Integrative Geophysical and Environmental Monitoring of a CO₂ Sequestration and Enhanced Coalbed Methane Recovery Test in Central Appalachia

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Dissertation submitted to the faculty of the Virginia Polytechnic Institute and State University in partial fulfillment of the requirements for the degree of

Doctor of Philosophy
In
Mining Engineering

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28 October 2016
Blacksburg, Virginia

Keywords: carbon sequestration, coalbed methane, enhanced gas recovery, microseismic monitoring, surface deformation, geostatistical analysis
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ABSTRACT

A carbon storage and enhanced coalbed methane (CO₂-ECBM) test will store up to 20,000 tons of carbon dioxide in a stacked coal reservoir in southwest Virginia. The test involves two phases of CO₂ injection operations. Phase I was conducted from July 2, 2015, to April 15, 2016, and injected a total of 10,601 tons of CO₂. After a reservoir soaking period of seven months, Phase II is scheduled to begin in Fall 2016. The design of the monitoring program for the test considered several site-specific factors, including a unique reservoir geometry, challenging surface terrain, and simultaneous CBM production activities which complicate the ability to attribute signals to sources. A multi-scale approach to the monitoring design incorporated technologies deployed over different, overlapping spatial and temporal scales. Technologies selected for the monitoring program include dedicated observation wells, CO₂ injection operations monitoring, reservoir pressure and temperature monitoring, gas and formation water composition from offset wells, tracer studies, borehole liquid level measurement, microseismic monitoring, surface deformation measurement, and various well logs and tests. Integrated interpretations of monitoring results from Phase I of the test have characterized enhanced permeability, geomechanical variation with depth, and dynamic reservoir injectivity. Results have also led to the development of a recommended injection strategy for CO₂-ECBM operations. The work presented here describes the development of the monitoring program, including design considerations and rationales for selected technologies, and presents monitoring results and interpretations from Phase I of the test.
Recent efforts to manage and reduce atmospheric carbon dioxide (CO₂) emissions include the development of technologies for carbon capture, utilization, and storage (CCUS) operations. CCUS technologies are used to capture CO₂ emissions from a power plant or other point source, transport the captured CO₂ to a field site, and inject the CO₂ underground into a geologic reservoir. There it is securely stored within a deep, sealed geologic formation and/or is utilized to enhance oil or gas recovery from the formation. CCUS operations conducted on a commercial scale could play an important role in combating anthropogenic climate change. Field tests for carbon storage and utilization operations support the objective of scaling up by demonstrating the storage potential of target reservoirs, the profit potential from enhanced recovery, and the safety of all field operations. Field tests are monitored intensively in order to understand reservoir behavior in response to CO₂ injection and to evaluate progress toward project objectives.

An ongoing small-scale carbon storage and utilization test in southwest Virginia is testing the potential for CO₂ storage and enhanced gas recovery from a depleted coalbed methane reservoir. The carbon storage and enhanced coalbed methane (CO₂-ECBM) test will store up to 20,000 tons of carbon dioxide in a coal reservoir composed of approximately 20 individual seams. The test involves two phases of CO₂ injection operations. Phase I was conducted from July 2, 2015, to April 15, 2016, and injected a total of 10,601 tons of CO₂. After a reservoir soaking period of seven months, Phase II is scheduled to begin in Fall 2016. The design of the monitoring program for the test considered several site-specific factors, including a unique reservoir geometry, challenging surface terrain, and simultaneous coalbed methane production activities which complicate the ability to attribute signals to sources. A multi-scale approach to the monitoring design incorporated technologies deployed over different, overlapping spatial and temporal scales. The work presented here describes the development of the monitoring program, including design considerations and rationales for selected technologies, and presents monitoring results and interpretations from Phase I of the test.
DEDICATION

This is for my mother, Alison, my father, Kirby, and my brother, Lytton. Look what we did. Let’s go to Braum’s.
ACKNOWLEDGEMENTS

First, I would like to thank my immediate and extended family for their tremendous support. My family has been a primary and constant source of motivation, confidence, and resilience during my doctoral program and throughout my life.

Sincere thanks to Dr. Michael Karmis and Dr. Nino Ripepi, who have been fantastic mentors over the last several years and have provided countless exceptional research and professional opportunities.

Additional thanks to Dr. Ripepi, my advisor, for encouraging me to do a Ph.D. and for changing my mind when I initially declined. It has been the effort I anticipated, but I am glad I did it and grateful for your persistence. I thank all of my committee members for constructive feedback throughout the process which improved my project and the final products.

This work is part of a highly collaborative project, and I would like to thank the large team of research, academic, and industrial partners involved. In particular, I thank the research and administrative staff of the Virginia Center for Coal and Energy Research for their individual contributions toward the success of our project. I would also like to extend thanks across the VT campus to the LISA statistics consulting group and across the pond to Dr. Andy Sowter of Geomatic Ventures for their time spent assisting me with data processing and analysis.

I am fortunate to have too many supportive friends to thank here. However, I would like to send especially heartfelt thanks to Rebecca Orr and Jessica Sparks, two good gals to have in a storm, who have shared genuinely in celebrations and commiserations along the way.

Finally, and with no shame, I thank my sweet, hilarious cats, Magpie and Bode. Their frequent vocal protests of the extra hours and strange schedule of my doctoral studies were reminders to maintain balance and take breaks for play time. Guess who’s getting a big pile of warm laundry to nap in.
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1 INTRODUCTION

Recent efforts to manage anthropogenic carbon emissions include the development of Carbon Capture, Utilization, and Storage (CCUS) technology. This involves capturing carbon dioxide (CO₂) from a power plant or other point source, transporting it to a depleted oil or gas field, and injecting it by well into the geologic reservoir. This process securely stores the CO₂ in the under-pressured reservoir and can simultaneously enhance gas recovery from neighboring wells, offsetting the expense to capture CO₂.

An ongoing carbon storage / enhanced coalbed methane (CO₂-ECBM) test in Buchanan County, Virginia, is testing the potential for CCUS operations in thin, stacked coals. The coal reservoir is attractive for CCUS because coal exhibits preferential adsorption of gases, including methane and CO₂. When CO₂ is introduced to reservoir, the coal matrix will release chemically bonded methane in order to preferentially store CO₂ and in larger volumes. This favors both CO₂ storage and enhanced recovery from coal reservoirs. Additionally, the stacked reservoir geometry of the coals in Buchanan County provides access to multiple “containers” from a single vertical wellbore.

The CO₂-ECBM field test in Buchanan County will inject up to 20,000 tons of CO₂ into the coal reservoir to assess the potential for CO₂ storage and the potential for enhanced coalbed methane from the unique reservoir. Injection operations include two injection phases. Phase I was conducted from July 2, 2015, to April 15, 2016, and injected a total of 10,601 tons of CO₂. After a reservoir soaking period of seven months, Phase II is scheduled for November 15, 2016-April 15, 2017.

In order to meet the project objectives of evaluating storage and enhanced recovery potential, an intensive monitoring program has been developed for the field test. The program focuses on
time-lapse data acquisition in order to characterize reservoir behavior in response to CO₂ injection. Additionally, monitoring technologies are deployed on overlapping spatial and temporal scales to cross-validate responses and to integrate and constrain data interpretations. This is especially important for the Buchanan County field site, where active CBM production activities can complicate the ability to attribute signals to sources.

The research presented here relates to the development and implementation of the monitoring program for the CO₂-ECBM test in Buchanan County, Virginia. This work comprises five main chapters: Chapters 2-4 describe several design aspects of the monitoring program, and Chapters 5 and 6 presents results from Phase I of the test. Concluding remarks are provided in a final Chapter 7.

Chapter 2, *Selection of Monitoring Techniques for a Carbon Storage and Enhanced Coalbed Methane Recovery Pilot Test in the Central Appalachian Basin*, describes the approach to the design of the monitoring program and provides a rationale for the selection of specific technologies. Several site-specific factors were important in the monitoring design: 1) the reservoir geometry of thin, distributed coal beds was below resolution limits for many conventional well logging and geophysical imaging technologies, 2) steep, forested terrain limited access for the installation of monitoring stations and also presented challenges for geospatial monitoring, and 3) active coalbed methane production activities complicated source attribution for monitoring responses. To address the challenges presented by these site factors, technology selection focused on high-sensitivity data acquisition, including a shallow-buried microseismic array and X-band radar imaging coupled with advanced image processing. Deployment focused on overlapping data acquisition, spatially and temporally, to cross-validate results and constrain interpretations.
Chapter 3, *Geospatial Monitoring of Surface Deformation Associated with Energy Production and Carbon Sequestration*, describes in detail a design to combine satellite-acquired Interferometric Synthetic Aperture Radar (InSAR) data with ground-based Global Positioning System (GPS) data to measure potential surface uplift due to CO₂ injection. Elevation measurements in steep or forested terrain typically result in poor data coverage and large measurement errors. Advanced processing of high-resolution InSAR data using an Intermittent Baseline Subset (ISBAS) method has potential to achieve meaningful results in the variable terrain over the CO₂-ECBM study area.

Chapter 4, *Monitoring Design and Data Management for a Multi-well CO₂ Storage / Enhanced Coalbed Methane Test in a Stacked Coal Reservoir, Buchanan County, Virginia, USA*, focuses on the deployment and management of a Supervisory Control and Data Acquisition (SCADA) system. The SCADA system provides near-continuous (60-second) recording of CO₂ injection parameters, including injection rates, pressures, and temperatures. These data are critical for understanding monitoring responses due to CO₂ injection operations. The SCADA system can be accessed remotely to review data in real time and adjust injection parameters. Reservoir pressure and temperature data from monitoring wells are also recorded continuously by the system.

Chapter 5, *Monitoring results from Phase I of a CO₂-ECBM Field Test in Stacked Coals of Central Appalachia*, summarizes Phase I monitoring results to date. The results are analyzed to characterize dynamic injectivity for the reservoir. An integrated interpretation of reservoir behavior includes enhanced permeability related to geologic structure and geomechanical variation of the reservoir with depth. An injection strategy for CO₂-ECBM operations is recommended based on the Phase I monitoring results.
Chapter 6, *Geostatistical Analysis of Microseismic Monitoring Results from a Carbon Storage/Enhanced Gas Recovery Field Test in a Stacked Coal Reservoir*, is a detailed geostatistical analysis of microseismic monitoring results. Microseismic data, recorded continuously over several days prior to and at the start of CO₂ injection, were processed using a seismic emission tomography (SET) method. The processing provides a three-dimensional distribution of relative acoustic energy levels for each day of recording. Interpretation of the distributions are constrained by additional monitoring data, including pressure data, well logging, and tracer arrivals. Results support interpretations of enhanced permeability and geomechanical variation of the reservoir with depth. Additionally, a large, deep-focusing signal observed only during injection near one injection well is interpreted as formation water evacuating the wellbore. An important aspect of this study is the reduction of large data volumes generated by microseismic processing. The methods used in the study preserved original resolution in the dimensions of investigation.

The monitoring program has demonstrated success in characterizing the behavior of the coal reservoir in response to CO₂ injection. The monitoring results from Phase I of the CO₂-ECBM test will guide deployment of the monitoring program during Phase II operations. Additionally, the results and recommendations from Phase I can improve future CO₂-ECBM operations in stacked coal reservoirs.
2 SELECTION OF MONITORING TECHNIQUES FOR A CARBON STORAGE AND ENHANCED COALBED METHANE RECOVERY PILOT TEST IN THE CENTRAL APPALACHIAN BASIN

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This work is published in International Journal of Coal Geology 118 (2013), 105-112. It is reprinted with the permission of the publisher, Elsevier.

ABSTRACT

The goals of monitoring, verification, and accounting (MVA) for carbon capture, utilization, and storage (CCUS) studies include improved understanding of injection and storage processes, evaluation of interactions among carbon dioxide (CO₂), reservoir fluids, and formation solids, and assessment and minimization of environmental impacts (DOE and NETL, 2009). Site-specific selection of tools for a well-rounded MVA program may include technologies for atmospheric, near-surface, and subsurface monitoring.

An upcoming small-scale CCUS study in an active coalbed methane field in Buchanan County, Virginia, presents a unique application for several established, effective MVA methods. The study will involve injecting up to 20,000 tonnes of CO₂ into three injection wells over a one-year period in order to test the injection and storage potential of the coal seams and to assess the potential for enhanced coalbed methane (ECBM) recovery at offset production wells. The reservoir consists of approximately 15 to 20 coal seams, averaging 0.3 m (1.0 ft) in thickness and distributed over 300 m (1,000 ft) of vertical section. This reservoir geometry creates an unusual target for CO₂ injection and also a challenging one for many monitoring and imaging techniques. MVA for the Buchanan
County test will include gas content measurements at offset wells, groundwater monitoring, injectate tracer analysis, well logging, surface deformation measurement, passive microseismic monitoring, and tomographic fracture imaging. Multiple monitoring wells will be drilled in order to facilitate the MVA efforts. Surface deformation measurement, microseismic monitoring, and tomographic fracture imaging are state-of-the art tools that have potential to define the subsurface CO\(_2\) plume beyond the borehole scale. The results of the MVA program for the Buchanan County injection demonstration can be used to improve design for potential future studies of CCUS in thin coals.

2.1 INTRODUCTION

Geologic storage of carbon dioxide (CO\(_2\)) is emerging as a viable method to reduce atmospheric levels of greenhouse gases and mitigate anthropogenic climate change. Demonstrations of carbon capture and storage (CCS) technologies have been conducted at sites worldwide. Notable CCS projects include the In Salah industrial-scale project in Algeria, the Sleipner industrial-scale project in Norway, the Illinois Basin-Decatur field demonstration in Illinois, USA, and the upcoming FutureGen 2.0 project in Illinois, USA. In August 2012, the first fully integrated project, demonstrating CO\(_2\) capture at a functioning power plant, transportation by pipeline, and injection into a geologic reservoir, was completed by the Southeast Regional Carbon Sequestration Partnership (SECARB) near Citronelle, Alabama (Koperna et al., 2012). Recently, the technology has expanded into carbon capture, utilization, and storage (CCUS). In this case, utilization refers to injecting captured CO\(_2\) into producing oil and gas reservoirs in order to displace existing hydrocarbons for enhanced recovery at nearby production wells (DOE and NETL, 2010). This process stores most of the injected CO\(_2\) in the subsurface, but some CO\(_2\) will break through
at offset production wells and be produced back to the surface with the methane production stream. The CO₂ that is reproduced at the surface can be separated and reused for injection in other wells. Natural geologic deposits of CO₂ near oil fields are often tapped and used for this purpose, but the potential commercialization of anthropogenic CO₂ capture and pipeline transport would expand this option to new and different hydrocarbon fields, including unconventional plays.

A robust monitoring, verification, and accounting (MVA) program is important for any CO₂ storage or utilization project, especially with the increasing amount of research and media attention focused on subsurface extraction and injection processes and their environmental implications. For this reason, in 2009 the U.S. Department of Energy’s (DOE) National Energy Technology Laboratory (NETL) developed a best practices manual on MVA for geologic storage of CO₂, entitled *Best practices for: monitoring, verification, and accounting of CO₂ stored in deep geologic formations*. The stated objectives for an MVA program include improved understanding of injection and storage processes, evaluation of interactions among CO₂, reservoir fluids, and formation solids, and assessment and minimization of environmental impacts (DOE and NETL, 2009). A 2012 update to the manual outlines more ambitious MVA goals consistent with rising expectations for emissions reduction technologies, including the “safe, effective, and permanent” storage of CO₂ “in all types of geologic formations” (DOE and NETL, 2012).

The best practices document provides a summary of available MVA technologies, divided into atmospheric, near-surface, and subsurface options, and lists the pros and cons of each. As the manual emphasizes, it is important to select a subset of technologies well-suited to the unique characteristics of the site, reservoir properties, and the test objectives and to adjust the technologies and sampling schemes used, as appropriate over the lifecycle of the project. Table 2-1 summarizes the MVA technologies and their advantages and disadvantages, as described in the manual.
Common atmospheric methods include CO₂ detectors and eddy covariance measurements, which both quantify atmospheric levels of CO₂ and can, therefore, help to either detect a leak or confirm storage. At a test site in Bozeman, Montana, an eddy covariance tower was used to detect a controlled, shallow release of CO₂ simulating a leakage scenario. Data from the tower successfully measured the leakage rate within 7 percent accuracy (Lewicki and Hilley, 2009).

Near-surface methods include groundwater monitoring, which can also indicate leakage or proper containment, and surface deformation meters, such as GPS or tiltmeters, which can help
define the CO₂ plume by delineating the inflated portion of the reservoir or new fractures induced by the pressure of the plume. At the Southwest Partnership for Carbon Sequestration’s Pump Canyon injection test site in the San Juan Basin, New Mexico, a surface tiltmeter array and GPS stations were used to try to image any ground deformation due to swelling of the 915-meter (3,000-foot) deep coal reservoir in the presence of CO₂. After 14 months of monitoring, no uplift was detected near the injection well, although offset wells did show subsidence due to depletion (Oudinot et al., 2011).

Subsurface methods include borehole logging techniques and geophysical imaging techniques, such as seismic or electrical conductivity/resistivity surveys. Both logging and imaging techniques are often conducted in a time-lapse manner, pre- and post-injection, in an attempt to record changes in properties due to the presence of the CO₂ plume. At the Frio injection test near Houston, Texas, time-lapse vertical seismic profiling (VSP) and crosswell surveys were conducted to image and assess the CO₂ plume in a deep saline reservoir. The VSP surveys detected the presence of CO₂ as significantly decreased amplitudes for the injection horizon. The crosswell surveys were used to generate a tomogram, showing an obvious low-velocity zone at the depth of injection, which was also tied to time-lapse logging in order to generate a CO₂ saturation model for the reservoir (Daley et al., 2007).

This paper describes the selection of MVA technologies for an upcoming CCUS field demonstration in the Oakwood coalbed methane (CBM) field of southwest Virginia. The coal reservoir is a unique application for many MVA methods because of its geometry, which includes several thin, dispersed seams. The reservoir geometry became a guiding factor in the selection of effective technologies for the MVA program. Other important considerations were the unique
reservoir properties of coal, including swelling of the matrix in the presence of CO₂, and MVA results from a nearby CO₂ injection feasibility test conducted in 2009.

2.2 CCUS IN THIN, STACKED COALS OF THE CENTRAL APPALACHIAN BASIN

2.2.1 Motivation

Coal is an attractive reservoir rock for CO₂ storage due to its unique storage properties. The microporous texture of coal can provide a storage capacity of five or six times that of a typical sandstone (Al-Jubori et al., 2009; Shi and Durucan, 2005). Additionally, coal exhibits an adsorption phenomenon with some gases, including CO₂, meaning the gas is attracted to and held on the coal surface by Van der Waal’s forces (Al-Jubori et al., 2009). Shi and Durucan (2005) suggest that 95 to 98 percent of gas stored in coal is stored by adsorption within the micropores of the coal matrix.

Coalbed methane fields are attractive settings for CCUS due to the favorable storage properties of coal and the potential for enhanced coalbed methane recovery (ECBM). Like CO₂, methane also adsorbs onto the surface of coal, but when coal is exposed to both methane and CO₂ under typical reservoir conditions, it will preferentially adsorb the CO₂ and release previously adsorbed methane (Ottiger et al., 2008; Harpalani et al., 2006; Shi and Durucan, 2005). The exchange of gases due to preferential adsorption creates a chemical storage mechanism for the CO₂ and enhances CBM production due to the release of trapped methane. Both of these effects are beneficial to achieving the objectives of CCUS. Additionally, the chemical bonding of CO₂ to the formation means that more of the injected volume of CO₂ is likely to be stored in the subsurface and less CO₂ will break through at offset wells. This results in a purer methane production stream and reduces the efforts required to manage and process the gas stream. The disadvantage of CO₂
adsorption on coal is associated swelling of the coal matrix. Laboratory tests by Siriwardane et al. (2009) showed that exposure of Appalachian coal samples to a CO₂ medium could reduce permeability by more than 90 percent. Injection rates and strategies must be tailored to prevent injectivity loss due to swelling and must be adjusted based on changes in wellhead pressure. Significant swelling of the coal matrix, especially early during an injection test, could impede the ability to store the full, desired volume of CO₂ and/or could prevent potential ECBM from being released and produced. Other CCS tests in coal, including the Pump Canyon test in the San Juan Basin, New Mexico, and Consol Energy’s injection test in Marshall County, West Virginia, have highlighted the importance of optimizing injection rate and strategy in order to mitigate matrix swelling and permeability loss (Oudinot et al., 2011; Locke and Winschel, 2012). A limited amount of swelling late in an injection test could potentially prove beneficial by swelling natural and induced fracture pathways, restricting the migration or leakage of free gas.

Another advantage of the CBM field setting is that the existing infrastructure used for CBM production can be utilized for conducting CO₂ injection tests. Depleted production wells can be converted for use as injection test wells with relatively little effort and, if desired, returned to production when the testing is complete.

2.2.2 Geologic characterization

The Oakwood coalbed methane field lies within the Cumberland Overthrust Block, a large tectonic feature within the Central Appalachian Basin. The southwest-northeast oriented block extends approximately 250 km (155 mi) in length and 40 km (25 mi) in width through portions of Tennessee, Kentucky, Virginia, and West Virginia (Henika, 1994). During Alleghanian orogenesis, a major episode of tectonic activity in the formation of the Appalachian Basin, the
block was subjected to detachment, transportation and rotation along large faults (Grimm et al., 2011; Henika, 1994). Prominent structural features of the Cumberland Overthrust Block include several large southeast-dipping thrust faults which form the southeast boundary of the block, several steeply dipping transverse faults, and a number of sizeable structural folds and small basins (Henika, 1994). The southern portion of the Oakwood field, where the CCUS field tests are located is bounded by two of the prominent faults, the transverse Russell Fork fault on the southwest margin and the Boissevain thrust fault on the southeast margin, as shown in Figure 2-1.

