



November 14, 2008

Mr. Benjamin Deitchman
National Association of State Energy Officials
1414 Prince Street
Suite 200
Alexandria, VA 22314

Dear Mr. Deitchman:

Subject EERC Final Report Entitled “Determination of Carbon Dioxide Storage Capacity and Enhanced Coalbed Methane Potential of Lignite Coals”, EERC Fund 9157

Enclosed please find the subject report. If you have any questions, please contact me by phone at (701) 777-5287 or by e-mail at jsorensen@undeerc.org.

Sincerely,

James A. Sorensen
Senior Research Manager

JAS/sah

Enclosure

c/enc: Michelle New, National Association of State Energy Officials

DETERMINATION OF CARBON DIOXIDE STORAGE CAPACITY AND ENHANCED COALBED METHANE POTENTIAL OF LIGNITE COALS

Final Report

Submitted to:

Michelle New

National Association of State Energy Offices (NASEO)
State Technologies Advancement Collaborative (STAC)
1414 Prince Street
Suite 200
Alexandria, VA 22314

Submitted by:

James A. Sorensen

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58208-9018

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DETERMINATION OF CARBON DIOXIDE STORAGE CAPACITY AND ENHANCED COALBED METHANE POTENTIAL OF LIGNITE COALS

EXECUTIVE SUMMARY

Coal seams are known to have the ability to store significant amounts of gases by adsorbing them. A key research objective of the State Technologies Advancement Collaborative (STAC) Program is to mitigate emissions from electric power production through the development of technologies that simultaneously use the injection of carbon dioxide (CO₂) into coal seams for storage and enhanced coalbed methane (ECBM) recovery. The objectives of the Energy & Environmental Research Center (EERC) project conducted under the STAC Program are to develop estimates of the methane content and CO₂ storage capacity of lignite coals in western North Dakota and eastern Montana and to determine the potential for application of CO₂-based ECBM to those coals.

Previous laboratory- and field-based research projects have focused on bituminous or subbituminous coals, and their results are not entirely applicable to lignite coals. Permeability and gas sorption capacity are two key characteristics of coal that are known to vary according to rank. To address the lack of data available on lignite, an unminable lignite seam in Burke County, North Dakota, was characterized, sampled, and analyzed. Gas content data, coal quality data, permeability, and CO₂ and CH₄ sorption isotherm data have been generated to determine if CO₂ injection into a lignite would be feasible and enhance CH₄ recovery. Key findings of the project include the following:

- The methane content of the Burke County lignite seam is very low, ranging from 0.75 to 1.72 scf/ton, indicating limited ECBM opportunities in the study area lignite.
- The low vitrinite reflectance values and maceral group composition data for the Burke County lignite, when considered with respect to the low gas content values observed for the lignite, are consistent with the relationships that have been observed in other North American and European coals.
- Methane and CO₂ adsorption isotherm data indicate that the Burke County lignite has a considerably higher (approximately 1 order of magnitude) capacity to adsorb CO₂ than methane.
- Permeability test results suggest that the adsorption of CO₂ may cause lignite to swell significantly, resulting in a loss of permeability in the coal seam which, in turn, may translate into reduced injectivity.

The theoretical maximum CO₂ storage capacity of the evaluated Burke County coal seam in a 300-square-mile study area was estimated to be approximately 128 million tons, or 427,000 tons per square mile.

It is important to note that there are currently no field-based data on the ability of lignite to adsorb CO₂ or produce methane to verify the laboratory-based observations and conclusions of this project. While the results provide valuable insight that was previously unavailable, until such field-based data are developed for comparison and verification, they should in many ways be considered to be preliminary and applied with caution.

DETERMINATION OF CARBON DIOXIDE STORAGE CAPACITY AND ENHANCED COALBED METHANE POTENTIAL OF LIGNITE COALS

PROJECT OBJECTIVES

A key research objective of the State Technologies Advancement Collaborative (STAC) Program is to mitigate emissions from electric power production through the development and optimization of field practices and technologies that simultaneously utilize the injection of carbon dioxide (CO₂) into unminable coal seams for sequestration and enhanced coalbed methane (ECBM) recovery.

The objectives of the Energy & Environmental Research Center (EERC) project are to develop estimates of the gas content and CO₂ storage capacity of lignite coals in the Fort Union Group of the North Dakota and Montana portions of the Williston Basin and to determine the potential for application of CO₂-based ECBM in those coals.

BACKGROUND

Coal seams are known to have the ability to store significant amounts of gases by adsorbing them. The capacity of coal to store CO₂ is significantly greater than its capacity to store CH₄, which is the principal component of the sorbed-phase natural gas in coalbed reservoirs. The net ratio of CO₂ injected to CH₄ recovered is not 1:1 but, instead, varies from 2:1 to as high as 10:1 (Seidle, 2000; Wong et al., 2000; Stricker and Flores, 2002; Nelson, 2003b; Carroll and Pashin, 2003). This storage mechanism occurs naturally and is well documented, suggesting that a gas, particularly CO₂, can be reliably stored in coal seams.

Several factors make this research project both timely and important. First, coal-fired electric power plants in North Dakota and Montana generate significant quantities of CO₂, which is currently emitted directly to the atmosphere. According to the U.S. Environmental Protection Agency (EPA), in 1999, Montana and North Dakota produced 22.19 MMTCE (million metric tons carbon equivalent) of anthropogenic CO₂ (see Table 1). The major stationary sources (utility and industrial) contributed 17.51 MMTCE, or more than three-fourths of the total for the two states. The utility sector, which in Montana and North Dakota is represented almost exclusively by coal-fired electric power plants, contributed 12.89 MMTCE, representing over half of the CO₂ emissions for the two states (U.S. Environmental Protection Agency, 2004).

Table 1. Summary of 1999 CO₂ Emissions in Montana and North Dakota (MMTCE)

State	Utility	Industrial	Other Stationary	Transportation	State Total
MT	4.36	1.43	0.54	2.04	8.37
ND	8.53	3.19	0.55	1.55	13.82
Total	12.89	4.62	1.09	3.59	22.19

To meet the President's Global Climate Change Initiative (GCCCI) goal, carbon intensity (ratio of greenhouse gas emissions to economic output, or gross domestic product) in North Dakota and Montana would need to be reduced 18% (approximately 4 MMTCE) by 2012. In order to achieve the GCCCI goal, it is imperative that approaches and technologies be identified and developed that will facilitate the economical sequestration of large volumes of CO₂ (White et al., 2003).

