injection wellhead.
- Mass of CO_2 equipment release and vented CO_2 emissions from surface equipment located between the production flow meter and the production wellhead.
- Mass of CO_2 stored in subsurface geologic formations.
- Cumulative mass of CO_2 stored by the project since it became subject to these reporting requirements.

A series of mass balance equations are provided within the regulations document, so that the owner or operator may correctly determine all mass flow values. It is highly recommended that data from a flow meter be used, although other data sources may be acceptable if flow meters are unavailable. Flow meter calibration standards and requirements are also provided.

The GHG reporting requirements also include delineation and frequent updating of the area to be monitored. The rule specifies two distinct monitoring areas: the Maximum Monitoring Area (MMA) and the Active Monitoring Area (AMA). The MMA is defined as the "area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." This represents the expected maximum area to be monitored for CO_2 throughout the life of the project.

The AMA is an area of increased monitoring focus within the MMA. The AMA is defined as an overlay between "(1) The area projected to contain the free phase CO_2 plume at the end of year ***t***, plus an all around buffer zone of one-half mile or greater if known release pathways extend laterally more than one-half mile; and (2) The area projected to contain the free phase CO_2 plume at the end of year ***t+5***." Figure 22 illustrates these conditions and the resulting AMA delineation. Although monitoring efforts should be focused within the AMA region, continued monitoring should also be performed within the MMA to assure containment and avoid undetected CO_2 release.

The boundaries of the AMA must be periodically re-evaluated and approved by the EPA Administrator. The AMA must be monitored for at least one year before a re-evaluation is made. It is expected that, as CO_2 injection efforts move forward and the CO_2 plume continues to expand, the AMA delineation will also expand and eventually span the same area as the MMA. Figure 23 describes the relationship and progression of the MMA and AMA.

The rule does not specify which monitoring techniques should be applied within the AMA or the MMA. This is intended to allow some flexibility within a given project, so that site-specific regional, geologic, and geographic conditions may be taken into account. The

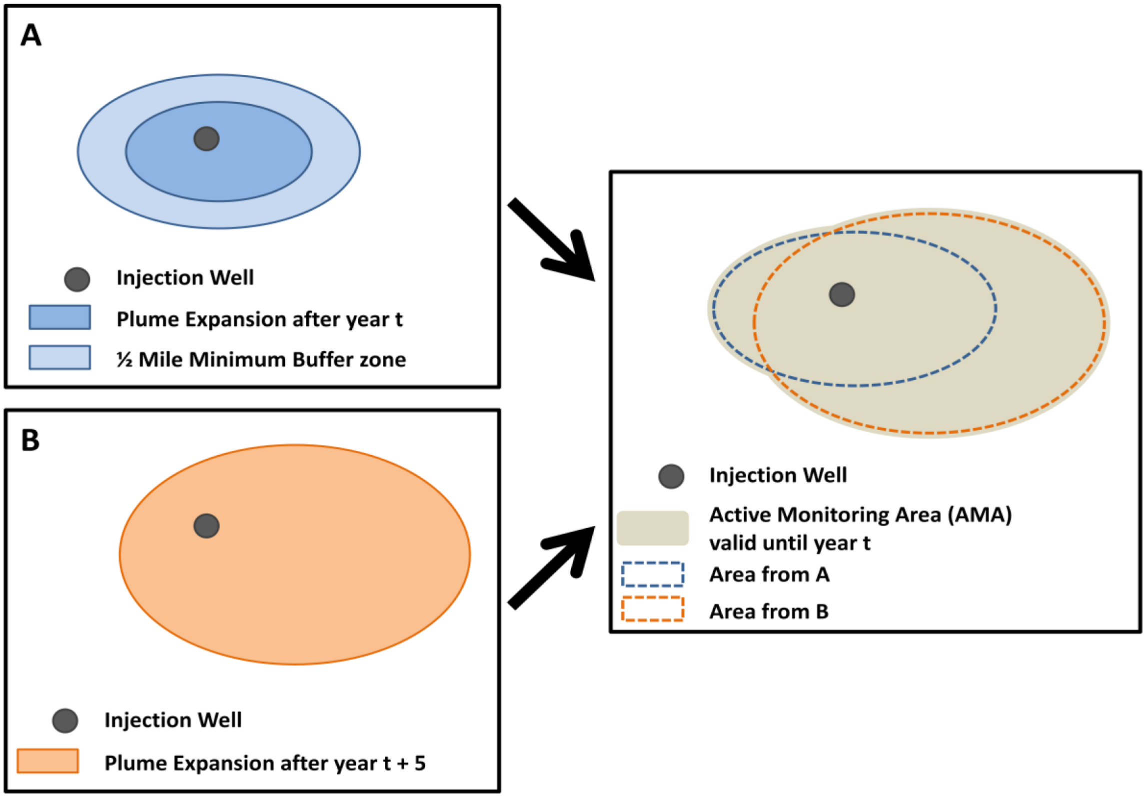


Figure 22: Diagram Showing Overlay Components for Delineation of AMA.

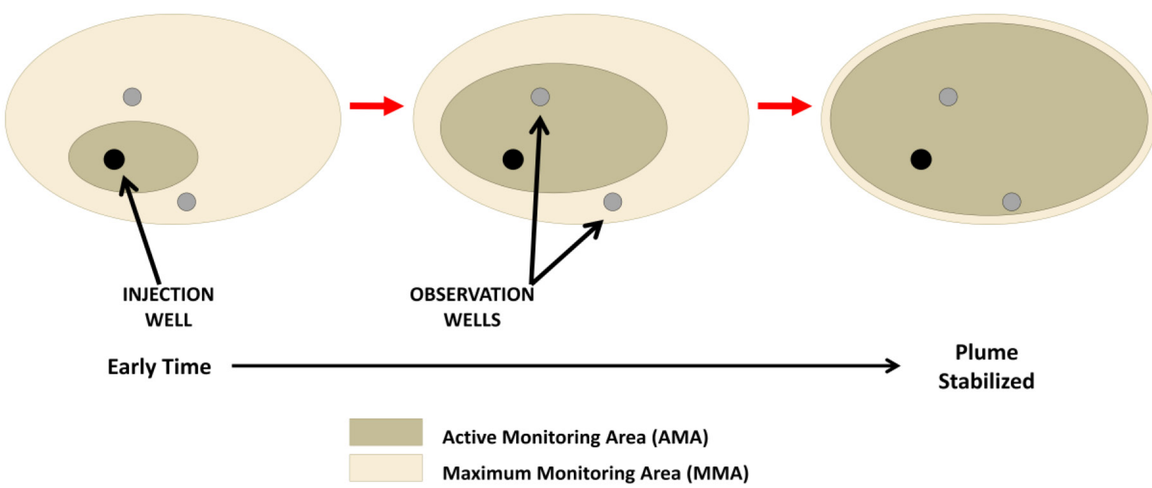


Figure 23: Diagram Showing Relationship Between MMA and AMA Through the Life of the Project.

monitoring schedule and plan must be developed by the project supervisor and approved by the EPA Administrator. Once the required reports are submitted to EPA, they will be evaluated to determine if the CO_2 plume is being properly contained and safely monitored. The EPA Administrator may require or suggest modifications to the MVA plan in order to better assure proper containment. If containment within the defined monitoring areas is not possible, a re-evaluation of the MMA, AMA, monitoring technologies, and schedules will be required for approval by EPA.

A Monitoring, Reporting, and Verification (MRV) Plan must also be developed for the project area. The major components are as follows:

- Delineation of MMA and AMA.
- Identification, Evaluation, and Risk Analysis of surface release pathways in MMA.
- Strategy for detecting and quantifying surface release of CO_2.
- Approach for establishing baselines for monitoring CO_2 surface releases.
- Summary of considerations made to calculate site-specific variables for mass balance.

The plan must be approved by the EPA Administrator and updated throughout the stages of a GS project. The MRV Plan must include recent results from CO_2 project mass balance calculations and the boundaries of the monitoring areas (AMA and MMA). It should also include a baseline of surface CO_2 atmospheric levels, surface conditions, and current surface equipment calibrations. The baseline CO_2 flux value will serve as a reference level for determining possible CO_2 release throughout the life of project.

The MRV Plan must also specify which field parameters will be analyzed to detect fluctuations in surface CO_2 levels or deviations from predicted behavior of the CO_2 in the subsurface. These indicator parameters may be environmental (such as subsurface pressure, soil CO_2 flux rates, etc.) or operational (such as the injection pressure and the annular pressure in the well). The MRV Plan must also describe potential surface release pathways in the MMA and the likelihood, magnitude, and timing of any potential release pathways including faults, fractures and abandoned wells. The MRV plan should also include a strategy for surface release prevention and detection. Finally, the plan must include the permits for all wells included within the project.

4.8 Overlap Between GHG Reporting Requirements and UIC Class VI Rule

There is some overlap between the GHG reporting requirements and the UIC Class VI rule, as shown in Table 8 (shown in red). One area of overlap is in the reporting of injected CO_2. The GHG plan requires the reporting of injected amounts of CO_2 to facilitate accurate calculations of the CO_2 mass balance within the project area. The UIC Class VI rule, on the other hand, requires monitoring of CO_2 injected for proper containment assurance. The UIC Class VI rules and GHG Reporting rules also both require surface emissions monitoring. In the case of the GHG Reporting rules, emissions monitoring is required for the purpose of mass balance and accountability of CO_2. The UIC Class VI rule requires emissions monitoring to ensure protection of water resources and public safety. The two rules are meant to be complementary of each other in as many ways as possible.

In order to avoid redundancies in reporting, EPA will accept the issuance of a UIC Well Class VI permit as completion of certain GHG reporting requirements. The GHG reporting requirements that are satisfied by the completion of a UIC Well Class VI permit are shown in Table 9 and described below.

The UIC Class VI rule requires GS projects to perform a complete geological site characterization, with detailed information on hydrogeological, geochemical, and geomechanical characteristics of the site. The UIC requirement also includes computational modeling and periodic re-evaluation of the AoR. This information can also fulfill certain requirements of the MRV Plan under the GHG reporting rules. UIC permit information on surface CO_2 monitoring, water resource monitoring, and long-term CO_2 plume monitoring may also be useful for GHG reporting. Therefore, EPA will accept approved UIC Class VI permits as fulfillment of select parts of the MRV Plan.

Table 8: Comparison Between Reporting Requirements and UIC Class VI Rule (Federal Register, 2010)

	GHG RR	UIC Class VI
Quantity of CO_2 Received	**YES**	N/A
Quantity of CO_2 Injected	YES	YES
Equipment Release and Vented Emissions from Surface Equipment Between Flow Meters and the Wellhead	**YES**	N/A
Quantity of CO_2 produced with Oil or Natural Gas or Other Fluids	**YES**	N/A
Percentage of CO_2 Estimated to Remain with Oil or Other Fluids	**YES**	N/A
Quantity of CO_2 Emitted from the Subsurface	**YES**	N/A
Quantity of CO_2 Stored in the Subsurface	**YES**	N/A
Cumulative Mass of CO_2 Stored in the Subsurface	**YES**	N/A
Monitoring Plan for Detecting Air Emissions	YES	YES
Monitoring Plan for Quantifying Air Emissions	**YES**	N/A

Table 9: Components of GHG Reporting Requirements Fulfilled Through Approval of UIC Well Class VI Permit

	UIC Class VI	GHG RR
Complete Geological, Geochemical, and Geomechanical Assessment of Injection Site	Requirement for initial site characterization.	Can provide basis for development of MRV Plan.
Continuous Modeling and Re-Evaluation of Monitoring Areas	To be performed at all stages of the project.	Part of monitoring area re-evaluation and reporting.
Director-Approved Surface Air and Soil Gas Monitoring	To identify CO_2 release that may pose risk to USDWs.	To identify CO_2 release that may be offsetting CO_2 mass balance.

4.9 EPA GHG Reporting Requirements for All Other CO_2 Injection Projects

Projects that inject CO_2 for purposes other than GS follow a different set of EPA GHG reporting requirements, as described in Title 40, Part 98, Subpart UU of the CFR. Examples include projects with ER efforts and GS R&D projects that have received, or are in the process of receiving, an EPA exemption. Such projects are subject to a reduced list of reporting requirements, including:

- Mass of CO_2 received.
- Source(s) of CO_2 identified.

This information must be recorded quarterly, reported yearly, and the data must be retained for at least three years. As with the GHG GS project regulations, mass balance equations are provided within the finalized document in order to calculate the correct mass of CO_2 received and reported. Specific instructions are provided for different methods of CO_2 delivery and different types of flow measurement devices.

Carbon dioxide injection projects that fall within this definition are not required by the GHG reporting rule to maintain an extensive mass balance as with the GS projects. The current EPA GHG reporting rule does not require records of CO_2 mass injected, produced, or released for these wells. The delineation of monitoring areas (MMA and AMA) and the development of an MRV Plan are also not required. However, injection and monitoring plans may still be required as part of the UIC well permitting requirements for specific wells.

Further Information and Links

For further information on EPA regulations related to CO_2 injection, please see the official EPA and U.S. Government links, provided below.

General information on the EPA's Underground Injection Control Program is available at:
http://water.epa.gov/type/groundwater/uic/index.cfm.

The complete text for CFR Title 40, Part 146, Underground Injection Control Program, is available in the U.S. Federal Register, at:
http://www.epa.gov/region4/water/uic/downloads/di/40cfr146.pdf.

Information pertaining to UIC Class VI wells is available in the U.S. Federal Register, at:
http://www.gpo.gov/fdsys/pkg/FR-2010-12-10/pdf/2010-29954.pdf.

General information on the EPA's Greenhouse Gas Reporting Program can be found at:
http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

The complete text of CFR Title 40, Part 98, Mandatory Greenhouse Gas Reporting, is available in the U.S. Federal Register, at:
http://www.epa.gov/climatechange/emissions/downloads09/GHG-MRR-FinalRule.pdf.

Appendices: Field Tests of MVA Tools and Techniques

Introduction to Appendices A-K

The key to successful monitoring of CO_2 storage in large-scale injection applications is field testing of new and existing tools in controlled settings. To this end, DOE's RCSPs have launched 20 small-scale and 9 large-scale field projects for testing MVA tools and techniques in real CO_2 injection settings. The RCSP field projects have been designed specifically for deployment and testing of a wide range of MVA. Key monitoring goals for the RCSP tests include proving storage permanence, developing protocols to monitor potential releases, developing protocols to monitor induced seismicity, determining plume extent and vertical migration, and confirming no adverse impacts on USDWs.

The preceding chapters discussed the objectives and goals of CO_2 monitoring, the status of existing and emerging MVA technologies, and the suitability of various tools to meet reservoir management and regulatory requirements. Appendices A through K highlight the insights gained from the use of monitoring technologies by the RCSPs. Site-specific monitoring plans and monitoring results are provided from field projects operated by SECARB, MRCSP, MGSC, the PCOR Partnership, SWP, and the Big Sky Carbon Sequestration Partnership (BSCSP). The case studies are intended to provide the reader with examples of effective monitoring techniques used in a variety of field settings. They also provide valuable lessons learned that may be applicable to other large-scale CCUS monitoring efforts.

Monitoring objectives discussed in the case studies include: establishing a baseline for atmospheric monitoring, quantifying atmospheric CO_2 flux using tracers, identifying the extent of the CO_2 plume and pressure front with geophysical methods, and detecting out-of-injection-zone CO_2 migration. Also included are passive seismic studies that can provide a better understanding of the potential for induced seismicity in GS projects. This is a research need identified in NRC's recent report on induced seismicity (NRC, 2012).

Each field example contains an overview of the geologic setting and the objectives of the field test, the relationship between site-specific risk analysis and monitoring plans, monitoring requirements, site injection operations, and the lessons learned from deploying monitoring tools in each setting. Collectively, these features constitute the best practices for MVA of CO_2 in various geologic settings.

MVA field test results and plans are presented in Appendices A through K for the following Projects: SECARB Phase III Early Test at Cranfield Field (Appendix A); SECARB Appalachian Basin Coal Test (Appendix B); MRCSP Michigan Basin Phase II Validation Test (Appendix C); MRCSP Michigan Basin Phase III Development Test (Appendix D); MGSC Loudon, Mumford Hills, and Sugar Creek Phase II Validation Tests (Appendix E); MGSC Decatur Phase III Development Test (Appendix F); PCOR Partnership Zama Phase II Validation Test (Appendix G); PCOR Partnership Bell Creek Phase III Development Test (Appendix H); SWP San Juan Basin Phase II Validation Test (Appendix I); SWP Farnsworth Phase III Development Test (Appendix J); and BSCSP Kevin Dome Phase III Development Test (Appendix K).

Appendix A: SECARB Phase III "Early Test" at Cranfield Field

Overview

The SECARB Phase III "early test" is underway at Cranfield Field, approximately 10 miles east of Natchez, Mississippi. The Validation Phase test is focused on the Denbury Onshore, LLC CO_2-EOR project in the depleted oil reservoir and the Development Phase test is focused on the downdip water leg on the east side of the same reservoir. At Cranfield, the lower Tuscaloosa D-E sandstone, a 60- to 80-foot thick injection zone, is in a broad four-way structural closure at a depth greater than 10,000 feet. Complexly incised channels form a regionally continuous sandstone flow unit with lateral variability in permeability over short distances. Reservoir-scale vertical compartmentalization has isolated oil charge to the lower part of the lower Tuscaloosa Formation at Cranfield. The middle marine Tuscaloosa forms the lowest regional confining zone.

Site Characterization

Many penetrations from the 1944-1966 development of the field provided wireline log and side-wall core data of the reservoir and cuttings of the confining system. Denbury collected modern logs suites, whole core and sidewall cores, brine samples, and a 3-D seismic survey of the entire field. The SECARB project collected focused data, including 60-foot-long reservoir cores and open-hole logs. Hydrologic testing, baseline crosswell surveys, cased-hole logging, and pre-injection tracer application served as both part of characterization and the first elements of the monitoring program.

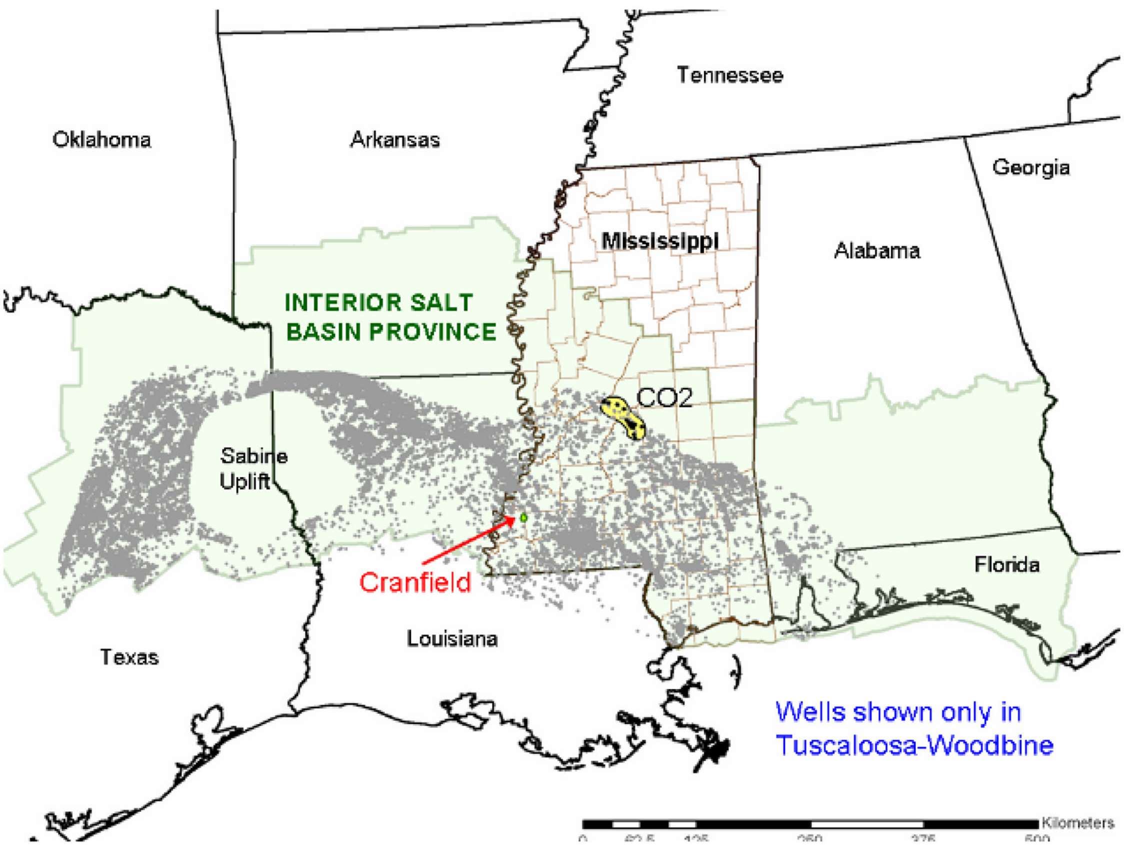


Figure 24: One of the Major Porous Units of the Interior Salt Basin Province of the Gulf Coast is the Upper Cretaceous Tuscaloosa Formation and Its Approximate Equivalent in Texas, the Woodbine Formation. Well locations (gray) define the regional extent of these units, and the location of the Cranfield study within the trend. The CO_2 source location at Jackson dome is also shown.

Risk Assessment

Commercial risk assessment was conducted by Denbury as part of its investment and was not part of the SECARB study. The SECARB team partnered with the Carbon Capture Project (CCP) to test the Certification Framework approach to risk assessment in an oilfield setting. The major finding was that well penetrations of the confining system are the major leakage risk factor, especially those that are neither newly drilled injectors nor operating producers that serve pressure formations. One of these wells, Ella G. Lees #7 (EGL7), was selected for dual completion with perforations open to formation in the lower Tuscaloosa injection zone and a 3-meter-thick, regionally extensive sandstone designated as the above-zone monitoring interval (AZMI) to assess well integrity at EGL7 and other wells in the surrounding area. One area of anomalously high methane and CO_2 soil-gas was identified prior to the start of injection. A fault forming the northeast margin of a crestal graben displaces the lower Tuscaloosa injection zone and is a barrier to horizontal flow. Interpretation of 3-D seismic shows that displacement on the fault diminishes upward and does not offset the Midway shale.

Permit Requirements

Denbury's commercial EOR program, supplemental injection wells, and additional downdip injection wells were permitted by the Mississippi Oil and Gas Board under UIC Program Class II rules.

Injection Operations

Carbon dioxide injection was started by Denbury at Cranfield in June 2008 on the north side of the field. In April 2009, injection was monitored under Phase III funding, with a focus on wells drilled deeper than usual into the water leg on the east side of the field. From December 2009 through February 2011, injection was augmented by Federally purchased CO_2 to attain higher than normal injection rates into the water leg. Reservoir response was measured during this time. In April 2010, 1 million metric tons/year injection rate was attained, as well as 1 million metric tons cumulative injection volume. Much of the field is now in production, and recycled mass of CO_2 and methane makes a significant contribution to the injection rate. As of March 2012, the volume stored is 3.5 million metric tons; the cumulative volume injected and re-injected via recycle is more than 5 million tons (Denbury, written communication, 2012).

Monitoring Plan, Results, and Lessons Learned

The monitoring plan was targeted to the research goals of the RCSP Development Program: (1) evaluation of protocols to demonstrate that it is probable that 99 percent of CO_2 is retained, and (2) predict storage capacities within +/- 30 percent. Observations were linked through a large number of models, allowing the significance of the measurement to be assessed. Some monitoring data were collected at points distributed across the study area and at a wide range of time intervals; other data sets were collected in focused study areas or during intensive sampling campaigns (Hovorka and others, 2009; 2011).

The SECARB early test at Cranfield was highly leveraged by participation of groups that brought non-SECARB-funded expertise to the project. For example, the project hosted experiments funded by the National Risk Assessment Program (NRAP); the Research Institute of Innovative Technology for the Earth (RITE); the DOE-funded SIM-SEQ; Stanford, Princeton, and CCP rock-physics analyses; American Water Works Association (AWWA)-funded controlled release; analyses by ORNL; University of Tennessee-funded biological sampling; BP test of wellbore gravity; and Scottish Carbon Capture and Storage (CCS) Centre-funded noble gas sampling.

Permanence of Retention of CO_2

The permanence of retention of oil and gas in the geologic system at Cranfield was well understood prior to the test, because significant accumulations were trapped in two zones (Tuscaloosa and Wilcox), demonstrating that confinement is effective. However, three elements are altered from natural hydrocarbon accumulation conditions and must be assessed to determine whether they constitute CO_2 release risk. First, well performance is the highest uncertainty and the focus of monitoring research. Second, during injection, pressure in the reservoir was increased above its initial pressure. Finally, fast injection and production means that CO_2 flow is mostly in a radial pattern away from injection wells, and this raises the possibility that CO_2 may migrate downdip and out of the trap.

