Well test results and reservoir performance for a carbon dioxide injection test in the Bass Islands Dolomite in the Michigan Basin

Joel Sminchak, Neeraj Gupta, and Jacqueline Gerst

ABSTRACT

Analysis of well test results and reservoir behavior is presented for a 10,241-t carbon dioxide (CO_2) injection test in the Michigan Basin. The test site was located in Otsego County, Michigan, and was part of the Midwest Regional Carbon Sequestration Partnership (MRCSP) program. The injection target was a deep saline rock formation, named the Bass Islands Dolomite, at a depth of 1049–1071 m (3442–3514 ft). Rock core tests on this formation suggested an average permeability of 22 md and porosity of 13% across 22 m (72 ft). Hydraulic monitoring included metering injection at the wellhead and downhole pressure and temperature logging in the injection well and a nearby deep monitoring well. Pressure response curves were analyzed for a step-rate injection and shut-in recovery tests. Downhole pressure in the injection well was approximately 13,800–13,930 kPa at injection rates of 400–600 t CO_2 per day. Step-rate injection testing suggested that injection rates of several hundred thousand metric tons CO_2 per year may be sustainable in a single well. Injection test pressure falloff analysis showed that the overall reservoir permeability may be more than twice as high as indicated from rock core tests. This successful test provides extremely valuable field information on all aspects of the CO_2 storage feasibility for both the test region and the broader deployment of the technology.

INTRODUCTION

This article describes well test results and reservoir performance from injection of 10,241 t of carbon dioxide (CO_2) into the Bass Islands Dolomite formation at a geologic sequestration test site in the Michigan Basin, a major sedimentary basin in the Midwestern

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AUTHORS

Joel Sminchak ~ *Battelle, 505 King Ave, Columbus, Ohio 43201; sminchak@battelle.org*

Joel Sminchak has worked at Battelle since 1997 as a research scientist with a focus on carbon sequestration and hydrogeology. He earned his B.S. degree in geology from the University of Dayton and his M.S. degree in hydrogeology from Ohio State University.

Neeraj Gupta ~ *Battelle, 505 King Ave, Columbus, Ohio 43201*

Neeraj Gupta is the senior research leader for carbon management at Battelle. He received his Ph.D. in hydrogeology from Ohio State University, his M.S. degree in geochemistry from George Washington University, and his M.Sc. and B.Sc. degrees in geology from Panjab University, India.

Jacqueline Gerst ~ *Battelle, 505 King Ave, Columbus, Ohio 43201*

Jacqueline Gerst is a geophysicist at Battelle with an emphasis on carbon sequestration research. She has a B.S. degree in applied physics and geology and an M.S. degree in geology from Rensselaer Polytechnic Institute.

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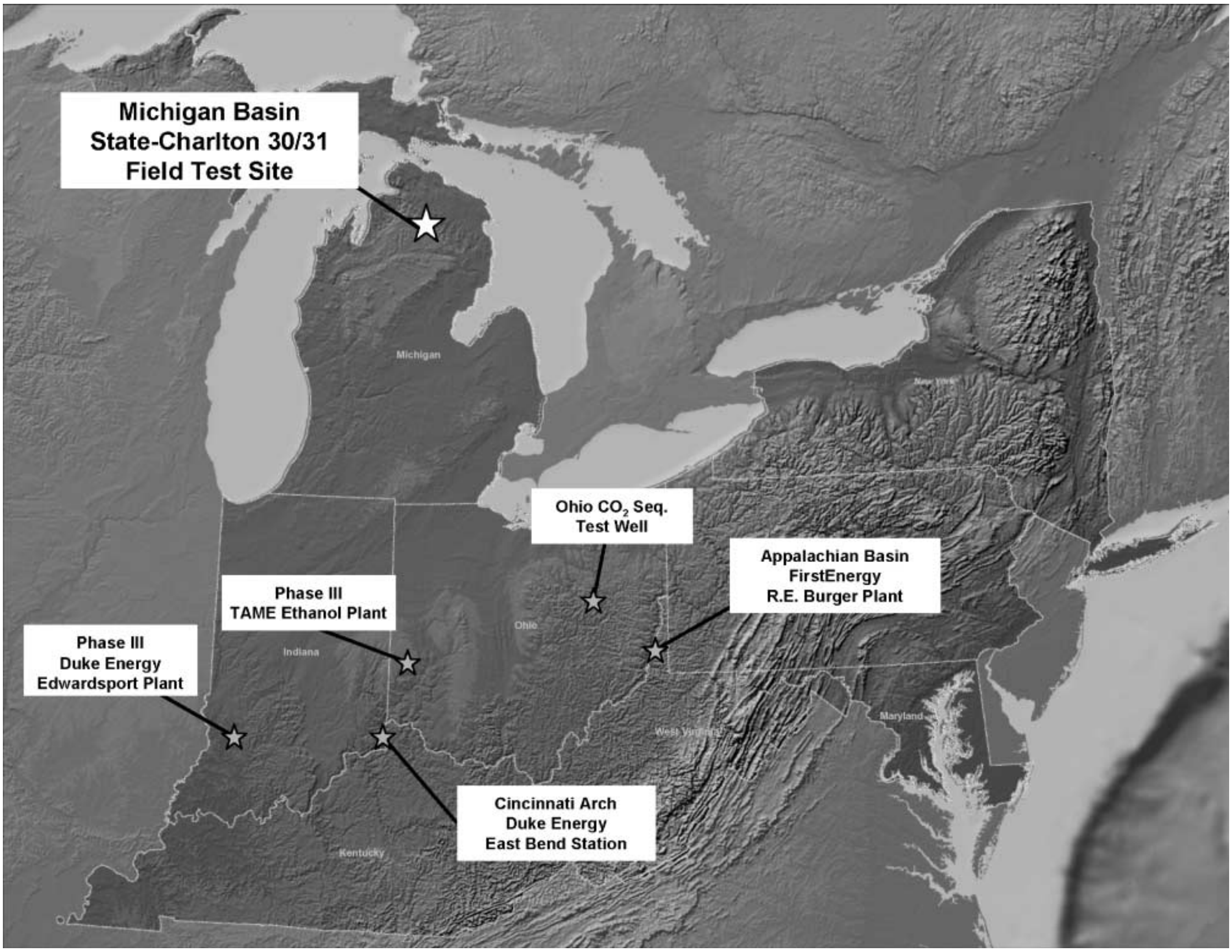