Figure 2-1. Map showing locations of the Russell and Buchanan County test sites relative to CBM and deep mining operations and geologic structure. The contoured surface is the Pocahontas No. 3 coal seam. The location of the injection well is circled in blue, and the three injection wells for the Buchanan County test are circled in red.
The coal reservoir in the Oakwood coalbed methane field includes 15 to 20 individual coal seams from the Pennsylvanian-aged Pocahontas and Lee formations, rarely exceeding 0.6 m (2.0 ft) in thickness, resulting in net thicknesses of approximately 4.5 to 9.0 m (15 to 30 ft). The seams are distributed over approximately 300 m (1,000 ft) of vertical section at depths ranging from roughly 275 to 640 m (900 to 2,100 ft) depending upon the well, with interbeds of shales and sandstones. Regional stratigraphy includes several confining units. Three low-permeability shales, including the Hensley shale, overlie the shallowest seams of the coal reservoir and underlie the deepest anticipated freshwater source. The Hensley shale has been previously identified as an effective seal against potential CO₂ leakage due to its thickness of over 15 m (50 ft) throughout southwest Virginia, lateral continuity, and high clay content resulting in low permeability (Grimm et al., 2011). Characterization efforts at the Buchanan County test site indicate that all three of these confining shale units are at least 10 m (34 ft) thick locally with permeability values ranging from 0.001 to 0.1 md. The Lee sandstone, a thick, well-cemented sandstone, lies between key injection horizons within the Pocahontas formation and forms an additional seal for deeper seams. At the Buchanan County site, the Lee sandstone is nearly 60 m (200 ft) thick with permeability ranging from 0.0014 to 0.04 md. A generalized stratigraphic column for the site is shown in Figure 2-2.
2.2.3 Field validation test in Russell County, VA

In January 2009, SECARB conducted a small CO₂ injection test at field site in a producing CBM field in Russell County, Virginia. Over a one-month period, 907 tonnes of CO₂ were injected into a production well for the purpose of assessing and verifying the storage capacity of Central Appalachian coal beds. The injection reservoir was comprised of 19 individual coal seams from the Pocahontas and Lee formations with a net thickness 7.9 m (26 ft).

The MVA program for this test was designed to monitor and collect data from atmospheric, surface, and subsurface levels. Atmospheric monitoring was conducted using infrared gas
analyzers (IRGAs) to measure CO₂ concentrations both near the surface and 15 m (50 ft) above it. Surface monitoring methods consisted of soil CO₂ flux measurement, tracer analysis, and surface water sampling. For these measurements, 18 surface monitoring locations were arranged in concentric circles around the injection well, a pattern selected based on preliminary modeling of the plume extents, and six additional water sampling stations were established. For subsurface monitoring, seven offset production wells were sampled and two deep monitoring wells were drilled in alignment with local face and butt cleat orientations. Well tests included spinner surveys, pressure testing, temperature logs, gas composition, production data analysis, formation water sampling, and tracer analysis.

This MVA design produced several significant findings: 1) No leakage was detected by any available means, including IRGAs for atmospheric detection, soil CO₂ flux measurement, surface water sampling, or surface tracer sampling. 2) A spinner production rate survey (run during CO₂ injection) encountered liquid CO₂ at a depth of 506 m (1,660 ft). This phase change was confirmed by a sudden decrease on the temperature log at the same depth. 3) The CO₂ concentration at monitoring well No. 1 (41 m (135 ft) from the injection well) reached over 95 percent within hours of the start of injection. Monitoring well No. 2 (87 m (285 ft) from the injection well) reached over 95 percent CO₂ concentration within 8 days of injection. The rapid accumulation of CO₂ at these wells indicates a well-developed hydraulic and/or natural fracture system in the reservoir. Both wells remained at over 95 percent CO₂ concentration during the soaking phase. 4) Increased concentrations of N₂ and CH₄ during initial flowback of the injection well indicate successful, preferential adsorption of CO₂ onto the coal matrix. 5) Enhanced coalbed methane (ECBM) was achieved in three production wells. The injection well was returned to production following the injection test and has since been producing larger volumes of methane, sufficient to increase the
estimated ultimate recovery of the well by 36 percent. Despite the small amount of CO₂ injected, production curve analysis predicts that the enhanced methane recovered as a result of the injection test will pay for the cost of the CO₂ within ten years. Additionally, two offset production wells exhibited smaller amounts of increased methane production with no breakthrough of CO₂. Tracer was detected at all immediate offset wells and at several within the second tier of wells, up to 1,130 m (3,700 ft) from the injection well, while CO₂ breakthrough was not encountered at any offsets. This may be due to the larger size of the tracer molecule, which would prevent its adsorption in the coal matrix and allow it to travel more freely through the coal cleat system and hydraulic fracture network. Tracer detection took several months at some offset wells, suggesting connection between the existing cleat system and induced hydraulic fracture network, as the observed hydraulic fracture lengths in this location would not be sufficient to connect wells.

2.2.4 Field demonstration in Buchanan County, VA

Up to 20,000 tonnes of CO₂ will be injected into three production wells at a field demonstration site located in Buchanan County, Virginia, over a one-year period. Similar to the Russell County test, the goals of this study are to assess the injection and storage potential of fractured coal seams and to evaluate the potential for ECBM recovery at offset production wells. The Buchanan County field is located 12.1 km (7.5 mi) northwest of the Russell County site, as shown in Figure 2-1. The seams comprising the coal reservoir in Buchanan County are essentially the same as those in Russell County but are thinner. For the three injection wells there are 15-20 coal seams from the Pocahontas and Lee formations that will be targeted for injection, averaging 0.3 m (1.0 ft) in thickness, for net reservoir thicknesses of approximately 4.5-6.0 m (15-20 ft).
Selection of the Buchanan County field site was based on several favorable site characteristics. A single, cooperative landowner maintains surface and mineral rights for all three injection wells, as well as rights to several offset wells. The field site is a sufficient distance from subsurface mining activity and is in sufficient proximity to the Russell County study for extrapolation of findings between the two locations. Although the Cumberland Overthrust Block was formed by complex tectonic activity, the field site location within the block is structurally quiet, with no significant documented faults near the injection wells, and no recorded sizeable seismicity or other geohazards. Folding is present at the injection site and throughout the south Oakwood field and is apparent in the structure model for the Pocahontas No. 3 seam shown in Figure 2-1.

The Oakwood CBM field has been active since the early 1990s when the primary field operator, CNX Gas Company (CNX), began drilling wells on 0.32-km² (80-acre) field units. Typical well completion includes perforation of the wellbore casing in targeted coal seam intervals in order to perform multi-stage hydraulic fracturing treatments with nitrogen foam and sand proppant. In recent years, CNX conducted an infill drilling program, adding CBM wells on several established production units and reducing the development spacing to approximately 0.16 km² (40 acres) per well. Analysis of gas production data from the injection wells and surrounding offset wells indicates sufficient local reservoir depletion so that injection of the maximum volume of CO₂ will not approach the original gas content of the reservoir. Water production at and near the injection wells is low, which is expected to favor injectivity, and is estimated to average approximately 30 bbls per month for the three injection wells. Analysis of gas and water production data over the larger study area reveals anomalous production trends related to geologic structure. These trends are apparent in the gas and water production data shown in Figure 2-3.
For the initial drilling program, wells drilled on a local structural high, the Hurricane Creek anticline, had much higher gas production compared to wells drilled on a local structural low, the Hurricane Creek syncline. The average estimated ultimate recovery (EUR) values are 29.7 million m$^3$ (1050.0 MMcf) and 17.6 million m$^3$ (621.0 MMcf) for wells drilled on the anticline and syncline, respectively. Conversely, for the recent infill drilling program, wells drilled on the anticline have produced much less gas than wells drilled on the syncline and have average EUR values of 5.7 million m$^3$ (202.5 MMcf) and 21.1 million m$^3$ (746.7 MMcf), respectively. On average, the infill wells drilled on the syncline outperform the initial wells for the same development units. These observations may be related to higher initial water production in the
syncline. It is likely that gas, stored largely by adsorption, is distributed uniformly throughout the reservoir on both features. However, wells drilled on the anticline are likely to encounter higher free gas saturations and higher relative permeabilities to gas, while wells located on the syncline are likely to encounter higher initial water saturations and lower relative permeabilities to gas. Consequently, field development units on the high and low features would have similar amounts of total gas in place. Initial wells on the anticline would effectively produce most of the recoverable gas within their units while development on the syncline would require the drilling of more wells and longer production times to sufficiently de-water the coal seams and optimize production. In addition to implications for the infill drilling program, production results in the area have important implications for the CO2 injection test. Initial reservoir modeling suggested injected CO2 would spread as nearly identical ellipsoid plumes around the three injection wells, but the production trends suggest that well DD-7, which lies on the flank of the Hurricane Creek anticline, may experience asymmetrical spreading due to updip migration of CO2 toward the depleted anticline crest, whereas injection wells DD-7A and DD-8 located down-dip would be more likely to experience injectivity loss.

2.2.5 MVA plan

An MVA focus area was determined for the Buchanan County injection site, based on overlapping 730-m (2400-ft) proximities from the injection wells, as seen in Figure 2-4. The MVA techniques selected for the Buchanan County test are indicated in bold in Table 2-1. Technologies were selected based on their advantages described in the table, as well as their suitability for the site characteristics, such as steep terrain and dense land cover, and their applicability to the unique geometry of the coal reservoir. Many of the tests performed at the Russell County site will be
repeated at the Buchanan County site. Atmospheric monitoring of CO\textsubscript{2} levels will be conducted. Offset production wells will be used to measure ECBM recovery and detect possible CO\textsubscript{2} or tracer breakthrough. Unique tracers will be assigned to each well and possibly to specific zones of the reservoir. An array of infill surface stations will be established for soil CO\textsubscript{2} flux measurements, surface water sampling, and possible tracer breakthrough detection.

![Figure 2-4. Overview map of MVA program for the Buchanan County test site. Injection wells DD-7, DD-7A, and DD-8 are indicated with green hexagons. Candidate locations for monitoring and characterization wells are indicated with black diamonds. Small blue hexagons indicate theoretical locations for TFI stations.](image)

Three monitoring wells will be drilled for additional gas content testing and formation logging, such as reservoir saturation and acoustic (sonic) logging. One of the wells will be cored for
laboratory testing that will aid the geologic characterization and reservoir modeling efforts. The locations of these wells will depend on several factors, including access, predicted plume growth, optimal placement for specific tests, and potential future utilization of the wells (conversion for production). A summary of the general MVA design is depicted in Figure 2-4.

The original MVA objectives for the Buchanan County test included the use of a time-lapse seismic imaging method, either vertical seismic profile (VSP) or crosswell surveys, in order to image the reservoir and injected CO₂ plume. Time-lapse seismic imaging has been used effectively for this purpose in several CO₂ injection studies but was determined to be poorly suited for the Buchanan County study based on site and reservoir characteristics. The steep mountain terrain of the Buchanan County field site limits potential borehole locations to existing well pad sites and roadsides, which may not provide an option for a well-oriented and representative cross section of the plume. More importantly, the thin coal seams comprising the reservoir are poor targets for seismic imaging. A crosswell configuration, which would eliminate shallow noise, that is closely spaced and focused on a subset of the thickest (0.6-m (2.0-ft) thick) coal seams may be the best option for resolving the reservoir using borehole seismic imaging. However, even if successful, this imaging method would present interpretation challenges. If there was an observable change between pre- and post-injection surveys, it could be difficult to distinguish the effect of fluid displacement due to injected CO₂ from other factors that may influence the data, such as swelling of the coal matrix and resultant permeability change or even seasonal acoustic variation. Additionally, the survey would require close borehole spacing, possibly less than 10 m, in order to image the thin coals, and it would not be possible to extrapolate any interpretation with reasonable confidence over the area of a plume, which may extend as far as 0.4 km (¼ mi) from the injection well. For these reasons, the plans for time-lapse seismic imaging were abandoned
and replaced with plans for technologies better suited for the site conditions and reservoir geometry.

Instead of time-lapse seismic imaging, a buried passive seismic array will be used to monitor the reservoir. The passive seismic data will be used for two purposes: to detect any microearthquakes that may occur during the treatment period and for Tomographic Fracture Imaging™ (TFI™), a proprietary technology of Global Geophysical Services, Inc. (Geiser et al, 2012; Lacazette and Geiser, 2013; Sicking et al, 2013). TFI sums cumulative seismic activity over extended time periods (minutes to hours or days) and produces images of fracture flow paths as discrete surfaces and networks, as shown in Figure 2-5.

Figure 2-5. TFI map-view slice (in the plane of a horizontal wellbore) distinguishing the natural fracture network from fractures induced during a hydraulic fracturing treatment stage for the well (modified after Geiser et al., 2012).
An additional product is the volumes of cumulative seismic activity that are used to make the TFIs. The energy summed by this process includes microearthquakes detectable by conventional methods, microearthquakes too small to be detected by conventional methods; long-period, long-duration (LPLD) events (Das and Zoback, 2011; Zoback et al, 2012); and perhaps energy from as yet unrecognized microseismic phenomena. The method is very sensitive because it accumulates total energy production over long periods of time instead of looking only for discrete, strong events (e.g. microearthquakes strong enough to have resolvable P and S wave first-arrivals). This technology is well-suited to the Buchanan County injection test because the low injection rates, intentionally below the hydraulic fracture gradient, are likely to only produce only weak seismic emissions. Also, TFI is deployed as a buried surface array of recording stations, similar to some conventional microseismic arrays, and will, therefore, monitor the full areal extent of the plume. Interpretation of the TFI results will still present some challenges because, like microseismic events, the data do not necessarily indicate only the presence or spread of CO2. Fluid injection produces measureable seismic activity by reducing friction on pre-existing fractures allowing slip, by poroelastic stress increase, or both. However, chemical tracers and other methods to be used in this study can provide evidence of direct fluid connections thereby allowing fluid movement traced by TFI to be distinguished from stress effects. Also, the propagation velocity of microseismic effects can sometimes be used to directly distinguish fluid movement from the propagation of stress waves.

Measuring surface deformation at the Buchanan County field site during CO2 injection could potentially indicate a boundary of uplifted earth correlated directly to the addition of CO2 and swelling of the coal matrix. It may also indicate the rates of plume growth in multiple directions from the injection wells. However, the steep terrain and dense tree cover at the field site make it
a poor candidate for several surface deformation measurement technologies, including many satellite-based methods. Differential GPS, which makes measurements relative to a surface base station, is a viable option. As mentioned previously, the Pump Canyon injection test used tiltmeters and differential GPS stations to monitor CO₂ injection in the Fruitland coal reservoir but detected no uplift, although subsidence was detected near offset wells due to depletion from production activity. The Fruitland coal reservoir is 915 m (3,000 ft) deep (Oudinot et al., 2011), whereas the coals at the Buchanan County site are as shallow as 275 m (900 ft), which may allow matrix swelling or other deformation due to CO₂ injection to have a more measurable effect.

2.3 DISCUSSION

The unique characteristics of the Buchanan County CO₂ injection test site require a unique approach to designing the MVA program. The mountainous terrain of the Central Appalachian Basin restricts the use of some ground-based technologies by limiting the options for borehole and instrument placement. Moreover, the combination of difficult terrain and dense tree cover prohibits other technologies, including most satellite-based monitoring options. Just as CO₂ injection will hopefully have the effect of enhancing gas production, consideration must be given to historical CBM production, its implications for reservoir behavior, and the effect it may have on the injected CO₂ plume. Perhaps the most important factor in designing the MVA program is the unusual geometry of the coal reservoir. Technologies like time-lapse VSP or crosswell seismic surveys, which have been useful for many CO₂ storage demonstrations in thick, saline aquifers, must be scaled to their imaging target and are not practical for use in thin, distributed coal seams. Furthermore, the individual seams may respond uniquely to CO₂ injection, complicating the data interpretation for some MVA methods.
The most informative and cost effective MVA program for the Buchanan County test may be one that combines technologies that collect data over large areal extents, such as passive microseismic or TFI monitoring and surface deformation measurement, with substantial data from monitoring and offset wells. These data sets complement and validate each other by defining the relationships between the spreading plumes of pressure, CO₂, methane, and tracer and relating them to matrix swelling, ground uplift, and seismic response. The overlapping nature of these data sets and their temporally dense sampling compared to some time-lapse methods will make their interpretation and extrapolation more straightforward and relevant. The results of the MVA program for the Buchanan County test will provide important information regarding CCUS in thin stacked coal reservoirs and will help guide future MVA efforts in similar settings.

ACKNOWLEDGEMENTS

Financial assistance for this work was provided by the U.S. Department of Energy through the National Energy Technology Laboratory’s Program under Contract No. DE-FE0006827. The authors would like to thank Al Lacazette of Global Geophysical Services, Inc., for input which improved an earlier version of this manuscript.

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3 GEOSPATIAL MONITORING OF SURFACE DEFORMATION ASSOCIATED WITH ENERGY PRODUCTION AND CARBON SEQUESTRATION

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This work is published in the proceedings of the 2nd Environmental Considerations in Energy Production Conference (September 2015). It is reprinted with the permission of the publisher, the Society for Mining, Metallurgy, and Exploration (SME).

ABSTRACT

Geospatial monitoring methods, including time-lapse Global Positioning System (GPS) and interferometric synthetic aperture radar (InSAR) surveys, can be used to assess surface deformation associated with energy production. These methods can be applied near underground mining operations to measure subsidence from ore extraction and in oil or gas fields to monitor subsidence near production wells or uplift near disposal/ injection wells. Recently, time-lapse geospatial monitoring has also been used to assess land impacts and reservoir processes associated with carbon storage and utilization field tests.

Time-lapse GPS and InSAR monitoring are currently in use at an ongoing carbon storage/enhanced gas recovery test site in the Central Appalachian Basin. Up to 20,000 tonnes of CO2 will be injected into three wells in a coalbed methane field within a one-year period. The geospatial data will help delineate the boundaries of surface impacts due to the injection test and could also
identify impacts from gas extraction in the surrounding coalbed methane field. Additional components of the monitoring program include atmospheric gas sampling, surface water and groundwater sampling, a passive microseismic monitoring array, injectate perfluorocarbon tracer studies, gas and water sampling at offset production wells and three dedicated monitoring wells, and well-based pressure and temperature monitoring (downhole and surface). Combining the geospatial results with other monitoring results will help evaluate reservoir processes, such as swelling of the coal matrix, which could be indicated by surface uplift, changes in microseismic activity, or pressure redistribution.

Surface and reservoir characteristics at the test site may present challenges for geospatial data analysis. The land surface is characterized by dense tree cover, which can limit the effectiveness of satellite-based methods like InSAR, and by steep, variable terrain, which complicates the interpretation of elevation data. An innovative differential processing technique for InSAR data, the intermittent small baseline subset (ISBAS) method, will be used to help overcome these factors. The use of time-lapse GPS and InSAR with ISBAS processing at the carbon storage test site will be an important feasibility test for these technologies in a unique setting. The results will help guide future efforts to monitor surface deformation associated with energy production in Central Appalachia and other mountainous regions.

3.1 INTRODUCTION

Time-lapse geospatial monitoring may be conducted using a variety of remote sensing or ground-based technologies and often involves a combination of both. Remote sensing methods collect data indirectly, by satellite or other means, and are especially useful for monitoring large areal extents. Remote sensing technologies include several variations of synthetic aperture radar
(SAR), light detection and ranging (LiDAR), and aerial photogrammetry (Campbell and Wynne 2011; Yu et al. 2008). Ground-based technologies, such as Global Positioning System (GPS) or tiltmeter arrays, use direct earth contact to make physical measurements and are often used in conjunction with remote sensing methods to establish a ground reference and cross validate results (Konca et al. 2008; Lillesand et al. 2007; Perissin and Wang 2011).

The applications for geospatial monitoring range widely and include investigations of natural and man-made processes and features. Geospatial surveys can be used to map the distribution of plant, animal, or human populations. Time-lapse surveys can assess changes to the lateral extents of natural features, such as coastlines, ice sheets, or migrating rivers, and can also assess the extents of human impacts from land uses including agriculture, urban development, or deforestation. The use of time-lapse geospatial surveys to monitor surface deformation refers primarily to the measurement of surface elevation changes due to subsidence or uplift, although these motions will have associated lateral components that may be of interest for some studies. Deformation can also result from natural or man-made processes or can be the product of both. Geospatial monitoring has been effective for evaluating subsidence associated with energy production operations, including underground mining and oil and gas extraction from subsurface reservoirs. Recently, time-lapse geospatial surveys have been used to monitor several field tests to inject and store carbon dioxide in geologic formations and have demonstrated success at measuring surface uplift and deformation associated with CO₂ injection.

3.2 APPLICATIONS FOR GEOSPATIAL MONITORING OF SURFACE DEFORMATION

3.2.1 Natural phenomena
Geospatial monitoring is commonly used to evaluate geologic or tectonic hazards and to assess the impacts of natural disasters. Remote sensing has been used to monitor over 500 volcanos worldwide (Biggs et al. 2014). Analysis of ground movement recorded by GPS has been used to predict volcanic activity and to characterize the structural evolution of volcanic domes throughout their eruption cycles (Dixon et al. 1997; Mattioli et al. 1998). In earthquake-prone regions, including the subduction zones of Sumatra and Northern Chile known to produce large megathrust events, geospatial monitoring has been used to quantify the ground displacement or deformation associated with ruptures (Bejar-Pizzaro et al. 2013; Konca et al. 2008). Remote sensing data and images acquired before and after a giant landslide resulting from the notable Wenchuan earthquake of 2008 were used to determine the volume and redistribution of affected land mass (Chen 2014). Remote sensing with InSAR has also been used to monitor deformation and instability of permafrost on the Tibet Plateau of China (Chen 2013).

3.2.2 Man-made phenomena

Geospatial monitoring of man-made activities typically relates to the use or conservation of natural resources. Subsidence due to the extraction of groundwater for human and agricultural use is a concern in areas of high population and scarce water supplies and carries significant social, economic, and environmental implications for affected communities (Chaussard et al. 2013; Yu et al. 2008). A research partnership between the European Space Agency (ESA) and the National Remote Sensing Center of China (NRSCC), the Dragon Project, was formed to study this issue in several regions of China, where rapid infrastructure development associated with the growth of existing and new cities further contributes to land subsidence (Perissin and Wang 2011). Efforts to characterize subsidence from groundwater extraction have also been made in parts of Australia.
and in central Mexico, where extraction poses an additional, geologic hazard by redistributing pore pressure and causing motion on faults underlying heavily populated regions (Chaussard et al. 2013; Cigna et al. 2011; Yu et al. 2008). Remote sensing with SAR technologies has been used to evaluate the construction and structural integrity of large man-made features, including a headrace (water transportation) tunnel in the Swiss Alps and a critical dam on the Yangtze River, constructed as part of the Three Gorges Project (Perissin and Wang 2011; Strozzi et al. 2011). Some applications of geospatial monitoring, such as the subsidence of engineered fill material preceding levee failure in New Orleans during Hurricane Katrina, involve both natural and human impacts (Dixon et al. 2006).

