PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP PHASE II – CO_2 SEQUESTRATION VALIDATION TEST IN A DEEP, UNMINABLE LIGNITE SEAM IN WESTERN NORTH DAKOTA REGIONAL TECHNOLOGY IMPLEMENTATION PLAN

Task 4 – Deliverable 53

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TABLE OF CONTENTS

Continued…

TABLE OF CONTENTS (continued)

Continued…

TABLE OF CONTENTS (continued)

LIST OF FIGURES

Continued…

LIST OF FIGURES (continued)

LIST OF TABLES

PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP PHASE II – CO_2 SEQUESTRATION VALIDATION TEST IN A DEEP, UNMINABLE LIGNITE SEAM IN WESTERN NORTH DAKOTA REGIONAL TECHNOLOGY IMPLEMENTATION PLAN

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EXECUTIVE SUMMARY

The U.S. Department of Energy (DOE) established the Regional Carbon Sequestration Partnership (RCSP) Program to conduct comprehensive evaluations of the opportunities for carbon dioxide (CO_2) capture and storage in North America. One of the options for storage is the injection of CO_2 into unminable coal seams. To evaluate this storage option, the Plains CO_2 Reduction (PCOR) Partnership, which is led by the Energy & Environmental Research Center (EERC) at the University of North Dakota, conducted laboratory- and field-based investigations of an unminable lignite coal seam located in Burke County in northwestern North Dakota. The purpose of the study was to assess the feasibility of storing anthropogenic CO_2 in lignite seams while simultaneously producing coalbed methane (CBM). More specifically, the goals of the study were as follows:

- To demonstrate that CO_2 can be safely injected and trapped in lignite by means of adsorption.

- To assess the feasibility of CO_2-enhanced methane production from lignite.

- To evaluate a variety of carbon storage operational conditions to determine their applicability to similar coal seams within the region or beyond.

In order to culminate all that was learned during the 4 years of the validation test, a Regional Technology Implementation Plan (RTIP) has been developed. The purpose of the RTIP is to provide direction on site selection and development; permitting; well drilling, casing, completion, and development; and CO_2 injection and monitoring. The RTIP expounds upon the experiences gained at the lignite test site to offer critical evaluations of decisions that were made and valuable insight into lessons that were learned.

The selection of the demonstration test site was driven by a number of technical and nontechnical factors. The former included the review of geophysical logs from the database of the North Dakota Industrial Commission Oil and Gas Division, which identified multiple coal seams. Following this reconnaissance effort, water well logs and other available data sets, e.g., gamma ray logs, were examined to identify the water quality, coal characteristics, and baseline geologic settings in these candidate coal seams. At the same time, the availability of mineral rights was also an important screening factor. This review led to the identification of an area in Burke County in northwestern North Dakota as the general location of the demonstration test site.

The injection well and the four monitoring wells were drilled as part of a single mobilization. A core was collected during the drilling of the injection well to provide samples for the conduct of selected laboratory tests.

Development of the wells was conducted by applying different stimulation techniques, in stages, with the intent of avoiding the use of more aggressive techniques that had the potential to negatively influence the injection zone and complicate the interpretation of postinjection monitoring. The techniques employed during the demonstration, in order of application, included swabbing, sonic hammer, nitrogen N-fit test (i.e., minifrac), and acid treatment. The results of the N-fit tests indicated that the coal formation was significantly underpressured, with an actual reservoir pressure of about 345 psia versus an expected formation pressure of approximately 470 psia. This underpressured situation was not anticipated, and as a result, well drilling, completion, and development activities were greatly affected.

Approximately 90 tons of CO_2 was injected over a roughly 2-week period into a 10–12-ft-thick coal seam at a depth of approximately 1100 feet. Monitoring, verification, and accounting (MVA) techniques were selected based on the characteristics of the site, and a number of techniques were utilized. Of these techniques, reservoir saturation tool logs and time-lapse crosswell seismic tomography provided the most valuable information. These techniques demonstrated that the CO_2 did not significantly move away from the wellbore and was contained within the coal seam for the duration of the approximately 3-month monitoring period. Evaluation of CO_2 fate beyond this time period would require an extended monitoring period which is beyond the scope of this demonstration.

Despite the atypical properties of the reservoir at the demonstration test site, which dramatically changed the dynamics of the test, the primary goal of the test, which was to demonstrate that CO_2 could be injected and stored in an unminable lignite seam, was achieved. This conclusion opens the door for the conduct of other similar CO_2 injection tests but at a larger scale and longer duration that can be used to confirm an optimal injection regime, investigate the economics of this carbon storage option, and apply and validate a more streamlined MVA strategy.

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1.0 BACKGROUND

1.1 Program Goals and Objectives

The U.S. Department of Energy (DOE) established the Regional Carbon Sequestration Partnership (RCSP) Program to conduct comprehensive evaluations of the opportunities for carbon dioxide (CO_2) capture and storage in North America. One of the options for storage is the injection of CO_2 into unminable coal seams. To evaluate this storage option, the Plains CO_2 Reduction (PCOR) Partnership, which is led by the Energy & Environmental Research Center (EERC) at the University of North Dakota, conducted laboratory- and field-based investigations of an unminable lignite coal seam located in Burke County in northwestern North Dakota. The purpose of the study was to assess the feasibility of storing anthropogenic CO_2 in lignite seams while simultaneously producing coalbed methane (CBM). More specifically, the goals of the study were as follows:

- To demonstrate that CO_2 can be safely injected and trapped in lignite by means of adsorption.
- To assess the feasibility of CO_2-enhanced methane production from lignite.
- To evaluate a variety of carbon storage operational conditions to determine their applicability to similar coal seams within the region or beyond.

With regard to the last goal, successful practices were identified to support the planning and implementation of similar projects that will need to address the following factors:

- CO_2 storage capacity, methane content, and applicability of existing experimental methodologies to assess these and other critical storage parameters

- Features of fluid transport in lignite

- Stability of CO_2 stored within lignite

- Factors controlling the success of CO_2 storage/CBM production operations in lignite

- Economics of operation

Using anthropogenic CO_2 to enhance the production of CBM from unminable lignite coal seams, while leaving the CO_2 in long-term storage in the coal after the CBM has been produced, represents a value-added storage opportunity that offers both a near-term economic return and a long-term environmental benefit.

1.2 Project Time Line and Key Study Elements

1.2.1 Site Selection, Permitting, and Drilling of Wells

The time line for the laboratory and field tests that were conducted is presented in Figure 1-1. As shown, the field study was conducted over the period from August 2007 through July 2009. Selection and permitting of the test site, which included searching various data sets and collaborating with numerous partners as well as conducting an informational public meeting in Bowbells, North Dakota, occurred prior to drilling the five wells. The locations of these wells within the site are provided in Figure 1-2.

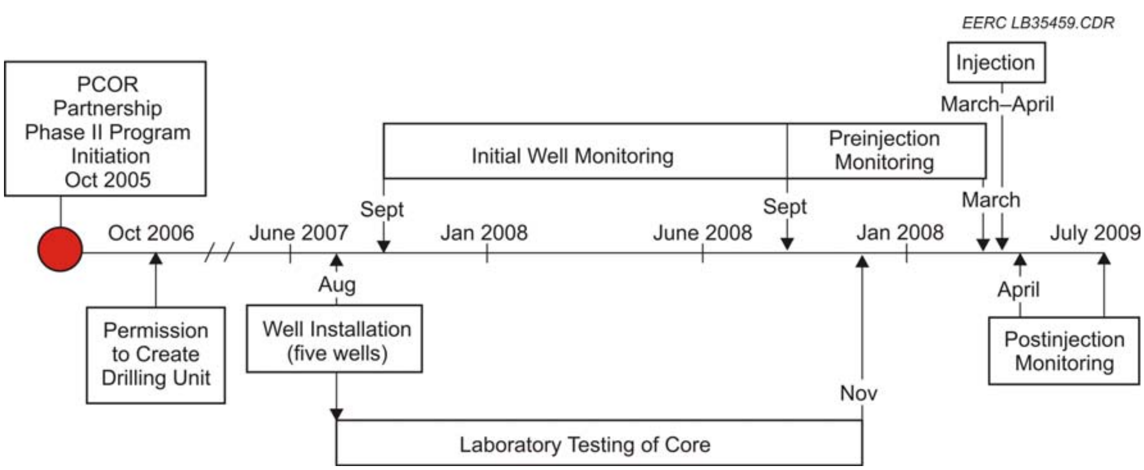

Figure 1-1. Test time line.

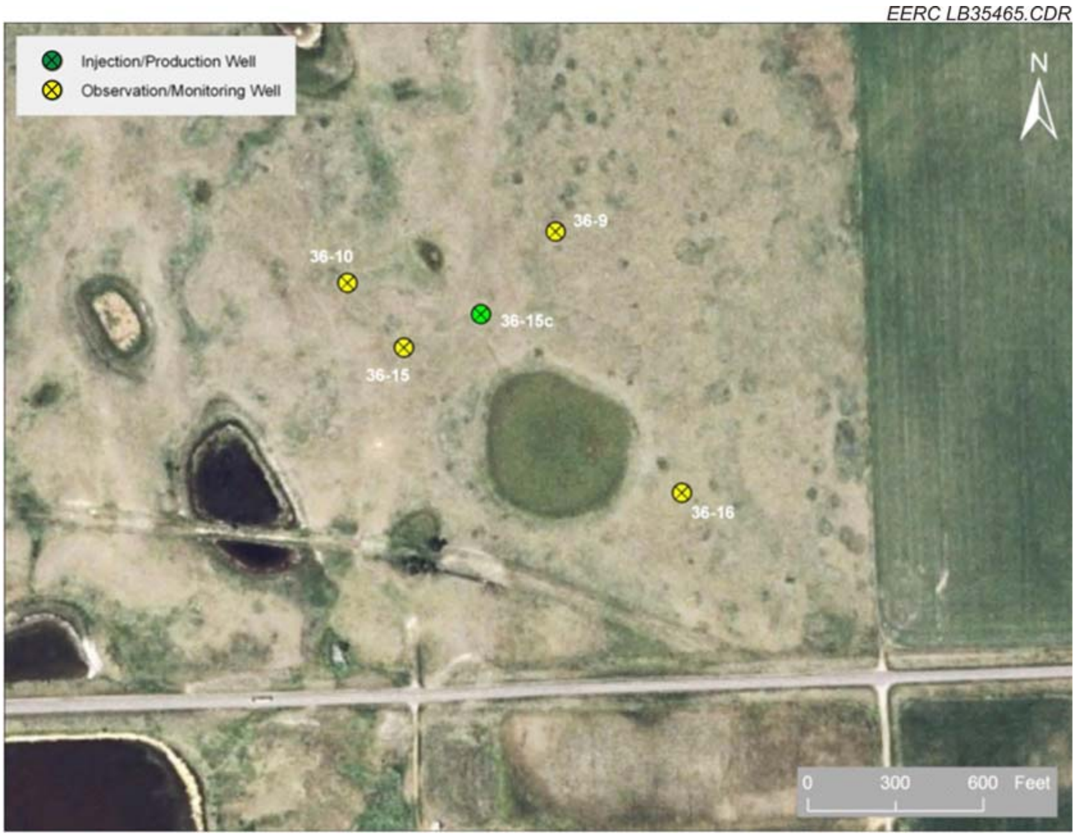

Figure 1-2. Well locations.

1.2.2 *Laboratory Tests of Core*

During the drilling of one of the wells, a core 20 feet in length was recovered. This core included the coal seam as well as a few feet of the clay from the upper and lower seals. This core was subjected to a series of laboratory tests that were designed to characterize the reservoir. These tests measured the following parameters:

- Gas content
- Gas specific gravity
- Methane and CO_2 adsorption isotherms
- Diffusion coefficients
- Gas desorption times
- Coal ash density and compressibility
- Rock porosity and permeability

The laboratory tests were completed in early fall 2008. The results of these tests are summarized and discussed in this report but are presented in detail in a report dated November 2008 (Sorensen, 2008) (see Appendix A).

1.2.3 Well Completion

Well completion immediately followed the drilling and consisted of casing and cementing the boreholes over the entire depth interval. At the time of completion, this was considered necessary to provide zonal isolation and ensure that CO_2 was injected into the lignite interval. The wells were perforated with 23-gram raptor charges, targeting a coal seam of 10 feet in thickness at a depth of approximately 1100 feet.

1.2.4 Initial Well Monitoring

An initial well-monitoring program was begun in September 2007 and concluded 1 year later, at the end of August 2008. During that time span, the operations were shut down between November 2007 and April 2008. While monitoring took place over this entire period, there was lessened frequency during the periods of inactivity. The monitoring was performed using portable field instruments and focused on pressure changes, fluctuations in water elevations, and the documentation of the presence of gases. Composition of the gases was also measured by taking samples from the wells and characterizing them using a gas chromatograph within 24 hours. Fluid samples were also collected routinely from the wells via swabbing. These samples were analyzed in the field for conductivity, temperature, and pH and in the laboratory for sodium, calcium, magnesium, iron, potassium, chloride, carbonate, bicarbonate, and sulfate (pH, total dissolved solids [TDS], and sodium chloride concentrations were calculated using these same data).

1.2.5 Well Development

Based on the results of the initial well-monitoring program, the wells were subjected to a combination of several different well development techniques (in order of application):

- Swabbing
- Sonic hammer
- Nitrogen fracture initiation tests (N-fit)
- Acid treatment, with and without perforation balls

The purpose of applying these techniques was to ensure communication between the wellbores and the formation.

1.2.6 Preinjection Well Monitoring

Following well development, preinjection well monitoring was conducted from September 2008 to the onset of CO_2 injection in March 2009. During this period, each well was equipped with surface and downhole sensors to monitor temperature, pressure, specific conductance (conductivity), and pH. The downhole sensors were deployed at the top of the perforated interval of each well. The data collection frequency was varied to capture well responses during certain well development activities.

1.2.7 CO_2 Injection

CO_2 injection was completed over a 16-day period, beginning on March 10, 2009, and ending on March 26, 2009. The impacts of various injection pressures and temperatures on the CO_2 injection rate were investigated. The overall approach consisted of an initial injection of CO_2 at the maximum allowable pressure of <780 psi, which was based on a determination of the estimated fracture pressure of the rocks. This pressure resulted in a peak flow of ~3 gpm within 12 hours. The flow rate then steadily declined. Since the maximum injection rate accepted by the coal seam was exceeded by the injection rate, injection was frequently started and stopped, allowing pressure to build and decline during these intervals. In general, the duration of this average injection cycle was about 40 minutes. At the same time, the temperature of the CO_2 was maintained at ~100°F; however, during part of the injection period, for approximately 48 hours, the temperature and pressure were manipulated such that liquid-phase CO_2 was injected into the formation.

1.2.8 Postinjection Monitoring (MVA)

Postinjection monitoring occurred from the conclusion of injection through June 2009. The objectives of the postinjection monitoring, or MVA (monitoring, verification, and accounting), were threefold:

- To provide insight into CO_2 containment within the targeted injection interval
- To help understand the physical processes of CO_2 injection into lignite and the geochemical interactions of CO_2 with lignite
- To evaluate the possibilities of CO_2–enhanced coalbed methane (ECBM) production

The MVA techniques that were used were selected judiciously, considering the small scale and short duration of the injection. As such, the techniques and measurements selected were largely from among those routinely applied in oil fields and included the following:

- Surface sensors for measurement of temperature, pressure, and flow rate.
- Downhole sensors for measurement of temperature, pressure, conductivity, and pH.
- Reservoir saturation tool (RST) well log for measurement of gas saturation near the wellbore.
- Multiple lines of time-lapse crosswell seismic tomography for the measurement of translational differences of sound waves created by CO_2 injection.
- Passive seismic monitoring for registering microseismic events induced by the injection.

- Analyses of gas samples from the wellheads to measure methane, CO_2, and oxygen concentrations and other key gas-phase constituents such as a fluorocarbon tracer, which was injected with CO_2 at the beginning of the test to provide a means of distinguishing between CO_2 that may be naturally occurring in the reservoir and that which was injected.

- Analyses of fluid samples to evaluate any inflections in pH or carbonate concentrations.

1.3 Unique Characteristics of Demonstration Test

By its very nature, a demonstration test is designed to explore a range of operating conditions to provide information that can be used to define the optimal operating conditions for a commercial facility. On the one hand, more extreme operating conditions may be examined to better understand how the system will respond and to delineate the boundaries of operation that may be feasible. On the other hand, in many instances, the conditions that are selected for investigation may be overly conservative to ensure that the demonstration test, itself, does not result in unintended harm to the environment or other local resources.

Several aspects of this demonstration test were uniquely designed to ensure that the study data were properly generated and could be easily interpreted. Some examples of these unique design and/or operating features are highlighted below.

First, overly conservative techniques were used during the casing of the wells. Specifically, the boreholes were cased and cemented throughout the whole depth interval. This type of completion was considered necessary by the working group to provide zonal isolation and to ensure that the CO_2 was injected into the targeted lignite interval.

Second, well development was approached in stages with the desire to avoid using more aggressive techniques that had the potential to negatively influence the injection zone and complicate the interpretation of postinjection monitoring data. For example, even though acid treatment of the wells might be the first choice when installing wells for a commercial facility, the demonstration test began with sonic hammers, with the hope of avoiding the potential impacts of acid addition on the demonstration test observations.

Lastly, the discovery that the lignite formation was underpressured (~345 psia versus an expected pressure of ~470 psia) represented an atypical situation that affected two important aspects of the demonstration. The underpressure resulted in overbalanced drilling and the plugging of potential permeability. Further, it likely caused higher pressure buildup during the injection of the CO_2. The lower reservoir pressure was also a likely cause of the low methane content of the formation that was observed. More discussion of these aspects of the demonstration test is provided later in this report.

The remainder of this report presents the details of each of the demonstration test elements and discusses the data that were generated and their interpretation as it relates to the feasibility of storing CO_2 in unminable coal seams while simultaneously enhancing the production of CBM.

2.0 SITE SELECTION

Most of the coal (lignite) in North Dakota is found within the sediments of the Fort Union Group (Tertiary/Paleocene). Fort Union Group sediments were deposited as a clastic wedge thinning from eastern Montana into North Dakota (Murphy and Goven, 1998). In general, the entire Fort Union Group can be described as consisting of alternating interbeds of sandstone, siltstone, clays, and lignite, with some limestone. The lignite beds (seams), as with most other Fort Union sediments, were deposited in a complex fluviolacustrine environmental system. Lignite seams vary in thickness and distribution and range from a foot to a few feet in thickness. The thickest lignite seams in North Dakota are in the 10-m (30-ft) range (Murphy and Goven, 1998).

The site selection for the field validation test had many components. First, a thorough search was conducted of the North Dakota Industrial Commission (NDIC) Oil and Gas Division (OGD) database for geophysical logs that were available from the recently glaciated portion of the state. The search resulted in the identification of multiple coal seams in the area. The initiation of the reconnaissance-level search in the glaciated portion of the state originated from the hypothesis that the multiple glaciation events that took place over this area could have provided the freshwater needed for the generation of biogenic gas that could be present. Glaciation could have also caused fracturing in the coals because of relaxation of the sediments after the glaciers retreated, similar to the fracturing that occurs in the Antrim Shale in the Michigan Basin.

Only unminable coals were evaluated using the following North Dakota criteria (Murphy, personal communication, 2007) to assess the economic feasibility of coal mining:

- A minimum cumulative coal thickness of 10 feet, typically occurring in one or two beds
- A minimum individual bed thickness of 2.5 feet
- A maximum stripping ratio of 10 feet of overburden for every foot of coal
- A minimum of 20 feet of overburden to minimize the effects of weathering
- Coal depth of less than 170 feet

Those coals that failed to satisfy at least one of these criteria were considered to be unminable.

The availability of mineral rights was also a consideration in selecting a site. Activities were closely coordinated with NDIC OGD and the North Dakota State Land Department (NDSLD) to develop a list of candidate locations that would be appropriate for CO_2 injection and ECBM production. An area in Burke County in northwestern North Dakota was identified as having geological characteristics that met the criteria for conducting a validation test that met all of the primary goals of the project.

Ultimately, the PCOR Partnership worked with NDSLD to obtain the mineral lease for Section 36, T159N, R90W in the southeast corner of Burke County for CO_2 injection and ECBM production. NDSLD granted permission for the proposed project, and a more in-depth study of the available geophysical data in the vicinity of the proposed site was conducted. Burke County is located in northwestern North Dakota in the central part of the Williston Basin. The site for the pilot-scale CO_2 storage/ECBM project is located in the southeastern part of the county (Figure 2-1).

An abandoned lignite mine and lignite monitoring well exist within a 35-mile radius of the selected site (Murphy and Goven, 1998). However, both of them monitor shallower lignite seams and did not contribute to a better understanding of the targeted coal. Several hydrocarbon wells producing predominantly from the Mississippian Madison Formation have been drilled in the vicinity of the site. Gamma ray and sonic logs from these wells provided an indication that the targeted coal seam existed in the area. Logs indicated a relatively thin, less than 10-ft coal seam at depths of 1060–1160 ft that shallows to the east of the area. The team felt that there likely was another lignite layer present above the targeted one and separated from it by a sandstone layer about 20–30 ft in thickness. However, it should be noted that several presumably low-permeability argillaceous and siltstone layers overlie the lignite, which the team felt, would likely mitigate gas and fluid migration in any preexisting conduits or fractures in the target zone caused by CO_2 injection.