Unminable coal seams are among the types of geological formations that are being considered by industry and government agencies for use as sites for geological CO₂ sequestration (Wong et al., 2000; White et al., 2003). All of the coal-fired power plants in western North Dakota and eastern Montana are located directly on top of or proximal to significant deposits of lignite or subbituminous coal. Many of these coal deposits occur at depths greater than 350 feet, which renders them uneconomical for recovery by surface mining and, thus, potentially viable targets for CO₂ sequestration (Stricker and Flores, 2002). The North Dakota portion of the Williston Basin (Figure 1) has an estimated 351 billion tons of lignite contained within the rock formations of the Fort Union Group (Figure 2). The Fort Union Group is a clastic wedge that thins from eastern Montana into central North Dakota. In western and central North Dakota, the Fort Union Group covers an area of approximately 32,000 square miles and consists of five formations of which four are coal-bearing strata (Murphy, 2001). A dozen or more coalbeds, the majority of which are only a few feet thick, may underlie any given place in western North Dakota and eastern Montana. The results of the project will provide previously unavailable insight regarding the potential to store CO₂, and perhaps simultaneously produce CBM, in the major lignite coal seams that underlie western North Dakota and eastern Montana.

Second, absent regulatory drivers or carbon credits, CO₂ sequestration in unminable coal seams would most likely only be conducted in areas where natural gas recovery would provide a value-added revenue stream to partially offset the cost of the CO₂ capture and sequestration processes (Wong et al., 2000; White et al., 2003). While bituminous and subbituminous coals have been proven to contain large reserves of natural gas, little work has been done to determine the potential natural gas reserves within lignite coals. Many regions of the United States have vast resources of lignite coal, including North Dakota, Montana, Alaska, and Texas (Nelson, 2000a, 2001 and 2003a). The project results shed light on whether a lignite coal seam in western North Dakota contains natural gas resources.

Third, it is not anticipated that all coalbed gas reservoirs will be suitable candidates for CO₂ sequestration or application of ECBM technology. Laboratory and field studies of CO₂ sequestration and CO₂-related ECBM have been conducted in several regions of North America. Three of the most well-documented ECBM evaluations include projects conducted in Colorado, Alberta, and Alabama. Burlington Resources has conducted pilot-scale CO₂-related ECBM evaluations in coalbed reservoirs in the San Juan Basin; the Alberta Research Council has conducted pilot-scale CO₂ sequestration studies in coal seams in southern Alberta, Canada; and the Alabama Geological Survey evaluated the CO₂ sequestration potential of coalbed reservoirs in the Warrior Basin (Nelson, 2000a, Wong et al., 2000; White et al., 2003; Carroll and Pashin, 2003). These laboratory research and field projects have focused on bituminous or

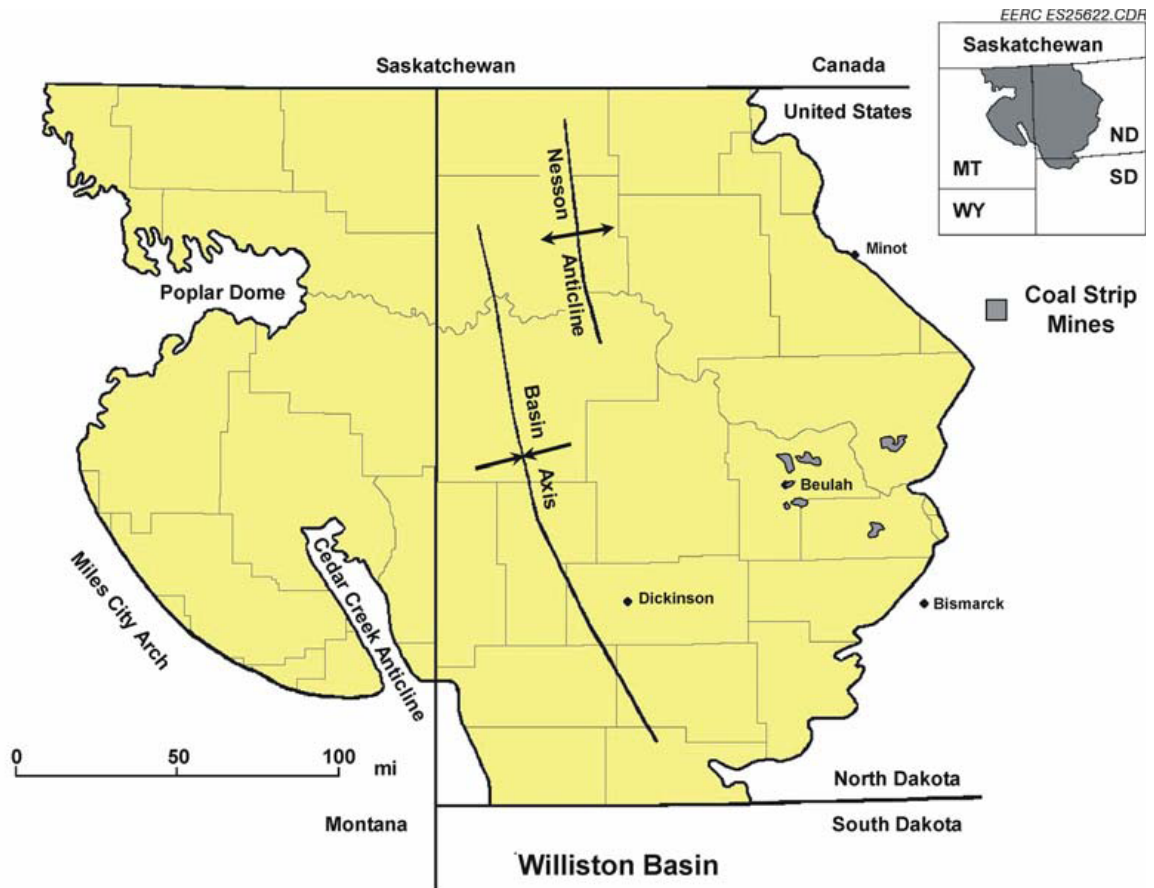


Figure 1. Map showing the areal extent of lignite resources and major structural features within the North Dakota and Montana portions of the Williston Basin.

subbituminous coals, and their results, although relevant, are not entirely applicable to the lignite coals of the Williston Basin. Permeability and gas sorption capacity are two key characteristics of coal that are known to vary significantly according to coal rank. The results of the Colorado, Alberta, and Alabama projects, therefore, have limited applicability to lignite coals. With this in mind, permeability and sorption isotherm tests have been conducted in order to determine if CO₂ injection into a lignite would be feasible and would enhance CH₄ recovery from a lignite reservoir. The project has experimentally evaluated the permeability and the CO₂ and CH₄ storage capacity characteristics of a North Dakota coal seam. Specifically, a coal seam in a study area in Burke County in northwestern North Dakota (Figure 3) was characterized, sampled, and analyzed as part of this project.

