CO₂ Sequestration in Unmineable Coal with Enhanced Coal Bed Methane Recovery: The Marshall County Project

James E. Locke, Manager, Field Services, CONSOL Energy Inc.
4000 Brownsville Road, South Park, PA 15129, USA,
jimlocke@consolenergy.com
Phone: 412-854-6607

Richard A. Winschel, CONSOL Energy Inc.
Richard A. Bajura, Thomas H. Wilson, Hema J. Siriwardane, Henry Rauch, and Shahab D. Mohaghegh
West Virginia University

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Abstract

A pilot test is being conducted in Marshall County, West Virginia, USA, to evaluate enhanced coal bed methane recovery and simultaneous carbon dioxide sequestration in an unmineable coal seam in the Northern Appalachian Basin. Injection of carbon dioxide (CO₂) began in September 2009 and it continues at the time of this writing. This paper describes the project and its current status and summarizes recent work by the research collaboration.

Introduction

This paper reports on continued activities at the CONSOL Energy carbon sequestration enhanced coal bed methane (CBM) pilot test in Marshall County, West Virginia. This pilot test was developed to evaluate the potential for geologic sequestration of CO₂ in unmineable coals and the simultaneous enhancement of CBM production (ECBM). The CONSOL pilot site is located in the foreland area of the Appalachian Basin near the western limits of detachment (Figure 1). The test site is located in the Fish Creek valley, in the soil-covered flat-lying sedimentary rock strata of the Dunkard Group of Permian age. The stratigraphic sequence consists of alternating layers of clastic sedimentary rocks (sandstone, siltstone, shale, mudstone,
CO₂ injection into the Upper Freeport coal seam is ongoing.

CBM production wells were drilled by CONSOL early in the project. The production wells included both vertical and horizontal components to assure an extensive contact of the well bore with the coal seam. Methane production from the Upper Freeport wells along the edge of the site (red lines, Figure 2) and in the center of the site (thick black lines, Figure 2), and production from wells in the overlying Pittsburgh seam (thin black lines in Figure 2) began in 2004. The peripheral horizontal wells enclose a 200-acre square.

The center wells drilled into the Upper Freeport coal seam were later converted into CO₂ injection wells (thicker lines in Figure 2) before CO₂ injection commenced in September 2009. At this site, the Upper Freeport coal is located at depths of 1,200 to 1,800 feet (topography dependant). The impacts of CO₂ injection into the center wells on the production and composition of the coal bed methane produced in the peripheral and overlying wells is being monitored. Injection will cease when either 20,000 short tons have been injected or when the coal bed methane from the peripheral or overlying wells becomes contaminated with CO₂.

West Virginia University and National Energy Technology Laboratory (NETL) researchers are working collaboratively with CONSOL Energy to expand monitoring and characterization activities at the site in a project funded by the U.S. Department of Energy and managed by the NETL. Monitoring activities include monitoring for perfluorocarbon tracers injected in the CO₂ stream (NETL), soil gas flux monitoring (NETL), CBM monitoring (CONSOL), ground water monitoring (CONSOL and WVU), surface tilt monitoring (WVU), and seismic monitoring (WVU). Monitoring activities are widely distributed across the site and surrounding area (Figure 2). Monitoring will continue for two years after injection ceases.

More than 2,000 short tons of CO₂ out of the planned 20,000 short tons have been injected into the Upper Freeport coal seam. CO₂ Injection began in September 2009 and has been subject to injection pressure limitations and mechanical difficulties. Presently, the injection system operation is limited to an injection pressure of 933 psig by the West Virginia Department of Environmental Protection (WDEP) Class II underground injection control (UIC) permit. The injection increased to and was maintained just below this pressure for more than a year. After the maximum pressure was achieved, the daily injection rates gradually decreased to a rate of only 6 tons per day, far below our 27 tons per day target. An increase in the allowable injection pressure to 1,450 psig is presently awaiting the outcome of a public comment period.

### CO₂ Injection Summary

Liquid CO₂ is delivered to the site by truck and transferred into a 50-ton holding tank. A two-cylinder reciprocating cryogenic-service pump transfers the liquid CO₂ from the holding tank to the vaporizer. The pump is capable of generating a discharge pressure of up to 1500 psig and is driven by a variable frequency drive that allows the pump speed to be varied either by a 4-20 milliamp signal or by a potentiometer. The vaporizer consists of a natural gas-fired boiler that heats water, and a vaporizer section where the liquid CO₂ is vaporized by heat transfer from the hot water. Upon exiting the vaporizer, the gaseous CO₂ is split into two streams and is transferred to the two injection wells, designated MH-18, flowing to the north; and MH-20,
flowing to the south. Each injection line is equipped with a flow meter and pressure transducer as well as a pneumatic control valve, which allows for accurate measurement and control of the gaseous CO$_2$ injection.

