SECARB CO₂ Injection Test in Mature Coalbed Methane Reservoirs of the Black Warrior Basin, Blue Creek Field, Alabama

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ABSTRACT

The SECARB Black Warrior field verification test employed a diverse suite of well testing and monitoring procedures designed to determine the injectivity, capacity, heterogeneity, and performance of mature coalbed methane reservoirs. A total of 3,250 bbl of water and 252 t of CO₂ were injected into coal in a battery of slug tests. These tests demonstrate that significant injectivity exists in Black Warrior coalbed methane reservoirs and that reservoir heterogeneity is a critical factor to consider when implementing CO₂ sequestration and CO₂-enhanced recovery programs.

The primary test well produces coalbed methane at wellhead pressures just above atmospheric, and yet desorption testing indicates that less than 20% of the original gas in place has been recovered by primary production. Injection of CO₂ was conducted at sustained rates of about 90 t/d of CO₂. Reservoir pressure declined exponentially following the emplacement of each CO₂ slug. Slug and pressure-buildup tests verify that permeability decreases exponentially with depth and also decreased during injection.

Monitoring operations included multi-zone pressure logging and gas sampling in deep observation wells and groundwater sampling in a shallow observation well. Results indicate that significant permeability anisotropy exists in each coal group. In the Black Creek coal, pressure response was greatest in the dominant natural fracture direction. In the Pratt coal group, pressure response was dominated by hydrofractures. CO₂ broke through to the observation wells only in the Pratt coal group and only along the major fracture directions. No significant flow of CO₂ out of zone was detected, and no impact on shallow groundwater resources was identified.

Key words: coalbed methane; Black Warrior Basin; CO₂ injection; subsurface monitoring; well testing

1. Introduction

Coal is among the most promising sinks for the geologic storage of CO₂, and injection of CO₂ into coal has potential for enhanced recovery of coalbed methane (CBM) (e.g., Byrer and Guthrie, 1999; Gentzis, 2000; White et al., 2003). The National Energy Technology Laboratory of the U.S. Department of Energy estimates that the CO₂ storage potential of coal in the United States is between 56 and 114 Gt, and most of this potential lies in the southeastern states (NETL, 2012).

The Black Warrior Basin of Alabama (fig. 1) is the birthplace of the modern CBM industry (Elder and Deul, 1974, 1975; Hinkle and Sexton, 1984; Pashin, 2010) and has significant potential for geologic storage of CO₂ and enhanced coalbed methane recovery (ECBM) (Pashin et al., 2009). The storage potential of coal seams in the Black Warrior

Basin is estimated to be 0.7 to 1.5 Gt (NETL, 2010). A conservative assessment of technical feasibility in the Black Warrior CBM fields indicates that more than 0.31 Gt of CO₂ can be sequestered while increasing CBM reserves by more than 20% (Pashin et al., 2009).

To test the potential for carbon sequestration in coal of the Black Warrior Basin, the Southeastern Regional Carbon Sequestration Partnership (SECARB) has conducted a field verification test that was funded by the U.S. Department of Energy and was led by the Geological Survey of Alabama. This test was similar to other bituminous tests performed in Virginia and Illinois (Ripepi, 2009; Morse et al., 2010). The SECARB tests add to the global inventory of CO₂ sequestration and ECBM programs, which have been conducted at the pilot to commercial scales (e.g., Reeves, 2001; van Bergen et al., 2006; NETL, 2012). The SECARB tests, along with another test led by CONSOL Energy in West Virginia (Siriwardane et al., 2012), are the first such tests to be performed in the Appalachian region.

The test was a small-scale, short-term (~2 month) test that incorporated a range of geological characterization, reservoir modeling, well testing, and monitoring techniques. The field test centered on injection of 252 t of CO₂ into a mature production well in Blue Creek Coal Degasification Field (figs. 1, 2), where technical feasibility and the potential for commercial application of carbon storage and ECBM technology are high (Pashin et al., 2009). The test well (Chevron 17-09-122; State Oil and Gas Board permit 12450-C) was owned and operated by El Paso Exploration and Production, Incorporated, who hosted the test site and managed project operations. This test was conducted as a series of well treatments under a Class II Underground Injection Control Permit.

Basic geologic architecture and reservoir heterogeneity provided the logical foundation for the test design. Coal seams in the Black Warrior Basin are distributed through a thick stratigraphic section and are clustered in a series of coal groups within the Pennsylvanian-age Pottsville Formation. In the test area, CBM is produced from the Black Creek, Mary Lee, and Pratt coal groups (figs. 2, 3). Coal is a stress-sensitive rock type in which permeability decreases exponentially as overburden stress increases (McKee et al., 1988). Permeability can vary by more than an order of magnitude at any depth, making the reservoirs heterogeneous (e.g., Pashin, 1998, 2007; Pashin and Groshong, 1998; Groshong et al., 2009). Multi-seam completion technology was developed to recover gas from numerous coal seams with varied reservoir properties (Graves et al., 1983; Schraufnagel et al., 1991; Young et al., 1993), and thus injection procedures should be optimized to realize the CO₂ storage and ECBM potential offered by multiple coal seams. Accordingly, this program was the first step in this process.

2. Analytical methods

This study employed a diverse suite of analytical methods to characterize coal seams and to test and monitor operations at the test site. Monitoring wells (fig. 4) were drilled using an air-rotary rig, and the target coal zones were cored with a 30-foot-long H-gauge core barrel. Cores were described and sampled for petrologic analysis, CH₄ and CO₂ adsorption isotherms, and geochemical analysis. Geophysical logs include gamma ray, high-resolution density, and caliper logs. The logs were correlated and used to construct structural contour and isopach maps and integrated with the results of core analysis to parameterize COMET3 reservoir models. Pre-injection and post-injection COMET3

models were developed based on geological data, pressure data, and injection volumes.

Details of the reservoir modeling procedures are given in ARI (2011).

Adsorption isotherms and associated Langmuir parameters for CO₂ and CH₄ were determined at respective reservoir temperatures for 26 coal samples at the University of British Columbia using methodology and apparatus similar to Mavor et al. (1990). Proximate and ultimate analyses were performed on splits of the coal according to ASTM standards. Desorption tests were run on coal samples from one core (monitor well 1S) to determine gas-in-place using the modified U.S. Bureau of Mines direct method (Diamond and Schatzel, 1998).

Gas and water production data for the test well were compiled and used to construct decline curves. Wellhead pressure data were provided by El Paso. A Geokon pressure-temperature probe was installed in the test well prior to injection to monitor bottom-hole pressure. The monitoring system employed in the deep observation wells incorporated a system of helium pressure chambers, capillary tubing, surface pressure transducers, and a Geokon data logger. This type of system also was employed in the Illinois Basin Tanquary field verification test (Morse et al., 2010). At the SECARB site, pressure and temperature data were recorded at 5-minute intervals to provide a high-resolution record.

Well testing began with a mechanical integrity test, and major project activities included a series of production-buildup and injection-falloff tests. Injection-falloff testing employed the injection of a series of water and CO₂ slugs of varying size. Pressure response in the primary test well and in the observation wells was analyzed and interpreted using various techniques for analyzing decline curves, pressure transients, and

slug tests in CBM reservoirs (e.g., Ramey et al., 1975; Lee, 1982; Koenig and Schraufnagel, 1987; Saulsberry et al., 1996).