3.2.3 Energy production

The most established use of geospatial monitoring related to energy production is for underground longwall mining of coal, which can cause profound subsidence at the surface as mining advances and excavated portions of the panel collapse. Differential InSAR has been used to assess deformation in the Silesian coalfield of the Czech Republic, where multiple levels of mining have contributed to net surface subsidence of up to 130 feet (Stow and Wright 1997). Geospatial methods have also been used to evaluate sites of mining-related subsidence in Australia, where mining near New South Wales at a depth of 1380 feet can cause 1 cm of subsidence in a 24-hour period, as well as sites in China and the UK (Chang et al. 2007; Perissin and Wang 2011; Sowter et al. 2013; Stow and Wright 1997). Following two fatal collapses at the Crandall Canyon mine in central Utah, pre- and post-event InSAR images were used to quantify surface subsidence resulting from the collapses and to model ground response scenarios that could have caused the rock failures (Plattner et al. 2010). Geospatial monitoring is also used to assess
surface deformation caused by gas and oil field activities, primarily extraction from production wells. Oil and gas reservoirs are deeper than most groundwater aquifers but the similar methods of extraction and large scale of operations in these settings can produce measurable surface subsidence. SAR data collected over shallow oil fields of the San Joaquin Valley in California revealed subsidence rates of up to 40 cm/yr (Fielding et al. 1998). At an enhanced oil recovery site in the Middle East, SAR data were integrated with GPS data from 40 ground stations to characterize the net effect, primarily subsidence, resulting from combined water flooding and oil extraction operations and to assess the relationship of operations and deformation to a number of local faults (Tamburini et al. 2010).

3.2.4 Carbon storage in geologic formations

The limited examples of geospatial monitoring for carbon storage and utilization (enhanced recovery) operations indicate that these tools could provide low-cost, high-resolution options to monitor the long-term impacts of CO₂ injection. The most notable example of geospatial monitoring of CO₂ injection is in In Salah, Algeria, where CO₂ is produced from the Krechba gas reservoir with the production stream and reinjected into the water leg of the reservoir (Tamburini et al. 2010; Verdon et al. 2013). The 65-foot thick sandstone reservoir is approximately 6200 feet deep. Time-lapse remote sensing with InSAR during the first five years of injection revealed uplift over most of the site with maximum total uplift of 2 cm surrounding the three injection wells (Verdon et al. 2013). The pattern of uplift indicates permeability anisotropy associated with local faults and fracture systems which creates an uneven distribution of CO₂ in the reservoir (Tamburini et al. 2010). A single active downhole geophone will be used to compare rates of microseismicity to deformation trends observed with InSAR (Verdon et al. 2013). Microseismicity does not
directly measure rock deformation or displacement but has been analyzed with simultaneously-recorded pressure data from CO2 injection tests at the Weyburn oil field of Saskatchewan, Canada, and at the Illinois Basin-Decatur demonstration site, to infer geomechanical responses of the reservoir (Coueslan et al. 2014; Verdon et al. 2013).

At the Pump Canyon test site in the San Juan Basin of New Mexico, CO2 was injected into a depleted coalbed methane reservoir, in order to test the potential for CO2 storage and enhanced gas recovery (Kaiser et al. 1994; Koperna et al. 2009). A combination of tiltmeters and differential GPS measurements were used to monitor surface deformation associated with the test and were consistent in finding little change despite indications of coal swelling (Koperna et al. 2009; Siriwardane et al. 2008). The lack of measurable uplift, despite indications of coal swelling, could be caused by competing and counteractive signals from gas production or could relate to accommodative properties of the overburden which may dampen a small uplift signal from the 3000-foot deep reservoir.

3.3 CARBON STORAGE-ENHANCED GAS RECOVERY FIELD DEMONSTRATION

3.3.1 Overview

Pre-injection monitoring and site preparations are underway at a carbon storage and enhanced recovery test site in Buchanan County, Virginia, USA. The site is located within the Oakwood coalbed methane field, shown in Figure 3-1, which produces from unmineable coal seams in the Central Appalachian Basin. The Oakwood field was first developed in the early 1990s when CNX Gas Company began an initial drilling program on 80-acre operational units. An infill drilling program has been active in the area since the mid-2000s. The CBM reservoir is comprised of 15-20 individual coal seams from the Pennsylvanian-aged Pocahontas and Lee formations. The thin
seams are distributed over approximately 1000 feet of vertical section, interbedded with shale and sandstone units. Production wells are perforated in the reservoir seams, which are hydraulically fractured to increase reservoir permeability and gas recovery.

Figure 3-1. Location of the Oakwood coalbed methane field within the Central Appalachian Basin (modified from EIA, 2007).

For the injection test, three CBM production wells have been converted for CO₂ injection operations, scheduled to begin in summer 2015. Up to 20,000 tonnes of CO₂ will be injected into the multi-seam reservoir within a one-year period. The injection wells are located on the southeast flank of the Hurricane Creek Anticline, a gently dipping structure which trends southwest-northeast. The focused study area, defined by a ½-mile radius surrounding the injection wells, also includes sixteen offset production wells. Within the study area, the average thickness of the
reservoir seams is only one foot and net reservoir thickness is 15-20 feet. The depths of the reservoir seams range from approximately 800 to 2200 feet.

Within the Oakwood field, there are two primary confining zones which would protect the shallow subsurface, including underground sources of drinking waters (USDWs), from potential leakage of CO₂ or methane. A series of three low permeability (0.001 to 0.1 mD) shales serves as a shallow confining zone, located below the deepest anticipated freshwater source but overlying the shallowest reservoir seams. One of these units, the Hensley shale, has been characterized through detailed regional studies and laboratory analysis as an effective seal based on its thickness (average of 50 feet), lateral continuity, and high clay content (Grimm et al. 2011). The Lee Sandstone provides an additional, mid-reservoir seal. This unit has a thickness of approximately 200 feet in the focused study area, is laterally continuous, and exhibits low permeability (0.001 to 0.04 mD) due to cementation.

3.3.2 Monitoring program

The monitoring, verification, and accounting (MVA) program for the injection test includes atmospheric, near-surface, and subsurface monitoring technologies. An MVA overview map, showing the deployment stations for several key components of the program is shown in Figure 3-2. The approach to monitoring at the site involves combining high-resolution, borehole data from offset wells with data collected over large areal extents in order to interpolate the evolution of the injected CO₂ plume within the reservoir. Data sets with different spatial and temporal sampling can also be used to distinguish monitoring responses related to CO₂ injection from competing signals caused by other activities, including gas production, waste water injection, and nearby mining.
Atmospheric monitoring includes ambient air sampling across the study area to monitor CO₂ levels relative to established baselines and soil CO₂ flux chambers, which have been installed in several locations to monitor CO₂ levels at the air-earth interface. Near-surface methods include surface water and groundwater sampling, shallow pressure gauges in dedicated monitoring wells, a 20-station GPS array, and remote sensing with InSAR. Subsurface monitoring includes a passive, 28-station microseismic array and all forms of well-based monitoring, including perfluorocarbon tracer studies, downhole pressure gauges in dedicated monitoring wells, and well logging. Additionally, offset and monitoring wells will be sampled frequently for gas composition, formation water composition, and tracer breakthrough.
3.3.3 Challenges and advantages for geospatial monitoring

The mountainous terrain of the injection test site presents several challenges for the monitoring program and for geospatial monitoring in particular. The steep topography limits physical access across the study area and restricts the locations of monitoring stations to roads, well pads, and reclaimed surface mining benches. Geospatial data quality is affected by dense tree cover which impedes line-of-sight to satellites and, coupled with steep grades, creates radar shadows, geometric distortions, and other imaging inaccuracies (Campbell and Wynne 2011). The lack of coherent radar reflectors in this remote setting and variability in physical characteristics due to vegetation and other factors may compromise the ability to process satellite imagery data (Sowter et al. 2013).

In contrast to the surface terrain, characteristics of the coal injection reservoir favor the use of geospatial monitoring. Coal exhibits preferential adsorption of CO₂ over methane and undergoes matrix shrinkage or swelling as a result of methane desorption or CO₂ adsorption, respectively (Karacan 2007; Pan and Connell 2010; Plattner et al. 2010). Experimental and computational modeling studies have investigated factors impacting the degree of coal swelling, including pore size, adsorbed CO₂ volume, and microlithotypes (Cui et al. 2007; Karacan 2007; Yang et al. 2011). All studies use volumetric strain as a measure of coal swelling. The observed relationship of increased volumetric strain difference for decreasing pore size has important implications for the coal reservoir in Buchanan County (Yang et al. 2011). Coal samples collected at the site are currently undergoing laboratory analysis but are qualitatively assessed as microporous and, therefore, likely to experience significant swelling. Additionally, several reservoir seams are less than 1000 feet deep, which may be sufficiently shallow to allow surface expression of reservoir swelling. In this case, the results of pre-injection passive microseismic monitoring, shown in
Figure 3-3, indicate a well-developed existing fracture system capable of transporting CO$_2$ over a large areal extent.

![Inferred existing fracture system at the CO$_2$ injection test site (depth slice at 1700 ft) based on pre-injection passive microseismic monitoring and tomographic fracture imaging.]

Figure 3-3. Inferred existing fracture system at the CO$_2$ injection test site (depth slice at 1700 ft) based on pre-injection passive microseismic monitoring and tomographic fracture imaging.

**3.4 GEOSPATIAL DATA COLLECTION AND ANALYSIS**

**3.4.1 Global Positioning System (GPS)**

The Global Positioning System (GPS) is a public service, originally developed by the U.S. Department of Defense, which uses a network of satellites to provide position, navigation, and timing data. The GPS can be used to monitor surface deformation by providing position data for a fixed location, used as a geodetic benchmark, over time. At the Buchanan County study area, an
array of 20 GPS survey monuments, shown in Figure 3-2, have been installed to serve as geodetic
benchmarks for time-lapse data collection. Eighteen monuments are located within the focused
study area, and two are located a quarter of a mile outside the study area boundary, where
deformation due to CO₂ injection is not expected, as control points.

The installation procedure used at the site was modified from a procedure recommended by
the National Oceanic and Atmospheric Administration (NOAA) and National Geodetic Survey.
Boreholes were drilled to a depth of approximately four feet and used to set six-inch diameter PVC
 housings for steel measuring rods, which were driven into the earth and secured with rebar, poured
cement and sand fill. The measuring rods are exposed at the top of the boreholes and each was
fitted with a spherical steel cap that has a single point indentation to provide a consistent survey
datum.

GPS data are collected manually at the site using four survey-grade CHC X90-OPUS GPS
receivers distributed by iGage Mapping Corporation of Salt Lake City, Utah. Data are collected
by leaving a receiver fixed in place at a monument for an occupation time of at least two hours.
The data collection assembly is shown in Figure 3-4. Data are processed using NOAA’s Online
Positioning User Service, which incorporates IGS satellite orbits and the Continuously Operating
Reference Station (CORS) regional networks for robust error correction. Since the research
objective is to measure changes in elevation rather than absolute elevation, elevation data are
recorded as ellipsoidal height versus orthometric height in order to avoid introducing errors
associated with approximating the global sea level.
Baseline GPS data collected at the site indicate a strong correlation between occupation time and accuracy. Significant variability in measurement accuracy between stations is likely due to occluding terrain and tree cover. In order to improve accuracy, data collection at some monument locations may require as much as 24 hours of occupation time. The highest quality measurements collected to date have peak-to-peak errors as low as 7mm and correspond to a 95% confidence interval of 8.3mm. Data collection at the site will continue on a periodic basis during injection and post-injection phases of test operations.
3.4.2 Interferometric Synthetic Aperture Radar (InSAR)

The German Aerospace Center (DLR) awarded a proposal to acquire InSAR image data over the Buchanan County test site using its TerraSAR-X satellite. The satellite, launched in 2007, is a side-looking instrument with an X-band carrier frequency of 9.65 GHz. Orbit height is 512 km at the equator, and the orbit repeat cycle is 11 days. Additional system and orbit parameters of the TerraSAR-X instrument are provided in Table 3-1, and a detailed description of the satellite and its operational modes is available in DRL’s “TerraSAR-X Ground Segment Basic Product Specification Document” (DLR 2010).

Table 3-1. System and orbit parameters for DLR’s TerraSAR-X satellite from “TerraSAR-X Ground Segment Basic Product Specification Document” (modified after DLR 2010).

<table>
<thead>
<tr>
<th>System Parameters</th>
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<tr>
<td>Radar carrier frequency</td>
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</tr>
<tr>
<td>Radiated RF Peak Power</td>
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</tr>
<tr>
<td>Incidence angle range for stripmap / Scan-SAR</td>
<td>20°-45° full performance (15°-60° accessible)</td>
</tr>
<tr>
<td>Polarizations</td>
<td>HH, VH, HV, VV</td>
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<tr>
<td>Antenna length</td>
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<tr>
<td>Antenna Width</td>
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<tr>
<td>Nominal look Direction</td>
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</tr>
<tr>
<td>Number of stripmap / ScanSAR elevation beams</td>
<td>12 (performance range) 27 (access range)</td>
</tr>
<tr>
<td>Number of spotlight elevation beams</td>
<td>91 (full performance range) 122 (access range)</td>
</tr>
<tr>
<td>Number spotlight azimuth beams</td>
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</tr>
<tr>
<td>Incidence angle range for spotlight modes</td>
<td>20°-55° full performance (15°-60° accessible)</td>
</tr>
<tr>
<td>Pulse Repetition Frequency (PRF)</td>
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<tr>
<td>Range Bandwidth</td>
<td>max. 150 MHz (300 MHz experimental)</td>
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<tr>
<td>Nominal orbit height at the equator</td>
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<tr>
<td>Orbit Parameters</td>
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<tr>
<td>Orbits/day</td>
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<tr>
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<tr>
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</tr>
<tr>
<td>Ascending node equatorial crossing time</td>
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</tr>
<tr>
<td>Attitude steering</td>
<td>&quot;Total Zero Doppler Steering&quot;</td>
</tr>
</tbody>
</table>
Data acquisition at the Buchanan County field site is conducted in single polarization Stripmap mode, which produces a single image layer using a full performance incidence angle range of 20-45 degrees. The scene extents for InSAR acquisition at the Buchanan County field site are shown in Figure 3-5 and are designed to cover additional regions of interest outside the study area, including abandoned and active mine workings and several large faults. The single polarization mode provides better azimuth resolution and larger scene extents (30 km by 50 km). Ground range resolution is on the meter scale, but with processing, elevation changes can be resolved to millimeter scale.

Figure 3-5. Scene extents for radar acquisition (InSAR) with DLR’s TerraSAR-X satellite. Extents are 30 km by 50 km and cover abandoned and active mine workings and geologic features of interest.
Acquisition of pre-injection, baseline data for the site has begun and will soon be conducted on a regular, 11-day schedule (every orbit), which will continue during injection and after shut-in as part of long-term monitoring. Existing reflectors in the study area are limited and include primarily roads and well pad features such as water tanks and other fixed infrastructure. These reflectors may be sufficient to evaluate surface deformation, i.e. by transects of roadways across the study area. However, corner reflectors may be installed in some locations to improve the density of meaningful data.

In addition to CO₂ injection, which may produce measurable uplift, several potential mechanisms for ground motion are present at the study area and over the larger scene extents. Active gas production at wells offset to the injectors, as well as throughout the surrounding Oakwood field, may produce subsidence, which could interfere directly with the accurate measurement of CO₂-induced uplift. Abandoned and active mine workings are present in multiple locations and are likely to contribute to localized surface subsidence. Additionally, several large faults with surface expression lie within the scene extents, but displacement along them is not expected.

3.4.3 Intermittent Small Baseline Subset (ISBAS) processing and data analysis

Radar acquisitions will be used for differential data analysis, which is a standard tool to evaluate time-lapse changes such as surface deformation. The small baseline subset (SBAS) method uses changes between individual acquisitions to generate interferograms which are combined to create a displacement time series (Berardino et al. 2002; Casu et al. 2006). An assessment of the SBAS method, compared to ground-based data, demonstrated accuracy for a single displacement measurement to less than 1 cm with a standard deviation of 5mm and
estimated the mean deformation velocity for a set of 40-60 acquisitions to a standard deviation of 1mm/yr (Casu 2006).

Assessment of the SBAS method also determined that accuracy varied across the study area as a function of reference location density. This observation relates to a limitation of the algorithm in using only reflectors which are coherent for all acquisitions, which lends its use to certain environments, including urban and rocky terrains, over others (Bateson et al. 2014; Sowter et al. 2013). The SBAS method requires consistent reflectors because it involves combining the interferograms of all acquisitions before phase-unwrapping the data based on a coherence criterion (Berardino et al. 2002). However, a recent modification of this method performs phase unwrapping on individual interferograms before combining them, which creates an opportunity to identify all pixels which meet a coherency criterion for that interferogram, but which may be intermittently coherent across all acquisitions, and use them toward the calculation of the displacement time series (Sowter et al. 2013). This method, the intermittent small baseline subset (ISBAS) method, has been used successfully to measure surface deformation over coal fields in the UK where the rural terrain and lack of coherent reflectors would have prevented meaningful results by other methods (Bateson et al. 2014; Sowter et al. 2013).

The advantages of the ISBAS method are well-suited to the rural, mountainous terrain of the CO₂ injection test site in Buchanan County. Steep topography and dense vegetation may cause natural reflectors which are fixed over short temporal scales to vary over the multi-year timeline of the project. Due to the higher density of points, the ISBAS method improves the definition of edges for areas of displacement, which would help determine the boundary of potential uplift due to CO₂ injection. Resolving this boundary would be important in order to compare the deformation response to other monitoring observations. In particular, relating any surface deformation to the
microseismic and pressure responses, which will also cover the areal extent of the test site, can provide insights into the extended geomechanics of the reservoir system.

### 3.5 DISCUSSION

Geospatial monitoring with GPS and InSAR at a CO$_2$ injection and enhanced gas recovery test site in southwest Virginia will provide an important feasibility test for using these technologies in mountainous terrain. Although tiltmeter and differential GPS surveys conducted at a CO$_2$ injection test in a coal reservoir in Pump Canyon, New Mexico, did not detect changes in surface deformation, several characteristics of the test in Buchanan County, Virginia, are favorable for measuring a meaningful response. Experimental data and computational modeling suggest that the microporous coal reservoir will undergo significant swelling in the presence of CO$_2$. The shallow depths of several reservoir seams could contribute to measurable uplift at the surface. High resolution processing of radar image data will be calibrated with GPS data acquired at several survey monuments installed across and outside the study area. An integrative approach to analyzing these data sets, which includes the use of ISBAS to increase measurement density in variable terrain, may provide the best opportunity to measure potential uplift associated with the CO$_2$ injection. This response could be tied with other monitoring results, including microseismic and pressure data, to improve understanding of the geomechanical responses of coal to CO$_2$ injection and to provide input for reservoir models. It is worth noting that, while the use of geospatial monitoring in this region has been motivated by the CO$_2$ injection test, the scene extents for InSAR acquisitions cover several potential sites of surface deformation, including a large portion of the Oakwood CBM field and active and abandoned mine workings. Measurable surface deformation at any of these locations within the challenging regional terrain will provide a useful
demonstration of the ability of the ISBAS method to resolve ground response in variable environments. The results of the geospatial monitoring program for the field test in southwest Virginia will help guide future efforts to monitor CO$_2$ injection and energy production in mountainous terrain.

ACKNOWLEDGMENTS

Financial assistance for this work was provided by the U.S. Department of Energy through the National Energy Technology Laboratory's Program under contract no. DE-FE0006827. Dr. Matthew Hall and Dr. Christopher A. Rochelle publish with the permission of the Executive Director of the British Geological Survey (NERC).

REFERENCES


ABSTRACT

Three legacy coalbed methane (CBM) production wells have been converted to injection wells for a one-year carbon dioxide (CO2) injection test to evaluate the potential for CO2 storage in the coal reservoir and the potential for enhanced gas production at offset wells. The injection reservoir is composed of 15-20 individual coal seams with an average thickness of 30 cm (1.0 ft), spanning a depth range of approximately 240 m (800 ft) to 670 m (2200 ft).

The monitoring program for this test includes gas and water sampling of the three injection wells, three dedicated monitoring wells, and approximately 20 offset production wells. Key technologies used for monitoring the study area include time-lapse GPS and InSAR acquisitions for surface deformation measurement, a 28-station buried passive microseismic monitoring array, real-time downhole pressure and temperature sensing, and perfluorocarbon tracer fluids which will be injected with the CO2 stream. The schedule for the monitoring program includes pre-injection
(baseline), during-injection, and post-injection data collection. This schedule will allow data to be analyzed for time-lapse changes and trends, which are important for understanding the migration of gas and fluid phases in the reservoir, including CO₂, methane, other hydrocarbons, and water, and for observing the changing distributions of reservoir pressures and stresses.

The results of the monitoring efforts for this study have implications for monitoring mining operations. The combined use of GPS and InSAR geospatial data to evaluate elevation changes across and beyond the study area may prove to be an accurate option for measuring surface deformation, including mining-induced subsidence, in unstable terrain. Long-term microseismic monitoring using high-sensitivity instruments has several applications in mining operations, including rock stability monitoring, production monitoring, and miner location detection during emergencies. Tracer studies and short-term microseismic monitoring used to assess methane extraction can also be used to develop and optimize degasification systems for underground coal mines.

4.1 INTRODUCTION

Carbon capture and storage (CCS) technology has the potential to safely and effectively store carbon dioxide (CO₂) underground, reducing the amount of CO₂ released into the atmosphere and mitigating anthropogenic climate change. Additionally, CCS operations may be adapted for oil and gas field settings to enhance recovery from depleted reservoirs, in a process known as Carbon, Capture, Utilization, and Storage (CCUS), improving the economic viability of the technology. Large-scale demonstrations of CCS and CCUS operations include the Sleipner CO₂ Storage Project in the North Sea (offshore Norway), the In Salah CO₂ Storage Project in Algeria, and the Weyburn-Midale CO₂ Monitoring and Storage Project in Saskatchewan, Canada.
The potential for enhanced recovery from CCUS operations is especially high for unconventional plays, including organic shale and coalbed methane reservoirs. These rocks display a preferential adsorption phenomenon, which causes them to release stored methane in the presence of CO₂ in order to adsorb the CO₂ (Gale and Freund, 2001; Weniger et al., 2010). The released methane can be produced from offset wells, and CO₂ storage is improved by the combination of adsorption and physical mechanisms. Because of their unique storage properties and their potential for enhanced recovery, unconventional reservoirs are attractive settings for CCUS operations and have become a recent focus of CCUS research.

Monitoring of CCS and CCUS operations includes the use of atmospheric, near-surface, and subsurface techniques to evaluate CO₂ injection and storage processes and to assess potential leakage or environmental impacts (DOE and NETL, 2012). Monitoring strategies focus on time-lapse deployment of technologies and sampling surveys so that changes caused by CO₂ injection can be identified and quantified through comparison of pre- and post-injection data. Common methods include time-lapse seismic imaging (vertical seismic profiles, crosswell surveys, or 3-D seismic surveys) and geospatial monitoring for surface deformation (GPS, tiltmeters, or InSAR) (Coueslan et al., 2014; Daley et al., 2007; Oudinot et al., 2011; Verdon et al., 2013). Dedicated monitoring wells may be used for sampling or formation logging. In CCUS settings, offset production wells provide an additional monitoring opportunity for pressure data and for gas and water composition. Additionally, the drilling and production records for these wells provide information about historical reservoir behaviour and are useful for reservoir characterization and modelling.