CO$_2$ injection began on September 8, 2009, and fully automated CO$_2$ injection commenced on January 26, 2010. By April 2010, injection pressures achieved the original UIC permit maximum injection limit of 700 psig. At this pressure the mass injection rate averaged only 6 to 10 tons of CO$_2$ per day (TPD), which is well below the project goal of 27 TPD. CONSOL pursued and received a modification to the UIC permit to raise the maximum injection pressure to 933 psig. On August 19, 2010, the injection system began operation at the new pressure limit, though mechanical problems prevented continuous injection through the next several months. The injection pressure quickly climbed to 933 psig and the injection rate gradually decreased to the present rate of approximately 6 TPD. To date, just over 2,100 tons of CO$_2$ have been injected into the target formation.

Figure 3 summarizes the injection pressure and cumulative tons of CO$_2$ injected during this project. Throughout the project, we have encountered a number of disruptions to the injection including: severe weather-related power outages, freezing boiler fuel supply lines, and failure of the CO$_2$ injection pump. From the graph in Figure 3, one can see these periods of interrupted injection as decreases in the injection rate and a decrease in the injection well pressure.

Two notable observations have been recorded as injection has progressed over time. Initially, when the CO$_2$ injection would cease, well pressure would decrease to a level as low as 560 psig. On June 28, 2011, the injection system was idled due to mechanical failures in the cryogenic pump. Since that time, the well pressure has stabilized at approximately 680 psig.

Additionally, the gas flow had mainly been going to the northwest, through well MH-18; in some months as much as 70% of the flow, but normally approximately 60%. The flow trend continued until January 2011 when the flow rates began to converge. On March 11, 2011, MH-20, to the southeast, began taking more of the flow and the trend has continued to the present rate where MH-20 is now taking approximately 60% of the CO$_2$.

At the present time, explanations for these occurrences have not been developed. To gain a better understanding of the difficulties that may be encountered in coal bed sequestration and ECBM, work is being done to characterize the subsurface structure, including: a geophysical seismic study, reservoir modeling, and tiltmeter observations.

**Geophysical Characterization**

The Upper Freeport coal lies at the top of the Pennsylvanian Conemaugh Group. The pilot site is located on a bench in the southeast flank of the Washington anticline (Figure 4a). A local view of the Upper Freeport isopach reveals that its thickness is quite variable over short distances and may have pod-like distribution through the area (Figure 4b). Subsurface depth to the Upper Freeport seam varies largely as a result of surface topography from about 1,200 feet to 1,800 feet. Its depth along with abrupt thickness change and irregular distribution make the Upper Freeport unmineable in the area. Work has been performed by WVU to improve upon the existing subsurface maps to better understand the structure and fractures.
Depth Conversion

WVU has worked to improve the subsurface structure maps of the area using pre-injection 3D seismic survey data by converting the 3D time volume to depth using a velocity function that would accurately render Pittsburgh and Upper Freeport subsurface structure by establishing a series of control points within the area of 3D seismic coverage to facilitate accurate time-to-depth conversion. Control points (Figure 4) provide depths to the Pittsburgh and Upper Freeport seams at numerous locations (the cyan colored triangles) within the area of 3D survey coverage. The virtual wells were located in such a way that their values, when contoured, would reproduce Pittsburgh and Upper Freeport structure derived from the vertical wells and horizontal well trajectories. The same control points were used for both Pittsburgh and Upper Freeport structure (Figure 5).

Cleat and Fracture Model Development

Discontinuities in the seismic were enhanced using the Ant Track (Schlumberger, 2008) attribute (e.g. Figure 6). The 3D attribute volume was converted into a gridded attribute volume that could be used to control the distribution of short fractures and cleats within the coal seam reservoir as well as in the cover or sealing strata. The darker zones (Figure 6) are considered to be indications of potential areas of increased fracture intensity. Vertical continuity in places extends for about 120 feet or so between the Pittsburgh and Upper Freeport coal seams. These zones could localize accumulation of injected CO$_2$. In general, the distribution of high intensity features is fairly discontinuous in a vertical sense. In addition, these zones of discontinuity suggest possible areas where specialized time-lapse analysis can be focused in the subsequent monitor survey.