Figure 1. Site location map showing the Michigan Basin test site and other Midwest Regional Carbon Sequestration Partnership (MRCSP) geologic sequestration field test sites.

United States. The test is part of the Midwest Regional Carbon Sequestration Partnership, one of seven partnerships in a nationwide effort by the U.S. Department of Energy's National Energy Technology Laboratory to determine regionally appropriate carbon sequestration options and opportunities.

SITE DESCRIPTION

The test site is located at an oil and gas field in Otsego County, Michigan (Figure 1). Currently, natural gas is produced from the Antrim Shale formation in the area at depths of 300–500 m (984–1640 ft). This gas contains 15–30% CO_2, which is removed at central gas processing plants before the gas is ready for use. Consequently, high-purity CO_2 was available in the area. Periodically, this CO_2 is used for enhanced oil recovery in deeper Niagaran Reefs at depths of 1500–2000 m (Brock et al., 1995). As a result, a significant amount of compression and pipeline transport infrastructure was available for testing CO_2 sequestration in deep saline formations.

The test site's geologic setting is the northern part of the Michigan Basin, a large, mature sedimentary basin present across most of lower Michigan. Paleozoic sedimentary rocks up to 3000 m (9842 ft) in total thickness underlie a 200-m (656-ft)-thick glacial layer in the study area. Precambrian crystalline basement rocks underlie the Paleozoic rocks. Middle Devonian–middle Silurian rock formations were targeted for the test based on nearby well logs, which showed porous intervals at depths of 1000–1100 m (3281–3609 ft). However, these formations were relatively unexplored in the area.

The objective of the test was to inject 10,000 t of supercritical CO_2 into a deep saline rock formation to evaluate CO_2 sequestration potential in the Michigan

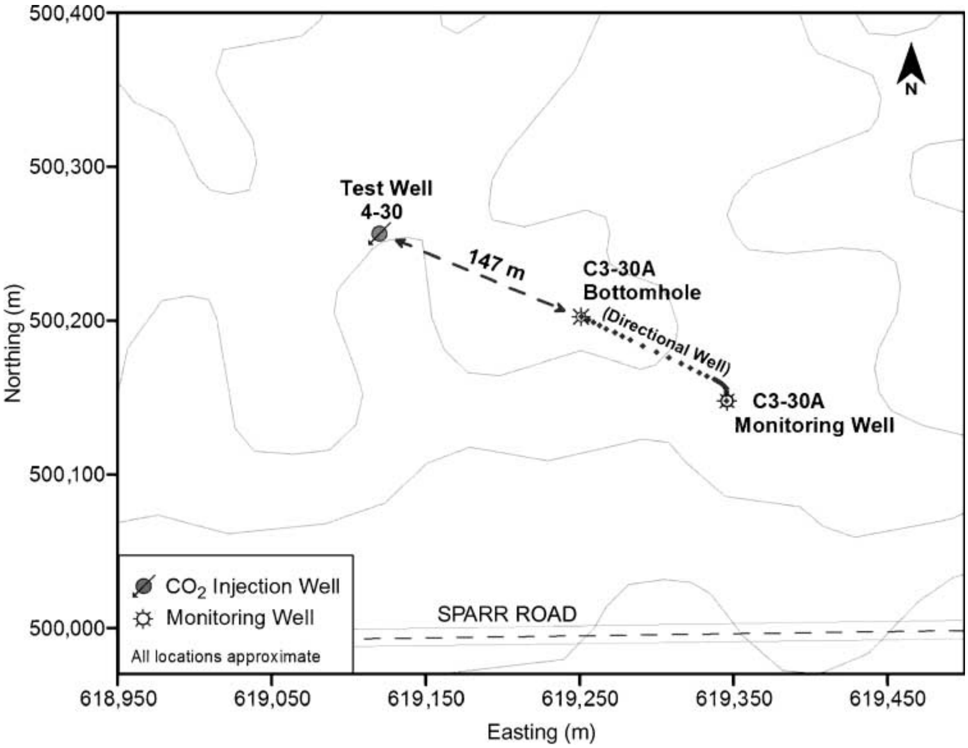


Figure 2. Map showing the location of the State-Charlton 4-30 injection well and State-Charlton 3-30A well used in the hydraulic monitoring of the CO_2 injection test.

