CONFERENCE PROCEEDINGS

CO_2 Storage Pilot Study for Lignite Coal

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ABSTRACT

The United States possesses abundant unminable lignite resources that can provide viable options for geologic carbon storage. However, the feasibility of carbon dioxide (CO_2) storage in lignite coal has yet to be proven. The Plains CO_2 Reduction (PCOR) Partnership at the Energy & Environmental Research Center (EERC) has developed a lignite field validation test in Burke County, North Dakota, to investigate the feasibility of CO_2 storage in unminable lignite seams. The PCOR Partnership is one of seven partnerships investigating carbon storage funded by the U.S. Department of Energy National Energy Technology Laboratory Regional Carbon Sequestration Partnerships and commercial partners.

This paper will present methodology and results from the EERC's lignite field validation test, including cross-well seismic imaging of injected CO_2, downhole sensor measurements, and monitoring. The success and economics of carbon storage in lignite coal largely depend on adequate CO_2 trapping, adsorption, storage capacity of the reservoir, injectivity, and land surface access. The work presented provides a greater understanding of injectivity, trapping, adsorption, and storage capacity for lignite coal.

EXECUTIVE SUMMARY

Approximately 90 tons of carbon dioxide (CO_2) was injected over a roughly a 2-week period into a 10–12-ft-thick lignite 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 cross-well seismic tomography provided the most valuable information. These techniques demonstrated that the CO_2 did not move away from the wellbore a significant distance and was contained within the coal seam for the duration of the approximately 3-month monitoring period.

In spite of the atypical characteristics of the reservoir (underpressured, low-permeability, variations of wellbore skin, sand) 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, 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 further technical investigations. 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. 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 1) optimization of carbon storage and enhanced coalbed methane (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.

INTRODUCTION

The U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) 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 at 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.

EXPERIMENTAL SETUP AND PROCEDURES

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 1 displays a map of the well locations, and Figure 2 provides an aerial view of the project location, with the drill rig located on the injection well site pad.

Figure 1. Map of injection and monitoring well locations.

Figure 2. Aerial view of project site.

A single core was collected from the injector well (36-15C) (Figure 3). 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 that 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 uphole cavings that resulted from 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.

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Figure 3. 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.

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 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.

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. The results of this laboratory testing program are summarized in Table 1.

Table 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.

The testing program consisted of several tests, each of which provided different information about the characteristics of the reservoir. These laboratory data, when combined with the data from various field-based geophysical tests, i.e., geophysical logs and fracture tests, allowed for an assessment of the reservoir characteristics as they related to the ability to store CO_2 and produce CBM.

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 4.

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.

The majority of the CO_2 injection was conducted in cycles, which began with the buildup of the bottomhole pressure (BHP) to the predefined threshold followed by a slow decline. On average, each injection cycle took about 40 minutes. The bottomhole 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 of <780 psig.

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Figure 4. Site photo of pump skid and CO_2 storage tank.

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 a gaseous state at the perforated interval.

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

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 a reservoir saturation tool (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 needed 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 cross-well 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 cross-well 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.

Given the goals of the demonstration test, additional monitoring, verification, and accounting (MVA) measurements, in addition to the RST and cross-well 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.

RESULTS

Logging activities enabled characterization of the coal in the injection and monitoring wells. The coal was determined to be segregated by a thin layer of sand (Figure 5). Logging of the injection well enabled further identification of coals and low-permeability layers of clay (Figure 6) located above and below the target injection zone. The many low-permeability sediments act as a significant impediment to vertical migration of CO_2.

Results from coring and subsequent analysis are summarized in Table 2. The analysis includes maceral, proximate, ultimate, heating value, adsorption isotherms, permeability, porosity, and vitrinite reflectance. The maceral analysis indicates a high presence of inertinite and vitrinite relative to liptinite. The ratios are indicative of the coal's rank, as shown in Figure 7. The proximate and ultimate analyses reveal the high moisture, high ash, and low heating values normally associated with lignite coals. Adsorption isotherms provide an indication of the coal ability to store methane and CO_2 at various pressures. The reservoir pressure for the pilot study is 350 psia. Gas content analysis obtained from core provided for very low gas contents. Powder River Basin coals, which have the lowest commercial CBM gas contents, range from 20–75 scf/ton. Lignites in North Dakota have measured up to 12% gas content in previous study (1). Laboratory permeability tests generally agreed with field nitrogen fracture injection tests to determine permeability, which ranged from <1 md to 5 md for the injection well and monitoring wells. Laboratory porosity was also determined both for wet and dry conditions. Vitrinite reflectance results indicate the coal is potentially more representative of lignite rank than subbituminous rank determined from proximate and ultimate analysis.