Ant Track lengths measured from the Ant Track interpretation suggests that fracture lengths have normal to log-normal distribution. There is generally a steady rise in the number of fractures as length decreases. The frequencies drop off as the lengths get smaller; however this is due primarily to a lack of resolution. We expect that smaller and smaller fractures would be observed with increasing frequency if resolution permitted.

The cleat networks developed in this study use approximate face and butt cleat trends of N70W and N20E. A fracture elongation ratio (length to height ratio) of 4 was used along with a maximum cleat length of 30 feet. Cleat apertures were assumed to be in the sub-micron range. The aperture distribution was generated in a two-step process: 1) A normal distribution of apertures was initially distributed; 2) This distribution was then scaled by cleat length. Mean initial aperture of 0.5µm was used with a standard deviation of 50µm. A mean dip of 90° was assumed with dip azimuths of N20E (face cleat) and N70W (butt cleat). Note that dip azimuths are perpendicular to cleat strike so that the N20E dip-azimuth corresponds to a N70W strike. A scale of 5 was used with shape of 2.1. The maximum cleat length was set at 20 feet. The resulting length distribution (Figure 7) used in the model reveals that the majority of fractures generated in this example model have lengths largely between 5 and 8 feet.

The butt cleats were modeled using a smaller length distribution. Maximum fracture length for the butt cleats was set at 10 feet with a scale factor of 3. The scale facture basically sets the minimum fracture length at 3.
The combined distribution of face and butt cleats is presented in Figure 9 and provides a parallel view similar to that shown in Figure 8 for the face cleats.

**Reservoir Modeling**

To provide an understanding on how CBM production may be enhanced and geologic injection limitations, work is being performed by WVU researchers to develop production and injection models for this project site. Due to the special features and the nature of gas retention in CBM reservoirs, modeling these scenarios is more complex than in conventional resources. The key geological and reservoir parameters that are germane to driving enhanced coal bed methane (ECBM) production and sequestration processes in the Upper Freeport coal seam are being addressed by carrying out sensitivity analyses on different reservoir parameters including cleat permeability, cleat porosity, CH\(_4\) adsorption time, CO\(_2\) adsorption time, CH\(_4\) Langmuir Isotherm, CO\(_2\) Langmuir Isotherm, Palmer and Mansoori parameters. A CBM reservoir is thought to be an anisotropic and dual-porosity system. Due to stress dependency of coal permeability and porosity, as well as the shrinkage/swelling of the coal matrix, a compositional simulator is chosen to accommodate these characteristics for the Upper Freeport coal seam. Structure and isopach maps (Figure 10 and Figure 11) for the Upper Freeport coal seam were used for building the reservoir model.

Simulation results such as history matching of production and injection, initial and final reservoir parameter settings and prediction of injection and ECBM production are presented and discussed in the following sections.

Table 1 summarizes the selected parameter inputs for the base model case.

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Table 1. Initial model parameter settings.
History Matching

Sensitivity Analysis

To understand and evaluate the critical parameters’ effects on both CH₄ production and CO₂ injection, sensitivity analysis has been carried out on several parameters, namely:

- Young’s Modulus,
- Poisson ratio,
- Cleat porosity,
- CH₄ desorption time,
- CO₂ desorption time,
- CH₄ Langmuir Isotherm,
- CO₂ Langmuir Isotherm, and
- Palmer and Mansoori parameters.

Almost 150 runs have been conducted to achieve the history matching and each run takes almost 90 minutes with the simulation time from August 2005, to April 2011.

The influence of these parameters on the amount of production injection in the CBM reservoir has been graphically illustrated in Figure 12.

Production and Injection History Matching

The act of adjusting the characteristics of the model until it closely reproduces the past behavior of a reservoir is called “History Matching.” The historically available production data and pressures (if available) are matched as closely as possible. The accuracy of the history matching depends on the quality of the reservoir model and the quality and quantity of pressure and production data. Once a model has been history matched, it can be used to simulate future reservoir behavior with a higher degree of confidence, particularly if the adjustments are constrained by known geological properties in the reservoir.

In this case, matching of the production and injection rates was attempted by setting the pressure as constraint. This process started with the production wells, by changing the parameter that will most affect the gas production rate, cleat permeability.