Water samples were taken from the 17-09-122 well and from a shallow observation well. Samples from the 17-09-122 well were analyzed to ensure to verify that the target coal seams were not protected underground sources of drinking water (USDW). Samples from the shallow monitoring well were taken to determine the impact of project activities on potable groundwater. Water from the 17-09-122 well was sampled prior to injection, whereas that from the observation well was sampled monthly for one year. Water from the observation well was sampled using a bladder pump and tubing. Techniques used for the analysis of the water samples are those described in detail by Pashin et al. (2014).

Gas samples were obtained from the 17-09-122 well and the deep observation wells to determine baseline gas composition and to identify breakthrough of injected CO₂ to the observation wells. Pre- and post-injection gases were sampled weekly using an Isotube system (fig. 5), and geochemical analysis was performed by Weatherford Laboratories. These analyses included bulk compositional analysis for He, Ar, O₂, N₂, CO₂, and C₁-C₆₊ hydrocarbons. Stable isotope analysis of methane was performed on pre-injection gas samples and included $\delta^{13}\text{C}_1$ and δD determinations (PDB).

3. Test site

Site selection during the SECARB Black Warrior program was influenced by a plethora of geologic, engineering, legal, and regulatory factors. Regional factors that influenced the project location are proximity to major coal-fired power facilities, locations of coal mines and their reserve areas, reservoir continuity, and gas capacity.

Two major coal fired power plants are located just north of the Black Warrior CBM fields (fig. 1). The plants generate more than 4.2 Gw of electricity and emit more than 27 Mt of CO₂ annually. Both plants employ flue-gas desulfurization units, which make capture of CO₂ for sequestration and ECBM technically feasible.

The Black Warrior Basin is a strategic source of high-quality metallurgical coal and hosts the deepest vertical shaft coal mines in North America (fig. 1). Mining is concentrated primarily in the Mary Lee coal group and secondarily in the Pratt coal group. A key criterion for site selection was to be sure the project would not impact the coal mines and reserve areas, which eliminated most of Oak Grove and Brookwood fields from consideration (Pashin et al., 2009). Formation water, moreover, contains less than 10,000 mg/L TDS in much of the mining area and is thus protected from underground injection under the Safe Drinking Water Act (Pashin and McIntyre, 2003; Pashin et al., 2009).

The Black Warrior Basin contains abundant normal faults, which pose major reservoir discontinuities and may facilitate cross-formational flow (e.g., Pashin and Groshong, 1998; Groshong et al., 2003, 2009). Sequestration potential is greatest between fault swarms, where large structural panels can accommodate multiple inverted 5-spot injection patterns. Some of the largest structural panels are in the northwestern CBM fields near the power plants.

With these criteria in mind, discussions with El Paso resulted in the establishment of a test site around the Chevron 17-09-122 well (Alabama State Oil and Gas Board Permit 12450-C) in Blue Creek Field. A Class II UIC permit was obtained from the State Oil and Gas Board of Alabama, and a series of injection tests were performed as well treatments.

These treatments constituted a series of 36- to 54-t CO₂ slugs, and a total of 252 tons was ultimately injected.

The Chevron 17-09-122 well was drilled by El Paso in 2002 and began producing in February 2003 (fig. 10). The well is on a hilltop, and a lease road runs along the east flank of the hill. Monitoring wells were drilled along this road to facilitate access to project facilities (fig. 4). Alabama State Route 69 runs just west of the well pad and provided ready access for the trucks and equipment required to implement the field test.

As is typical of this area, the 17-09-122 well is completed in the Black Creek, Mary Lee, and Pratt coal groups (fig. 2). The well has a total depth of 1,070 m (3,510 ft) and intersects the base of the Pottsville Formation. The well penetrated more than 5 m (17 ft) of coal in the Black Creek-Pratt production interval. Isolith and structural models show coal is thicker than in adjacent areas and dips gently south-southeast (fig. 3).

Surface casing was set to a depth of 93.7 m (307.5 ft), and production casing was set to a depth of 990 m (3,248 ft) (fig. 5). Beds in the Pratt, Mary Lee, and Black Creek coal groups were perforated with 4 shots per foot through casing adjacent to coal beds between depths of 286.5 and 548.6 m (940 and 1,800 ft). Water is produced through tubing set to a depth of 595.3 m (1,953 ft) near the base of the Black Creek coal group. Gas is commingled and produced through the annulus between tubing and casing. A drillable bridge plug was set in the well at 640 m (2,100 ft) to help isolate the perforated coal zones.

The well was hydrofractured in three stages using nitrogen foam. The Black Creek bed sanded out during treatment with gel and N₂ at an average pressure of 20 MPa (2,900 psig) and an average rate of 22 bbl/min. The Mary Lee and Pratt coal groups were

stimulated with gel and N₂ at average pressures of 12 MPa (1,713 psig) and 7 MPa (1,025 psig) and average rates of 36.3 and 34.8 bbl/min, respectively. Fluid volumes are not fully documented; Proppant volumes in the Mary Lee and Pratt groups were 32 and 36 t.

The 17-09-122 well is historically a below average producer of gas and water. Cumulative gas production prior to the field test was greater than 2,180,397 m³, and cumulative water production was 7,704 barrels (bbl) (fig. 6). Gas and water production peaked in 2003. However, early water production data are not available for this well, and so the peak water rate was probably not recorded. Gas production exhibits a general exponential decline that began in late 2003 and continued until the end of 2006. Between 2007 and 2010, production leveled between 280 and 570 m³/d, and production dropped to less than 170 m³/d shortly before field test operations commenced.

4. Project design

Design of the SECARB Black Warrior field verification test centered on well treatments that provided a basis for pressure-buildup, pressure-falloff, and multi-well interference testing with water and CO₂. A similar approach to small-scale reservoir testing in coal has been conducted successfully by the Alberta Research Council in western Canada (Gunter et al., 2005), and multi-well interference testing has been proven to be an effective method for characterizing CBM reservoirs in the Black Warrior Basin (Koenig, 1989; Young et al., 1993; Saulsberry et al., 1996).

4.1. Well testing design

The well testing design for the 17-09-122 well comprised a series of production tests, water treatments, and CO₂ treatments (fig. 7). First, a production test (T1) determined the time required for pressure to build up and stabilize after shut-in. Next, the well was filled with water to fill the headspace in the hydraulic fractures and help ensure that CO₂ remained close to the wellbore. The main battery of reservoir tests focused on the injection of multiple slugs of water and CO₂ (T2-T7). Each target coal zone was treated by emplacing water slugs to fill the existing hydraulic fractures, test hydraulic confinement, and estimate the permeability of each coal group (T2, T4, T6).

After each water slug was emplaced, two injection-falloff tests were scheduled to be performed with CO₂ (T3A, T3B; T5A, T5B; T7A, T7B) (fig. 7). The CO₂ was stored in tanks and pumped through tubing (fig. 8), and coal beds were isolated between a bridge plug and a packer (fig. 5). The design included the placement of a down-hole pressure-temperature probe between the packer-bridge plug pair. Pressure also was monitored in the tubing-casing annulus to ensure proper sealing of the packer above the perforations.

The CO₂ used for testing is of food grade (99.9% pure) and is from the Jackson Dome, which is a natural source in west-central Mississippi. Injection was performed by Flo-CO₂ using the same system that was used for the SECARB Plant Daniel saline formation test in southwestern Mississippi (Koperna et al., 2009) (fig. 8). A pair of ~52-ton slugs of CO₂ was scheduled for injection into each coal group (fig. 7). Whether to use liquid, gaseous, or supercritical CO₂ for well testing was debated. El Paso decided, based on concerns about gas expansion in the event of equipment failure between the injection

skid and wellbore, that the safest approach would be to inject liquid CO₂ and to allow the liquid to vaporize in the reservoir.