Monitoring to assess permanence was undertaken in four zones: the injection zone, a selected AZMI, the shallowest of the fresh water zones (Catahoula Formation at about 300 to 500 feet below the surface), and soil-gas transects near the wells.

Monitoring to Assess Permanence in the Injection Zone

In-zone methods used to assess retention are: CO_2 mass-balance, injection zone pressure monitoring, 4-D seismic, and time-lapse VSP, complemented by modeling. These methods are also used as part of capacity assessment. Above-zone methods used to assess retention include AZMI pressure monitoring, AZMI geochemistry, 4-D seismic, and AZMI and distributed temperature, also complemented by modeling. Groundwater geochemistry methods used are quarterly water-level and geochemical sampling, with a push-pull test conducted to validate models. Soil-gas methods used were reconnaissance and repeat soil-gas sampling at accessible well pads, and a follow-up test at a localized methane anomaly instrumented with shallow wells. Details of these methods have been described in topical reports, and results will be provided as archived data sets and summarized in upcoming publications.

Carbon dioxide mass-balance, commonly referred to as the injection/withdrawal ratio (IWR), accounts for the injected CO_2 and the produced volumes of CO_2, methane, oil, and brine. High-quality mass measurements of CO_2 brought to the field are made by Denbury at the custody transfer meter. Flow to the field is also quantified as the injection stream (CO_2 plus recycled produced methane) is sent to the injection wells at the outflow of the separation plant. Flow to individual wells is measured by non temperature-corrected meters and reported daily; the mass is corrected to sum to the outflow of the separation plant by allocation. Each production well is tested by Denbury in rotation at least once a month at the production test separator, where volumes of CO_2 plus methane, oil, and brine produced are quantified. IWR provides a high-value overview of the operation. However, the system is both geologically and operationally complex, and it was found that IWR is not sensitive to significant release in this setting. In a field with a more classic layout of well patterns and steady operating conditions, better sensitivity might be obtained.

Finding of This Study Relevant to Future Studies: IWR may not be an adequate release detection strategy for storage value.

Injection zone pressure monitoring was conducted in perforated wells open to the formation using three tools: surface-pressure gauges that measure tubing pressure at wellhead, pressure gauges with digital memory that are placed in wells for a period then retrieved and downloaded, and permanently installed downhole pressure gauges attached to tubing and connected to surface readout via wireline. Surface gauges are the lowest cost of these tools and can have significant value when tied to a high-frequency data recording system, because a pressure change in the tubing reflects a change in the reservoir. Surface pressure responds to daily variation in the temperature near the surface; this must be filtered out and is a source of error. During the period of breakthrough, when CO_2, methane, or oil is displacing brine in the tubing, bottom-hole pressure is decoupled from surface tubing pressure.

Initiation of injection at wells up to one-half mile from the bottom-hole pressure gauge at observation well EGL7 produced a distinct pressure response (Meckel and Hovorka, 2009). Mapping these responses showed that the eastern graben-bounding fault was sealed to cross-fault pressure. When injection was stopped, the signature of pressure fall-off was recorded. If a well should suddenly start to release at high rates, it would leave a distinctive signal in bottom-hole pressure in wells in the area. However, gradual initiation of release or slow release would not be detected, and even sudden release does not leave a unique signal and could be confused with heterogeneous pressure fluctuations. Boundary conditions are modeled, not measured, and therefore are a major source of uncertainty that could mask a release signal (Nicot and others, 2009). This uncertainty is especially significant during the phase of the project in which new areas are invaded by CO_2, because relative permeabilities to CO_2 are dynamic.

Three Findings of This Study Relevant to Future Monitoring: (1) High-frequency pressure data contains information about reservoir response; however, all the events have to be recorded at the same frequency (minutes to hours); (2) low-cost, easily repaired wellhead tubing pressure gauges have value if calibrated to density of fluid in tubing; and (3) doubt remains that injection zone mass balance or pressure monitoring would be sufficient to detect release, mostly because of large uncertainties about boundary conditions.

Four-dimensional seismic and time-lapse VSP data were collected to explore the uncertainty of downdip, off-structure, and out-of-injection-zone migration of CO_2. Injected CO_2 was successfully detected in the injection zone, subtracting the pre-injection 3-D survey from the 2010 repeat survey; however, noise is high. Resolution of these methods is limited in terms of their ability to detect thin, saturated zones; heterogeneous reservoir zones; and complex fluids. No above-zone migration of CO_2 has been detected. Processing continues, and final conclusions will be presented by project end.

Monitoring to Assess Permanence in a Selected Above-Zone Monitoring Interval

In gas-storage reservoirs, surveillance of pressure above the injection zone is a conventional monitoring technique. However, prior to this project, this method had not been used for documentation of CO_2 storage. The premise of AZMI monitoring is that any fluids released upward, out of the injection zone, are at pressure higher than that of hydrostatic fluids in overlying permeable units. Therefore, if the release flow path is in contact with overlying units, fluids will enter the AZMI formation and raise pressure.

At Cranfield, for AZMI monitoring, one of the lowest sandstones above the Tuscaloosa middle marine regional confining system was selected (Meckel and Hovorka, 2010; 2011). At EGL7, the AZMI sandstone was conventionally perforated and the AZMI zone was isolated by packers from the rest of the well casing and from the tubing. A pressure and temperature gauge was set at the upper packer and equipped with wireline readout. A cement squeeze isolated the injection zone from the AZMI, but no squeeze was performed at the AZMI because of budget constraints. At the DAS, the well completion was too complex to accommodate a dual completion to measure pressure at the AZMI. Casing-deployed pressure gauges set at the AZMI with wireline readout at the surface on both wells were selected. Casing-deployed instrumentation requires drilling a larger diameter borehole and installing a thicker cement sheath, so that the pressure gauge is embedded within the cement. It is not possible to develop and maintain the connections between the gauge and the formation through perforations, which is a limiting element of this type of completion.

Findings of This Study Relevant to Future Monitoring: AZMI pressure monitoring shows promise as a sensitive release detection method. In future installations, it is recommended that baseline hydrologic characterization of the AZMI interval, as well as well construction, is invested in more heavily to ensure that AZMI pressure gauge is well-connected to the formation and isolated from well construction.

Monitoring USDW to Assess Permanence

A groundwater monitoring plan was developed to sample the shallowest (300 to 400 feet deep) freshwater-bearing sandstone of the Catahoula Formation in the area of the injected CO_2 plume (Yang and others, 2009). Core samples of the upper 240 feet of sediments provide rock data important to hydrochemical modeling. Available wells were logged using a slim-hole gamma-ray logger to constrain the stratigraphy and local continuity of the freshwater-bearing sandstones. Quarterly groundwater sampling by hydrogeologists from the University of Mississippi used a portable pump to purge wells, measure field parameters, and preserve samples for further analysis at the Institute of Clean Energy Technology (ICET) chemistry laboratory of Mississippi State University. The local potentiometric surface was mapped to determine fate and transport and mixing inputs for rock-water reaction calculations. A recently completed controlled release of CO_2-saturated groundwater into the 400-foot deep sandstone tested the rock water reaction, should CO_2 be released into this zone.

Findings of This Study Relevant to Future Monitoring: In order to obtain meaningful groundwater monitoring data, a classic, contaminated site type of study is required. Such a study should include ambient water composition data, formation rock composition data, mapping of the local and regional potentiometric surfaces, and fate and transport calculations to determine where to set and perforate optimal monitoring wells. In addition, optimization of the constituents sampled, the sampling method, and sampling frequency are required. Comprehensive monitoring of the USDW may require this process for each of the hydrologically separated units.

Monitoring to Assess Permanence via Soil Gas Transects

Surface activities related to oil and gas accumulation and production may affect soil-gas geochemistry. A reconnaissance survey of soil gas near historic wells was undertaken in 2008 and repeated in 2010. Prior to any CO_2 being injected in the area, anomalously high CO_2 and methane was detected at one location. Analyses of fixed gas (N_2, O_2, CO_2, and CH_4) (Romanak and others, 2011), stable-isotopic and noble-gas compositions were used to determine that CO_2 is a microbial degradation product of thermogenic methane (sourced from the deep subsurface) in the presence of atmosphere. This is a case where CO_2 concentration alone is not useful as a release indicator. Additional studies to assess the geochemical interaction between soil and elevated methane and CO_2 are underway.

Findings of This Study Relevant to Future Monitoring: A reconnaissance study of soil-gas anomalies was used to identify pre-injection localized high CO_2, interpreted as a biodegradation product of methane. The process-based approach to separating in-situ generated gases from exogenous gases is being tested for the first time at a CO_2 storage site and shows promise. Values of this methodology include the separation of the release signal from in-situ natural processes, and a reduced need for pre-release background measurements to identify the release signal.

Prediction of CO_2 Storage Capacity

The monitoring program at the SECARB early test at Cranfield includes techniques that may be useful for assessing the CO_2 storage capacity of the reservoir. These techniques include: time-lapse cased-hole well logging (reservoir saturation tool [RST]), time-lapse cased-hole logging dipole sonic, time-lapse crosswell seismic tomography, crosswell continuous ERT, borehole gravity, tracer measurements using the U-tube sampler, and numerous other tools.

Findings of This Study Relevant to Future Monitoring: In the system assessed, CO_2 preferentially moved through sinuous channel units, occupying only a fraction of the 80 foot-thick permeable sandstone reservoir. Sweep efficiency is rate-dependent and not a constant value. Repetition of this type of detailed capacity study in other rock-fluid systems may be valuable for improving the predictive capabilities of the method. This type of study is not appropriate for monitoring commercial projects. Additional effort would be needed to define interactions between geomechanical and fluid-flow processes relevant to large-scale geologic storage.

Appendix B: SECARB Appalachian Basin Coal Test

Overview

In order to assess and verify the capacity of coal seams in the Central Appalachian Basin to store CO_2, the SECARB Coal Group successfully injected 1,007 tons of CO_2 into a coalbed methane (CBM) well in Russell County, Virginia, over a one-month period beginning on January 9, 2009 (Figure 25). Nineteen distinct coals, with a net coal thickness of 26 feet, comprised the injection zone (Figure 26). These coals include the Pocahontas and Lee Formations. The Pennsylvanian-aged Pocahontas Formation, which overlies the late Mississippian Bluestone Formation, was deposited in an unstable, restricted marine setting and deformed during late Alleghanian orogenesis. Coal seams of the Pocahontas Formation are normally high-rank, medium- to low-volatile, high gas-content coals.

This Coal Seam Project Field Test was one of two field injection tests in coal under SECARB. The other was in the Black Warrior Basin in Alabama. The CO_2 was injected into unmineable coal seams with high methane content. Research from the design, implementation, and monitoring of the field validation test identified important injection parameters and vital monitoring technologies that are applicable to commercial-scale deployment. Results from the injection test, and the subsequent return of the well to commercial production, confirmed that fractured coal seams have the potential to store CO_2 and enhance CBM production, adding significant recoverable reserves and extending the life of the CBM fields in the region.

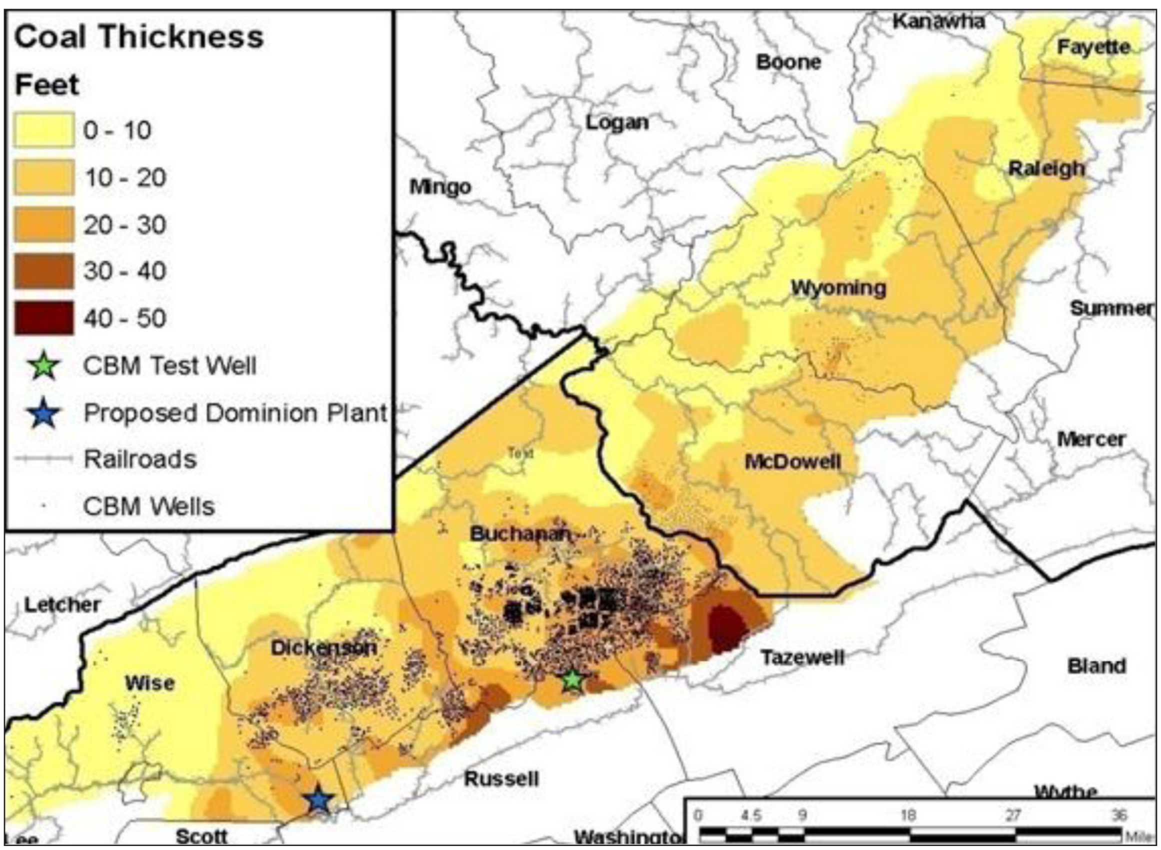


Figure 25: Location of Injection Well, Russell County, Virginia

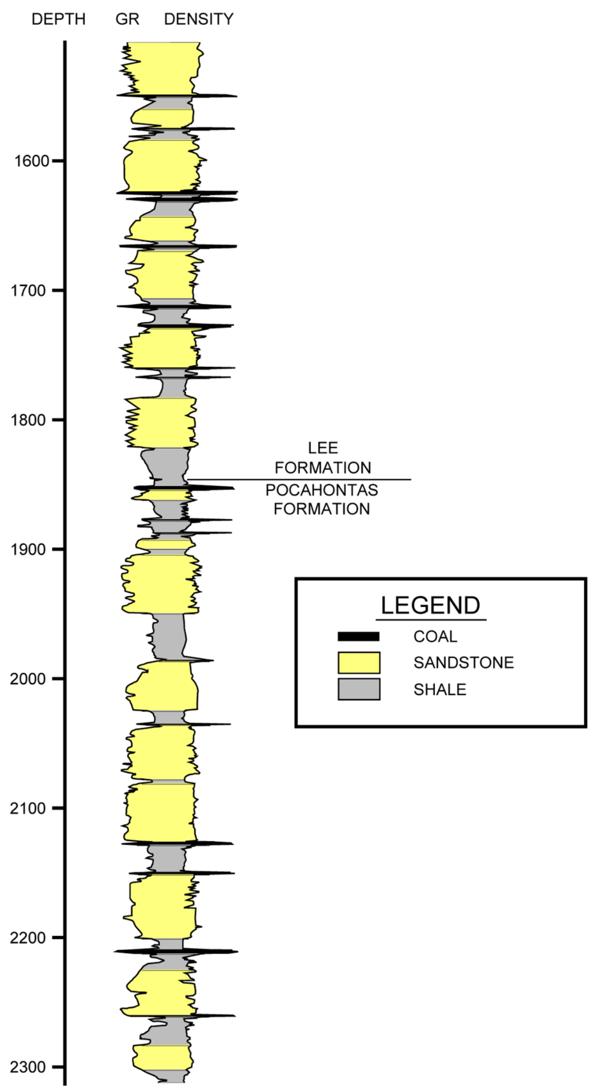


Figure 26: Stratigraphic Section of Injection Zone

Site Characterization

Site Characterization included compiling information on topography, soil composition, wetland locations, historic resources, infrastructure (including roads, electric lines, and pipelines), site-specific geology, and well drilling and stimulation reports. This CBM field was developed on 60-acre spacing, and the coals were typically hydraulically fractured with a nitrogen foam treatment in four stages with average completion depths from 1,000 to 2,300 feet.

Two monitoring wells were drilled and logged as part of site characterization. One of the wells was continuously cored, and the coal seams were analyzed for gas content, adsorption isotherms, petrology, and computed tomography (CT) imaging. Regional shale seals were examined to verify their ability to seal vertical migration of CO_2. As part of the geologic characterization, the following maps were developed: stratigraphic cross-sections of injection zones, coal seams, regional seals, fresh water formations, isopach maps of total coal thickness by formation, and structure and isopach maps of the Pocahontas No. 3 and Lower Horsepen Coals Seams.

Risk Assessment

Risk was defined in two ways: (1) risk to the environment due to potential CO_2 release, and (2) risk of human injury from injection-related activities. The risk of safety at the site was governed by a safety plan that required training and personal protection equipment according to the site owner's stringent safety regulations. Risk of CO_2 release was assessed by the following: identification of all well penetrations within a quarter-mile of the anticipated plume; identification of all underground coal mining in the area; identification of the stratigraphic extent of ground water resources; and sampling and laboratory analysis of the competence of multiple regional shale seals above the shallowest injection zone. Samples were collected and analyzed before, during, and after injection – including samples of groundwater and surface water, measurements of CO_2 soil flux, soil geochemical surveys, and PFT sampling at the surface.

Permit Requirements

The research team applied for and was granted a Class V UIC Permit from EPA. The requirements for testing and measurements in the permit included: a cement bond log (CBL), an MIT on the casing, identification and sampling of any groundwater wells within a quarter-mile of the anticipated plume, and a defined monitoring plan that included two monitoring wells. Prior to injecting high-pressure CO_2, the mechanical integrity of BD114's casing was tested above the shallowest perforation in accordance with EPA's Tubing/Casing Annulus Pressure Test. A combination of the information from the MIT and the CBL was used to establish confidence in the ability to keep the injected CO_2 confined to the coal seams. The monitoring plan approved by EPA formed the basis for the monitoring program implemented at the site.

Injection Operations

The injection commenced on January 9, 2009, and was completed on February 10, 2009. The field test successfully injected 1,007 tons of CO_2 at the Russell County, Virginia, test site hosted by CNX Gas, a subsidiary of CONSOL Energy. An oilfield team from Praxair, Inc. conducted injection operations and assembled resulting data. Praxair utilized 20-ton highway trucks to transport the CO_2 to the site and then transferred the CO_2 to a 60-ton storage vessel located near the hardtop road. A 10-ton off-highway truck then moved the CO_2 from the 60-ton storage vessel to a 34-ton vessel at the injection site. This allowed for up to 104 tons of CO_2 storage. The set-up for the injection operations included the onsite, 34-ton storage vessel; an oilfield triplex injection pump; an in-line propane heater; and a communication system that measured flow rate, pressure, temperature of the injected fluid, and pressure on the annulus of the tubing. The injection had higher than anticipated injection rates. The maximum daily injection rate was 55 tons of CO_2 per day, with an average injection rate of more than 40 tons per day.

Monitoring Plan, Results, and Lessons Learned

The goals of the MVA program for the Appalachian Basin Coal Test were to assess the lateral extent of the injected CO_2 plume, ensure vertical containment of the CO_2, obtain data to assist with pre- and post-injection reservoir modeling, and to quantify ECBM recovery due to the plume. To achieve these goals, an MVA network was designed to monitor, collect, and report relevant data about the storage system, especially physical and chemical processes, before, during, and after injection. The network's data acquisition and control system included real-time remote data collection and online data dissemination.

The monitoring network consisted of 18 surface monitoring locations, 2 deep monitoring wells, 7 offset CBM production wells, 6 surface water sampling locations, and a weather and atmospheric monitoring tower (Figure 27). The surface monitoring locations were arranged in three concentric circles surrounding the injection well with radii of 150 feet, 300 feet, and 450 feet. This pattern and size, covering 14.6 acres total, was chosen based on preliminary modeling of the injected plume extent. Two deep monitoring wells were drilled to align with local face and butt cleat directions, relative to the injection well, and were left open-hole below surface casing. These wells were drilled prior to injection to provide geologic characterization data.

The MVA network was designed to monitor and collect data from atmospheric, surface, and subsurface levels. Atmospheric monitoring was conducted using IRGAs that measured CO_2 concentrations near the surface and 50 feet above the ground. Surface monitoring methods consisted of soil CO_2 flux measurement, tracer analysis, and surface water sampling. Subsurface monitoring and well tests included spinner surveys, pressure testing, temperature logs, gas composition, production data analysis, formation water sampling, and tracer analysis.

Atmospheric Monitoring: A portable IRGA was used to measure CO_2 concentration 0.5 m above the surface at 17 of the surface stations. Measurements were taken for 30 minutes at a time and repeated each quarter for five quarters. Average CO_2 concentration over the study area ranged from 372 parts per million (ppm) (during a pre-injection quarter) to 462 ppm (during an active injection quarter). The highest value for a single measurement was 647 ppm, recorded during the injection phase, and has been attributed to injection activities, such as CO_2 transport and exchange from the 10-ton truck to the 34-ton vessel.

A second IRGA was mounted inside the control unit 25 feet above the ground at the injection well to measure ambient CO_2 concentration during injection operations. Near-continuous measurements were recorded during the operations/injection phase of the project. The highest recorded concentration was 6,331 ppm. The stationary IRGA recorded 20 additional "high" measurements, ranging from 600 ppm to 5,269 ppm. These high concentrations were directly related to CO_2 transport and manipulation at the injection site. Specifically, all events were recorded when tubing used to pump CO_2 from delivery trucks to the onsite storage tank was disconnected and purged with CO_2.

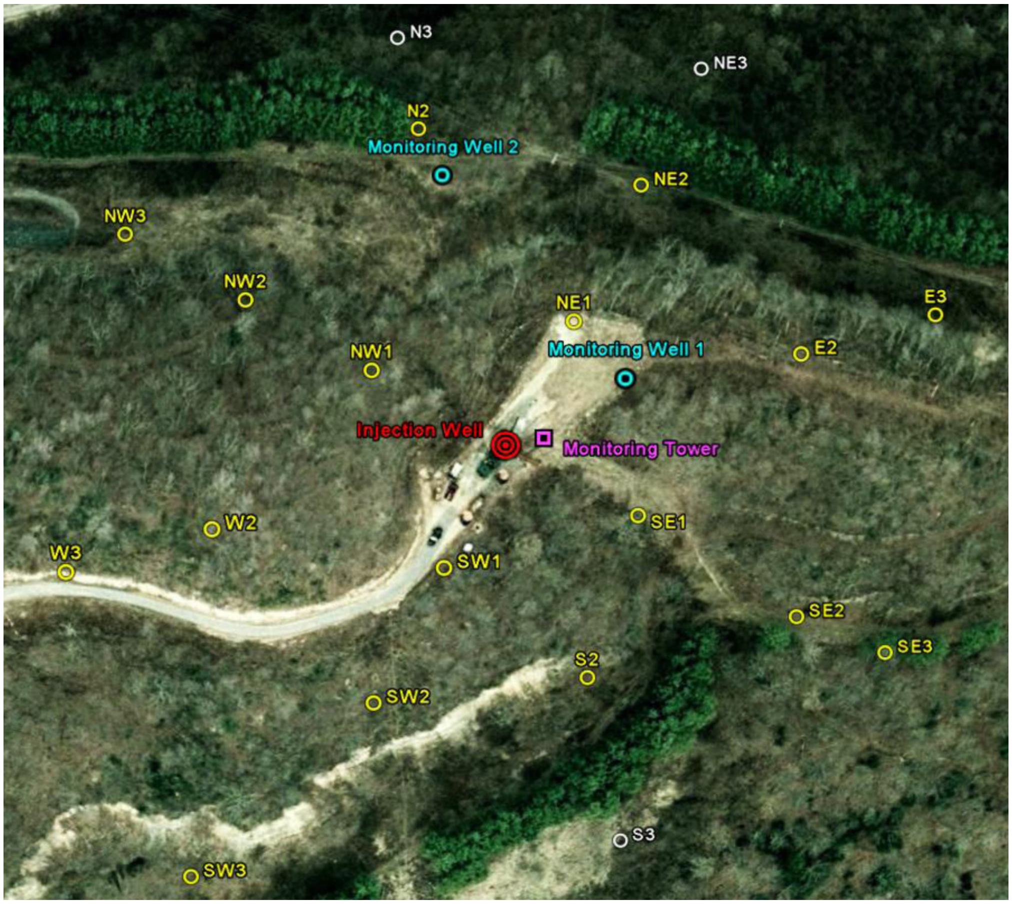


Figure 27: Monitoring Layout

Surface Monitoring: Soil CO_2 flux was measured at all 18 surface monitoring locations using an LI-8100-103 survey chamber (Figure 28). PVC collars 4.5 inches tall and 8 inches in diameter were installed at all locations to ensure a tight seal with the survey chamber. Sampling began in the spring of 2008, approximately eight months prior to injection, in order to establish a baseline. Measurements were taken weekly at the three locations closest to the injection well and biweekly at all other locations through the spring of 2009. During pre-injection months, average flux values ranged from 0.47 to 4.69 μmol/m^2/s, with a maximum single measurement of 8.77 μmol/m^2/s. During injection, average flux values ranged from 0.15 to 0.45 μmol/m^2/s, with a maximum single measurement of 0.51 μmol/m^2/s. Post-injection average flux values ranged from 0.23 to 2.47 μmol/m^2/s, with a maximum single measurement of 2.65 μmol/m^2/s. The curve for soil CO_2 flux over time correlates strongly with curves for soil and ambient air temperatures. Variations at specific measurement points may have been due to unique local factors, such as soil composition, root respiration, or microbial activity.