After getting the match for production wells, injection wells were subjected to this process. To accomplish this, the CO₂ desorption time and CO₂ Langmuir strain were increased and the values for CO₂ Langmuir volume and cleat porosity were decreased.

To get a proper match for production and injection wells, the best CO₂ Langmuir volume value should be found and the cleat permeability should be decreased reasonably. The history matching results have been demonstrated in Figure 13 and Figure 14.

Injectivity Test

An injectivity index was created as a means for better reservoir management, providing the desired cumulative injection of CO₂ at different injection pressures and at different times. It was
immediately visible that cumulative CO₂ injection increased in direct proportionality to the injection pressure. Using the initial constraints, we concluded that it is impossible to inject 20,000 tons of CO₂ in two years. All different models appeared to yield the same result for cumulative gas injection because the chosen gas rates (ft³/day) were too high for the pressure constraint of 933 psi; however, changes were noticed when lower gas rates were used. Upon history matching the model, a five-year prediction was made to evaluate the injectivity of CO₂ into the Upper Freeport coal seam (Figure 15). It was concluded from the prediction that around 6,234.35909 tons of CO₂ would be injected into the coal seam via wells MH-18 and MH-20.

Reservoir Modeling Conclusions

1. Langmuir strain, Langmuir isotherm, sorption time, cleat permeability, cleat porosity are the five most effective parameters on production and injection in coal seam; While Young’s modulus & Poisson’s ratio, coal compressibility have less influence.
2. Cumulative CO₂ injection increases as the injection pressure increases.
3. When using 933 psi as maximum injection pressure with different maximum injection gas rate as constraints, it shows that it is impossible to inject 20,000 tons of CO₂ in two years. Even in twenty years, the maximum that can be injected is 11,779.30 tons.
4. When using 933 psi as maximum injection pressure, 120,000 ft³/day was shown to be the maximum gas rate for MH-18 while 40,000 ft³/day was shown to be the maximum gas rate for MH-20.
5. Upon history matching the model, a five-year prediction was made to evaluate the injectivity of CO₂ into the Upper Freeport coal seam. It was concluded from the prediction that approximately 6,234 tons of CO₂ would be injected into the coal seam via MH-18 and MH-20.

Tiltmeter Monitoring Results

In this section, a description of the tiltmeter monitoring at the field site is presented. Thirty-six high-precision tiltmeters were installed along with two GPS stations to measure surface deformations as a result of CO₂ injection. The tiltmeters placed at the field site have the precision needed measure surface deformations in the sub-millimeter range. Figure 16 shows the monitoring array of 36 tiltmeters and 2 GPS stations installed at the site. These tiltmeters and two GPS receivers were calibrated prior to the injection of carbon dioxide. Tiltmeter data was collected on a daily basis by using a computer-based data collection system.

Injection of carbon dioxide began on September 8, 2009, and as of May 23, 2011, about 2,000 tons of carbon dioxide was injected. Pre-injection data shows that no measurable ground movements took place prior to injection. The measured cumulative surface deformations as of May 23, 2011, with an injection volume of approximately 2,000 tons are shown in Figure 17. Tiltmeter measurements show some surface uplift (positive deformations) along the trajectories of injection wells. A maximum surface uplift of 3.3 mm (0.13 inches) was measured. When a fluid is injected into the coal reservoir, surface uplifts may be due to increase in the reservoir pressure or may be caused by coal swelling during the injection of carbon dioxide. So far, the measured displacement magnitudes are very small. Monitoring is being continued as more CO₂
is injected into the coal seam. In addition to the field monitoring of ground deformations, numerical modeling of flow and overburden response is being performed to compute surface deformations. Model results will be compared with field measurements over a period of time. Numerical modeling together with tiltmeter measurements will provide an understanding of the response of reservoir and overburden geologic strata.

**Environmental Monitoring**

**Deep Well Monitoring**

Prior to injection, fifteen wells within a quarter-mile of the area of review (AOR) were sampled to determine baseline characteristics of the gas and water (if available) produced. Four samples were collected in consecutive weeks to establish the baseline. Gas samples were analyzed for oxygen, nitrogen, methane, ethane, higher hydrocarbons, and CO$_2$. Water samples were analyzed for pH, dissolved oxygen, oxidation-reduction potential (ORP) and conductivity, dissolved solids, and numerous anions and cations. Temperature was also measured.