Pressure was to be allowed to stabilize after each CO₂ slug was injected. After stabilization of the second CO₂ slug in each test, the wellbore could be filled with water to minimize flowback of CO₂, equipment could be removed, and the retrievable bridge plug could be placed below the next set of perforations. Next, the packer and probe could be set to isolate the upper coal groups. The plan was to repeat these tests at successively higher stratigraphic levels (figs. 3, 5, 7). After the three sets of injection-falloff tests were completed, a final production-buildup test (T8) was performed to determine if pressure response and reservoir properties had changed.

Injection pressures for each coal group were estimated on the basis of pre-completion data from the 17-09-122 well and nearby wells in Blue Creek Field (Table 1). Estimated hydraulic fracture gradients range from 16 kPa/m (0.71 psi/ft) to 22 kPa/m (0.98 psi/ft), and maximum injection pressure was set at 90% of these gradients to avoid creating new fractures. Thus, the maximum injection pressure at reservoir depth was estimated to be 5.2 MPa (752 psi) in the Pratt coal group, 6.9 MPa (1,005 psi) in the Mary Lee coal group, and 8.7 MPa (1,258 psi) in the Black Creek coal (Table 1).

4.2. Monitoring design

The deep observation wells reached total depth between 538 and 545 m (1,766-1,790 ft) (figs. 3, 5). These wells were placed ~100 to 140 m from the 17-09-122 well, forming an effective inverted four-spot test pattern (fig. 4). The northeastern observation well (3N) was sited relative to the injection well along the natural fracture direction (N. 45°

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4 E.-N. 60° E. for systematic joints and face cleats), which can be associated with increased
5 permeability (Ward et al., 1984; Koenig, 1989). The southeastern well (1S) was sited
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7 along the cross-fracture direction (i.e., cross joint and butt cleat direction). A third
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9 observation well (2E) was drilled about N. 80° E. of the injection well, along the modern
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11 maximum horizontal stress direction, which is where hydraulic fractures have been
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13 observed to grow in the Black Warrior Basin (Steidl, 1993).
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19 The upper 91 m (300 ft) of the wells were cased with conductor pipe and cemented
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21 to protect shallow groundwater and to ensure wellbore stability (fig. 5). The observation
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23 wells were completed in open hole to maximize contact between the coal seams and the
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25 wellbore. Coal groups were cored with an H-gauge drill-stem barrel in all three wells to
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27 retrieve samples for proximate, ultimate, isotherm, and petrologic analysis. Samples from
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29 well 1S were placed in canisters for desorption testing. Geophysical logs (gamma-ray,
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31 bulk density, and caliper) were run in each observation well for added depth control and
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33 to evaluate wellbore integrity. The caliper logs demonstrate that wellbore width varies by
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35 less than 0.25 inch, indicating that inflatable packers could be seated effectively between
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37 the coal groups.
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43 Three inflatable packers were used in each well to isolate the target coal beds (fig. 5),
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45 and pass-throughs were milled to accommodate capillary tubing. Seven lines of capillary
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47 tubing were installed in each well. A single 6.4 mm (0.25 in) line was used to inflate the
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49 packers. Six 3.2 mm (0.125-in) tubing lines were installed in each well for pressure
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51 monitoring and fluid sampling; i.e., a pressure line and a sampling line for each coal
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53 group. Each pressure tube entered a helium pressure chamber that was hung adjacent to
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the target coal seams. The sampling tube terminates near the top of each coal zone below the isolation packer.

The monitor wellhead assemblies were designed with a release valve on one side and a pass-through to conduct the capillary lines out of the well. All lines were passed to a transducer box. The four pressure lines entered the box, which was connected to a central data logger. The sampling lines were labeled and capped outside the box so that Isotube samples could be collected.

Pressure was monitored simultaneously in all three coal groups throughout the production, water treatment, and CO₂ stimulation tests. Simultaneous monitoring in multiple coal groups was used to determine if significant cross-communication exists between the coal groups. For example, when the Black Creek coal is treated with water and CO₂, no pressure response should be observed in the Mary Lee and Pratt coal groups if the Black Creek is hydraulically confined.

The shallow observation well (M1) was designed to monitor groundwater quality and was drilled near the northeast corner of the production well pad (fig. 4). Construction standards followed the well installation guidelines of the U.S. Environmental Protection Agency and employed ASTM-approved materials. The well was drilled and cored to a depth of 56 m (183 ft) and was completed in the Utley coal group between 52 and 54 m (172-178 ft). The well was allowed to equilibrate to aquifer conditions for about 1 month prior to sampling. Water was sampled monthly to establish a pre-injection baseline, and monthly sampling continued through site closure. Water levels were monitored, and water samples were analyzed for a range of hydrologic and geochemical parameters.

5. Baseline reservoir data

5.1. Gas and water composition

Gas produced from Black Warrior CBM reservoirs is typically dry, sweet CH₄ with minor concentrations of N₂, wet hydrocarbons, and CO₂ (Rice, 1993; Scott, 1993; Pashin et al., 2014). Gas recovered from the 17-09-122 well and the monitor wells is typical of that in the Black Warrior Basin (Table 2). The gas from the 17-09-122 well contains nearly 99% CH₄, 0.8% N₂, and only 0.2% CO₂. Ethane constitutes less than 0.2% of the baseline gas sample, and concentrations of heavier hydrocarbons are negligible. The isotopic composition of the gas is -51.9‰ $\delta^{13}\text{C}_1$ and -202‰ δD , suggesting a mixed biogenic-thermogenic origin (see Pashin et al., 2014).

The capillary tubes in the monitor wells were initially filled with He that needed to be flushed before sampling. After flushing, two samples still contained significant He. Two other samples contained near-atmospheric volumes of O₂ and N₂, indicating insufficient flow of subsurface gas into the isotube. Because of these issues, no valid gas samples were recovered from the Black Creek coal group. The Mary Lee and Pratt analyses are nearly identical to results from the production well, although traces of heavier hydrocarbons were detected in the monitor wells (Table 2). Values of $\delta^{13}\text{C}$ were determined on a limited number of samples because of atmospheric contamination but are within the range of other isotopic analyses of gases from the area (Pashin et al., 2014).

Produced water from the Chevron 17-09-122, which was sampled prior to field testing, well is of Na-Cl type (Table 3). TDS content is 21,900 mg/L (milligrams per liter) on the basis of geochemical analysis and 21,824 mg/L on the basis of conductivity. Chloride concentration is 13,500 mg/L, and Na concentration is 7,750 mg/L. Bicarbonate

and Ca account for the bulk of the remaining dissolved solids. Shallow groundwater in the Utley coal group has a maximum TDS content of 329 mg/L, and this water is of Na-HCO₃ type.