Twelve days after the start of CO_2 injection, 500 ml of a PFT, perfluorotrimethylcyclohexane (PTCH), were added to the injection well by a DOE-NETL research team. A syringe pump was loaded with PTMCH 25 miles from injection operations to avoid contamination of the site. The loaded syringe pump was securely fitted to a valve at the wellhead with stainless steel tubing and fittings, and wrapped in multiple insulating layers containing 50 g of activated carbon to adsorb any fugitive tracer molecules. The tracer was injected at a rate of 42 ml/h over 12 hours and then flushed with 550 ml of methanol. During tracer injection, CO_2 injection continued at a rate of 0.16 bbl/min and pressure of 721 pounds per square inch (psi). Surface monitoring for the tracer was conducted to detect potential release from the reservoir. Sorbent tubes were placed at 17 of the surface monitoring locations. The sorbent tubes were capable of detecting the tracer at two levels—at the surface and one meter deep. The results showed no indications of tracer one meter deep, but tubes at several locations indicated tracer present at the surface. This is attributed to tracer escaping to the atmosphere as rigs worked on

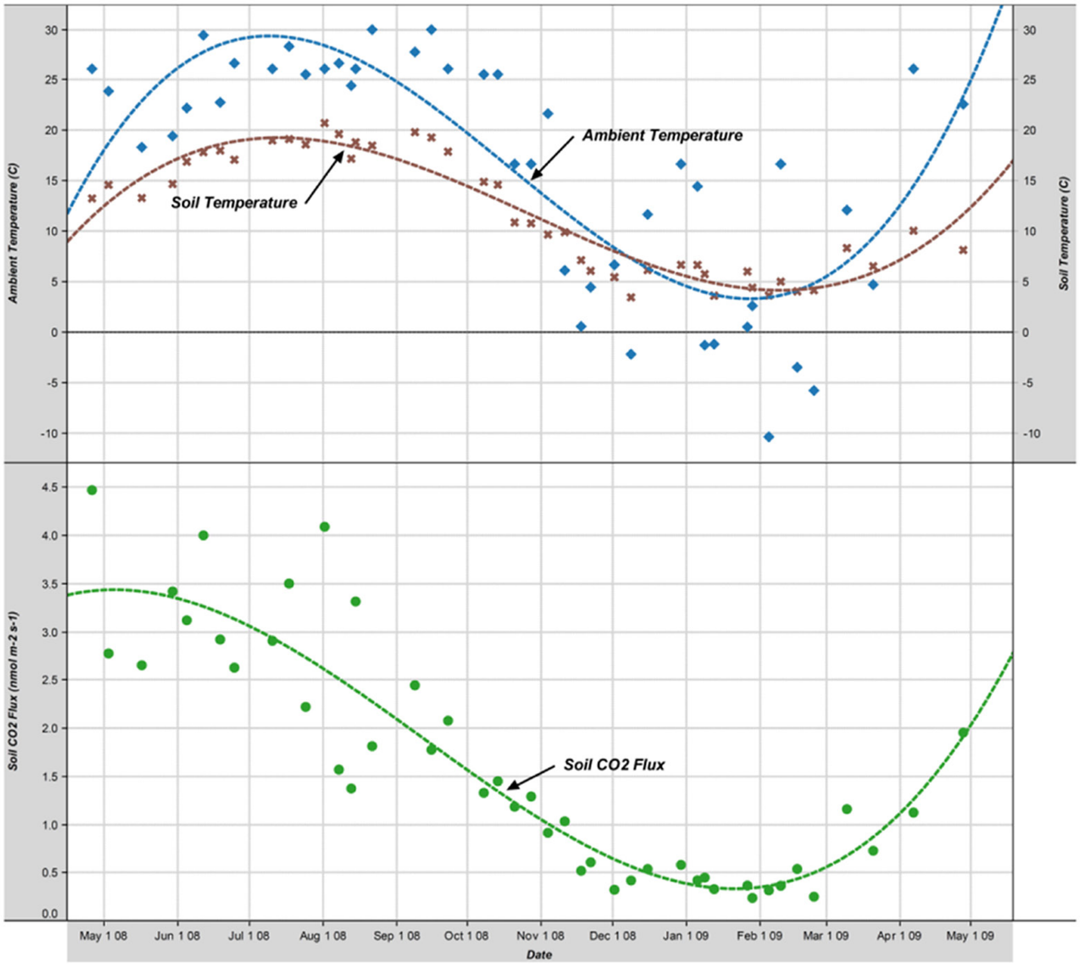


Figure 28: Soil Flux Measurements.

the monitoring wells. Offset wells were also monitored for breakthrough of the tracer, as described in the subsurface monitoring and well tests section.

Surface water sampling was conducted pre- and post-injection at six locations, all previous underground mining locations, to test for indications of CO_2 release. Comparison of pre- and post-injection data showed no changes that could be attributed to a release of injected CO_2 from the reservoir.

Subsurface Monitoring and Well Tests: Spinner production rate surveys were conducted on the injection well prior to CO_2 injection and during the final days of injection. The pre-injection survey was conducted in an attempt to quantify the contribution of each coal seam to the total gas production from the well. After taking the well off-line and installing the packer and tubing assembly, the well was shut in and allowed to flow through a choke, at which time the survey was run. The survey had limited success, because water was encountered in the wellbore, preventing accurate measurement of the gas flow rate below the water level. The second survey was conducted during CO_2 injection in attempt to quantify the amount of CO_2 accepted by each coal seam. In addition to the flow rate, temperature and pressure were measured for this survey. This survey experienced complications similar to those in the first survey when the spinner encountered liquid CO_2 at a depth of 1,660 feet. A sudden decrease in the temperature log confirmed this phase change from gas to liquid. The temperature log also showed significant changes at each perforation where CO_2 was injected, with the greatest changes occurring at the shallowest seams. The changes in temperature are likely correlated with changes in injection flow rates.

Pressure readings were collected from the injection well and two monitoring wells on an hourly basis and uploaded to a server for remote analysis (Figure 29). All readings were for surface pressure at the wellhead. Just 30 minutes into injection operations, the pressure in Monitoring Well #1 rose dramatically and then mirrored the pressure profile of the injection well for the duration of the month-long injection, suggesting a direct connection between the wells by hydraulic or natural fractures. Results from Monitoring Well #2 were compromised by a malfunction of the measurement instrument that caused inaccurate readings above 300 pounds per square inch absolute (psia). Results from the end of injection and post-injection indicate that Monitoring Well #2 mirrored the others two wells and was also connected to the fracture network. After injection operations were completed, pressures in the monitoring wells rose until all three wells were at nearly identical pressures, apparently reaching equilibrium at 675 psia. Unexpectedly, though, pressures in all three wells began to rise three weeks after the end of injection. This phenomenon was attributed to vaporization and phase change of the CO_2 from liquid to gas. During the flowback phase, pressure in the monitoring wells displayed dependence upon pressure and flowback rate at the injection well. All three dropped initially, and then the monitoring wells rose slightly when the flowback rate at the injection well decreased due to water invading the wellbore. When the injection well was brought back online as a producer with a water pump, pressure in all three wells decreased to less than 50 psia, confirming their connection to each other.

Gas composition was analyzed at both monitoring wells throughout the injection, soaking, and flowback phases. The CO_2 concentration for Monitoring Well #1 was measured at more than 95 percent just hours after injection began, while Monitoring Well #2 reached more than 95 percent CO_2 after eight days of injection. This rapid spread of CO_2 can be linked to hydraulic or natural fractures connecting the injection and monitoring wells. Both wells maintained CO_2 concentrations more than 95 percent during the soaking phase. Early in the flowback phase, both wells exhibited a spike in N_2, indicating that the coal matrix had preferentially released N_2 in order to adsorb CO_2. Gas composition was also sampled at seven offset production wells, at pre- and mid-injection stages, without showing any indication of CO_2 breakthrough. Continued sampling during injection and during the soaking and flowback phases showed CO_2 concentration changes of less than one percent at four offset distances. These changes could not be directly linked to the CO_2 injection, as typical produced gas

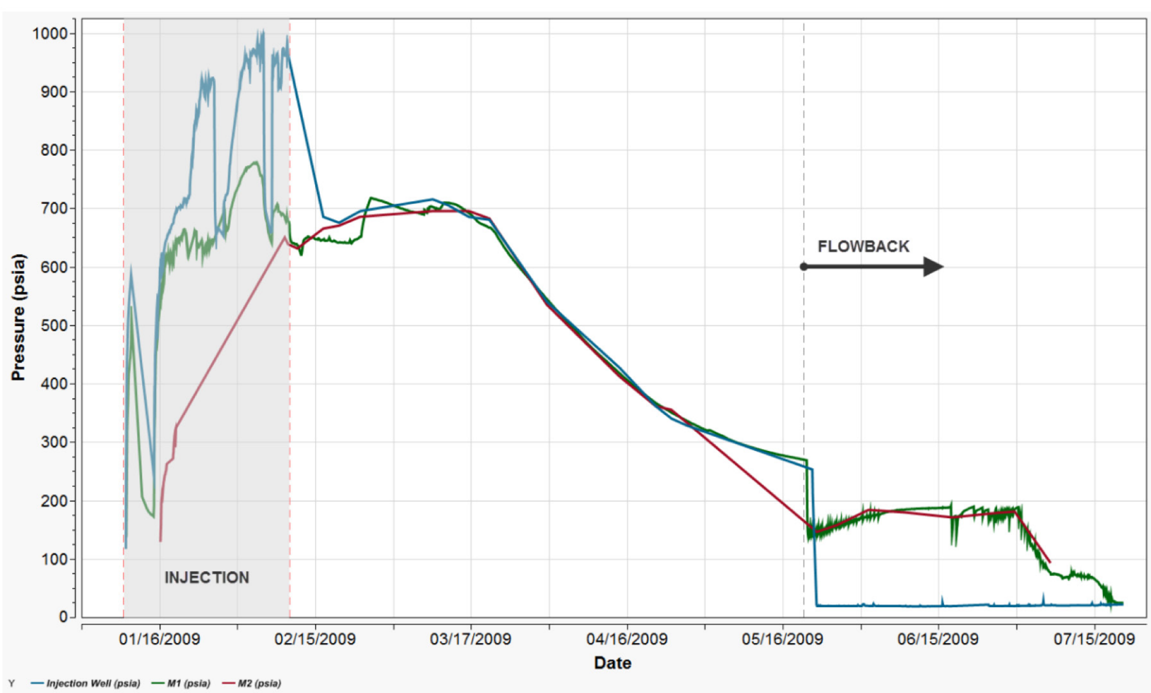


Figure 29: Pressure Response at Injection and Monitoring Wells.

from these wells contained 1.5 to 3.5 percent CO_2. The injection well showed similar results to the monitoring wells upon initial flowback, with an initial increase in N_2 and CO_2 concentration close to 95 percent. During the second phase of flowback, production was measured at 80 percent CH_4 and 20 percent CO_2, increasing to 87 percent CH_4 five months later and eventually to 93 percent CH_4. It is estimated that 12 percent of the CO_2 was produced one year after injection, and 25 percent was produced three years after injection with the majority remaining in the formation.

Production data, including flow rate, differential pressure, and temperature, were reported for the seven offset wells on an hourly basis for one year to identify any increased production due to injection of the CO_2 (Figure 30). Two of these wells exhibited increased production simultaneously during the early stages of injection, indicating a direct effect. One of the wells quickly returned to pre-injection production levels, but the other continued to show elevation production levels for five months after the end of injection. A third offset well showed increased production during the soaking phase, but this cannot be directly linked to the CO_2 injection.

Formation water was sampled at 13 wells, including the injection well and one monitoring well. The seven closest offsets to the injection well were sampled pre-injection to establish baselines. These wells showed a drop in pH immediately following the end of injection, but quickly returned to pre-injection values of approximately 7.0 pH. Samples from the injection well during flowback had a lower pH than the seven offset wells and higher levels of iron, manganese, and free CO_2 by factors of two to four.

A PFT was added to the CO_2 injection stream 12 days into injection operations using a procedure described in the surface monitoring section. Less than three months after the end of injection, gas samples from two of the seven offset wells unexpectedly tested positive for the tracer (Figure 31). New samples from the same two wells and two others were obtained a few weeks later, with all four testing positive for the tracer. The final three offset wells were sampled and tested positive for the tracer, as did an additional three wells from the next "ring" of offsets. The most distant positive sample was taken 0.71 miles from the injection well, much farther than the CO_2 was expected to travel. This fact, combined with tracer detected at all directions from the well, suggests that the hydraulic and natural

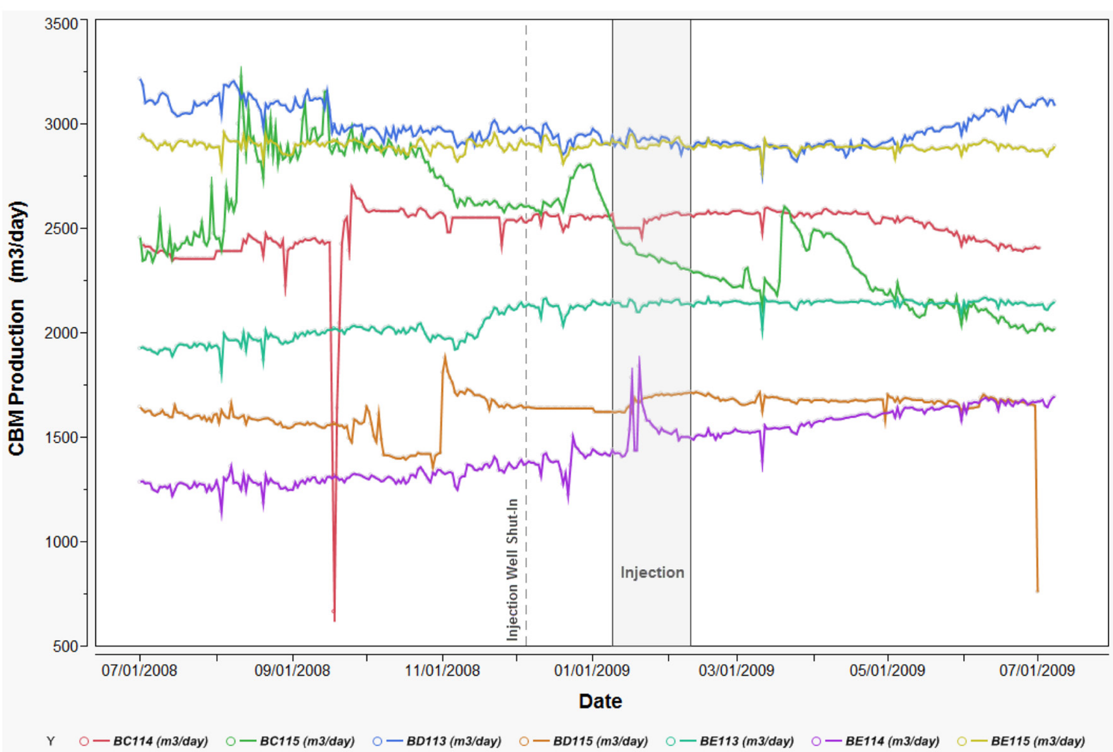


Figure 30: Gas Production at Injection and Offset CBM Wells.

fracture networks are well developed in this CBM field. The amount of tracer detected at the offset wells was in the parts–per-trillion range, and a high percentage of the injected tracer was detected in the produced gas during the flowback of the injection well. It is believed that the size of the tracer did not allow access to the micropores of the coal, so it stayed in the cleats and fractures within the coal matrix and did not adsorb in the same way the CO_2 did.

Atmospheric and surface monitoring were employed in the Central Appalachian Coal Test primarily to monitor for release of the injected CO_2. Results from two IRGAs, soil CO_2 flux measurements, surface tracer sampling, and surface water sampling all found no signs of release, indicating successful containment of the injected CO_2 within the target reservoir. Subsurface methods proved important for assessing the injected plume of CO_2, learning about adsorption processes, identifying which seams accepted the CO_2, and quantifying the effect of injected CO_2 on production at offset wells. Pressure response, gas composition, and tracer detection at offset wells all indicated a well-developed hydraulic fracture network and suggest a more complex plume shape than was anticipated based on simulations. Temperature surveys during the injection showed distinct changes at open perforations and also confirmed phase changes of CO_2 downhole. Increased N_2 and CH_4 initially during flowback at the injection and monitoring wells indicated successful adsorption of CO_2 to the coal reservoir matrix. Increased production at two offset wells without CO_2 breakthrough was a direct result of injection operations, a promising result for future CO_2 injection studies in active CBM fields.

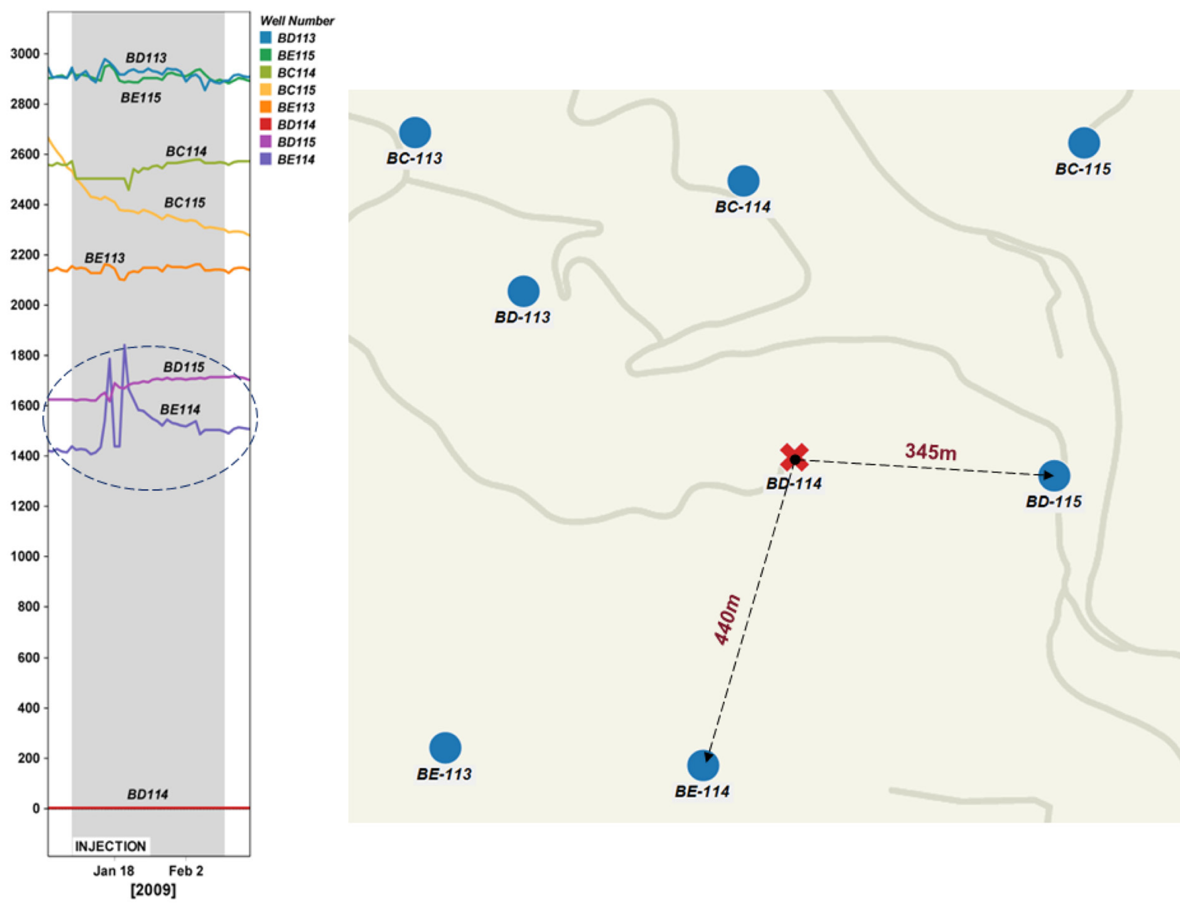


Figure 31: Tracer Detection at Offset CBM Wells.

Appendix C: MRCSP Michigan Basin Phase II Validation Test

Overview

Carbon dioxide storage potential was investigated in the Bass Islands Dolomite and adjacent Bois Blanc deep saline formations within the northern Michigan Basin. The storage site is located in the State-Charlton 30/31 field, Otsego County, Michigan (Figure 32), in the vicinity of an EOR field operated by Core Energy LLC, one of the industry hosts for this test. The CO_2 was supplied from natural gas processing plants located in the Chester 10 area, including the Turtle Lake facility, owned by DTE Energy at the time of the injection test. A total of approximately 60,000 metric tons of CO_2 was successfully injected in two campaigns: (1) from February to March 2008 (~10,000 metric tons), (2) and from January to July 2009 (~50,000 metric tons).

Site Characterization

Initial characterization efforts included a preliminary geological assessment, drilling a test well that was later permitted as the injection well, coring through the test interval, core testing, and wireline logging. The initial geologic assessment was based on available well logs in the area, which suggested that the Sylvania Sandstone would be the best potential storage zone within the depth range of interest. However, after drilling the test well, the Sylvania Sandstone was found to pinch out to the south of the project location. The stratigraphy was re-evaluated, and it was concluded that the Bass Islands Dolomite provided the best storage target within the depth range of interest. The Amherstburg and Lucas Formations were identified as the primary caprock within the confining zone.

Figure 32: MRCSP Michigan Basin Phase II Validation Test Site.

Risk Assessment

Initial risk assessment activities for the Phase II site included site screening review of general review of site logistics, environmental factors, major risk factors, geologic framework, CO_2 storage targets, and containment layers. After the site was selected for testing, technical risk assessment was completed to identify items that may affect the storage system safety and performance. The risk assessment was divided into two parts: (1) a systematic FEPs screening, and (2) deterministic modeling to assess the potential for CO_2 release. In general, the risk assessment identified wellbores as the primary risk factor for the CO_2 storage project. As such, a perfluorocarbon (PFC) tracer study was implemented around the injection well and other nearby wells.

Permit Requirements

The test well was permitted as a Class V experimental CO_2 injection well through U.S. EPA Region 5. The permit application included details on the injection zone, injection operations, system monitoring, wells in the AoR, financial assurance, and other items necessary to fulfill UIC regulations.

Prior to injection, a CBL, temperature log, annular pressure test, and pressure fall-off test were completed at the test well and submitted to U.S. EPA Region 5. During injection, the UIC permit required monitoring of injectate composition and continuous monitoring of injection operations. Injection parameters included volumetric flow (injection) rate, injection pressure, annulus pressure, total injection volume, and temperature. Monthly reports summarizing operating parameters were submitted during the two-month test. Additional monthly reports summarizing wellhead pressures were required after injection.

For the extended injection, a one-year permit extension was requested from U.S. EPA Region 5. The agency requested additional information to confirm that the CO_2 would not extend beyond the quarter-mile radius AoR defined in the original permit. Reservoir simulations were completed for the increased injection volume, which indicated CO_2 would not extend more than a quarter-mile from the injection well.

The permit extension was considered a minor modification permit and allowed up to 100,000 metric tons and extended the permit expiration date. Similar to the initial storage test, it was necessary to demonstrate well mechanical integrity with a CBL, annular pressure test, and temperature log before injection. Monthly monitoring reports were also submitted to U.S. EPA Region 5 during injection and following completion of injection.