The most recent gas monitoring data show gas composition that is typical of the measured baseline and, therefore, no evidence of CO$_2$ breakthrough. Table 2 summarizes the gas concentrations measured, comparing the most recent sample set to the baseline and average of the injection period dataset. Likewise, water monitoring results also show no evidence of CO$_2$ breakthrough.
Values Reported in Percent

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Table 2. Summary of deep well gas monitoring results.

Shallow Hydrogeologic Monitoring

Additional environmental monitoring is being conducted by WVU researchers. Stream water, shallow ground water, and shallow vadose zone gas are being monitored for CO₂ gas leakage and to develop better hydrogeologic monitoring procedures for detecting CO₂ seepage at this or other geologic sequestration sites with similar hydrogeologic settings. Current samples are compared to background (pre-injection or distant) environmental conditions.

Figure 2 provides the locations of the hydrogeologic monitoring sites. The monitored shallow hydrogeologic features are located within bedrock of the Washington Formation of the middle Dunkard Group (Fish Creek, monitoring water wells W-1, W-2, and W-3, sampled domestic wells B-1, B-2, G-1, G-3, and G-4, and domestic spring G-2); or within soil or alluvium (Fish Creek and vadose soil zone wells W-1A, W-2A, W-2B, W-3A, W-4A(4), and W-5).
The three shallow ground-water monitoring wells are 105 ft (32 m) deep. Wells W-1 and W-2 have casing that penetrates to below the water table and hence are not directly connected with the vadose zone, while well W-3 has casing that bottoms out above the water table.

As wells W-1 and W-2 are inadequate for sampling vadose zone gas, and well W-3 vadose gas was found to be contaminated with methane; six shallow soil vadose zone wells, W-1A, W-2A, W-2B, W-3A, W-4A(4), and W-5, were constructed in May and June of 2011. During well construction the screen annulus zone was filled with coarse sand and the casing pipe annulus zone was filled with bentonite clay to land surface. Well W-4A replaced well W-4 due to soil plugging of the latter’s well screen and shutting off its connectivity with soil vadose zone gas.

Formal sampling and chemical analysis of the monitored test site wells and most monitored domestic water supplies was initiated in October 2008, (after trial field sampling in September 2008). Sampling has continued through July 2011, and should continue for many more months. Table 3 identifies the sampling points and provides the sampling frequency and analytical parameters.

<table>
<thead>
<tr>
<th>Location</th>
<th>Sampling Frequency</th>
<th>Analytical Parameter</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stream Points: S-1, S-2, and S-3</td>
<td>Weekly to biweekly</td>
<td>Conductivity, Temperature, pH, Total dissolved sulfide</td>
<td>Conductivity, pH, Cations (Ca^{2+}, Mg^{2+}, Na^{+}, K^{+}, Fe^{2+}, Al^{3+}, and Mn^{2+}), Anions (HCO_{3}^{-}, Cl^{-}, SO_{4}^{2-})</td>
</tr>
<tr>
<td>Monitoring Wells: W-1, W-2, and W-3</td>
<td>Weekly</td>
<td>Depth to water table, Conductivity, Temperature, pH, Total dissolved sulfide, CO_{2} Gas, CH_{4}</td>
<td>Conductivity, pH, Cations (Ca^{2+}, Mg^{2+}, Na^{+}, K^{+}, Fe^{2+}, Al^{3+}, and Mn^{2+}), Anions (HCO_{3}^{-}, Cl^{-}, SO_{4}^{2-})</td>
</tr>
<tr>
<td>Domestic Water Wells: G-1, G-2, G-3, G-4, B-1, and B-2</td>
<td>Biweekly to monthly</td>
<td>Conductivity, Temperature, pH, Total dissolved sulfide</td>
<td>Conductivity, pH, Cations (Ca^{2+}, Mg^{2+}, Na^{+}, K^{+}, Fe^{2+}, Al^{3+}, and Mn^{2+}), Anions (HCO_{3}^{-}, Cl^{-}, SO_{4}^{2-})</td>
</tr>
</tbody>
</table>

Table 3. Shallow hydrogeologic sampling matrix.

Following water geochemical checking and correcting for data errors, the saturation index for calcite (SI_{C}) and theoretical equilibrium CO_{2} gas partial pressure for water was calculated using MINTEQ. Also, speciation calculations were performed via EXCEL for hydrogen sulfide species (H_{2}S, HS^{-1}) in water, based on pH and total dissolved sulfide.
Table 4 illustrates the average (mean) chemical values for selected parameters for the monitoring wells and stream spots.