5.2. Reservoir pressure and temperature (T1)

In the 17-09-122 well, original pressure measurements in the Pratt and Black Creek coal groups were 2.7 MPa (394 psig) and 5.3 MPa (768 psig), respectively, indicating normal hydrostatic pressure (9.7 kPa/m; 0.43 psi/ft) prior to completion. In the Mary Lee Group, the original reservoir pressure was 2.7 MPa (398 psig), which indicates significant underpressure at this level (6.3 kPa/m; 0.28 psi/ft). Underpressure in this part of the Black Warrior Basin is thought to be related to isolation from recharge (Pashin and McIntyre, 2003; Pashin, 2007). Stratification of reservoir pressure indicates that the Mary Lee group is hydraulically confined. The wellhead gauge of the 17-09-122 well consistently reported 55 to 62 kPa (8-9 psig) prior to well testing (fig. 9). Therefore, wellhead pressure is only slightly above atmospheric. This is because wellhead pressure is not sensitive to the hydrostatic pressure in the formation.

The deep monitor wells enabled the determination of baseline reservoir pressure in each coal group (fig. 10). The results indicate that pressure in the Black Creek coal is substantially higher than that in the Mary Lee and Pratt coal groups. Indeed, pressure in the Black Creek was between 1.0 MPa (143 psig) in well 3N and 1.5 MPa (221 psig) in well 2E. In the Mary Lee Group, baseline pressure was between 0.2 MPa (25 psig) and 0.3 MPa (45 psig), whereas baseline pressure in the Pratt group was only slightly higher than the operating pressure at the production wellhead.

Shut-in tests were performed on the production well in May 2010 (fig. 9). Cessation of pumping had no effect on wellhead pressure or gas flow. In a series of 1-hour shut-in tests, wellhead pressure rose by 83-90 kPa (12-13 psig). No response was observed in the monitoring wells. Next, a longer shut-in pressure-buildup test (T1; fig. 13) was conducted, and wellhead pressure rose to a stabilized pressure of 26 psig in one week. Analysis of the pressure rise using the procedure of Lee (1982) indicates that bulk permeability for all coal zones combined is about 17 mD.

The response to the shut-in pressure-buildup test (T1) was different in each coal group and in each monitoring well. No response was observed in the Black Creek coal in the monitoring wells. In the Pratt coal group, by contrast, the response to shut-in was rapid in well 2E (fig. 9), indicating hydraulic communication along the hydrofracture direction. The lag time from shut-in to detection in well 2E was 1.25 hours. No response was observed in well 1S, and an intermediate response was observed in well 3N, indicating communication in the face cleat direction and no communication in the butt cleat direction (Pashin et al., 2010). Similar responses were observed in the Mary Lee group, although the pressure rise in well 2E had a lag time of about 45 hours and was sluggish, suggesting a combination of lower permeability and lesser hydrofracture growth.

Virgin reservoir temperatures based on analysis of well log header data from other wells near the Chevron 17-09-122 well were typically between 32°C in the Black Creek coal group and 27°C in the Pratt coal group (Pashin and McIntyre, 2003). Direct measurement with the down-hole probe indicates that formation temperatures in the 17-09-122 well prior to injection were substantially lower than the typical virgin reservoir

temperatures in the. Indeed, stabilized temperatures in the Black Creek, Mary Lee, and Pratt coal groups were 24, 22, and 19°C, respectively. Thus, reservoir temperature at the wellbore appears to have fallen by about 8°C as an adiabatic response to gas production.

5.3. Gas capacity and gas content

Adsorption isotherms derived from coal at the SECARB test site have similar properties to those from other investigations of the Black Warrior Basin (e.g., Kim, 1977; Pashin et al., 2009) (fig. 11). In general, coal at the test site can adsorb about twice as much CO₂ as CH₄. Analysis of Langmuir volume and Langmuir pressure confirms this relationship (fig. 12). The mean ratio of adsorption capacity for the two gases is 1.89, and the standard deviation of this ratio is only 0.2.

Isotherms with low Langmuir pressure tend to flatten at elevated pressure, whereas those with high Langmuir volume tend to maintain slope, which favors gas mobility. For CH₄ and CO₂, Langmuir pressure ranges between 1.4-3.5 MPa (206-512 psia) and tends to increase with Langmuir volume (fig. 12). The correlation between Langmuir volume and pressure is stronger for CO₂ than for CH₄.

The Black Creek through Pratt coal groups have dry, ash-free volatile matter content of 43 to 33% and are thus of HvB to HvA bituminous rank. Rank increases with depth, but adsorption capacity is effectively invariant. Isotherms were derived at reservoir temperature, and so the effect of rank increasing with depth was negated by increasing temperature (e.g., Yang and Saunders, 1985; Zhou et al., 2000; Gasem et al., 2009). Ash content (as-received) ranges from 3-34%, averages 12%, and correlates negatively with Langmuir volume for each gas ($r = -0.54$, as-received). The coal can be classified as

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4 vitrinertite containing 74.6-91.2% vitrinite, 5.8-25.0% inertinite, and 0.4-5.8% liptinite.

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7 No significant correlation was identified between maceral composition and adsorption
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9 capacity or Langmuir parameters.

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11 Desorption testing of the core samples from well 1S indicates that a large amount of
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13 gas remains in the study area (fig. 13). Remaining gas content differs greatly among coal
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15 seams. The Pratt, New Castle, and Blue Creek seams have gas content less than 4.7 scc/g
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17 (150 scf/t). About 7.5 cc/g (240 scf/t) of gas remains in the America seam, whereas the
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19 Pratt seam contains only 2.4 cc/g (75 scf/t). Hence, the efficiency of gas drainage can
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21 differ substantially within a single coal group. Both seams were hydrofractured in a
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23 single stage, and so it is probable that stimulation of the thick Pratt seam (1.9 m) was
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25 more effective than in the thinner America seam (0.4 m). Gas content in the Black Creek
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27 coal is about 10.6 cc/g (340 scf/t), suggesting minimal depletion by production as a result
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29 of screenout during hydrofracturing. Desorption testing of all coal zones suggests that as
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31 much as 10.3×10^6 scm (365×10^6 scf) of gas remains unswept in the 32-ha (80-ac)
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33 production unit of the 17-09-122 well (fig. 39). Therefore, primary production may have
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35 recovered only 17% of the original gas in place. This result indicates that potential exists
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37 for improving production through recompletion and ECBM operations.

38 39 40 41 42 43 44 45 46 47 48 **6. Injection testing** 49

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51 Prior to injection, the 17-09-122 well was certified for mechanical integrity. A cement
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53 bond log verified proper contact of cement with the wellbore and casing, and the long
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55 casing string passed pressure testing at 6.9 MPa (1,000 psig). The well was permitted as a
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57 gas injector in March 2010 and then converted for the injection field test. The down-hole
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pressure-temperature probe was installed in the 17-09-122 well below the Black Creek perforations at a depth of 579 m (1,900 ft), and injection testing began in June 2010 (T2-T7; fig. 7). A baseline pressure of 269 kPa (39 psig) was recorded by the downhole gauge just prior to the start of injection.

Water was injected into all three coal groups by simple gravity feed on 6/5/2010 (fig. 14). The well immediately went on vacuum, and the pressure transducer recorded suction for much of the water injection. The volume of water required to fill the available head space in the reservoir, hydrofracture, and wellbore was 1,800 bbl. Water injection was conducted at a temperature of 22°C at reservoir depth.