Basin. A test well, named State-Charlton 4-30, was drilled at the site in November 2006. Full rock coring, rotary sidewall coring, and wireline logging were completed in the borehole to characterize the sequestration target and confining layers. A deviated well was drilled from a nearby abandoned well, State-Charlton 3-30A, to provide a monitoring location for the injection test (Figure 2). The monitoring well was completed in the Bass Islands Dolomite at a distance approximately 150 m (492 ft) from the injection well. Table 1 summarizes the well construction specifications of the injection and monitoring wells.

Table 1. Well Construction Specifications for the State-Charlton 4-30 Injection Well and the State-Charlton 3-30A Monitoring Well

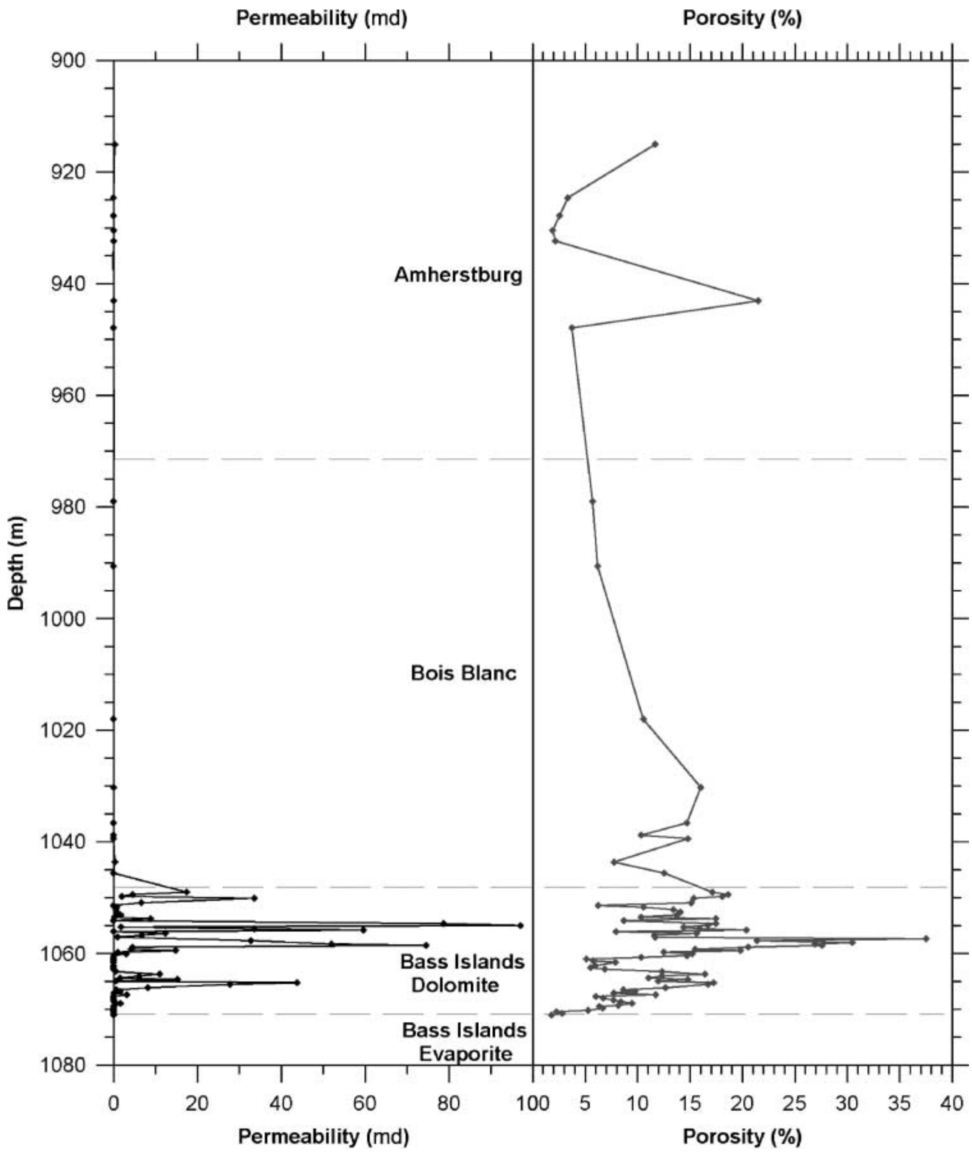
Parameter	Injection Well	Monitoring Well
Well name	State-Charlton 4-30	State-Charlton 3-30A
API number	211375791600	211373260502
Perforation interval (m)	1048–1071	1052–1075
Borehole diameter (cm)	27	20
Casing diameter (cm)	22	14
Comments	CO_2 injection test well	Recompleted as a deviated hole, January 26, 2007