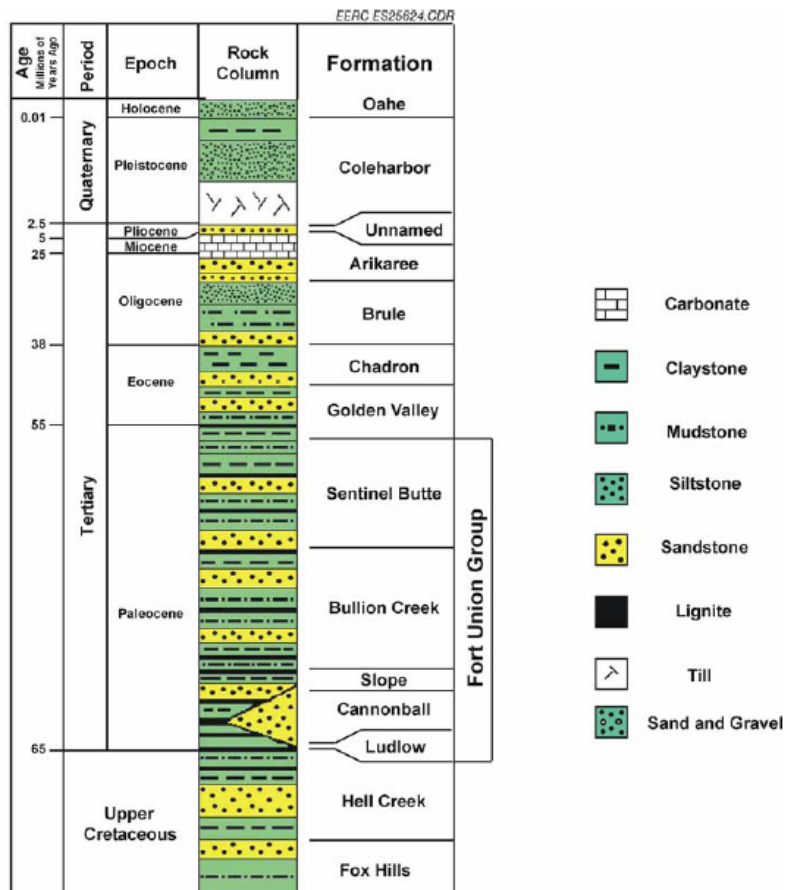


Figure 2. Composite stratigraphic column (Upper Cretaceous to Quaternary) in North Dakota (modified after Murphy and Goven, 1998).

STUDY SITE LOCATION – BURKE COUNTY, NORTH DAKOTA

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



Figure 3. Location of the lignite study site relative to the state of North Dakota.

The following criteria are currently used by the state of North Dakota to assess the economic feasibility of coal mining (Ed Murphy, personal communication, 2007):

- A minimum cumulative coal thickness of 3 m (10 feet)—typically occurring in one or two beds
- A minimum individual bed thickness of 0.76 m (2.5 feet)
- A maximum stripping ratio of 10 feet of overburden for every foot of coal
- A minimum of 6 m (20 feet) of overburden to minimize the effects of weathering
- Coal depth is less than 52 m (170 feet)

At a depth of over 300 m (1000 ft), the lignite seam examined by this project is considered to be unminable.

The site for the EERC CO₂ sequestration–ECBM project is located in Section 36, Township 159 North, Range 90 West in southeastern Burke County, North Dakota (Figure 3). In the Burke County project area, the coal seam that is the focus of this study is approximately 3 m (10 ft) thick. Lateral continuities of lignite seams vary greatly; in general, thicker seams are more continuous than thinner beds. According to well log data obtained from the North Dakota Department of Mineral Resources (NDDMR), the coal seam of interest can be traced within a

4-mile radius of the project site. The targeted coal seam is a part of the lower Fort Union Formation at an approximate depth of 335 m (1100 ft). The composite stratigraphic column of the section is shown in Figure 2. The test is designed in a five-spot configuration, allowing for an effective data collection program. Figure 2 shows a map of the study site. The five wells were drilled in August 2007. Development of the wells was conducted over the summer of 2008 in an effort to maximize communication between the wells and the target lignite seam. The study of the lignite and its properties has been conducted in two scales: laboratory and field scale. The following subsections describe the results of the study.

Laboratory Tests on Burke County Coal Core Samples

In August 2007, five wells were drilled at the Burke County lignite test site. On August 14, 2007, approximately 10 feet of core, most of which was from the lowermost coal seam in the study area, was collected from Well 36-15C (the well marked in green on Figure 4). The data presented and discussed in this report were generated from tests conducted on the coal from this core. The testing program consisted of a wide variety of tests, including canister desorption followed by bulk density, moisture, and ash measurements. Other tests included vitrinite reflectance, maceral, and proximate/ultimate/Btu analyses. Additionally, permeability and methane and CO₂ adsorption isotherm measurements were taken.

Canister Desorption Measurements

The 3-inch-diameter core was extracted from the subsurface and divided into three samples each 1ft long (Figure 5). The corresponding driller depths are as follows: Sample 1 – 1084.5 ft to 1085.5 ft, Sample 2 – 1086.0 ft to 1087.0 ft, and Sample 3 – 1089.0 ft to 1090.0 ft. Samples 1–3 were placed in desorption canisters at the well site (Figure 6). The canisters were maintained at reservoir temperature. Desorption data were collected from the samples for a period of time on location. The canisters containing the samples were then transported to the laboratory for continued desorption.

Upon arrival at the laboratory, the canisters were maintained at reservoir temperature and underwent continued long-term desorption. After completion of the long-term desorption, the samples were removed from the canisters, and sample mass and bulk density were measured. Lost gas calculations were performed using the U.S. Bureau of Mines (USBM) Direct Method (Diamond and Levine, 1981) and the Smith and Williams Unipore Model (Smith and Williams, 1984). Table 2 summarizes the results of the gas content and bulk density measurements. Generally speaking, the methane content of the Burke County lignite seam samples is very low, ranging from 0.75 to 1.72 scf/ton. Considering that the gas content of commercial CBM-producing coals generally ranges from tens of scf/ton (as in the Powder River Basin) to hundreds of scf/ton (as in the San Juan Basin), the data generated by this project suggest that there is a very low likelihood that CBM could be commercially produced from the Burke County lignite seam using conventional CBM drilling, completion, and production techniques. However, it is important to note that this is the first attempt to quantify gas content from a lignite core, and it is possible that a significant amount of gas may have been lost from the sample during the transit time to bring the core from the reservoir depth to



Figure 4. Map of the Burke County study site. Core were collected from the center well which has been designated as a possible CO₂ injection/CBM production well for a future pilot-scale ECBM project.



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



Figure 6. Canisters and apparatus used in the field to maintain core samples at reservoir conditions as part of the gas content analysis procedure.