The assumptions regarding the presence of lignite seams in the studied area and their geometry were developed on the basis of the analysis of gamma ray logs from 54 wells located within a 10-mile radius of the project site. Both sonic and gamma ray log curves were used to

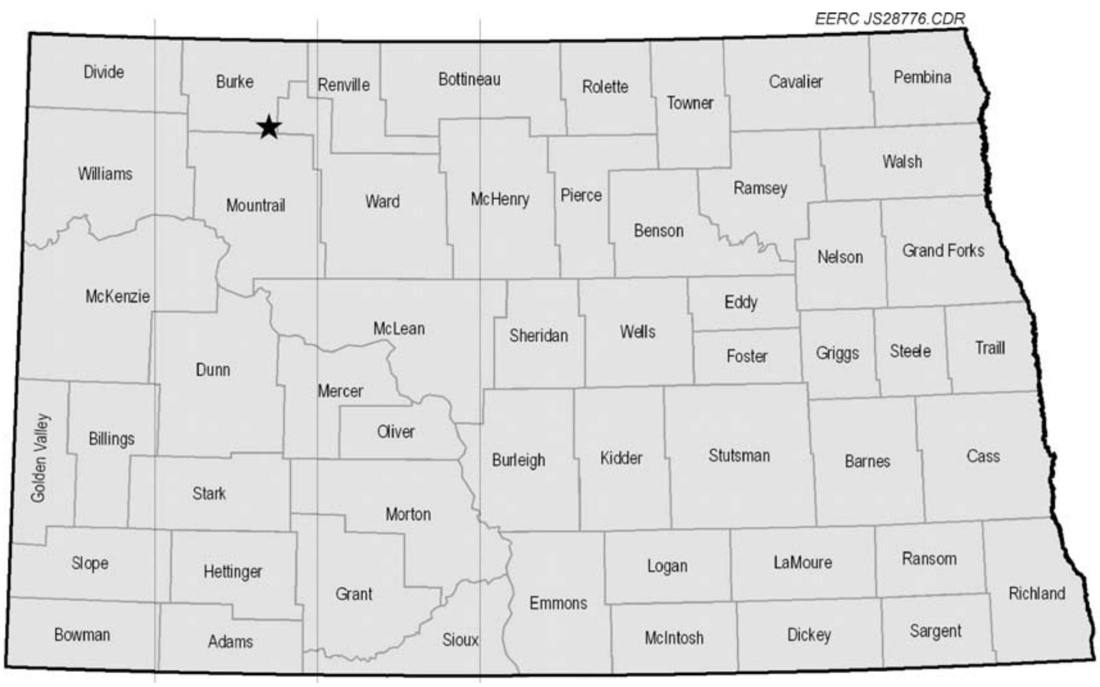

Figure 2-1. Location of the lignite study relative to the state of North Dakota.

pick signatures characteristic of coal beds. Resistivity curves were used in those instances when either gamma logs were not available or were difficult to interpret. Depths and thicknesses of possible lignite beds were determined and recorded, and consistent confining markers of the coal beds were identified using gamma ray log curves. This methodology also allowed for the tracing of some of the beds throughout the study area.

A sample of the logs from the Howell No. 15-44 well, currently operated by Marathon Oil Company (NDIC File No. 38991), showing the targeted lignite seam (red dashed line) is presented in Figure 2-2.

The preliminary investigation found six geologic logs of particular utility near the study area. They confirmed that multiple coal seams were present, ranging in thickness from 1 to 16 ft. Of the coal seams identified, three could be traced throughout the area. Figure 2-3 shows the well logs from NE–SW with the targeted coal seam highlighted.

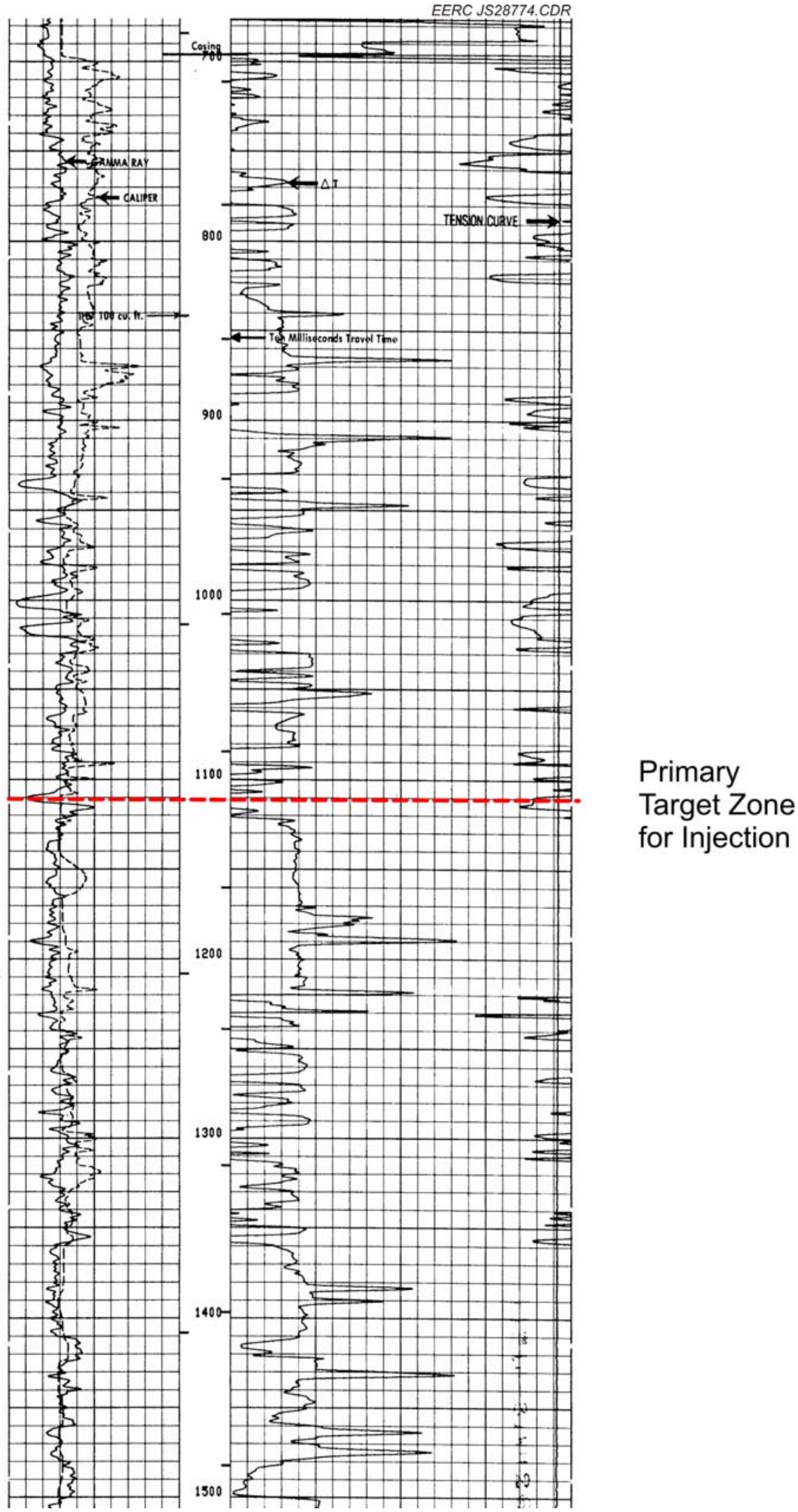

Figure 2-2. Gamma ray and sonic logs from Howell No. 15-44 well.

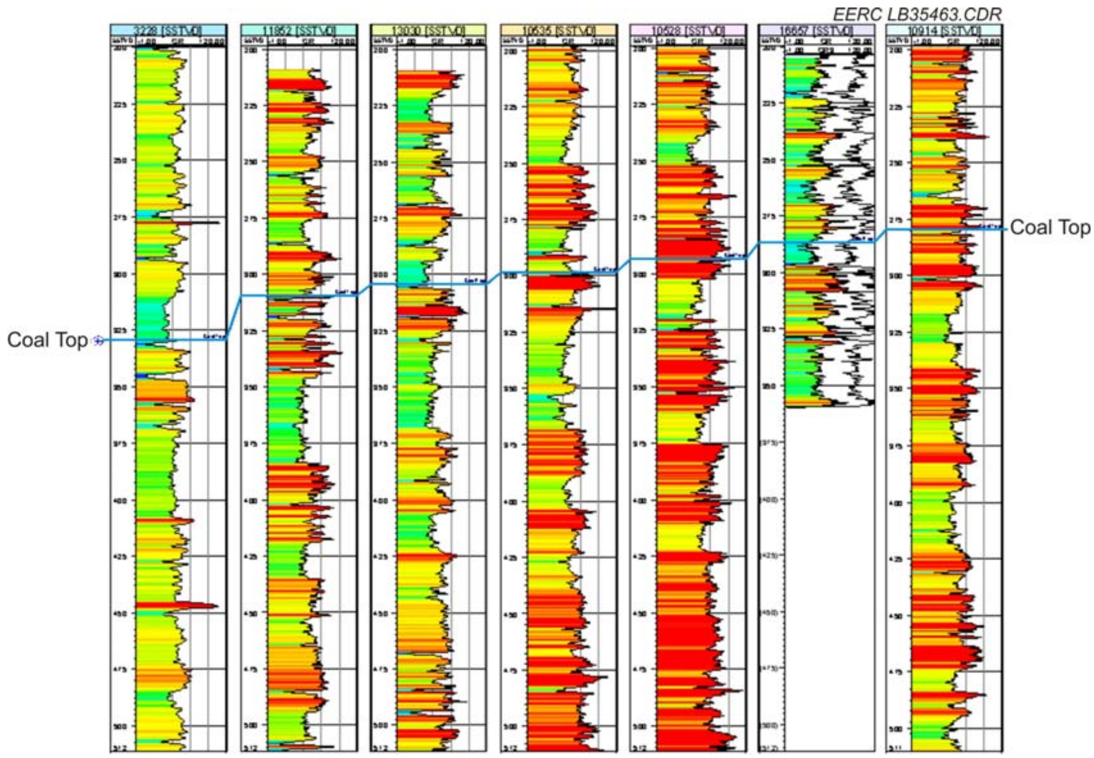

Figure 2-3. Six geologic well logs from the study area. The correlated coal seam of interest is highlighted.

3.0 PERMITTING REQUIREMENTS

3.1 Federal Requirements

In the United States, the National Environmental Policy Act (NEPA) of 1969 establishes national environmental policies that stipulate certain procedural requirements for federal agency actions.

To begin the lignite field validation test, the EERC was required to complete DOE's environmental questionnaire. The purpose of this questionnaire is to determine, as early as possible, whether the validation test requires an environmental assessment or an environmental impact statement, or if the test qualifies for a categorical exclusion. Based on the completed questionnaire, the field validation test was granted a categorical exclusion.

3.2 State of North Dakota Requirements

The North Dakota Administrative Code (NDAC) (Chapters 43-02-03, 43-02-05, 43-02-06, 43-02-08, 43-02-09, 43-02-10, 43-02-11, and 43-02-12) contains the general rules and regulations adopted by the NDIC to conserve and govern the natural resources of North Dakota. For the purposes of this field validation test, the following requirements were met.

3.2.1 Well-Spacing Exemption

According to NDAC 43-02-03-18, "no more than one well shall be drilled to the same pool on any such governmental quarter section or equivalent lots, except by order of the commission." (NDIC, 2009). In the fall of 2006, the EERC requested an exception from the NDIC to these standard spacing rules for gas wells. The EERC proposed to drill five research wells in a single 160-acre spacing unit as part of the validation test. The NDIC granted the well-spacing exception following a hearing to discuss the project and review exhibits.

3.2.2 Drilling Permits

Applications for drilling permits were submitted to the NDIC in the spring of 2007. The permit application included an accurate plat, certified by a registered surveyor, showing the location of the proposed well(s) with reference to the nearest lines of a governmental section. It also included a drilling prognosis, which provided the proposed total depth (including measured depth if appropriate) to which the well would be drilled and the estimated depth to the top of important geological markers. The drilling prognosis also included the following information regarding the proposed program:

- The mud program
- The casing program, including size and weight
- The depth at which each casing string was to be set
- The amount of cement to be used
- The estimated top of the cement

3.2.3 Sundry Notices

To comply with administrative code requirements, various sundry notices had to be submitted to NDIC. These notices were required for any remedial work, or attempted remedial work, such as acidizing, repair work, perforating, reperforating, or other similar operations. These notices were also submitted when a variance was requested from state requirements. For example, a notice was submitted to request the collection of samples every 30 feet, from surface to total depth, for three of the monitoring wells. The state requirement specifies that a sample be collected every 10 feet. The request was made to preserve resources. Samples from every 10 feet had been taken during the drilling of the first two wells drilled, and little variance between the two wells was observed. Since the five wells were drilled in such close proximity to one another, it was decided that a 30-foot collection interval would provide the same quality of data as samples taken every 10 feet. Other notices that were submitted are listed below:

- Notice providing outline of the perforating program for the wells and for the mud pit reclamation on each well.

- Notice to waive the requirement of open-hole logs in one of the monitoring wells after numerous attempts to overcome an assumed sediment bridge that was preventing the deployment of the logging sonde were unsuccessful.

- Notice detailing the work performed on each of the five wells following completion of all well development techniques.

3.2.4 Injection Application

In late spring 2008, the injection application was submitted to NDIC for approval. The following information was provided with the injection application:

- Surface and bottom-hole location
- Geologic data on the injection zone and the confining zones, including geologic names, lithologic descriptions, thicknesses, and depths
- Estimated bottom-hole fracture pressure of the top confining zone
- Average and maximum daily rate of fluids to be injected
- Average and maximum requested surface injection pressure
- Geologic name and depth to base of the lowermost underground source of drinking water, which may be affected by injection
- Existing or proposed casing, tubing, and packer data
- A brief description of the proposed injection program

A plat depicting the area of review (AoR) (¼-mile radius) and detailing the location, well name, and operator of all wells in the AoR was also included in the application. Injection wells, producing wells, plugged wells, abandoned wells, drilling wells, dry holes, and water wells in the AoR were identified on the plat (see Figure 3-1).

The application required sampling from the two nearest freshwater wells. Because of some idiosyncrasies in the North Dakota State Water Commission's database of freshwater wells, the EERC decided to sample several surrounding wells for completeness (see Figure 3-1). The results were submitted as part of the injection application, and the results of the pre- and postinjection monitoring can be found in Appendix B.

A legal description of land ownership within the AoR was part of the injection application. An affidavit of mailing certifying that all landowners within the AoR were notified of the proposed injection well, that comments could be submitted to the Commission, and that a hearing would be held at which comments could also be submitted was also a requirement of the injection application.

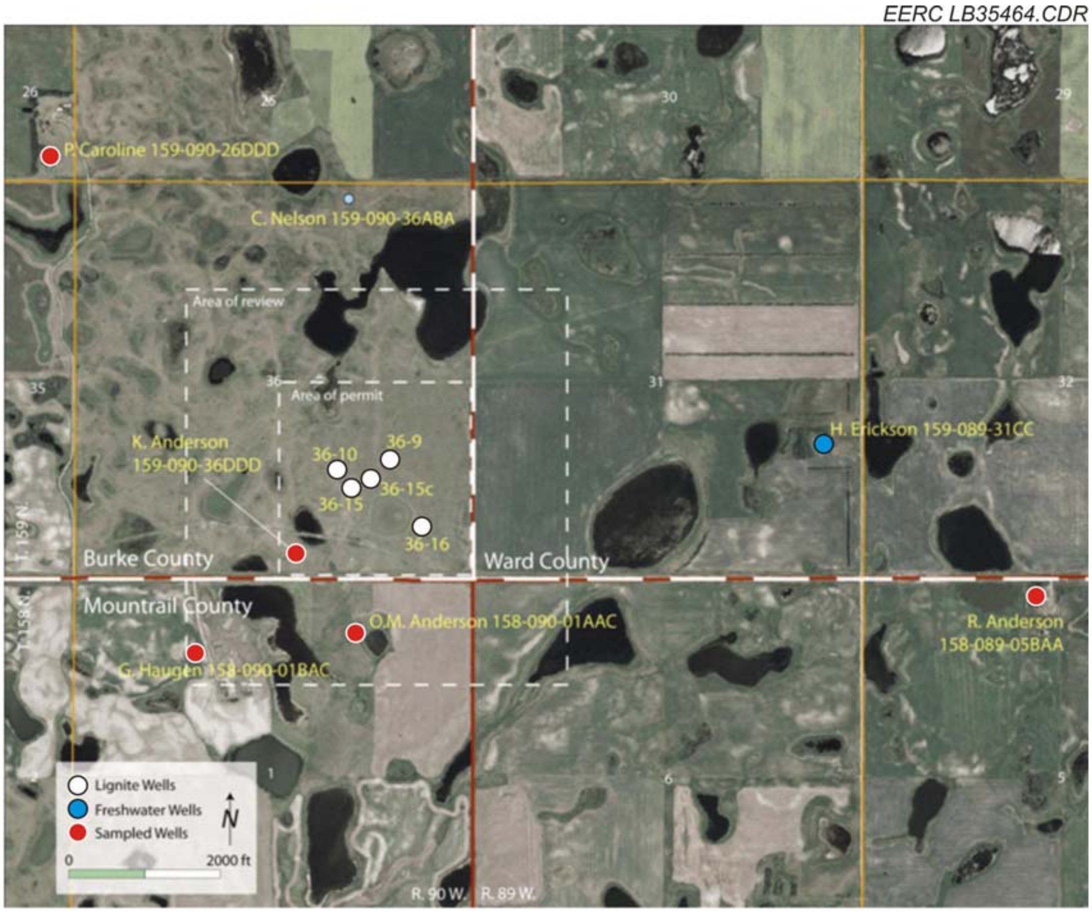

Figure 3-1. Location of AoR and related wells.

Schematic drawings of the injection system including current wellbore construction and proposed wellbore and surface facility construction were provided as part of the injection application. Additionally, all state requirements for the siting, construction, mechanical integrity, operating, and monitoring of Class II injection wells were met.

3.2.5 Aquifer Exemption

In addition to submitting the application for injection, an aquifer exemption request was made. This was required since the intended injection zone, or a portion thereof, met the criteria for a potential underground source of drinking water. Based on the analysis of data gathered during the drilling and development of the injection well, the EERC was able to demonstrate that the injection zone would qualify as an exempted aquifer in accordance with NDAC 43-02-05-03. Upon receiving concurrence for approval from the U.S. Environmental Protection Agency (EPA) regarding the aquifer exemption request, the state of North Dakota issued a final order approving the application for injection at the test site.

4.0 DRILLING, LOGGING, AND COMPLETION

In August 2007, five wells were drilled in a modified five-spot configuration within a 160-acre spacing unit (designated as Wells 36-9, 36-10, 36-15, 36-15C [injector well], and 36-16). Figure 4-1 displays a map of the well locations, and Figure 4-2 provides an aerial view of the project location with the drill rig located on the injection well site pad.

A summary of the sampling and logging activities that were performed on each of these wells is provided in Table 4-1. The details regarding each of these activities are provided in the remainder of this section.

4.1 Mud System

A freshwater/native mud system was employed to drill both the conductor/surface hole and test/production hole for all five wells. Mud weights were designed to be as low as possible to avoid fluid invasion and subsequent formation damage at depth (more regarding this philosophy in the discussion section of this report). Weights of 9.2 to 9.8 pounds per gallon were recorded at total depth. Mud viscosity was controlled as required for coring and logging, ranging from 28 centipoise to a maximum of 51 centipoise.

Figure 4-1. Map of injection and monitoring well locations.

Figure 4-2. Aerial view of project site.

Table 4-1. Summary of Sampling and Logging Activities for the Injection and Four Monitoring Wells

Specification	36-9	36-10	36-15	36-15C	36-16
Total Depth, ft	1242	1274	1643	1246	1211
Drilling Cutting Samples	X	X	X	X	X
Core Collection				X	
Platform Express Logging Suite	X	X	X	X	
Sonic Scanner Log				X	
Cement Bond Log	X	X	X	X	X
Cased-Hole Neutron Log				X	X

4.2 Sample Collection

Throughout the drilling, a 24-hour/day, two-person geological well site team collected drill cutting samples and recorded mud gas concentrations from near surface to total depth. A Pason (P3) gas detector with chromatograph was used to monitor and record total mud gas and document the gas composition. As the coal interval was drilled, anywhere from 30 to 110 units (1 unit = 100 ppm methane) of gas were detected. See Appendix C for the complete mud log analysis. Drill cuttings were collected at 10-foot sample intervals for the first two wells drilled (36-15 and 36-15C) and at 30-foot intervals for the remaining wells (36-9, 36-10, and 36-16). The samples were tagged to depth, cleaned, dried, and described (see Figure 4-3).

EERC LB35578.CDR

Figure 4-3. Shaker from which drill cuttings were collected.

4.3 Core Collection

In addition to collecting drill cuttings from each well, a single core was collected from the injector well (36-15C) (Figure 4-4). The coring program was designed to collect the targeted coal seam and a few feet of representative clay from above and below the coal seam. Only a limited amount of core was cut to ensure the coal would not lose inherent porosity and permeability because of the compression caused by pressures associated with coring excessive intervals of sediment above and below the coal seam. A 20-foot core was cut from the depth interval extending from 1070 to 1090 feet. There was 100% core recovery; however, coal was present in only the last 4 feet of the core, indicating that the entire coal seam of interest, as well as the lower clay interval, had not been captured during the coring process.

The partial collection of core from the zone of interest occurred as a result of the methods used to terminate the coring process and a lack of absolute stratigraphic control while coring. The core point was picked by comparing the drill rate from Well 36-15 to Well 36-15C and by analyzing the unprocessed log data from Well 36-15. During the coring procedure, drill cutting sample returns were closely monitored for the presence of coal. Significant coal returns were noted upon initiating coring. After approximately 15 feet of coring, the sample returns became 100% silt and remained so until coring was terminated. It was assumed at this time, that this represented the bottom of the coal interval. This change in cutting samples from lignite to silt was also accompanied by a slight drop in pump pressure, which was also thought to be indicative of the base of the coal interval. In reality, the sample returns reflected uphold cavings due to coring, and the pump pressure drop was indicative of the beginning of the coal interval instead of the bottom. In turn, the entire coal seam of interest and underlying clay were not retrieved during this coring process.