<table>
<thead>
<tr>
<th>Location</th>
<th>From (date)</th>
<th>To (date)</th>
<th>Field pH</th>
<th>Lab pH</th>
<th>Field EC (μS/cm)</th>
<th>Lab EC (μS/cm)</th>
<th>HCO₃⁻ (mg/L)</th>
<th>Cl⁻ (mg/L)</th>
<th>Ca²⁺ (mg/L)</th>
<th>Mg²⁺ (mg/L)</th>
<th>K⁺ (mg/L)</th>
<th>Na⁺ (mg/L)</th>
<th>SO₄²⁻ (mg/L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>W-2</td>
<td>10/10/2008</td>
<td>6/28/2011</td>
<td>8.67</td>
<td>8.20</td>
<td>647</td>
<td>653</td>
<td>178</td>
<td>97</td>
<td>7.70</td>
<td>1.30</td>
<td>0.96</td>
<td>126</td>
<td>8.29</td>
</tr>
<tr>
<td>W-3</td>
<td>10/10/2008</td>
<td>6/28/2011</td>
<td>9.30</td>
<td>9.15</td>
<td>812</td>
<td>850</td>
<td>434</td>
<td>24</td>
<td>0.83</td>
<td>0.23</td>
<td>0.59</td>
<td>195</td>
<td>5.09</td>
</tr>
<tr>
<td>S-1</td>
<td>10/10/2008</td>
<td>6/28/2011</td>
<td>7.58</td>
<td>7.22</td>
<td>208</td>
<td>208</td>
<td>82</td>
<td>9</td>
<td>25.8</td>
<td>4.32</td>
<td>1.98</td>
<td>7.13</td>
<td>19.4</td>
</tr>
<tr>
<td>S-2</td>
<td>10/10/2008</td>
<td>6/28/2011</td>
<td>7.77</td>
<td>7.21</td>
<td>235</td>
<td>231</td>
<td>82</td>
<td>16</td>
<td>26.6</td>
<td>4.53</td>
<td>1.94</td>
<td>10.6</td>
<td>19.4</td>
</tr>
<tr>
<td>S-3</td>
<td>10/10/2008</td>
<td>1/4/2011</td>
<td>7.75</td>
<td>7.28</td>
<td>272</td>
<td>270</td>
<td>86</td>
<td>27</td>
<td>29.0</td>
<td>5.00</td>
<td>2.12</td>
<td>15.1</td>
<td>19.2</td>
</tr>
</tbody>
</table>

Table 4. Mean chemical parameter values for sampled test site waters.

High field pH could be caused by methane with sulfate redox chemical reactions resulting from upwards seepage of methane gas through shallow aquifers and alluvium. Relatively low lab pH could be caused by redox chemical reactions, involving oxygen with hydrogen sulfide species and possibly methane, and maybe precipitation of CaCO₃ during bottled water sample transport to or pre-analysis storage within the lab.

Water chemistry data for wells W-1, W-2, and W-3 so far have not shown any discernible trends with the rate of CO₂ gas injection or with the CO₂ gas pressure at the two injection wells. Investigation of possible water chemical trends with injected CO₂ parameters is continuing.

A more sensitive and direct method for monitoring seepage would probably involve the chemistry of gas within the vadose zone situated between the water table and ground surface. Evidence for this conclusion is unpublished monitoring data collected by Henry Rauch and the U.S. Geological Survey (Yousif Kharaka’s team) at the ZERT CO₂ gas injection test site run by Montana State University at Bozeman, Montana; this experiment is labeled MSU-ZERT.

At the CONSOL test site, the six soil vadose zone gas wells have shown low to moderate CO₂ soil gas concentrations, ranging 3.3 to 6.3 % on average during mid May to late July 2011. See Figure 2 for the map location of these wells.

Figure 18 shows a plot of vadose CO₂ gas concentration versus relative topographic position. Data trends are shown for the average monthly trends of late May, June, and July; and for the mean trend (shown by purple round dots and lines) of combined monthly data spanning May 13th through August 2nd.

In general, CO₂ gas concentration increased from May to June to July associated with rising average temperature and hence increased rates for plant respiration and organic matter decay.
The one outlier point from these data trends, for well W-2B in June, is associated with only one CO$_2$ gas measurement, taken June 30$^{th}$.