The injection well was fully characterized with geophysical logs, full rock cores, rotary sidewall cores, and rock core tests for hydraulic parameters. Based on test-well characterization, the injection interval was identified as the Bass Islands Dolomite at a depth of 1049–1071 m (3442–3514 ft) (Barnes et al., in press). Full core was collected across the entire Bass Islands interval. Rock core tests on 63 plugs from the formation indicated an arithmetic average porosity of 13% and a permeability of 22 md. As shown in Figure 3, the Bass Islands has variable permeability and porosity distribution typical of many carbonate units in the region. The overlying Bois Blanc Formation (972–1049 m [3189–3442 ft]) was included in the storage interval because of relatively high-porosity shows in wireline logs; although, rock cores suggested relatively impermeable microporosity. The formations were saturated with dense brines with total dissolved solids exceeding 250,000 mg/L. Confining layers included carbonate and evaporate rocks in the Amherstburg-Lucas Formation at a depth interval of 682–972 m (2237–3189 ft) (also termed the Detroit River Group in parts of the Michigan Basin).

HYDRAULIC TESTING AND MONITORING

The objective of injection testing was to investigate maximum injection rates, demonstrate storage security,

Figure 3. Plot of permeability and porosity at depth from sidewall and full rock core tests in the State-Charlton 4-30 injection well.



and determine the reservoir response to injection. The CO_2 was compressed to a supercritical fluid at the compression facility and transported via a 13-km (8-mi) pipeline to the injection wellhead. Hydraulic monitoring involved collecting data on CO_2 injection rates, injection pressures, bottomhole reservoir pressures, and bottomhole temperature in the injection and monitoring wells. Equipment for hydraulic monitoring included a wellhead flowmeter and retrievable bottomhole pressure and temperature loggers in both the injection and monitoring wells. The wellhead meters provide a record of CO_2 density, temperature, pressure, and flow rates. The downhole meters provided a continuous record of pressure and temperature in the injection reservoir. A logger was installed in the injection zone of the State-Charlton 4-30 injection well. In the State-Charlton 3-30A monitoring well, the logger was sealed below a bridge plug to isolate the reservoir interval. Additional monitoring for the project included wireline logs, a microseismic monitoring array, cross-well seismic surveys, surface gas sensors, and soil gas surveys for perfluorocarbon tracers added to the injection stream.

Site characterization data were integrated into reservoir models to provide estimates of injection pressures and CO_2 distribution in the storage target (Bacon et al., 2008). However, predicting the effects of natural geologic heterogeneity, well cements, and the perforation job on injection performance was difficult. In addition, the injection target was a carbonate rock with indications of secondary or vugular porosity unlike traditional sandstone rock formations, which are commonly targeted for deep well injection. Finally, testing was completed in

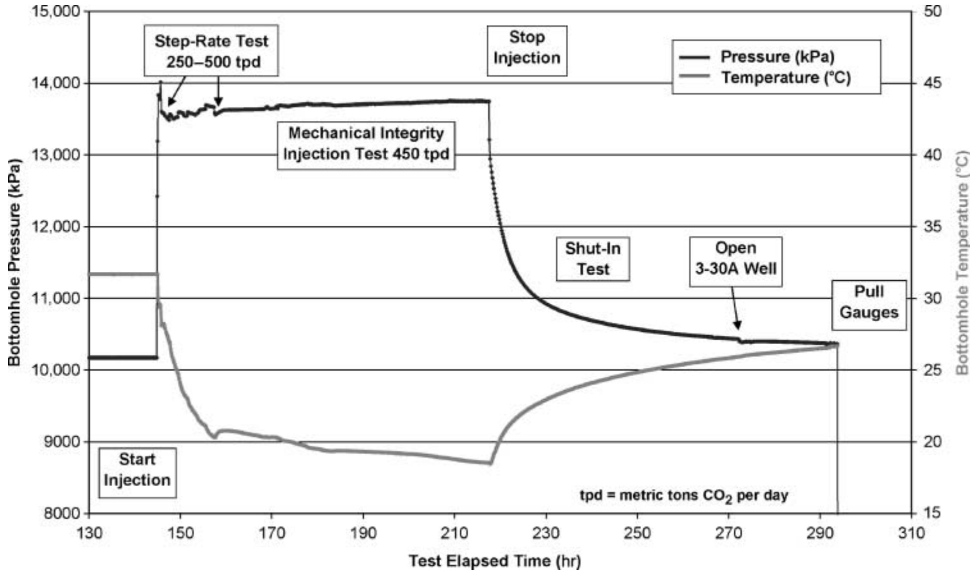


Figure 4. Graph of downhole pressure and temperature measured in the State-Charlton 4-30 injection well during initial step-rate and mechanical integrity CO_2 injection testing.

February–March 2008 when temperatures were commonly below −10°C (14°F).

Step-Rate Test

Prior to injection, an initial step-rate test was completed to investigate maximum injection rates, determine formation fracture pressures, and demonstrate the mechanical integrity of the well. The step-rate test was completed with CO_2, and injection rates were stepped from 250–500 t CO_2 per day in 50 t per day increments (Figure 4). Each rate was sustained for approximately 2 hr. The downhole pressure response was measured with a pressure logger installed in the injection interval.