EERC LB35470.CDR

Figure 4-4. Core barrel.

When the core barrel retrieval began, little to no increase was noted in the string weight. Because of the possibility that the core catcher had not closed, it was decided to bring the core out slowly to minimize the chance of losing it. The time loss because of this process was significant, and there may have been significant gas loss from the coal during the process.

4.4 Open-Hole Logging

Immediately after drilling, the Schlumberger Platform Express logging suite was run in each individual well, except in 36-16, where an assumed sediment bridge created hole problems that prevented open-hole logging. Additionally, a Schlumberger Sonic Scanner log was run in the injector well. These geophysical well-logging technologies were used to characterize a wide variety of reservoir parameters. The sonic log provides data that can be used to predict pore pressure, determine density, and estimate geomechanical properties, such as rock elastic constants and bulk compressibility. The Platform Express logging suite provides measurements of porosity, resistivity, sand/shale content, and borehole diameter. The Schlumberger logging tool is shown in Figure 4-5. The logs indicate that the primary target zone is a coal seam that is occasionally bifurcated, in places separated by approximately 1 to 2 feet of silty clay. The total thickness of the seam is approximately 10 to 12 feet and is overlain by a continuous layer of clay approximately 4 feet thick, which provided a suitable seal for the injection test.

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Figure 4-5. Photo of Schlumberger logging truck and sonde.

4.5 Casing

Drilling was completed through 40 feet of 32-pound, 9 5/8-inch-diameter conductor pipe which served as surface casing. This pipe was set in a 16-inch-diameter hole that was cemented to the surface with approximately 50 sacks of cement. A test/production hole, 8¾ inch in diameter, was then drilled to depth and cased. The test/production string consisted of 7-inch-diameter, 23-pound casing. The casing was cemented to surface with approximately 175 sacks of Class “C” cement.

4.6 Cased-Hole Logging

Cement bond logs were run in all of the wells. In addition, a cased-hole neutron log was run in both Wells 36-16 and 36-15C, since open-hole logs could not be run in the former and there was a desire to collect as much information as possible for the latter since it was the injector well.

4.7 Well Completion

The targeted injection zone, a 10-ft coal seam at an approximate depth of 1100 ft (see Table 4-2), was perforated in each well with 23-gram raptor charge. With this type of charge, a hole diameter of ½ inch is created. The charges were spaced at 6 shots per foot with 90 degree phasing. Each wellbore was filled with freshwater prior to perforation to help maximize the depth of the charge penetration. Figure 4-6 shows the freshwater fill leaving the borehole at the time of well perforation.

Table 4-2. Perforated Coal Interval

Well Name	Perforated Interval, ft
State of ND 36-15C	1086–1096
State of ND 36-9	1092–1102
State of ND 36-16	1084–1094
State of ND 36-10	1103–1112
State of ND 36-15	1100–1110

Figure 4-6. Freshwater fill leaving the borehole upon release of perforation charges.

5.0 LABORATORY TESTING OF CORES

During the drilling of the injection well (Well 36-15C) in August 2007, approximately 10 feet of 3-inch-diameter core, most of which was from the lowermost coal seam in the study area, was collected (see injection well marked in green on Figure 5-1). The results of this laboratory testing program are summarized in the remainder of this section of the report but are presented in more detail in a report dated November 2008 (Sorensen, 2008).

The testing program consisted of several tests, each of which provided different information about the characteristics of the reservoir. These tests, the data that are generated, and the purpose of these data are listed in Table 5-1. These laboratory data, when combined with the data from various field-based geophysical tests, i.e., geophysical logs and N-fits (see Section 11.4), allowed for an assessment of the reservoir characteristics as they related to the ability to store CO_2 and produce CBM.

Figure 5-1. Test core from the Burke County study site was collected from the CO_2 injection/CBM production well.

Table 5-1. Summary of Core Laboratory Tests

Test	Type/Purpose of Data
Canister Desorption Tests	Generates estimates of the quantity of methane that may be generated during the injection of CO_2 into the coal seam. Following the desorption tests, bulk density of the core material was also measured.
Vitrinite Reflectance and Maceral Analysis	Vitrinite reflectance provides measures of thermal maturity of the coal, and maceral composition is one of the controlling factors for sorption capacity and gas content of the coal.
Proximate/Ultimate Btu Analysis	Heat content of coal provides information about the rank of the coal, which can influence the sorption characteristics of the reservoir. Analysis also produces data regarding the moisture, volatile matter, and ash content of the coal.
Methane/CO_2 Sorption Isotherms	Provides data necessary to quantify the potential adsorption capacity of the coal for methane and CO_2.
Permeability Tests	Provides a measure of the permeability of the coal seam to helium and CO_2 at the initiation of CO_2 injection.

5.1 Canister Desorption Tests

The core from Well 36-15C was divided into three samples, each 1 foot in length (Figures 5-2 and 5-3). Each of these samples was placed in a desorption canister while on-site, immediately after separation from the main core (Figure 5-4). These canisters were maintained at reservoir temperature. The collection of offgas from the core was initiated on-site, to avoid the loss of gas at the site prior to the initiation of the laboratory desorption tests. The canisters were then transported to the laboratory to complete the desorption tests.

Upon arrival at the laboratory, the canisters were maintained at reservoir temperature, and the desorption tests were completed. At that time, the core samples were removed from the canisters, and the sample mass and bulk density were measured. The volume of the offgas that was collected from the core was calculated using the U.S. Bureau of Mines (USBM) Direct Method (Diamond and Levine, 1981) and the Smith and Williams Unipore Model (Smith and Williams, 1984). Table 5-2 summarizes the results of these gas content and bulk density measurements.

It should be noted that the total gas volume that was desorbed from the core, listed in Table 5-2 as the “total gas,” is the sum of the gas volume that was collected during the gas desorption test (i.e., “total measured gas”) as well as the volume of gas that was estimated to have been lost (i.e., “lost gas”) during the time that it took to retrieve the core from the bottom of the wellbore until it was placed in the on-site desorption canister. This estimate was based upon an extrapolation of the initial gas loss rate that was recorded during the initial stages of the canister experiments. The details of this calculation are presented in Appendix D.

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Figure 5-2. Preparing coal core for canister test.

Figure 5-3. Burke County lignite coal core immediately after collection and prior to placement in canister for gas content analysis.

Figure 5-4. Canisters and field apparatus used to initiate gas desorption tests at the study site.

Table 5-2. Summary of Gas Volume and Bulk Density Measurements

					Desorbed USBM Total Gas, scf/ton		
Core Subsample	Sample Weight, g	Total Measured Gas, scc	USBM Lost Gas, scc	USBM Total Gas, scc	Raw Basis	DAF Basis	Bulk Density, g/cc
1	2367.4	34	21	55	0.75	NA*	1.655
2	2048.8	46	28	75	1.17	NA	1.457
3	1769.4	49	46	95	1.72	NA	1.293

* Not applicable.

5.2 Vitrinite Reflectance/Maceral Analysis

Vitrinite reflectance can be used as an indicator of thermal maturity, which is related to the rank of the coal, while maceral group composition has been identified as one of the controlling factors for sorption capacity and gas content. However, the literature is divided regarding which maceral group may be more important to CO_2 absorption. For example, several studies on North American and European coals indicate that vitrinite-rich coals have higher sorption capacities than inertinite-rich coals, while other studies have shown no systematic variation with maceral groups. In fact, studies of Australian low-rank coals indicate that, for some low-rank coals, inertinite may have a higher sorption capacity than vitrinite (Mohinudeen and Sherwood, 2006). The vitrinite reflectance and maceral analyses, which were conducted only on Subsample 3 of the core (see Table 5-3), were performed in accordance with the ASTM International (ASTM) standard, ASTM D2798 (Storer, 1990a). Table 5-3 summarizes the vitrinite reflectance measurements, while Table 5-4 presents the maceral analytical results.

5.3 Proximate and Ultimate Analysis/Heat Content

The proximate (i.e., moisture, ash, volatile matter, and fixed carbon) and ultimate (i.e., carbon, hydrogen, nitrogen, sulfur, and oxygen) analysis of the coal and its heat content provides additional insight regarding the nature of the coal, particularly with respect to determining rank. Each of these factors may also exert influence on the sorption characteristics of a coal and is used in a variety of CBM static and dynamic modeling software packages to predict CBM productivity and/or CO_2 sorption. These parameters were determined for the Burke County coal, using ASTM D3172 (Storer, 1990b) for the proximate and ultimate analysis and ASTM D2015 (Storer, 1990c) to determine the heat content. The results of these analyses are summarized in Table 5-5. Also provided in Table 5-5 is the classification of the rank of the coal based on the analytical results of the proximate analysis. These data are discussed further in Section 11.2.1.

Table 5-3. Summary of Vitrinite Reflectance Measurements

Core Subsample 3	Min. R_o	Max. R_o	Mean R_o	Rank
	0.17	0.34	0.24	Lignite

Table 5-4. Summary of Maceral Analysis (point count %)

Maceral	Core Subsample 3	
Vitrinite		52.00
Detrovitrinite	45.60	
Telovitrinite	6.40	
Liptinite		2.10
Sporinite	2.00	
Cutinite	0.00	
Resinite	0.10	
Exudanite	0.00	
Inertinite		45.90
Micrinite	0.40	
Fusinite	7.80	
Semifusinite	37.70	
Macrinite	0.00	
Detroinertinite	0.00	
Total		100.00

Table 5-5. Summary of Proximate and Ultimate Analysis and Heat Content of Coal Sample (as-received; dry; and dry, ash-free [DAF] basis)

Core Subsample 3	Proximate Analysis, wt%						
	Moisture	Ash	Volatile Matter	Fixed Carbon	Heating Value, Btu/lb	Sulfur	Coal Rank
As-Received	26.83	9.53	27.60	36.04	7,657	0.16	Subbituminous C*
Dry	0	13.02	37.72	49.26	10,465	0.22	
DAF	0	0	43.37	56.63	12,032	0.25	

Core Subsample 3	Ultimate Analysis, wt%						
	Moisture	Ash	Hydrogen	Carbon	Nitrogen	Sulfur	Oxygen
As-Received	26.83	9.53	2.36	46.80	0.65	0.16	13.67
Dry	0	13.02	3.23	63.96	0.89	0.22	18.68
DAF	0	0	3.71	73.54	1.02	0.25	21.48

* See Section 11.2.1 for discussion of this.

5.4 Methane and CO_2 Adsorption Isotherms

Methane and CO_2 adsorption isotherms were experimentally developed for the Burke County lignite seam using Subsample 3 of the core. The isotherms provide a means to quantify the potential adsorptive capacity for the coal with respect to methane and CO_2. The adsorption isotherm testing exposed the moisture-prepared coal sample at the reservoir temperature to either methane or CO_2 gas at a series of pressures. Each adsorption step consisted of charging a reference vessel to a calculated starting pressure. After allowing for the stabilization of the pressure and temperature, the pressure was released from the reference vessel into the sample chamber. The pressure was monitored until no further change in pressure was observed, i.e., until equilibrium was achieved. The resulting data were analyzed and reduced using 1) fundamental gas law principles, considering the nonideality introduced because of gas compressibility and changes in dead volume associated with adsorbed gas, and 2) the Langmuir adsorption equation.

The results of these sorption tests can be presented by plotting the volume of gas adsorbed against the system pressure (Figure 5-5 and 5-6). These plots typically show a rise in the volume of gas that is absorbed as the system pressure is increased, with the volume of gas adsorbed eventually approaching an asymptote. If the gas sorption process follows the Langmuir model of sorption, a plot of the ratio of the system pressure divided by the adsorbed volume of gas against the system pressure (Figure 5-7 and 5-8) will yield a straight line.

Using these plots of the data, it is possible to determine the Langmuir volume, or V_L, which is the maximum volume of gas that can be adsorbed by the coal. The Langmuir volumes that were calculated for methane and CO_2 for the core subsample, on an as-received, dry, and DAF, are summarized in Table 5-6.

As shown, the coal is capable of adsorbing an order-of-magnitude greater volume of CO_2 than methane. Furthermore, previous studies of CO_2 absorption on bituminous coal and carbon black indicate that the strength of absorption of CO_2 on these forms of carbon is greater than that for methane, which suggests that the sorption of CO_2 will be very stable and that it will replace any sorbed methane upon entering the coal seam (Nelson and others, 2005).

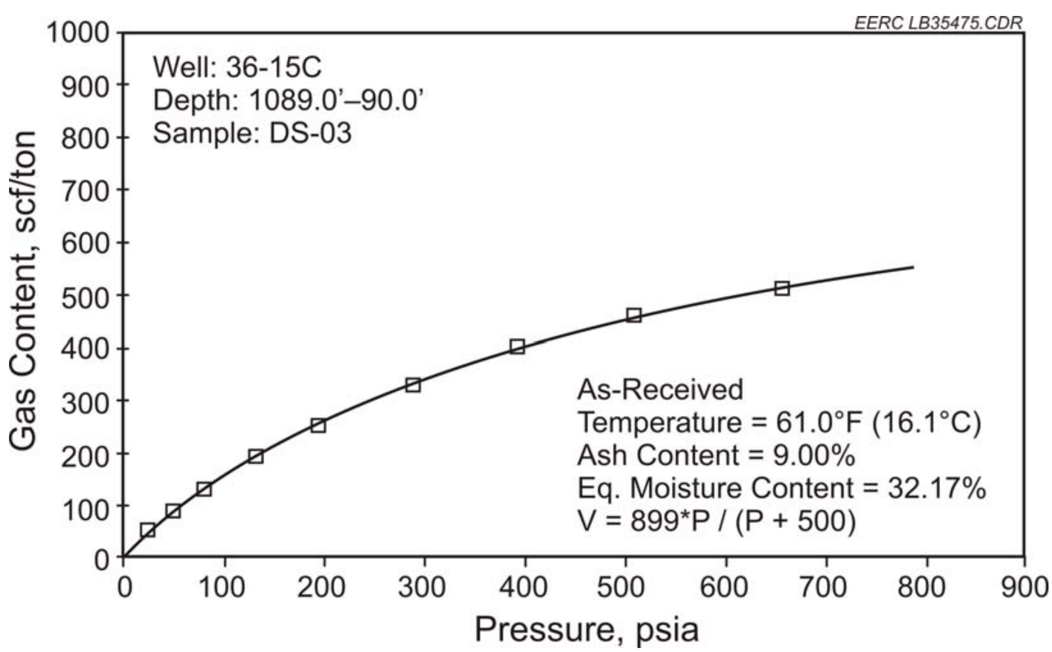

Figure 5-5. CO_2 adsorption isotherm, as-received coal.

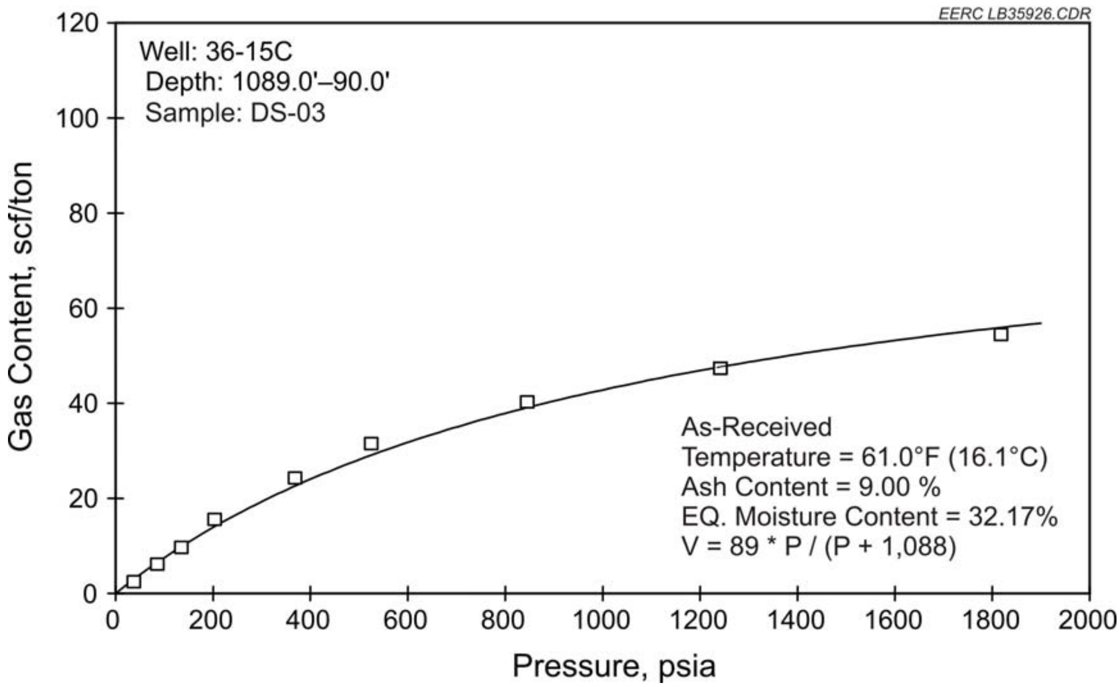

Figure 5-6. Methane adsorption isotherm, as-received coal.

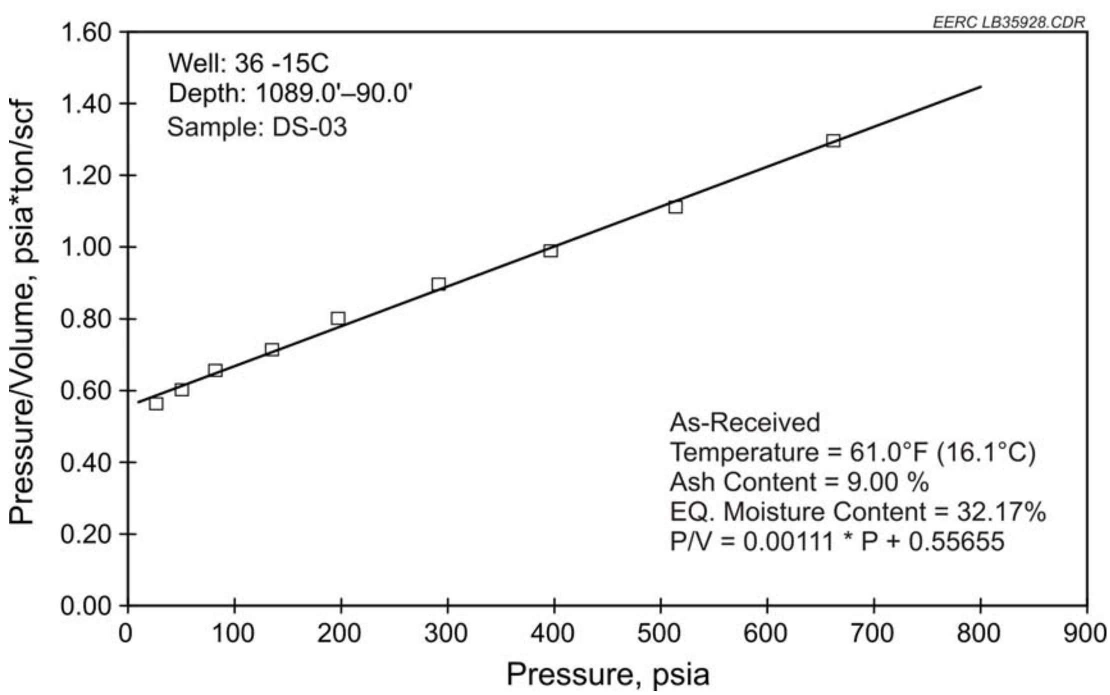

Figure 5-7. CO_2 Langmuir adsorption plot, as-received coal.

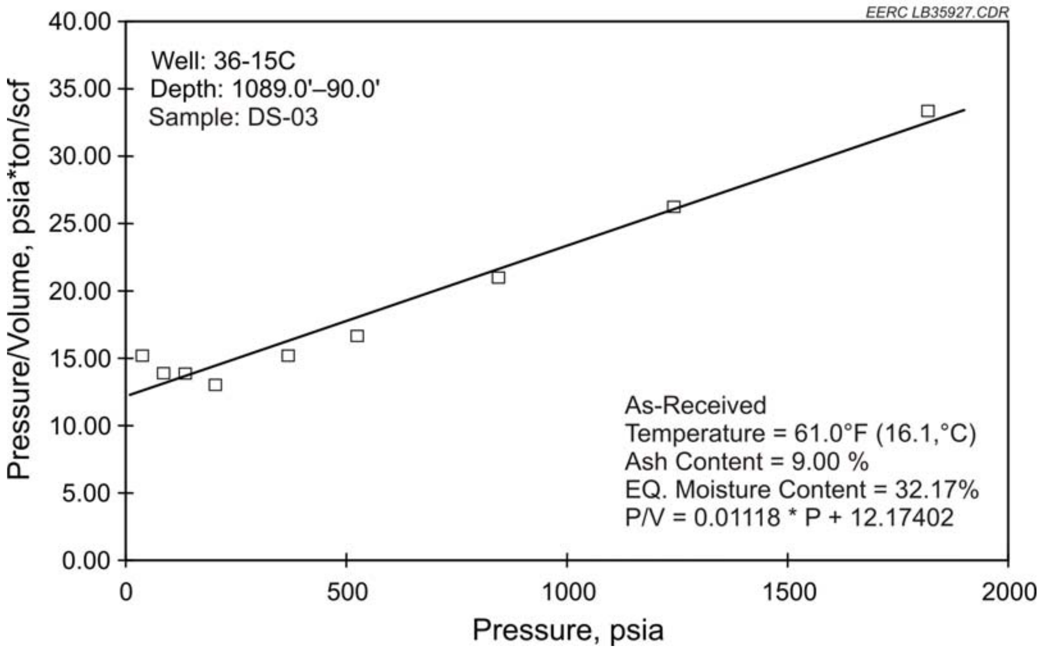

Figure 5-8. Methane Langmuir adsorption plot, as-received coal.