Injection Operations

Approximately 10,000 metric tons of CO_2 were injected into a 73-foot thick perforated zone extending from a 3,442- to 3,515-foot depth across the Bass Islands Dolomite from February 7 to March 8, 2008. An extended injection test took place approximately one year later from February 25 to July 8, 2009, and involved the injection of approximately 50,000 additional metric tons of CO_2. During injection testing, CO_2 was injected at a rate of approximately 400 to 600 metric tons per day. The injection zone was capable of accepting CO_2 at the maximum flow rate possible with the compression system available, while retaining the CO_2 within the injection zone and confining system. The maximum rate was limited by compressor capacity at the site and not by reservoir conditions. Wellhead pressures monitored during the injection suggest that higher injection rates may be possible in this formation using a single injection well, at least initially, without exceeding the maximum injection pressure allowed by the UIC permit.

Monitoring Plan, Results, and Lessons Learned

The objective of monitoring was to assess the status of CO_2 from the capture facility to the storage reservoir, including transport to the injection facility, injection in a deep well, and storage of the injected CO_2 in the deep geologic reservoir. The monitoring program included wellhead monitoring (e.g., flow, annulus pressure), CO_2 surface gas detectors, downhole pressure and temperature logging, geochemical analysis of brine samples, microseismic monitoring and analysis, crosswell seismic surveys (processed as both reflection and waveform tomographic images), pulsed neutron capture (PNC) logging, wellbore and formation gas sampling using wireline methods, cement sampling and evaluation, and PFC tracer surveys (including soil-gas and atmospheric PFC sampling).

Tracking the movement and alteration of the injected CO_2 in the subsurface was one of the more challenging aspects of the monitoring program. This is due, in part, to the limited accessibility of deep reservoirs. Geologic heterogeneity made it difficult to estimate the transport pathway of CO_2 once injected. Indirect methods such as crosswell seismic and well logging that can detect the contrast of CO_2 versus native brines were considered to be the most promising to detect out-of-injection-zone plume migration. Methods for subsurface monitoring deployed at this site are discussed in more detail below.

Downhole temperature surveys were conducted in the injection well before injection, during the MIT, and after injection. Temperature changes in injectate were expected to have a detectable effect on the formation and to provide data that could be used to track reservoir behavior. These surveys provided direct evidence of the injected CO_2, because the CO_2 stream was much colder (60 to 65°F) than the conditions in the storage formation (88 to 92°F). The surveys consisted of logging temperature at depth with a wireline probe in the well.

Microseismic monitoring was conducted to record microseisms – small magnitude releases of mechanical energy that can occur for many reasons, including the pressure change caused by injection and natural microseismic events. Sensitive downhole receivers placed in the two monitoring wells continuously recorded seismic signals that occurred in the region around the borehole before and during the first injection campaign. The output of these receivers was recorded at the surface and analyzed. The analysis provided both magnitude and location (in three dimensions) of each detected event.

It was expected that the acoustic emission monitoring data from CO_2 injection could be utilized to determine CO_2 storage field distribution in deep saline formations. However, only one event (magnitude less than -2) was detected, because downhole CO_2 injection pressures were not high enough to cause significant microseismic events. Instead, the microseismic monitoring was useful in terms of verifying safety (e.g., there was no indication of fracturing of the confining zones).

Crosswell Seismic Surveying, a geophysical technique that can be used to monitor the distribution of CO_2 in the injection zone, was deployed using the injection well and two monitoring wells. Carbon dioxide saturation was expected to have an effect on formation velocity, and these velocity changes may make it possible to determine the plume geometry. For the initial injection phase, a baseline survey was conducted between the injection well and the closest monitoring well (bottom-hole section located approximately 480 feet away). The crosswell seismic survey was repeated after injection of 10,000 metric tons. Prior to the extended injection campaign, crosswell seismic surveys were conducted between the injection well and closest monitoring well, as well as the second monitoring well (located approximately 1,500 feet away). The second survey was added to help determine the nature of the velocity deviation seen on the first repeat. After injection of the additional 50,000 metric tons, the surveys were repeated. For all surveys, the injection well was the source well and the monitoring wells were used as the receiver wells. Field gathers from both before and after injection yielded high-quality data, typified by high signal-to-noise ratio and clear first arrivals.

Each crosswell seismic survey was processed in two ways. A reflection image was created and primarily used for baseline analysis. In addition, a tomographic inversion was performed. For this technique, the velocity at any given zone in the subsurface structure was calculated using the arrival times of all combinations of sensor and source positions. For subsequent surveys, differences in subsurface velocities could be calculated. These changes in velocity were attributed to the presence of CO_2.

Crosswell seismic was the first technique to show CO_2 in the interface between Bois Blanc and Amherstburg. Additional crosswell surveys helped detect CO_2 migration patterns in the subsurface and improve the conceptual geological model. Carbon dioxide was observed to migrate through the top of Bass Island, the primary injection zone, and into the overlying Bois Blanc, the secondary injection zone. The CO_2 continued to migrate upwards until it was confined by the caprock that comprises the Amherstburg (first layer of the confining zone). It appears that none of the CO_2 injected in the tests migrated through the Amherstburg into the Lucas formation (the second layer of the confining zone).

The **Pulsed neutron capture (PNC)** wireline logging technique, which is sensitive to the change in formation fluids due to the introduction of CO_2, was expected to be a useful method for detecting the vertical distribution of CO_2 adjacent to the logged well. A baseline logging run was collected prior to injection, and data from subsequent logging runs were compared to the baseline. By holding the rock matrix constant, any differences detected between an initial PNC log and any subsequent logs could be attributed to the presence of CO_2.

The PNC logging was performed in the injection well and two monitoring wells to augment the repeated crosswell seismic data. Overall, the repeat PNC surveys indicated that CO_2 was present within the injection zone and trapped by the overlying caprock. The PNC log data in the injection well showed CO_2 present in the perforated interval of the Bass Island Formation and no CO_2 moving along the wellbore into the Bois Blanc. In the monitoring wells, CO_2 was present in the overlying Bois Blanc and Amerstburg formations, but no CO_2 was observed in the Lucas Formation overlying the Amherstburg. The results are consistent with the crosswell seismic data.

PFC Tracer Survey: Atmospheric and soil-gas monitoring using PFC tracers was completed at the site to check for CO_2 released to the near-surface during the initial injection. Because the injection interval was situated between shallower Antrim shale natural gas production and EOR-related CO_2 floods in the lower Niagaran reefs, analysis of CO_2 levels or carbon isotopes could not be used, as observations could be the result of these other sources. Tagging CO_2 with PFC tracers was expected to be a reliable MVA technique for verifying containment in geologic settings with multiple CO_2 sources by providing a distinct signature in the storage test. The study was performed by NETL scientists and involved injecting a slug of PFC tracer in the CO_2 stream and sampling a grid of soil gas monitoring points before, during, and after injection. Results showed no indication of CO_2 release to the vadose zone or atmosphere.

Additional Monitoring Data: Wellbore and formation gas sampling and cement evaluation were performed to further investigate the observations made from crosswell seismic and PNC logging.

Gas Sampling: A Cased-Hole Dynamics Tester was used to collect gas samples within the formation and wellbore. Gas samples collected from the formation were essentially identical to the injected CO_2, indicating CO_2 had migrated from the injection well. Gas samples collected from the wellbore were different from the injected CO_2 sample, indicating that the CO_2 in the formation did not originate from a wellbore release.

Cement Evaluation: In addition, a cement evaluation tool was run, and at the end of the test, cement samples were collected. These analyses also helped rule out the wellbore as a potential release pathway.

Conclusions: MVA techniques can provide a more thorough understanding of CO_2 storage processes as well as practical monitoring information. The MVA Program was successful in supporting UIC requirements, ensuring safety of the injection system, and meeting research objectives. The monitoring observations also helped improve understanding of the site geology and reservoir modeling parameters.

Appendix D: MRCSP Michigan Basin Phase III Development Test

Overview

The MRCSP Phase III field test continues to develop the application of carbon storage technology as part of a regional strategy to reduce the amount of CO_2 that is emitted into the atmosphere. The MRCSP Development Phase test site is located in Otsego County, Michigan (Figure 33), near a natural gas processing and compression facility, which is the source of CO_2 for the test. The facility currently produces 600 to 1,200 metric tons-per-day of high-purity CO_2. The CO_2 is a constituent of natural gas produced from Antrim shales in the area. The CO_2 is stripped from the natural gas at a processing facility so the natural gas is suitable for burning. The CO_2 is either vented to the atmosphere or used for EOR operations.

EOR operations offer opportunities to research carbon storage technologies while providing valuable information about optimizing the recovery of additional oil. In Otsego County, EOR operations are taking place within pinnacle reefs also known as Niagaran Reefs. These reefs are highly contained geologic structures that are present at a depth of approximately 5,000 to 6,000 feet below the ground surface. Many of these reefs are greatly depleted and no longer produce economic amounts of oil. Therefore, they are expected to be excellent "containers" for geologic CO_2 storage. The MRCSP project is aimed at advancing monitoring and modeling techniques important for proving the security of CO_2 storage. Several different reefs at various stages of development will be tested to better understand both CO_2 storage and EOR potential.

Site Characterization

The site characterization and baseline data collection efforts will produce key parameters such as permeability, porosity, mineralogy, pressure, brine chemistry, and injectivity. Activities will provide parameters for calibrating seismic surveys and developing more specific monitoring designs for future tasks. Once the field data have been obtained, an integrated model will

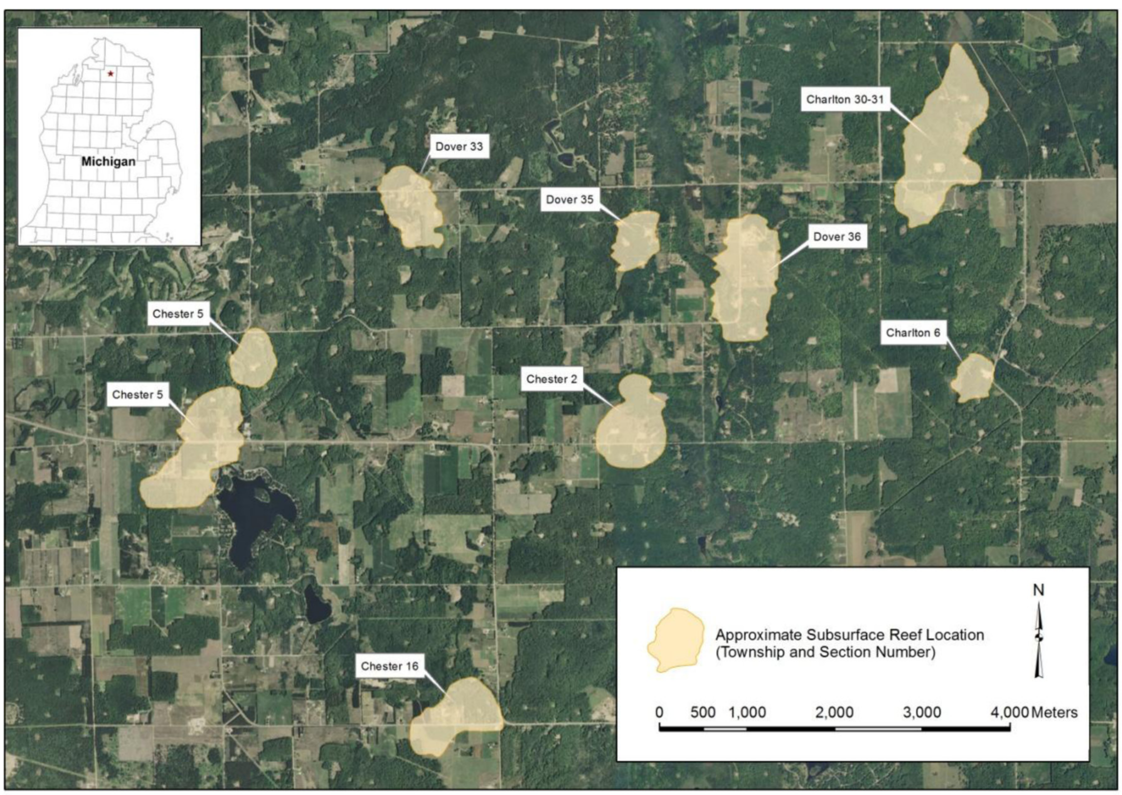


Figure 33: MRCSP Michigan Basin Phase III Development Test Site

be prepared to support injection system design and monitoring specifications. The site characterization activities include the following steps:

- Assessment of the existing well infrastructure, well history, and current well configurations.
- Compilation of seismic data; production histories; and any log, core, and deviation surveys data.
- Seismic data analysis to delineate deep geologic structures and rock formations.
- Initial static model construction using regional geologic studies, well logs, and seismic surveys.
- New data collection and analyses, including wireline logging, borehole gravity survey, brine sampling, temperature and pressure monitoring, VSP feasibility study, microseismic feasibility study, reservoir testing in wells, and historical and baseline land surface deformation studies.

Risk Assessment

A comprehensive risk assessment is being implemented for the project to provide guidance on injection system operations, the monitoring program, reservoir simulations, and other project activities. The risk assessment will include three main items:

1. Systematic survey of the site features to describe geologic setting, surface features, and risk pathways.
2. FEPs programmatic review of risks that may inhibit project performance or safety.
3. What-If Analysis of technical risks inherent to the scientific and engineering objectives of a CCUS project.

The risk assessment will focus on performance and safety aspects of the project, including:

- The release of CO_2 (e.g., via wellbores, faults or fractures, etc.).
- Potential injection pressure increases or seismic events.
- Gravity-driven CO_2 movement or residual trapping.
- Displacement of brine or other fluids.

Initial risk assessment activities have been completed. Based on the contained nature of the Niagaran Reefs being targeted for CO_2 injection, there are few risk items related to geologic seals of the reservoirs. The main risk items identified were wellbores that penetrate the reefs, and these wells are being included in the monitoring program. Results of the monitoring program will be integrated into the risk assessment as the project progresses.

Permit Requirements

Injection will occur under Class II UIC permits implemented by the U.S. EPA Region 5 UIC program. These permits are written for EOR using CO_2. Table 10 summarizes operating, monitoring, and reporting requirements under the UIC permit. The permit also requires MITs of the well every five years. Reporting and record keeping will be completed by Core Energy, LLC. As with any UIC permit, any significant variance to proper operation and maintenance of the injection system requires notification of EPA and may require mitigation measures. Reports documenting any new well workover, logging, or well testing must be reported to U.S. EPA Region 5 within 60 days of completion of the activity.

Table 10: Minimum Operating, Monitoring, and Reporting Requirements

Characteristic	Monitoring		Reporting
	Frequency	Type	Frequency
Injection Pressure	Weekly	–	Monthly
Annulus Pressure	Weekly	–	Monthly
Flow Rate	Weekly	–	Monthly
Cumulative Volume	Weekly	–	Monthly
Annulus Liquid Loss	Quarterly	–	Quarterly
Chemical Composition of Injectate	Annually	Grab	Annually

Injection Operations

The Phase III field test will inject 1,000,000 metric tons of CO_2 into oil fields which are at different stages in their life cycles. Carbon dioxide injection and monitoring operations will be carried out for three categories of Niagaran Reefs, distinguished by different stages in the life cycle of EOR. Category 1 Niagaran Reefs are late-stage CO_2 EOR reefs that have undergone extensive primary and secondary oil recovery, and are mostly depleted of oil. Category 2 Niagaran Reefs are operational EOR reefs that have finished primary oil recovery and currently undergoing secondary oil recovery using CO_2. Wells and pipelines will be instrumented to obtain geological and operational data that will be used to validate reservoir simulation models and provide material balances on the EOR operations to determine how much CO_2 is retained in the formations. Category 3 Niagaran Reefs are newly targeted reefs that have typically undergone primary oil recovery, but no secondary oil recovery using CO_2 has been attempted. These reefs will provide valuable new information about the geology because MRCSP will have the opportunity to piggyback on new wells that will have to be drilled for the CO_2 EOR operations to collect extensive core samples, advanced wireline logs, and advanced reservoir well tests.

Monitoring Plan, Results, and Lessons Learned

A comprehensive monitoring program will be developed for each reef. Table 11 provides a list of the monitoring techniques considered and expected outcomes. This effort will include options for assessing the distribution of the CO_2 in the target reservoir, out-of-zone injection monitoring, and storage mechanisms. In addition, numerical models of the CO_2 storage system will be calibrated and validated with monitoring data to further develop the usefulness of these methods to demonstrating CO_2 storage. Lessons learned from initial injection will be used to design monitoring strategies in subsequent injection events and to understand CO_2 migration in reservoirs, interaction with surrounding media, geochemical and geomechanical impacts, and storage capacity.

Table 11: Summary of Monitoring Activities Considered and Expected Outcomes

Monitoring Technique	Expected Outcomes
Pressure, Temperature, and Flow Rate Monitoring	Wellhead monitoring will provide fundamental information necessary for UIC permitting on injection rates, wellhead pressure, annulus pressure, and the properties of the injected CO_2.
Pulse Neutron Capture (PNC) Logging	PNC logging will be useful for detecting the vertical distribution of CO_2 adjacent to the logged well.
Vertical Seismic Profiling (VSP)	VSP will provide information to better characterize the geology of the injection region and determine changes that occur in the reservoir as a result of CO_2 injection into the reservoir. Time-lapse VSP is considered a viable method to overcome the potential resolution limitation of 4-D seismic. Time-lapse VSP has the best potential to assess the target area before CO_2 injection (a baseline VSP) and assess the changes by comparing these results with a post-injection VSP.
Microseismic Monitoring	The value of this monitoring method for a depleted formation is not well-understood. Microseisms primarily occur when pore pressure exceeds the frictional resistance on existing fractures. In this case, however, the production of oil from the reef has reduced the pore pressure in the formation. It is anticipated that the injection will bring the pressure in the reef to near original pressure; therefore, microseisms from fracturing are not expected. However, changes to the formation may occur when the low-pressure regions are re-pressurized. Implementation will be considered based on preliminary tests.
Geochemical Assessment/ Tracer Tests	The use of isotope tracers in concert with other geochemical parameters, such as pH, alkalinity, and metal and anion concentrations, provides a means for long-term monitoring of the CO_2 plume migration and trapping mechanisms, calibrating transport models as an aid to interpreting the time-series geophysical data, identify CO_2 breakthrough, and identify rock/CO_2/brine interactions.
Borehole Gravity Survey	The feasibility assessment concluded that the gravity signal at the surface is low (non-detectable) because of the low injection quantity of CO_2 and high injection depth in the reef. Using a borehole gravity meter will greatly improve the detection. Borehole gravity meters provide deep density measurements of rock formations surrounding a well through casing. Minimum expected anomalies would be detectable with the borehole instrument just above the reservoir or in the reservoir (useful to follow the displacement of the CO_2 front).
Interferometric Synthetic Aperture Radar (InSAR)	Commercial satellites are available and applicable for monitoring CO_2 migration through the reservoir as an expression of surface terrain deformation in response to large-scale injection. However, the deployment of InSAR in vegetated terrain for CO_2 injection sites is still in a research phase. The nature of the terrain at the proposed locations, with low wooded slopes, farmed fields, and open, cleared areas, may give a reasonable density of natural reflectors. Baseline monitoring and analysis will be performed to determine where artificial corner reflectors will be installed. Also, historical deformations (e.g., recorded between 1992 and 1999) will be assessed in order to quantify background natural displacements and to monitor potential subsidence associated with oil extraction.

Appendix E: MGSC Loudon, Mumford Hills, and Sugar Creek Phase II Validation Tests

Overview

Three EOR pilot-scale field tests (Loudon Field, Sugar Creek, and Mumford Hills) were conducted in Mississippian reservoirs in the Illinois Basin. The Loudon Field project was a CO_2 huff 'n' puff-type EOR in the Cypress Sandstone, which consists of elongated sandstone pods formed in a shallow marine depositional environment. An immiscible CO_2 flood pilot was conducted in the Jackson sandstone (Big Clifty Sandstone Member) at the Sugar Creek Field in Hopkins County, western Kentucky. The depositional environment and reservoir architecture of the Jackson are similar to the Cypress. A miscible (liquid) CO_2 flood pilot project tested storage of CO_2 in the Clore Formation (Chesterian Series) channel sandstones. The pilot was conducted at the Bald Unit within the Mumford Hills Field in Posey County, southwestern Indiana.

Figure 34: Location Map of Loudon, Mumford Hills, and Sugar Creek Test Sites in Illinois Basin.

Site Characterization

A geostatistical approach was used to create a model of the Loudon Field site's reservoir architecture. Well log data were normalized and then transformed into permeability and porosity values using core data. These results were used to produce multiple models of the framework of reservoir properties. The average of these reservoir models was considered as the most likely scenario and was used for reservoir simulation. Core analyses, porosity and permeability data, and geophysical logs from 40 wells were used to construct cross sections and structure contour and isopach maps to characterize and define the reservoir architecture of the Mumford Hills Field. Data used to develop the geocellular and reservoir models of the oil reservoir were limited for the Sugar Creek Field. Neither cores nor drilling samples were available for visual inspection within the pilot area, but some core analysis reports provided information about porosity and permeability. A limited suite of resistivity and spontaneous potential (SP) geophysical logs from 37 wells were used to define the structure and architecture of the formation. At each site, a geocellular model of the reservoir was built for reservoir modeling to estimate CO_2 EOR and storage capacity and to quantify the distribution of CO_2 in the subsurface.

Risk Assessment

Risk assessment for the EOR projects involved identification of potential risks during CO_2 injection by examining historical operations at the sites and the current operators' role in the day-to-day activities of existing oil fields. Risk was qualitatively assessed and minimized during the site screening and selection process. Based on the proposed CO_2 injection well and surrounding wells for each pilot, a five-tier screening process was used. The first screening tier was primarily designed to classify the CO_2-crude oil interaction as immiscible-gas, miscible-liquid, or miscible-critical fluid. The screening was primarily based on current reservoir pressure and temperature, API gravity, and geologic formation. The second tier was to determine the number of geologic zones open to the potential injection well, a centrally located well with (preferably) four existing producing wells surrounding the injection well. Surface injection pressure, water injection rate, and oil/water/gas production at the surrounding wells were considered in this tier. The third tier was the surface conditions that would accommodate the injection and data acquisition equipment and CO_2 tank truck delivery. Other surface features included proximity to lakes/ponds, flood plains, homes, and major roads. For example, if a home was too close to injection operations, and noise or safety impacts could be an issue, or if a topographically low area was present near the injector that CO_2 could accumulate in, the site was rejected. The fourth tier was the number of zones currently completed in the injector and the ability to isolate zones in a single wellbore. Type of completion (e.g., cased and perforated or openhole), along with well workover type and frequency in the area and in specific wells, was important in the screening process. Recent injection pressure history was also reviewed. The fifth tier consisted of the geologic modeling and reservoir modeling results. Greater consideration was given to injection patterns for which modeling predicted that oil production and pressure results would be measurable and quantifiable within the planned duration of CO_2 injection and budget of the project.

Permit Requirements

The Loudon project was considered a single-well stimulation and a permit was not required. For the Mumford Hills and Sugar Creek projects, there were no specific tests required by permit. Specific measurements required were cumulative injection volumes and surface and subsurface injection. These values were reported annually.

The injection well at Mumford Hills was not previously permitted for injection. For CO_2 injection, a permit was required from the Department of Natural Resources, Division of Oil and Gas, State of Indiana. The state of Indiana issued a permit for CO_2 injection up to 10.3 MPag (1,500 pounds per square inch gauge [psig]) bottom-hole pressure. Injection could commence only after a state-approved MIT. The pressure requested by the operator was significantly lower than the 14.8 MPag (2,150 psig) water injection pressure designated on the permit.

The injection well at Sugar Creek was previously permitted as a water injection well (UIC Class II) with U.S. EPA Region 4. It was permitted at 31.8 m^3 (200 barrels) of water per day at 9.31 MPag (1,350 psig) surface injection pressure. Because CO_2 density is less than brine density, for this project an application was made to U.S. EPA Region 4 to increase the surface pressure that would correspond to the same bottom-hole pressure. The existing bottom-hole injection pressure for water was 14.88 MPag (2,158 psig). For injecting the less dense CO_2, an increase in the surface injection pressure to 9.818 MPag (1,424 psig) was requested and approved.

Injection Operations

At the Loudon Field huff 'n' puff site, 39.1 tonnes (43 tons) of CO_2 were injected into the annulus of an oil-production well. The CO_2 gas was injected over a period of approximately one week at a rate of 4.5 to 9.1 tonnes per day (5 to 10 tons per day). After injection, the well was shut-in for one week and reservoir fluids (oil, brine, CO_2) were produced. Prior to CO_2 injection, the well produced 0.079 to 0.16 m^3 (0.5 to 1.0 barrels) of oil per day (bopd); however, during the first week of production after CO_2, injection oil production increased to a maximum daily rate of 1.3 m^3 per day (8 bopd), then declined to 0.48 to 0.79 m^3 per day (3 to 5 bopd). Over two months, the well was estimated to produce approximately 16 m^3 (100 barrels) of oil above the pre-injection forecast for oil production.