The three soil vadose gas wells located outside the test square site have the lowest CO$_2$ gas concentrations; ranging 3.3 to 4.4 % CO$_2$ gas for May to July, on average; this is considered typical of soil CO$_2$ gas generated during early summer by the biochemical reactions of biological respiration and organic decay.

The three soil vadose gas wells located within the test square site have the highest CO$_2$ gas concentrations; ranging 5.2 to 6.3 % CO$_2$ gas for May to July, on average.

The test square center wells, W-2A and W-2B, have the highest average CO$_2$ gas concentrations of 6.3 and 5.5 %, respectively, for May to July, on average; these CO$_2$ gas values are significantly above the values for wells outside of the test square, assuming a precision error of +/-0.5 %. This data trend, as reflected by Figure 16, might indicate evidence for microseepage of CO$_2$ gas from the deep injection zone of the Upper Freeport coal bed within the central test square area, but it might also entirely indicate geographic variation due to natural causes such as vegetation differences.

CO$_2$ gas injection has entirely ceased during the period June 24, 2010, through July, resulting in declining CO$_2$ gas pressure within the Upper Freeport coal bed, yet the shallow vadose gas wells have continued to hold steady or rise in CO$_2$ gas content during this down-injection time. However, the upwards pressure of CO$_2$ gas within the Upper Freeport coal bed (685 and 673 psig at wells MH-18 and MH-20, respectively) still exceeded the expected minimum downwards hydrostatic pressure of 516 psig exerted by ground water, assuming 1,200 ft (366 m) of overburden rock and soil and no rock strata dewatering beneath the water table. Increasing the overburden thickness would increase hydrostatic pressure at the Upper Freeport coal bed injection zone, but increasing the degree of deep strata dewatering, associated with coal bed methane gas extraction wells, would decrease it. Moreover, only relatively high CO$_2$ gas wells W-2A and W-2B are located within the area of a ground surface deformation bulge noted by WVU researchers, where ~0.5 mm of uplift at the SW bulge edge had occurred due to past CO$_2$ gas injection.

More evidence, such as carbon isotope analysis and/or perfluorocarbon (PFC) organic chemical tracer analysis of vadose gas, is required to determine the existence, if any, of surface CO$_2$ gas microseepage. We anticipate that such research will be done within the next year, funding permitting. Even if the theory of surface CO$_2$ gas microseepage is eventually confirmed, such seepage should not be a deterrent to future CO$_2$ gas injection at the test site if soil CO$_2$ gas remains under the UIC limit of 10 % over background (which is ~4 % during summer), or under ~14 % total, within the soil gas vadose wells.

**CBM Production**

CBM production is taking place from wells drilled at the project’s North Site and South Site (Figure 2). The following sections detail the wells and their respective production during the project.
North Site Wells

Four wells (MH-3 and MH-4, in the Pittsburgh seam; and MH-5 and MH-6, in the Upper Freeport seam) were drilled down-dip at the “North Site” using slant-hole techniques. As such, the North Site wells cannot be effectively dewatered from their own wellheads. An unrecoverable drill string was left in the Upper Freeport Seam well MH-6, which is sealed.

Historically, gas production from the two Pittsburgh seam wells and one Freeport seam well (MH-5) has been low and sporadic, and the wells were frequently shut in for periods of time. Since the start of unattended injection, production from these wells became more consistent and they have been left open to production. Figure 19 provides a trend of the gas production rates of each of the North Site project wells. The North Site wells are equipped with circular charts to record production and production is reported on a monthly-total basis that is divided by the number of operating days reported for the month to provide an average daily production value.

On October 6, 2010, a contractor who was working on meters for the project notified CONSOL employees that he had located a leaking gathering line in the vicinity of the North Site wells. For safety, the North Site well production valves were shut; however, this action did not stop the leak. Further investigation revealed that the line was owned by another gas production company who was notified and repaired the line. The North Site wells remained closed to production until March 2, 2011. During this time, CO₂ injection continued.

Following the reopening of the valves, production from well MH-5, the only producing Upper Freeport well at the North Site, spiked to 333 thousand cubic feet (MCF), the highest production level recorded for the well. The majority of the production was likely due to buildup in the well during the five previous months of inactivity. After March, the production level decreased, but MH-5 has continued to produce at an average rate (207 MCF/month) that is slightly higher than the average production was before the CO₂ injection started (138 MCF/month).