Recent advancements toward real-time and continuous monitoring of CCS and CCUS operations offer advantages for early detection of leakage or other hazards, enabling earlier
intervention or remediation and reducing project risk. Common technologies deployed using real-time or continuous acquisition include passive microseismic monitoring and ambient atmospheric or environmental monitoring methods (Barr et al., 2011; Geldern et al., 2014; Hovorka et al., 2011; Verdon et al., 2013). These data can be compared to injection parameters, including CO$_2$ flow rates, pressures, and temperatures, for detailed analysis of the injected CO$_2$ plume evolution and reservoir response over time. However, real-time and continuous monitoring also present challenges for managing and processing the large data volumes acquired.

A CCUS field demonstration in Buchanan County, Virginia, will use three wells to inject up to 20,000 tonnes of CO$_2$ into a depleted coalbed methane reservoir over a period of one year. The project aims to assess the injectivity and storage potential of the coal reservoir as well as the potential for enhanced coalbed methane recovery at offset wells. The monitoring program for the test is designed to combine technologies which collect data at different spatial scales and at different temporal resolution. A customized data management system will collect continuous pressure, flowrate and temperature data in the three injection wells and pressure and temperature data in the three monitoring wells. The data will be available to the project team in real time to monitor and manage injection operations by adjusting flow valves depending on flowrate, pressure and temperature constraints set according to permit limits and monitoring well response. This system will ultimately improve the understanding of CO$_2$ injection processes and reservoir responses for coalbed methane settings.

4.2 CCUS TEST IN THE OAKWOOD CBM FIELD OF BUCHANAN COUNTY, VIRGINIA, USA
The CCUS field test site in Buchanan County, Virginia, lies within the Oakwood coalbed methane (CBM) field. The Oakwood field is one of several CBM fields in the Central Appalachian Basin, where coal and natural gas resources are abundant. The test site is approximately 2.4 km (1.5 mi) from inactive underground coal mine workings, and several active mining operations are located in the county. Coalbed methane operations began in the 1990s, and wells now populate the area at a density of approximately one well per 16 hectares (40 acres). An overview of the test site location within the Oakwood CBM field is shown in Figure 4-1.

Figure 4-1. Overview map of the CCUS field test site in Buchanan County, Virginia. The three injection wells are indicated with yellow circles. Contour lines indicate the geologic structure of the Pocahontas No. 9 coal seam and general structure of the reservoir. The gray outline in the northeast shows the footprint of an inactive underground coal mine.
The CBM reservoir in the Oakwood field is composed of coal seams from the Pocahontas and Lee formations, which are considered unmineable due to their limited thickness and corresponding depth. In the study area for the field test, most wells have 15-20 individual seams completed for production. The average thickness of the coal seams in the study area is 30 cm (1.0 ft), and the seams are distributed in depth from approximately 240 m (800 ft) to 670 m (2200 ft). Interburden consists of interbedded sandstone and shale units. The low-permeability Hensley Shale and Lee Sandstone serve as confining units for the reservoir. A generalized stratigraphic column for Oakwood field is shown in Figure 4-2.

Figure 4-2. Generalized stratigraphic column for the Oakwood coalbed methane field.
4.2.1 CO₂ injection operations overview

Three CBM production wells at the field test site in Buchanan County, Virginia, have been converted for use as injection wells. Two of the wells, DD-7 and DD-8, were drilled as part of the initial drilling program in the Oakwood field in 2000 and 2001, respectively, and are both currently approximately 50 percent depleted. The third well, DD-7A, was drilled in 2007 as part of an infill drilling program and is approximately 20 percent depleted but also has the lowest expected recovery.

Conversion of the injection wells involved setting packers on tubing above the shallowest completed reservoir seams. A schematic of the injection wellhead design is shown in Figure 4-3. The 2.375-inch (6-cm) tubing will be used to inject CO₂ through the existing perforations in the well casing. A tracer injection port will be used to add a unique perfluorocarbon tracer to the CO₂ injection stream of each well, and pressure and temperature sensors will collect real-time, continuous monitoring data on injection operations. Additional site preparations included the construction of the injection skid, which will be deployed at DD-7 and is also equipped with real-time monitoring for flow control, and the construction of a CO₂ injection pipeline from DD-7 to DD-7A and DD-8.
Figure 4-3. Generalized schematic for injection wellheads (A), photograph of DD-8 wellhead after conversion for injection operations (B), schematic of tracer injection assembly (C), and schematic of pressure, temperature, and PSV assembly (D).

Underground Injection Control (UIC) Class II permits issued by the U.S. Environmental Protection Agency for the test include restrictions on maximum CO₂ injection pressures and rates.
The maximum injection pressure is unique to each well and is intentionally below the recorded hydraulic fracture gradient for the well. In compliance with UIC permits, the maximum allowable injection pressures are 5860 KPa (850 psig), 6480 KPa (940 psig), and 7930 KPa (1150 psig) for wells DD-7, DD-7A, and DD-8, respectively. The maximum injection rate for a single well is 45 tonnes/day (50 tons/day). The strategy for the start of operations involves injecting into a single well at the maximum rate for several days in order to observe and monitor the single-well response, followed by a transition to simultaneous injection in all wells at a rate of 18 tonnes/day (20 tons/day) per well. The injection scheme may be adjusted based on early observations of injectivity and reservoir response.

4.2.2 Monitoring program

The monitoring program for the CCUS field test in Buchanan County, Virginia, includes a combination of atmospheric, near-surface, and subsurface technologies. An overview of the monitoring program for the focused study area is shown in Figure 4-4. The white 0.25-mile (0.4-km) boundary represents the estimated extents of the injected CO₂ plume as predicted by initial computational injection simulations. The blue 0.5-mile (0.8-km) boundary represents the focused monitoring area and extends significantly beyond the modelled plume extents in order to define the edge of the advancing plume.
Figure 4-4. Overview of monitoring program for the focused study area of the CCUS field test in Buchanan County, Virginia. The white 0.25-mile (0.4-km) boundary indicates the monitoring focus area based on modeled plume extents for CO₂ injection. The blue 0.5-mile (0.8-km) boundary indicates the focused study area. Blue lines depict the estimated orientation and length of hydraulic fractures for the three injection wells, DD-7, DD-7A, and DD-8.

The stacked reservoir geometry and mountainous terrain in the study area presented unique challenges and considerations for the design of the monitoring program. Some common monitoring methods, such as time-lapse seismic imaging with vertical profiles or 3D surveys, could not be deployed on a useful scale at a resolution high enough to reliably image the thin reservoir seams and were abandoned in favour of technologies better suited to the reservoir and site characteristics. The selected technologies are deployed at different spatial scales and include methods to acquire data over large areal extents and at discrete locations such as production wells or surface stations. Additionally, the monitoring program uses time-lapse deployment of technologies in order to assess changes in the injected CO₂ plume and reservoir response over time and includes the use of time-discrete measurements as well as continuous monitoring of injection...
operations. Acquisition of data at different spatial and temporal scales will allow interpolation and cross-validation of measured responses.

Atmospheric monitoring technologies for the CCUS field test include ambient air sampling and soil CO₂ flux measurements, which will both be compared to pre-injection, baseline surveys to detect any changes in CO₂ levels or potential shallow leakage. Near-surface monitoring includes sampling of surface waters and groundwater sampling at residential wells. Additionally, geospatial monitoring for surface uplift due to adsorption-induced coal swelling will be conducted using Interferometric Synthetic Aperture Radar (InSAR) and a GPS array of 20 ground-based stations (shown in Figure 4-4). Two of the GPS stations were installed far outside the boundary of the focused monitoring area as control points. Pre-injection, baseline GPS surveys have indicated an expected correlation between accuracy and the occupation time of the receiver. Variation in measurement accuracy and required occupation time across the study area is likely due to tree cover and terrain, which limit line-of-sight to satellites at some locations. The mountainous terrain will also complicate InSAR acquisition and processing. However, a recently developed method for processing InSAR data, the Intermittent Baseline Small Subset (ISBAS) method, is well-suited to the imaging challenges of unstable and will be used to process data from the field test.

Subsurface monitoring includes the use of three dedicated monitoring and characterization wells, 16 offset production wells within the focused monitoring study area, and a shallow buried array of microseismic monitoring stations. The locations of all wells used for monitoring are shown in Figure 4-4. The location of monitoring/characterization well, C-1, used for continuous coring of the reservoir and confining zones, was chosen based on its relative isolation from other production wells. The location for monitoring well, M-1, was selected to study the inter-well region and possible communication between injection wells, DD-7A and DD-8, and to assess the
reservoir response in the hydraulic fracture direction where permeability is highest. Conversely, the location for monitoring well, M-2, was selected to evaluate the reservoir response in the slow permeability direction for comparison. All three wells were used for formation logging, and additional logs were run on C-1 for characterization, including resistivity, neutron porosity, sonic, formation imaging (FMI), and acoustic borehole imaging logs. The design for the monitoring wells includes surface and downhole temperature and pressure sensors installed on the tubing and annulus for real-time continuous monitoring of the reservoir and surface responses to CO₂ injection. A schematic of the wellhead design for M-1 is shown in Figure 4-5. Monitoring wells and offset production wells within the monitoring study area have been sampled for pre-injection gas and formation water composition and will be used throughout the field test for continued composition sampling, including the detection of unique gas and liquid tracers deployed in the three injection wells.
Figure 4-5. Wellhead schematic for the M-1 monitoring well (left) and connected pressure and temperature gauge components for tubing and annulus measurements (right).

The locations of the 28 passive microseismic stations are shown in Figure 4-4. Three-component geophones were installed in boreholes at an approximate depth of 20 m (75 ft) to reduce noise impacts of the shallow weathering layer. Passive microseismic data are recorded over defined time intervals rather than continuously and processed to identify and locate microseismic events and to map the reservoir fracture network using Tomographic Fracture Imaging™ (TFI), a semblance-based processing algorithm developed by Global Geophysical Services, capable of resolving signals from low-acoustic energy environments. It is necessary to have several stations located outside of the focused monitoring area in order to orient signals from within the focused monitoring area boundary. Microseismic results can be correlated with pressure data and surface deformation to understand the geomechanical effects of CO₂ injection and adsorption-induced
swelling. A pre-injection microseismic survey was conducted to characterize the existing fracture network of the reservoir at the test site.

In addition to the described monitoring program, the three injection wells, DD-7, DD-7A, and DD-8, are instrumented for continuous, real-time monitoring of the injection operations. This includes monitoring the injection pressure, flowrate and temperature at the wellhead, as well as monitoring the wellhead casing pressure which could indicate a leakage from the tubing into the annulus. The injection data will be useful to correlate to other monitoring data and reservoir responses and will also help to prevent and mitigate operational hazards through early identification of potential leaks.

4.2.3 Data acquisition

The monitoring schedule for the CCUS field test in Buchanan County, Virginia, includes pre-injection (baseline), during-injection, and post-injection data acquisition in order to assess the evolution of the injected CO₂ plume and study the impacts of CO₂ injection over time. Specific acquisition and sampling schedules vary based on the monitoring method and project phase. Pre-injection data acquisition has been completed for all atmospheric, near-surface, and subsurface monitoring methods. These data have been used to develop important compositional and isotopic baselines for the study site, including the composition of gas and formation waters from production wells and the composition of surface and ground waters. A pre-injection microseismic survey was conducted to characterize the ambient, baseline acoustic energy at the site and to develop an initial map of the reservoir fracture network. Pre-injection InSAR data acquisitions and ground-based GPS surveys will be incorporated into a baseline elevation model for the study site.
The start of CO₂ injection will be monitored intensively to capture the early migration pattern of CO₂ in the reservoir and the early reservoir response to the injection. Continuous downhole pressure and temperature sensing in the monitoring wells will provide real-time feedback on injection operations and geomechanical impacts on the reservoir. A portable gas chromatograph will allow immediate, onsite compositional analysis of gas samples from offset and monitoring wells in the field. These data, which will be sampled discretely but analysed nearly real-time, may provide indications of preferential adsorption and gas exchange in the reservoir and may identify breakthrough of CO₂ or tracers injected at the start of the test. The ability to compare and correlate the gas composition data to real-time reservoir pressure data in the field will provide additional information on the reservoir response to CO₂ injection and the effectiveness of the injection parameters, which can be used to adjust and optimize injection operations. A second microseismic survey will capture the start of CO₂ injection, including the acoustic response to the initial, single-well injection operations and the transition to the three-well injection operations. Repeat ground-based GPS surveys will be conducted for elevation and surface deformation monitoring during the start of injection, but InSAR acquisitions are limited to the 11-day orbit repeat cycle of the satellite.

As injection operations and measured reservoir conditions approach steady-state, all monitoring methods will remain in use, but data acquisition schedules will relax, with the exception of continuous, real-time monitoring in the injection and monitoring wells. Sampling plans for this phase of the injection test are tentative and subject to change based on monitoring observations, which may suggest the continued use of certain monitoring methods over others or supplementary, on-demand sampling. During normalized operations, a second round of tracers, unique to each injection well, will be deployed and a third passive microseismic survey will be recorded. Ongoing monitoring will continue for one year following the end of injection operations.
4.2.4 Continuous, real-time data management and flow control

Continuous, real-time data will be collected from the monitoring wells, injection wells, and the injection skid using a customized data acquisition and control system developed in partnership with Eagle Research Corporation. The system includes features to send alarms or cease operations if predetermined threshold values are exceeded. These features ensure safe operations and reduce project risk. The monitoring and characterization wells, M-1, M-2, and C-1, are equipped with temperature and pressure sensors installed on the tubing annulus at the wellhead and downhole. The injection wells, DD-7, DD-7A, and DD-8, have temperature and pressure sensors installed at the wellhead to monitor CO₂ injection parameters. The temperature sensors are programmed to send an alarm to operators if the temperature moves outside a defined range of -1- 49°C (30-120°F). Pressure sensors are programmed to send alarms if the pressure reaches 94 percent of the maximum allowable limit for the well and to shut down injection operations if the limit is reached. Additional pressure sensors on the wellhead casing are installed to monitor for leakage of injected CO₂ into the annulus and are programmed to send alarms to operators if pressure reaches 34 KPa (5 psig) and to shut down CO₂ injection at 69 KPa (10 psig). The injection skid will control and monitor flow rate into each injection well with alarms in place for flow rates exceeding low and high thresholds with the ability to close the flow valve in order to balance flow between the three injection wells. Pressure control valves on the skid communicate with pressure sensors on the injection wells to monitor operations and send alarms or cease injection in the case of reaching maximum pressure limits. The skid also logs data on the CO₂ pump rate, CO₂ injection pressure, and heater output.
All of the data recorded at the monitoring wells, injection wells, and injection skid are collected every sixty seconds. The essentially continuous acquisition reduces the uncertainty associated with analyzing data that are sampled less frequently or are time-discrete. The data are automatically updated to an FTP site, which serves as a repository for monitoring data and is accessible to the project team, including researchers and operations personnel. Real-time access to these data provides an opportunity to evaluate and adjust operations in the field and can provide early indications of leakage or operational hazards, enabling early intervention and mitigation. However, the majority of data collected over the project timeline will not be of interest or concern, presenting challenges for managing and processing the large data volumes collected under the acquisition design. The threshold-based alarm and shut-down features make timely and meaningful use of the data, but other significant data trends and patterns are not identified. The customized acquisition and control system described here could be incorporated into an intelligent monitoring system (IMS) with more advanced pattern recognition capabilities and visualization modules to facilitate the processing and analysis of large data volumes. An IMS platform could centralize the management of all data from a monitoring program, incorporating data sets from sophisticated and emerging technologies such as continuous microseismic monitoring and distributed sensing (temperature, pressure, strain, acoustic, chemical, etc.) with fiber-optic cables. This IMS platform could be used to further optimize injection operations for CCUS field tests and to further reduce project risk.

4.3 APPLICATIONS FOR MINING INDUSTRY

Several of the monitoring technologies used at the CCUS field test in Buchanan County, Virginia, or at other CCUS demonstrations have applications for underground mining operations
and safety. Geospatial monitoring with InSAR or with ground-based methods such as GPS or tiltmeters is already an established tool for evaluating surface deformation associated with underground mining (Bateson et al., 2014; Chang et al., 2007; Gao et al., 2011; Gourmelen et al., 2011; Plattner et al., 2010; Stow and Wright, 1997). These tools are used to assess subsidence due to longwall mining and to assess deformation, either subsidence or uplift, after mine abandonment. The ISBAS processing method that will be used for InSAR data collected during the CCUS field test is well-suited to data from unstable terrain and has potential to expand the use of InSAR for mine monitoring to the Central Appalachian Basin and other mountainous settings (Bateson et al., 2014; Sowter et al., 2013). Several active and abandoned mine workings are located near the CCUS test site in Buchanan County, Virginia, and lie within the InSAR acquisition scene extents. Deformation detected at these locations, regardless of results at the CCUS test site, would demonstrate the usefulness of this technology for challenging and unstable terrain.

Microseismic surveys, recorded continuously or on-demand over discrete time intervals, could passively monitor mining operations and provide information to improve production and safety efforts. Currently, the use of microseismic monitoring in mine environments often focuses on ground control applications and is used to investigate rock stability in areas where fracturing has already been observed (Luo et al., 2001; Milne, Weir-Jones and Taale, 2013). Highly sensitive monitoring arrays, like the one installed for the CCUS field test, can identify regions of weak seismic activity where rock stresses are likely to accumulate but have not yet led to failure. Stress mapping of these data could be used to prevent rock failures or minimize their impacts to production and safety. Microseismic monitoring can also be used to evaluate the drilling of degasification wells and the effectiveness of degasification programs. Additionally, on-demand
surveys could be deployed in emergencies to assist miner location efforts and to evaluate physical
mine conditions in order to coordinate evacuation and rescue efforts.

Tracer gas studies like the ones conducted at the CCUS field test are already used in mine
settings to evaluate ventilation networks, and regular gas composition testing for air quality is
mandated by Title 30: Mineral Resources of the U.S. Code of Federal Regulations (Hodkinson,
1957; Patterson and Luxbacher, 2012; Widodo et al., 2008). However, recent advancements in the
use of fiber-optic cables for distributed sensing provide new opportunities for monitoring
atmospheric conditions in underground mines. Fiber-optics for distributed chemical sensing can
be deployed in tube bundle systems or installed in high-priority areas for continuous monitoring
of air quality and for hazardous gas detection.

In addition to chemical sensing, fiber-optic distributed sensing technology is available or in
development for temperature, pressure, strain, and acoustic (seismic) sensing (Boersma, et al,
2011; Guemes, Fernandez-Lopes, and Soller, 2010; Mateeva et al., 2014). Fibers for each
parameter can be combined and deployed in a single cable, simplifying the installation and
monitoring efforts (Freifeld et al., 2014). Multi-sensing with fiber-optics has applications for in-
well monitoring during CCUS field tests and for passive monitoring of mine environments.
Applications in underground mining include those listed for microseismic monitoring of
operations and production, but the multi-sensing capabilities mean additional responses can be
correlated to validate observations and interpretation. The ability to evaluate the effectiveness of
a rock blast, for example, would be improved by considering chemical, temperature, pressure, and
strain responses in addition to the acoustic response. Additionally, multi-sensing capabilities
would be beneficial for mine safety applications, including ground control monitoring with
combined acoustic and strain sensing and for continuous, real-time monitoring during mining.
emergencies. The fiber-optic deployment has advantages for emergency applications because a damaged cable is still functional until the point of damage. One option for installing distributed multi-sensing in a mine for emergency applications is to incorporate the fiber-optic cables into existing safety infrastructure, such as lifelines which are required in escapeways. Adding distributed multi-sensing to lifelines, which are designed to guide miners out of a mine during an emergency, would provide continuous, real-time information on the location of miners and their environmental conditions.

The benefits of centralizing the management of monitoring data into an intelligent monitoring system (IMS) also transfer from CCUS operations to mining operations. Having all current data available to personnel for processing and analysis would allow earlier identification of important trends related to production or operations, as well as early identification of potential safety hazards. Customized data analysis modules could include mine operations modelling and forecasting, which managers could use to adjust and optimize mine schedules, maintenance, and production.

Early identification of potential safety hazards could be used to prevent incidents or minimize their impacts through informed, early intervention. In the case of a mine emergency, an IMS could help members of rescue teams to optimize the use of real-time monitoring data to assist evacuation and rescue efforts. The use of an integrated IMS for applications in the mining industry has potential to add value, protect assets, and reduce risk for mines.

4.4 CONCLUSIONS

A 20,000-tonne CCUS field test in Buchanan County, Virginia, will test the injectivity and storage potential of a coalbed methane reservoir and will assess the potential for enhanced gas recovery. Technologies selected for the monitoring program are well-suited to the unique
characteristics of the stacked coal reservoir and the challenging terrain of the study site. A monitoring schedule, including pre-injection (baseline), during-injection, and post-injection data collection, has been developed in order to identify and quantify time-lapse changes in the injected CO₂ plume and in the geomechanical response of the reservoir. The overlapping spatial and temporal extents of the monitoring technologies will be used to interpolate and cross-validate results. A customized data acquisition system will be used to collect continuous, real-time pressure and temperature data at the injection and monitoring wells. The data will be automatically uploaded to an FTP site, providing real-time access for the project team and enabling timely adjustments to injection operations based on the observed reservoir response. This acquisition system could be incorporated into an intelligent monitoring system (IMS) to facilitate the management and analysis of large data volumes.

Several of the technologies selected for the CCUS test monitoring program also have applications for mine operations and safety. Geospatial monitoring with InSAR or ground-based arrays can be used to detect surface deformation associated with underground mining activities and abandonment. Passive microseismic monitoring with high-sensitivity arrays can be used to predict and minimize the impact of rock failures. On-demand surveys can be conducted during emergencies to locate miners and evaluate physical mine conditions in order to coordinate rescue efforts. Additionally, emerging technologies used for CCUS applications are readily transferable to mining applications. Distributed multi-sensing with fiber-optic cables can combine temperature, pressure, strain, acoustic, and chemical sensing fibers into a single cable that is robust and easy to deploy. A multi-sensing cable could be incorporated into lifelines or other existing safety infrastructure in an underground mine. Similarly, customized data acquisition systems and
centralized data management using IMS platforms offer the same time-saving advantages to both CCUS and mining operations to add value, protect assets, and reduce risk.

ACKNOWLEDGEMENTS

Financial assistance for this work was provided by the U.S. Department of Energy through the National Energy Technology Laboratory's Program under contract no. DE-FE0006827.

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5 MONITORING RESULTS FROM PHASE I OF A CO$_2$-ECBM FIELD TEST IN STACKED COALS OF CENTRAL APPALACHIA

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This work is under review by coauthors for submission to a refereed journal.