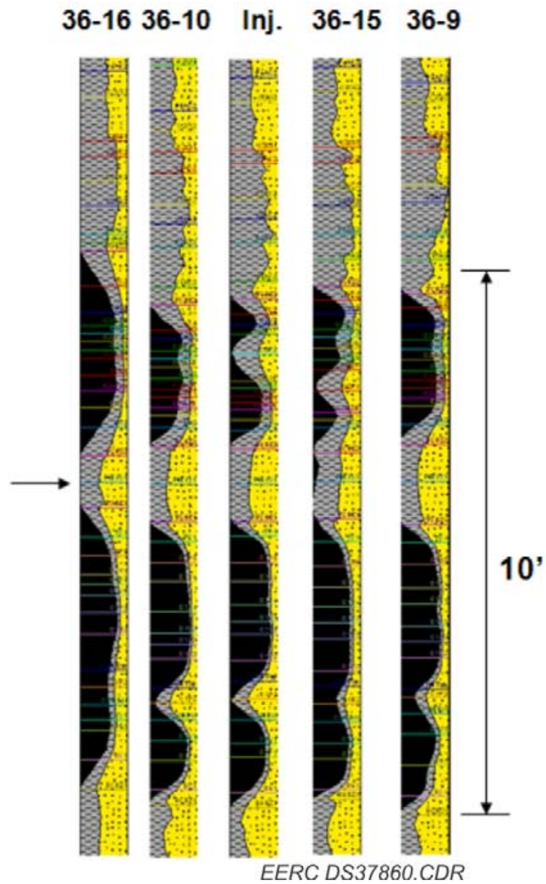

Figure 5. Target zone characterization of coal from logging.

Site development included various tests for characterization. Multiwell tests identified the preferred permeability to be in the southwest to northeast direction. Fracture injection tests determined permeability, skin, reservoir pressure, and fracture closure pressure. Results included the determination of a skin-damaged wellbore and underpressured reservoir. The implications provide for potential compartmentalization, greater pore space, higher injection pressure differential, lower gas storage capacity, and necessitate underbalanced drilling.

Injection was completed over a period of 16 days, injecting 90 tons of CO_2 at a permitted downhole injection pressure of 780 psig maximum. Tests were conducted to determine best practices for CO_2 injection. Heating the CO_2 at the surface and injecting high-pressure gas provided for a greater injection rate than pumping cold liquid. Attempts to decrease density and viscosity by lowering downhole pressure did not allow for high enough injection pressure to improve injectivity. An average injection rate of 1.4 gpm was achieved, and approximately 25% of the initial injection rate was lost over the first 2 days, but sustained with no injectivity loss for the remainder of the test.

Various tools were used to track and identify the fate of CO_2 injected into the coal. A RST was used to identify the presence of CO_2 after injection. CO_2 was identified in the target zone at the injection well and not outside the clay seals, which prevent vertical movement. The expected plume migration was limited to monitoring wells closest to the injection well. The RST did not reveal the presence of CO_2 at any of the distant monitoring wells. Cross-well seismic (Figure 8), was successful in providing a sound wave velocity difference image of the reservoir in the direction of preferred permeability between Monitoring

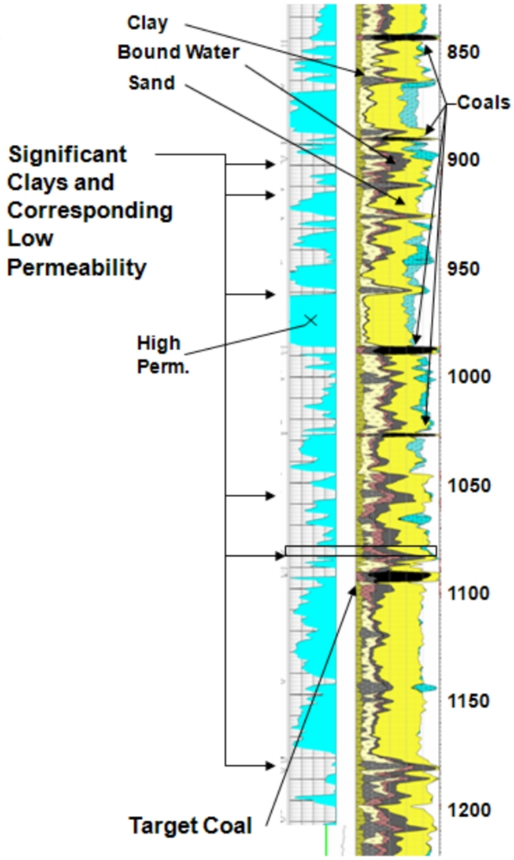

Figure 6. Identification of clay seals and various coals to inhibit buoyancy effects of CO_2.