Table 5-6. Langmuir Volumes

	Langmuir Volume, VL (scf/ton)	
Core Subsample 3	CO_2	Methane
As-Received	899	89
Dry	1325	132
DAF	1528	152

5.5 Permeability Measurements

Two measures of permeability were made: one to reflect the conditions of the core at the beginning of CO_2 injection and the other after it had been exposed progressively to CO_2 for a long period of time. The latter was examined to address the concern that lignite might swell as it adsorbs CO_2, which would result in a loss of permeability over the course of CO_2 injection.

5.5.1 Permeability at Atmospheric Pressure

The permeability of the core subsample was determined for helium and CO_2 near atmospheric pressure. The goal of these experiments was to determine the permeability of the coal that would be expected to exist at the beginning of CO_2 injection. During this experiment, the confining pressure on the core was kept constant at 480 psig, and differential pressures were measured across the core as the flow rates of the gases were varied between 2 and 10 cm^3/min. The experiment data are summarized in Table 5-7 and indicate that the average permeability for CO_2 was 0.620 mD for the average flow rate of 0.127 cm^3/sec, whereas for helium, the average permeability was 0.533 mD for the average flow rate of 0.065 cm^3/sec.

Table 5-7. Permeabilities for He and CO_2 Measured with the Core Outlet at Atmospheric Pressure

Gas	Core Length, cm	Core Diameter, cm	Area, sq cm	Gas Visc., cP	Flow Rate, cm^3/ min	Flow Rate, cm^3/s	Delta P, psig	P, atm outlet	P, atm inlet	Calculated Permeability, mD
He	4.3434	3.7897	11.2774	0.0198	2.9130	0.0486	6.8172	0.9658	1.4669	0.6073
He	4.3434	3.7897	11.2774	0.0198	3.5900	0.0598	9.1630	0.9658	1.6276	0.5317
He	4.3434	3.7897	11.2774	0.0198	5.2400	0.0873	13.9600	0.9658	1.9562	0.4603
CO_2	4.3434	3.7897	11.2774	0.0149	68.150	0.1136	11.9600	0.9658	1.8192	0.5485
CO_2	4.3434	3.7897	11.2774	0.0149	7.4467	0.1241	11.9500	0.9658	1.8185	0.6000
CO_2	4.3434	3.7897	11.2774	0.0149	7.9370	0.1323	11.8800	0.9658	1.8137	0.6442
CO_2	4.3434	3.7897	11.2774	0.0149	8.3760	0.1396	11.7600	0.9658	1.8055	0.6885

5.5.2 Permeability at Elevated Pressures

The permeability of the core was measured for CO_2 only after it was exposed progressively to CO_2 for a long period of time (~695 hours). This was done to examine the potential effects of adsorbed CO_2 on the permeability of the coal seam.

During these experiments, a back-pressure regulator was used to set the outlet pressure on the core at 800 psig. Consequently, the confining pressure was 1280 psig. As in the atmospheric tests, the pressure drop across the core was measured as the flow rate of the gas was varied from 700 to 1300 cm^3/min. These experimental results are summarized in Table 5-8 and show an average permeability for CO_2 of 0.494 mD at an average flow rate of 14.9 cm^3/sec.

Table 5-8. Permeabilities for CO_2 Measured with the Core Outlet at 800 psig

Gas	Core Length, cm	Core Diameter, cm	Area, sq cm	Gas Viscosity, cP	Z	Flow Rate, cm^3/min	Flow Rate, cm^3/sec	Delta P, psig	P, atm outlet	P, atm inlet	Calculated Permeability, mD
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	745	12.4167	32.2400	54.7945	57.0027	0.4099
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	745	12.4167	31.1000	54.7945	56.9247	0.4255
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	753	12.5500	30.1200	54.7945	56.8575	0.4446
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	754	12.5667	29.2000	54.7945	56.7945	0.4597
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	747	12.4500	29.0000	54.7945	56.7808	0.4587
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	721	12.0167	28.0000	54.7945	56.7123	0.4591
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	731	12.1833	27.1000	54.7945	56.6507	0.4815
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	857	14.2833	29.0000	54.7945	56.7808	0.5262
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	987	164500	31.6000	54.7945	56.9589	0.5544
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	1012	16.8667	33.4000	54.7945	57.0822	0.5366
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	1054	17.5667	34.8000	54.7945	57.1781	0.5355
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	1052	17.5333	34.4000	54.7945	57.1507	0.5410
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	1058	17.6333	37.0000	54.7945	57.3288	0.5042
CO_2	4.3434	3.7897	11.2774	0.0191	0.5848	1310	21.8333	40.0000	54.7945	57.5342	0.5754

6.0 INITIAL WELL MONITORING

Once all wells were drilled, cemented, and perforated, well monitoring and data collection began. Preinjection monitoring is divided into two events since well-monitoring data were collected using different methods. Initial well monitoring of the wells occurred from September 2007 to August 2008. During this period, all wells were monitored using portable field instruments. Wells were monitored for pressure changes, water level fluctuation, and gases present. During the monitoring from September 2008 until CO_2 injection, which is referred to as preinjection monitoring, the wells were equipped with surface and bottom-hole sensors to monitor temperature, pressure, specific conductivity, and pH. This section only addresses the initial well-monitoring period; the preinjection monitoring effort is described in Section 8.

Surface casing for all wells is 9 5/8 inches and is cemented to about 40 ft below the surface. Seven-inch well casing is attached to the surface casing with an opening for 2 3/8-inch tubing (or 2 7/8 inches for Well 36-15). Tubing is inserted inside the casing and extends to the perforations in each well, creating two zones within the well: annular space and tubing space. At the top of the tubing and extending out of the casing are 2-inch ball valves. Wells were fitted with ¼-inch ball valve and tubing to isolate and access the annular space and tubing separately, while maintaining isolation from atmospheric influence (Figure 6-1).

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Figure 6-1. Pressure and gas access points.

Annular and tubing pressure was measured using a Dwyer Manometer 477 (see Appendix E for all instrument specifications). Positive and negative pressures relative to atmospheric pressure were measured and recorded. Gas samples were collected when positive pressure was present. A photoionization detector was used to check for volatile organic compounds in each well. All gas samples were collected in a 1-L Tedlar bag and processed at the EERC lab using gas chromatography within 24 hours of collection. The results of these analyses can be found in Appendix F.

Pressure and gas readings were obtained while wells were closed to the atmosphere. To measure fluid height, wells were opened at the 2-inch ball valve at the top of the tubing. Fluid height in each well was measured using a Sonic Water Level Meter 200. An acoustic signal was used to measure fluid height in the well and reported depth-to-water in feet. The instrument was centered over the tubing of each well while the instrument reported fluid height from the top of the tubing.

During periods of well inactivity (September 2007 to April 2008), all wells were monitored monthly and showed little fluctuation in tubing and annular space pressures, and fluid levels remained fairly constant (see Figure 6.2). One may note the increased fluid level in Well 36-15 compared to the other wells. The exact cause of this is not known, but based on field observations and the timing of well development activities, it is thought that the perforations in this well became somewhat plugged after swabbing and did not allow fluid to enter the reservoir. Starting May 2008, well development treatments began, and monitoring was conducted more frequently. As expected, well development activities contributed to fluctuations in pressure and fluid levels in each well during the initial well-sampling phase.

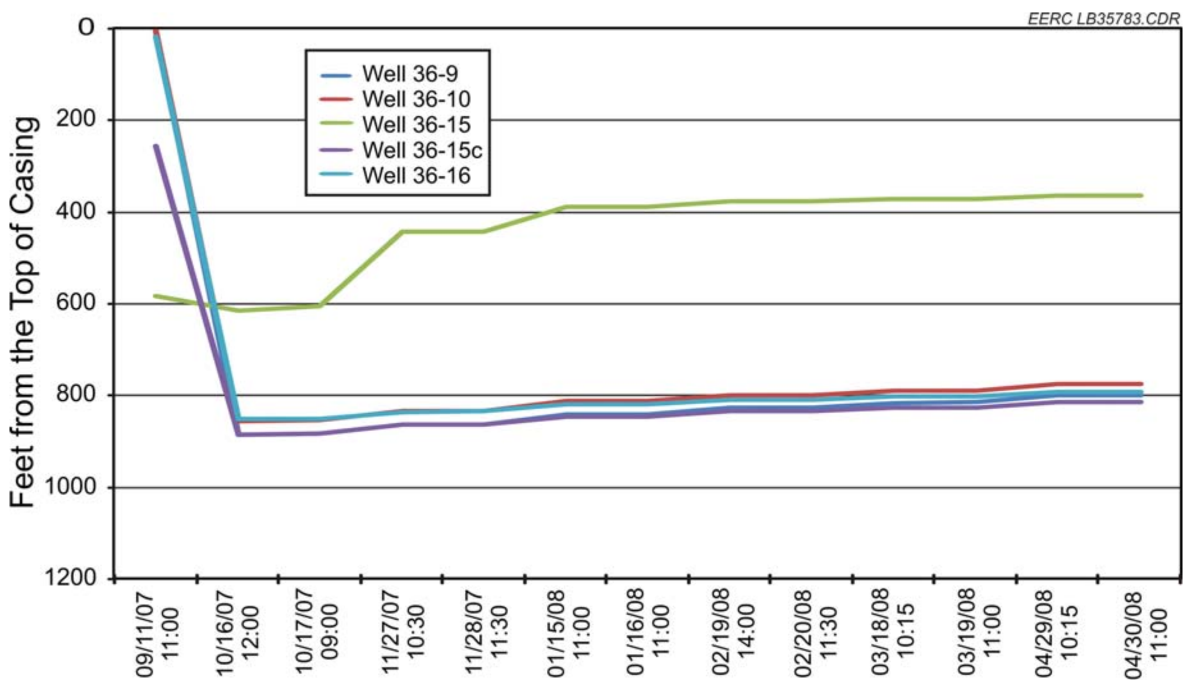

Figure 6-2. Fluid level during well inactivity.

Fluid samples were collected routinely via swabbing, which was performed by Eagle Well Service. Swabbing is the removal of water or drilling mud from a well to allow oil, gas, or other formation fluids to flow into a well. A truck-mounted swabbing unit is used to lower a swab tool down the tubing string on a wireline. A swab tool is a hollow steel rod with rubber swab cups. When the swab tool is raised, the swab cups seal against the tubing to act as a piston and lift (swab out) the liquid out of the well. A lubricator is temporarily attached above the valve on the tubing head or casing head to provide a pressure seal (Hyne, 2001). A port with a ¼-inch barb fitting was used for sampling fluid from the well before it reached the surface tank. Dual samples were collected in 150-mL sample bottles. One sample was processed in the field using a YSI Sonde and the other sent to a certified lab for analysis. Field samples provided conductivity, temperature, and pH. In the laboratory, samples were analyzed for Na, Ca, Mg, Fe, K, Cl, CO_3, HCO_3, SO_4, and pH. TDS and NaCl were both calculated. The results of these analyses can be found in Appendix F.

7.0 WELL DEVELOPMENT

Field operations focused on development of the wells to determine hydrogeologic properties of the formation. During the initial stages of well development, none of the wells drilled into the lignite seam yielded substantial fluid volumes. Development of the wells was conducted by employing different stimulation techniques in stages with the desire to avoid using the more aggressive techniques that had the potential to negatively influence the injection zone and complicate the interpretation of postinjection monitoring data. These techniques included swabbing, sonic hammer, nitrogen N-fit test (i.e., minifrac), and acid treatment (see Table 7-1).

After completion in the fall of 2007, the wells were monitored for pressure buildup. None of the wells gained significant amounts of formation fluid, apparently because of poor communication between the wellbores and the formation. Further, the wells were shut in for the winter season, and regular water level readings (monthly on average) were taken to trace the dynamics of fluid movement in the wells. The water levels in all five wells remained nearly constant throughout the period of closure, again indicating poor hydrologic communication between the wellbore and the formation. Thus, after field operations were resumed, it was decided additional well development techniques would need to be applied. As previously mentioned, in order to avoid compromising native reservoir characteristics, less invasive treatments would be tried first before undergoing traditional CBM well development protocols.

Table 7-1. Summary of Well Development Techniques

	Well Identification				
Well Development Technique	36-9	36-10	36-15	36-15C	36-16
Swabbing	X	X	X	X	X
Sonic Hammer			X		X
Acid Job Without Perforation Balls	X				X
Acid Job with Perforation Balls	X	X	X	X	X
Nitrogen N-fit Test		X		X	
Pump Test			X		

7.1 Sonic Hammer Tool

A sonic hammer is an instrument which emits sonic pulses in the wellbore (Figure 7-1). The vibrations cause a minifracture in the coal, increasing the space between the cleats and opening the perforations, in the hopes of providing better communication with the formation. The tool was run in Wells 36-16 and 36-15, and after each job was completed, swabbing commenced in an effort to bring fluid to the surface. Both wells were unable to recover all of the water used for the sonic jobs. As such, the application of this tool did not yield significant improvement in communication with the formation.

7.2 N-fit

Nitrogen treatment and pressure transient analyses (N-fits) were conducted in the injection well (Well 36-15C) and two of the monitoring wells (Well 36-10 and Well 36-16) to improve communication between the wells and the formation. The results of the tests concluded that the reservoir is underpressured, with an estimated pressure ranging from 2.28 MPa (330 psia) to 2.38 MPa (345 psia), while the normal pressure gradients at the reservoir depth would be approximately 3.24 MPa (470 psi). Further discussion of these tests is included in the section on reservoir characterization, Section 11.2.

7.3 Minipump Test

A pump test was designed to try to confirm communication with the formation and to derive vital hydrogeological parameters of the coal seam. However, the pumping did not provide desirable results because of significant sand production from the formation, which may have blocked the fluid paths. As a result, fluid flow rapidly ceased and did not allow for the estimation of the parameters.

Figure 7-1. Sonic hammer tool.

7.4 Acid Treatment

Initially, acid treatments (Figure 7-2) were applied without the use of perforation balls. When the desired results were not obtained, perforation balls were added (Figure 7-3).

Acidizing provided better results in terms of establishing communication between the wellbore and the formation in that, after acid treatments, all of the wells experienced an increase in water levels. However, fluid flow rapidly tapered off in the wells. At this point, two working hypotheses were developed regarding the lack of fluid entering the wellbores: 1) the lack of the communication between the wellbores and the formation and 2) the lack of fluids in the formation.

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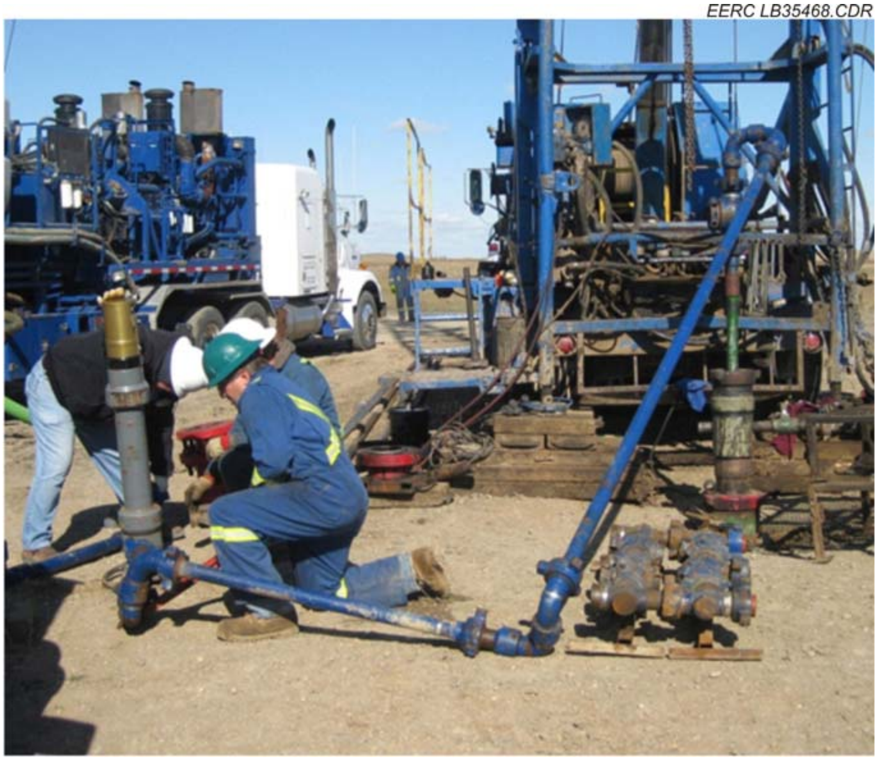

Figure 7-2. Connecting ball dropper to well for acid job.

Figure 7-3. Perforation balls using during acid job.

8.0 PREINJECTION WELL MONITORING

Wells were modified to accommodate surface and bottom-hole sensors. Each well contained three sensors: a Level Troll 500 (LT500), a Troll 9500, and an Aqua Troll 200 (AT200) or Level Troll 700 (LT700). See Figure 8.1 for a schematic of the monitoring wellhead assembly. A LT500 was attached to each wellhead to monitor surface temperature (°F) and pressure (psi). The Troll 9500 was deployed at 500 feet (because of pressure limitations) in each well to measure pH and temperature. The AT200 sensors monitored fluid temperature, pressure, and conductivity (µs/cm) in each well, while the LT700 measured high pressures and fluid temperatures. Both sensors were utilized during preinjection monitoring depending on well activities. These sensors were deployed at the top of the perforated interval of each well. Sensors varied in recording sample rates to capture well responses during certain well development activities; however, data were plotted at 1-hour intervals. A Rugged Reader handheld device was used to calibrate, configure, and download all sensors. Sensors were removed during well development activities, routine calibration, and well or sensor maintenance.

During periods of well inactivity, tubing and annular space pressures fluctuated very little, and fluid levels recovered slowly after they had been swabbed down following all well treatments. Well development activities, as expected, continued to affect pressure during the preinjection phase.

Bottom-hole sensors did not show significant changes in water chemistry while deployed in the wells prior to injection. Not surprisingly, during swabbing events, water chemistry changes reflected the well development techniques performed on each well.

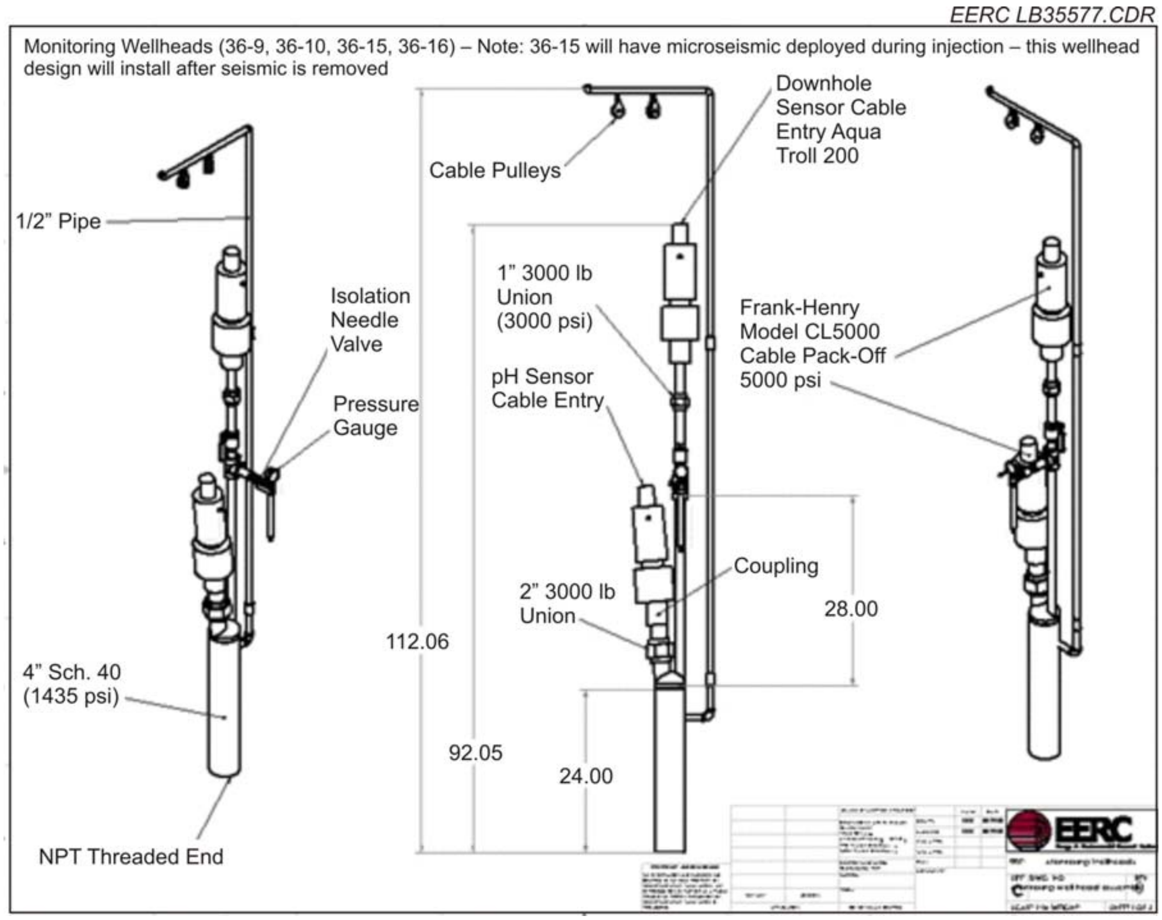

Figure 8-1. Monitoring wellhead assembly.

Additionally, prior to injection, RST logs were run in all wells, and crosswell seismic surveys were conducted between Wells 36-9 and 36-15 and Wells 36-16 and 36-10 as a baseline for postinjection monitoring. These activities will be discussed in detail in the postinjection monitoring section of the report.