ABSTRACT

The monitoring program for an ongoing CO$_2$-ECBM test in Buchanan County, Virginia, includes technologies deployed at multiple, overlapping spatial and temporal scales. Specific technologies include continuous CO$_2$ injection operations monitoring, reservoir pressure and temperature monitoring, analysis of produced gas and water composition, tracer studies, borehole liquid level measurement, microseismic monitoring, surface deformation monitoring, formation logging, and well production rate tests. Monitoring results from Phase I of the test demonstrate success for characterizing reservoir behavior in response to CO$_2$ injection. Key findings to date include enhanced permeability related to local geologic structure, permeability and fracture variation with depth, and dynamic injectivity for the coal reservoir. Additionally, a recommended injection strategy for CO$_2$-ECBM operations has been developed from the monitoring results of Phase I.
5.1 INTRODUCTION

Carbon capture, utilization, and storage (CCUS) technologies involve capturing carbon dioxide (CO₂) produced at power plants or industrial facilities and injecting it into depleted oil or gas reservoirs to enhance recovery from production wells. This process, which results in secure geologic storage of CO₂, is a potentially cost-effective method to mitigate anthropogenic climate change. Life cycle assessment models indicate that using CO₂ captured from fossil fuel-burning power plants for enhanced oil recovery (CO₂-EOR) is effective at reducing the carbon footprint associated with conventional crude oil production (Azzolina et al., 2016; Cooney et al., 2015).

Within the U.S., Regional Carbon Sequestration Partnerships (RCSPs) developed by the Department of Energy (DOE) have conducted several large-scale tests to demonstrate and study CCUS field operations in a variety of geologic settings. Active field projects are located in the Farnsworth oilfield of the Anadarko Basin, Texas (Southwest Regional Partnership on Carbon Sequestration), the Bell Creek oilfield of the Powder River Basin, Montana (Plains CO₂ Reduction Partnership), and Niagaran reef trends of the Michigan Basin, Michigan (Midwest Regional Carbon Sequestration Partnership) (Ampomah et al., 2016; Hamling et al., 2013; Gupta et al., 2014).

Projects managed under the DOE Carbon Storage program have intensive monitoring, verification, and accounting (MVA) programs which comprise monitoring technologies deployed in the field to collect data to support research objectives, regulatory compliance requirements, and economic assessments (DOE and NETL, 2012). The selection of technologies for an MVA program may be influenced by physical characteristics of the field site or geology, and deployment may be adapted to suit changing physical parameters or temporal resolution needs over the lifespan of a project. Monitoring data provide valuable information about injection and storage processes.
that can be used to characterize CO₂ plume migration, reservoir behavior, and environmental impacts. Analysis of monitoring data can help to optimize active and future operations. This paper presents the monitoring results to date from an ongoing carbon storage and enhanced coalbed methane (CO₂-ECBM) test in a stacked coal reservoir.

5.2 BACKGROUND

5.2.1 CO₂ for Enhanced Coalbed Methane (CO₂-ECBM)

Unmineable coal seams are often drilled for coalbed methane production. The microporous texture of coal provides a large storage capacity for gases, which are stored by adsorption on the surface of the coal (Walker et al., 1988; Golding et al., 2011). Coal displays preferential and enhanced adsorption of CO₂ relative to methane, meaning a coal reservoir will release stored methane in order to store CO₂ and also has a greater capacity for CO₂ over methane (Connell et al., 2014; Bhowmik and Dutta, 2013; Weniger et al., 2010). These additional mechanisms for CO₂ storage and enhanced recovery make depleted coalbed methane reservoirs attractive targets for CO₂ injection and storage operations (CO₂-ECBM).

The high CO₂ storage capacity of coal is associated with swelling of the coal matrix (Reucroft and Patel, 1986; Hol and Spiers, 2012). From a monitoring perspective, this geomechanical response is beneficial because it provides an opportunity to observe the deformation signal through changes in reservoir pressures, surface deformation, and microseismicity. However, swelling can reduce permeability of the reservoir and CO₂ (Durucan et al., 2009; Van Bergen et al., 2009; Oudinot et al., 2011). For this reason, it is important to have an adaptable CO₂ injection strategy that includes the ability to monitor and adjust injection parameters based on monitoring responses.
5.2.2 Oakwood coalbed methane field

The Oakwood coalbed methane (CBM) field is located at the northeast margin of the Cumberland Overthrust Block, a large-scale geological feature in southwest Virginia that extends southwest into Kentucky and Tennessee (Figure 5-1). The Cumberland Overthrust Block contains significant fossil fuel resources, including the Southwest Virginia coalfield, which has an abundance of both mining and CBM operations (Nolde, 1995). Development of the overthrust block involved differential movement of up to seven miles along the Pine Mountain thrust fault, an extensive bedding plane-derived fault (Harris and Zietz, 1962). During transportation of the overlying block, rotation, warping, frictional dragging, and crosscut structures contributed to complex internal deformation and resulted in localized folding, truncated beds, and duplicated beds (Harris and Zietz, 1962). Localized structural complexity has implications for the distribution and quality of coal bed methane resources.

Figure 5-1. Location of the Oakwood coalbed methane field within the Southwest Virginia Coalfield. The red star indicates the location of the CO2-ECBM field site in Buchanan County (modified after EIA, 2007; Nolde, 1995).
The Oakwood CBM field is one of the largest in the Southwest Virginia coalfield, covering portions of Buchanan, Tazewell, and Russell Counties. The southern margin of the Oakwood field is bounded by the Boissevain and Russell Fork faults. Here, the local geologic structure is characterized by gentle folds and small faults filled with calcite. Stratigraphic targets for coalbed methane drilling include 15-20 coal seams from the Early-Pennsylvanian Pocahontas and Lee formations (Figure 5-2). Individual seams vary in thickness but are typically less than two feet thick and are typically distributed over approximately 1000 feet in depth. A series of three tight shale units, including the 50-foot-thick Hensley shale, overlie the coal reservoir and are laterally continuous across the field, providing a stacked seal to vertical migration.

In the early 1990s, the Virginia Oil and Gas Board approved development of the Oakwood CBM field on 80-acre drilling units (Nolde, 1995). In the mid-2000s, operators began infill drilling...
programs, reducing units to approximately 40 acres per well. The primary operator in the south Oakwood field is CNX Gas. A typical well is cased and perforated at key intervals in the coal reservoir and then hydraulically fractured in vertical stages using nitrogen foam and sand proppant.

5.2.3 2009 CO₂-ECBM test in Russell County, Virginia

A small-scale CO₂-ECBM validation test was conducted in the south Oakwood field at a site in Russell County in 2009 (Figure 5-3). A volume of 1000 tons of CO₂ was injected into a depleted CBM production well over a one-month period. The well was then shut in for an additional one-month soaking phase, allowing the coal reservoir to adsorb CO₂ and desorb methane before flowback. The primary objective of this “huff-and-puff” injection technique is to enhance gas recovery from a depleted well, but a large fraction of injected CO₂ is stored in the process.
The injection test successfully enhanced recovery from the well, increasing the estimated ultimate recovery (EUR) for the well by 85 percent (Figure 5-4). To date, approximately 65 percent of the injected CO$_2$ volume remains stored in the reservoir. A comprehensive description of MVA results from the Russell County CO$_2$-ECBM test is provided in Ripepi (2009).
Figure 5-4. Estimated ultimate recovery (EUR) for test well from 2009 CO2-ECBM test in Russell County, Virginia. The EUR for the well increased by 85 percent following the test with approximately 65 percent of the injected CO2 stored in the reservoir.

5.3 CO2-ECBM TEST IN BUCHANAN COUNTY, VIRGINIA

5.3.1 Site characterization

An ongoing CO2-ECBM demonstration test in the Oakwood field will inject up to 20,000 tons of CO2 at a site in Buchanan County, approximately 7.5 miles from the location of the 2009 huff-and-puff test in Russell County (Figure 5-3). For this larger test, three CBM production wells have been converted for use as injection wells. The test represents a scaling up of CO2-ECBM operations from the Russell County test. The tests have similar goals, to assess the potential for CO2 storage and enhanced coalbed methane recovery in the unique stacked coals of Central
Appalachia, but the specific objectives and design of the tests differ. The huff-and-puff test in Russell County was conducted similarly to a well treatment, with a primary objective to enhance production from the injection well and a benefit of storing a large amount of CO₂. The demonstration in Buchanan County involves continuous, long-term CO₂ injection and is designed to store a maximum amount of CO₂ with a potential benefit of enhancing production at offset wells.

Three CBM production wells operated by CNX Gas were converted for injection operations at the Buchanan County field site. The oldest well, DD7, was drilled in 2000 and is located on the flank of the local Hurricane Creek Anticline. Because of variable topography across the study area, DD7 is the deepest of the three injection wells. Injection well DD8 was drilled shortly after DD7 in early 2001. The third injection well, DD7A, was drilled as an infill well on the DD7 unit in 2007. The coal reservoir has a net thickness of approximately 20 feet at this location, compared to a reservoir thickness of 26 feet for the test well in Russell County. Individual seams average only 1.0 feet in thickness and are distributed vertically over approximately 1000 feet. Seams occur at depths ranging from approximately 800 to 2200 feet due to the variable topography. The Basal Lee sandstone is a regional stratigraphic marker that distinguishes the shallow injection zone (Greasy Creek- Pocahontas 7 seams) from the deep injection zone (Pocahontas seams 1-6), as shown in Figure 5-2. Across the study area, the Lee sandstone has a thickness of approximately 200 feet and micro-Darcy-scale permeability, providing additional confinement for the deep reservoir.

Face cleat and butt cleat orientations for the coal reservoir are N018W and N067E, respectively. Underground mining operations have encountered hydraulic fractures associated with CBM wells in the Oakwood field at consistent orientation of approximately N057E. The estimated fracture half-length is 650 feet, and in some places fracture apertures are several inches.
The production history for DD7 shows superior production performance in comparison to DD7A and DD8 (Figure 5-5). The peak production rate of DD7 was 170 Mcfd, compared to only 56 Mcfd for DD7A and 78 Mcfd for DD8, and the average production rate has been consistently higher for DD7 over its lifespan. Despite being the oldest of the three wells, DD7 continues to produce at a significantly higher rate than DD7A or DD8. In the six months leading up to the test, DD7 produced at an average monthly rate of 1191 Mcf, compared to 798 Mcf and 768 Mcf for DD7A and DD8, respectively. The production history of DD7 suggests that it had a larger amount of original gas in place than DD7A or DD8. This could relate to conventional fluid migration on the Hurricane Creek Anticline or enhanced permeability due to local deformation.

Figure 5-5. Gas production history for injection wells DD7, DD7A, and DD8.
5.3.2 $CO_2$ injection operations

The three injection wells were issued EPA Class II Underground Injection Control (UIC) permits for the test. Wells were converted for $CO_2$ injection operations by removing pumping units, production tubing, and other downhole equipment, and installing 2.375-inch tubing and packer systems for injection. A camera was run down the injection boreholes to confirm that all perforations were clean and open to communication with the reservoir. In accordance with EPA UIC permit requirements, wells were subjected to and passed mechanical integrity testing.

The $CO_2$ injection skid was built on the DD7 pad site. The skid houses the injection controls and connects to the DD7 wellhead on site and to pipelines to DD7A and DD8. A supervisory control and data acquisition (SCADA) system developed by Eagle Research Corporation records injection parameters continuously. The SCADA system can be used remotely by project personnel to evaluate and adjust injection parameters in real time.

Liquid $CO_2$ is delivered to the pad site in trucks and transferred to on-site storage vessels. Praxair, Inc. of Danbury, Connecticut, USA, was contracted for $CO_2$ delivery, transportation, and injection. All $CO_2$ injected for the test to date was gathered from anthropogenic sources.

$CO_2$ injection operations for the test are divided into two phases. Phase I began on July 3, 2015, and was completed on April 15, 2016. A total of 10,601 tons of $CO_2$ were injected during Phase I of the test. A summary of injection parameters recorded for Phase I are shown in Figure 5-6.

The start of injection operations was staggered so that only DD7A began injecting $CO_2$ on July 3. DD7 began injecting $CO_2$ four days later on July 7, followed by DD8 on July 8. UIC permit
regulations required that injection pressures remain below the documented hydraulic fracture gradient of the reservoir. Following a seven-month soaking period, Phase II of injection is expected to begin on November 15, 2016, and continue through April 15, 2017. A post-injection monitoring period will last approximately one year until site closure on March 31, 2018.
Figure 5-6. Summary of Phase I CO₂ injection operations monitoring, including CO₂ injection rates, CO₂ injection pressures, estimated reservoir injectivity, and CO₂ injection temperatures. The end of Phase I is indicted with a gray dashed line.
5.4 MVA PROGRAM

5.4.1 Approach

The selection of technologies for the MVA program was limited by the steep and heavily forested terrain at the study area, which restricts physical access almost entirely to roads and well pads. The unique geometry of the coal reservoir, comprising several thin, dispersed seams, also presented challenges for monitoring and geophysical imaging, preventing the use of some technologies. The MVA program includes technologies deployed over different, overlapping spatial scales and data acquired at varying temporal sampling rates. Correlating datasets acquired at a borehole scale with data acquired over large areal extents allows interpolation of results across the study area. Combining overlapping datasets in this way can better define CO₂ plume migration or other reservoir-scale processes. The ability to cross-validate interpretations with overlapping datasets is especially important in the setting of an active production field because simultaneous operations can further complicate the ability to attribute signals to sources.

5.4.2 Design overview

An overview of the monitoring program is shown in Figure 5-7. Injection wells DD7, DD7A, and DD8 are indicated with blue symbols with blue lines to represent estimated hydraulic fracture lengths and orientations. The MVA focus area is indicated by a white boundary, which represents a ¼-mile radius surrounding the injection wells. The focus area was derived from a preliminary simulation of the injected CO₂ plume extents for the target injection volume. The larger MVA study area is indicated the blue ½-mile boundary. The study area was expanded beyond estimated plume extents in order to better define plume edges. Note that locations for monitoring stations are limited primarily to existing roadways and well pads due to hazardous terrain.
Three dedicated monitoring wells, M1, M2, and C1, are indicated in Figure 5-7 with red symbols. The wells were drilled prior to injection at varying distances and orientations from the injection wells. The monitoring wells are key features of the MVA program because they represent points of overlap for several types of data acquisition, including reservoir pressure and temperature monitoring, produced gas composition, and well logging. M1 was drilled between injection wells DD7A and DD8 in order to study the inter-well region during injection operations. Fracture communication between DD7A and DD8 is likely due to the orientation and proximity of the wells to each other. M1 is approximately aligned with the hydraulic fractures to observe reservoir responses in the induced high-permeability orientation. The location of M2 was selected to observe reservoir responses at an orientation offset to hydraulic fractures, where natural
permeability would govern fluid migration. C1 was drilled farthest from the injection wells and is also relatively isolated from other production wells in the study area. Because of its proximity from CBM operations and mechanical alteration from hydraulic fracturing, C1 was also designated as a reservoir characterization well and used for formation logging and continuous coring.

5.4.3 Selected Technologies and Deployment

The monitoring technologies selected for the MVA program are summarized in Table 5-1 and described in detail below. The data acquisition schedule for the MVA program is shown in Figure 5-8. The schedule reflects a focus on time-lapse acquisition to observe changes due to CO₂ injection and adaptive sampling frequency based on operational activities.
Table 5-1. Summary of monitoring technologies selected for the MVA program for the CO2-ECBM field test in Buchanan County, Virginia.

<table>
<thead>
<tr>
<th>Technique</th>
<th>Deployment/Acquisition</th>
<th>Sampling Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CO2 injection operations monitoring</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Injection rate</td>
<td>Controlled at CO2 injection skid; recorded by coriolis flowmeters</td>
<td>Continuous, real-time recording</td>
</tr>
<tr>
<td>Injection pressure</td>
<td>Recorded at injection wellheads</td>
<td>Continuous, real-time recording</td>
</tr>
<tr>
<td>Injection temperature</td>
<td>Controlled at CO2 injection skid; recorded at injection wellheads</td>
<td>Continuous, real-time recording</td>
</tr>
<tr>
<td><strong>Reservoir pressure</strong></td>
<td>Recorded at monitoring observation wells on sensors installed on tubing and annulus, downhole and on wellheads</td>
<td>Continuous, real-time recording</td>
</tr>
<tr>
<td><strong>Reservoir temperature</strong></td>
<td>Recorded at monitoring observation wells on sensors installed on tubing and annulus, downhole and on wellheads</td>
<td>Continuous, real-time recording</td>
</tr>
<tr>
<td><strong>Gas composition</strong></td>
<td>Samples collected from 19 offset production wells, all monitoring observation wells, and nearby gas compressor station</td>
<td>Daily-weekly for first two months of Phase I injection, then monthly</td>
</tr>
<tr>
<td><strong>Formation water composition</strong></td>
<td>Produced water samples collected from 19 offset wells</td>
<td>Weekly-monthly</td>
</tr>
<tr>
<td><strong>Tracers (gas and liquid)</strong></td>
<td>Gas and liquid tracers added to CO2 injection stream at wellhead; liquid tracers added to water pre-injection</td>
<td>Deployment is on-demand; gas composition monitoring includes tracer detection</td>
</tr>
<tr>
<td><strong>Borehole liquid level measurement</strong></td>
<td>Echometer wellhead attachment</td>
<td>Daily-weekly at start of injection, then monthly</td>
</tr>
<tr>
<td><strong>Microseismic monitoring array</strong></td>
<td>Surface array of 28 stations; shallow borehole installation at depth of approximately 75 feet</td>
<td>On-demand surveys, continuously recorded over 15-20 days</td>
</tr>
<tr>
<td><strong>Surface deformation</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Global Positioning System (GPS)</td>
<td>Four receiver units, rotated acquisition at 20 monuments</td>
<td>Weekly-monthly rotation</td>
</tr>
<tr>
<td>Synthetic Aperture Radar (SAR)</td>
<td>TerraSAR-X satellite</td>
<td>11-day satellite orbit</td>
</tr>
<tr>
<td><strong>Well logging and tests</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir characterization logging</td>
<td>Down-hole logging of monitoring observation wells</td>
<td>On-demand</td>
</tr>
<tr>
<td>Spinner test (production rate)</td>
<td>Down-hole flow rate, pressure, and temperature logging of injection wells, DD7 and DD8</td>
<td>On-demand</td>
</tr>
<tr>
<td>Water flood test (kill test)</td>
<td>Down-hole flooding and flow rate logging of CC7A and DD8A</td>
<td>On-demand</td>
</tr>
</tbody>
</table>
Figure 5-8. Data acquisition schedule for the MVA program. Indicated dates up to the present are actual acquisitions. Future dates are planned estimates and indicated with lighter symbols.

**CO₂ injection operations monitoring**

Monitoring of CO₂ injection operations is conducted continuously (every 60 seconds) for DD7, DD7A, and DD8. At the injection skid, each injection pipeline is equipped with a Coriolis flowmeter to measure the injection rate. Injection wellheads are equipped with sensors to record injection pressure and temperature. The CO₂ injection rate and temperature are controlled from the injection skid. All real-time injection operations data are accessible remotely using a SCADA system, which can also be used to adjust CO₂ injection rate and temperature settings. The SCADA system also ensures that injection operations are conducted in compliance with permit specifications by triggering alarms when injection parameters approach defined operational limits or by force-stopping injection if limits are reached.

**Reservoir pressure and temperature**
Monitoring observation wells M1, M2, and C1 are equipped with reservoir pressure and temperature sensors installed on the tubing and the annulus, downhole and at the wellhead. Pressure and temperature data are recorded continuously (every 60 seconds) and accessible remotely in real-time using a SCADA system.

**Gas composition**

Gas samples are collected regularly from 19 offset production wells in the study area and from the annulus and tubing of monitoring observation wells M1, M2, and C1. Gas from a nearby compressor station has also been sampled. Samples are analyzed using a gas chromatograph for percent composition of methane, CO₂, N₂, and several additional heavy hydrocarbon constituents, which are present in very small amounts. A published database of gas composition for the project will be updated over the remaining course of the project (Louk et al., 2016). Samples are also analyzed for the presence of tracers that were added to the CO₂ injection stream and water in the injection wells.

**Formation water composition**

Samples of formation water are collected regularly from 19 offset wells in the study area for lab- and field-based testing. Samples are analyzed in the lab for isotopes of 20 trace element constituents using inductively coupled plasma mass spectrometry (ICP-MS). Salinity is measured in the lab using a refractometer. Additional measured parameters include alkalinity, pH, temperature, oxidation/reduction potential, dissolved oxygen, total dissolved solids, total organic carbon, sodium adsorption ratio, and electrical conductivity.

**Tracers (gas and liquid)**
Tracers were deployed at three distinct times during Phase I operations to track the migration of reservoir fluids under different pressure conditions. The three rounds of tracers were deployed at the start of injection operations, when the injected volume reached 15 percent of the total injection target, and when the injected volume reached 40 percent of the total injection target.

Prior to the start of injection operations, the three injection wells were shut-in from production to be converted to injection wells, and formation water collected in the wellbores. Unique perfluorocarbon tracers were added to the water in each of the wells in order to track migration of the water plume in the reservoir. A volume of 150 mL of perfluoromethylcyclopentane (PMCP) was added to water in DD7, 150 mL of perfluoromethylcyclohexane (PMCH) was added to water in DD7A, and 250 mL of perfluoromethylcyclohexane (PECH) was added to water in DD8. Additionally, on July 17, 2015, during the first days of CO2 injection, a volume of 2000 mL of sulfur hexafluoride (SF6) was added to the CO2 injection stream of DD8 to track migration of the CO2 plume during early injection operations.

A second round of tracers was injected from October 14-17, 2015, when the injected volume reached approximately 15 percent of the total injection target (30 percent of the total Phase I volume). Unique refrigerant tracers were added to the CO2 stream of each injection well to track CO2 migration under steady-state and relatively low-pressure injection operations (CO2 injected in gas phase). A volume of 2500 cm3 of trifluoromethane (CHF3) was added to the injection stream of DD7, a volume of 2000 cm3 carbon tetrafluoride (CF4) was added to the injection stream of DD7A, and a volume of 4000 cm3 of octofluoropropane (C3F8) was added to the injection stream of DD8.

A third round of tracers was injected on March 29, 2016, when the injected volume reached approximately 40 percent of the total injection target (75 percent of the total Phase I volume).
Unique perfluorocarbon tracers, distinct from those previously injected, were added to the CO₂ injection stream of each injection well to track CO₂ migration during higher-pressure injection operations (CO₂ injected in gas and liquid phases). A volume of 500 mL of perfluoromethylpentane (PMP) was added to the injection stream of DD7, a volume of 500 mL of perfluoroethylpentane (PEP) was added to the injection stream of DD7A, and a volume of 500 mL of perfluorodimethylcyclohexane (PDMCH) was added to the injection stream of DD8.

Borehole liquid level measurement

The liquid level in the three injection wellbores was measured regularly during Phase I operations in order to track the evacuation of formation water from the wells into the reservoir. An Echometer wellhead attachment was used for the measurements. The unit sends an acoustic signal down the wellbore that reflects off the water and received again by the unit. The travel time is used to calculate the distance to the water surface. The Echometer unit was also used to measure wellbore liquid levels for water flood tests conducted on offset production wells CC7A and DD8A, described under “Well logging and tests.”