Table 2. Analysis of Lignite Coal

Maceral Analysis, %	
Vitrinite	52
Liptinite	2.1
Inertinite	45.9
Ultimate and Proximate Analysis, %	
Moisture	26
Ash	10
Volatile Matter	28
Fixed Carbon	36
Sulfur	0.16
Heating Value, Btu/lb	7657
Adsorption Isotherm	
CO_2, scf/ton @ 350 psia	350
Methane, scf/ton @ 350 psia	23
Gas Content, scf/ton	0.75–1.72
Laboratory Permeability, md	0.5–0.6
Porosity, after drying 6.1%	1.8
Vitrinite Reflectance (subbituminous < 0.47)	0.24
Classification Based on Composition (based on Ro = lignite)	Subbituminous C

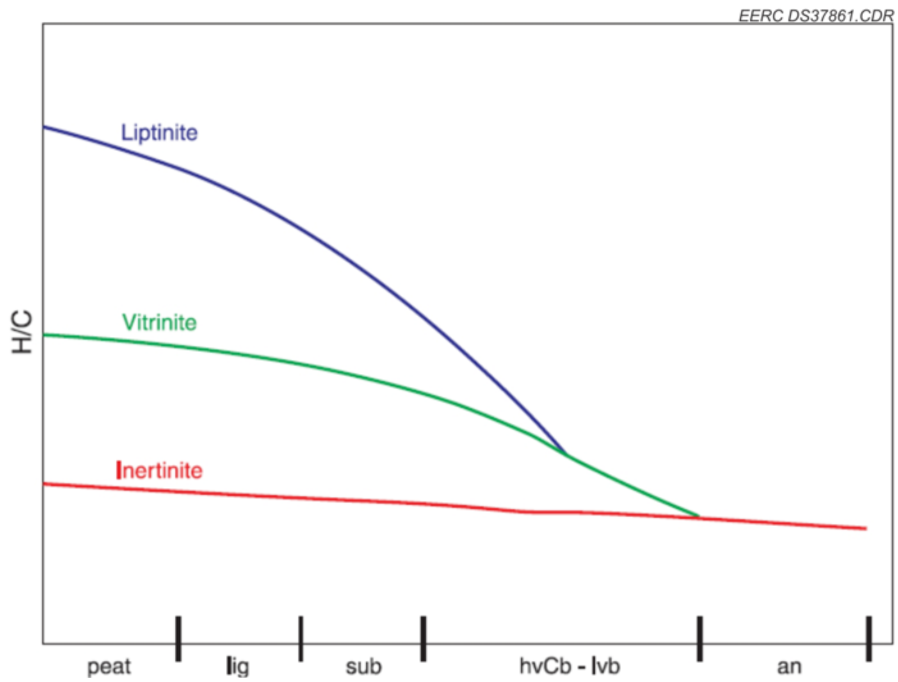

Figure 7. Maceral ratio relative to coal rank.