Table 2. Summary of USBM Gas Content and Bulk Density Measurements

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

the surface. Gas content data generated from coal cuttings collected from a deeper and thicker coal seam in the southwestern part of North Dakota in 2001 (Nelson, 2003) showed methane to be as high as 12 scf/ton. While that value is still low by Powder River Basin or San Juan Basin coal standards, it is significantly higher than the Burke County gas content values and suggests that exploration for CBM resources in lignite coals may yet bear fruit.

Vitrinite Reflectance/Maceral Analysis

Vitrinite reflectance can be used as an indicator of thermal maturity, while maceral group composition has been identified as one of the controlling factors for sorption capacity and gas content. Several studies on North American and European coals indicate that vitrinite-rich coals have higher sorption capacities than inertinite-rich coals, although some studies have alternatively shown no systematic variation. In fact, studies of Australian low-rank coals indicate

that for some low-rank coals, inertinite may have a higher sorption capacity than vitrinite (Mohinudeen and Sherwood, 2006). The vitrinite reflectance/maceral analyses were conducted in accordance with ASTM D 2798 (Storer, 1996a) specifications. A subsample was potted in epoxy, compressed in a mold, and allowed to air-dry for 2 days. Following curing, the pellets were ground and polished according to ASTM D 2798 specifications. Table 3 summarizes the vitrinite reflectance measurements, while Table 4 presents the maceral analysis results. The low vitrinite reflectance values and maceral group composition data for the Burke County lignite, when considered with respect to the low gas content values observed for the lignite, are consistent with the relationships that have been observed in other North American coals (Mohinudeen and Sherwood, 2006). However, it should also be noted that the work on Australian low-rank coals suggests that relationships between maceral group content and reservoir properties may vary between and within areas of CBM exploration; therefore, predictions on resource and producibility simply on the basis of vitrinite reflectance and maceral analysis may be misleading.

Proximate/Ultime/Btu

The proximate/ultimate/Btu analytical data provide additional insight regarding the nature of the coal, particularly with respect to determining rank. Each of these factors may exert influence on the sorption characteristics of a coal. The relationships of these factors to CBM production and/or

Table 3. Summary of Vitrinite Reflectance Measurements

Sample	Depth	Min. R _o	Max. R _o	Mean R _o	Rank
3	1089.0-90.0	0.17	0.34	0.24	Lignite

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

Maceral/Sample	3 1089.0-90.0
Vitrinite	52.00
Detrovitrinite	45.60
Telovitrinite	6.40
Liptinite	2.10
Sporinite	2.00
Cutinite	0.00
Resinite	0.10
Exudanite	0.00
Inertinite	45.90
Micrinite	0.40
Fusinite	7.80
Semifusinite	37.70
Macrinite	0.00
Detroinertinite	0.00

CO₂ storage potential within a given coal are complex and often not well understood (especially with respect to lignite, for which there is substantially less published data), and detailed discussion of those relationships and their potential consequences is beyond the scope of this report. However, each are used in a variety of CBM static and dynamic modeling software packages to predict CBM productivity and/or CO₂ sorption; therefore, the Burke County coal was analyzed for these data, and they are provided in this report. Proximate/ultimate analysis testing was performed in accordance with ASTM D 3172 (Storer, 1990b) specifications. Moisture, volatile matter, and ash contents were measured by heating the samples and observing the weight loss. Time, temperature, and atmospheric conditions were rigorously maintained. Fixed carbon was calculated by subtracting the summation of percent moisture, ash, and volatile matter from 100%. The specific energy (Btu) was measured on the samples according to ASTM D 2015 (Storer, 1990c). A weighed portion of the sample and Eschka mixture (BaCl₂ solution) were electrically ignited together in a submerged pressure-resistant cylinder. Following combustion, the temperature of the submerging fluid was monitored. The amount of heat given off by the sample was determined from the temperature rise by reference to previous calibration runs with a thermochemical standard. The results of these analyses are summarized in Table 5. Perhaps the most notable result of these analyses on the Burke County coal sample is that based on the values generated for these specific factors, the Burke County coal was actually classified as being a subbituminous coal rather than a lignite.

Methane and Carbon Dioxide Adsorption Isotherms

Methane and CO₂ desorption isotherms were experimentally developed for the Burke County lignite seam from core samples. The isotherms provide a means to quantify the potential adsorptive capacity for the coal with respect to methane and CO₂. The adsorption isotherm testing consisted of exposing the moisture-prepared coal sample at reservoir temperature to the methane or carbon dioxide gas at a series of pressures calculated to yield the desired equilibrium adsorption pressures. Each adsorption step consisted of charging a reference vessel to a calculated starting pressure. After allowing for stabilization of the pressure and temperature, the pressure was released from the reference vessel into the sample chamber. The pressure was monitored until equilibrium was achieved. The resulting data were analyzed using Boyle's law. Gas compressibility and changes in dead volume due to adsorbed gas were considered in the data reduction process. The results of these analyses are summarized in Table 6 and presented in Figures 7 and 8. The data indicate that the Burke County lignite has a considerably higher capacity to adsorb CO₂ than methane.

Table 5. Summary of Proximate/Ulimate/Btu Analysis (as-received, dry and dry-ash free [DAF] basis)

Sample 3		Proximate/Ulimate Analysis, wt %					
Moisture	Ash	Volatile Matter	Fixed Carbon	Heating Value	Sulfur	Coal Rank	
26.83	9.53	27.60	36.04	7657	0.16	Subbituminous C	
0	13.02	37.72	49.26	10,465	0.22		
0	0	43.37	56.63	12,032	0.25		
Moisture	Ash	Hydrogen	Carbon	Nitrogen	Sulfur	Oxygen	
26.83	9.53	2.36	46.80	0.65	0.16	13.67	
0	13.02	3.23	63.96	0.89	0.22	18.68	
0	0	3.71	73.54	1.02	0.25	21.48	

Table 6. Summary of Adsorption Isotherm Analysis

Sample No. 3		Gas Content			
Methane	Langmuir Parameters	Pressure, psia	Raw Basis, scf/ton	Dry Basis, scf/ton	DAF Basis, scf/ton
Depth	$V_{I_{raw}} = 89.4$	37	2.4	3.6	4.2
1089.0'–90.0'	$PI_{raw} = 1088.5$	86	6.2	9.1	10.5
EQ H ₂ O		135	9.7	14.3	16.5
= 32.17%	$V_{I_{dry}} = 131.8$	203	15.6	23.0	26.5
Ash = 9.00%	$PI_{dry} = 1088.5$	369	24.3	35.8	41.3
		525	31.5	46.4	53.5
Grain Density	$V_{I_{daf}} = 152.0$	845	40.3	59.4	68.5
= 1.359 g/cc	$PI_{daf} = 1088.5$	1242	47.3	69.8	80.5
		1818	54.5	80.3	92.6