Monitoring data indicated that a downhole pressure increase of approximately 3500 kPa was necessary to initiate injection. After injection began, bottomhole pressures stabilized at around 13,400–13,800 kPa. Injection rates during the step test were manually adjusted at the compression station and were difficult to stabilize at lower rates. A better pressure response was encountered at higher injection rates. No formation breakdown or hydraulic fracturing was encountered. Maximum allowable pressure limits, defined by a fracture pressure gradient of 18 kPa/m (0.80 psi/ft) in Michigan, were not approached. During the step-rate test, only a 200-kPa pressure increase was observed as the injection rate increased from 250 to 500 t per day, making it difficult to interpret pressure response curves. The CO_2 supply was limited by a compression facility capacity of 600 t CO_2 per day, and higher injection rates were not possible. However, step test results appeared to indicate that injection rates more than 1500 t CO_2 per day may be possible in the well.

Shut-In Test

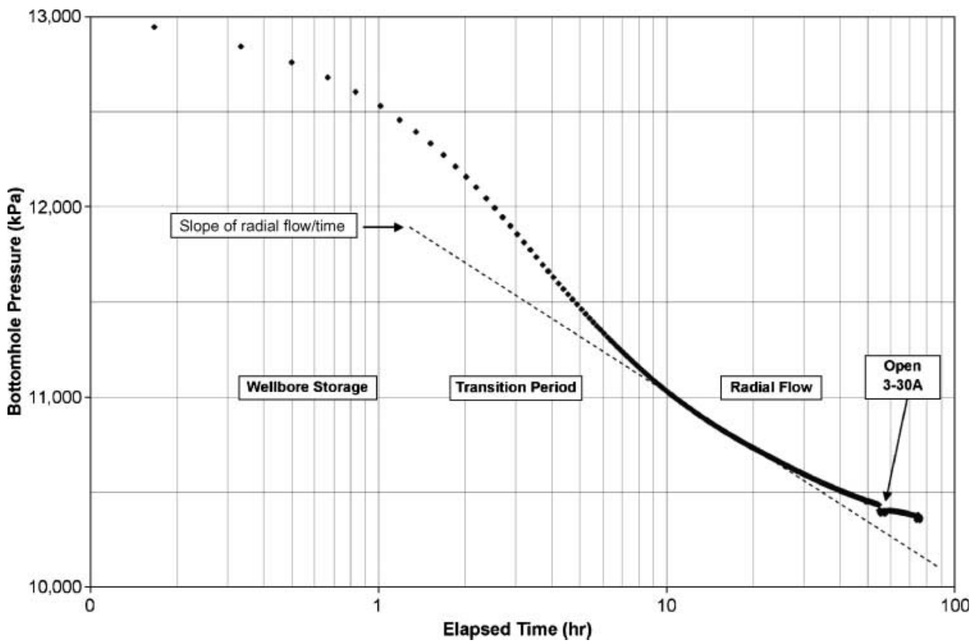
Immediately following the step-rate test, 60 hr of constant injection at 450 t CO_2 per day was performed as part of verifying the mechanical integrity of the test well prior to commencing full-scale injection. Injection was then stopped, and the well was shut in for 72 hr to analyze the pressure response. The bottomhole pressure exhibited a smooth falloff curve, decreasing from 13,800 to 11,000 kPa (Figure 5). Temperatures in the injection well decreased from 31 to 18°C (87.8 to 64.4°F) during injection because the injected CO_2 was cooler than downhole conditions. During shut-in, downhole temperatures rebounded to 27°C (80.6°F).

Pressure falloff was analyzed with falloff test methods (Horner, 1951; Earlougher, 1977). These methods are typically used to estimate permeability from production data in oil and gas wells. For this application, the method was rearranged to solve for permeability based on pressure falloff after injection instead of pressure buildup after production:

$$k = \frac{162.6 \times q \times \beta \times \mu}{m \times h}$$
$$= \frac{162.6 \times 3144.6\ \text{bpd} \times 1.0 \times 1.08\ \text{cp}}{140 \times 73\ \text{ft}} = 54\ \text{md}$$

where k is the permeability (md), h is the thickness (73 ft [22 m]), μ is the viscosity (estimated at 1.08 centipoise

Figure 5. Semilog plot of pressure falloff in the State-Charlton 4-30 injection well after mechanical integrity CO_2 injection tests.



for 20% NaCl brine at 32°C [89.6°F] and 10,100 kPa), q is the injection rate (3144.6 bbl/day based on an average flow rate of 450 t CO_2 per day and a CO_2 density of 0.9 at the wellhead), β is the formation factor (1.0, assumed to be 1.0 for formation fluid), and m is the slope of a semilog straight line through the radial flow part of a semilog plot (~140 from Figure 5).

This is a basic analysis of the falloff data involving several assumptions on viscosity, constant injection rate, and formation factor. However, it does provide a benchmark to compare with site characterization data. Results suggest a permeability of approximately 54 md, somewhat higher than what the site characterization test data averages (22 md).