At the Mumford Hills field site, the CO_2 injection period lasted from September 3, 2009, through December 14, 2010, with one, three-month interruption caused by cessation of CO_2 deliveries due to winter road restrictions enforced by the township road commissioner. By mid-January 2010, 2,600 tonnes (2,860 tons) of CO_2 had been injected. Water injection began at the end of January and continued through May 2010, when CO_2 injection started again. During this time, 2,080 m^3 (13,100 barrels) of water were injected at approximately 25 m^3 per day (150 bpd). The second CO_2 injection period resulted in an additional 3,700 tonnes (4,080 tons) of CO_2 being injected. Through September 30, 2011, increased oil production due to pre-CO_2 injection well work was estimated at 95 m^3 (600 barrels) and increased oil production due to CO_2 was 330 m^3 (2,100 barrels). This includes variations in oil production due to cessation of CO_2 injection and booster pump failure and other operational problems, and does not necessarily reflect the CO_2 EOR completely. The CO_2 produced and metered at the gas-liquid separator was approximately 27 tonnes

(30 tons), or 0.5 percent of the injected CO_2. During the monitoring period, 99.5 percent of the injected CO_2 was estimated to have remained in the Clore sandstone.

At the Sugar Creek field site, CO_2 injection started on May 13, 2009. Oil production increased by nearly 1.6 m^3 (10 barrels) per day after three months of CO_2 injection. The increased production was sustained for the next three months until CO_2 injection was temporarily suspended due to a release in the injection line from the pump skid to the injection well, and winter road conditions that were unsafe for the CO_2 delivery truck. By the time injection ceased at the end of May, 2010, 6,560 tonnes (7,230 tons) of CO_2 had been injected. The CO_2 produced from the casing-tubing annulus of individual wells and at the tank battery was 1,090 tonnes (1,200 tons), or 16.6 percent of the injected CO_2. Through September 30, 2011, increased oil production due to pre-CO_2 injection well work was estimated as 1,574 m^3 (9,900 barrels) and increased oil production due to CO_2 as 334 to 509 m^3 (2,700 to 3,200 barrels). Increased oil production includes variations in oil production due to operational problems (e.g., flowline breach) and does not necessarily reflect the CO_2 EOR completely.

Monitoring Plan, Results, and Lessons Learned

The overall goals of the MVA Program for the EOR projects were to test the deployment strategies and monitoring capabilities of selected MVA techniques and to detect significant CO_2 release events if they were to occur. The MVA Program's techniques consisted of: (1) atmospheric monitoring, (2) shallow geophysical surveys, (3) gas (soil and well) sampling, (4) shallow groundwater monitoring, (5) groundwater and geochemical modeling, (6) cased-hole well logging, (7) reservoir brine monitoring, and (8) infrared aerial photography.

Lessons Learned

The shallow geophysical surveys consisted of EM and resistivity surveys, which were only attempted at the Loudon site. These techniques were adversely affected by electrical lines as well as buried steel pipes, which were both abundant and not mapped at the oil fields. Because of these problems, these geophysical techniques were not attempted at the other CO_2-EOR sites. Use of color infrared aerial imagery to monitor the condition of crops and other vegetation in the vicinity of the EOR sites was not cost-effective due the short duration of the projects and relatively small CO_2 volumes injected. The detailed aerial images, however, were invaluable in planning and deployment of site activities as well as monitoring site conditions during the project. Hyperspectral aerial monitoring for plant stress during a known CO_2 pipeline leak at the Sugar Creek site was not an effective tool given the short duration of the release. The specific equipment used was not intended for direct observation of CO_2 concentrations or occurrence. Other techniques such as atmospheric and soil flux monitoring, thermal infrared imaging, and soil temperature were more effective at defining the extent of the release. However, where EOR is deployed on a commercial scale, other aerial imagery techniques are likely to be more cost-effective in identification of potential leaks to the land surface.

From experience at several MGSC study sites, soil-gas monitoring may have moderate to limited success in parts of the Illinois Basin because of saturated soil conditions near the surface. Gas sampling of the casing gas was important and necessary to quantify the CO_2 production and corrosion potential. Residential and shallow groundwater monitoring near EOR sites is considered an important monitoring effort. In one case at the Loudon site, groundwater monitoring alleviated concerns of a landowner when excessive odor in a water well was suspected of being CO_2 related. Available monitoring results were used to verify the odor was from a different origin.

Groundwater monitoring and cased-hole logging at all sites indicated that injected CO_2 remained in the injected interval. Distribution and volume of CO_2 within the formation were approximated with reservoir simulations calibrated to pressure data and sampling results at the monitoring and production wells. Pressure, produced gas composition, and brine attributes (e.g., pH) were the most reliable indicators of the presence of CO_2 at specific well locations. The collection and analysis of aqueous and gas chemistry data allowed for interpretation of reservoir characteristics and, to some degree, prediction of the fate of CO_2 in the reservoir. Dissolution of CO_2 into the reservoir brine caused pH to decrease by one pH unit from approximately 6.8 to 5.8. For some wells, the pH decrease occurred before the arrival of free-phase CO_2, indicating rapid dissolution of CO_2 into brine. The CO_2 dissolution and associated dissociation reactions increased alkalinity and dissolved inorganic carbon, indicating some solubility trapping of CO_2. Both $\delta^{13}C$ and ^{14}C were found to be viable tracers of injected CO_2, although ^{14}C was judged to be more effective.

Appendix F: MGSC Decatur Phase III Development Test

Overview

The Illinois Basin – Decatur Project (IBDP) is a large-volume injection and storage test located in Decatur, Illinois. The goal of the project is to demonstrate the ability of the Mt. Simon Sandstone, the thickest and most widespread saline reservoir in the Illinois Basin, to accept and retain 1 million tonnes of CO_2 injected over a period of three years. The Mt. Simon Sandstone is 1,650 feet (503 meters) thick at the site. Its upper part was deposited in a tidally influenced system, while the lower 600 feet (183 meters) is an arkosic sandstone that was deposited in a braided river/alluvial fan system. This lower Mt. Simon Sandstone is the principal target for storage, in part because the dissolution of feldspar grains has created good secondary porosity. The Eau Claire Formation is the primary confining layer or seal and is 695 feet (212 meters) thick. Its lower part is

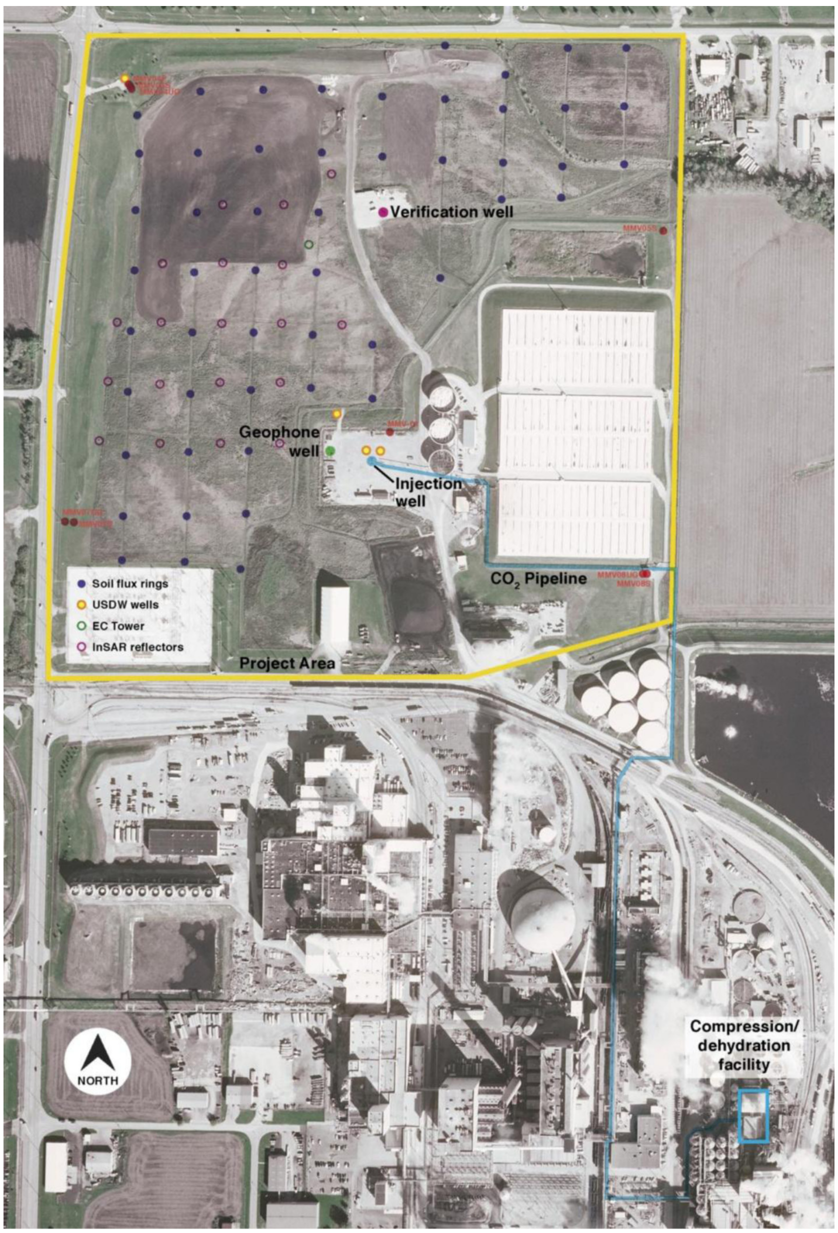


Figure 35: Illinois Basin – Decatur Project Site and Selected Infrastructure and Monitoring Locations.

comprised of shale, and its upper part is comprised of low-permeability limestones and siltstones. Injection began in November 2011, and as of the end of July 2012, approximately 226 kilotonnes (kT) of CO_2 had been injected into the Mt. Simon Sandstone.

Site Characterization

A comprehensive subsurface characterization program was put into place to evaluate seal and reservoir properties and to predict movement of injected CO_2 within the Mt. Simon Sandstone. Two-dimensional seismic reflection profiles were acquired for initial assessment of the subsurface geology. The injection well (ADM CCS#1), a geophysical monitoring well (GM#1), and a deep observation well (VW#1) were drilled to total depths of 7,230 feet (2,204 meters), 3,500 feet (1,067 meters), and 7,264 feet, (2,214 meters), respectively (Figure 35). Fluid samples, core samples, and wireline logs were collected from the injection well, which was fitted with a downhole pressure sensor, a DTS system, and an array of three geophones during well completion. Fluid injection tests in this well were used to estimate reservoir properties. Completion of the geophysical monitoring well included installation of a 31-level multi-component geophone array for 3-D VSP and passive seismic monitoring. Fluid samples, core samples, and wireline logs were also collected from the deep observation well. Three-dimensional surface seismic data were acquired and correlated with wireline data from all three wells. Well and seismic data indicate that the Eau Claire seal is continuous across the site, and these data have been used to create an integrated subsurface geologic model to constrain reservoir flow simulations.

Risk Assessment

Risk management for the IBDP began in 2008, prior to field activities, and will carry on for the duration of the project. The risk management process has included risk identification, evaluation, treatment development, and treatment execution tracking. Experts evaluated FEPs to assess their associated risks to project goals and values. The experts quantified severity (S) and likelihood (L) of negative impacts and computed the product, S×L, which is defined as "Risk." High-risk FEPs were used to develop specific scenarios that would result in negative impacts. The scenarios were used, in turn, to develop more than 200 risk treatments (i.e., actions that reduce the severity and/or the likelihood of negative impacts). Specific risk treatments were developed that involve well engineering, subsurface characterization, computer modeling, monitoring, public communications, and other efforts. Project risks will be re-evaluated based on monitoring data, preliminary CO_2 injection experiences, and updated reservoir flow simulations.

Permit Requirements

The IBDP injection activities are operating under a UIC Program Class I (non-hazardous) injection permit issued by the Illinois EPA. For the permit, a range of tests and monitoring efforts are prescribed, along with specified reports. These efforts include:

For the injection well (CCS#1):

- Annulus pressure testing for mechanical integrity every 12 months.
- Temperature survey and time-lapse sigma log every 24 months.
- Wellhead pressure monitoring every 30 seconds.

For the verification well (VW#1):

- Pressure measurements from three zones and temperature measurements from one zone every month.
- Quarterly synchronization of recording device.
- Verification of well tubing pressure test after installation of Westbay automated pressure logging system.
- Westbay QA zone monitoring.
- Annulus pressure test every 12 months.

For the Illinois EPA-designated lowermost USDW:

- Four regulatory compliance wells monitored quarterly for 11 indicator and field parameters with groundwater summary reports submitted quarterly to the Illinois EPA.

For other site activities:

- A 30-Day Notice submitted to the Permit Section, Division of Land Pollution Control, prior to any pressure/mechanical tests, logs, or inspections.
- Copies of all wireline logs with qualified log analysis.

Injection Operations

The source of CO_2 for the project is the Archer Daniels Midland Company (ADM) ethanol fermentation units. The CO_2 is 99 percent + (vol.) pure and is saturated with water vapor at 80°F and 1.5 psig (10.5 kPag). Common impurities are ethanol and nitrogen. Other impurities may include oxygen, methanol, acetaldehyde, and H_2S. The CO_2 is compressed from 0 to 1,400 psig (0 to 9.66 MPag) using a 1,250-horsepower, 4-stage centrifugal blower followed by two, 3,250-horsepower, 4-stage reciprocating compressors operating in parallel. Carbon dioxide leaves the compression facility and travels through a 6,400-foot (1,950-meter), 6-inch (15-cm) diameter, above-ground, insulated, carbon-steel pipeline to the wellhead. Automated measurement of critical flow rates, temperatures, pressures, CO_2 water content, and oxygen content are integrated with ADM's Distributed Control System (DCS) so that automated shutdown can be performed as needed to ensure safe operation and to prevent equipment damage.

Monitoring Plan, Results, and Lessons Learned

A wide range of monitoring techniques has been applied to the IBDP test site. These are summarized in Table 12.

Significant effort during the early phase of CO_2 injection at the IBDP site has involved plume and pressure front tracking using a geologic model, calibrated reservoir flow model, and characterization of the reservoir geochemistry.

Table 12: Techniques in Use at the IBDP Site to Monitor Injection Formation Response, Track CO_2 Movement, and Verify Containment in Injection Formation

Monitoring Level	Measurement Technique	Measurement Parameters	Application
Atmosphere	Eddy Covariance	CO_2 Flux	Characterize net CO_2 fluxes. Detect and quantify CO_2 release to atmosphere should it occur. Data collected continuously from automated system with 6 to 12 months of baseline.
	CO_2 Detectors – IRGA	CO_2 Concentration	Temporally characterize CO_2 concentrations within 3 m of land surface. Data collected continuously from automated system with 6 months of baseline.
	Tunable Diode Laser	CO_2 Concentration	Field test prototype equipment and develop operational protocols. Detect, locate, and quantify CO_2 release to atmosphere should it occur. Data collected manually and continuously from automated system. Deployment planned in 2012.
Near-Surface	Accumulation Chamber	Soil CO_2 Flux	Spatially and temporally characterize ecosystem fluxes. Detect, locate, and quantify CO_2 release should it occur. Data collected continuously and weekly with 18 to 24 months of baseline data.
	Natural Tracers – Isotopes	Isotopic Composition of Injected and Soil Gas CO_2	Characterize source CO_2 and soil gas. Source CO_2 analyzed at least quarterly with 12 months of baseline.
	Gas Sampling	Soil and Vadose Zone CO_2 Concentrations	Detect, locate, and quantify CO_2 release should it occur. Data collected quarterly with approximately three months of pre-injection data.
	Aircraft-Based Color Infrared (CIR) Imagery	Infrared Imaging of Land Surface to Detect Vegetative Stress	Detect and locate vegetative effects of CO_2 and/or brine releases. Data collected semi-annually or as needed with 18 months of baseline.
	InSAR	Radar from Satellite	Detect surface deformation. Evaluate method performance in temperate climates. Maximum data collection frequency of 8- to 16-days with at least one period of baseline data acquisition.
	Groundwater Sampling	Chemical and Isotopic Compositions	Characterization of shallow groundwater and USDW for public assurance, CO_2 release detection, and regulatory compliance monitoring. Data collected monthly to quarterly with 12 to 18 months of baseline.
	High Resolution Earth Electrical Resistivity	Resistivity of Shallow Geologic Materials	Characterize shallow subsurface geology (<40m) and detect potential CO_2 or brine impacts. Data collected semi-annually with 18 to 24 months of baseline.

Monitoring Level	Measurement Technique	Measurement Parameters	Application
Subsurface	Seismic: (1) 2-D; (2) Time-Lapse 3-D; (3) Time-Lapse 3-D, VSP; and (4) Passive	P and S Wave Velocity; Reflection Horizons; Seismic Amplitude; Attenuation; Magnitude and Characteristics of Microseismic Events	Geologic characterization of injection site (1, 2). Track distribution and movement of CO_2 in and above storage formation. Provide detailed footprint of plume migrating from injection well into storage formation (2, 3). Monitor fluid movement and any rock fracturing (4). 2-D data collected prior to injection. 3-D data collected prior to and after injection. VSP data collected annually. Passive data collected continuously from automated system in injection well and dedicated geophone well.
	Open- and Cased-Hole Logging of Injection and Verification Wells	Multiple Parameters	To characterize fluids, rocks, sediments (gamma, resistivity, sonic imaging, elemental spectroscopy, magnetic resonance, temperature, sidewall core, fluid sampling, CO_2 saturation [pulsed neutron]), well integrity (cement bond, ultrasonic imaging, and multi-finger caliper), and seismic velocities (zero offset VSP). Logging activities conducted during and after well installation and on a yearly basis.
	Distributed Temperature Sensing	Temperature of Injection Well Annulus/Near Wellbore Geologic Formations	Detect migration of CO_2 near injection well. Monitor well integrity and CO_2 phase change in injection well. Data collected continuously from automated system with 13 months of baseline data
	Subsurface Pressure	Formation Pressure, Annulus Pressure, Formation Pressure Above Primary Seal	Control of formation pressure below fracture gradient. Monitor wellbore and injection tubing condition. Monitor for release out of the storage formation. Data collected continuously from automated systems with 12 months of baseline.
	Fluid Sampling	Major and Minor Ions, Isotopes, Trace Elements, Carbonate Species, pH, TDS and Gas Composition	Characterize fluid compositions in the storage formation and in the first porous/permeable zone above the primary seal. Provide chemical data for geochemical modeling. Determine CO_2-brine-rock interactions. Quantify chemical trapping mechanisms of CO_2. Monitor for release out of the storage formation. Data collected semi-annually with three baseline sampling events.
	Injection Pressure Fall-Off and Step-Rate Test	Formation Pressure, Pumped Fluid Volume, Rate, and Temperature	Determine injectivity, permeability, and fracture gradient of injection formation. Data collected from injection.

Plume and Pressure Front Tracking

The IBDP is using ECLIPSE 2011.2 reservoir simulation software with the CO_2STORE module to predict the long-term fate of CO_2 injected into the Mt. Simon Sandstone. The static geological model includes the entire Mt. Simon formation and the overlying Eau Claire seal. The geological model was downscaled around the injection wellbore for greater resolution in reservoir simulations. Vertical resolution of the geological model was honored in the lower 700 feet (213 meters) of the reservoir, where CO_2 was expected to remain for at least 100 years. However, in the upper sections of the model, vertical resolution was reduced. As a result, the final reservoir model is represented by a high-resolution grid.

The model has been calibrated using observed data (e.g., measured injection rates) for the prediction of model conditions (e.g., bottom-hole pressures at the injection well, pressures at five different depths in the Mt. Simon Sandstone corresponding to the monitoring zones in VW#1). Wireline spinner data collected from the injection well provided an estimate of the amount of CO_2 movement to the two sets of perforations in the injection well, and RST logs provided an indication of CO_2 saturation around CCS#1 and VW#1. Reservoir permeability, relative permeabilities, and skin were the most sensitive parameters adjusted to provide the best fit between the measured and predicted data. Once the injection well bottom-hole pressure was sufficiently predicted (Figure 36), simulated pressures at the verification well were calibrated by adjusting the vertical and horizontal hydraulic conductivity ratio of the tight sections in the Mt. Simon Sandstone and compressibility of the reservoir rock.

The calibrated reservoir model estimated that the pressure pulse front reaches its maximum size at the end of the first year of injection and then declines. A CO_2 saturation of one percent was the threshold used to define the CO_2 plume. The plume front was estimated to radiate approximately 1,000 feet (305 meters) or less from the injection well after injection of 140 kT of CO_2. RST logs at the verification well confirm this estimate.

Geochemical Monitoring

Chemical and isotopic characterization of fluids from USDWs (e.g., local shallow groundwater), the Ironton-Galesville formation, and the Mt. Simon Sandstone reservoir was conducted prior to injection and will continue through the duration of the project.

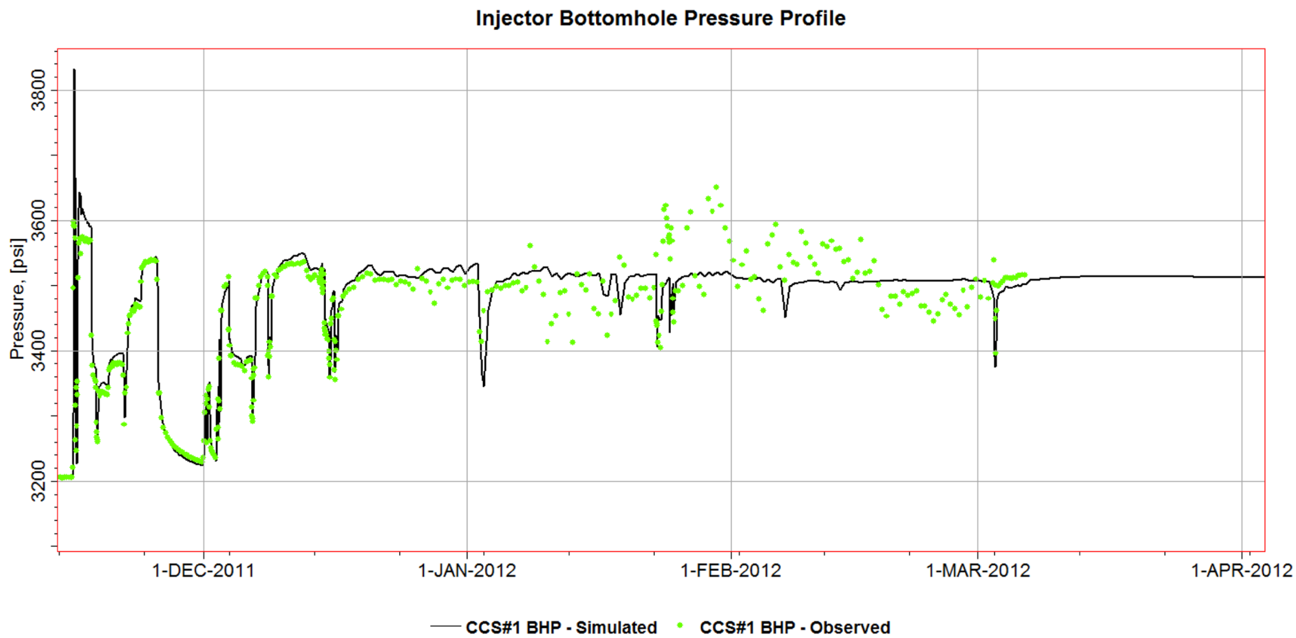


Figure 36: Predicted and Measured Bottom-Hole Pressures at CCS#1.

USDW – Shallow Groundwater Characterization

Two years before injection began, 13 monitoring wells were installed to monitor shallow (<300 feet; <91 meters) groundwater quality and water levels and have been sampled monthly. In 2010, four monitoring wells were installed at a depth of approximately 140 feet (43 meters) to monitor water quality of Pennsylvanian bedrock, the Illinois EPA-designated lowermost USDW. To date, no changes in groundwater quality have occurred that could be attributed to CO_2 or brine release; however, seasonally related and other water-quality variations have been observed. Project experience has demonstrated that baseline data must be collected over sufficiently long periods (e.g., one to three years) in order to adequately assess groundwater quality, especially when heterogeneous fluid chemistries of shallow formations are involved. Table 13 provides a gross characterization of shallow groundwater quality at the IBDP site and a comparison to other formation fluid chemistry.

Injection Reservoir Fluid Characterization

Brine and gas samples have been collected to establish baseline fluid geochemistry in the Mt. Simon Sandstone and in the Ironton-Galesville Sandstone above the primary seal. Fluid samples were collected during drilling of CCS#1 and completion of VW#1 using wire line tools. Also during VW#1 completion, swab samples were collected from individual perforated zones, and a Schlumberger Westbay multilevel groundwater characterization and monitoring system was installed.