9.0 CO_2 INJECTION

Based on the estimated fracture pressure of the rocks, the permitted maximum allowable bottom-hole pressure (BHP) of the CO_2 was 780 psi, and the permitted average BHP was 720 psi. The corresponding average CO_2 injection rate is estimated at approximately 14 gpm, using the following formula (e.g., Towler, 2002):

$$q = \frac{0.007082kh}{0.5B\mu} \cdot \frac{p - p_i}{\ln \frac{0.0002637kt}{\phi \mu c_t r_w^2} + 0.80907} = 642\,bbl/day = 14gpm$$

The parameters and the values used in this calculation for the demonstration site are presented in Table 9-1. The parameter values are specific to the injection well and to the initially planned injection duration of 10 days. However, the estimated injectivity is based on the transmissibility of the formation, which was based on the lowest permeability at which injection in the formation was feasible, i.e., 4 mD. (It should be noted that the formation permeability was estimated based on nitrogen fracture injection tests and ranged from 0.6 to 34 mD. To be conservative, a formation permeability of 4 mD was chosen, which was the lowest permeability at which injection into the formation was feasible.) Thus, it was expected that the injection rates observed during the demonstration would deviate from this estimated rate.

Injection of CO_2 was accomplished with equipment supplied by Praxair, which included an 80-ton (trailer) storage tank and a pumping skid. CO_2 was supplied to the site via ground transportation. The pump skid consists of a diesel engine, booster pump, triplex piston pump, diesel-fired line heater, and controls. Flow rate was measured using a turbine flowmeter for liquid CO_2 prior to a line heater, and gauges were provided to measure temperature and pressure of CO_2 at the discharge of the pump and line heater. The line heater is an indirectly fired glycol-based shell and tube heat exchanger. The triplex pump can typically provide flow rate and pressure ranging from 2 to 20 gpm and 100 to 3000 psi, respectively. The equipment is shown in Figure 9-1.

CO_2 injection started at approximately 11:15 a.m. on March 10, 2009, and concluded on March 26 at approximately 3:11 a.m. Over this 16-day period, a total of 21,035 gallons (~89 tons) of CO_2 was injected into the formation. The initial injection rate was 1.2 gpm, which peaked at 2.7 gpm following the first 12 hours of injection. From that point forward, the injection rate steadily declined, reaching an overall average rate of 0.9 gpm.

Table 9-1. Parameters for Injection Rate Calculation

q, bbl/day	Volumetric injectivity
k = 4 mD	Permeability, based on the lowest permeability at which CO_2 injection is feasible
h =10 ft	Thickness of injection interval
$p - p_i$ = 385 (av), 445 (max) psi	BHP buildup
B = 1	Formation volume factor
μ = 0.015 cP	CO_2 viscosity
ϕ = 6%	Lignite porosity
$c_t = 10^{-6}\ psi^{-1}$	Compressibility
r_w = 0.29 ft	Wellbore radius
t = 240 h	Time

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Figure 9-1. Site photo of pump skid and CO_2 storage tank.

The majority of the CO_2 injection was conducted in cycles, which began with the buildup of the BHP to the predefined threshold followed by a slow decline. On average, each injection cycle took about 40 minutes. The bottom-hole temperature varied from 50°F (10°C) to 62.5°F (17°C).

The CO_2 injection was completed by injecting the maximum quantity possible without exceeding the facture gradient limitations of an average of 720 psig and a maximum of 780 psig. These various injection pressures were investigated to determine the potential influences of pressure on the injection rate. The injection plan included the following experiments:

1. Inject at the maximum achievable pressure <780 psig.

2. Inject at consistent cycles near an average of 720 psig.

3. Discontinue heating of CO_2 and maintain the maximum sustainable liquid volume in the wellbore.

4. Continue heating of CO_2 and decrease injection pressure to maintain gaseous state at perforated interval.

5. Continue heating of CO_2 and increase injection pressure to maximize CO_2 flow rate.

During each injection, the operating procedure was as follows. Personnel monitoring the surface and downhole injection pressures communicated to Praxair personnel when to start and stop injection. Since the minimum pumping rate of the Praxair skid exceeded the continuous injection rate accepted by the coal seam, pumping was frequently started and stopped, resulting in a pressure buildup and decline within specified intervals. The temperature of the CO_2 exiting the skid was controlled by a line heater. Glycol in the line heater was maintained at a given set point by firing diesel fuel from thermostatic control. The target temperature for the CO_2 was 100°F. Ambient air temperatures at the site ranged from −20° to 40°F, which greatly affected heat losses from the insulated line between the pump skid and the wellhead.

Using this procedure, a total of nine distinct phases of CO_2 injection took place. Table 9-2 provides a summary of each of these injection phases, including the timing and duration, the start and end set point pressures, and the total volume and average flow rate of CO_2 injection. Additional comments, as necessary, are also provided in Table 9-2. A review of the information in this table reveals the following:

- The duration of the injection phases ranged from as few as 6 (Phase 4) to as many as 76 (Phase 2) hours of operation.

- The pressure swings ranged from a low of 605 psia (Phase 8) to a high of 770 psia (Phase 2 and Phase 6).

- The average CO_2 flow rate ranged from 0.13 (Phase 8) to 1.45 (Phase 2) gpm.

- The volume of CO_2 injected ranged from 308 (Phase 4) to 6660 (Phase 2) gallons.

Of particular note is that liquid CO_2 was injected only during Phase 6 of the injection program. During this phase, nearly 3000 gallons of CO_2 was injected at an average rate of approximately 1 gpm.

10.0 POSTINJECTION MONITORING

10.1 Technical Approach

In addition to guiding the site operations, one of the primary objectives for site data collection at the study site is to monitor the fate of the CO_2 that has been injected into the subsurface. The approaches for monitoring CO_2, or any other fluid, can be divided into two groups: 1) direct measurements, which provide information directly related to the fluid pathways or the shape of space occupied by a fluid, and 2) indirect measurements, which provide data regarding certain parameters that characterize the fluid movement in discrete points of the formation. The first group consists of different types of imaging techniques, while the majority of wellbore measurements can be assigned to the second group. Each of the techniques has its advantages and shortcomings and can be more or less beneficial in certain settings.

Generally speaking, for CO_2 storage applications, imaging techniques (e.g., seismic or electromagnetic tomography, passive seismic monitoring, etc.) are beneficial in that they are capable of delineating the CO_2 plume. However, their resolution may not be sufficient to image slight changes that may be taking place in a reservoir. Indirect techniques (e.g., RST measurements, downhole pressure and temperature monitoring) image the near-wellbore environment only. While their resolution is higher than that of the imaging techniques,

Table 9-2. Summary of CO_2 Injection Phases

Phase No.	Time			Pressure (psia)		CO_2 Injected, gal/Average Rate, gpm	Comments
	Start	Finish	Duration	Start Set Point	End Set Point		
1	03/10/09 11:15	03/10/09 20:28	9 hr 13 min	660	720	660/1.20	• Tubing water pushed into formation during the first hour of injection. • Praxair had relay switch problems which caused minor injection delays of 15 min for two different periods.
2	03/10/09 20:30	03/14/09 00:50	76 hr 20 min	680	770	6660/1.45	• Praxair lost prime on injection pump twice because of faulty Murphy valve. Problem was resolved. • Test conducted on 03/12/09 to determine if phase change was causing resistance to flow. Injection well was vented for ~one-half hour, releasing 13 gallons of CO_2. Reduced pressure at the wellhead did not increase flow when pumping was resumed.
3	03/14/09 00:52	03/16/09 08:04	55 hr 12 min	690	740	2444/0.74	• Noticeably lower injection flow rates recorded during the periods between 12:00 and 17:00 on both 3/14 and 03/15.
4	03/16/09 08:06	03/16/09 14:46	6 hr 40 min	720	758	308/0.77	
5	03/16/09 14:48	03/19/09 14:00	71 hr 12 min	705	740	4194/0.98	

Continued. . .

Table 9-2. Summary of CO_2 Injection Phases (continued)

Phase No.	Time			Pressure (psia)		CO_2 Injected, gal/Average Rate, gpm	Comments
6	03/19/09 14:02	03/2109 12:24	46 hr 22 min	730	770	2946/1.06	• Liquid CO_2 was injected during this period. • Flow reported only by Praxair as EERC flow meter unable to measure liquid CO_2.
7	03/21/09 12:26	03/22/09 09:30	21 hr 4 min	705	745	959/0.76	
8	03/22/09 09:32	03/24/09 18:03	50 hr 06 min	605	640	433/0.13	• Power outage resulted in loss of pumping for 6 hr and 25 min.
9	03/24/09 18:05	03/26/09 03:11	33 hr 6 min	710	750	2432/1.2	• Pump cycle averaged 10 minutes during this period. • CO_2 storage vessel relief valve opened on 03/24/09 (23:10 to 23:23, releasing CO_2 for ~13 min.

there is a need to extrapolate wellbore measurements into the interwell space. Given these different strengths and weaknesses, it is believed that a combination of the direct and indirect techniques is required to achieve a good understanding of fluid movement in a reservoir. Optimal combinations of these monitoring methods decrease uncertainty in the interpretation of the data that are collected at a site.

One significant challenge faced at the Burke County lignite site was to monitor CO_2 injection into a shallow, thin injection interval. Surface and borehole seismic techniques would either lack the vertical resolution or horizontal coverage needed, especially with the small amount of CO_2 being injected. The injection well and four monitoring wells could be logged with RST to give very accurate CO_2 saturation changes with 2-ft vertical resolution but would not fill in any of the space between or around the wells. Since the coal was found to have low permeability and there existed porous and permeable reservoirs both above and below the coal, the concern was to determine if the CO_2 moved out of the lignite, either above or below the coal seam. A combination of seismic image tomography and RST measurements was thought to provide the best possible solution to the monitoring need at the site. This combination permitted the verification of the CO_2 injection into the targeted depth interval through the RST measurements. However, no extrapolation to reconstruct the plume geometry could be done from the RST measurements alone, since the injected CO_2 did not reach the monitoring wells in amounts that could be registered with the RST. Thus, crosswell seismic tomography was used to bridge the gap and provide valuable missing information regarding the plume geometry. Using the four monitoring wells to acquire two two-dimensional surveys with high vertical and horizontal resolution that crossed at or near the injection well, it was possible to calibrate the response at the wells with the RST and then fill in the gaps between the wells with the crosswell seismic data. This solution answered the needs of the site, with one identified issue. Since the reservoir was so shallow, and thus acoustically slow and attenuative, the long offset survey (i.e., between Wells 36-10 and 36-16) did not give enough signal to get anything but noise on the measured results. The short survey (i.e., between Wells 36-9 and 36-15), on the other hand, did give enough signal, and the results tied in with the RST logs in those two wells and the injection well between them.

10.2 Other MVA Measurements

Given the goals of the demonstration test, additional MVA measurements, in addition to the RST and crosswell seismic measurements, were made at each of three monitoring wells at the site. These measurements included the following:

- Surface sensors for measurement of temperature, pressure, and flow rate.
- Downhole sensors for measurement of temperature, pressure, conductivity, and pH.
- Gas sampling at wellheads to measure methane, CO_2, and oxygen concentrations and provide analytical results from gas chromatography, including the measurement of a fluorocarbon-based tracer that was injected with CO_2 at the beginning of the test.

Prior to CO_2 injection, the fourth monitoring well (Well 36-15) located closest to the injection well was outfitted with microseismic equipment, which included both geophones and tiltmeters deployed above a bridge plug. The bridge plug was located at approximately 900 feet, and hung below the bridge plug were self-recording pressure sensors. This arrangement was implemented during the CO_2 injection period. Upon completion of CO_2 injection, Monitoring Well 36-15 was returned to the same arrangement as the other monitoring wells. The details of the measurement devices that were used as part of this MVA program, the instrumentation of the monitoring wells, and the data acquisition system are described in detail in Appendix E.

11.0 DISCUSSION OF RESULTS/CONCLUSIONS

11.1 Critical Factors for Site Selection, Well Drilling, Logging, Completion, and Development

In traditional deeper oil and gas exploration, the zones that were of interest for this project are drilled through without being logged or sampled. Therefore, few reliable data were available to fully anticipate and understand the atypical properties of the target injection zone. Since the initial site selection research was conducted, more data have become available regarding the complexities of the shallow subsurface systems. Additional shallow wells have been drilled during the time this project was conducted, and they also have exhibited below normal pressure gradients. Emerging data that suggest that some Tertiary and Cretaceous rocks may be underpressured regionally is an area that warrants further study.

The suite of logs was chosen to address critical questions of the project. A Schlumberger Sonic Scanner log and the Schlumberger Platform Express logging suite were run in the central well at the Burke County lignite site. The Platform Express provides measurements of porosity and resistivity which are important for understanding hydrological characteristics. For example, fluid flow within a formation strongly depends on porosity and water salinity, which can be estimated using the resistivity log. Also part of the Platform Express are natural radiation measurements that help in understanding lithology, which is important for the development of optimal injection scenarios. The caliper log that is included in the suite measures borehole dimensions, which can be helpful in geomechanical studies. Additionally, the Sonic Scanner log generates data that can be used to predict pore pressure, determine density, and estimate geomechanical properties such as rock elastic constants and bulk compressibility.

An example of interpreted geophysical logs for the five wells is provided in Figure 11-1. The logs indicate that the primary target zone is a coal seam that is occasionally bifurcated, in places separated by approximately 1 to 2 feet of silty clay. The total thickness of the seam is approximately 10 to 12 feet.

A somewhat unique aspect to this coal seam is the fact that it appears to be isolated from the surrounding strata and overlain and underlain by a competent clay seal. Although a seal is desirable for CO_2 storage in coal seams, it may have prohibited natural gas production in the seam by limiting fluid recharge as glacial rebound occurred. One can speculate that another lignite seam that is not sealed as well may exhibit more normal pressures and, once dewatered, may be more productive with respect to natural gas.

The well-drilling program was designed based on the need to collect petrophysical data. This required drilling below the injection zone to accommodate the logging tools. The zone of interest then needed to be isolated to ensure injection control. This led to a completion program that required the casing and cementing of the entire wellbore, followed by perforating the injection zone. Given that the reservoir was underpressured, a fact not known prior to drilling, drilling mud and cement may have penetrated the reservoir and, perhaps, reduced some of the permeability. A commercial-scale operation that has fully characterized the intended injection reservoir may choose to drill and case to the top of the coal seam and then air-drill the injection zone as it is less invasive and may reduce near-wellbore damage.

As long as potential injection sites are appropriately characterized and judiciously selected and injection operations are designed and conducted according to longstanding engineering and regulatory standards, the leakage of CO_2 is likely to be a preventable and infrequent occurrence.

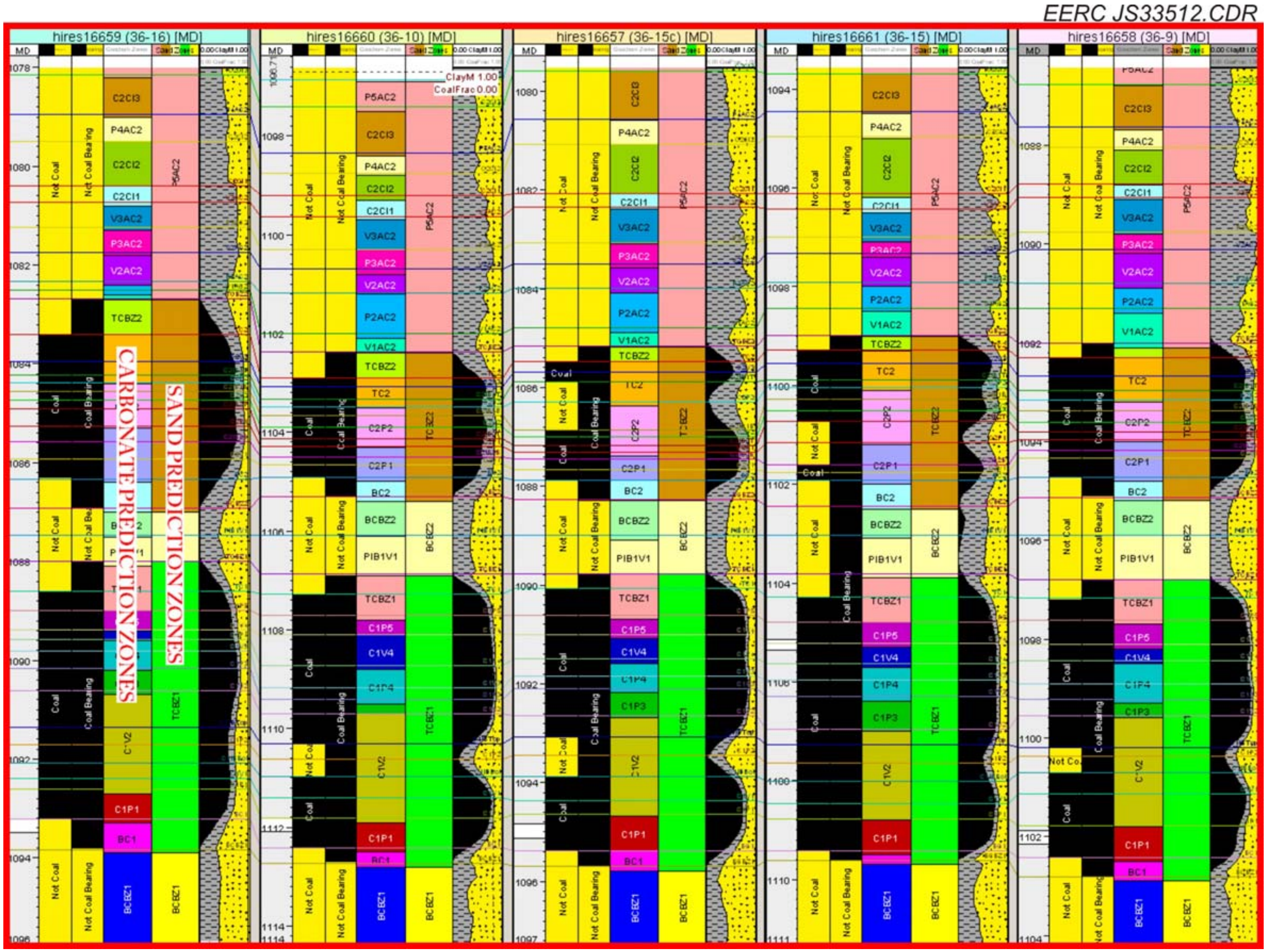

Figure 11-1. Summarized representation of processed and interpreted well-logging results from the application of Schlumberger Platform Express in boreholes at the Burke County site. Coal was collected from the lower coal seam.

11.2 Reservoir Characteristics

An initial reservoir characterization at the study site was conducted using data available from the literature. The reservoir characteristics estimated from these data served as the basis for the planning of the CO_2 injection and the subsequent MVA activities at the study site (Dobroskok and others, 2007). However, to more precisely characterize the targeted lignite seam of the study area and its reservoir properties, a series of site-specific laboratory and field tests were conducted. The reservoir characteristics that were determined based on the results of these tests are discussed here. Several lines of evidence were gathered to provide information about the characteristics of the coal seam as it related to CO_2 storage and ECBM production. Of particular interest is the ability to inject CO_2 into the formation and the potential for the coal to store CO_2 and release methane.

11.2.1 Coal Composition

The proximate and ultimate analysis of the coal and its heat content were analyzed. With an ash content of ~10%, a carbon content of ~40%, and a heat content of ~7000 Btu/pound (all on an as-received basis), the coal was officially classified as a subbituminous coal rather than as a lignite coal. At the same time, the assessment of the coal rank based on the vitrinite reflectance classified the coal as lignite. However, since subbituminous and lignite coals are both considered low-rank coals because of their lower carbon and energy content, it is not surprising that different methods might assign the rank differently between these two forms of coal. Furthermore, the specification of the coal rank is not a critical factor since the relationship between coal rank and the potential for CO_2 storage or CBM production is complex and not well understood, especially for lignite, for which there are substantially fewer published data. A more detailed discussion of coal rank and its potential impact on CO_2 storage and CBM production is beyond the scope of this report.

Investigation of the maceral composition of the coal was also completed to provide additional insights regarding its potential sorption capacity and gas content. While studies on both vitrinite-rich and inertinite-rich coals have been conducted to investigate their gas sorption capacities, there is no consensus regarding which of these maceral fractions has the higher sorption capacity. The low vitrinite reflectance values and overall maceral group composition (nearly equal amounts of vitrinite [52%] and inertinite [45.9%]) of the Burke County lignite, when considered with respect to the low gas content values observed for the lignite (see Section 11.4.1.2), are consistent with the relationships that have been observed in other North American coals (Mohinudeen and Sherwood, 2006). However, it should also be noted that work on Australian low-rank coals suggests that the relationships between maceral group content and reservoir properties may vary between, and within, areas of CBM exploration; therefore, predictions on resource and gas production simply on the basis of vitrinite reflectance and maceral analysis should only be done with extreme caution.

11.2.2 Gas Content of Coal

Gas desorption tests were conducted on cores of the coal seam taken from a depth of 1085 to 1090 feet, and it was determined that the methane content of the Burke County lignite seam is very low, ranging from 0.75 to 1.72 scf/ton. Considering that the gas content of commercial CBM-producing coals generally ranges from tens of scf/ton (as in the Powder River Basin) to hundreds of scf/ton (as in the San Juan Basin), these data suggest that there is a very low likelihood that CBM could be commercially produced from this particular Burke County lignite seam at this location using conventional CBM drilling, completion, and production techniques. With this in mind, it is important to mention that the estimated methane content (1.21 scf/ton on average) is lower than the average methane content (5.49 scf/ton) for North Dakota lignites that was estimated using data available from previous studies (e.g., Tewalt and others, 1989; Baez and others, 2004; Nelson and others, 2005). It is also worth noting that the volume estimate from the laboratory studies on this demonstration site may be biased low because of possible losses of gas from the sample that occurred during the transit time associated with bringing the core from the reservoir depth to the surface. However, an estimate of the volume of gas that may have been lost during this transit time was made based on the results of the desorption experiments and was factored into the volume estimate presented above in an attempt to account for this potential loss mechanism. Further evidence that this estimate of methane content may be low is provided from gas data generated from coal cuttings collected from a deeper and thicker coal seam in the southwestern part of North Dakota in 2001 (Nelson, 2003) which showed methane content to be as high as 12 scf/ton. While that value is still low by coal standards of the Powder River Basin or San Juan Basin, it is significantly higher than the estimated gas content for the study site and suggests that some lignite coals may be viable sources of CBM.