Sample No. 3		Gas Content			
Carbon Dioxide	Langmuir Parameters	Pressure, psia	Raw Basis, scf/ton	Dry Basis, scf/ton	DAF Basis, scf/ton
Depth	$V_{I_{raw}} = 898.9$	27	47.1	69.4	80.0
1089.0'–90.0'	$PI_{raw} = 500.3$	51	84.0	123.9	142.9
EQ H ₂ O		82	124.9	184.2	212.4
= 32.17%	$V_{I_{dry}} = 1325.2$	135	189.3	279.1	321.8
Ash = 9.00%	$PI_{dry} = 500.3$	197	246.1	362.8	418.3
		292	325.2	479.4	552.7
Grain Density	$V_{I_{daf}} = 1528.0$	397	401.0	591.2	681.7
= 1.359 g/cc	$PI_{daf} = 500.3$	514	462.3	681.6	785.9
		662	510.7	752.9	868.1

Permeability Measurements

Permeability at Atmospheric Pressure

Permeabilities for He and CO₂ were measured at pressures close to the atmospheric pressure. The goal of these experiments was to determine the permeability of the coal that would be expected to exist at the beginning of a CO₂ injection project. The confining pressure on the core was kept constant at 480 psig. A Setra Instruments pressure transducer, with a range of 0–25 psig, was used for measuring differential pressures. Flow rates were measured with an Omega flowmeter, with a range of 0–10 cc/min. Because of the low flow rates measured in this first step, the viscosity coefficient and permeability values from Darcy's law may be affected by errors (gas permeability in porous media with low permeability can be affected by molecular slippage at the wall, known as the Klinkenberg effect). From Table 7, the average initial permeability for CO₂ was 0.620 mD for the average flow rate of 0.1274 cc/sec. For helium, the average permeability was 0.533 mD for the average flow rate of 0.0652 cc/sec.

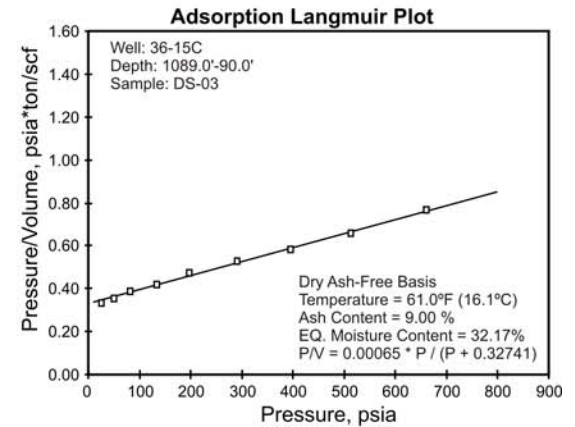
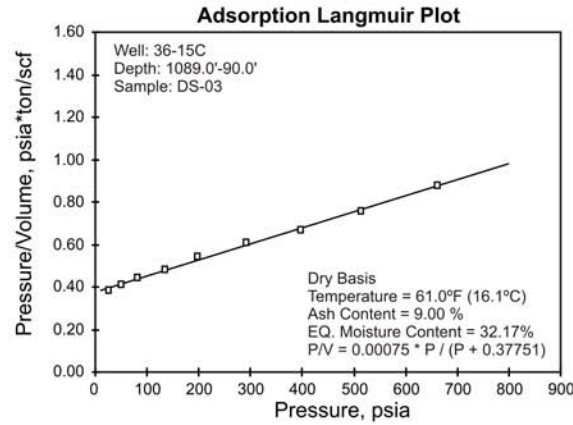
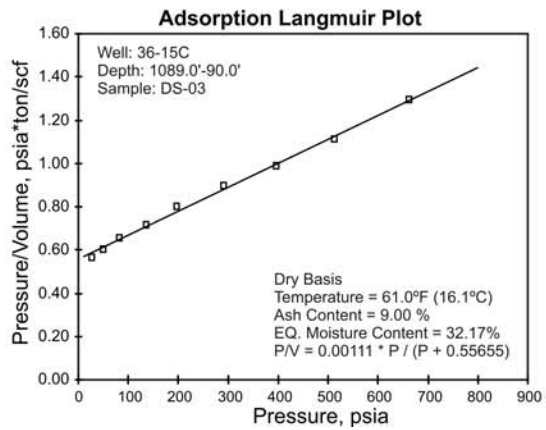
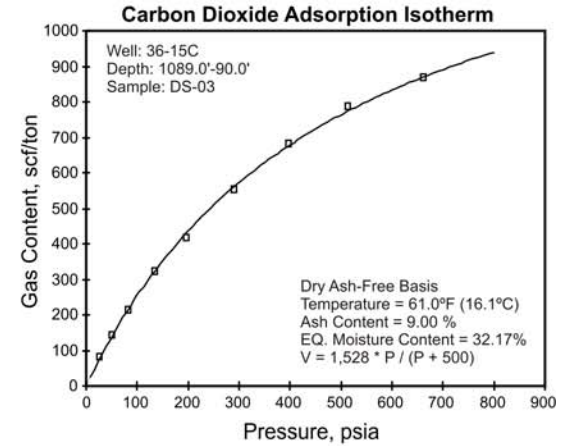
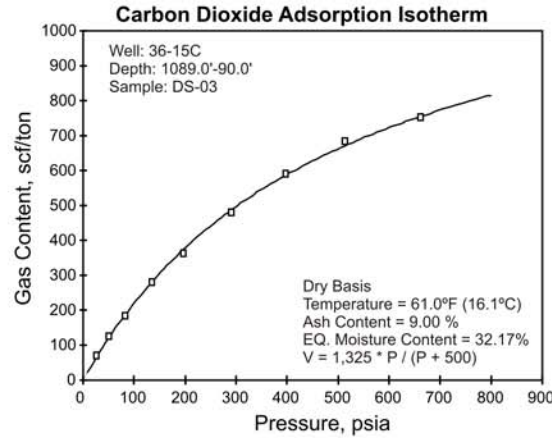
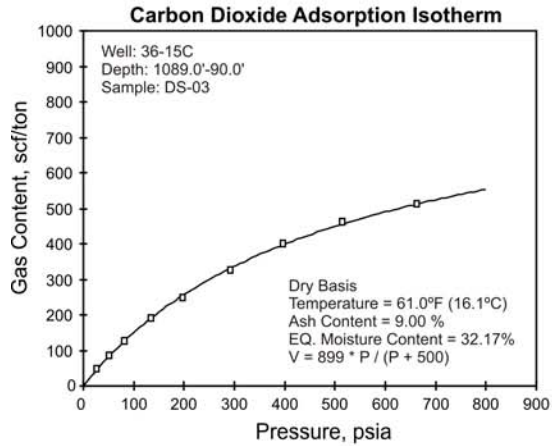
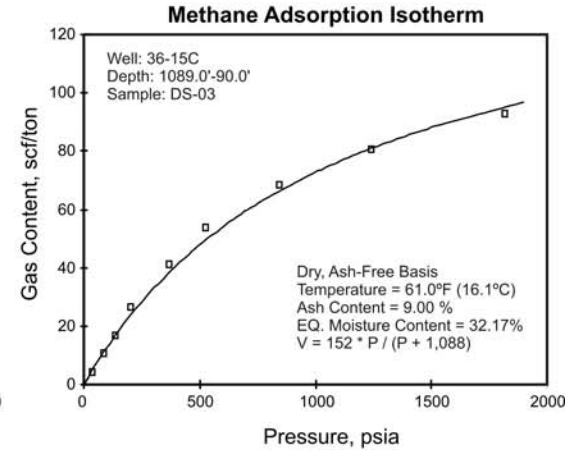
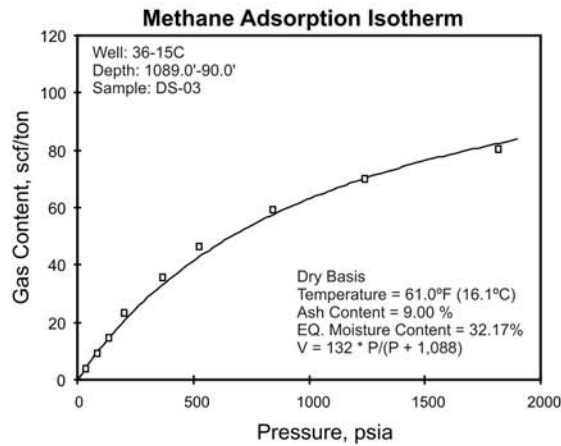
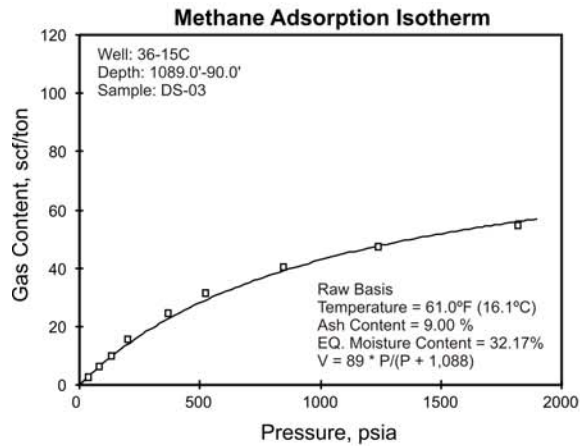