Swabbing of VW#1 purged large volumes of fluid from sampling zones to remove non-native fluids that were introduced during drilling and completion and greatly improved the representativeness of sample collected. The Westbay system has allowed direct fluid sampling and pressure monitoring to be conducted in nine zones within the Mt. Simon Sandstone and two porous and permeable zones of the Ironton-Galesville Formation that are above the primary reservoir seal (Eau Claire). To date, three sampling events (one swabbing, two Westbay) occurred pre-injection, and one Westbay sampling event has occurred concurrently with injection. This has been an important effort to collect direct measurements of the chemical and isotopic character of reservoir brines and gases. In March 2012, samples of injected CO_2 that had migrated 1,000 feet (305 meters) from CCS#1 to VW#1 and brine in zones above and below the CO_2 plume were collected. Table 13 presents a gross characterization of Ironton-Galesville and Mt. Simon brines.

Experience collecting brine samples using multiple techniques and at multiple times has allowed development of procedures to confirm that the sampled fluids are representative of anticipated formation geochemistry. In addition to measurement of routine parameters (e.g., pH, temperature, specific conductance, and dissolved oxygen), tests are performed for fluid density, as well as concentrations of chloride, bromide, and other analytes. For the IBDP, density, bromide, potassium, and ammonium have been among the most diagnostic indicators of groundwater chemistry changes.

Table 13: IBDP Water-Quality Comparison for Shallow Groundwater (16 Well Average), Ironton-Galesville Sandstone (Two Zone Average), and Mt. Simon Sandstone (Nine Zone Average)

Constituent	Shallow Groundwater < 300 ft (91 m) Deep	Ironton-Galesville	Mt. Simon (Injection Formation)
Conductivity (mS/cm)	1.5	80	170
TDS (mg/L)	1,000	65,600	190,000
Cl^- (mg/L)	170	36,900	120,000
Br^- (mg/L)	1	180	680
Alkalinity (mg/L)	380	130	80
Na^+ (mg/L)	140	17,200	50,000
Ca^{2+} (mg/L)	100	5,200	19,000
K^+ (mg/L)	1	520	1,700
Mg^{2+} (mg/L)	50	950	1,800
pH (units)	7.2	6.9	5.9

Appendix G: PCOR Partnership Zama Phase II Validation Test

Overview

The Zama F Pool acid gas EOR project is a brown-field (previously developed) oil field that has been established within the existing Alberta Energy Resources Conservation Board (ERCB) regulatory framework. The field is located along 59°N latitude in the extreme northwestern corner of the Province of Alberta, approximately 875 kilometers (550 miles) northwest of Edmonton. The field spans an area of approximately 2,000 km^2 (500,000 acres) in the Middle Devonian Zama sub-basin, known as the Fort Nelson Lowland.

The carbonate Zama reservoirs are found in the Middle Devonian Zama sub-basin. The sedimentary succession consists of the Middle and Upper Devonian carbonates, evaporates, and shales; Mississippian carbonates; and Lower Cretaceous shales overlain by Quaternary glacial sediments. The Zama Oil production primarily originates from within the Middle Devonian Keg River pinnacle reef reservoirs at a depth of approximately 4,900 feet (1,500 meters). The Keg River reef build-ups were formed in a lagoon partially surrounded by carbonate banks and fronted by the Presqu'ile Barrier to the west. To date, more than 600 pinnacles have been discovered in the Zama sub-basin. On average, these pinnacles cover roughly 40 acres (0.16 km^2) at the base and are roughly 400 feet (120 meters) high. As of May 2012, cumulative acid gas injected into the F Pool was 133,550 tons (CO_2 fraction – 93,485 tons), with a net CO_2 stored of 40,357 tons.

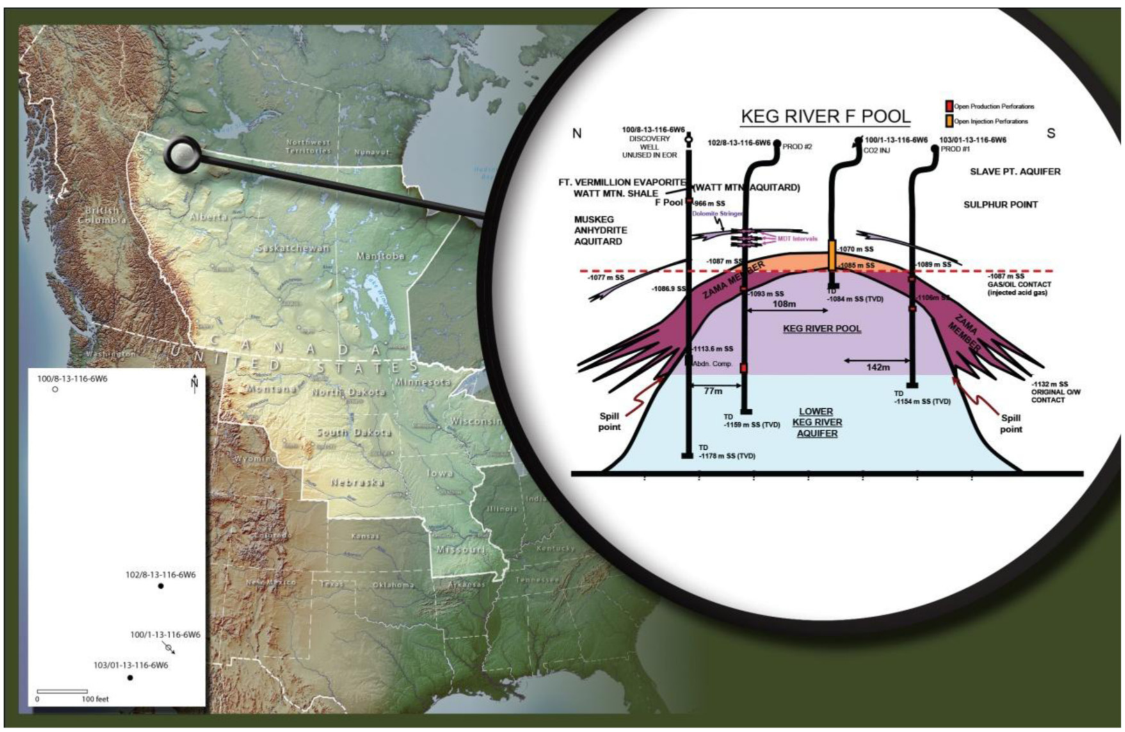


Figure 37: Relative Locations of Wells in F Pool Pinnacle Reef in Zama Oil Field.

(Inset cross-section illustrates general geology of pinnacle reef and depths of each well; inset map shows geographic location of each well.)

Site Characterization

Geologic characterization was carried out at four scales utilizing the following activities:

- Geological Evaluation
- Geochemical Evaluation
- Hydro-Geological Evaluation
- Geomechanical Evaluation
- Wellbore Integrity Evaluation

At reservoir scale, the focus was on the Zama F oil pool and the immediately underlying and overlying confining units, the Lower Keg River Formation limestone and Muskeg Formation anhydrite, respectively. The local scale encompasses the stratigraphy of the Zama F Pool, a few adjacent pinnacle reefs, and the entire sedimentary succession from the basement to the surface. The regional or sub-basin scale focused on evaluating relevant data and information from the basement to the surface, over the entire Zama oil field/sub-basin. Studies at the basin scale, which covers the flow regime in the underlying Keg River, were used to determine the discharge area and flow characteristics.

Risk Assessment

Existing public and proprietary operator well and reservoir information on the Zama Keg River F Pool and adjacent pools was gathered to assess current knowledge and discern monitoring techniques currently used. Gaps in existing data were indentified and integrated into the collection of new data. Reservoir engineering analyses were used to characterize the reservoir and formation impacts on the project.

Risk assessment provides a more accurate understanding of the relevant, project-specific technical risks, while establishing a robust framework designed to mitigate risk throughout the life of the project. By identifying knowledge gaps in current data, risk assessment activities can provide direction for future studies and characterization work. Additionally, geologic storage risk assessment supports the development of a project-specific, risk-based MVA plan.

Permit Requirements

In order to implement an EOR miscible flood project at Zama-Keg River F Pool, Apache Canada, Ltd., needed to submit a Directive 065 (Resources Applications for Conventional Oil and Gas Reservoirs) and a Directive 051 (Injection and Disposal Wells – Well Classifications, Completion, Logging, and Testing Requirements) to the Alberta ERCB.

Directive 065 simplifies the application process to the Alberta ERCB by using one resource application for all necessary approvals needed to establish a strategy to deplete a pool or portion of a pool. The directive also enables the applicant to review, in a single document, the application requirements for most conventional oil and gas reservoir topics that need Alberta ERCB approval.

Directive 051 defines Alberta ERCB requirements for injection and disposal wells, including well classifications, completion, logging, and testing requirements.

A program of monitoring to ensure continued wellbore and formation integrity is required for a Class III Well, which is the type of well Apache Canada was required to use. In addition, logs that indicate cement top location, hydraulic isolation, and casing integrity are required. Other required testing includes an initial annulus pressure test and an annual packer isolation test.

Injection Operations

The injection program for the Zama EOR and CCUS project was designed, implemented, and operated by Apache Canada according to regulatory guidelines established by the Alberta ERCB. The purpose of the injection program is to: (1) cost-effectively capture, transport, and inject acid gas from the Zama gas-processing plant into the Zama F Pool reservoir; (2) facilitate the production of incremental oil from the F Pool reservoir; and (3) support the documentation of effective CO_2 storage in the F Pool. Key aspects of the Zama injection program include the capture and infrastructure elements of the project, well preparation and maintenance activities, acid gas injection and EOR operations, and determination of CO_2 storage capacity.

Monitoring Plan, Results, and Lessons Learned

MVA data acquisition was coordinated with routinely scheduled operation activities so as to minimize disruption of normal Apache operations. Monitoring activities were focused on the near-reservoir environment, including caprock integrity, wellbore release, and spill point breach. Integrated geological and hydro-geological characterization and geochemical sampling and analysis programs were focused on the potential movement of the injected gases and the detection of any potential release from the storage reservoir.

In addition to verifying the known, long-term storage capacity of the Keg River pinnacle reef pools, the Zama Field Validation Study was designed to test its integrity for oil and gas containment during injection of high concentrations of acid gas.

Geological, hydro-geological, geochemical, and geomechanical validation studies, as well as field-based MVA operations, were undertaken to monitor the effects of acid gas injection at Zama.

MVA activities included:

1. Monitoring of the injected acid gas plume through:
   - Reservoir pressure monitoring of the F Pool through intermittent pressure surveys and analytical modeling.
   - Wellhead and formation fluid sampling (oil, water, gas) of the F Pool Production wells perforated at various depths within the pinnacle.
2. Identifying any early warning signs of storage reservoir failure through:
   - Injection well and reservoir pressure monitoring of both the F Pool and overlying FFF Pool with pressure surveys at six-month intervals.
   - Gas soluble PFC tracers injection into the F Pool and monitoring for seepage to the overlying FFF Pool with gas sample analysis at six-month intervals.
3. Monitoring injection well condition, flow rates, and pressures through:
   - Wellhead pressure and flow gauges.
   - Well and packer integrity tests required annually by the Alberta ERCB.
   - Surface H_2S and CO_2 monitoring near injector points and high-risk areas.
4. Monitoring solubility and mineral trapping through:
   - Study of core material previously exposed to acid gas injection.

Tracer MVA Program

The objective of the inter-well tracer program is to monitor the possible migration of acid gas out of the Zama/Keg River lower injection zone into the upper Slave Point producing zone.

On February 26, 2008, 5.5 kg of Core Labs IGT-1100 gas soluble chemical tracer compound was injected into the Keg River F Pool via the 100/01-13 injection well. Initial pressure testing and gas sampling was performed on the Slave Point FFF Pool at the 100/08-13 well in April 2008. A second pressure survey was completed in December 2008, and a second gas sampling operation was completed in May 2009. The most recent pressure test and samples were taken in July 2009. No chemical tracer has been detected to date. Pressure comparisons suggest the Slave Point pool at this location has experienced a 350-kPa pressure increase over the 15-month interval between the initial pressure test and the most recent test. It is not yet clear if this pressure increase is due to leakage from the Keg River F Pool, or to minor formation support or recharging in the Slave Point. No tracer has been detected in any of the gas samples to date, and the composition of the samples appears relatively unchanged.

Pressure Monitoring MVA Program

As a secondary MVA protocol to detect larger-scale reservoir pressure communication, the reservoir pressures of both the Keg River F Pool at 2,175 psi (±15,000 kPa) and the SP FF Pool at roughly 870 psi (3000 kPa) were monitored on the same six-month schedule as the tracer samples.

The premise is that if the wellbore allows release, it will eventually be detected with an increase in the lower pressure Slave Point completion. Predictive material balance reservoir models were developed for both the Keg River F and up-hole Slave Point FF reservoirs. These models were intended to provide a basis for the monitoring of reservoir pressures in each pool during acid gas injection into the Keg River F Pool and to allow injection or formation influx with the Slave Point FF Pool to be represented. The Slave Point FFF model was much simpler, as there was no need to use the more complex compositional fluid PVT model.

The Slave Point FFF contains one producing well 100/08-13-116-06W6-02. The well began production in August 1997 and continued to produce until early 1999 when it was shut-in as a result of excessive water production inhibiting flow. Small volumes were produced on several occasions between 1999 and mid-2005, at which time it was turned back on and produced until the end of 2006. The gas production volumes were obtained from public data along with the majority of the reservoir parameters. Some pressure values were obtained from the operator that could not be found in the public data. The cumulative produced gas up to February 2009 is 22,500 103 m^3, and the cumulative water produced is 422 m^3. The Original Gas in Place volume determined by the modeling was approximately 27,000 103 m^3.

Appendix H: PCOR Partnership Bell Creek Phase III Development Test

Overview

The field demonstration test conducted in the Bell Creek area of Powder River County, Montana, will evaluate the potential for combined geologic CO_2 storage and commercial EOR. The CO_2 will be obtained from the Lost Cabin gas processing plant in Fremont County, Wyoming. More than 1 million tons of CO_2 per year will be injected into a sandstone reservoir in the Lower Cretaceous Muddy (Newcastle) Formation at a depth of approximately 4,500 feet (1,372 meters).

The Bell Creek oil field located in southeastern Montana lies within the northeastern corner of the Powder River Basin. The sedimentary succession in the Bell Creek area consists of, in ascending order, Jurassic (gypsum, sandstones, and shales); Upper and Lower Cretaceous (sandstones, shales, and carbonates); and Tertiary (consolidated and unconsolidated clastic sediments).

The Bell Creek sand is considered to have been deposited in a near-shore, marine barrier bar depositional environment. The sediment was sourced from previously deposited marine sand, such as the Inyan Kara Formation.

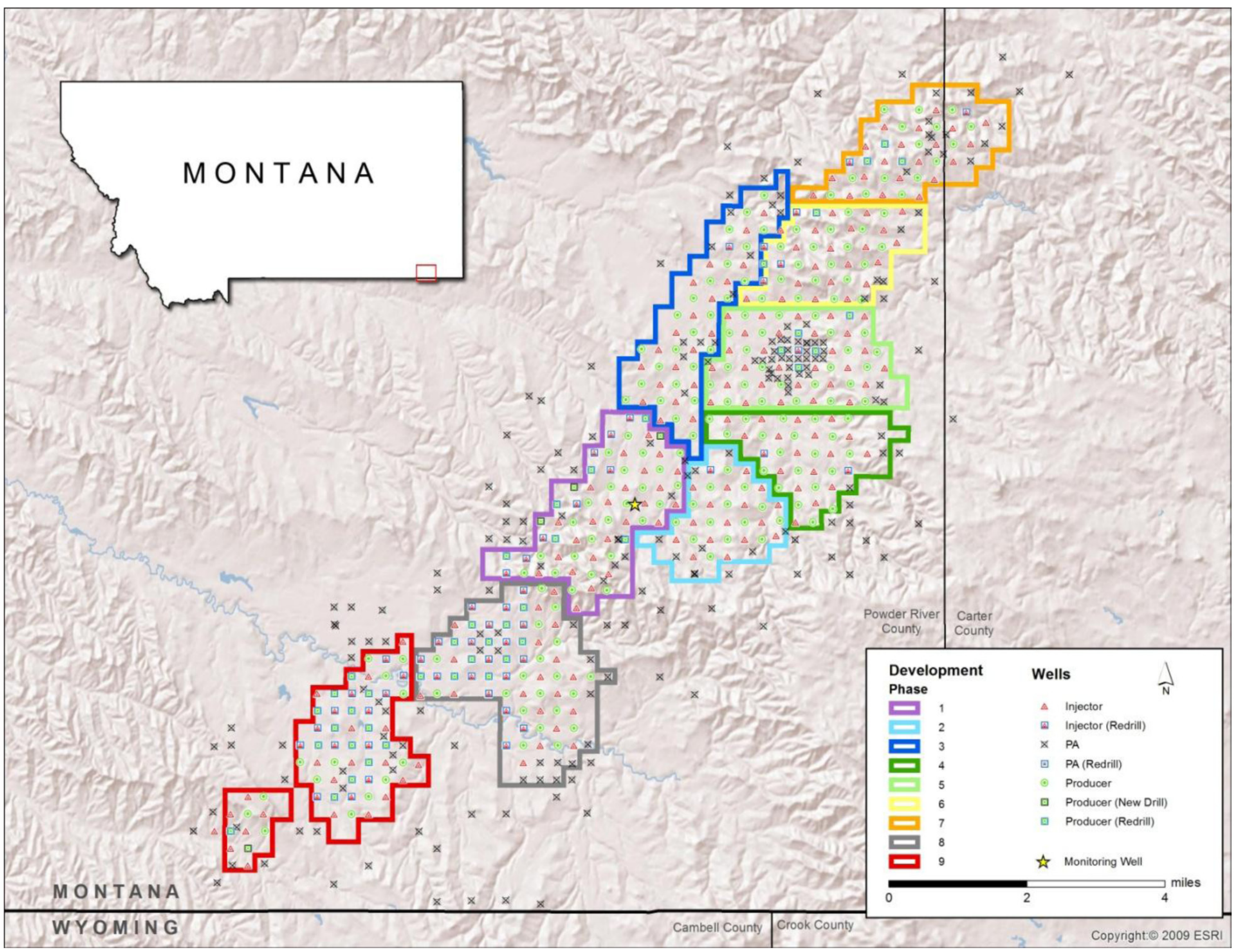


Figure 38: CO_2 Injection Phases of Bell Creek Oil Field Located in Powder River County, Montana

Site Characterization

Site characterization affecting the long-term mobility and fate of the injected CO_2 will be evaluated at the pool scale (unit of the Bell Creek oil field into which injection will occur), field scale (the entire Bell Creek oil field), and the regional or sub-basin scale (northeastern portion of the Powder River Basin). A variety of geotechnical activities will be utilized to establish baseline pressure, temperature, geologic, geomechanical, and geochemical conditions to characterize and model the subsurface, for monitoring CO_2 plume movement, to establish baseline CO_2 concentrations in the shallow subsurface, and to ascertain aspects of the site that can significantly affect reservoir injectivity, capacity, and integrity.

Risk Assessment

Risk assessment plays an integral role in site characterization and monitoring activities at the Bell Creek demonstration project. By identifying key project risks and performing additional characterization, the monitoring program is focused on areas with the greatest uncertainty. Primary risks include injectivity, containment, retention, and capacity. Initial steps to address these identified risks have been incorporated into the monitoring plan.

Permit Requirements

An area permit for Class II injection was received by commercial partner Denbury Resources, Inc. In accordance with the Montana Board of Oil and Gas Conservation rules, MITs and chemical analysis of injected fluids must be conducted on a routine basis. Monthly injection volume, maximum injection rate, total cumulative injection, maximum injection pressure, average injection pressure, and maximum and average annulus pressure must be reported on a monthly basis. Additionally, as part of the permit application, water analysis from the deepest potential USDW must be provided. The name, description, depth, water-quality information, estimated formation pressure, and reservoir characteristics of the injection zone also must be provided. The name, lithologic characteristics, depth, and estimated fracture gradient of the confining zone are required as well.

Injection Operations

The field demonstration project conducted in the Bell Creek oil field will evaluate the potential for simultaneous CO_2 storage and CO_2 EOR. The CO_2 will be obtained from the ConocoPhillips Lost Cabin gas-processing plant in Fremont County, Wyoming, which currently generates approximately 50 million cubic feet of CO_2 per day. The CO_2 will be transported to the site and injected into an oil-bearing sandstone reservoir in the Lower Cretaceous Muddy Formation at a depth of approximately 4,500 feet (1,372 meters). Injection will be implemented in a phased approach throughout the Bell Creek Field. Carbon dioxide produced with the oil will be separated and re-injected into the Phase I area until saturation level has been achieved, at which point a new phase will begin injection. The activities at Bell Creek will inject an estimated 1.1 million tons of CO_2 annually, virtually all of which will be permanently stored.

Monitoring Plan, Results, and Lessons Learned

The MVA plan, which will be guided by the site characterization, modeling and simulation, and risk assessment activities, will consist of both near-surface and deep subsurface aspects. The near-surface monitoring goals are to establish pre-injection baseline conditions and to provide a source of data to show that surface environments remain unaffected or to quantify the impact of a release event. The deep subsurface monitoring program is designed to track the movement of the CO_2 in the subsurface; to evaluate the recovery and storage efficiency of the injection process, as well as allow the ability to check simulation results; and to identify potential injectivity issues or remediation targets. Data acquired during monitoring activities will, in turn, provide updates for the characterization and modeling activities.

Surface and Near-Surface Monitoring

The surface and near-surface monitoring plan presented here comprises three parts: sampling of soil-gas concentrations in the vadose zone, sampling of surface water features, and sampling of shallow groundwater formations. Sampling these three zones will provide a pre-injection baseline concentration of CO_2, which can later be used to help determine if a CO_2 concentration found in any of these mediums post-injection is due to natural occurrence (is within pre-injection baseline) or may be the result of vertical CO_2 migration. Chemical analyses performed during monitoring efforts may additionally aid in determining the source of CO_2 found in these shallow or surface environments.

Soil-gas sampling consists of extracting representative samples of the gases present within the soil, which often includes naturally occurring CO_2. Seasonal variations can dramatically impact the concentration of CO_2 in the vadose zone. Seasonal changes of soil-gas concentrations in near-surface soils are typically caused by plant respiration and decomposition and as part of the natural soil-weathering process. The ratio of the stable carbon isotopes that make up the CO_2 may also vary with the seasons; thus, sampling and analysis will be repeated several times throughout the year prior to injection to capture seasonal variations.

Water sampling will be carried out to measure the levels of CO_2 and other dissolved constituents naturally present in surface and subsurface environments. Publicly available data, including data from the Montana Groundwater Information Center (GWIC), will be reviewed to select a subset of wells and surface water locations that will best establish pre-injection baseline conditions. Shallow groundwater sampling will be carried out via a network of existing public and private groundwater wells. Samples collected from these wells will be analyzed for the composition of a variety of constituents, including CO_2 content and isotopic signatures. Surface water samples will be collected from ponds, streams, and rivers present on the site and will undergo similar analysis to the groundwater samples.

The MVA Program will focus on the Phase I injection area; however, soil-gas and water samples will also be collected at select locations throughout the remainder of the Bell Creek oil field in order to provide field-wide coverage, albeit at a lesser frequency and intensity than in the Phase I area. Soil-gas, groundwater, and surface water samples will be collected periodically to cover seasonal variation, beginning in the fall of 2011. Injection is scheduled to begin in Q1 2013; this allows for multiple pre-injection sample events. Once injection begins, soil-gas, groundwater, and surface water will be sampled annually (during summer months to take advantage of optimal site access).

Deep Subsurface Monitoring

The deep subsurface monitoring plan will utilize a combination of wellbore technologies, such as pulsed neutron well logs, pressure and temperature sensors, chemical analysis, and combined 4-D surface seismic surveys crosswell and/or 3-D VSP surveys to accurately track CO_2 movement and chemical interactions within the subsurface during the injection process. Wellhead pressures at active production and injection wells and selected down-hole pressure measurements will be taken throughout the field prior to and during injection.

Data acquired during the monitoring activities will be used to update modeling and simulation work on an iterative basis in order to identify and eliminate variances between the real-world physics of injection and predicted behavior of the CO_2, reservoir fluids, and rock matrix. This iterative update process will aid in the identification of CO_2 and subsurface fluid movement during EOR activities, an accurate assessment of long-term site security, and the ability to predict CO_2 movement and chemical interactions within the reservoir after site closure.

Collection of accurate baseline measurements of fluid saturations, seismic velocities and amplitudes, current reservoir fluid compositions, temperatures, and pressures are necessary prior to injection. The baseline data will be utilized for later comparison of pre-injection conditions with time-lapse data, which will be acquired periodically once injection begins. Much of this baseline data will be acquired during the monitoring well characterization phase or during existing well re-entry activities.