11.2.3 Methane and CO_2 Sorption Capacity

The sorption isotherm data for CO_2 and methane indicate that Burke County lignite has a considerably higher capacity to adsorb CO_2 than methane. The maximum volume of CO_2 that can be adsorbed by the coal was determined to be approximately 900 scf per ton of coal (as-received basis), whereas the capacity for methane is an order of magnitude less, at 90 scf/ton of coal (as-received). At the field test reservoir pressure of 345 psia, roughly 360 scf CO_2 could be absorbed by each ton of coal. The capacity for methane adsorption is about 20 scf/ton lignite. These values indicate that, compared to other coals, the tested lignite has a somewhat lower sorptive capacity to methane. Typical values for higher-rank coal seams are in the range of 100–800 scf/ton (NDIC, 2008). These results, however, are not a surprise as previous laboratory and field-based studies of North Dakota lignite yielded similar results (Baez and others, 2004).

The literature data also suggest that the CO_2 is sorbed more strongly to the coal than is the methane (Nelson and others, 2005). This observation would suggest that the CO_2 would likely replace sorbed methane upon entering a coal seam, thereby maximizing the production of the CBM to the extent that it is present in a formation.

11.2.4 Permeability of Coal Seam

The permeability of the coal seam was investigated by DOE National Energy Technology Laboratory (NETL) in the laboratory at atmospheric, as well as at elevated, pressure to evaluate conditions representative of the initiation of CO_2 injection as well as injection after extended exposure to CO_2, respectively. The average permeability for CO_2 at the onset of CO_2 injection was determined to be 0.620 mD, whereas following exposure to CO_2 injection of ~695 hours, the average permeability was determined to be 0.533 mD. Taken at face value, these results suggest that the adsorption of CO_2 may result in a loss of permeability in the coal seam which, in turn, may translate into reduced injectivity. At the same time, the literature suggests that the presence of nitrogen in the system, which is chemically inert and not adsorbed by the coal, may prop open the cleat structure of the coal, thereby having an offsetting effect on the permeability and injectivity of a coal seam into which CO_2 is being injected.

This laboratory evaluation provides valuable insight, but anomalies resulting from the conduct of laboratory experiments must be considered when the data are examined. Because of the low flow rates measured during the atmospheric permeability test, the viscosity coefficient and permeability values from Darcy's law may be affected by errors induced by phenomena such as the Klinkenberg effect, where molecular slippage at the wall of the vessel can affect gas permeability in porous media with low permeability. Furthermore, additional experimental data are needed to determine if the observed differences in the permeability are statistically significant and represent a real change in the observed coal permeability.

11.3 Geophysical Characteristics of Formation

11.3.1 General Characteristics

An interpretation of the geophysical logs for five wells was previously presented in Figure 11-1. As noted in Section 4, the well logs indicate that the primary target zone is a coal seam that is occasionally bifurcated in places, separated by approximately 1 to 2 feet of silty clay. The total thickness of the seam is approximately 10 to 12 feet. The seam is overlain by a continuous layer of clay approximately 4 feet thick, which provided a suitable seal for the CO_2 injection test.

A thorough geomechanical analysis was not possible at the site because of the poor consolidation of the rocks; however, the interpretation of sonic scanner data provided some valuable information. Specifically, the acoustic data indicate that a developed cleat system may not be present in the coal. This conclusion is in agreement with direct core observations and is important for the prediction of CO_2 injection performance. Sonic data also indicate that the stress field in the coal is likely to be homogeneous, with the maximum principal stress being the overburden pressure with minimal influence of tectonic forces. This results in limitations on injection rates, which must be maintained low enough to prevent vertical fracturing of the coal and any subsequent out-of-zone fluid migration. The sonic data also indicated that drilling of the well may have resulted in the creation of a significant damage zone (>1.2 m [4 ft]) around the wellbore. This conclusion is also in agreement with data from field operations that focused on the development of the wells, which was discussed in Section 7.0.

11.3.2 Underpressurization of Reservoir

Immediately after the wells were drilled and completed, it became apparent that the behavior of the system strongly differed from the expected behavior in that no, or very little, formation water entered the wells. Possible reasons for this observation include 1) lack of communication between the wells and the formation, 2) low or no permeability in the formation, and 3) lack of formation water in the reservoir. An extensive stimulation program, as previously described, was undertaken to establish communication between the wells and the formation but did not provide significant improvements. This indicated that the unusual behavior of the system was likely a result of intrinsic formation properties.

N-fits were conducted in three wells (Wells 36-10, 36-16, and 36-15C) to provide data to help explain these field observations (Appendix G). The tests indicated that the target geologic formation is likely to be hydraulically disconnected (compartmentalized) from the rest of the geological system in the area. Indeed, in addition to the lack of inflow in the wells, the N-fits indicated that the formation is significantly underpressurized. The targeted reservoir (lignite) is located at a depth of approximately 1100 ft. At this depth, a freshwater gradient of 0.43 psi/ft yields an estimated formation pressure of 473 psi. Figure 11-2 is a graph of the pressure observed during the N-fit of Well 36-16 versus reciprocal time. A straight dashed line is drawn through the portion of the observed data representing pseudoradial flow (i.e., the data to the left of the vertical line in Figure 11-2) and extended to the pressure axis (i.e., y-axis). The point of intersection with this axis is an estimate of the initial reservoir pressure, or p_i = 345 psia (2.38 MPa). However, the normal pressure gradient at the reservoir depth would yield pressure of about p = 470 psi (3.2 MPa). (It should be noted that similar analyses of the N-fit for Wells 36-15C and 36-10 yielded estimates of the initial reservoir pressure of 335 psia and 300 psia, respectively. Also, similar initial reservoir pressures are estimated when it is assumed that the coal is saturated with gas and not water.) This may largely explain the damage to the zone around the wells. Specifically, the evidence indicates that the wells were drilled using a significantly overbalanced drilling mud density (e.g., higher density than was required to maintain borehole stability). This meant that drilling fluid, and later cement, could penetrate deep into the formation.

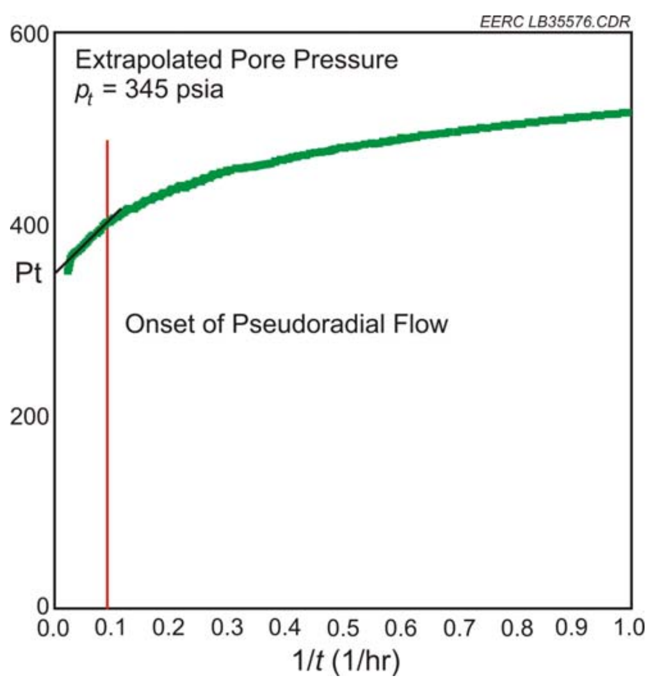

Figure 11-2. Observed pressure versus reciprocal time.

The nature of occurrence of underpressured zones is not fully understood. However, two theories generally explain the phenomena for the known pressure anomalies. A description of the known mechanisms of underpressure that are part of these two theories are as follows:

1. Underpressure in a reservoir occurs in the vicinity of rapid shallowing and outcropping of the formation. The underpressure occurs as a result of hydraulic balance in the reservoir. Sometimes this phenomenon occurs in the vicinity of artificial outcrops, e.g., longwall mining in Black Warrior Basin (Pashin and McIntyre, 2003).

2. Underpressure in a reservoir can occur as a result of uplift and erosion (Spencer, 1988). In this case, the reservoir rocks expand because of the decrease of overburden stress, and more pore space becomes available for the formation fluid. If the reservoir is hydraulically connected to the surrounding rocks, it will recharge with waters from the adjacent aquifers. For this reason, the existence of the zone of underpressure clearly indicates compartmentalization of the reservoir (Puckette and Al-Shaieb, 2003).

The analysis of geophysical logs indicates that the depth of the targeted coal in Burke County is very consistent and no outcropping of the coal occurs in the vicinity of the test site, which results in a rejection of the first theory for underpressurization. On the other hand, uplift and erosion are the more likely mechanisms of underpressure in the targeted coal seam in Burke County, North Dakota, particularly given that Williston Basin studies have indicated that evidence exists for uplift and erosion in many formations (Fischer and others, 2005).

Underpressure in the reservoir has both positive and negative implications regarding CO_2 injection operations. On the positive side, underpressure in the reservoir allows for higher pressure buildup during the injection. However, on the downside, unexpectedly low pressure in the reservoir resulted in drilling the wells using a significantly overbalanced drilling mud density (e.g., higher density than was required to maintain borehole stability). This meant that drilling fluid, and later cement, penetrated deep into the formation. Plugging permeability in coals by cementing is considered a common problem because of the specific cleat structure of the coal matrix. Thus, balance should be found between zonal isolation and preventing formation damage through cementing. Finally, low reservoir pressure also can result in low natural gas content. As previously noted, the estimated methane content of the Burke County coal ranged from 0.0.75 to 1.72 scf/ton of coal (as-received), which is lower than the average methane content (5.49 scf/ton) for North Dakota lignites that was estimated using data available from previous studies (e.g., Tewalt and others, 1989; Baez and others, 2004; Nelson and others, 2005) as well as gas content data generated from a coal seam in the southwestern part of North Dakota in 2001 (Nelson, 2003) which showed methane content to be as high as 12 scf/ton. The low methane content at the demonstration site effectively negates any potential to implement ECBM production during CO_2 storage at this site.

11.3.3 Shut-In Pressure, Fracture Initiation Pressure, and Transmissibility

In addition to providing insights regarding the pressurization of the reservoir, the N-fits that were conducted in three of the wells permitted the examination of other important characteristics of the reservoir, such as shut-in pressure, fracture initiation pressure, and transmissibility (see Table 11-1). The test data showed that while the estimated reservoir pressure was consistent between the wells, i.e., ranged from 330 to 345 psi, shut-in pressures and fracture initiation pressures differed substantially, 730 to 790 psi and 775 to 844 psi, respectively. This can be explained by the high compressibility of the nitrogen, which was used as the fracturing fluid. Compression of the injected fluid can take part of the mechanical load and thus influence the pressure measurements.

The transmissibility varies even more significantly among the wells, ranging from 3 to 2666 mD•ft/cP. Although there is nearly three orders-of-magnitude difference in estimated transmissibilities of the injector well and Monitoring Well 36-10, this observation is consistent with other field observations; i.e., the operation history indicated that the injection well usually provided the most pronounced hydrological response among all the wells. Furthermore, this difference does not look very surprising if the cleat nature of coals is taken into account. Indeed, a well intersecting a cleat or located in a close proximity to a cleat can be considered to be placed in a "sweet spot," i.e., a spot of increased permeability. See Appendix H for complete N-fit analysis.

11.4 CO_2 Injection

Pressure, temperature, and flow data for the nine phases of CO_2 injection during the demonstration test are presented in Figure 11-3. Specifically, the surface and BHP and surface temperature of the injection well (Well 36-15c), as well as the CO_2 flow, are presented as a function of time. A review of this figure indicates that, for the most part, the injection periods were relatively short, with the maximum period being 76 hours for Phase 2. These short test periods resulted from the desire to cost-effectively screen and/or examine the effects of pressure and temperature, and combinations of these two variables, on CO_2 flow rate. It was also understood that the density of the gaseous CO_2 and/or the phase distribution of the CO_2 would also be changing at the same time that these variables were being changed. One goal was to maximize the injection of CO_2 into the formation, while the ultimate goal was to learn about the effects of various operating parameters on CO_2 injection rates in lignite.

Table 11-1. Selected N-fit Results for the Injector and Monitoring Wells

Estimated Parameter	Injector	Monitoring Well 36-16	Monitoring Well 36-10
Average Reservoir Pressure	335 psi	345 psi	330 psi
Instantaneous Shut-In Pressure	790 psi	730 psi	788 psi
Fracture Initiation Pressure	Not determined	775 psi	844 psi
Transmissibility	2665.9 mD•ft/cP	55.0 mD•ft/cP < kh/μ < 68.4 mD•ft/cP	2.9 mD•ft/cP

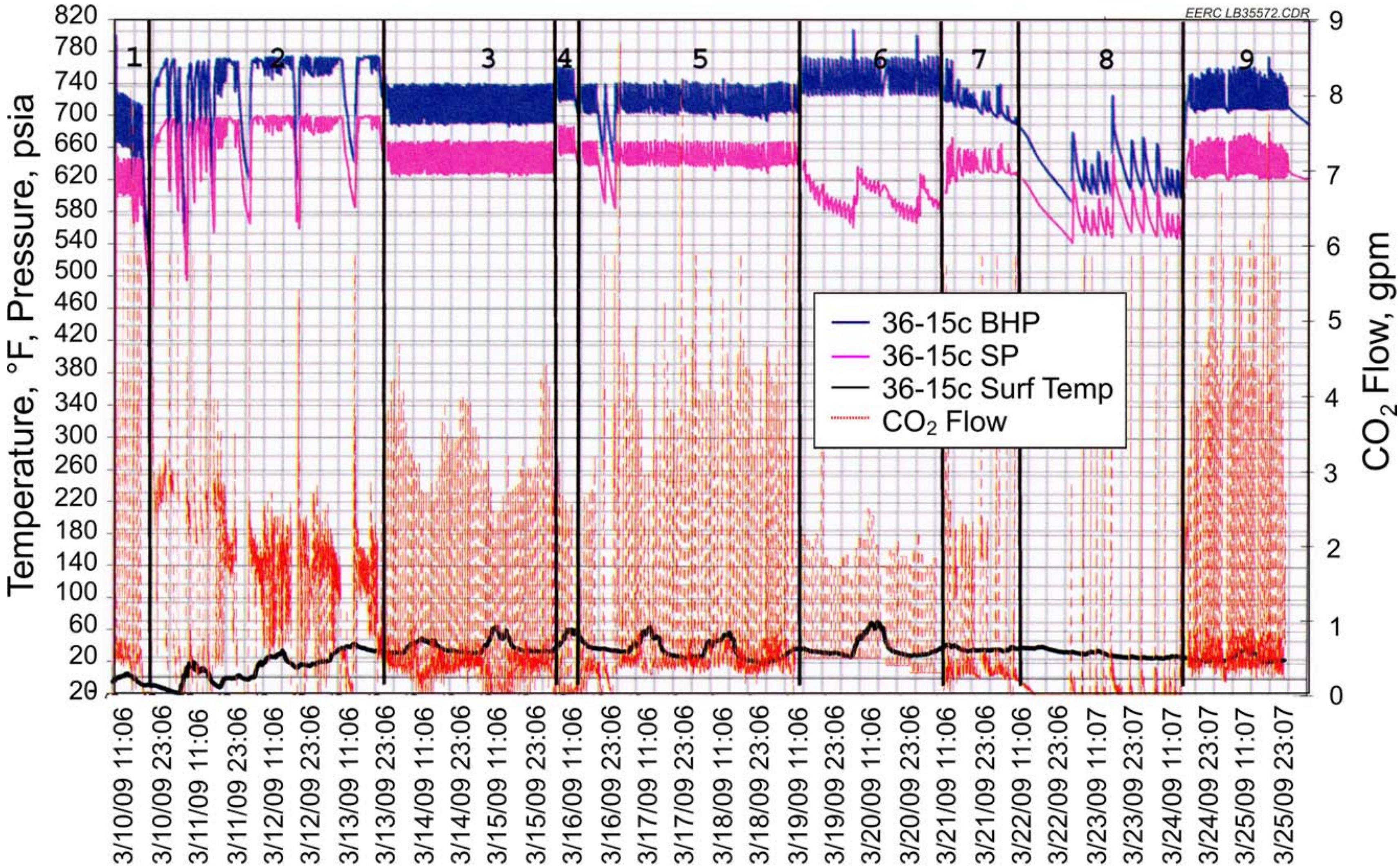

Figure 11-3. Pressure, temperature, and flow data for nine phases of CO_2 injection (SP is surface pressure).

As noted earlier in this report, decisions were made to investigate: 1) CO_2 injection at the maximum acceptable pressure for the formation (i.e., 780 psig), 2) CO_2 injection cycling near an average of 720 psig, and 3) CO_2 injection at various combinations of temperature and pressure to vary the density of the gaseous CO_2 and/or the proportion of liquid and gaseous CO_2 from 100% of either phase to a mixture of the phases. The ultimate goal of investigating these alternative injection strategies was to define those conditions which would maximize the flow of CO_2 that could be injected into the coal seam.

The rationale for this approach began with the initial premise that higher injection pressures would yield higher injection rates of CO_2. Once this approach had been implemented (Phase 2), it was decided to test the hypothesis and make sure other injection regimes did not yield better results. Therefore, shorter injection cycles were implemented that reduced the drop in the BHP that occurred before the next injection cycle was initiated (Phase 3). With no observed increase in injection rate, the thinking was that the bottom-hole temperature might play a more important role in the efficiency of the CO_2 injection. Temperature would affect the formation permeability by shrinking the rocks, resulting in the opening of the cleats and fractures. To check this assumption, both pressure and temperature were decreased (Phase 5). At this point, it was recognized that a mixed phase of CO_2 (liquid and gas) may be entering the formation. Since Phase 5 conditions did not yield positive results, it was decided to move forward ensuring that either all gas or all liquid injection was occurring during any given injection scenario. In Phase 6, the temperature was decreased even further, which resulted in the injection of liquid CO_2 (this was the only phase of injection that consisted solely of the injection of liquid CO_2). In Phases 7, 8, and 9, gas injection was resumed, and changes in pressure and cycling were investigated further.

If one looks at the data averaged over 8-hour time periods (see Figure 11-4) simple trends begin to materialize. After injection at the highest pressure rate, it appears that some injectivity may have been lost. When trying to maintain an average injection pressure of approximately 720 psig, the averaged data suggest the flow rate may have started to recover. When liquid CO_2 was injected it appears that even though the bottom-hole pressure was the same as the gas phase, a lower flow rate was achieved. This leads to the assertion that heating the CO_2 provided better flow rates at this lignite seam. Additionally, when the averaged data are analyzed, it does not appear that injectivity into the lignite seam was lost over the entire injection period. This is a positive outcome because a concern when injecting into coal is that the coal may swell and close off any permeability that may be present.

Although the short durations of these individual injection phases made it difficult to reach any firm conclusions, the data did suggest that some improvements in injection rates could be achieved by heating the CO_2 and injecting it in a purely gaseous state at fairly high pressures.

In general, because of the inability to conduct multiple injection tests within the short time lines of each injection phase, the injection history in Figure 11-3 did not allow for arriving at any firm conclusions about the combination of variables that would maximize the rate of CO_2 injection. However, it is evident from the data that regardless of the changes in conditions that were made, the average flow of CO_2 never exceeded 1.5 gpm. This observation suggests that the low permeability of the coal, which was confirmed by the laboratory tests conducted on the core,

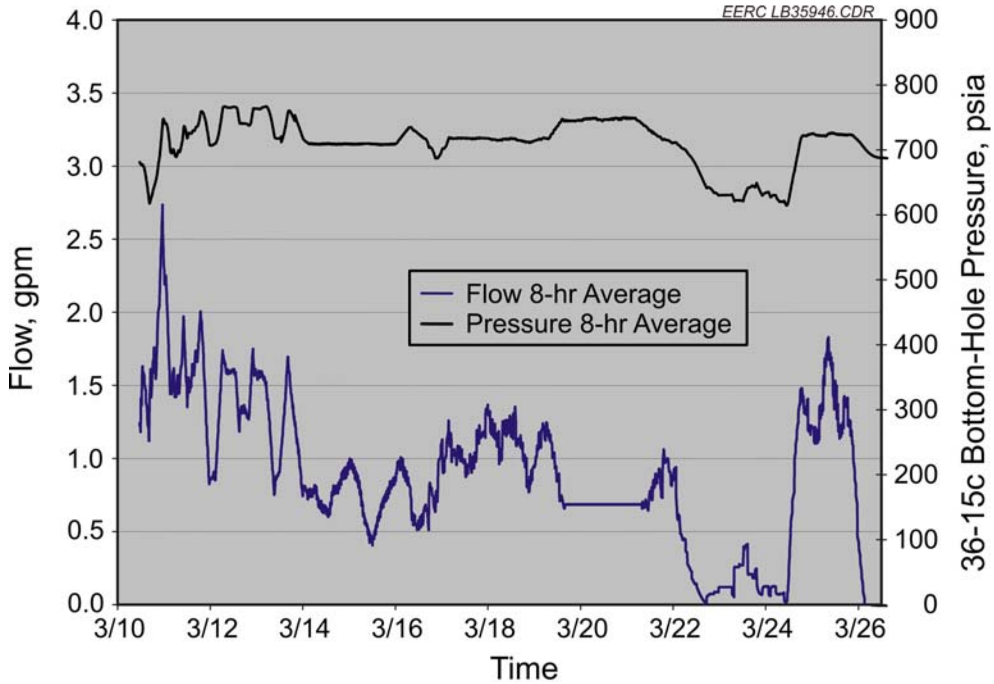

Figure 11-4. Injection data averaged over 8-hr time periods.

is the primary factor that is limiting CO_2 injection and that none of the variables that were investigated could overcome or remove this limitation. For this reason, it is difficult to use these demonstration test data to make a general recommendation of an injection strategy that would maximize the injection of CO_2 into unminable coal seams. Rather, it is likely that the definition of such a strategy for a given site will require iterative investigations during facility start-up to allow for a site-specific optimization based on actual site observations.