Figure 7. Carbon dioxide isotherms.



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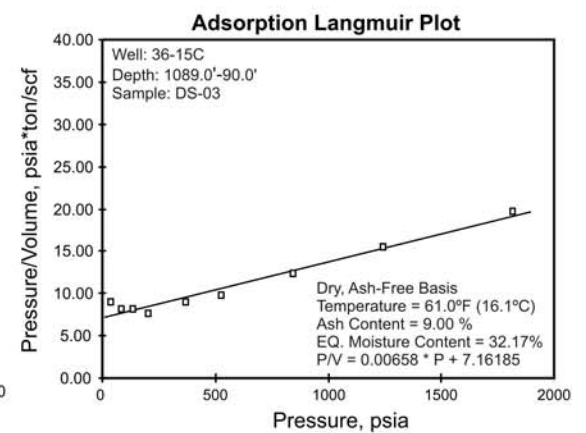
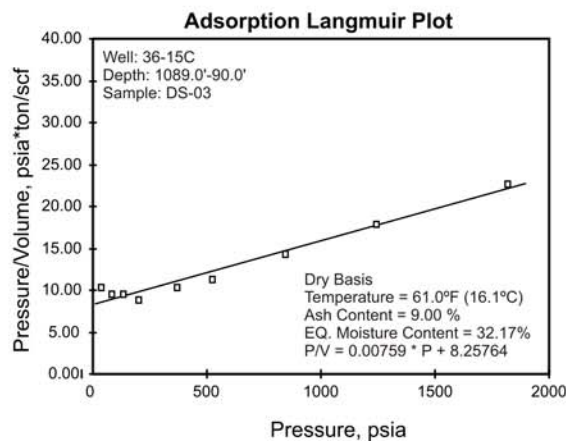
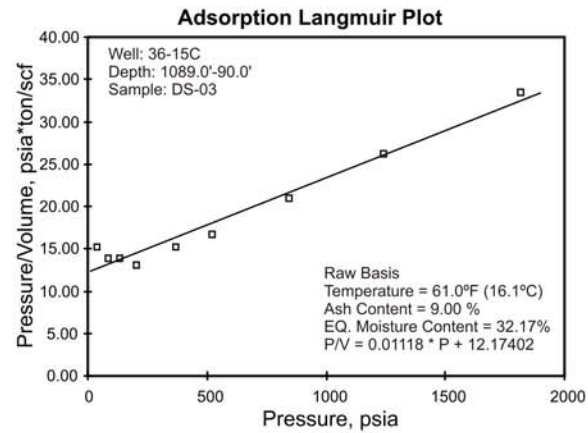


Figure 8. Methane adsorption isotherms.

Table 7. Permeabilities for He and CO₂ Measured with the Core Outlet at Atmospheric Pressure

Gas	Core Length cm	Core Diameter cm	Area sq. cm	Gas Visc. cP	Flow Rate cc/min	Flow Rate cc/s	Delta P psig	Poutlet atm	Pinlet atm	Calculated Permeability mD
He	4.3434	3.7897	11.2774	0.0198	2.9130	0.0486	6.8172	0.9658	1.4669	0.6073
He	4.3434	3.7897	11.2774	0.0198	3.5900	0.0598	9.1630	0.9658	1.6276	0.5317
He	4.3434	3.7897	11.2774	0.0198	5.2400	0.0873	13.9600	0.9658	1.9562	0.4603
CO ₂	4.3434	3.7897	11.2774	0.0149	6.8150	0.1136	11.9600	0.9658	1.8192	0.5485
CO ₂	4.3434	3.7897	11.2774	0.0149	7.4467	0.1241	11.9500	0.9658	1.8185	0.6000
CO ₂	4.3434	3.7897	11.2774	0.0149	7.9370	0.1323	11.8800	0.9658	1.8137	0.6442
CO ₂	4.3434	3.7897	11.2774	0.0149	8.3760	0.1396	11.7600	0.9658	1.8055	0.6885

Permeability Using a Back Pressure Regulator

Largely because previous laboratory data indicated that lignite has a large capacity to adsorb CO₂, there was some concern that lignite would swell as CO₂ was adsorbed, resulting in a loss of permeability over the course of injection which could adversely affect such an operation. Therefore, the permeability of the core was measured after it was exposed progressively to CO₂ for a long period of time (695 hours). A Tescom dome-loaded back pressure regulator was used to set the outlet pressure at 800 psig. Consequently, the confining pressure was set at 1280 psig. For flow rate measurement, a 0–2000-cc/min Omega flowmeter was used. The results in Table 8 show an average permeability of 0.494 mD at an average flow rate of CO₂ inside the core of “15 cc/sec. These results suggest that the adsorption of CO₂ may result in a loss of permeability in the coal seam which, in turn, may translate into reduced injectivity. The literature suggests that the presence in the system of nitrogen, which is chemically inert and not adsorbed by the coal, may serve to essentially prop open the cleat structure of coal, thereby having an offsetting affect on the permeability and injectivity of a coal seam into which CO₂ is being injected.