The decrease coincides with our recent shut down of injection activities, though it will not be known if there is any relationship between the decrease and the shut down until we resume injection.

South Site Wells

South Site wells were drilled into both coal seams (MH-11, in the Upper Freeport seam; and MH-12, in the Pittsburgh seam); each well was drilled with two horizontal legs. MH-12 has consistently produced CBM at an average daily rate of approximately 200 thousand cubic feet per day (mcfd).

MH-11 has produced CBM at approximately 9 mcfd since production was initiated. Wells at the South Site are equipped with digital recording devices with satellite reporting capabilities. Daily values are reported for each well.

Over the past twelve months, production from MH-11 has been higher than the overall average. The average for the past twelve months has been 13 mcfd, with some months including days reported as high as 25 to 34 mcfd. Production from MH-11 has decreased slightly over the past several months, as in the case with MH-5 in the north; although, when compared to early
production rates, the current rate is more stable and is still higher than the previous average production rates. Figure 20 presents the daily CBM production from each of the South Site wells.

Summary

As of this writing (early August, 2011), 2,138 short tons of CO₂ have been injected without indication of CO₂ leakage. We have noticed some increases in the production of CBM from the targeted injection seam; however, more data must be evaluated before we can conclusively claim ECBM has been achieved.

Injection will continue until CO₂ breakthrough occurs or 20,000 short tons of CO₂ are injected, whichever is first. Monitoring will continue throughout the injection period and for two years following its completion.

Acknowledgment

This work was funded in part by the U. S. Department of Energy through its National Energy Technology Laboratory under cooperative agreement No. DE-FC26-01NT41148 and, in part, under Montana State University Grant No. G137-05-W0221.
Figure 1: Red box shows the approximate location of the CONSOL Energy carbon sequestration pilot site (from Shumaker and Wilson, 1996).

Figure 2: Site map shows location of the CO₂ pilot site between the towns of Bellton and Georgetown along Fish Creek in southern Marshall County, WV.
Figure 3. Daily CO$_2$ injection summary.

Figure 4: a) Subsurface structure in a 170km$^2$ area near the site reveals its location southeast limb of the plunging nose of the Washington anticline. b) Isopach of the Upper Freeport coal seam.
Figure 5: a) Structure on the Pittsburgh coal and b) Upper Freeport coal showing outline of the 3D seismic coverage (thin black line) and control points or virtual wells (cyan triangles) to be used in the depth conversion process. Vectors highlight down-dip direction on the Upper Freeport surface (b).

Figure 6: Discontinuity property-grid (Ant Tracks). Individual cells in the grid are 20 feet on a side. This layer in the grid shows features detected in the vicinity of the upper Freeport seam. The Upper Freeport grid cells are only 5 feet thick. The general locations of the northern and western injection laterals are shown for reference.
Figure 7: a) Length distribution obtained in the example Upper Freeport cleat model; b) aperture distribution (units are in feet).

Figure 8: a) View of face cleat distribution superimposed on seismic discontinuities mapped at the Upper Freeport level. b) Close-up view of the model face-cleats. Blue bubbles show locations of Upper Freeport structural control inferred from vertical well penetrations and horizontal well trajectories.
Figure 9: Combined butt and face cleat distributions in the Upper Freeport seam shown on a) the up-scaled discontinuity property and in b) without backdrop. Fractures are color coded by fracture length (bluer colors are shorter fractures; yellow and orange colored fractures, longer. View is to the north and out along the northern lateral. Blue bubbles show locations of Upper Freeport structural control inferred from vertical well penetrations and horizontal well trajectories.

Figure 10. Structure map of the Upper Freeport coal seam.

Figure 11. Isopach map of the Upper Freeport coal seam.
Figure 12. Sensitivity analysis on different reservoir parameters

Figure 13. Final history matching result for production wells
Figure 14. Final history matching result for injection wells

Figure 15. Five-year CO2 injection prediction after history matching
Figure 16. Locations of tiltmeters

Figure 17. Surface displacements determined from tiltmeter data
Figure 18. Data plot of mean geographic trends for percentage CO₂ of gas within the shallow vadose soil gas wells. The CONSOL Energy test square area extends between the two vertical dashed lines, with its center near wells W-2A and W-2B.
Figure 19. North Site CBM production graph. CO₂ Injection began on September 8, 2009.

Figure 20. South Site CBM production graph. CO₂ Injection began on September 8, 2009.