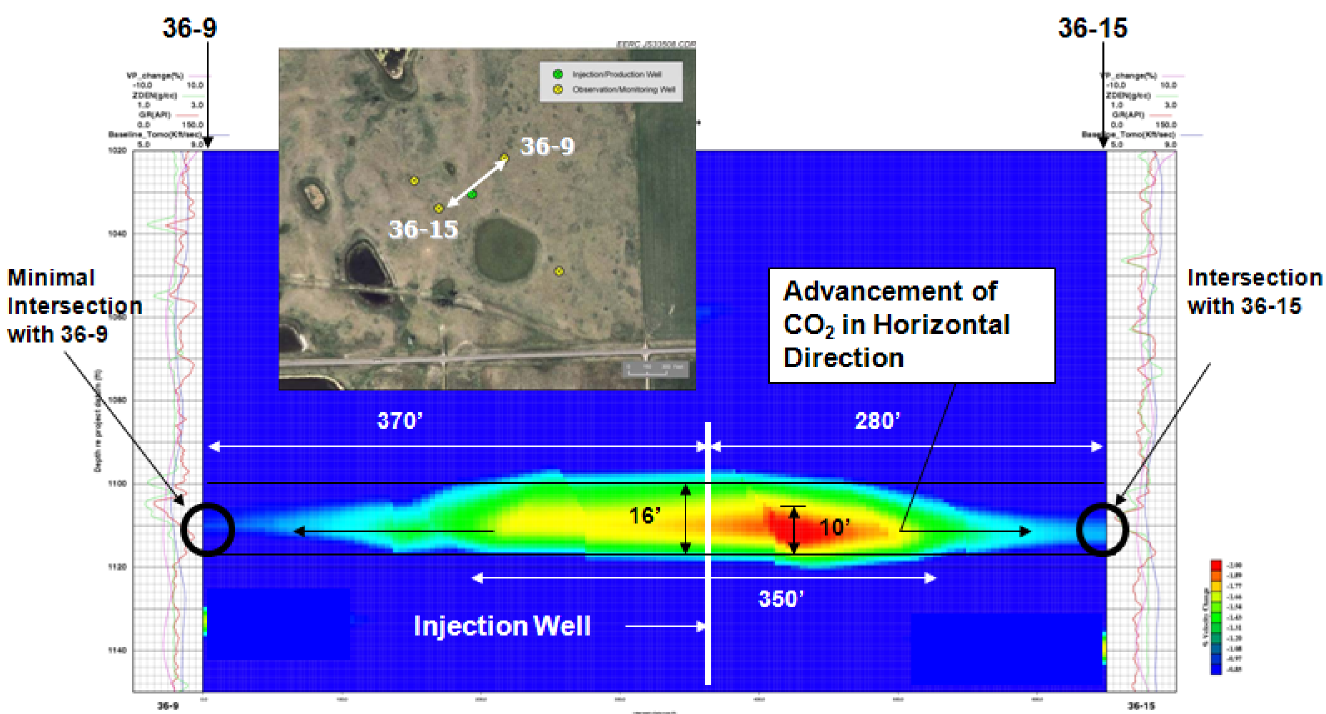

Figure 8. Cross-well seismic results.

Wells 36-9 and 36-15. Cross-well seismic taken perpendicular to this direction did not yield a successful image because of the larger distance impeding the ability to generate interpretable data. The image indicates the preferred flow of CO_2 in the horizontal direction and limited migration in the vertical direction. A greater influence of the injection appears to impact Well 36-15 over Well 36-9. Corroborating the seismic data are the results of the downhole pH and pressure measurements (Figure 9). A pressure increase was measured at Well 36-15 before a deflection of pressure and pH were measured at Well 36-9. Also, the magnitude of the pressure difference at Well 36-15 was greater than the measured effect at Well 36-9. A pH sensor was not deployed in Well 36-15.

DISCUSSION

The measured results of the project enable the determination of the fate of CO_2 injected into lignite coal. Generally, the CO_2 remained within the target coal. No significant fracturing was indicated during injection from the microseismic monitoring deployed in Well 36-15. Downhole measurements of pressure and pH corroborate the cross-well seismic findings. In addition, the low permeability and no indication of CO_2 at the northwest and southeast monitoring wells support an estimated elliptical plume shape elongated in the northeast–southwest direction. Combining all of the information, conclusions are supported to estimate that the CO_2 has migrated within the coal zone in equivalent directions to the northeast and southwest. The timing and presence of measurements in the monitoring wells support an elliptical plume shape in the northeast–southwest direction, and progression of the CO_2 along the centerline of the coal suggests either preferential adsorption or higher permeability of the middle sand layer. The calculated gas content based on seismic interpretation is 18.1 scf/ton, which could be a combination of adsorption and porosity occupation of the CO_2.