Table 8. Permeabilities for CO₂ Measured with the Core Outlet at 800 psig

Gas	Core Length cm	Core Diameter cm	Area sq. cm	Gas Viscosity cP	z	Flow Rate cc/min	Flow Rate cc/sec	delta P psig	Poutlet atm	Pinlet atm	Calculated permeability mD
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	745	12.4167	32.2400	54.7945	57.0027	0.4099
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	745	12.4167	31.1000	54.7945	56.9247	0.4255
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	753	12.5500	30.1200	54.7945	56.8575	0.4446
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	754	12.5667	29.2000	54.7945	56.7945	0.4597
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	747	12.4500	29.0000	54.7945	56.7808	0.4587
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	721	12.0167	28.0000	54.7945	56.7123	0.4591
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	731	12.1833	27.1000	54.7945	56.6507	0.4815
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	857	14.2833	29.0000	54.7945	56.7808	0.5262
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	987	16.4500	31.6000	54.7945	56.9589	0.5544
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	1012	16.8667	33.4000	54.7945	57.0822	0.5366
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	1054	17.5667	34.8000	54.7945	57.1781	0.5355
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	1052	17.5333	34.4000	54.7945	57.1507	0.5410
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	1058	17.6333	37.0000	54.7945	57.3288	0.5042
CO ₂	4.3434	3.7897	11.2774	0.0191	0.5848	1310	21.8333	40.0000	54.7945	57.5342	0.5754

FIELD-BASED TESTS AND DATA

A Schlumberger Sonic Scanner log and the Schlumberger Platform Express logging suite were run in the central well at the Burke County lignite site. These geophysical well-logging technologies can be used to characterize a wide variety of reservoir parameters. The sonic log generates data that can be used to predict pore pressure, determine density, and estimate geomechanical properties such as rock elastic constants and bulk compressibility. The Platform Express logging suite provides measurements of porosity, resistivity, sand/shale content, and borehole diameter. An example of interpreted geophysical logs for the five wells is provided in Figure 9. The logs indicate that the primary target zone is a coal seam that is occasionally bifurcated, in places separated by approximately 1 to 2 feet of sandy clay. The total thickness of the seam is approximately 10 to 12 feet. The seam is overlain by a continuous layer of clay approximately 4 feet thick, which may provide a suitable seal for a CO₂ injection test.

In the case of the Burke County site, because of poor consolidation of the rocks in this section, thorough geomechanical analysis was not possible, although the interpretation of sonic scanner data provided some valuable information. Particularly, acoustic data indicate that a developed cleat system might not be present in the coal. This conclusion is in agreement with direct core observations and is important for the prediction of injection performance. Sonic data also indicate that the stress field in the coal is likely to be homogeneous, with the maximum principal stress being the pressure of overburden with minimal influence of tectonic forces. This sets limitations on injection rates, which should be maintained low enough to prevent vertical fracturing of the coal and any subsequent out-of-zone fluid migration. The data also indicated that drilling of the well may have resulted in the creation of a significant damage zone (>1.2 m [4 ft]) around the wellbore. This conclusion is also in agreement with data from subsequent field operations focused on development of the wells to determine hydrogeologic properties of the system. Indeed, in the initial stages of well development, none of the wells drilled into the lignite seam yielded substantial fluid volumes. Development of the wells was conducted by employing different stimulation techniques, including swabbing, sonic hammer, nitrogen minifrac, and acid treatment. Acid treatment provided the best result with respect to the development of the wells. Nitrogen treatment and pressure transient analysis have resulted in a conclusion that the reservoir is sufficiently underpressured, with an estimated pressure of $p = 2.38$ MPa (345 psi), while the normal pressure gradient at the reservoir depth would yield pressure of about $p = 3.2$ MPa (470 psi). This may largely explain the damage to the zone around the wells. Specifically, the evidence indicates that the wells were drilled using a significantly overbalanced drilling mud density (e.g., higher density than was required to maintain borehole stability). This meant that drilling fluid, and later cement, could penetrate deep into the formation. The underlying mechanism responsible for the underpressured condition of the reservoir is not quite understood. However, under pressure can be attributed to the expansion of the reservoir rocks in response to uplift and erosion (Spencer, 1988). Studies of the Williston Basin have indicated that evidence exists for these effects in many formations (Fischer et al., 2005). Isostatic rebound from the geologically recent removal of glacial ice from Burke County at the end of the Pleistocene Ice Age may also account for expansion due to uplift.

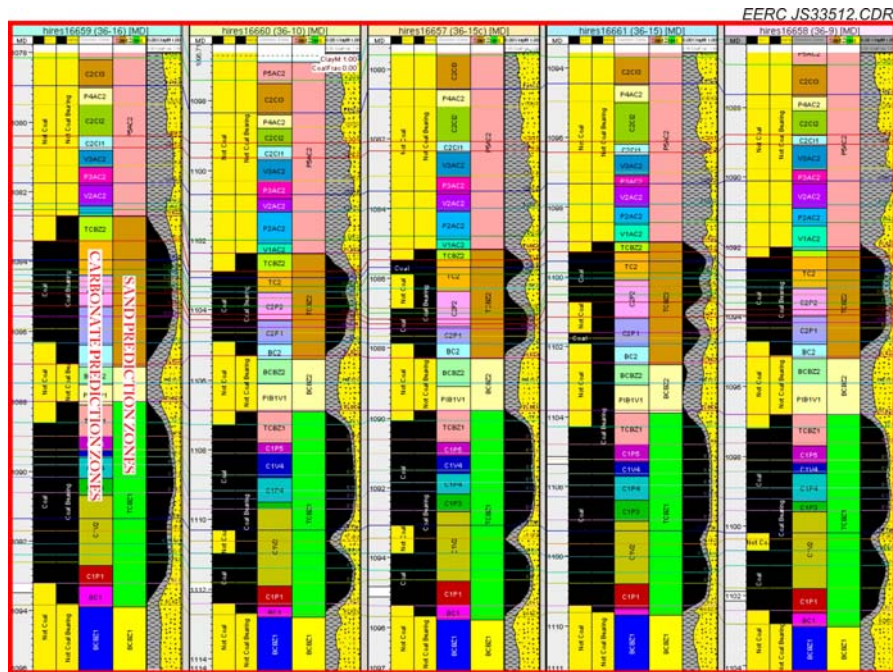


Figure 9. Summarized representation of processed and interpreted well-logging results from the application of Schlumberger Platform Express in boreholes at the Burke County site. Coal was collected from the lower coal seam.