11.5 MVA

The RST and crosswell seismic measurements provided the best MVA data/information by providing the best depiction of the CO_2 movement at the site. These results are also generally supported by pressure data collected from Monitoring Wells 36-15 and 36-9 as well as preliminary models that predict the fate of CO_2 immediately following injection.

11.5.1 RST Logs

Schlumberger RSTPro logs were run on the injector and each of the monitoring wells prior to CO_2 injection and after CO_2 injection was completed. These logs were processed, and the difference logs were created. The difference logs for the injection interval for the injection well (36-15c) and for Monitoring Well 36-15, are shown in Figure 11-5, on the right-hand side of Panels a and b, respectively. Preinjection logs are shown in blue, and postinjection curves are shown in red. The perforation (injection) intervals are shown in the depth scales by black bars.

The separation between the curves is clearly seen in the 36-15c log (highlighted yellow), indicating saturation of the near-wellbore area with the injected CO_2. Significant separation of the curves at the top of the injection interval in 36-15c is attributable to the placement of a plug, which was necessary for the injection operations, rather than to excessive saturation of the area with CO_2. The lack of separation of the curves in the perforated interval in Monitoring Well 36-15 indicates that even if injected CO_2 had reached the well by the time the repeat RST survey was run, its concentration was not high enough to result in changes in the RST readings. Slight separations of the logs above and below the injection interval are attributed to changes in the wellbore environment and to the inaccuracy distinct to any geophysical measurements. The logs for other monitoring wells (see Figure 11-6) are similar to that for Well 36-15. The lack of response in the monitoring wells indicates that the majority of the injected CO_2 stays in close proximity to the injection well.

11.5.2 Time-Lapse Crosswell Seismic

Given the conditions at this demonstration site, time-lapse crosswell seismic was the most effective of the applied MVA techniques. The reason for the success of the technique is close spacing between the monitoring wells and the resulting high resolution of the obtained images. However, in general, seismic tomography is less effective for coals than for other types of rocks. Thus of the two seismic lines (Well 36-16 to Well 36-10 and Well 36-9 to Well 36-15), the one which had larger well spacing (Well 36-16 to Well 36-10) did not provide reliable results for the interpretation.

Meanwhile, short profile (Well 36-9 to Well 36-15) yielded good seismic reflection images and good difference tomography results. These results show a good correlation with geology as well as the expected location of the CO_2 injection. The reflection image displays a vertical resolution of around 5 cycles per 100 ft. That is to say that a full depth cycle in the image is 20 feet. With the general assumption that a wavelet can be interpreted to one-half or one-quarter of a cycle, the reflection image may give resolution to as low as 5 vertical feet. The difference tomography displays a velocity change in the location of the injection well. When the zone of velocity change is coupled with the reflection image, the top and bottom of the velocity change zone matched very well with the lithology in the area. In addition, the difference tomography results display a localized larger velocity change as well as a more broad small velocity change. These changes may indicate the location of the CO_2 plume and/or existence of a pressure gradient induced by injection. Figure 11-7 shows the difference tomograms, both in terms of a) absolute velocity change and b) percent change. It can be seen that the changes are most pronounced right in the injection zone (corresponding to the peaks of the gamma ray logs also shown in Figure 11-7). However, changes are also noticeable in the adjacent layers. It can be suggested that the maximum changes occur in the vicinity of the injection well which is shifted from the central line towards the Well 36-15 (green spot in Figure 11-7a and red spot in Figure 11-7b).

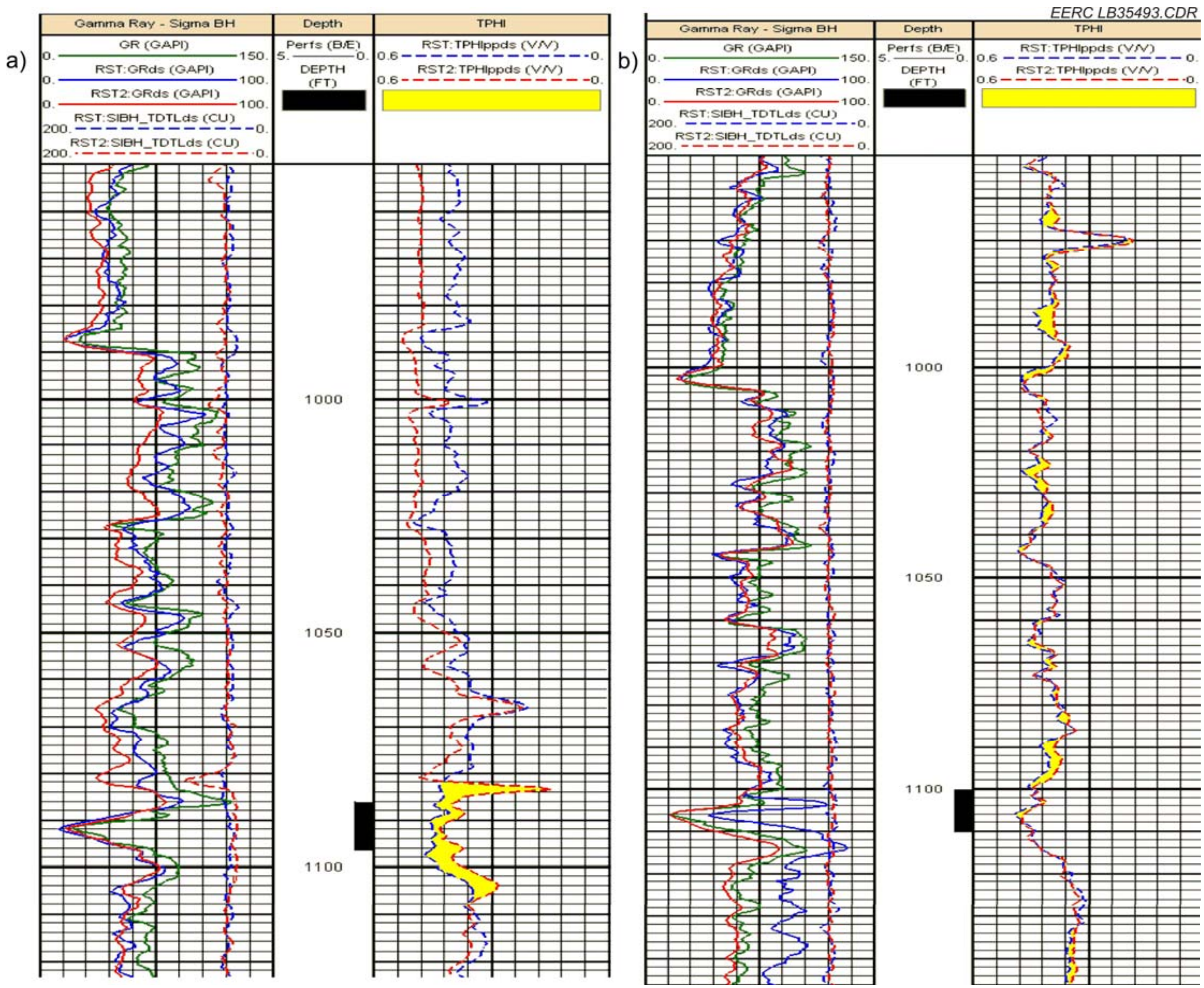

Figure 11-5. RST difference logs for a) Injection Well 36-15c and b) Monitoring Well 36-15.

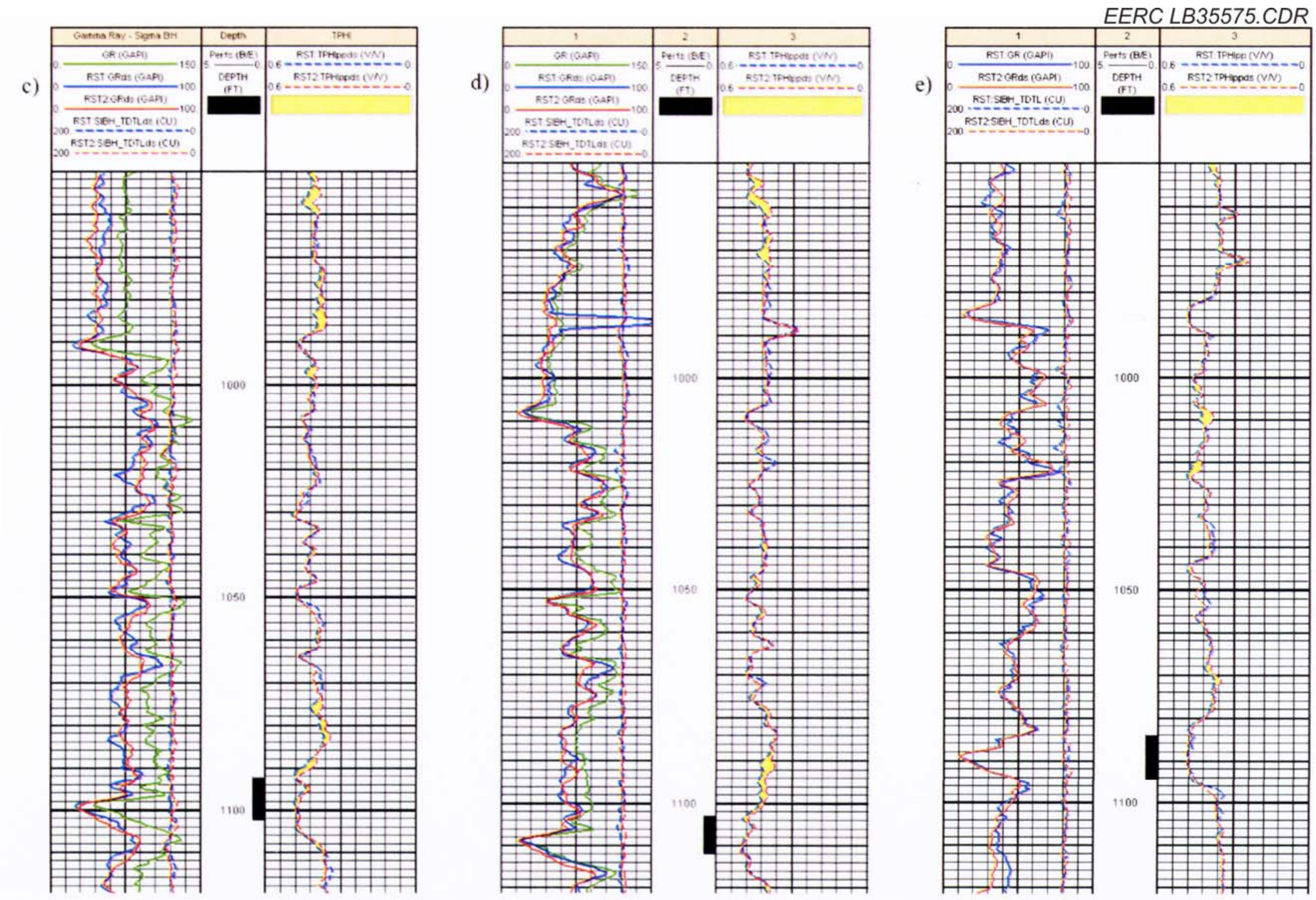

Figure 11-6. RST difference logs for c) Monitoring Well 36-9, d) Monitoring Well 36-10, and e) Monitoring Well 36-16.

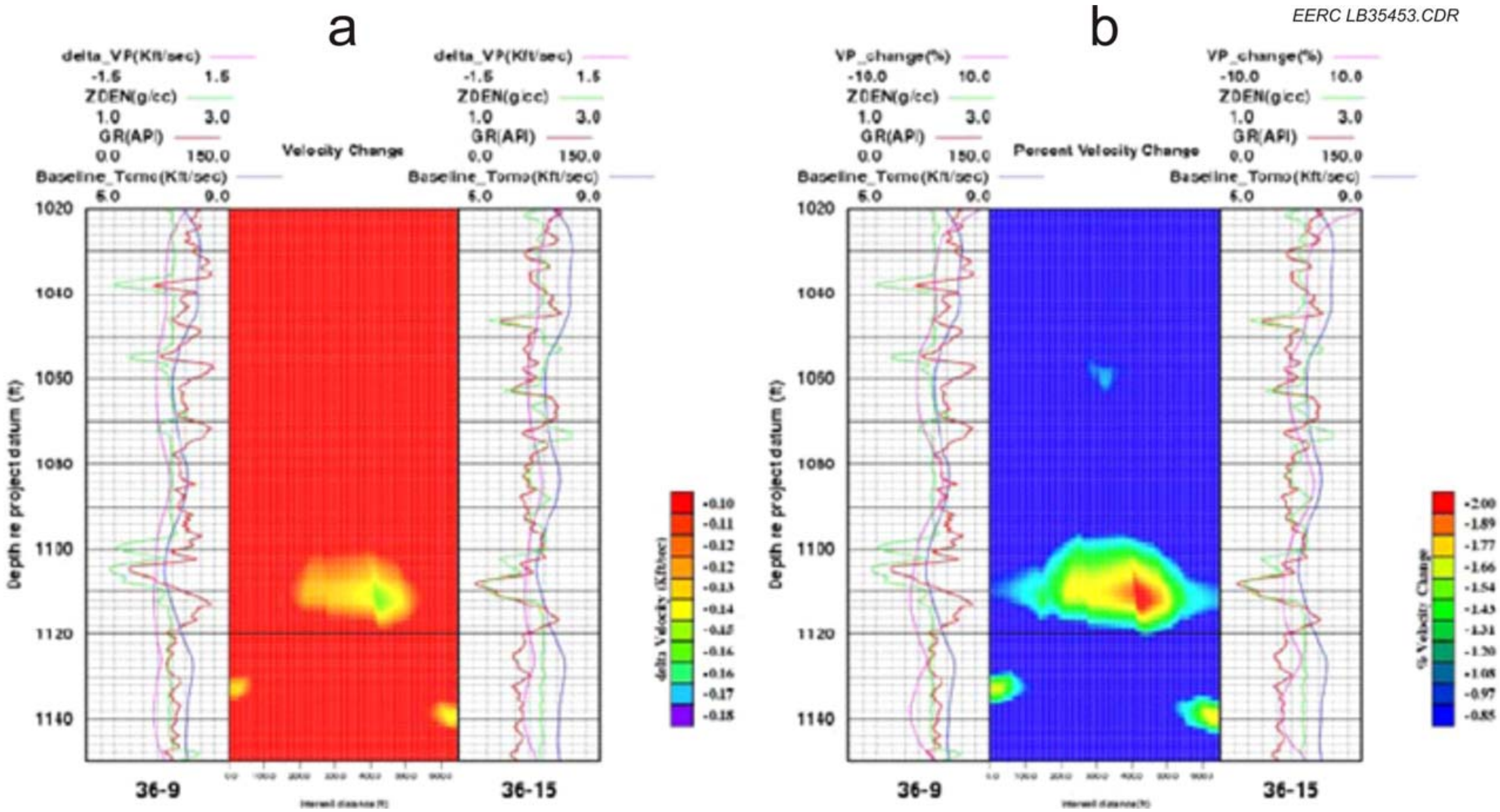

Figure 11-7. Profile view of the CO_2 plume.

The long profile (36-16 to 36-10) had a much lower signal-to-noise ratio. This lower signal-to-noise ratio is due to a combination of issues. These issues include the shallow depth of the zone of interest (which limits the aperture of the data) and the general attenuation of the geology in the shallow formations. These issues result in a lower-quality reflection image that is difficult, if not impossible, to interpret. Because of these issues, the long profile data were deemed unacceptable for presentation in this report. For detailed time-lapse crosswell seismic analysis and results, see Appendix I.

11.5.3 Microseismic Monitoring with Geophones and Tiltmeters

Because of high noise levels in the hybrid tool string caused by the inability of the tilt tools to level, it was decided that for the initial part of the monitoring (first three project days), all tilt tools would be turned off and monitoring would be done using microseismic technology only. Once CO_2 injection started, it was found that the achievable injection rates were substantially lower than earlier anticipated. As a result, no microseismic events were recorded. See Appendix G for full microseismic analyses.

11.5.4 Tracer Study

Praxair provided SeeperTrace^{SM} leak detection activities as an MVA technique. A proprietary "tracer" compound was mixed into the CO_2 stream that was being injected into the target lignite seam. The plan was to collect a series of postinjection gas samples from the monitoring wells for detailed laboratory analysis of the tracer. Unfortunately, in three of the monitoring wells, pressure buildup did not occur, making it impossible to take a sample. The monitoring well that did experience a slight pressure increase (Well 36-15) was not able to be sampled in accordance with the prescribed methods. Difficulty in retrieving the bridge plug that had been placed in Well 36-15 to accommodate the microseismic monitoring array caused the small pressure buildup to be released before a gas sample could be taken.

11.5.5 Monitoring Well Measurements and Preliminary Modeling Results

Other MVA measurements that were made during the demonstration at the site was the measurement of the CO_2 concentration and BHP in Monitoring Wells 36-9, 36-10, 36-15, and 36-16. These wells are located 380, 471, 288, and 920 feet, respectively, from Injector Well 36-15c. At no time during the demonstration test did the CO_2 concentration measurements at any of these monitoring wells exceed the background concentration of CO_2 in the formation; however, a pressure front was recorded at both 36-15 (Figure 11-8) and 36-9 (Figure 11-9). The former shows the recorded values of pressure in Injection Well 36-15c and Monitoring Well 36-15 plotted against time. It can be seen in Figure 11-8 that the pressure front from the injection well reaches Monitoring Well 36-15 on, or about, March 19 (following ~9 days of injection). It is also interesting that the observed pressure buildup also occurs immediately following the onset of liquid CO_2, injection, which occurred during Phase 6 of the injection, i.e., March 19 (14:02) through March 21 (12:02). At the same time, similar pressure responses were not observed in the other monitoring wells except for Well 36-9, where a pressure front was also measured beginning on March 19 (Figure 11-9). However, the observed pressure buildup in that well was very slow and practically negligible (i.e., 0.5 psi [357 to 357.5 psi] in 3 days [March 19 to March 22]).

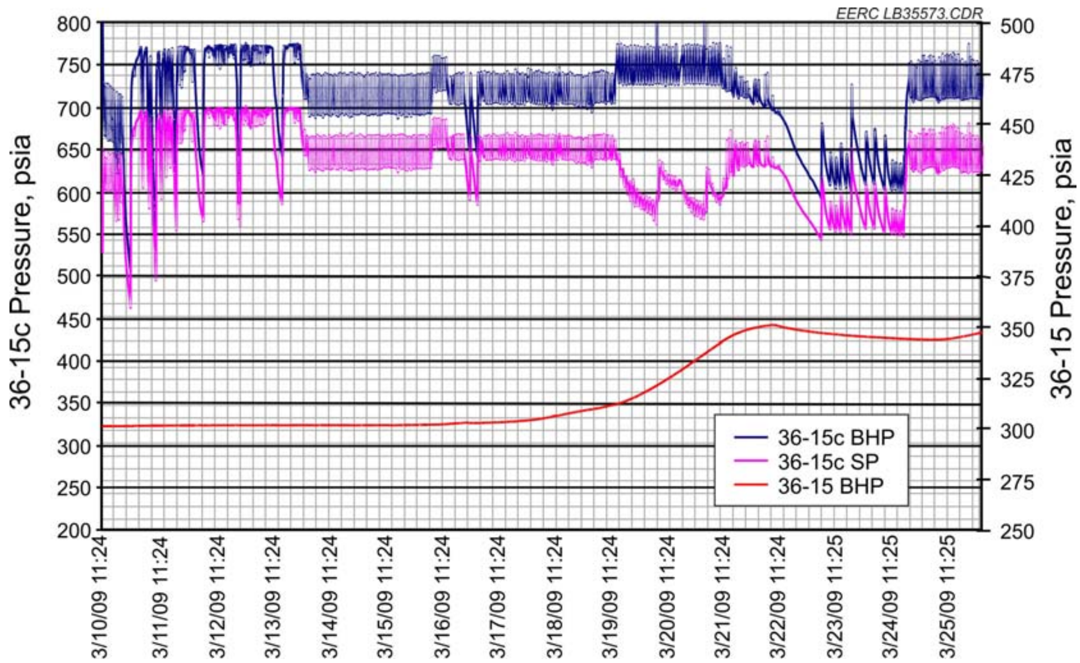

Figure 11-8. Pressure changes with time in Injector Well 36-15c and Monitoring Well 36-15: March 10 through March 25, 2009.