Microseismic monitoring array

A buried surface array of 28 three-component 10-Hz geophones was installed for passive microseismic monitoring (Figure 5-7). The technology was selected for its high sensitivity, which is well-suited to the low-pressure CO₂ injection operations. A lateral array configuration was selected to optimize lateral resolution over the study area. Geophones were installed in shallow boreholes at a depth of approximately 75 feet to avoid attenuation near the surface and improve received signal quality. The distribution of geophone stations was designed to optimize aperture for imaging the estimated maximum lateral extents and depth of the injected CO₂ plume. Passive,
continuously-recorded microseismic monitoring is conducted for surveys lasting several days. A pre-injection survey was conducted on December 20, 2014-January 1, 2015, while injection wells were still producing gas under typical operational conditions. An early injection survey was conducted on June 27-July 16, 2015 and included five pre-injection days before the start of staggered injection operations. Installation of the array and data acquisition were conducted by Global Geophysical Services of Houston, TX.

**Surface deformation**

Potential surface deformation due to CO₂ injection is monitored using interferometric synthetic aperture radar (InSAR) and global positioning system (GPS) measurements. InSAR uses time-lapse images acquired by satellite to identify changes in the land surface. The TerraSAR-X satellite, operated by the German Aerospace Center, DLR, acquires synthetic aperture radar (SAR) images over the CO₂-ECBM study area. The full extents of the acquisition scene are 30 km x 50 km. A detailed description of the satellite and its operational parameters is available in DRL’s “TerraSAR-X Ground Segment Basic Product Specification Document” (2010). The satellite orbits from a height of 514 km on a repeat cycle of 11 days. The X-band radar has a high carrier frequency of 9.65 GHz, associated with a short wavelength of 31 mm and high imaging resolution. For acquisitions over the study area, which the radar operates in single-polarization, stripmap mode, the ground range resolution is 3 m.

Ground-based surface deformation monitoring is conducted using four GPS receivers which are mounted onto survey monuments. Twenty monuments were installed across the study area (Figure 5-7). Monuments are concentrated within the MVA focus area, but several are located outside of the study area and expected region of influence for the test. Monument installation involved driving steel rods into the earth within shallow boreholes and securing the rods in position.
with poured cement and rebar. Four survey-grade CHC X90-OPUS GPS receivers are rotated around the monuments to take elevation readings. The receivers can measure elevation to an estimated accuracy ± 5mm.

**Well logging and tests**

The location of the C1 well, selected for its relative isolation from CBM operations, was used for multiple characterization tests. In July 2014, a location on the C1 well pad was continuously cored to collect samples of the reservoir coal seams and seals for characterization including gas content analysis. The core hole was filled, and the C1 well was drilled and instrumented approximately 10 feet away. In March 2015, formation logging was conducted on C1, including caliper, density, gamma ray, neutron porosity, resistivity, sonic, and temperature logs. Schlumberger Ltd conducted imaging logs using their Formation Microimager (FMI) tool, an optical televiewer, and their Ultrasonic Borehole Imager (UBI) an acoustic televiewer.

Days prior to injection, in June 2015, a water flood test (kill test) was performed on offset production well CC7A. A water flood test involves incrementally filling the wellbore with water to cover an increasing number of seams of the stacked reservoir while measuring gas flow rate. The test can determine which seams contribute most to production. Echometer readings are conducted throughout the test to measure the increasing level of water in the wellbore. In December 2015, additional water flood tests were performed on CC7A and DD8A.

In March of 2016, near the end of Phase I injection operations, spinner tests were conducted on injection wells DD7 and DD8 to determine the production rate from different depth zones of the reservoir. The spinner tests were conducted by Weatherford International as part of an injection
logging service. A single toolstring deploys the spinner instrument and runs logs for gamma ray, CCL, temperature, pressure, and radioactive density.

5.5 PHASE I MVA RESULTS

Key monitoring results from Phase I of the CO₂-ECBM field test in Buchanan County, Virginia, are described for selected technologies below.

CO₂ injection operations monitoring

Injection operations into three wells began with a staggered start on July 2, 2015 and ended on April 15, 2016. Injection rates, injection pressures, injectivity, and temperatures for the three injection wells, DD7, DD7A, and DD8, are shown in Figure 5-6. Here, data recorded continuously (every 60 seconds) have been reduced by daily averaging. Gaps in injection are due to equipment maintenance or interruptions in CO₂ supply. Very brief losses in injection indicate temporary well shut-in for well tests. The injection rate and pressure curves demonstrate the expected relationship between sustained CO₂ injection operations and increasing injection pressure. Data for injection rates and pressures are plotted beyond the end of injection operations in order to observe the pressure fall-off response observed at the injection wellheads. A reservoir injectivity parameter is calculated as the injection rate divided by the injection pressure (Pashin et al., 2015). By this measure, the slopes of the decline curves may be interpreted as indicators of relative permeability. Pressure fall-off following the end of injection operations suggests injectivity for the reservoir is restored during the soaking phase. Injection temperatures decrease steadily at the start of Phase I for most of the injection test, but level out and rise slightly over the last few months. This rise correlates with a steady increase to high injection pressures and marks a transition from gas- to liquid-phase CO₂, as shown in Figure 5-9.
Figure 5-9. Phase diagram of CO$_2$ for three injection wells over the duration of Phase I operations. Pressure and temperature data are monthly values calculated from daily values.

Reservoir pressure and temperature

Data quality and retrieval from sensors in M1, M2, and C1 were compromised by complications with the SCADA system and well instrumentation. Limited data are available from M1 and M2 and during the Phase I injection period. Increased pressures during injection were expected for M1 because it is located in the inter-well region between injection wells DD7A and DD8. Available data confirm consistent, gradual increases in in tubing and annulus pressures for M1 measured downhole and at the wellhead (Figure 5-10). Supplementary data graphs, covering
a period of late Phase I injection and the soaking phase, were available for pressures at the M1 wellhead. The M1 graphs were interpreted to compare to observed data from M1 (Figure 5-10).

Tubing and annulus pressure both increased rapidly toward the end of Phase I CO₂ injection operations. At the end of injection, annulus pressure shows a sudden drop, while tubing pressure indicates an even more impulsive drop followed immediately by a sharp pressure rebound. Following the immediate response to the end of CO₂ injection, tubing and annulus pressure both rise slightly over several weeks of soaking before gradually declining. Available data from M2
indicate no observed pressure changes during CO\textsubscript{2} injection and are inconclusive beyond the end of Phase I operations.

**Gas composition**

Gas composition analysis for samples collected at offset production and monitoring wells shows CO\textsubscript{2} breakthrough at one offset well, DD8A, as shown in Figure 5-11. Computational simulations of CO\textsubscript{2} injection predicted breakthrough at this location. Other wells, including M1, show increases in CO\textsubscript{2} composition but have not been confirmed as having experienced CO\textsubscript{2} breakthrough. Enhanced coalbed methane recovery (ECBM) was not detected for any wells in the study area.

![Figure 5-11. Gas composition (CH\textsubscript{4}, CO\textsubscript{2}, and N\textsubscript{2}) for offset production well DD8A shows breakthrough of CO\textsubscript{2} and elevated N\textsubscript{2} due to injection operations.](image-url)

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During Phase I injection operations, CO₂ composition for DD8A increased from a baseline of less than one percent to 12.9 percent. Breakthrough of CO₂ at DD8A was confirmed in fall 2015 and assumed to originate from injection well DD8 due to proximity and simulations. The increase of CO₂ at DD8A was monitored with no adjustments to production of the well or CO₂ injection operations because the CO₂ composition did not reach impact thresholds for either activity. Gas produced from the DD8A well is comingled with gas from a large number of wells across the study area at a compressor station. The CO₂ composition of the comingled gas did not increase significantly because of breakthrough at DD8A and did not affect mechanical equipment at the station, the primary concern of the operator. The peak CO₂ composition measured at DD8A, 12.9 percent, equates to approximately three percent of the daily volume of CO₂ injected at the time of measurement. By this calculation, CO₂ injected for the test was reproduced from DD8A at a maximum rate of 0.30 ton/ day. The amount of CO₂ reproduced as a result of breakthrough at DD8A was determined to have a negligible impact on project objectives.

Nitrogen composition increased moderately during CO₂ injection operations. Like methane, nitrogen also desorbs from coal in the presence of preferred CO₂. The observation of elevated nitrogen composition may be an indication of gas exchange in the reservoir due to preferential adsorption.

**Formation water composition**

Formation water testing established important baselines for production wells across the study area. Baseline pH values measured in the lab were generally acidic, ranging from 4.07 to 6.87 and averaging 5.51 across the study area. Baseline salinity values were extremely high, ranging from 61‰ to 142‰ and averaging 93‰ across the study area.
Preliminary analysis of samples collected during Phase I operations does not indicate an impact to the pH of formation water in the study area. However, it was determined during the test that only pH values measured in the field are representative because of rapid compositional changes upon sample collection. Many lab-derived values, including baseline measurements, may be unreliable.

DD8A was selected for a closer preliminary analysis, as the only well with confirmed CO₂ breakthrough and impact from CO₂-ECBM operations. No impact to pH was detected, but formation water temperature shows a potential correlation with the CO₂ injection temperature curve for DD8.

**Tracers (gas and liquid)**

Gas samples collected at offset production wells and monitoring wells for composition analysis were also analyzed for the presence of tracers. Tracers were deployed at three distinct times during Phase I injection operations, but only two tracers from the first round, deployed at the start of injection, were detected at other wells. A summary of the detection results is shown in Figure 5-12. A perfluorocarbon tracer, PMCP, added to the water in the DD7 wellbore shortly before the start of injection, was detected in gas samples from three offset production wells. Additionally, SF6 added to the CO₂ stream of DD8 was detected at 5 wells. Arrow thickness in Figure 5-12 corresponds to the approximate travel time to the well, estimated by the number of days between tracer deployment and detection. It is possible that these or other tracers did reach offset wells without detection due to sampling outside the specific time window for detection.
It is possible that the PMCP added to the water of DD7 evaporated out of phase while still sitting in the DD7 wellbore prior to injection and/or in the offset wellbores where the tracer was detected in gas samples. The tracer was detected at azimuths from DD7 that could be related to one or multiple factors. DD7 is located on the flank of a NE-SW trending anticline, and the three azimuths are all structurally updip from DD7. Detection at these azimuths could relate to enhanced permeability and conventional, updip fluid migration on the anticline. Additionally, CC7A and EE6 are approximately aligned with the hydraulic fracture direction. Another factor may be pressure interference from injection at the other wells that affects CO₂ migration in regions of overlap. The detection of SF6 from DD8 at M1 contradicts this suggestion. However, detection at M1 occurred very early during CO₂ injection operations, only 6 days after the start of injection in DD8, when pressures had not increased significantly. Pressure interference could become a factor for higher injection pressures or for increased distances within regions of overlap.
The five offset wells where SF6 from DD8 was detected represent varying azimuths. The number of days between tracer deployment and detection is low for very close offset locations at M1 and DD8A, but the correlation between distance and detection time is not consistent for farther offset locations.

**Borehole liquid level measurement**

Liquid levels in the injection wellbores, calculated using an Echometer, measured the gradual evacuation of water from the wellbore into the formation due to CO2 injection. Prior to the start of injection operations, the standing water columns in the wellbores were approximately 500 feet for DD7, 300 feet for DD7A, and 250 feet for DD8. At the start of CO2 injection, the water level in DD7 dropped rapidly and was completely displaced from the wellbore within one week. For DD7A and DD8, the water level increased slightly before slowly declining and evacuated the wellbores completely within four months.

The difference in the response of the formation water to CO2 injection is likely due to geologic structure. DD7 is located on the flank of the Hurricane Creek anticline, and DD7A and DD8 are located down-dip, approaching the Hurricane Creek syncline. Production history for wells on these structures shows a trend of relatively high water production for wells on the syncline and low production for wells on the anticline (Gilliland et al., 2013). The trend demonstrates localized conventional behavior for formation water on the structures. Water from DD7 was likely pushed down-dip, consistent with observed conventional behavior, and may have contributed to the brief rise in water levels at DD7A and DD8 before their decline. However, enhanced permeability may have assisted rapid water migration in a wide range of azimuths.
Microseismic monitoring array

Continuously-recorded passive microseismic data were processed in two ways: 1) to identify traditional micro-earthquakes (MEQs) and locate their hypocenters, and 2) to generate coherence volumes and interpret fracture networks using Tomographic Fracture Imaging SM (TFI). No MEQs were detected during the pre-injection survey (December 20, 2014-January 1, 2015) or during the early injection period (June 27-July 16, 2015). Coherence volumes are generated using Streaming Depth Imaging (SDI), a variation of seismic emission tomography. SDI sums total trace energy from all stations for all voxels in a discretized model over defined time steps. Stacking the incremental time steps over a day of recording produces a coherence volume which provides a relative measure acoustic energy levels distributed throughout the reservoir model. Coherence volumes can be further processed using TFI to interpret fracture networks.

TFI volumes were generated for each day of each survey. Daily TFI volumes were synthesized into combined TFI volumes for the pre-injection survey and the early injection survey, as shown in Figure 5-13. Note that the early injection recording period began five days prior to the start of injection. Results from these pre-injection days and days of staggered initial injection operations are included in the combined TFI volume. The white 1/4-mile boundary indicating the MVA focus area also represents the area of optimized array aperture for imaging. Note that the range of time-normalized amplitude values is generated uniquely for each processed volume, and the scales are not comparable between volumes. The color scale is an accurate relative measure of acoustic energy within the volume for the processed time period. Combined TFI volumes for pre-injection and early injection surveys show similarities in the distribution and density of fractures throughout the reservoir. The volumes also show similar distributions of acoustic energy, indicated by amplitude, including hotspots of high activity on the western margin of study area, approaching
the Hurricane Creek anticline. The similarities in TFI results for the two surveys suggest that the same fracture networks are activated during ambient pre-injection conditions (including production from the injection wells) and during early CO₂ injection operations. SDI and TFI processing were conducted by Global Geophysical Services.

Figure 5-13. Reservoir-depth slices through combined TFI volumes for pre-injection survey (left) and early injection survey (right). Blue symbols represent injection wells. Black symbols represent geophone stations. The white ¼-mile boundary indicates the MVA focus area and the estimated final CO₂ plume extents.

Daily coherence volumes generated for the early injection survey were used for a close examination of geostatistical trends in acoustic energy distribution. Characterizing the regions of highest energy was a priority because induced activity from CO₂ injection operations is likely to generate large signals relative to ambient activity. A subset of four volumes corresponding to pre-injection days in June 2015 was compared to a subset of four volumes corresponding to the last four days of early injection recording in mid-July. For each subset, the lateral distribution of the highest one percent of acoustic energy, representing the distribution of the highest activity, was
determined for all volumes. The distribution of high energy was then evaluated within each subset for persistence over time. A comparison of the persistence of the highest energy over time (maximum of four days) for the pre-injection and during-injection coherence volumes is shown in Figure 5-14. The comparison shows that the distribution of energy for the pre-injection subset is consistent for all days, the distribution of energy for the during-injection subset is consistent for all days, and the two distributions are different from each other.

Figure 5-14. Persistence of the lateral distribution of high acoustic energy recorded pre-injection (left) and during injection (right) for the early injection microseismic survey. Warmer colors indicate greater persistence over the time series (maximum of four days for each subset of volumes). Rose diagrams (insets) show the orientation of high energy locations referenced from the center of the model space.

For both subsets, acoustic energy is generally higher on the western margin of the study area, which is consistent with the TFI results. The pre-injection result shows high energy “streaks” at two dominant orientations of approximately N055E-N060E, which aligns with the hydraulic fracture direction, and approximately N120E. The during-injection result shows a consistent reorganization of energy to an orientation of approximately N085E-N090E. Additionally, the during-injection result shows persistent, deep-focusing hotspots of high energy near DD7 that are
present pre-injection and are likely due to water evacuating the DD7 wellbore in the early days of CO₂ injection operations.

**Surface deformation**

Coal swelling due to CO₂ adsorption could produce measurable uplift of the ground surface at the CO₂-ECBM test site in Buchanan County, Virginia. However, the steep, variable terrain and forestation across the study area present challenges for surface deformation measurement technologies, which rely on physical access to surface locations or satellite line-of-sight.

A recently developed technique for processing SAR imagery acquired by satellite has demonstrated improvements in measuring surface deformation over large areal extents in variable terrain. The intermittent small baseline subset (ISBAS) method is able to calculate elevation changes at more locations within an imaged scene than traditional techniques by incorporating data from intermittently coherent reflectors (Bateson et al., 2015). ISBAS provides a more complete deformation solution across the scene extents compared to traditional processing but, like all interferometric methods, requires a large data stack for accurate results.

The result of preliminary ISBAS processing of satellite radar imagery over the CO₂-ECBM study area is shown in Figure 5-15 and compared to the footprint of CBM operations in the Southwest Virginia coalfield. The locations of the three injection wells are indicated in yellow. The ISBAS result represents line-of-sight movement toward or away from the satellite, indicated respectively as “high” or “low,” over the acquisition period of approximately one year. This measure is a proxy for surface deformation. The preliminary ISBAS result was generated with a small data stack of 30 images. ISBAS processing was conducted by Geomatic Ventures Ltd.
The preliminary result over the CO₂-ECBM study area does not show a significant change relative to the surrounding region. The larger scene extents show a potential correlation between surface deformation and CBM production. Deformation could also correlate to underground mining or natural, geologic processes. However, the result demonstrates that the CO₂-ECBM test has not produced a deformation signal that is detectable above surrounding signals. Accuracy of the ISBAS solution will increase with additional acquisitions.
Ground-based GPS data collected at 20 locations across the CO₂-ECBM study area will provide cross validation of ISBAS results. Challenging terrain and tree cover have contributed to long occupation times and poor results at some locations. Higher quality measurements have peak-to-peak errors of approximately 7 mm, consistent with optimal operational accuracy.

Well logging and tests

Coal samples were collected from several reservoir seams during continuous coring of monitoring well, C1, and analyzed for gas content. The results of gas content analysis are summarized in Table 5-2. The percent of residual gas averages 17.95 percent for shallow coals (Greasy Creek- Pocahontas 7) and averages 23.18 percent for deep coals (Pocahontas 5-10- Pocahontas 3-20). The difference in averages suggests higher permeability of the shallow coals, but the population of samples is statistically small. Additionally, values calculated for individual samples may be influenced by the size of the sample, as larger samples tend to correlate with higher values of residual gas.

Table 5-2. Gas content analysis results for reservoir coal samples collected during continuous coring of monitoring well, C1.

<table>
<thead>
<tr>
<th>Coal name</th>
<th>Crushed sample weight (g)</th>
<th>Residual gas (scf/t)</th>
<th>Total gas (scf/t)</th>
<th>Percent residual gas (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>GC</td>
<td>1066.2</td>
<td>74.02</td>
<td>204.3</td>
<td>36.23</td>
</tr>
<tr>
<td>LS 20</td>
<td>462.7</td>
<td>47.7</td>
<td>409.12</td>
<td>11.66</td>
</tr>
<tr>
<td>UH 10</td>
<td>716.2</td>
<td>40.21</td>
<td>350.93</td>
<td>11.46</td>
</tr>
<tr>
<td>Poc 11</td>
<td>511.3</td>
<td>69.5</td>
<td>323.41</td>
<td>21.49</td>
</tr>
<tr>
<td>Poc 10</td>
<td>391.3</td>
<td>73.28</td>
<td>464.73</td>
<td>15.77</td>
</tr>
<tr>
<td>Poc 9</td>
<td>783.5</td>
<td>30.89</td>
<td>207.67</td>
<td>14.87</td>
</tr>
<tr>
<td>Poc 7</td>
<td>607.4</td>
<td>48.15</td>
<td>340.54</td>
<td>14.14</td>
</tr>
<tr>
<td>Poc 5-10</td>
<td>510.4</td>
<td>41.05</td>
<td>385.25</td>
<td>10.66</td>
</tr>
<tr>
<td>Poc 5-20</td>
<td>471.8</td>
<td>47.95</td>
<td>379.22</td>
<td>12.64</td>
</tr>
<tr>
<td>Poc 4</td>
<td>N/A</td>
<td>33.21</td>
<td>216.34</td>
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</tr>
<tr>
<td>Poc 3-10</td>
<td>1168.8</td>
<td>33.69</td>
<td>108.12</td>
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<tr>
<td>Poc 3-20</td>
<td>1948.6</td>
<td>37.91</td>
<td>106.57</td>
<td>35.57</td>
</tr>
<tr>
<td>Poc 2</td>
<td>366.9</td>
<td>52.88</td>
<td>217.76</td>
<td>24.28</td>
</tr>
</tbody>
</table>
Formation logging of the C1 well for reservoir characterization produced notable observations based on acoustic properties. Log analysis identified stress-induced anisotropy for reservoir intervals at orientations of N055E- N060E. This is orientation is consistent with the breakout orientation for hydraulic fractures at the study area. The shallow reservoir interval was associated with a lower Poisson ratio compared to the deep interval and also exhibited shear-wave splitting not detected in the deep interval. These observations indicate a change in principal stress orientations based on depth due to the stress of overburden.

Water flood tests (kill tests) were conducted on CC7A prior to injection and on DD8A and CCC7A five months into injection operations on December 16, 2015. In all cases, the tests indicated significantly higher gas flow rates from the shallow reservoir interval compared to the deep interval. Additionally, spinner tests were conducted late during the Phase I injection period on two of the injection wells, DD7 and DD8, to measure production rate. For both wells, flow rates were much higher for the shallow interval. For DD8, the spinner test determined that nearly all of the gas flow was produced from the shallowest perforated interval.

5.6 DISCUSSION

5.6.1 Reservoir characterization from phase I monitoring results

Injectivity loss is a well-documented issue for CO₂-ECBM operations. A loss of injectivity over sustained Phase I CO₂ injection operations was expected and observed. This may be due to back-pressure as fractures and cleats are filled and CO₂ transportation increasingly relies on the low-permeability coal matrix. Injectivity may also decline due to coal swelling. During the post-injection soaking phase, injection wellhead pressures declined to baseline levels. This response indicates well-developed fracture and permeability networks capable of diffusing the CO₂ and
pressure plumes over time. Additionally, injectivity for the coal reservoir, calculated from injection wellhead pressure, is restored over time. Measured injectivity loss is likely due, then, to near-wellbore phenomena and not representative of the larger reservoir response.

Several monitoring results describe differences between the shallow and deep reservoir intervals. Spinner tests conducted on the injection wells and water flood tests conducted on offset wells consistently measured higher gas flow associated with the shallower coals. This could be due to an expected reduction of permeability with depth, which is supported by the higher residual gas content measured for deep seams. Acoustic logging identified shear wave splitting, an indication of fracture-induced anisotropy, only in shallow intervals, suggesting that the shallow coals may also have better developed fracture networks than deep coals.