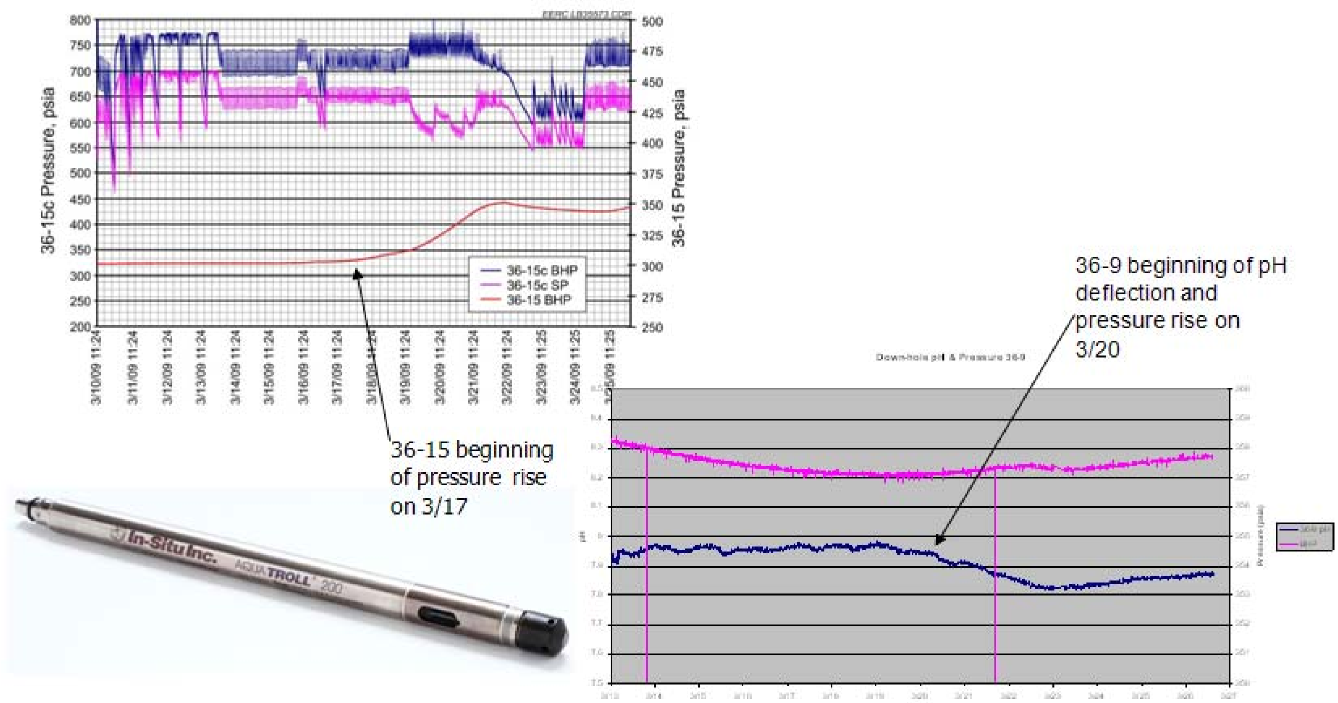

Figure 9. Downhole measurements.

Injectivity is the most significant economic hurdle regarding storage of CO_2 in lignite coal. The tests conducted on this project identified an injection rate of 1.4 gpm in 10 feet of lignite coal. Many of the candidate coals for storing CO_2 within the state of North Dakota are similar and may have low permeabilities. The land area required to store 1 year of CO_2 stack emissions from an average coal-fired power plant (500 MW) in the region is 20 square miles, assuming a depth of 1000 feet at 10 feet of thickness and 350 psia. Given an injection rate of 1.4 gpm, drilling of 1400 wells would be required to accommodate the flow rate. Therefore, it is paramount to the technical and economic feasibility of CO_2 injection in lignite coal that multiple coal seams are available to provide for a total pay zone of near 50 feet and that injection rates be improved from advanced completion technology to increase injection rates by a factor of 50 to 100. If feasible, the logistics for CO_2 injection and storage would be as follows. A total of 10–20 wells could accommodate 100% of the emissions from an average coal-fired plant, and land areas may be reduced to 4–5 square miles per year of CO_2 emission injection.

CONCLUSIONS

- Lignite coal appears attractive for storage of CO_2. Additional work is recommended to further understand in situ adsorption and effective injectivity.

- Injected CO_2 appears to preferentially travel along the path of the coal and can be contained within the expected injection zone.

- CO_2 enhanced methane production from lignite coal remains in question.

- Injectivity greatly impacts costs to drill and complete a sequestration project. Further work is required to improve injection rates that would enable feasibility.

REFERENCES

1. Murphy, E.C., and Goven, G.E., 1998, The coalbed methane potential of North Dakota lignites: Open-File Report 98-1, North Dakota Geologic Survey.