Pressure falloff analysis assumes the viscosity of formation brine for initial testing because the injection volume is relatively small. The injection test involves the injection of CO_2 into rock formations saturated with dense brine fluids. These fluid mixtures can present complicated multiple-phase flow conditions. However, we assumed that the pressure falloff response generally reflects the overall reservoir instead of the immediate area around the borehole. This may be a less valid assumption for larger CO_2 injection where CO_2 is the prevalent fluid surrounding the borehole. In this case, we estimated brine viscosity at 1.08 centipoise based on downhole pressure and temperature conditions and brine viscosity P-T curves (Matthews and Russell, 1967; Mian, 1992).

A derivative plot of the response curve was plotted using a nearest neighbor method to analyze reservoir behavior (Figure 6). The derivative plot depicts the instantaneous rate of pressure change during the falloff test and can reveal subtle changes in reservoir behavior (Bourdet et al., 1989). The derivative also helps to determine the period of wellbore storage, the transition to radial flow in the reservoir, and the presence of skin effects in the well. The general shape of the derivative plot from the State-Charlton 4-30 well appears to fall in between type curves for a homogeneous reservoir and a reservoir with secondary or fracture porosity. This would seem to match the visual inspection of the rock core from the Bass Islands, which showed a dolomite with some vugular porosity. The derivative plot also suggests the presence of minor wellbore storage and skin effects.

Full Injection Response

After the mechanical integrity test was completed, the full injection test was executed from February 18 through March 8, 2008. The injection rate was increased from 400 to 600 t/day after 1 week as shown in Figure 7. Bottomhole pressures were 13,800–13,930 kPa during injection and were generally stable throughout the 18 days of injection. Some fluctuations were present caused by supply variations at the compression station and other operational interruptions caused by very cold winter conditions in Michigan. Reservoir temperatures generally declined to 16°C (61°F), which reflects the pipeline supply temperature of the injected CO_2. Based on the downhole pressure-temperature conditions, the

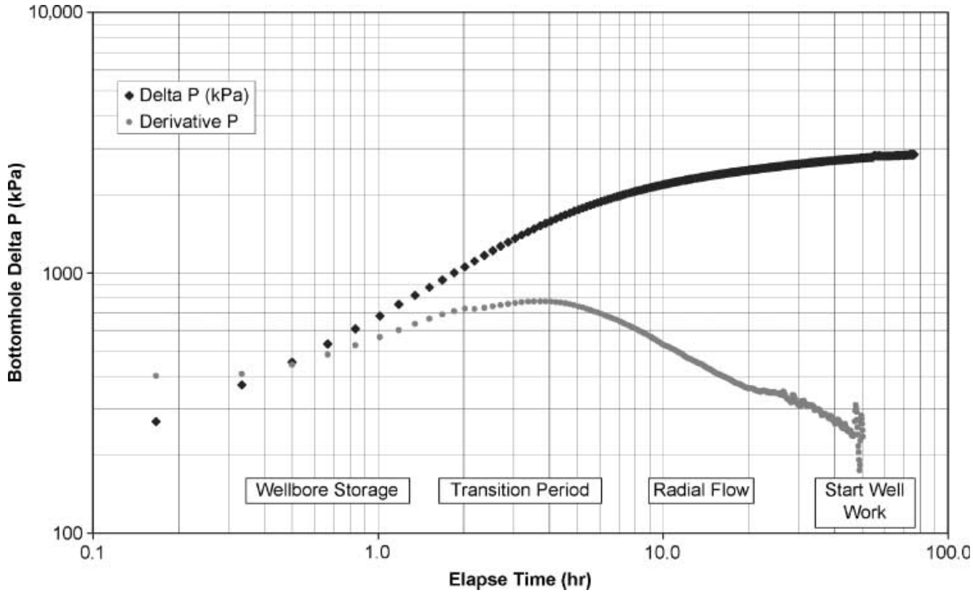


Figure 6. Pressure derivative plot of pressure fall-off in the State-Charlton 4-30 injection well after mechanical integrity CO_2 injection tests.

CO_2 may have had mixed liquid and supercritical phase behavior in the injection well.

Bottomhole pressure response in the State-Charlton 3-30A monitoring well located about 150 m (492 ft) from the injection well showed a 414-kPa increase within the Bass Islands Dolomite formation (Figure 8). Bottomhole pressure in the well appeared to peak only 16 min after the injection was stopped, suggesting a reasonable hydraulic connection between the injection well and the monitoring well. No direct indication of CO_2 breakthrough in the monitoring well was observed. Temperatures in the monitoring well decreased less than 0.05°C (1°F).

Postinjection Response

After injection stopped, the injection well was shut in and the pressure response was monitored. Pressures in