There are several indications of enhanced reservoir permeability at injection well DD7. Formation water completely evacuated the DD7 injection wellbore within days of starting CO₂ injection operations. The rapid evacuation of water was associated with a slight rise in the water columns for DD7A and DD8, suggesting a well-developed permeability network that allows communication between wells. Tracers deployed in the water of DD7 just before start of injection were detected at several wells up-dip from DD7. This result also demonstrates reservoir communication and suggests that water was also transported up-dip. Microseismic results show deep-focusing hotspots near DD7 during injection that are oriented both up-dip and down-dip from the wellbore, supporting the case for water movement along multiple azimuths. However, it is possible that the DD7 tracer evaporated out of the water prior to injection operations and traveled through the shallow reservoir interval with the CO₂ stream. This scenario is consistent with conventional reservoir behavior inferred from the production history of wells drilled on the local Hurricane Creek anticline, including DD7. In this case, CO₂ injected into DD7 would mostly
migrate up-dip while formation water would be pushed down-dip. Phase II of injection operations will provide an opportunity for additional observations of reservoir behavior at DD7.

5.6.2 Phase II and future work

Monitoring observations from Phase I of injection operations have guided plans for Phase II of the test, including the injection operations and the monitoring program. The start of injection operations will be staggered, as they were in Phase I, but will start with injection into DD7 only. This will provide an opportunity to isolate the response of the reservoir in this part of the study area where enhanced permeability has been observed. Conducting an additional tracer study at the start of injection and monitoring without potential pressure interference from the other injection wells will help to clarify the role of geologic structure in fluid migration.

Phase II operations will utilize low CO$_2$ injection rates, similar to Phase I. However, rates may be maximized (within permitted limits) at the end of the Phase II test period in order observe reservoir responses under high-pressure conditions. It is expected that CO$_2$ will be injected in liquid phase at this point. A final microseismic survey will be conducted at the end of the Phase II test period. This survey will monitor the last several days of high-rate, high-pressure injection operations into all wells, followed by the staggered-off end of CO$_2$ injection, and the first several days of the post-injection period. Spinner tests will also be conducted near the end of the injection period to measure the production rate associated with different depth intervals at the injection wells.

Breakthrough of CO$_2$ is expected to occur at DD8A again during Phase II operations. DD8A will be closely monitored for detection of breakthrough and for consequential impacts to formation water as CO$_2$ gas composition increases. As in Phase I, CO$_2$ composition will be allowed to
increase as long as the objectives of the CBM operations and the CO$_2$-ECBM test are not compromised. At some point following the detection of breakthrough, a water flood test (kill test) will be conducted on DD8A to determine which reservoir seams are transporting the CO$_2$.

A post-injection monitoring period will last for approximately one year after the end of Phase II injection operations. Sampling frequency will decrease for many methods during this period. Pressure readings will be measured continuously at the injection wellheads to monitor the decline during shut-in. At the end of post-injection monitoring, some characterization logging tests will be repeated in C1, including a caliper and/or acoustic televiewer to assess breakout in the open borehole. Geospatial monitoring with InSAR and GPS during Phase II and the post-injection period will increase the existing time series for more accurate measures of potential surface deformation.

Future work based on Phase I monitoring results and observations includes updating reservoir models to improve CO$_2$ injection simulations. Breakthrough at DD8A was successfully predicted by preliminary CO$_2$ injection simulations. Models will be updated with actual injection and production history, including the measured increase of CO$_2$ composition at DD8A, to more accurately reflect observed reservoir behavior. Monitoring results from the upcoming Phase II of CO$_2$ injection will provide an important comparison to the Phase I results and additional constraint on local reservoir behavior. Additionally, results from both phases of the CO$_2$-ECBM test in Buchanan County can be compared to the results of the huff-and-puff test in Russell County. The Buchanan County test is larger in scale and duration and involves more intensive monitoring. Notably, the Buchanan County test also utilizes injection wells with typical production histories for the field. The well utilized for the test in Russell County was an anomalous and poor producer.
The ultimate ECBM results for the Buchanan County test may be more representative for the Oakwood field than results from the Russell County test.

5.6.3 Monitoring-based recommendations for CO2-ECBM operations

Monitoring observations during Phase I of CO2 injection and the soaking phase suggest the following injection strategy for CO2-ECBM operations:

1) Inject CO2 at a low, sustained rate until either injectivity is lost (high injection pressures put reservoir integrity at risk) or CO2 breakthrough compromises project objectives or CBM operations.

2) Shut-in injection operations for a soaking period. The duration of the soaking period should match the duration of the injection operations (1:1), or may end sooner if measured pressures demonstrate reservoir equilibrium.

3) Repeat CO2 injection-soak cycles or flowback the well for production, depending on project objectives and achieved measured pressures.

4) Maximize CO2 injection prior to final well shut-in.

The use of multi-scale and overlapping monitoring technologies has been beneficial for characterizing the reservoir response to CO2 injection. These design elements are recommended for combined CO2 storage / enhanced recovery projects where simultaneous field operations can make it difficult to attribute monitoring response signals to sources. The ability to cross-validate multiple monitoring responses increases confidence in data interpretations.
CO₂ breakthrough was confirmed at one offset well in the study area. The increase of CO₂ content in the production stream of the well was monitored closely. No adjustments to operations were required because the CO₂ content was not high enough to compromise project objectives or CBM operations. Identifying the impact thresholds for CO₂-ECBM objectives and for the surrounding CBM operations is important in managing occurrences of CO₂ breakthrough. For this test, the specific gas handling system utilized by the CBM operator was a primary factor in the allowable CO₂ content for the well. The unique factors affecting operations for individual projects will vary.

5.7 CONCLUSIONS

Multi-scale monitoring technologies with overlapping spatial and temporal deployment have been used successfully to characterize reservoir behavior due to CO₂-ECBM operations. Passive microseismic data acquired over a large extent of the study area during Phase I of the injection test indicate high acoustic energy related to activity near the DD7 wellbore during CO₂ injection operations. This observation is supported by several borehole-scale observations: rapid evacuation of formation water from the DD7 wellbore during the same period, a slight rise in water levels at nearby injection wells, and a tracer from DD7 detected at several offset production wells. The microseismic and borehole responses cross-validate each other and assert an interpretation of enhanced reservoir permeability at DD7. Continuous monitoring of injection parameters has characterized the dynamic injectivity of the reservoir. Careful management of reservoir injectivity is a key component of a recommended strategy for CO₂-ECBM operations and is necessary to optimize CO₂ storage and enhanced recovery. Formation logs, production rate tests, gas content analysis, and tracer studies have characterized differences in permeability and fluid flow between
the shallow and deep reservoir intervals. Monitoring during the upcoming Phase II of the CO2-ECBM test will provide further constraint on interpretations of reservoir behavior.

ACKNOWLEDGEMENTS

Financial assistance for this work was provided by the U.S. Department of Energy through the National Energy Technology Laboratory's Program under contract no. DE-FE0006827.

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6 GEOSTATISTICAL ANALYSIS OF MICROSEISMIC MONITORING RESULTS FROM A CARBON STORAGE / ENHANCED GAS RECOVERY FIELD TEST IN A STACKED COAL RESERVOIR

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This work is under review by coauthors for submission to a refereed journal.

ABSTRACT

Microseismic monitoring was conducted during the early injection phase of an ongoing small-scale CO2-Enhanced Coal Bed Methane (ECBM) field test in order to record discrete microseismic events (microearthquakes) for hypocenter location and to record continuous low-amplitude signals for Streaming Depth Imaging (SDI) and Tomographic Fracture ImagingSM (TFI). This paper presents a geostatistical analysis of the SDI processing results. The SDI method, a variation of seismic emission tomography (SET), uses a modified depth migration technique to image weak acoustic signals and is well-suited to monitor low-pressure reservoir processes. SDI results were analyzed with geostatistical methods in order to identify and quantify spatial trends and changes in the distribution of acoustic energy due to CO2 injection. Results of the geostatistical analysis, supported by additional monitoring data, provide evidence for regions of enhanced permeability, water mobility in the deep reservoir interval, and geomechanical variation with depth. Analysis involved significant reduction of very large datasets generated by SDI but preserved original processing resolution in the dimensions of investigation.
6.1 INTRODUCTION

Up to 20,000 tons of carbon dioxide will be injected into a stacked coal reservoir for an ongoing CO₂-ECBM field test in Buchanan County, Virginia, USA. The test will assess the carbon storage potential of Central Appalachian coals and the potential for enhanced recovery from the depleted gas reservoir.

Three vertical gas production wells in the Oakwood CBM field were converted for injection operations, which began in July 2015. The reservoir is composed of approximately 20 thin coal seams from the Pocahontas and Lee Formations, which are widely distributed in depth. This unique geometry creates a challenge for monitoring reservoir behavior. Some conventional monitoring and imaging technologies could not be used due to insufficient resolution or impractical deployment. Steep, forested terrain at the field site further restricted monitoring options by limiting physical access across the study area.

Passive microseismic monitoring was selected as a technology well-suited to both the objectives and the site-specific characteristics of the test. A surface array (shallow-buried array) of 28 receiver stations was installed to monitor lateral migration of the CO₂ plume. The surface array provides data coverage over a large areal extent. The high-sensitivity geophones used for recording are well-suited to the low levels of acoustic energy anticipated for the test, as injection pressures must remain below the recorded fracture gradient of the reservoir.

The data recorded by the microseismic monitoring array has been processed through two separate workflows. The first identifies discrete microseismic events, often associated with monitoring of hydraulic fracture treatments, and the second uses the continuously-recorded
acoustic energy to generate coherence and TFI volumes. No discrete microseismic events have been recorded at the field site to date. This paper presents analysis of the SDI results derived from passive data, including geostatistical trends in the distribution of acoustic energy due to CO$_2$ injection.

6.2 BACKGROUND

6.2.1 CO$_2$ utilization for enhanced recovery and CO$_2$-ECBM

The petroleum industry has utilized CO$_2$ for enhanced oil recovery (CO$_2$-EOR) through miscible flooding since the 1970s (Dicharry et al. 1972; Holm 1982). The technology has relied largely on natural sources of CO$_2$, such as Jackson Dome in Mississippi, which serves locations in the Gulf of Mexico, and several natural domes in the Colorado Plateau, which serve the Permian Basin and other plays (API 2007). Though effective, deployment of the technology has been limited due to the small number of existing CO$_2$ pipelines.

Utilizing captured, anthropogenic CO$_2$ for EOR could benefit the oil and gas industry and provide effective management of carbon emissions. The abundance and widespread distribution of anthropogenic CO$_2$ point sources could expand enhanced recovery practices to more oil and gas fields. This would extend the lifespan of fossil fuel reservoirs without increasing the operational footprint. Simultaneously, anthropogenically-sourced CO$_2$-EOR would provide an option for commercial-scale carbon management and geologic storage that is more cost effective than storage in saline aquifers. Several field projects have been conducted to demonstrate key aspects or full integration of carbon capture, utilization (for enhanced recovery) and storage (CCUS) operations. Notable, mega-ton injection projects have been conducted in the Weyburn-Midale oil fields of

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Saskatchewan, Canada, and the Cranfield oil field in Mississippi, USA (Whittaker et al. 2011; Hovorka et al. 2013).

Targeting depleted coalbed methane reservoirs for CCUS operations (CO2-ECBM) is especially attractive because the organic coal matrix exhibits preferential adsorption for CO2 over methane (Shi and Durucan 2005; Weniger et al. 2010). This means that, exposed to both phases, the rock matrix will release chemically bonded methane in order to store CO2 on its surface. This phenomenon contributes to several advantages of CO2-ECBM operations: an additional mechanism for enhanced recovery, an additional mechanism for secure geologic storage of CO2, and a storage capacity for CO2 that can be several times larger than that for methane (Al-Jubori et al. 2009; Marsh 1987).

A number of field projects designed to study and demonstrate the potential of CO2-ECBM have been conducted worldwide, with the largest and most successful tests in the high-permeability Fruitland Coal seams of the San Juan Basin, New Mexico, USA. The Allison Unit CO2-ECBM pilot project injected 335,000 metric tons of CO2 into Fruitland coals, ultimately storing 80 percent of the injected CO2 volume and producing 1.6 Bcf in incremental methane recovery (Godec et al. 2014). The Pump Canyon demonstration project, completed in 2009, stored 18,407 tons of CO2 in the Fruitland coals with little to no breakthrough at offset wells (Oudinot et al. 2011).

The reservoir characteristics of the Pocahontas and Lee coal seams in Central Appalachia differ from those of the Fruitland coals but have also demonstrated potential for CO2-ECBM. A 1000-ton “huff-and-puff” test was conducted in Russell County, Virginia, in 2009. A huff-and-puff test involves injecting CO2 into a single well as a treatment to enhance production from that well. The test stored approximately 65 percent of the injected CO2 volume and has increased the estimated ultimate recovery (EUR) for the treated well by 85 percent. The current test in Buchanan County
represents a significant upscaling from the Russell County test in both the target injection volume and the monitoring effort. Approximately 10,600 tons of CO₂ were injected during Phase I of the test in Buchanan County. Already, the test in Buchanan County is the third largest CO₂-ECBM project in the world, behind the Allison Unit and Pump Canyon tests in the San Juan Basin. If the test in Buchanan County reaches its target injection volume of 20,000 tons during Phase II operations, it will surpass the Pump Canyon test.

6.2.2 Microseismic monitoring and Streaming Depth Imaging (SDI)

Within the energy industry, microseismic monitoring is commonly used to evaluate hydraulic fracture treatments of oil and gas wells but has also been used to study enhanced geothermal systems (EGS) and ground control in underground mines (Dyer et al. 2008; Milne et al. 2013). Conventional microseismic monitoring involves triggered recording of discrete microseismic events, or micro-earthquakes (MEQs), which have been defined as events with Mw < 2 (NRC 2013). Hypocenters for MEQs are typically located by triangulation of first arrival times from multiple stations or hodogram analysis of three-dimensional particle motion recorded by at least one three-component geophone (Soma et al. 2002; Maxwell et al. 2010; Lacazette et al. 2015). Microseismic data provide information about the distribution and strength of acoustic energy in the subsurface and are often used in reservoir characterization to interpret natural and induced fracture patterns (Block et al. 1994; Rutledge and Phillips 2003; Kochnev et al. 2007). Case studies have demonstrated that the occurrence of MEQs during injection operations can be much higher than predicted by the Gutenberg-Richter relationship of earthquake magnitude and frequency for natural occurrences, with b-values consistently and significantly larger than 1 (Urbancic et al. 1999; Vermylen and Zoback 2011).
Microseismic monitoring is well-suited to the low-pressure injection processes associated with carbon storage operations and has been used for several field projects in order to better understand reservoir processes involved in CO₂ injection, transportation, and storage in geologic formations. Notable examples include the Illinois Basin-Decatur saline storage demonstration project in Illinois, USA, the Weyburn oil field project in Saskatchewan, Canada, the Krechba gas field project in In Salah, Algeria, and the Michigan Basin oil field project in the Northern Reef Trend of Michigan, USA (Coueslan et al. 2014; Verdon et al. 2013; Battelle 2011).

Continuous microseismic recording of passive acoustic emissions can capture additional weak seismic signals not recorded by triggered acquisition of MEQs. Das and Zoback (2011) describe shear-dominated, long-period, long-duration events (LPLDs). LPLDs are distinguishable from other seismic phenomena, including MEQs, tectonic tremor, noise, and mechanical sources, based on spectral and temporal waveform characteristics including frequency content, amplitude, velocity spectra, and moveout, in addition to period. LPLDs, interpreted as slow-slip events caused by changes in pore pressure and often lasting several seconds, were shown to represent approximately 40 times more cumulative released energy than MEQs during a multi-well hydraulic fracture treatment recorded on a downhole geophone array (Das and Zoback 2013). Extended duration signals (EDS), which lack shear waveforms, have recently been identified on surface arrays and represent another type of low-level acoustic signal with significant cumulative energy during continuous recording of well treatments (Sicking et al. 2014). Fluid resonance in subsurface fractures and cyclic stick-split fracturing are other potential sources of signal (Tary and van der Baan, 2012; Van der Baan et al, 2016).

Streaming Depth Imaging (SDI), a seismic emission tomography method, processes total trace energy for continuously recorded passive microseismic data over defined time steps, incorporating
the large cumulative amount of energy from lower amplitude, long-duration signals in addition to MEQs (Lacazette and Morris 2015). Raytracing based on Kirchhoff migration is combined with a velocity model to cross-correlate traces incrementally and integrate energy over raypaths calculated between known receiver locations and model voxels (Lacazette and Morris 2015; Geiser 2006). The result is a 3D depth volume, or time series of volumes, of coherence which represents the distribution of cumulative acoustic energy during recording. The coherence volumes are often interpreted as a proxy for the permeability field and can be further processed to interpret natural and induced fracture networks (Lacazette and Laudon 2015; Sicking et al. 2013).

Continuous microseismic recording combined with stacking- or coherence-based processing algorithms for SDI can detect weak signals caused by redistribution of reservoir fluids and pore pressure, in addition to rock fracturing, fluid resonance, or reactivation of preexisting rock fractures. (Duncan and Eisner 2010; Geiser et al. 2012). This combination of technologies was selected for the monitoring program in Buchanan County to assess changes in the distribution of acoustic energy and implications for the permeability field due to low-pressure CO₂ injection.

6.3 DATA ACQUISITION AND SDI PROCESSING

A surface array (shallow buried array) for continuous microseismic monitoring was installed at the Buchanan County field site by a seismic acquisition and services contractor, Global Geophysical Services (GGS) of Houston, Texas, with an objective to record discrete MEQs for hypocenter analysis (“dots in a box”) and to process total trace energy with SDI. Design of the array took into account the unique reservoir geometry, consisting of 15-20 individual coal seams, averaging only one foot in thickness and ranging in depth from approximately 700 to 2200 feet. A shallow buried array was chosen instead of a downhole array for two important reasons: 1) to
optimize lateral resolution for coherence-based imaging of the CO₂ / pressure plume, and 2) to improve signal-to-noise and experiment repeatability for multiple surveys (Duncan and Eisner 2010; Lacazette and Morris 2015). Observations of very weak borehole breakout in monitoring wells drilled at the test site and large hydraulic fracture apertures encountered during underground mining in regions neighboring the study area suggested a low-stress environment where discrete MEQs might be infrequent and SDI results could be more useful.

The microseismic array consists of 28 three-component 10-Hz geophones installed at a depth of approximately 75 feet in order to avoid signal attenuation in the weathering layer. The initial design of the array featured a uniform, hexagonal grid of stations spaced at 1200 feet based on the minimum number of stations that could provide adequate aperture for the greatest depth of interest. This configuration could reliably detect and locate MEQs of Mw= -2 and possibly smaller. However, challenging terrain limited access at the site, resulting in significant deviations from this geometry in the final design (Figure 6-1). The array covers an area of approximately one square mile and was designed to optimize imaging within a volume defined by a ¼-mile radius from each of the three injection wells. This volume represents the estimated CO₂ plume extents based on preliminary modeling and simulations and is indicated in Figure 6-1. Imaged regions outside of this volume may show stretching of coherence amplitude due to inadequate aperture.
Continuous monitoring was conducted for 20 days at the start of CO₂ injection, from ordinal day (OD) 178-197 (June 27-July 16) of 2015, including five days of pre-injection/baseline
monitoring followed by staggered injection operations for the three injection wells, DD7, DD7A, and DD8. Prior to injection, production curves for the three wells indicated that DD7 was producing gas at a significantly higher rate than DD7A or DD8, despite being the oldest and most depleted of the wells. CO₂ injection began in DD7A on OD 183 (July 2) and continued for five days before wells DD7 and DD8 were brought on line on OD 188 (July 7) and OD 189 (July 8), respectively. Injection parameters varied for each of the three wells as depicted by injection rate and pressure curves shown in Figure 6-2. Observed injection pressures and temperatures indicate that CO₂ was injected in gas phase into all wells and remained in gas phase within the formation during this early period of the field test.

Figure 6-2. Recorded injection parameters for the start of Phase I CO₂ injection operations. Curves for injection wells DD7, DD7A, and DD8 are shown in blue, green, and yellow, respectively. The blue shaded region represents the last four days of microseismic recording. Coherence amplitude volumes from these days comprise the during-injection dataset used for geospatial analysis.

Initial processing of microseismic data was conducted by GGS. An autopicking routine for MEQs identified over 500 potential events, but all were rejected by manual inspection. No discrete MEQs were detected during the 20-day early injection survey. Continuously recorded ambient data were processed to produce separate elevation volumes of coherence amplitude for each day. For this study, only trace data for the vertical component were used. A three-hour window of
recording, between 12:00 AM and 3:00 AM, was determined to be the optimal quality window (best signal-to-noise) and duration for stacking and was used for the SDI processing. However, one day of pre-injection recording, OD 182 (July 1) was considered too noisy for high-quality processing and was eliminated from the dataset. Additional trace processing followed a standard routine, including removal of mechanical noise signatures and frequency filtering. A velocity model was obtained from a sonic log acquired in nearby characterization well, C1, and smoothed for SDI (Figure 6-3).

The SDI coherence volume was defined with dimensions of \( x = 6100 \) feet, \( y = 3400 \) feet, and \( z = 2000 \) feet (1234 to -766 feet ASL), centered laterally around the injection wells and encompassing the full depth extent of the distributed coal reservoir. Voxels in the coherence...
volume are cubic with an edge length of 25 feet. The SDI routine used by GGS is a patented, proprietary method, although seismic emission tomography routines operate by time-stacking calculations of total trace energy. More information about the method used by GGS is provided in Sicking et al. (2016). The result of SDI is a data volume, in which each voxel of the 3D volume has a uniquely calculated value of coherence amplitude, a measure of relative acoustic energy. The coherence amplitude volume, therefore, represents the distribution of relative acoustic energy measured over the processed time window.

One factor in the reliability of a SDI solution is the aperture provided by the monitoring array. A given voxel must have adequate aperture from the array on all sides for an accurate solution. The configuration of the array was designed to optimize aperture for the volume within the estimated CO$_2$ plume extents (Figure 6-1). Distortion and data stretching are expected near the model edges, especially in the southwest corner which is poorly constrained. The expected data quality, based on aperture, should be considered during data analysis and interpretation.

### 6.4 DATA ANALYSIS

Daily coherence amplitude volumes were computed with SDI by the contractor, GGS. Each volume comprises over 2.7 million data points referenced as (x, y, z, a, t) where x, y, and z represent the spatial location (referenced to state plane coordinates and elevation from sea level) of the unique voxel within the volume space, a represents the value of relative coherence amplitude, a proxy for relative level of acoustic energy, and t represents the time window over which coherence was processed.