Monitoring Well(s)

In order to facilitate the characterization and deep subsurface monitoring programs, a single monitoring well was drilled in the fourth quarter of 2011. During the drilling, completion, and post-completion process, modern data were acquired in the form of wireline logs, in-situ pressure and temperature surveys, and crosswell and/or VSP seismic surveys. CBLs and casing integrity pressure tests were also conducted in order to confirm zonal isolation between the storage reservoir and other porous formations. In addition to data acquisition, core was retrieved and a variety of analysis activities are under way. Once combined, this information will be utilized to better understand the target reservoir prior to the start of injection through calibration of historic well log data and enhancement of the modeling and numerical simulation work.

In addition to the new monitoring well, one or more existing wells may be re-entered to allow for additional baseline characterization work and monitoring activities, which cannot be conducted in the new monitoring well because of technical risk during the drilling operation and interference with seismic monitoring activities. These activities may include step-rate tests, which will allow for characterization of fracture initiation, propagation, closure pressures, and fluid sampling. Pressure sensors deployed in these perforated wellbores will also aid in the identification of compartmentalization between phases if it is present.

Appendix I: SWP San Juan Basin Phase II Validation Test

Overview

The San Juan Basin (SJB) ECBM project test, in San Juan County, New Mexico (Pump Mesa at 36.86°N, 107.7°W), is one of four CO_2 storage pilot tests undertaken by SWP. SJB was selected for a pilot test because of its advantageous geology, high methane content, proximity to potential anthropogenic CO_2 sources, and well-developed natural gas and CO_2 pipeline systems. Much of the infrastructure needed for the test was provided by the field operator. The coal formations used for the CO_2 injection test occur at depths of approximately 3,000 feet, are about 75 feet thick, and are split among three seams over a 175-foot thick section. Primary methane production is from the coalbeds in the Upper Cretaceous Fruitland Formation.

Site Characterization

Much of site characterization data for the SJB project was obtained from previous studies, including that of Fassett and Hinds (1977)[3]. Additionally, analysis of existing 3-D seismic data for a 9-mi^2 area around the injection well revealed a complex stratigraphy within the Fruitland Formation depositional system. The seismic analysis also indicated the presence of fractures and minor faulting with the Kirtland Shale caprock. Fractures within the Fruitland Formation itself are less significant and the vertical limit of the fractures and faults suggested that no release should occur. Further characterization data was collected from core obtained during the drilling of the characterization wells. Of particular interest to the field operator and SWP was

Figure 39: San Juan Basin Pilot CO_2 Injection Site, New Mexico.

(The pilot site at Pump Canyon was situated in the Fairway zone, a region within the San Juan Basin where permeability is highest and coalbed methane production is greatest.)

[3] Fassett, J.E. and Hinds, J.S., 1971, Geology and fuel resources of the Fruitland Formation and Kirtland Shale of the San Juan basin, New Mexico and Colorado: U.S. Geological Survey Professional Paper, 676, 76 p., (incl. geologic map, scale 1:380,160), Reprinted 1977.

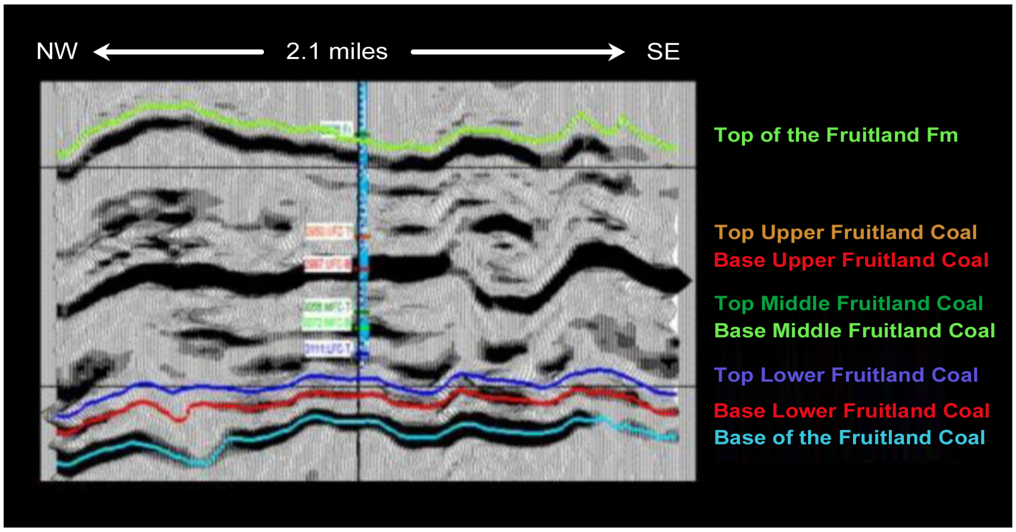


Figure 40: This Southwest-Southeast Line Illustrates a Reflection Discontinuity Along the Axis of the SJB; Local Structural Features Also Evident in Display.

the integrity of the seal unit. Petrophysical analysis of core from the Kirtland Shale provided data on capillary pressure, porosity, permeability, fluid density and saturation, mineralogy, helium gradients (seal efficacy), sorption isotherms, and geomechanical integrity.

Risk Assessment

The potential risks associated with ECBM include over-pressuring; induced seismicity; loss of CO_2 containment, including release through fractures and faults; brine displacement; coal swelling; release of potentially toxic hydrocarbons; and induced fracturing of coal. Major consequences may include property damage, public safety and health, environmental (ecosystem) safety, GHG emission release, and adverse impacts to USDWs. Proper characterization, modeling, and monitoring procedures are essential to mitigate these risks. SWP used the site characterization data to build a geodatabase and a reservoir simulator to evaluate some of the risks associated with the project. Based on iterative simulation results, MVA activities were modified to evaluate the effects of CO_2 injection, including the tiltmeter array, the VSP schedule, and the fluid sampling protocols.

Permit Requirements

Federal and state permitting and regulatory requirements to begin the SJB ECBM project included permits for drilling a CO_2 injection well, installing a CO_2 delivery pipeline, performing MVA activities, and fulfillment of the National Environmental Policy Act (NEPA). Additionally, the State Historic Preservation Office (SHPO) and the seven Native American tribes with heritage in the area were consulted before the proposed MVA activities were initiated.

The New Mexico Oil and Gas Conversation Division (NMOGCD) permitted the drilling and completion of the CO_2 injection well under the Class II UIC Program after the requisite civil, environmental, and archeological surveys. Following an archeological survey and environmental assessment, a surface right-of-way for the 2.6-mile pipeline spur was obtained from the U.S. Bureau of Land Management (BLM) and the New Mexico State Trust Lands Office (NMSLO). The wells for evaluating tracers, water composition, pressure, and temperature were pre-existing and already permitted through NMOGCD.

Several MVA activities required permanent to semi-permanent surface installations and allowances for conveyance and minor disturbance. These included the installation of 36 surface tiltmeter stations, two precision GPS stations, soil collars for soil flux surveys, and completion of offset VSP measurements. For these activities, archeological and environmental assessment surveys were performed, and the proper authorization was obtained from BLM and NMSLO. Landowners and stakeholders were informed and access was acquired along with the submission and authorization of proper NEPA documentation for tasks not involving surface disturbances (groundwater geochemistry, isotope and tracer studies).

Injection Operations

The SJB field demonstration originally planned for up to 31,000 metric tons of CO_2 to be injected simultaneously into the three coal layers of the Fruitland Formation. Early simulation results indicated that this volume would be the maximum volume to be contained within the 640-acre project area of the Pump Canyon site. Carbon dioxide injection started on July 30, 2008, and ended on August 12, 2009. The initial injection pressures for the test increased from about 0.5 MPa to greater than 7.5 MPa; the injection permit allowable limit was 7.83 MPa. Due to the high permeability of the coal, the initial injection rate was greater than 3,500 MSCF per day during the month of July 2008. However, the injection rate dropped to less than 250 MSCF per day near the end of the injection period due to matrix swelling and permeability reduction. During the 12-month injection period, approximately 16,700 metric tons (9 million cubic meters; 319 MMSCF) of CO_2 were injected into the Fruitland coals.

Monitoring Plan, Results, and Lessons Learned

Table 14 lists the MVA methods and techniques employed by SWP in the SJB ECBM test. For additional information on the MVA activities at the SJB pilot site, please consult Grigg et al (2010)[4].

Tracers

Two PFC tracer injections (20 liters of PFC co-injected with CO_2) were conducted shortly after the start of CO_2 injection:

- 90% perfluoromethylcyclohexane (PMCH) and 10% orthoperfluorodimethylcyclohexane (o-PDMCH), injection starting on September 18, 2008.
- 100% perfluorotrimethylcyclohexane (PTCH), injection starting on October 9, 2008.

Because of the low natural background levels of PFC tracers and their ultra-low detection levels, rigorous field protocols were observed to prevent cross contamination of samples and to minimize tracer release to the air during injection.

PFC tracers were monitored using three-quarter-inch steel pipes driven into the soil (1 meter depth), into which vials containing sorbent material were placed to collect any tracer. A total of 46 permanent installations and 36 sampling cages were setup to monitor tracers in the soil and the air. The installations were approximately 100 meters apart on a grid around the injection well. All but four of the atmospheric monitors were mounted 4 feet up on steel pipes containing the soil-gas monitors. Of these four, three were mounted near sensors that sample streams of production gas from the wells monitoring subsurface CO_2 breakthrough.

PFC tracers were detected by testing the sorbents in two wells near the injection well in mid-December 2008 and June 2009. PFC tracers were assumed to be present in the CO_2 phase, but the well sensors did not indicate CO_2 breakthrough. The breakthrough of PFC tracers occurred at the same locations where an increase in nitrogen had been observed at the same time.

Two subsurface tracer monitoring stations near the injection well showed PFC signals above background levels, but below significant release threshold levels. Post-injection CO_2, isotope, and hydrocarbon measurements at these sites did not indicate any significant changes from the baseline surveys.

4 Grigg, R., B. McPherson, and R. Lee, Phase II Final Scientific/Technical Report, in Southwest Regional Partnership on Carbon Sequestration 2010, New Mexico Institute of Mining and Technology: Socorro, New Mexico.

Water Chemistry Monitoring and Analysis

Water produced from wells adjacent to the injection well was monitored using ion chromatography and isotopic analyses to indicate the arrival of CO_2, the mobilization of metal ions, and for modeling fluid-mineral interactions. Forty water samples were collected pre-injection, and more than 70 samples were collected post-injection. Results suggest that there is no definitive change in water chemistry due to CO_2, and that bicarbonate ion concentration and pH might not be ideal indicators for CO_2 breakthrough in CBM formations.

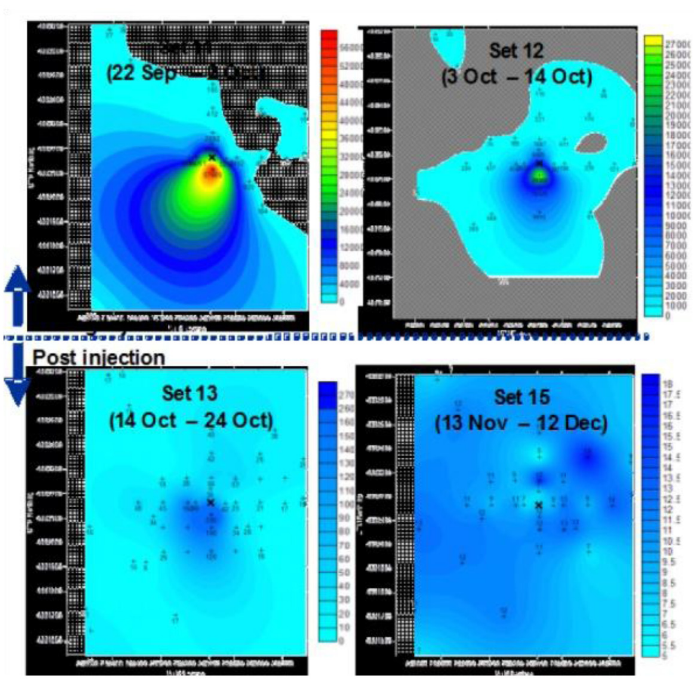


Figure 41: Atmospheric PMCH Tracer Plume at San Juan Basin Site.

Subsurface Pressure

Subsurface pressures were measured continuously to track the CO_2 movement within and outside the reservoir. Permeability relationships were inferred from the pressure data by modeling pressure fall-off curves. Results suggested that the initial permeability values were underestimated by approximately half and that the plume extent was almost twice as large as anticipated.

Well Sensors

Gas sensors were deployed at the three wells closest to the injection well to track the CO_2 plume. Overall CO_2 concentrations in the monitoring (production) wells did not show significant change during the period from July 2008 to November 2009, and therefore did not track CO_2 breakthrough.

Vertical Seismic Profiling (VSP)

Baseline (June 2008) and repeat VSPs (September 2009, one month post-injection) at the SJB injection well were used to image the CO_2 plume and its effects on changes in fluid saturation, pressure, and stress. No significant time-lapse differences were identified between the VSP surveys after seismic data processing. The seismic response may be limited by the small injected volume and the delayed final post-injection VSP survey. Seismic models could not effectively predict the interactions of coal with CO_2 at the SJB test site.

Satellite Imaging

Optical satellite imagery and InSAR were used to map surface effects of CO_2 injection and/or release. Satellite images provided 0.6-meter (2-feet) resolution and sufficient detail to image fractures along the edges of mesas around the SJB injection well. Image-mapped trends were noted and compared to detect variations in ground movement, before and after injection. Centimeter-scale differences and changes in surface elevation, pre- and post-injection, were mapped with InSAR. These remote sensing techniques currently do not have sufficient resolution to monitor sub-centimeter-scale changes, and did not indicate surface deformation given the small volume of CO_2 injected at SJB.

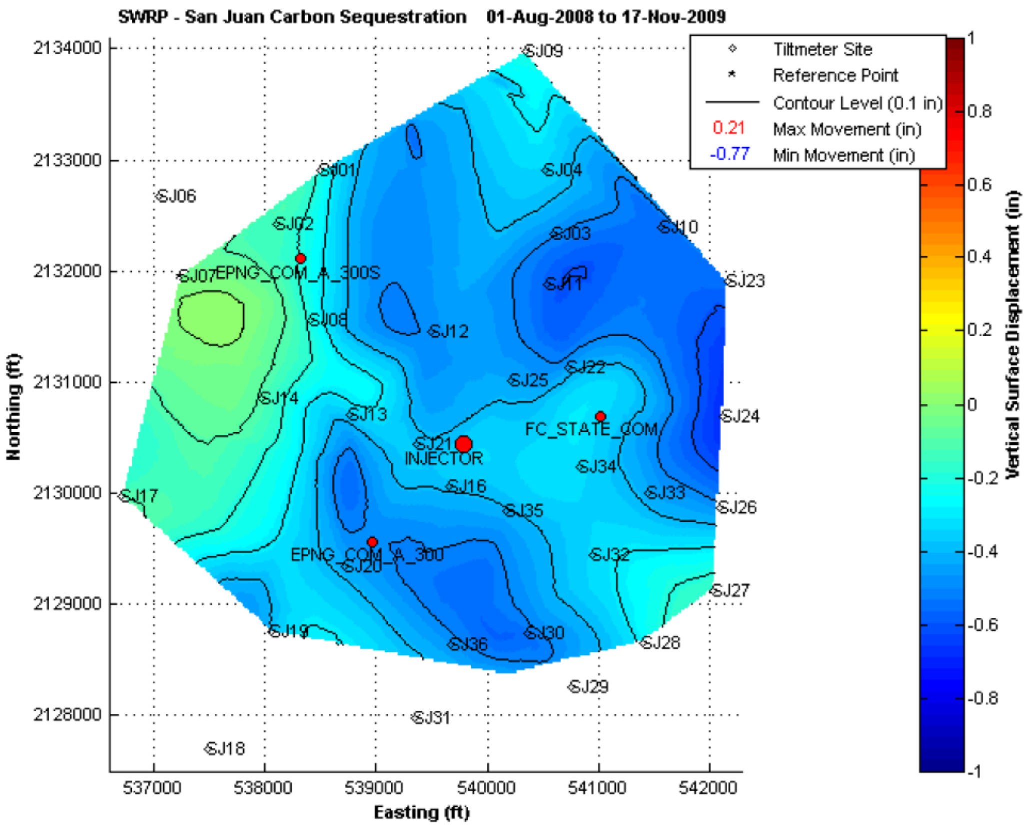


Figure 42: Cumulative Surface Deformation Obtained from Tiltmeter Network (August 1, 2008, to November 17, 2009).

Geodetic Surface Deformation

A network of 36 tiltmeters and 2 differential GPS base stations were installed around the injection well to monitor any surface deformation resulting from coal swelling after CO_2 adsorption. Surface tilt measurements were used to measure surface deformation and reservoir strain. Results indicate a slight overall subsidence in the field, away from the injection well, indicating that the deformation is unrelated to CO_2 injection. Similar to optical imaging and InSAR, the effectiveness of the geodetic instrumentation was probably limited due to the small volume of CO_2 injected.

Soil Gas Sampling and Surface CO_2 Flux Monitoring

Background CO_2 surface flux and soil-gas compositions were measured from gridded sampling locations around the injection well and localized sampling locations in the surrounding production wells. Four pre-injection data sets were taken in March and April 2007. Some tracer monitoring locations were also used for CO_2 surface flux monitoring, soil-gas depth profiling, and radon/thoron monitoring. The CO_2 soil-gas concentration increased nearly linearly with depth, but showed no clear seasonal trend or increase with CO_2 injection. SJB soil flux surveys revealed no elevated CO_2 flux related to injection operations.

Table 14: MVA Methods and Techniques Used by SWP in San Juan Basin ECBM Test

Measurement Technique	Measurement Parameters	Applications
Tracers (PFC)	▪ Travel time. ▪ Partitioning of CO_2 into brine. ▪ Identification of sources of CO_2.	▪ Tracing movement of CO_2. ▪ Quantifying solubility trapping. ▪ Tracing release.
Water Composition	▪ CO_2, HCO_3, CO_3^{2-}. ▪ Major ions. ▪ Trace elements. ▪ Salinity.	▪ Quantifying solubility and mineral trapping, CO_2-water-rock interactions. ▪ Detecting release into shallow groundwater formations.
Subsurface Pressure	▪ Formation pressure. ▪ Annulus pressure. ▪ Groundwater formation pressure.	▪ Control of formation pressure below fracture gradient. ▪ Wellbore and injection tubing condition. ▪ Release out of the storage formation.
Vertical Seismic Profiling	▪ P and S wave velocity. ▪ Reflection horizons. ▪ Seismic amplitude attenuation.	▪ Detecting detailed distribution of CO_2 in the storage formation, release through faults and fractures.
Remote Sensing	▪ Multispectral imagine of land surface. ▪ Radar imaging of land surface.	▪ Detect vegetative stress. ▪ Differential offset for deformation.
CO_2 Land Surface Flux Monitoring/ Flux Chambers/Eddy Covariance	▪ CO_2 fluxes between the land surface and atmosphere.	▪ Detect, locate, and quantify CO_2 releases.
Soil Gas Sampling	▪ Soil gas composition. ▪ Isotopic analysis of CO_2.	▪ Detect elevated levels of CO_2. ▪ Identify source of elevated soil gas CO_2. ▪ Evaluate ecosystem impacts.
Land Surface Deformation	▪ Tiltmeters. ▪ Vertical and horizontal displacement GPS.	▪ Detect geomechanical effects on storage formation and caprock. ▪ Locate CO_2 migration pathways.

Appendix J: SWP Farnsworth Phase III Development Test

Overview

The Farnsworth Unit (FWU) is located on the northwestern shelf of the Anadarko Basin, Texas (Figure 43). It is a combined CO_2-EOR and CO_2-storage project for SWP with the primary objective to demonstrate commercial-scale viability of injection and storage and to develop an overall methodology that optimizes engineering and planning for future commercial-scale storage operations.

The reservoir formation is the Pennsylvanian upper Morrow, a coarse to very coarse-grained arkose to arkosicwacke, which was deposited in a fluvial deltaic environment as a distributary channel (Munson, 1989). The Morrow play is approximately 8,000 feet below the surface with a variable thickness of 20 to 40 feet. The Paleocene/Eocene Ogallala formation (regional formation) occurs near the top of the stratigraphic column.

At least 1 million tons of CO_2 over the five-year project will be injected in the oil bearing Morrow formation. State-of-the-art reservoir modeling will be used to simulate flow and chemical processes and forecast ultimate CO_2 storage capacities. Given the historical success of EOR in other southwestern U.S. basins, the primary research objective is to evaluate and maximize efficacy of CO_2 subsurface monitoring technologies, and to improve our ability to track the fate of injected CO_2 and calculate ultimate storage capacity.

Site Characterization

The Morrow formation in the FWU area has decent permeability, ranging from 100 to 10,000 mD. Carbon dioxide storage capacity within the Farnsworth field is estimated to exceed 10 million tons. More accurate data needs to be obtained by geological characterization methods, including: (1) mapping surface geology; (2) describing the local stratigraphy; (3) mapping the reservoir, seals, and overlying formations; (4) characterizing the geology of the reservoir; (5) describing the geochemical, petrographic, and geomechanical properties of the seals; and (6) evaluating the production history. These activities will be carried out in the months prior to CO_2 injection activity.

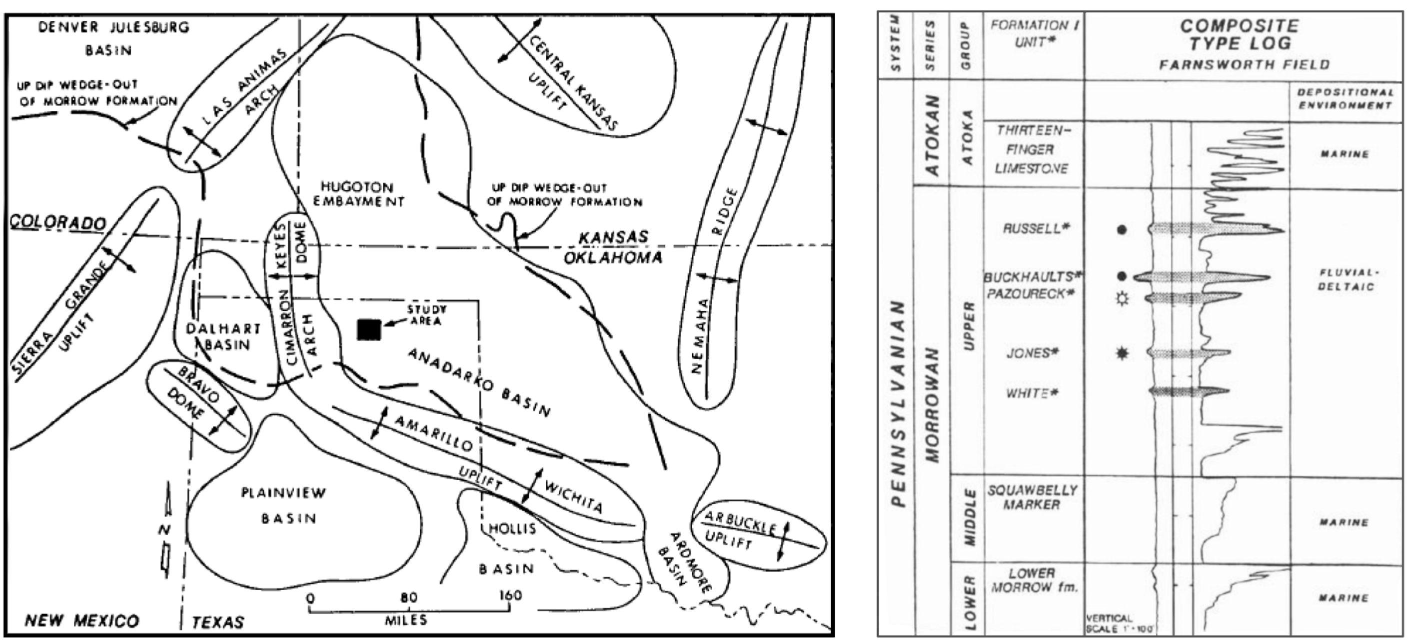


Figure 43: FWU Regional Geologic Setting (a) and Log of Upper Morrowan and Lower Atokan in FWU (b). (Munson, 1989)

Risk Assessment

Carbon dioxide injection for EOR has been used commercially for more than 40 years without serious incident. Industry experience can be used to address risks associated with this technology. Potential operational and technical risks include: (1) operational activities (pipelines and wells) potentially causing property damage and bodily injury, (2) release of CO_2 into shallow formations, and (3) release back into the atmosphere. Proper characterization, modeling, and monitoring procedures are essential to mitigate these risks. SWP will use characterization and modeling data to build a geodatabase and reservoir simulator to evaluate some of the risks associated with the project. Based on iterative simulation results, MVA activities will be modified to evaluate the effects of CO_2 injection.