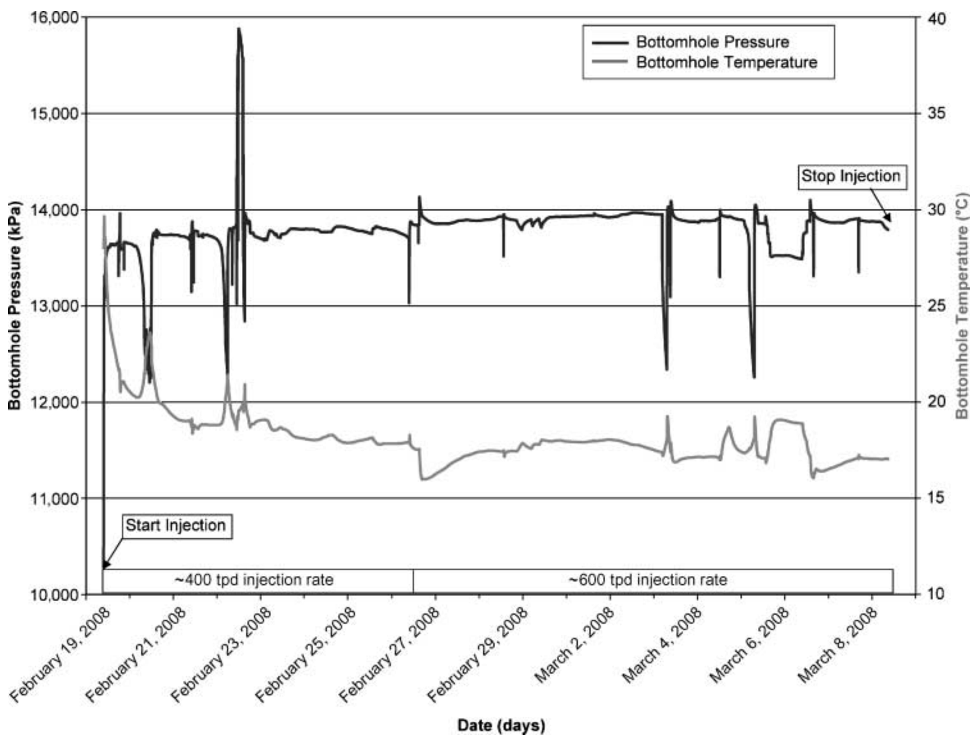


Figure 7. Graph of bottomhole pressure and temperature in the State-Charlton 4-30 injection well during full CO_2 injection tests.

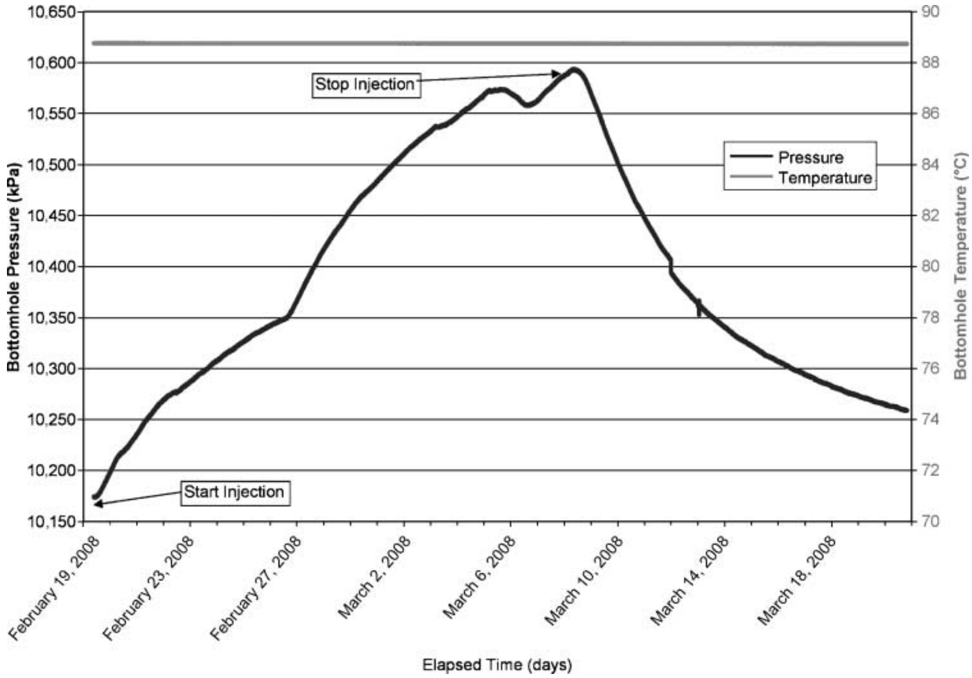


Figure 8. Graph of bottomhole pressure and temperature observed in the State-Charlton 3-30A monitoring well during full CO_2 injection tests.

the injection well declined from 13,790 kPa at the time the injection stopped to within 10% of preinjection levels in 3 days and reached a preinjection level of 10,280 psi in 13 days (Figure 9). Analysis of shut-in response curves suggests a similar response to previous testing. Temperature readings in the bottomhole gauges in the injection well increased from 16.1 to 24.4°C (60.98 to 75.92°F) 20 days after the injection was stopped. Pressure in the monitoring well decreased from a maximum of 10,590 to 10,260 kPa in about 12 days.