6.1. Black Creek injection (T2, T3A-C)

The well was prepared for CO₂ injection on 6/14/2010. Upon installation of the injection packer, a 70-bbl slug of water was injected into the Black Creek zone to verify that the packer was set properly and that the well was ready for CO₂ injection. The pressure peaked at 2.7 MPa (390 psig) and declined exponentially overnight. CO₂ injection began on 6/15 (fig. 14A). The T3A CO₂ injection was emplaced as a 36-t liquid slug in 10.5 hours. Sustained injection was achieved at a reservoir pressure of 7.6 MPa (1,100 psig) and at an average rate of 136 t/d. After injection, pressure declined exponentially. Pressure increased slightly on 6/16, apparently because of back-pressure caused by vaporization. After this, a new exponential decline began, which was recorded until the pressure reached 2.4 MPa (352 psig). Reservoir temperature plunged to 16°C during injection and rose asymptotically to the baseline temperature, which is 24°C.

Injection of the second CO₂ slug (T3B) began on 6/21, and after about 15.9 t was injected over a period of 10 hours, it was realized that the data logger was not recording because of a faulty power supply (fig. 14A). Upon replacement, a new slug of 38.6 t of CO₂ was injected (T3C) over a period of 14.4 hours (fig. 14A). Stable injection was reached at 7.1 MPa (1,025 psig), and an injection rate was achieved exceeding 113 t/d. The average rate was just over 90 t/d, indicating that back-pressure had built in the reservoir. Pressure decline followed a course similar to the initial T3A CO₂ injection, although the decline proceeded much more slowly and was asymptotic to a higher pressure. As CO₂ was injected, down-hole temperature dropped to 17°C. Temperature rose erratically for several days following the T3C slug, with repeated negative excursions to temperatures as low as 15°C. These negative excursions were apparently caused by liquid CO₂ backing into the wellbore as the injectate vaporized. Interestingly, the overall temperature trend was an asymptotic rise to baseline temperature.

Pressure decline after the first CO₂ slug test (T#A) indicates effective permeability of 0.2 mD and a skin factor of -3.8, whereas that associated with the third slug (T3C) indicates permeability of 0.1 mD and a skin factor of -3.7. These results are consistent with other slug tests in the Black Creek, which indicate low permeability associated with high in-situ stress (McKee et al., 1988; Saulsberry et al., 1996). Reduced permeability during the T3C injection can be attributed partly to capillary blocking by the initial water slug coupled with back-pressure from the first two CO₂ slugs. Matrix swelling related to gas adsorption also may reduce permeability (e.g., Palmer and Mansoori, 1998; Pekot and Reeves, 2003), but the short duration and low volume of the tests make the relative impact of this phenomenon uncertain.

A key to achieving the injection rates reported above was learning how to manage the injection system. Injection needed to be conducted above 0°C so that water in the reservoir would not freeze. If the CO₂ was above 10°C, however, the pumps would vapor-lock. Therefore, temperatures between 4 and 5°C proved to be optimal for maintaining sustained injection, and the recorded rates were determined by the injection system rather than by reservoir properties.

6.2. Mary Lee-Pratt injection (T4, T5A-B)

On July 8, a bridge plug was set above the Black Creek perforations, and the injection packer was reset above the Mary Lee coal group. An adequate seal was not achieved above the Mary Lee for undetermined reasons. The packer was moved above the Pratt perforations, and CO₂ slugs were injected into the combined Mary Lee and Pratt groups. The results are summarized by Pashin et al. (2010). These results are not discussed here for brevity but resemble those described below, which were obtained by isolation of the Pratt group (T6, T7).

6.3. Pratt injection (T6, T7A-B)

Two slugs of CO₂ (T7A and T7B) were injected into the Pratt coal group between 7/27 and 8/9 (fig. 14B). Prior to injection, a pad of 620 bbl of water was injected to fill headspace (T6). During water injection, reservoir pressure dropped rapidly to a minimum value of 103 kPa (15 psig).

Peak reservoir pressures recorded during injection of each CO₂ slug (T7A, T7B) were 3.9 MPa (563 psig) (fig. 14B). Injection rates were comparable to those achieved during

the other injection tests. Following injection of a 36-ton slug over 9.0 hours during test T7A, pressure declined rapidly to 203 kPa (33 psig). Following injection of the second slug (T7B), which took 12.8 hours and contained 52 t of CO₂, pressure declined to 290 kPa (42 psig), and the injection test was concluded. Post-injection pressure decline following the emplacement of each CO₂ was exponential, and no pressure rises attributable to vaporization were observed. Analysis of pressure decline indicates effective permeability of 16.1 mD and a skin factor of -4.1 following the T7A injection) and permeability of 10.3 mD and a skin factor of -4.2 following the T7B injection. As in the other coal seams, decreasing permeability is probably the result of reduced injectivity caused by capillary water blocking and back-pressure, perhaps with some influence by swelling of coal matrix.

The minimum temperature recorded in the Pratt coal zone near the start of the T7A injection was 1°C, and temperature at reservoir depth rose to 19°C on 7/29. Temperature cycling similar to that observed during Black Creek injection was detected. However, the temperature probe failed on July 29, and so no deep temperature data were recorded during the late part of the pressure decline or during injection of the T7B CO₂ slug.

7. Monitoring results

Data from the deep monitoring wells provide a high-resolution record of pressure changes in each coal group (figs. 10, 15). The initial water injection caused remarkably little pressure response in the monitoring wells (fig. 15). In the Black Creek coal, for example, no transients were observed, save for the pressure drift identified during baseline measurement and occasional pressure spikes from water temporarily backing up

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4 in the well. In the Mary Lee zone, pressure declined from 262 kPa (38 psig) on 6/8 to 248
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6 kPa (36 psig) on 6/10, and the cause of this decline is uncertain. In the Pratt zone, minor
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8 pressure cycling appears unrelated to the initiation of water injection. Subtle decline of
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10 reservoir pressure coincident with that in the Mary Lee zone was recorded in wells 2E
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12 and 3N, but again, the cause is unknown.
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19 *7.1. Black Creek injection (T2, T3A-C)*