Because volumes are processed separately for each day, values obtained for the coherence amplitude parameter, a, are comparable within a single volume but cannot be compared universally
across multiple volumes. This presents a significant limitation on meaningful analysis of the data as a time series. However, the monotonic nature of the data transformation involved in SDI and the approximately normal distribution of values within each volume means that some statistical analyses, including comparison of normalized daily datasets and quantiles, are valid across the volumes.

Daily volumes for pre-injection versus during-injection days were analyzed using geostatistical methods in order to evaluate changes in the distribution of coherence amplitude, \(a\), and infer changes in acoustic energy. Because pre-injection (baseline) monitoring was only successful for four days, the pre-injection dataset consists of the four volumes for these days. The during-injection dataset also consists of four daily volumes in order to use similar populations for statistical comparisons and represents the last four days of the monitoring period when all three wells were injecting CO\(_2\). On these days, the injection rate was higher for DD7 than for DD7A or DD8.

Three specific investigations were conducted to compare the pre- vs. during-injection datasets: 1) an analysis of several coherence slices from the SDI volumes, extracted at elevations representing key geologic horizons, 2) a quantile-based analysis of the lateral distribution of highest acoustic energy, and 3) the generation of simulated acoustic “well logs” to evaluate high-energy hotspots near DD7. All investigations involve reducing the large datasets but preserve the original processing resolution.

6.4.1 Investigation 1: Comparison of key geologic horizons

The objective of this investigation was to evaluate the lateral distribution of coherence amplitude, as a proxy for acoustic energy, for four key geologic horizons. Analysis involved
extracting horizontal slices from the 3D SDI volume nearest the approximate elevation of the geologic units (geology includes slight to moderate dip to the southeast). Three of the elevation slices represent horizons in the upper-shallow, lower-shallow, and deep reservoir zones, and the fourth slice is extracted from a thick confining formation, the Lee Sandstone, which separates the shallow and deep reservoir zones.

Figure 6-4 depicts an approximately east-west stratigraphic correlation through several wells in the study area, including the three injection wells, and the relative position of the four elevation slices. Key coal seams are indicated in blue and include the Lower Seaboard (upper-shallow), the Pocahontas 9 (lower-shallow) and the Pocahontas 3 (deep). The yellow shaded region represents the Lee Sandstone mid-reservoir confining zone. The green shaded region represents the coherence volume extents, which continue below the reservoir interval. Note that several coal seams are present above the model extents but are not part of the gas production / CO₂ injection reservoir (wells were not completed in these seams).
Figure 6-4. East-west stratigraphic correlation through study area. Red dashed lines indicate elevation slices representing key geologic horizons extracted from coherence amplitude models for analysis. Three elevation slices represent key intervals of the coal reservoir: the Lower Seaboard coal seam (1034 feet), the Pocahontas 9 coal seam (609 feet), and the Pocahontas 3 coal seam (209 feet). A forth elevation slice represents the Basal Lee Sandstone, a confining unit (384 feet).

The lateral distribution of coherence amplitude for each of the four elevation slices was interpolated using ordinary Kriging for each of the eight pre-and during-injection days (Figure 6-5). For all days, the results show little variation between elevation slices within a single daily volume. This may be due in part to the receiver geometry, which favors lateral over vertical resolution, and the coarse resolution of the velocity model relative to the coal seam thickness.
Figure 6-5. Coherence amplitude distribution for all elevation slices and for all ordinal days (pre- and during-injection). Warmer colors indicate higher coherence amplitude, a proxy for acoustic activity. The colorbar is not universal for all slices; it is reset for each ordinal day (OD). The colorbars apply to quantiles and can be compared, relatively, across days. Green symbols represent injection wells. Blue symbols represent CBM production wells.
Results for pre-injection days show “streaks” of higher energy in consistent locations on the western margin of the model, which could be influenced by reduced data coverage in this region. Alternatively, the geologic structure trends up-dip on the western margin toward a local anticlinal feature. The higher activity indicated may represent real phenomena caused by conventional fluid migration and/or enhanced permeability due to deformation. During-injection days show a more chaotic distribution of energy that appears somewhat consistent and may indicate a reorganization of energy during CO$_2$ injection. The streaks visible in the pre-injection data are not apparent during injection. However, without a universal scale for coherence amplitude, it is possible that the same streak features exist but are overwhelmed by larger signals on during-injection days. One significant observation is high-energy hotspots at DD7 that are persistent on all days during injection and for all elevation slices.

Descriptive statistics were calculated for distributions in the elevation slices, based on normalized values (z-scores normalization) for each full data volume, and are summarized in Table 6-1. Most of the statistical parameters show variation with depth and time, and it is difficult to identify or confirm trends in the small sample of eight days. However, one fairly consistent trend is that the values for normalized mean increase with increasing depth for each daily volume. This could be caused by one or multiple factors, including array aperture, differences in rock properties due to lithification by overburden, or depth-related differences in stress and fracture orientations that affect fluid migration systematically.
Table 6-1. Descriptive statistics for coherence amplitude distribution of elevation slices representing key geologic horizons.

<table>
<thead>
<tr>
<th>Ordinal Day</th>
<th>Data Subset (Z-slice, ft)</th>
<th>Normalized Minimum</th>
<th>Normalized Mean</th>
<th>Normalized Maximum</th>
<th>Normalized Range</th>
<th>Normalized Std. Deviation</th>
</tr>
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<tbody>
<tr>
<td>178</td>
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<td>0</td>
<td>7.6506</td>
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<td>1</td>
</tr>
<tr>
<td>178</td>
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<td>-0.0239</td>
<td>6.0392</td>
<td>8.6860</td>
<td>0.9699</td>
</tr>
<tr>
<td>178</td>
<td>609</td>
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6.4.2 Investigation 2: Lateral distribution of highest acoustic energy

This investigation was motivated by the identification of high-energy streaks and hotspots in Investigation 1 and involved a focused examination of the distribution of the highest energy recorded for each day. The objective of this analysis was to confirm and quantify a lateral reorganization of the highest acoustic energy due to CO₂ injection.

For each daily volume, the top one percent of values were extracted, representing the highest energy for that day and over 27,000 unique \((x, y, z)\) voxel locations. Because the lateral spatial distribution of high energy was of primary interest, each data subset was further reduced to eliminate points representing repeated lateral \((x, y)\) positions. Reducing the data to two dimensions in this way resulted in a data point reduction of over an order of magnitude for all subsets, confirming the persistence of lateral trends with depth. A new model was generated for each day, composed of lateral spatial dimensions and a new count parameter \((x, y, c)\), where \(c\) is a Boolean operator equal to one for points in the high-energy subset and zero for all other model locations. Models were then “added” for pre-injection and during-injection days to assess the persistence of high-energy distributions (Figure 6-6). The final models represent a count of days (maximum of four) for which each lateral model location experienced the highest one percent of acoustic energy. These models demonstrate the coherent organization of energy over time. More specifically, the distribution of high energy is consistent over all pre-injection days and is also consistent over all during-injection days, and the two distributions are different from each other. Azimuthal anisotropy factors calculated for the pre-injection and during-injection distributions were 2.44 and 3.00, respectively. However, this parameter becomes less meaningful for a limited data subset when multiple, distinct trends are present at different orientations, as in the case of the “streaks” of high energy observable in the pre-injection model.
Rose diagrams were generated for the same subset of unique (x, y) locations representing the distribution of the highest one percent of energy (Figure 6-7). The measured angle is the orientation of the (x, y) location from the center of the two-dimensional model. Note that this is not same as an absolute orientation of a trend but in the case of both the pre-injection and during-injection models, it is a close approximation. Additionally, any consistent difference in the diagrams would demonstrate a reorganization of energy, regardless of absolute orientations. The diagrams, which overlay data for each set of four days, display consistent trends in the distribution and orientation of high energy over time for pre-injection and during-injection datasets. Furthermore, the pre-injection diagram shows a dominant orientation consistent with the known
local hydraulic fracture direction of N055-060E, and the during-injection diagram shows a consistent reorganization toward N085-090E.

Figure 6-7. Bi-directional rose diagrams representing the lateral orientation of highest energy voxel locations from the volume center for all pre-injection days (left) and all during-injection days (right).

6.4.3 Investigation 3: Coherence wellbore extractions for DD7

The objective of this investigation was to further explore apparent hotspots of high acoustic energy near DD7 during CO₂ injection. This analysis involved conducting a wellbore extraction from the coherence volume for DD7. The extraction radius of 100 feet encompassed 51 \((x, y)\) voxel locations (Figure 6-8).
Simulated “well logs” of acoustic activity were generated for each day by plotting the range of coherence amplitude values, normalized from full-volume populations, along the wellbore (Figure 6-9). Values included in the highest one percent of acoustic energy for the volume are indicated in green. For all pre-injection days, the range of acoustic activity near the DD7 wellbore, measured as coherence amplitude, is skewed higher than the volume average. During CO$_2$ injection, all days exhibit a consistent shift toward a higher range of activity. All logs from during-injection days include values in the highest one percent of energy recorded, versus only one from the pre-injection days.
Figure 6-9. Simulated acoustic “well logs” for DD7, generated from wellbore extractions from coherence volumes. Coherence values in the highest one percent of all values recorded for the day are indicated in green. Red symbols indicate elevations of reservoir coal seams for DD7.

The dramatic shift in energy level is summarized in Figure 6-10, which averages the pre-injection and during-injection distributions of normalized coherence amplitude from Figure 6-9. The separation between the two distributions increases with increasing depth. Higher energy at deeper reservoir intervals may be related to changes in lithological or geomechanical properties, including permeability or fracture orientations, that affect fluid migration. Alternatively, high energy in the deep reservoir interval may be related to the evacuation of water from the DD7 wellbore.
Figure 6-10. Averaged distributions of coherence amplitudes for pre-injection vs. injection “well logs” shown in Figure 6-9. The gray shaded region represents the averaged pre-injection distribution. The blue shaded region represents the averaged during-injection distribution. Red symbols indicate elevations of reservoir coal seams for DD7.

6.5 DISCUSSION

6.5.1 Data validity

The microseismic array was designed to optimize aperture near the injection wells. The SDI solution becomes less reliable on the margins of the model volume where aperture is insufficient
and data may be distorted. Results may also be compromised where planned geophone stations had to be relocated due to terrain, leaving some voxel locations less constrained. Persistent anomalies can be artifacts from an insufficient aperture or can relate to real geologic phenomena. For pre-injection days, the lateral distribution of coherence amplitude shows “streaks” of high energy on the western margin of the model that are somewhat coincident with reduced aperture constraint. However, the consistent reorganization of energy during injection suggests that these features are not artifacts of the array aperture as they lack persistence over the time series.

6.5.2 Enhanced permeability

Several monitoring and data observations from DD7 support the possibility that high-energy streak features imaged consistently on pre-injection days relate to enhanced permeability associated with structural deformation: 1) DD7 is located on the flank of a local anticline where CBM production from wells is consistently higher than production from wells off-structure. 2) Production history for the three injection wells shows that DD7, the oldest and most depleted of the three injection wells, has consistently produced CBM at a higher than DD7A and DD8. In the months prior to shut-in for the injection test, DD7 continued to produce at a significantly higher rate than DD7A or DD8. 3) The early phase of CO\textsubscript{2} injection included a period of sustained, simultaneous injection into all three wells. During this time, the injection rate for DD7 was much higher than the rates for the other wells, but DD7 maintained a lower wellhead pressure. 4) Water levels measured in the injection wellbores with an Echometer wellhead attachment indicated that a water column of 500 feet was completely evacuated from the DD7 wellbore within days of injection. During this time water levels in DD7A and DD8 rose slightly and later declined gradually over several months. 5) Perfluorocarbon tracers were added to the water in each of the three wells before CO\textsubscript{2} injection. Of these, only the tracer for DD7 was detected at offset wells
(CC7A, CC6A, and EE6), confirming transportation due to CO₂ injection. These observations suggest that DD7 contacts hydraulically conductive fractures, which may be enhanced by structural deformation.

During injection, the distribution of energy is reorganized but remains consistently higher on the western margin. The consistent trend of higher activity on the western, up-dip margin of the model indicates a difference in reservoir properties that contributes to increased fluid mobility. Specific streaks or hotspots in the pre-injection or during-injection data may relate to discrete fracture systems, natural or induced. Fracture systems are likely to be more developed and/or active for this margin because of underlying enhanced permeability from structural deformation.

6.5.3 High-energy hotspots at DD7

Localized hotspots of high relative coherence amplitude near DD7 were initially suspected to relate to surface noise that had not been fully filtered during trace processing. The DD7 well pad houses the CO₂ injection skid, which includes pipelines to the other injection wells, and most major field operations are conducted at this location. However, the well pad was also very active prior to injection, during pre-injection recording, although operations were not identical. Additionally, the wellbore extractions for DD7 performed for Investigation 3 indicate deep-focusing energy for during-injection days.

The hotspots represent high levels of acoustic activity that are likely related to enhanced permeability associated with the local anticline. Localized high energy is persistent near DD7 but not the other injection wells. Although the presence of high energy at the DD7 well correlates with a higher injection rate compared to DD7A and DD8, the injection pressure for DD7 is significantly lower. It is most likely that the hotspots are associated with water evacuating the DD7 wellbore
and migrating through hydraulically conductive fractures. Here, natural and induced fracture development may be enhanced by structural deformation.

6.5.4 Geomechanical variation

Geostatistical analysis highlights differences in the spatial distribution of acoustic energy for pre-injection versus during-injection days, laterally and in depth. The lateral distribution of high-energy hotspots is consistently reoriented during injection. Wellbore extractions for DD7 show that high energy focuses in the deep reservoir interval during injection. These results suggest that variations exist in the geomechanical properties of the reservoir which may relate to depth and/or pressure.

Well logging and flow rate tests support the possibility of depth-defined variations in geomechanical properties within the reservoir. Acoustic logging of characterization well, C1, measured a lower Poisson’s ratio throughout the shallow reservoir interval compared to the deep interval. Additionally, shear wave splitting was identified in the shallow interval only. These observations indicate changes in principal stresses with respect to depth, which are likely for the relatively shallow extents of the reservoir due to the increasing overburden stress. Colmenares and Zoback (2007) observe this depth-dominated transition of stresses in CBM wells of the Powder River Basin. They describe the associated reorientation of hydraulic fractures, noting important implications for methane and water production (Colmenares and Zoback, 2007). Water flood tests (kill tests) were performed on CC7 prior to injection and on CC7 and DD8A five months into injection, in December 2015. All water flood tests measured significantly higher flow rates in the shallow reservoir interval. Spinner logs run on DD7 and DD8 in March 2016 to measure CO₂ flow rate also attributed a large majority of CO₂ flow to the shallow interval. Most of the well tests were conducted under different operational conditions than the microseismic monitoring, but the
results independently support the case for variation in geomechanical properties within the reservoir.

The largest signals detected during CO₂ injection occur near the DD7 wellbore and likely represent water mobility through hydraulically conductive fractures. The simultaneous lateral reorientation of energy during CO₂ injection suggests that these fractures are not activated during ambient conditions. The combined observations assert that the lateral distribution of energy on pre-injection days relates to gas transportation in the shallow reservoir interval, and the lateral reorientation of energy on during-injection days relates to water mobility in the deep interval.

6.5.5 Geostatistical analysis

Geostatistical analysis of SDI coherence volumes was used to explore and quantify changes in the three-dimensional distribution of acoustic energy due to CO₂ injection. This represents a meaningful analysis of weak, ambient signals, which in low-pressure, low-stress environments may be the only microseismic signals recorded. Geostatistical trends can be correlated with additional data, including well production history, CO₂ injection pressures, borehole water levels, well logging, and tracer arrivals, to support interpretations of reservoir behavior. Combining datasets provides an integrated characterization of fluid migration and geomechanical properties. Additionally, coherence amplitude volumes from SDI can be further processed using Tomographic Fracture Imaging℠ (TFI), a proprietary technology of the contractor, GGS, to interpret discrete fracture networks.

The geostatistical analysis conducted for this study required the management of very large datasets and significant data reduction. The eight data volumes analyzed in this study represent over 21 million data points in total. It is worth noting the challenges involved in managing and
reducing the datasets due to computational limits of analytical software, which prevented, restricted, and/or complicated some investigations. It is also worth noting that the data reduction techniques used for the analysis presented in this paper preserved the original processing resolution in the dimensions of interest for each investigation, where some methods involve resolution loss due to averaging or other processing.

6.6 CONCLUSIONS

SDI is a variation of seismic emission tomography which processes total trace energy from continuous microseismic recording using one-way depth migration and stacking over long time intervals in order to draw out weak signals. SDI can be used to monitor reservoir behavior associated with a variety of operations but is especially useful for low-pressure processes and low-stress environments where MEQs may be infrequent. Geostatistical analysis techniques provide a useful way to explore and quantify trends in the spatial distribution of acoustic energy within coherence amplitude volumes generated by SDI. Geostatistical observations of coherence volumes can be compared to additional monitoring datasets to validate and support interpretations of reservoir behavior.

Geostatistical analysis was used to evaluate SDI results for the early CO₂ injection period of a small-scale CO₂-ECBM field test. Data investigations determined, quantitatively, that the spatial distribution of high acoustic energy is consistent for the duration of pre-injection monitoring but reorganizes to a different, consistent distribution during injection. Both distributions display generally higher energy across the western margin of the model. Wellbore extractions for DD7 demonstrate a consistent increase in acoustic energy during CO₂ injection, which focuses in the deep interval of the reservoir. These findings were correlated with additional monitoring datasets
and other observations, including well production history, CO₂ injection rates and wellhead pressures, well logging, and tracer arrivals, in order to support an integrated interpretation of reservoir behavior, including:

- Enhanced permeability associated with structural deformation on the western margin of the study area, contributing to generally higher acoustic energy and specific high-energy hotspots/features.

- Rapid water evacuation from DD7 during early injection, responsible for high-energy hotspots near the well that are consistent during injection but absent pre-injection.

- Variation in geomechanical properties that may correlate to depth and/or pressure and contribute to the reorientation of high energy during injection.

An important result of this analysis is the extraction of meaningful data from microseismic monitoring in low-pressure and/or low-stress conditions where conventional, triggered recording of MEQs would be unsuccessful. Seismic emission tomography methods, like SDI, process weak ambient acoustic signals from continuous recording and are setting a new standard of sensitivity for microseismic monitoring. Geostatistical analysis is an effective way to explore, identify, and quantify trends in the spatial distribution of acoustic energy resolved by SDI.

Consistent, increased acoustic activity was observed at DD7 during injection but not at the other injection wells and is likely due to water evacuating the wellbore. The ability to resolve the site-specific signal of water mobility during CO₂ injection will improve the design of the microseismic survey planned for Phase II and help to meet monitoring objectives for field project. An additional implication of this analysis relates to the challenges of managing and reducing large
datasets. The data reduction techniques used here preserved original processing resolution in the
dimensions of interest (based on individual investigations). Preserving resolution was not an
objective for the analysis but could be important for some projects.

ACKNOWLEDGEMENTS

Financial assistance for this work was provided by the U.S. Department of Energy through the
National Energy Technology Laboratory's Program under contract no. DE-FE0006827.

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Development and Implementation of a Seismic Characterization and CO$_2$ Monitoring


7 CONCLUSIONS

The monitoring program for the CO\textsubscript{2}-ECBM test in Buchanan County, Virginia, has demonstrated success in characterizing the behavior of the coal reservoir in response to CO\textsubscript{2} injection. The monitoring results and findings from Phase I of the CO\textsubscript{2}-ECBM test presented in Chapters 5 and 6 validate the design efforts and rationales for technology selection described in earlier chapters.

The use of multi-scale monitoring technologies constrained interpretations of reservoir behavior in a complex monitoring environment. Perhaps the best illustration of this relates to a synthesis of monitoring observations from injection well DD7. Gas and water production history for the well indicate that it is a consistently strong gas producer with little water production. Its strong performance, coupled with its location on the flank of a local anticline, led to early suspicions that the reservoir near DD7 has enhanced permeability due to structural deformation.

Borehole liquid level measurements at the start of Phase I injection operations recorded the rapid evacuation of a 500-ft water column from the DD7 wellbore. In contrast, water levels in DD7A and DD8 rose slightly during the same time interval. Analysis of microseismic data recorded over the same period shows a strong, deep-focusing signal near DD7 that is persistent during early injection. This signal is interpreted as evacuation and transportation of formation water from the DD7 wellbore, possibly assisted by enhanced permeability. The rise in water levels at DD7A and DD8 are interpreted as pressure responses from the DD7 water plume.

A tracer deployed in the accumulated water of DD7 shortly before the start of CO\textsubscript{2} injection was detected at several offset CBM production wells, all up-dip from DD7. This seems inconsistent with the indication of water from DD7 impacting DD7A and DD8, which are located down-dip. Additionally, microseismic results indicate water transportation in both directions.
However, production rate tests performed on several wells across the study area and under different operational conditions all suggest that most gas flow occurs in the shallow reservoir interval. Formation logging supports this case with observations of geomechanical character for shallow and deep reservoir intervals. These observations point to a possibility that the tracer deployed in DD7 evaporated out of the formation water prior to CO₂ injection or was not successfully deployed in the water initially.

An integrated interpretation of all DD7 monitoring observations points to the governing role of geologic structure and suggests that injected CO₂ migrates up-dip in the shallow coal seams carrying the tracer. This is a conventional gas migration pattern. Coal is typically an unconventional reservoir, but CBM production history and rapid water transportation rates indicate enhanced permeability that could contribute to conventional behavior on the anticline. Water migrated down-dip under conventional behavior, but high injection pressures coupled with well-developed hydraulically conductive fractures on the anticline could have forced water in multiple directions during early injection.

In addition to demonstrating the benefits of multi-scale monitoring for data integration, monitoring results produced several recommendations. Geostatistical analysis of microseismic results proved to be successful for identifying and quantifying spatial trends and changes in the distribution of acoustic energy due to CO₂ injection. The management and reduction of large datasets can be obstacles to meaningful analysis, but methods applied to large microseismic data volumes were successful and preserved original data resolution in the dimensions of investigation. Finally, continuous monitoring of injection parameters throughout Phase I operations led to the development of a recommended injection strategy for CO₂-ECBM operations.
Recommended future work includes revisiting datasets related to surface deformation measurement which require very long time series for accuracy. Phase I results will be used to guide monitoring efforts for Phase II operations in Fall 2016. Comparison of results from Phases I and II, including repeatability of results and new observations, will further constrain reservoir behavior at the CO₂-ECBM study area.
### Appendix

**Injection Data**

*Notes: Daily values for injection data have been averaged from near-continuous (60-second) recordings. Very early values have been eliminated where they were not reliable or representative. Additional gaps in data or values of zero correspond to brief interruptions in CO₂ supply, equipment maintenance, well tests, or technical/communications difficulties with the SCADA system.*

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