Other Monitoring Results

Several other monitoring methods were applied in conjunction with hydraulic monitoring (Gerst et al.,

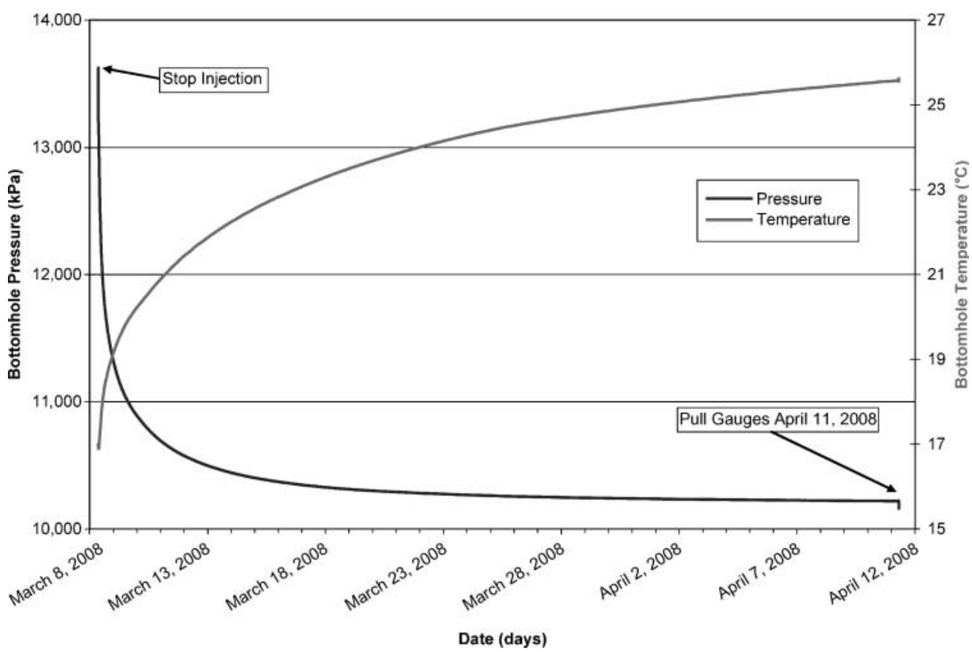


Figure 9. Graph of bottomhole pressure and temperature recovery in the State-Charlton 4-30 injection well after full CO_2 injection tests.

2008). Overall, these techniques supported the results from the hydraulic monitoring. Only one microseismic event, with a magnitude of less than 0, was detected during injection with the microseismic array. No indication of upward leakage was detected in post-injection wireline logging, tracer monitoring at surface soil gas points, and gas meters at the wellhead. Cross-well seismic data showed a decrease in seismic velocities in the Bass Islands Dolomite interval indicative of the presence of CO_2.

A full reservoir model was also developed with the computer code STOMP-WCSE (subsurface transport over multiple phases-water, CO_2, salt, energy) to simulate the CO_2 injection test at the site (Bacon et al., 2008). The model simulates complex, coupled hydrologic, chemical, and thermal processes, including multifluid flow and transport, partitioning of CO_2 into the aqueous phase, and chemical interactions with aqueous fluids and rock minerals. Initial model runs were based on site characterization data and more detailed realizations of reservoir permeability distribution. After the injection test was completed, the model was calibrated to actual injection flow and pressure monitoring field data. The model calibrated with an average reservoir permeability value of 50 md as concluded in the well test analysis, showing an excellent match to the pressure falloff curve seen in the State-Charlton 4-30 injection well. This supports some of the assumptions made in the pressure response analysis; although, because the two methods are based on the same Darcy flow theory, it would follow that the two methods would correspond.

CONCLUSIONS

Well test analysis of CO_2 injection at the site in the Michigan Basin was useful for demonstrating the CO_2 sequestration potential in the region. Existing infrastructure at the site allowed for the injection of a relatively large volume, 10,241 t CO_2. The formation targeted for injection was the Bass Islands Dolomite, which is one of many deep saline formations being considered for CO_2 storage applications in the region. Information gained from this test may be useful for evaluating other sites for CO_2 storage applications. However, geologic reservoirs must be considered on a site-specific basis when designing CO_2 storage systems.

During testing, an injection rate of 400–600 t CO_2 per day was sustained in a single well over 18 days. This is similar to industrial rates necessary for large-scale CO_2 storage applications. Step-rate injection testing appeared to indicate that injection rates greater than 500,000 t CO_2 per year may be possible in the well. A downhole pressure increase of approximately 3500 kPa was observed in the injection well during injection. This equates to a pressure gradient of 13.3 kPa/m, 35% above the hydrostatic pressure gradient. However, only a 414-kPa pressure increase was logged in a monitoring well 150 m (492 ft) away from the injection well, suggesting that high injection pressures did not extend far from the injection well.

Analysis of pressure falloff response observed during postinjection shut-in showed that the overall reservoir permeability was more than twice as high as indicated from rock core testing. The pressure recovery derivative appeared to fall between curve shapes for a homogeneous, porous reservoir and a reservoir with secondary or fracture porosity with some skin effects and wellbore storage. For CO_2 storage reservoir management, the overall transmissivity of the reservoir may be better defined through injection tests than with rock core data alone. It was assumed that the pressure response reflected the native brine fluids in the reservoir because the injection volume was relatively small compared to the total dimensions of the rock formation. Larger injection may be more indicative of CO_2 flow conditions.

As a follow-up to the successful initial injection test at the site, an additional injection phase with up to 50,000 t CO_2 has been authorized by the U.S. Department of Energy. This phase will be combined with additional monitoring and modeling during 2009 to further evaluate the long-term injection pressure response, the presence of boundary conditions, and model accuracy.

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