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21 Pressure data from the Black Creek coal indicate significant permeability anisotropy
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23 (fig. 15). A pronounced pressure response was recorded in the Black Creek in monitor
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25 well 3N within 2 hr of the start of injection, verifying significant pressure communication
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27 along the natural fracture direction. Pressure rose past 1.1 MPa (167 psig) by the time the
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29 data logger stopped recording on 6/20. When power was restored to the data logger on
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31 6/23, pressure had risen to 1.2 MPa (179 psig). Pressure began rising steeply as the T3C
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33 CO₂ slug was introduced to the reservoir on 6/24 and peaked at 1.4 MPa (206 psig) three
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35 days later. Pressure then declined gradually and leveled off at 1.3 MPa (182 psig) until
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37 7/19, by which time injection in the shallower coal zones was underway. From 7/19 to
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39 the end of the experiments, pressure in the Black Creek coal in well 3N rose greatly from
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41 1.3 to 2.0 MPa (182-276 psig); this rise appears to be related to a failing transducer.
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48 The pressure response in well 2E is muted in comparison to that in 3N (fig. 15),
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50 indicating limited pressure communication along the expected hydrofracture direction.
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52 Deviation from baseline pressure in well 2E was detected 2 days after injection began,
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54 and the maximum pressure recorded after the T3A and T3B CO₂ slugs were injected was
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56 1.3 MPa (193 psig) and only 21 kPa (3 psi) above baseline. A more distinctive pressure
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4 increase in well 2E occurred in concert with the emplacement of the T3C CO₂ slug on
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7 6/24. Pressure in well 2E plateaued at 1.4 MPa (202 psig) on 6/27. Afterward, pressure
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9 gradually drifted upward by 28 kPa (4 psi), reaching a maximum value as subsurface
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11 monitoring ended on 8/12. Although the hydraulic fracture in the Black Creek seam
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13 appears to have facilitated high injection rates, screenout during stimulation may have
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15 resulted in an ineffectively propped hydrofracture in areas distal to the wellbore, and thus
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17 the weak pressure communication observed with well 2E. An alternative interpretation,
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19 however, is that the hydraulic fracture system grew primarily along the major natural
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21 fracture direction, thereby facilitating strongest communication with well 3N.
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26 No significant pressure transient beyond long-term baseline drift was identified in
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28 well 1S until 7/29, which is long after the Black Creek injection (T3A-C) was completed
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30 (fig. 15). Prior to 7/29, pressure was at 1.8 MPa (258 psig), then on 7/29 it rose by 34 kPa
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32 (5 psi), and leveled off for the remainder of the monitoring period. Although subtle, the
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34 overall shape of the transient bears a resemblance to that caused by the T3C slug in well
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36 2E. If so, this transient indicates extremely poor pressure communication in the butt cleat
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38 direction, with permeability being $< 1 \mu\text{D}$. Analysis of pressure data in the other zones
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40 indicates that permeability in the Black Creek coal is only $\sim 0.1 \text{ mD}$.
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46 Some minor pressure excursions were recorded in the Mary Lee coal group in well 2E
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48 following the initiation of CO₂ injection in the Black Creek coal (fig. 15). From 6/16 to
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50 6/17, pressure declined from 241 to 220 kPa (35-32 psig). From 6/24 to 6/26, however,
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52 the pressure gradually rose to 248 kPa (36 psig). This pressure decline may not be related
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54 to the T3 injection tests in the Black Creek coal, considering that pressure decline began
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56 in the Mary Lee zone in well 2E during the initial phase of water injection.
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7.2. Pratt injection (T6, T7A-B)

During the Mary Lee-Pratt and Pratt injections (T4-T7) the largest pressure responses were measured along the hydrofracture direction, specifically in well 2E. Peak pressure in this well was achieved at the end of active injection for each CO₂ slug. During the Pratt injection, the T7A CO₂ slug resulted in a peak pressure of 772 kPa (112 psig) in well 2E, and the T7B slug resulted in a higher peak pressure of 1,172 kPa (170 psig) (fig. 16). Pressure decline following emplacement of each slug was exponential and indicates permeability on the order of 30 mD. No post-injection pressure increases related to vaporization were observed, and pressure remained significantly above baseline at the end of each test. Decline analysis indicates that at least an additional month of soaking would have been required for pressure to return near to baseline conditions.

The pressure rises and declines in well 3N, which is along the major natural fracture direction, were of relatively small magnitude but had similar characteristics to those in well 2E (fig. 16). Pressure rise in well 3N began 3 hours after the start of the T7A injection, yet peak pressures in well 3N were synchronous with those in well 2E. Pressure in well 3N rose from 110-214 kPa (16-31 psig) in response to the T7A CO₂ slug and from 117-490 kPa (17-71 psig) in response to the T7B slug. Accordingly, the proportional increase of pressure response caused by the second slug was much greater in well 3N (260%) than in well 2E (50%). This suggests that pressure buildup along the hydrofracture had reached a point where an increasing amount of injectate was being sent into the face cleats. No response was measured along the butt cleat direction in well 1S, indicating effective isolation from the slug tests.

Throughout the Pratt injection, no deviation from baseline pressure was detected in the Mary Lee coal group (fig. 16). This result confirms effective packer seals and, more importantly, that the thick shale separating the Mary Lee and Pratt coal groups is an effective reservoir seal. Similarly, no pressure events in the Black Creek coal group appear to be related to the Pratt injection. To summarize, pressure monitoring results indicate that flow in the Pratt coal group took place mainly along the hydraulic fracture system and secondarily along the face cleat direction. The magnitude of pressure response confirms that permeability is substantially higher in the Pratt coal group than in the other coal zones.

7.3. Post-injection production-buildup test (T8)

After the injection testing was completed, the injection packer and bridge plug were removed, and the injection well was returned to production status. A final production-buildup test was performed in September 2010 (fig. 17). By this time the deep observation wells had been plugged and abandoned. Prior to the production-buildup test, the well had been returned to a flowing wellhead pressure of 28 kPa (4 psig), which is lower than that prior to the field test. On 9/15, the well was pumped down to a wellhead pressure of 0.7 kPa (0.1 psig), and the well was shut in on September 16. Upon shut-in, pressure rose rapidly, and a peak shut-in pressure of 193 kPa (28 psig) was recorded on 9/18. This pressure is only 14 (2 psi) higher than that recorded during the pre-injection shut-in test (fig. 9). Pressure buildup analysis indicates that post-injection permeability was about 5.5 mD, suggesting that permeability was reduced by a factor of three following the reservoir testing.

After peak pressure was achieved, shut-in pressure decayed over the next 6 days to a stabilized pressure of 165 kPa (24 psig) (fig. 17). The probable cause of this decay is diffusion of CO₂ into coal matrix in response to the elevated shut-in pressure. Indeed, diffusion of CO₂ into coal is much faster than diffusion of CH₄ (e.g., Busch et al., 2003; Gruskiewicz et al., 2009), which helps explain why the post-injection shut-in response differed so distinctly from the pre-injection response (figs. 9, 17). Movement of water in and around the wellbore is another factor that may have affected the post-injection pressure response.

7.4. Gas composition

Pressure data indicate that significant hydraulic communication took place between the injection well and monitor wells 2E and 3N and that minimal communication took place with well 1S. Gas samples taken from the monitor wells on 8/8/2010, shortly before the close of major project operations, were analyzed to see if breakthrough of injectate to the monitor wells could be detected (Table 4). Pressure in the Black Creek sampling tubes was very low, and the gas samples contained more than 99% atmospheric gas. Accordingly, the composition of Black Creek reservoir gas could not be determined.

Samples from the Mary Lee coal group in the monitor wells contained more than 97% CH₄ (Table 4), indicating that no significant breakthrough of CO₂ occurred during any of the tests. Nitrogen (N₂) constituted 0.7-1.9% of the gas, which also is consistent with original composition (Table 2). CO₂ levels were lower than 0.16%, which is in some cases lower than the original CO₂ level of the sampled gas and perhaps indicates minor sweep of CH₄ and N₂ from coal matrix into the monitoring wells (Tables 2, 4).

By contrast, significant breakthrough of injected CO₂ was identified in the Pratt coal group. In well 2E, CO₂ composed more than 72% of the sampled gas (Table 4), indicating that major breakthrough to the monitor well took place along the hydrofracture. The sample further contained 27% CH₄, accounting for all but 1% of the remaining gas, which would be expected based on original gas composition (Table 2). In monitor well 3N, the post-injection gas contained more than 42% CO₂, indicating significant dilution of the original CH₄ by flow along natural fractures. No tangible rise in CO₂ content was detected in the Pratt coal group along the butt cleat direction in well 1S, confirming that this well remained isolated from the injection activities.

Post-injection COMET3 reservoir models are based on coal properties, pressure monitoring, and injection volumes. These models predicted no breakthrough to the monitoring wells in the Black Creek coal zone and significant breakthrough in the Pratt coal zone (fig. 18). The results from the Pratt coal zone are consistent with the detection of a large percentage of CO₂ in well 2E, a lesser percentage in well 3N, and no CO₂ in well 1S. These results confirm permeability anisotropy in the Pratt coal zone on the order of 5:1, favoring fluid transport along the hydrofractures and face cleats.