Permit Requirements

The permitting and regulatory activities for the CO_2 injection will include NEPA, SHPO, state and EPA UIC, land use compliance, and any access agreements. The planned MVA activities for this site will require fewer regulatory and permitting efforts compared to previous proposed Phase III sites, as much of the infrastructure needed for the testing already exists.

Over the five-year lifespan of the Phase III project, it is anticipated that a minimum of three new wells will be drilled by SWP on FWU for the purpose of characterization of the subsurface and pre- and post-injection monitoring. Chaparral Energy will drill additional new wells for injection and production. All new drilling activity for characterization, injection, monitoring, and production will be permitted (as Class II UIC) through the Railroad Commission of Texas. No additional permitting will be needed for CO_2 delivery, as the pipeline for the project is already in place.

Several MVA activities involve temporary and permanent surface installations and variable access to public and private lands. All involved landowners and stakeholders will be consulted and access agreements will be acquired prior to testing. Proper NEPA documentation and authorization will be developed for all activities.

Injection Operations

Chaparral Energy, LLC (CELLC) began CO_2 injection in January 2011 and is expected to continue until at least 2015. Carbon dioxide injection is presently occurring in five individual five-spot well patterns; three to five new patterns will be added each year until a total of at least 25 patterns are operational (Figure 44). The CELLC anthropogenic CO_2 sources

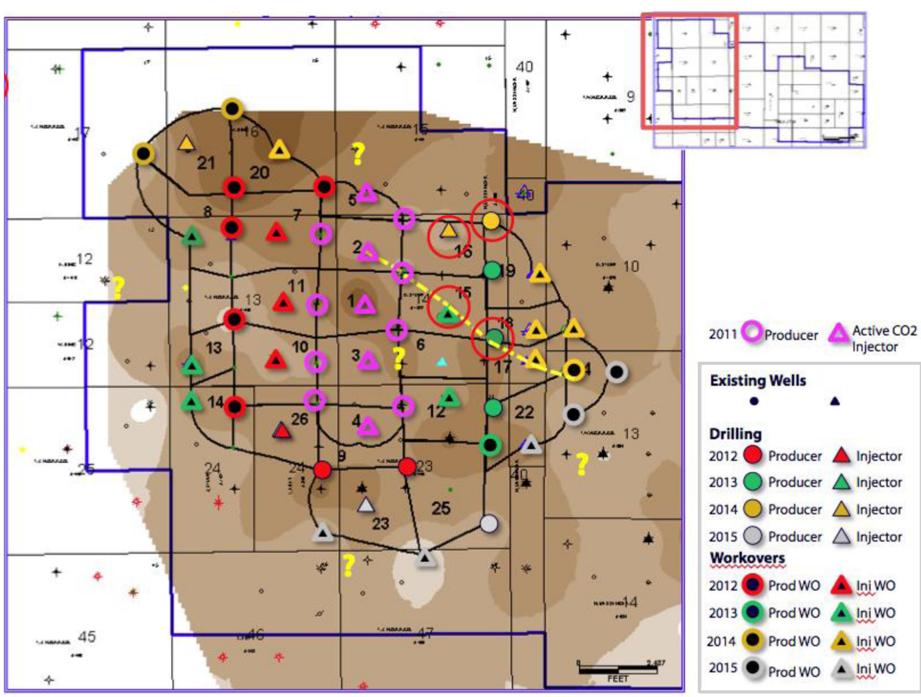


Figure 44: Chaparral Anticipated CO_2 Injection Plan.

used for the EOR operations are Agrium (fertilizer plant) at Borger, Texas (~19.0 MMscf/D), and Arkalon (ethanol plant) at Liberal, Kansas (~15 MMscf/D). Present and planned net CO_2 injection at Farnsworth is 10 MMscf/D (~210,000 tons/yr. or ~190,000 tonnes/yr.), or ~1,050,000 tons (950,000 tonnes) in five years. This does not include recycling the ~2 MMscf/D of CO_2 that is presently being utilized at Farnsworth.

Monitoring Plan, Results, and Lessons Learned

Table 15 lists the available MVA methods and techniques from which to draw at the Farnsworth site.

Introduced and Natural Tracers

The EOR Farnsworth field will be tested and monitored using vapor-phase (perfluorocyclic-hydrocarbons or PFCs) and aqueous phase (naphthalene sulfonates) tracers to determine fluid-flow patterns between injection wells and production wells. Vapor-phase tracers will also be applied to determine the rate of potential CO_2 release from the reservoir to the atmosphere. The tracers will be co-injected with the CO_2. Tracer sampling will take place at the production wellheads by sampling the brine for the aqueous-phase tracers and carbon adsorption tubes for the vapor phase tracers. Passive monitors containing sorbent exposed to atmosphere and soil-gas will be placed at potential point sources for release.

Water Composition

Periodic monitoring of the produced waters from the wells adjacent to the injection wells will be used to determine CO_2 breakthrough and mobilization of ions by injection. The baseline and syn-injection ion and trace metal concentration of the produced water will be analyzed by ion chromatography and ICP-MS, respectively. Additionally, the $\delta^{13}CCO_2$ isotopic values will be evaluated to determine the injected CO_2 plume front and for modeling of mineral reaction kinetics of the host rocks and fluids. Total organic carbon (TOC) will be measured in the produced waters to evaluate the solubility of low molecular hydrocarbons as a result of pH changes due to dissolution of CO_2.

Subsurface Pressure

Continuous measurement of subsurface pressures will be implemented to track the CO_2 movement within and outside the reservoir. Pressure monitoring is also important from the point of view of injection and production processes.

Down-Hole Sensors

Direct down-hole monitoring will include sampling of monitoring wells for geochemical indicators of the presence of CO_2. Sampling of multiple vertical intervals is planned to allow detection of CO_2 in the target formation, the overlying seal interval, and a shallow subsurface formation. Subsurface measurements will focus on borehole sensors that provide physical and chemical information about the reservoir rocks and gases and fluids within the pore space. Time-lapse borehole measurements will be used to map changes in physical and chemical properties of rocks and fluids between wells. Wireline logging will also be conducted to assess reservoir properties as a function of depth in the well vicinity (Srivastava et al, 1989).

Time-Lapse Seismic Imaging

Time-lapse 2-D seismic imaging will be used to track the injection and migration of CO_2 in the subsurface. Fluid saturation changes can be inferred from changes in seismic attributes such as amplitude, travel times, velocity, and reflectivity. A baseline VSP dataset with one zero-offset and several offset source locations will be acquired before CO_2 injection.

Passive Seismic Monitoring

Microseismic monitoring can be a useful tool in CO_2 storage projects for mapping pressure fronts, detecting and locating fault activation, and identifying potential release paths. Deployment of local seismic arrays will be part of the site-evaluation efforts preceding CO_2 injection and storage in order to characterize natural seismicity rates and magnitudes and for assessing the risk of inducing felt earthquakes. Once injection operations start, monitoring and characterizing seismicity will be used to understand the relationship of seismicity to injection and production operations and to evaluate the effect of pressure and stress changes on pre-existing structures.

Table 15: List of Available MVA Methods and Techniques at Farnsworth Site

Measurement Technique	Measurement Parameters	Applications
Introduced and Natural Tracers	▪ Travel time. ▪ Partitioning of CO_2 into brine or oil. ▪ Identification sources of CO_2.	▪ Tracing movement of CO_2. ▪ Quantifying solubility trapping. ▪ Tracing release.
Water Composition	▪ CO_2, HCO_3, CO_3^{2-}. ▪ Major ions. ▪ Trace elements. ▪ Salinity.	▪ Quantifying solubility and mineral trapping. ▪ Quantifying CO_2-water-rock interactions. ▪ Detecting release into shallow groundwater formations.
Subsurface Pressure	▪ Formation pressure. ▪ Annulus pressure. ▪ Groundwater formation pressure.	▪ Control of formation pressure below fracture gradient. ▪ Wellbore and injection tubing condition. ▪ Release out of the storage formation.
Well Logs	▪ Brine salinity. ▪ Sonic velocity. ▪ CO_2 saturation.	▪ Tracking CO_2 movement in and above storage formation. ▪ Tracking migration of brine into shallow formations. ▪ Calibrating seismic velocities for 2-D seismic surveys.
Time-Lapse 2-D Seismic Imaging	▪ P and S wave velocity. ▪ Reflection horizons. ▪ Seismic amplitude attenuation.	▪ Tracking CO_2 movement in and above storage formation.
Vertical Seismic Profiling	▪ P and S wave velocity. ▪ Reflection horizons. ▪ Seismic amplitude attenuation.	▪ Detecting detailed distribution of CO_2 in the storage formation. ▪ Detection release through faults and fractures.
Passive Seismic Monitoring	▪ Location, magnitude, and source characteristics of seismic events.	▪ Development of micro-fractures in formation or caprock. ▪ CO_2 migration pathways.
Electrical Techniques	▪ Self-potential monitoring.	▪ Tracking movement in CO_2 in and above the storage formation. ▪ Detecting migration of brine into shallow formations.
Visible and Infrared Imagine from Satellite	▪ Hyperspectral imaging of land surface.	▪ Detect vegetative stress.
CO_2 Land Surface Flux Monitoring Using Flux Chambers or Eddy Covariance	▪ CO_2 fluxes between the land surface and atmosphere. ▪ Atmosphere.	▪ Detect, locate, and quantify CO_2 releases.
Soil Gas Sampling	▪ Soil gas composition. ▪ Isotopic analysis of CO_2.	▪ Detect elevated levels of CO_2. ▪ Identify source of elevated soil gas CO_2. ▪ Evaluate ecosystem impacts.

Electrical Techniques

ERT can be used to make point measurements of state functions (P and T) and to track the disposition of injected CO_2 (Srivastava et al, 1989). ERT and induced-polarization (IP) tests electrical currents induced in the subsurface via two electrodes, with voltage being observed through two additional electrodes. ERT will be evaluated at FWU for imaging the injected CO_2. IP readings may indicate metallic materials in the subsurface strata (Srivastava et al, 1989).

Visible and Infrared Imaging from Satellite

Several potential remote-sensing techniques may be used, including QuickBird imagery, Synthetic Aperture Radar (SAR), and Color Infrared Transparency Film. QuickBird imagery utilizes high-resolution ground cell imagery to detail large fractures and uses time-lapse detail to analyze fault movement (Wilson et al, 2012). SAR is a satellite-based technology used to measure the reflection of radar radiation to provide high-precision information on the position of the ground surface (Gabriel et al, 1989). This technique measures the surface effect of subsurface phenomena. The surface deformation maps can be used to monitor groundwater and oil reservoir drawdown over time, understand earthquakes, and explore for geothermal resources (Srivastava et al, 2009). Color Infrared Transparency Film utilizes three sensitized film layers that reproduce IR radiation. Vegetative health can be determined from the relative strengths of IR light reflected. The data can be analyzed to determine vegetative health in the vicinity of the project site as an indicator of a possible CO_2 release pathway (Crum, 2006).

Soil-Gas Sampling and CO_2 Land Surface Flux Monitoring at the Surface

Background CO_2 surface flux and soil-gas hydrocarbons and CO_2 concentrations will be taken from specific sampling locations. A rectangular grid will be employed with regular spacing between monitor stations. In addition, monitors will be placed adjacent to nearby wells to evaluate potential release associated with wellbores. Other monitors off the main grid will be placed to evaluate areas of increased release potential.

Carbon dioxide surface flux monitoring will be conducted during each season, as well as at different times of the day, to get a comprehensive understanding of the magnitude of the CO_2 temporal variance over the area. The goal is to measure soil CO_2 flux before and during injection to establish a solid background level that can be expected during different seasons and at different times of the day. Any flux measurements that are consistently higher than approximately two to three times the average value will receive additional attention.

Appendix K: BSCSP Kevin Dome Phase III Development Test

Overview

BSCSP is in the early stages of conducting a large-scale storage test at Kevin (pronounced KEE-vin) Dome in North Central Montana. The Dome is an ~700 mi² feature extending from Shelby, Montana, to just south of the Canadian border. It contains naturally occurring CO_2 in Devonian Duperow (dolostone), which was likely generated via geochemical reactions caused by a sweep of hot fluids initiated by igneous intrusions that formed the Sweetgrass Hills to the southeast of the dome. The CO_2 resides in a 100-foot-thick porous section in the middle Duperow and in a thinner porous section in the lower Duperow. Estimated CO_2 in place is ~0.6 GT, or 10 TCF, equivalent to Jackson Dome. The CO_2 is estimated to have an areal extent of ~540 mi² and does ***not*** fill the dome to its spill point. The Kevin Dome project plans to drill and core producing wells, produce the natural CO_2, pipe it laterally 6 to 8 miles, and re-inject into the Duperow porosity zone in the brine

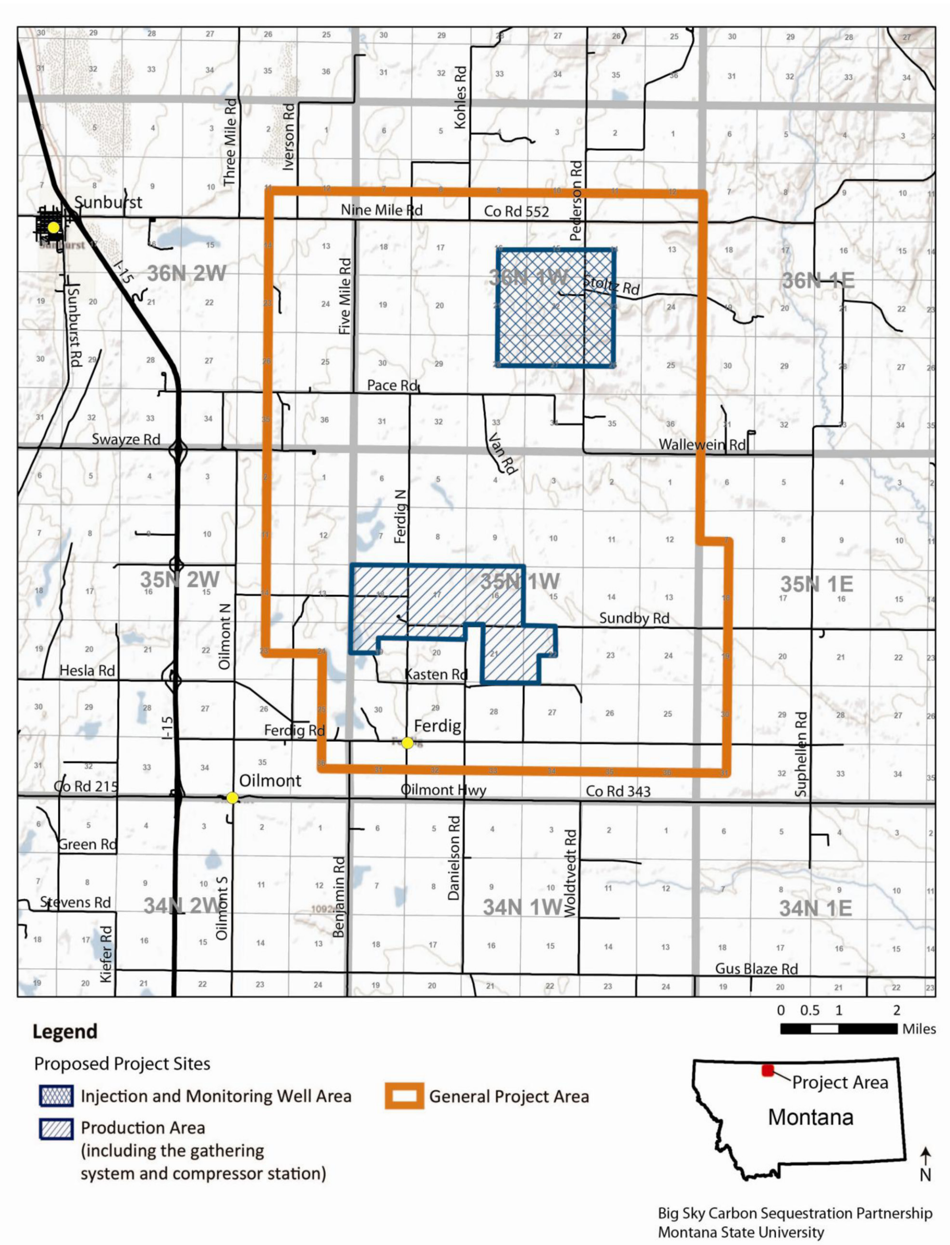


Figure 45: BSCSP Project Area.

(Orange boundary is 3D-9C seismic area. The proposed injection site is in the crosshatched region in the northeast quadrant. The hatched region in the south is the production region.)

leg. The primary seal is the upper Duperow (~200 feet of tight carbonate with inter-bedded anhydrites), and the secondary seal is the Potlach Anhydrite (175 feet), with multiple tertiary seals that have contained oil and gas in shallower horizons. This project will combine studies of natural reservoir storage capacity and carbonate geochemistry with studies of engineered injection and storage. While the injection is into a saline formation, the project provides valuable information concerning the use of structural features for CO_2 warehousing in a regional CCUS hub concept.

Site Characterization

BSCSP is shooting a 58-mi^2, 3-D, nine-component surface seismic survey over the planned CO_2 producing field, the injection region, and the intervening area. This initial survey will image the Duperow in both CO_2-saturated regions and brine-saturated regions, providing an opportunity to see if shear-wave seismic can detect pore fluid differences spatially without using time-lapse techniques. BSCSP will drill, log, and core a producing well, a monitoring well, and the injection well as part of the site characterization activities. The full porosity zone and a section of the primary caprock will be cored, and a full suite of core analyses will be performed. Logging will include resistivity, neutron, gamma, sonic/acoustic, density, formation micro-imager (FMI), combined gamma spectroscopy (RST-A), and dynamic fluid-logging. Additionally, baseline crosswell and 3-D, nine-component VSP will be shot using multiple boreholes. Background assurance monitoring will be performed, including flux chamber surveys, EC, surface and drinking water sampling and analysis, hyperspectral imaging and DIAL.

Risk Assessment

BSCSP has carried out an initial FEPs analysis using an expert team in a workshop format. Primary health and safety risks identified are related to site access and operations. Additional project risks relate to permitting issues and effects of unknown factors on budget and schedule. The top-ranked risk related to performance of the engineered geologic storage is injectivity and changes in injectivity caused by introduction of CO_2 into brine-saturated reactive rock. Monitoring related to this risk includes real-time downhole pressure measurement and fluid sampling above the injection zone. Although the risk is considered extremely low, the assurance monitoring program is designed to detect the (highly unlikely) movement of CO_2 out of the storage reservoir.

Permit Requirements

Injection and operational permits are not in place yet because the project is in the early stages.

Injection Operations

Because the CO_2 will be pressurized, it is anticipated that only one or two stages of compression will be needed. Producing wells and injection wells are not yet drilled, so there is not data on exact pressures or gas composition.

Monitoring Plan, Results, and Lessons Learned

Monitoring Wells

Three to four monitoring wells are planned. One will be placed more distal to the injector, updip, with an estimated breakthrough of ~750,000 tonnes CO_2 injected. The remaining monitoring wells will be placed symmetrically about the injector at the appropriate crosswell seismic distance. At least two wells will be used for geochemical fluid sampling and tracer studies using U-tubes.

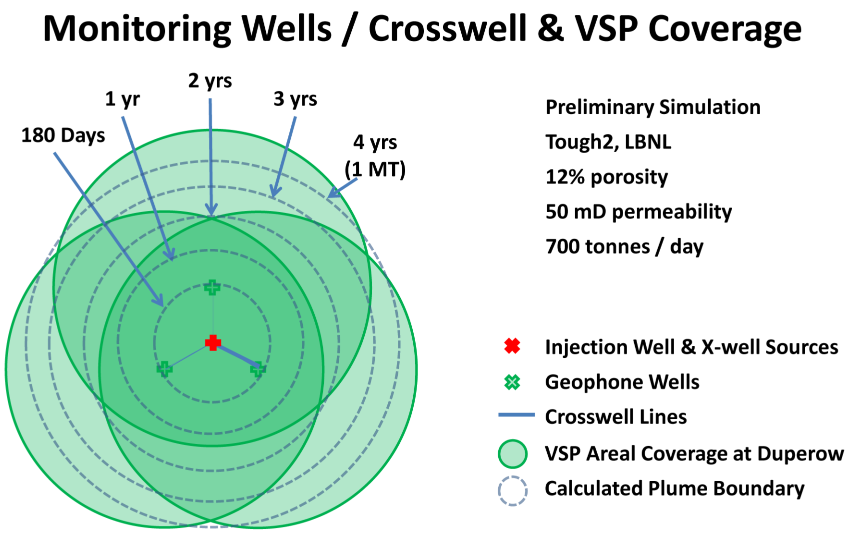


Figure 46: Monitoring Wells/Crosswell and VSP Coverage.

Seismic

The planned geophysical program is designed to use the highest resolution, greatest sensitivity method applicable to image the current plume dimensions. Resolution and areal extent is addressed by use of both borehole and surface seismic methods.

Surface Seismic: As mentioned previously, a 58-mi^2, 3-D, nine-component survey is underway. This survey serves multiple purposes: (1) it will be used for hazard identification and avoidance; (2) it will provide data to the static geologic model in the site characterization phase; (3) it will provide a test of potential for multi-component seismic detection of CO_2 without time-lapse (spatially, because it is being shot across the gas-brine interface); and (4) it will serve as a baseline for subsequent surveys used for time-lapse monitoring of the plume.

Vertical Seismic Profiling (VSP): Vecta's vibroseis trucks will be used with downhole, multi-component receivers in the monitoring wells to perform 3-D and 4-D nine-component VSP. Crude preliminary simulations indicate the CO_2 plume can be imaged for three to four years via this technique. VSP is intermediate in resolution and areal coverage to crosswell and surface seismic.

Crosswell Seismic: Crosswell seismic will be shot between monitoring wells or between the injector and monitoring wells. An experimental orbital vibrator developed at LBNL will be used as the source, and receivers will be multi-component. This method will provide high-resolution, "fenceline" data between wells at the early stages of the project (up to approximately six months of injection).

Table 16: Potential Seismic Survey Timings

Method	Timing After Initiation of Injection (Months)						
Crosswell	0	3	6				
VSP	0		6	18	36		
Surface	0				36	48	60

All seismic studies will acquire nine-component (shear-wave) seismic data. Vecta Oil and Gas, the primary partner in the Kevin Dome project, owns the only operational shear-wave vibroseis units in the United States and has extensive expertise in analyzing shear-wave seismic data. Shear-wave seismic has several advantages in a CO_2 monitoring project in consolidated rocks such as the Duperow:

- Shear-wave seismic is far more sensitive to microfractures and stress-induced azimuthal anisotropy than conventional, P-wave seismic data. If microfracturing is common in the Duperow reservoir/storage section, as it frequently is in other porous dolomites, it can create areas of high permeability that form preferential pathways for the lateral migration of CO_2 away from the injection site, making detecting and characterizing microfractures is an important objective of this study. These phenomena have been documented at other locations where shear-wave seismic was used for monitoring CO_2 EOR operations, such as Vacuum Field in Southeast New Mexico. At Vacuum Field, there was also evidence of a substantial shear-wave response to subsurface pressure changes caused by CO_2 injection, while little P-wave response was observed.
- Combining P-wave and shear-wave data allows measurement of the individual contributions of compressibility and stiffness to the 4-D seismic response from CO_2 injection. Pore fluid changes (CO_2 vs. water) manifest themselves as changes in compressibility of the rock, while alteration of the reservoir by reactive fluids is expected to change the stiffness more than the compressibility. P-wave data alone are not capable of "unbundling" these two separate effects in consolidated rocks such as the Duperow. An additional advantage of shear seismic is that is allows solution for the density term of the reflection coefficients, which contains valuable information about both 4-D pore fluid effects and static porosity, if data quality is high enough.
- Some dolomites have a higher shear-wave reflectivity than P-wave reflectivity. If the Duperow is one of these, it may be possible to characterize and monitor thinner Duperow porosity zones with multi-component data than using P-wave data alone, thereby improving the detection limits for CO_2.

Geochemical Monitoring

Up to four U-tubes will be deployed in monitoring wells to collect fluid samples. In addition to pH, alkalinity, cation and anion analysis, rare earth elements will be analyzed and tracers (including phase partitioning tracers) will be used to study geochemistry. One of the U-tubes will likely be used to monitor above injection zone fluids.

Assurance Monitoring

Soil flux chambers, EC towers, DIAL, and hyperspectral imaging will all be used in the Assurance Monitoring Program. Additionally, drinking water and surface water analysis will be performed in the vicinity of the injection.

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Printed in the United States on recycled paper

October 2012