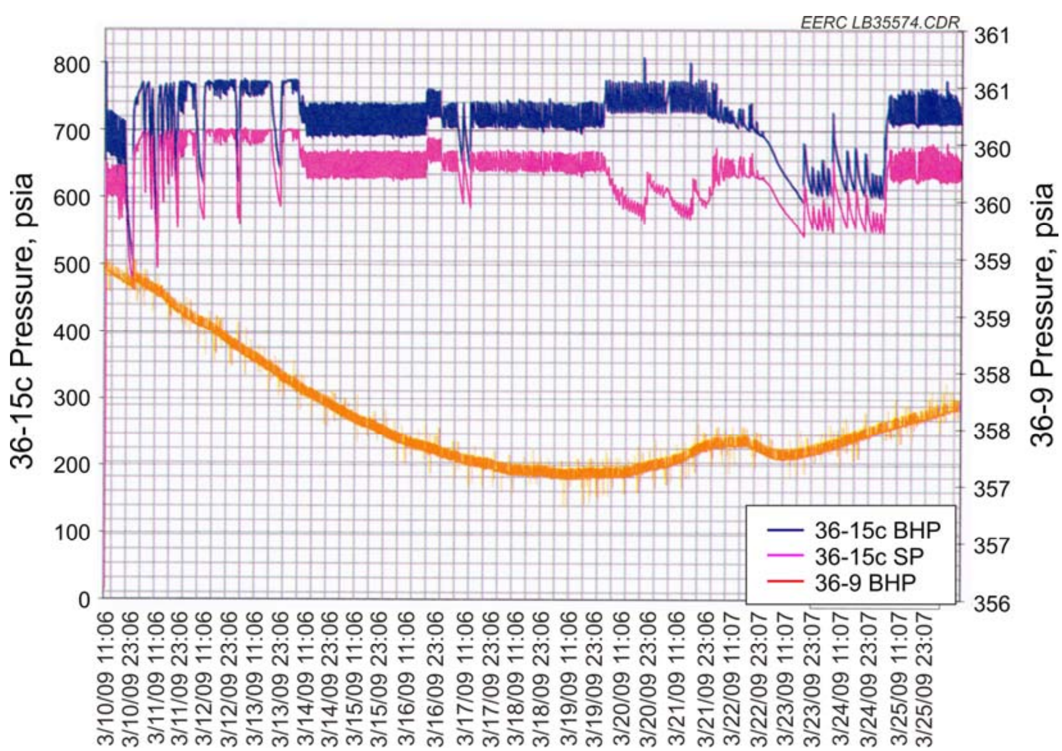

Figure 11-9. Pressure changes with time in Injector Well 36-15c and Monitoring Well 36-9: March 10 through March 25, 2009.

It should be noted that surface pressure buildup in the monitoring wells did not occur, therefore sampling for the tracer and other gas constituents was not able to be performed.

The observations in these two monitoring wells are consistent with the information provided by the RST logs and the crosswell seismic data in that they suggest that while the pressure front may have reached these wells, the CO_2 plume has not and is being contained within the coal seam, between the wells.

Preliminary modeling results of the CO_2 injection into the coal formation also generally support these MVA observations. While it is recognized that this specific physical system is difficult to model because of a number of technical difficulties, a preliminary model was developed that predicted that the farthest distance of CO_2 migration during the injection would be about 60 feet (Figure 11-10). A model depiction of the injector well and maximum migration of the CO_2 plume is shown in Figure 11-10. As noted above, all of the four monitoring wells noted above were 288 feet or more from the point of CO_2 injection, and none of them recorded any impact from a CO_2 plume. With the understanding that the well placements are not ideal for this analysis and comparison, i.e., they are significantly farther away from the source than 60 feet, as a first-order assessment and comparison, the well-monitoring information and modeling predictions are consistent and comport with the findings of the RST logs and crosswell seismic data.

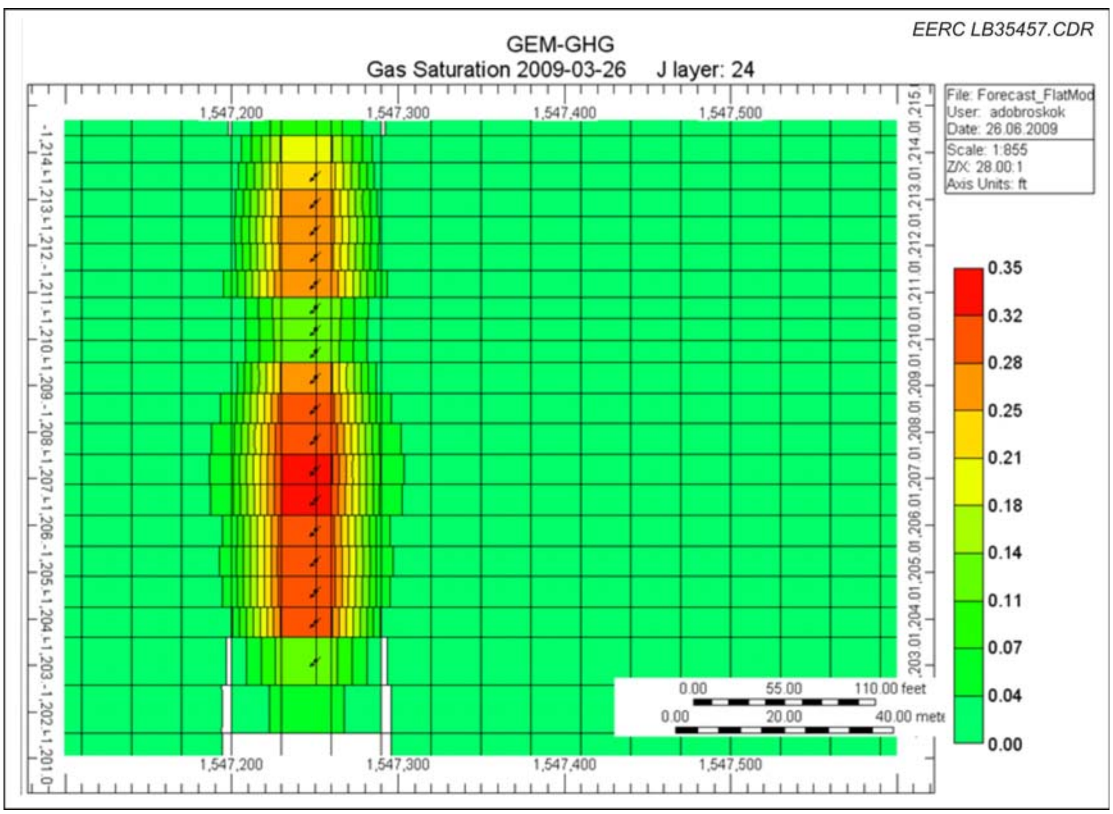

Figure 11-10. Two-dimensional view of CO_2 plume depicting maximum migration from the injector well.

11.6 Lessons Learned Summary

Consistent with the project goals, this demonstration test revealed both what works and what does not work when attempting to store CO_2 in an unminable coal seam. To some degree, these "lessons learned" are site-specific and may not apply beyond the Burke County location. However, others represent more generic lessons that can serve as the basis for refining the design of future projects of this type. Some of the more important of these lessons learned are discussed below.

Site Selection. The selection of the demonstration test site was driven by a number of technical and nontechnical factors. The former included the review of geophysical logs from the database of the NDIC OGD, which identified multiple coal seams. Following this reconnaissance effort, water well logs and other available data sets, e.g., gamma ray logs, were examined to identify the water quality, coal characteristics, and baseline geologic settings in these candidate coal seams. State criteria associated with the definition of an unminable coal seam were also used as part of the screening process. These criteria included a minimum coal depth, cumulative coal thickness, individual bed thickness, and overburden thickness as well as a maximum overburden-to-coal stripping ratio. At the same time, the availability of mineral rights was also an important screening factor. This review led to the identification of an area in Burke County in northwestern North Dakota as the general location of the demonstration test site. Eventually, a mineral lease was obtained for Section 36, T159N, R90W in the southeast corner of Burke County for the injection of CO_2 and enhanced production of CBM.

This site selection process was comprehensive and provided much of the information that was needed to make an informed decision about the test site. However, it would have been useful to have had log data from the upper geologic zones. In traditional deeper oil and gas exploration, the zones that are of interest for this project are drilled through without being logged or sampled. Therefore, few reliable data were available to fully understand the atypical properties of the target injection zone. Since the initial site selection research was conducted, more data have become available regarding the complexities of shallow subsurface systems. Additional shallow wells were drilled during the time this project was conducted, and they also exhibited below-normal pressure gradients, which was a critical factor affecting this demonstration test. Emerging data that suggest that some Tertiary and Cretaceous rocks may be underpressured regionally warrant further investigation.

Project Permitting. The demonstration test required the acquisition of a number of federal and state permits. The primary driver for the former was the National Environmental Policy Act (NEPA) of 1969, which stipulates specific procedural requirements for federal agency actions. In general, NEPA applies only to those projects where federal funds are used, federal lands are crossed and/or used, or federal permits are required. In this instance, a NEPA review was required because some of the demonstration test funds were provided by DOE. However, for many private sector-funded demonstrations or commercial ventures of this type, a NEPA review may not be required. In the end, neither a NEPA Environmental Assessment nor an Environmental Impact Statement was required for the demonstration test as it was determined that it qualified for a Categorical Exclusion. The exclusion was based on the information that was provided as part of a DOE questionnaire.

The permitting requirements for the demonstration test were specific to North Dakota; however, it is likely that most oil- and gas-producing states would have similar requirements. The North Dakota requirements, which are embodied in the North Dakota Administrative Code, contain general rules and regulations adopted by the North Dakota Industrial Commission to conserve and govern the natural resources of the state. Specifically, the demonstration test required a well-spacing exemption, drilling permits, an injection application, an aquifer exemption, and the submission of numerous sundry notices. These requirements are representative of the types of activities that would likely be required to initiate CO_2 storage operations in North Dakota. While they are test- and state-specific, they are probably not unlike what may be encountered in other states where unminable coal seams are being targeted for CO_2 storage.

Site Development and Well Drilling. The injection well and the four monitoring wells were drilled as part of a single mobilization, making it nearly impossible to use the data from one well to make adjustments in the locations or drilling depths of the other wells. Once on-site with the drill rig, all of the wells were drilled, logged, and cased. While this approach was taken as a measure to control the costs associated with multiple mobilizations of the drilling rig, a better approach would have been to drill the closest monitoring well and to fully characterize it prior to drilling the other wells. This would have provided critical information regarding the subsequent drilling of the injector and other monitoring wells. However, in addition to the cost of multiple mobilizations, there was also a concern about the availability of the drilling rig for the demonstration test from one mobilization to the next.

The demonstration test determined that the coal formation was significantly underpressured, with an actual reservoir pressure of about 345 psia versus an expected formation pressure of approximately 470 psia. This underpressured situation was not anticipated, and as a result, the wells were drilled with a significantly overbalanced drilling mud that had a higher density than was required for maintaining the stability of the borehole. This led to the migration of the drilling fluid, and later the cement, into the formation and may ultimately have been responsible for the difficulty in establishing a good connection between the borehole and the formation. This is an excellent example where a lapse of time between the installation of the initial well and the remainder of the site wells would have allowed for the consideration of critical information for the subsequent drilling activities.

A core was collected during the drilling of the injection well to provide samples for the conduct of selected laboratory tests. The intent was to capture the entire coal seam as well as the non-coal-confining layers that were present both above and below the coal seam. The core point was selected based on the comparative drill rates between the first monitoring well (Well 36-15) and the injector well (Well 36-15C) as well as the unprocessed log data from the first monitoring well (Well 36-15). This led to the acquisition of a 20-foot core, the bottom of which was coal and not the lower confining layer. To ensure that the bottom confining layer was not missed, it would have been prudent to have staggered the drilling of the wells over time, as noted above, to permit the use of information from the early wells to better inform the installation and sampling of the later wells. Using this approach, it is likely that the core point would have been properly selected and the entire interval of interest would have been secured during the collection of the core sample.

Well Logging, Casing, Completion, and Development. The wells were logged immediately after drilling using the Schlumberger Platform Express logging suite. A Schlumberger Sonic Scanner log was also run in the injector well. These logging techniques were easily implemented (one exception was a monitoring well [36-16] where an assumed sediment bridge prevented open-hole logging of the well) and provided valuable information for the test. Specifically, the open-hole logs assisted in the selection of the injection interval and highlighted the presence of a bifurcated coal seam. It also provided valuable insight regarding the possible lack of a cleat system in the coal and a relatively homogeneous stress field, which contributed to limiting the CO_2 injection rate.

Well completion and development for the demonstration test were somewhat unique, as the well-drilling program was designed based on the need to collect petrophysical data. This required drilling below the injection zone to accommodate the logging tools. The zone of interest then needed to be isolated to ensure injection control. This led to a completion program where the entire wellbore was cased and cemented, followed by perforation of the injection zone. Given the fact that the reservoir was underpressured, a fact not known prior to drilling, it is likely that drilling mud and cement penetrated the reservoir and, perhaps, reduced some of the permeability. A commercial-scale operation that has fully characterized the intended injection reservoir may choose to drill and case to the top of the coal seam and then air-drill the injection zone, as it is less invasive and may reduce near-wellbore damage.

Development of the wells was conducted by applying different stimulation techniques, in stages, with the intent of avoiding the use of more aggressive techniques that had the potential to negatively influence the injection zone and complicate the interpretation of postinjection monitoring. This approach is counter to the standard protocol that has been established for CBM production, wherein wells are acidized following perforation. The techniques employed during the demonstration, in order of application, included swabbing, sonic hammer, nitrogen N-fit test (i.e., minifrac), and acid treatment. Initially, acid treatments were applied without the use of perforation balls. When the desired results were not obtained, perforation balls were added. Acidizing provided the best results in terms of establishing communication between the wellbore and the formation in that, after acid treatments, all of the wells experienced an increase in water levels. However, fluid flow rapidly tapered off in the wells. This leads to two working hypotheses regarding the lack of fluid entering the wellbores: 1) there was a lack of communication between the wellbores and the formation and 2) there was a lack of fluids and/or hydrologic conductivity in the formation.

Another example of a good plan that did not work at this site was the use of a 5-spot well configuration. This layout was used in order to conduct a pump test to evaluate the "aquifer" that, in turn, would lead to a better understanding of the hydrodynamics of the injection zone. However, the underpressured zone and lack of hydraulic conductivity precluded the use of a pump test to develop this knowledge.

Lastly, to make a final comment regarding the drilling and completion of the wells at this site, the results of injection activities indicated that injecting 100% gas-phase CO_2 was perhaps the optimal regime for this coal seam. If this is the case, one would be severely limited with regard to the amount (i.e., mass) of CO_2 that could be injected over time. To overcome this limitation, long, horizontal wells could be used along with bigger-diameter pipe. Finally, alternative completion techniques could be employed, e.g., cavitation and hydraulic fracturing.

CO_2 Injection. A total of nine distinct phases of CO_2 injection were investigated over the course of the 16-day period of injection. During each phase, different injection strategies were employed in an attempt to maximize the rate of CO_2 injection into the formation. The strategies investigated were 1) CO_2 injection at the maximum acceptable pressure for the formation (i.e., 780 psig), 2) CO_2 injection cycling near an average of 720 psig, and 3) CO_2 injection at various combinations of temperature and pressure to vary the density of the gaseous CO_2 and/or the proportion of liquid and gaseous CO_2 from 100% of either phase to a mixture of the phases. Because of the properties of the reservoir, the majority of the CO_2 injection was conducted in cycles, which began with the buildup of the BHP to a predefined threshold of 708 psig, followed by a slow decline. On average, each injection cycle took about 40 minutes. The bottom-hole temperature varied from 50° (10°) to 62.5°F (17°C).

A summary of the key characteristics of these nine phases of CO_2 injection are provided below:

- The duration of the injection phases ranged from as few as 6 to as many as 76 hours of operation.

- The pressure swings ranged from a low of 605 psia to a high of 770 psia.

- The average CO_2 flow rate ranged from 0.13 to 1.45 gpm.

- The volume of CO_2 injected ranged from 308 to 6660 gallons.

Of particular note is that liquid CO_2 only was injected during only one phase of the injection program. During this phase, nearly 3000 gallons of CO_2 was injected at an average rate of approximately 1 gpm.

In general, because of the inability to conduct multiple injection tests within the short time lines of each injection phase, it was difficult to arrive at any firm conclusions with respect to the combination of variables that would maximize the rate of CO_2 injection. However, the data did suggest that some improvement in injection rates could be achieved by injecting 100% gaseous CO_2. It is also evident from the data that regardless of the changes in conditions that were investigated as part of this demonstration test, the average flow of CO_2 never exceeded 1.5 gpm. This observation suggests that the low permeability of the coal formation may be the primary factor that limited CO_2 injection and that none of the strategies that were investigated could overcome this limitation. For this reason, it is not prudent to use these demonstration test data to make a general recommendation of an injection strategy that would maximize the injection of CO_2 into unminable lignite coal seams. Rather, it is likely that the definition of such a strategy for a given site will require iterative investigations during facility start-up to allow for site-specific optimization based on actual site observations.

Value of Lab Studies. As part of the demonstration test, numerous laboratory studies were conducted on a core of the coal that was collected during the drilling of the injection well. These tests included coal compositional analyses (i.e., proximate and ultimate analyses, maceral analysis, and vitrinite reflectance), canister gas desorption studies, methane and CO_2 sorption isotherms, and permeability tests. These tests, even though they were performed at a small scale using only small quantities of coal, provided useful information regarding the potential to move CO_2 through the formation and the ability of the coal to adsorb CO_2 and methane and subsequently release them from the coal bed. At the same time, it is recognized that extending these laboratory results to the full-scale demonstration will not necessarily yield conclusive interpretations. That said, the conduct of these laboratory tests is recommended as part of future storage applications in unminable lignite coal seams. Assembling this laboratory/field database will improve the ability to predict field performance based on the results of the laboratory studies. It will also permit the investigation of correlations between lignite properties and the sorption and release of CO_2 and methane, both of which are critical variables that govern the economic success of this storage approach as well as its acceptance by the public.

Modeling Strategy/Value. A preliminary model was developed to predict the movement of CO_2 within and beyond the coal formation. However, the usefulness of this model was limited by the difficulty associated with capturing the physical and chemical properties of this complex geologic stratum and its interactions with the CO_2. Stated simply, the effort to create a model that could accurately predict the movement of CO_2 ultimately proved to be beyond the scope of the demonstration test, because a paucity of data, including the inability to conduct a pump test, resulted in an inability to adequately calibrate it or verify it, given the relatively short duration of the demonstration test itself. CO_2 fate and transport models have a place in the full-scale application of this storage technique but are probably best developed and evaluated as part of storage field tests that are conducted during larger demonstrations of the technology. The results of this demonstration test have provided information that suggests that these larger-scale tests can be conducted for model development, as well as other purposes, without threatening the environment or other local resources, e.g., groundwater.

MVA Strategy. Given the goals of the demonstration test, MVA measurements at the demonstration site included 1) direct measurements, which provided information directly related to the fluid pathways or the shape of space occupied by fluids, and 2) indirect measurements, which provided data regarding certain parameters that characterized the fluid movement at discrete points of the formation. More specifically, the methods used during this demonstration test included RST and crosswell seismic measurements as well as the following:

- Surface sensors for measurement of temperature, pressure, and flow rate.

- Downhole sensors for measurement of temperature, pressure, conductivity, and pH.

- Gas sampling at wellheads to measure methane, CO_2, and oxygen concentrations and subsequent analytical results from gas chromatography, including the measurement of a fluorocarbon-based tracer that was injected with CO_2 at the beginning of the test.

- Microseismic measurements, which included both geophones and tiltmeters.

Because of the low injection rates, many of the monitoring techniques chosen could not verify CO_2 injection and/or detect CO_2 plume movement. Higher injection rates may provide better results for some of the techniques used. After analysis of all gathered data, it was determined that a combination of seismic image tomography and RST measurements was found to provide the best MVA data/information at the site. This combination permitted the verification of the CO_2 injection into the targeted depth interval through the RST measurements. However, no extrapolation to reconstruct the plume geometry could be done from the RST measurements alone, since the injected CO_2 did not reach the monitoring wells in amounts that could be registered with the RST. Thus, crosswell seismic tomography was used to bridge the gap and provide valuable missing information regarding the plume extent. Using the four monitoring wells to acquire two 2-dimensional surveys with high vertical and horizontal resolution that crossed at or near the injection well, it was possible to calibrate the response at the wells with the RST and then fill in the gaps between the wells with the crosswell seismic data. The RST and crosswell seismic measurements provided the best MVA data/information by providing the best depiction of the CO_2 movement at the site. These results are also generally supported by pressure data collected from Monitoring Wells 36-15 and 36-9 as well as the results of the preliminary models that were developed to predict the fate of CO_2 immediately following injection.

11.7 Achievement of Objectives

In summary, the primary objectives that were defined at the beginning of this demonstration were largely met. To reiterate, these objectives were:

1. To demonstrate that CO_2 can be safely injected and trapped in lignite by means of adsorption.

2. To assess the feasibility of CO_2-enhanced methane production from lignite.

3. To evaluate a variety of carbon storage operations to determine their applicability to similar coal seams within the region or beyond.

In spite of the atypical characteristics of the reservoir at the demonstration test site, which dramatically changed the dynamics of the demonstration test, the test results show that CO_2 can be safely injected and stored in an unminable lignite seam. At the same time, the feasibility of recovering methane at this site was shown to be infeasible because of the very low methane content of the coal. The low methane content of the coal may very well have been directly related to the aforementioned characteristics of the reservoir or even to flawed methodologies. However, this is a site-specific observation that should not be extrapolated to other lignite coal seams without extensive technical justification. Likewise, the evaluation of the carbon storage and potential methane production operations that were conducted as part of this demonstration test was greatly influenced by the site-specific features of the reservoir, making it difficult to determine their applicability at other sites. However, as a general statement, the facility equipment operated as planned and the demonstration test was safely executed, suggesting that similar equipment could be deployed and similar operations could be successfully implemented at other field sites, without consideration of whether or not they represented an optimal storage strategy. That said, a subset of the MVA techniques applied at the site worked well and would be ideal for use at other unminable coal seams.

These conclusions open the door for the conduct of other similar CO_2 injection tests at a larger scale and of longer duration. The conduct of these tests should be focused on the 1) optimization of the carbon storage and ECBM production operations, 2) development, calibration, and verification of a CO_2/methane fate and transport model, and 3) evaluation of the economics of this carbon storage option. At the same time, a more streamlined MVA strategy can also be developed, applied, and validated as part of these more robust field tests.

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