7.5. Shallow Groundwater Monitoring

Monitoring the composition of shallow groundwater in well M1 showed no change of water chemistry during the operational phase of this project (figs. 19, 20; Tables 3, 5). Many inorganic constituents in the water from well M1 were below detection levels (e.g., Ag, As, B, Be, Br, Cd, CN, Co, Hg, Mo, Ni, NO₂, NO₃, P, PO₄, Sb, Se, Sn, Ti, Tl, V). Elements and compounds detected in significant quantities are reported in Tables 3 and 5.

Iron varied significantly in concentration, with the lowest values occurring during the summer months, when rainfall and percolation of groundwater were at minima.

Interestingly, the concentration of free CO₂ was highest prior to injection.

A piper diagram (fig. 19) shows the major contrast between the Na-Cl water from the CBM reservoir interval and the Na-HCO₃ water in the shallow Utley coal seam. Plotting Utley water chemistry from well M1 shows the extreme compositional stability of the formation water throughout the field test. Stiff diagrams provide another view of the stable water chemistry in well M1 (fig. 20). Indeed, no significant change in the geometry of the Stiff diagrams is discernible throughout the monitoring period. Accordingly, the SECARB Black Warrior field test had no measurable impact on water quality in well M1.

7.6. Post-test production performance

Since completion of the injection testing, the 17-09-122 well has produced 4,485 bbl of water and $0.9 \times 10^6 \text{ m}^3$ ($32 \times 10^6 \text{ scf}$) of gas (8/2010 through 8/2014). It took 32 months to produce the volume of water that was injected, and production peaked at 21 bbl/d in 6/2011. Water production declined to about 3 bbl/day over a period of 12 months and has been in the range of pre-injection water production since 1/2012 (fig. 6).

Gas production was $< 142 \text{ m}^3/\text{d}$ (5 mcf/d) until 1 yr after completion of the field test, which is when flowback of the injected water was effectively complete (fig. 6). Gas rates started rising in 8/2011 and reached a peak of $1,161 \text{ m}^3/\text{d}$ (41 mcf/d), which is more than twice the rate achieved by the well during the four years prior to the SECARB test. The gas rate has remained above $850 \text{ m}^3/\text{d}$ (30 mcf/d) since 7/2013, and so post-injection well performance is $> 50\%$ better than pre-injection performance. The amount of CO₂ in the

production stream declined from 65% at the start of flowback in 8/2010 to 22% by 12/15/2010, when all project operations ceased. By 2012, CO₂ constituted a nominal percentage of the produced gas stream. Flowback of the injected CO₂ accounts for no more than 17% of the gas produced since injection, thus there has been tangible improvement of CH₄ production since the injection tests.

Flowback following a 1,000-ton CO₂ injection test in a CBM well in Virginia resulted in an initial CH₄ concentration of more than 90%, indicating that a significant amount of methane was liberated from the coal matrix and highlighting the potential for ECBM recovery (Ripepi, 2009). The Black Warrior test was performed behind a water pad, whereas the Virginia test was not. This coupled with the smaller volume of CO₂ injected limited the possibility of an immediate ECBM response in the Black Warrior test, and the effect on gas production did not become apparent until after most of the injected water flowed back to the production well. Long-term improvement of the performance of the 17-09-122 well appears to owe to a variety of factors, including (1) scraping scale from casing during preparation of the well for testing, (2) acidization of the wellbore and perforations during the injection and flowback of CO₂, water, and any H₂CO₃ that may have been formed (3) dissolution of cleat-filling calcite, and (4) displacement and liberation of CH₄ from coal matrix as CO₂ was adsorbed.

8. Conclusions

The SECARB Black Warrior field test employed a diverse suite of well testing and monitoring procedures designed to determine the permeability, injectivity, capacity, heterogeneity, and performance of mature CBM reservoirs. A total of 3,250 bbl of water

and 252 t of CO₂ have been injected into coal in a battery of slug tests. The results of these tests demonstrate that significant injectivity exists in Black Warrior CBM reservoirs and that permeability anisotropy is a critical factor that must be considered when implementing CO₂ sequestration and CO₂-enhanced recovery programs.

Wellhead pressure measurements indicate that the production well operates just above atmospheric pressure. Pressure depletion by gas production has been strongest in the Mary Lee and Pratt coal groups, whereas significant reservoir pressure remains in the Black Creek coal. Reservoir temperature in all zones was lower than initially expected, indicating adiabatic cooling of the reservoir in response to a long history of depressurization and gas production. Adsorption isotherms indicate that the coal has high capacity for CO₂ (1.87 x CH₄ at elevated pressure), and desorption testing indicates that less than 20% of the original gas in place was recovered by primary production prior to well testing.

Injection operations began with water. The injection well stayed on vacuum through most of the water injection, and this part of the operation proved important for filling headspace in the reservoir, hydrofractures, and wellbore, and for quelling an effective vacuum condition. Injection of ~30 t slugs of CO₂ was conducted at average rates of about 90 t/d of in all coal groups. The rate was determined by the injection system used rather than reservoir properties, and as a result, injectivity (i.e., rate per unit pressure) was inversely proportional to the baseline reservoir pressure of each coal group as well as the maximum injection pressure in each coal group.

Reservoir pressure declined exponentially following the emplacement of each CO₂ slug, although vaporization of CO₂ resulted in temporary pressure rises in the Black

Creek coal. Pressure decline following injection was much slower in the Black Creek coal than in the shallower coal groups, indicating very low permeability. Measured temperature gradually rose to reservoir temperature following emplacement of each CO₂ slug. However, significant temperature cycling was superimposed on this trend in cases where liquid CO₂ episodically backed into the wellbore as the injectate vaporized. Slug test and pressure-buildup analysis verify that permeability decreases exponentially with depth and that permeability loss occurred following injection. Apparent permeability loss is thought to be related to back-pressure associated with the injected fluid slugs, as well as swelling of coal matrix as CO₂ adsorbed into the reservoir.

Monitoring operations included multi-zone pressure logging and gas sampling in the deep observation wells and monthly sampling of groundwater in the shallow observation well. Results indicate that significant permeability anisotropy exists in each coal group. In the Black Creek coal, pressure response was greatest in the natural fracture direction and secondarily in the hydrofracture direction. The weak response along the hydrofracture direction probably reflects screenout of the stimulation treatment when the well was originally completed. In the Mary Lee and Pratt coal groups, pressure response was dominated by the hydrofractures and secondarily by the cleat systems. Analysis of gas recovered through sampling tubes indicates that injected CO₂ broke through to the observation wells only in the Pratt coal group and only in the direction of the hydrofractures and face cleats. Monitoring of shallow groundwater indicates that water chemistry remained stable throughout the operational phase of the project. No significant flow of CO₂ out of zone was detected, and no impact on shallow groundwater resources was identified.

Post-test production performance of the test well has improved substantially relative to that in the four years prior to CO₂ injection. Gas production for the first year after the injection tests was limited as the bulk of the injected water flowed back to the wellbore. As the water rate decreased, the gas rate improved by > 50% relative to the pre-injection rate. Long-term improvement of well performance is apparently related to a number of factors, including the removal of wellbore scale, dissolution of cleat-filling calcite, and displacement of CH₄ as CO₂ adsorbed into the reservoir matrix.

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FIGURE CAPTIONS

Fig. 1. Map of the Black Warrior CBM fields showing cumulative gas production and the locations of coal-fired power plants, underground coal mines, and the SECARB Black Warrior test site.

Fig. 2. Geophysical logs of the Chevron 17-09-122 well showing stratigraphic units, perforated intervals, and injection test zones.

Fig. 3. Reservoir model showing net coal thickness and the structural geometry of each target coal interval.

Fig. 4. Diagrammatic layout of the SECARB Black Warrior test site showing locations of the production well, deep monitoring wells (1S-butt cleat direction relative to production well; 2N-hydrofracture direction; 3N-face cleat and systematic joint direction), and a shallow groundwater monitoring well (M1).

Fig. 5. Schematic diagrams of the 17-09-122 well and a deep observation well showing wellbore construction as well as packer, tubing, and monitoring configurations.

Fig. 6. Production history curve of the Chevron 17-09-122 well showing substantial improvement of well performance two years after the SECARB Black Warrior field test.

Fig. 7. Well testing plan for the SECARB Black Warrior field verification program showing relative timing of production-buildup and injection-falloff tests.

Fig. 8. Layout of storage tanks, injection apparatus, and the monitoring station at the SECARB Black Warrior test site.

Fig. 9. Results of pre-injection production-buildup test (T1) in the Chevron 17-09-122 well. Results for monitor well 3N not shown here for simplicity.

Fig. 10. Baseline (i.e., pre-injection) pressure measurements from the deep observation wells at the SECARB Black Warrior test site.

Fig. 11. Adsorption isotherms for CH₄ and CO₂ in the Pratt coal seam in monitoring well 2E.

Fig. 12. Plot of Langmuir volume versus Langmuir pressure showing fundamental properties of adsorption isotherms derived from various coal samples from monitor well 1S at the SECARB Black Warrior test site.

Fig. 13. Results of desorption testing of coal from monitoring well 1S at the SECARB Black Warrior test site. Gas content determinations indicate variable depletion of the coal seams and that a large volume of natural gas remains in place in the test area.

Fig. 14. Pressure and temperature changes associated with water and CO₂ injection in the Black Creek coal seam (T2, T3A-C) and Pratt coal group (T6, T7A-B).

Fig. 15. Results of multi-zone pressure monitoring and interference tests in the Black Creek coal seam (T2, T3A-C).

Fig. 16. Results of multi-zone pressure monitoring and interference tests in the Pratt coal group (T6, T7A-B).

Fig. 17. Results of post-injection production-buildup test (T8) in the Chevron 17-09-122 well.

Fig. 18. COMET3 reservoir models showing interpreted results of CO₂ injection based on coal properties, pressure measurements, and injection volumes. Note that injected CO₂ remains close to the wellbore in low-permeability Black Creek coal. In the Pratt group, permeability anisotropy favored transport of injected CO₂ along hydrofractures and natural fractures and breakthrough of injectate in wells 2E and 3N.

Fig. 19. Piper diagram showing stability of shallow groundwater chemistry in the Utley coal group in monitor well M1. Note stark contrast between the produced water from the coalbed methane well (17-09-122) and that from the shallow monitoring well (M1).

Fig. 20. Stiff diagrams showing stability of shallow groundwater chemistry in the Utley coal group in monitor well M1.

Table 1. Estimated pre-completion pressure, hydraulic fracture gradients and maximum injection pressures used in the SECARB Black Warrior field test.

Coal group	Pratt	Mary Lee	Black Creek
Depth (m)	287	437	548
Original pressure (MPa)	2.7	2.7	5.3
Original gradient (kPa/m)	9.5	6.3	9.7
Fracture gradient (kPa/m)	19.0	16.1	16.3
CO ₂ injection pressure (MPa)	5.2	6.9	8.7

Table 2. Baseline gas composition corrected for helium, oxygen, argon, and atmospheric nitrogen.

[illegible]

Table 3. Water chemistry from the Chevron 17-09-122 well and shallow monitoring well M1.

Well	Zone	Date	pH	Alkalinity (mg/L CaCO ₃)	Conduct- ivity (μS/cm)	TOC (mg/L)	TDS (mg/L)	HCO ₃ (mg/L)	Cl (mg/L)	SO ₄ (mg/L)	Ca (mg/L)	Na (mg/L)	K (mg/L)
17-09-122	Black Creek-Pratt	3/3/10	7.2	184	35,000	2.63	21,883	224	13,500	0	315	7,750	35
M1	Utley	12/2/09	7.8	189	199	< 0.50	319	229	4	9	16	56	5
M1	Utley	1/14/10	7.5	192	366	1.94	317	233	2	6	16	55	5
M1	Utley	2/16/10	7.4	125	380	1.02	322	237	3	7	16	55	4
M1	Utley	3/22/10	7.7	194	360	2.52	320	235	2	5	16	58	4
M1	Utley	4/28/10	7.8	193	301	< 0.50	317	234	2	5	16	56	4
M1	Utley	5/24/10	7.8	204	367	1.36	329	247	1	5	16	56	4
M1	Utley	6/21/10	7.8	202	378	< 0.50	328	245	2	5	16	56	4
M1	Utley	7/26/10	7.9	202	348	2.79	327	244	2	5	16	56	4
M1	Utley	8/30/10	7.9	198	328	< 0.50	322	240	2	5	15	56	4
M1	Utley	9/20/10	7.9	202	331	0.64	327	244	2	5	16	56	4
M1	Utley	11/02/10	7.7	197	376	2.62	320	239	2	5	16	54	4
M1	Utley	11/29/10	7.8	195	375	< 0.50	319	236	2	7	16	54	4

Table 4. Post-injection gas composition corrected for helium, oxygen, argon, and atmospheric nitrogen. Samples collected 8/26/2010.

[illegible]

Table 5. Inorganic constituents detected in water samples from shallow monitoring well M1.

Date	Al (µg/L)	Ba (µg/L)	Cu (µg/L)	Fe (µg/L)	Pb (µg/L)	Li (µg/L)	Mn (µg/L)	Sr (µg/L)	Zn (µg/L)	CO ₂ (mg/L)
12/02/09	< 60	65.9	10.5	60	2	13	92.4	337	71.5	6
1/14/10	478	129	15.1	2700	5	13	122.0	492	56.7	12
2/16/10	178	209	< 8	1930	4	19	91.5	512	10.3	10
3/22/10	311	277	13.7	2230	4	15	88.1	552	11.8	8
4/28/10	200	304	9	944	< 2	14	43.6	564	18	6
5/24/10	68	311	11.1	183	< 2	12	28.3	552	14	6
6/21/10	164	339	< 5	864	< 2	16	42.9	556	29.9	6
7/26/10	75	289	< 5	368	8.3	15	29.0	569	24.4	5
8/30/10	90	319	< 5	340	7.7	7	26.7	564	< 4	5
9/20/10	< 60	335	< 5	107	8.1	7	19.7	592	< 4	5
11/02/10	180	298	< 5	961	2	9	49.3	581	4	8
11/29/10	355	337	< 5	1600	4.1	10	65.9	577	8	6

Figure

- Coal
- Sandstone
- Shale
- Shallow groundwater sampling zone
- Perforated zone
- Test zone

Figure

Figure
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Figure

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Figure

- Well 17-09-122
- Well M1 pre-injection
- Well M1 during and post-injection

Figure