SUMMARY AND DISCUSSION OF KEY RESULTS

In addition to the standard suite of coal-specific laboratory experiments, coal sorptive, petrophysical, geomechanical, and structural properties were investigated. Particularly, CO_2 and methane adsorption isotherms were obtained (Figures 10a and 10b), and the dependence of coal permeability on confining and pore pressures and on the presence of CO_2 was studied. Tests indicated that, compared to other coals, the tested lignite has somewhat lower sorptive capacity to methane: Langmuir volume was estimated at $\text{VLCH}_4 = 89.4 \text{ scf/ton} = 2.9 \text{ scc/g}$ on a raw basis, while typical values for higher-rank coal seams are in the range of 100–800 scf/ton (North Dakota Industrial Commission, 2008). However, the low sorptive capacity to methane is not a surprise, as previous laboratory and field-based studies of North Dakota lignite yielded similar results (Baez et al., 2004). The lignite has a much higher sorptive capacity for CO_2 , and CO_2 Langmuir volume ($\text{VLCO}_2 = 898.9 \text{ scf/ton} = 28.0 \text{ scc/g}$) is 10 times higher than CH_4 Langmuir volume.

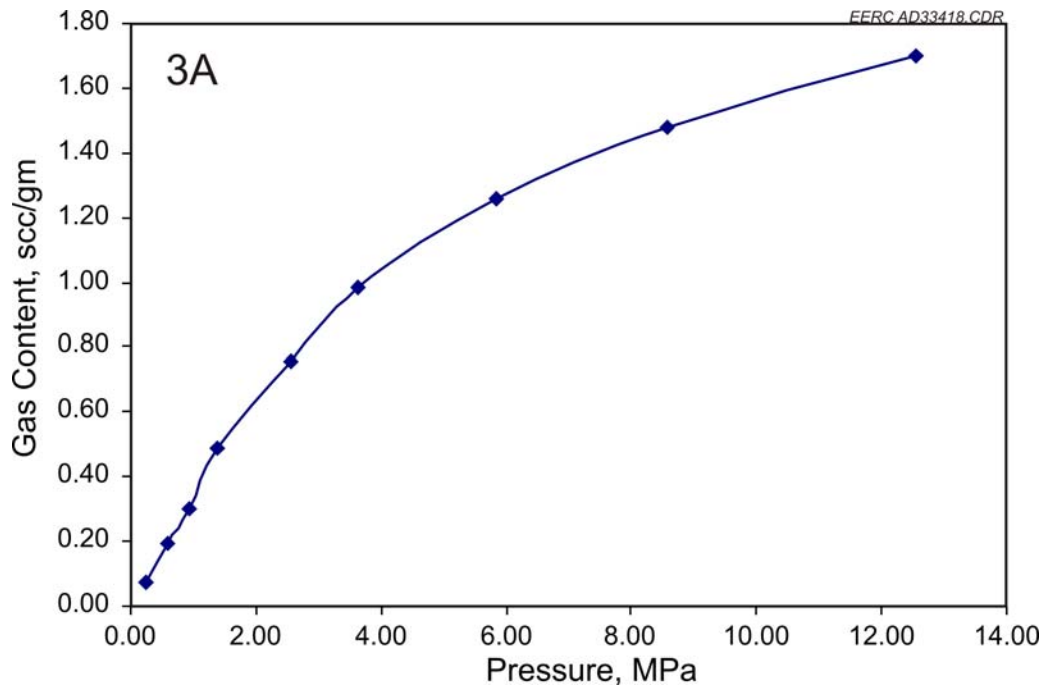


Figure 10a. Methane adsorption isotherm (raw basis: $T = 16^{\circ}\text{C}$ [61°F], ash content = 9%, equilibrium moisture content = 32.17%).

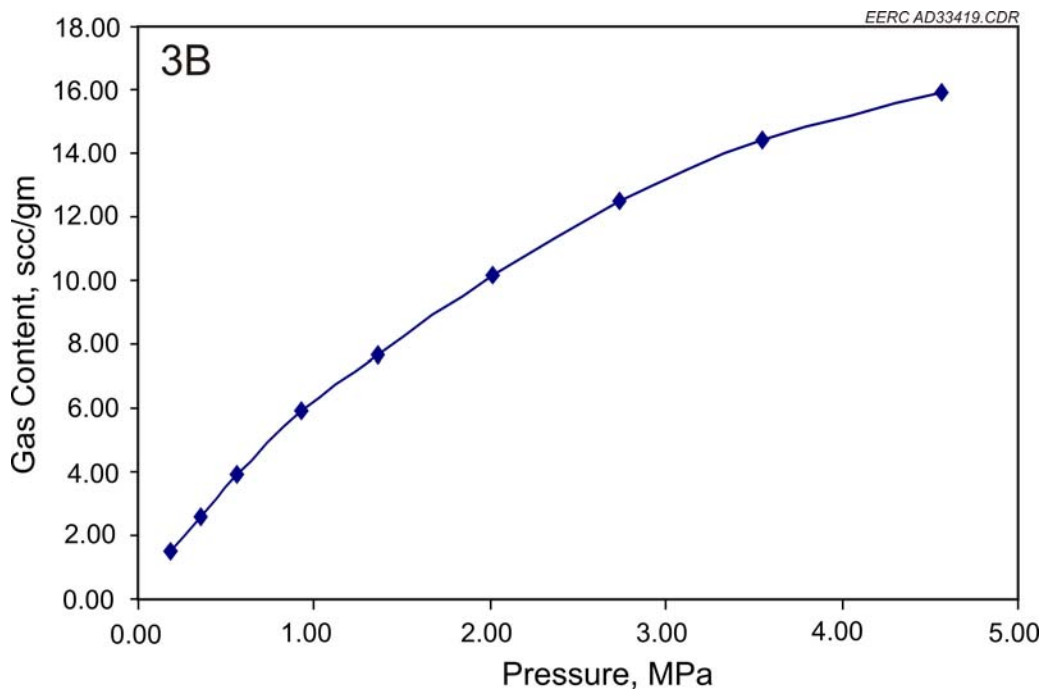


Figure 10b. Carbon dioxide adsorption isotherm (raw basis: $T = 16^{\circ}\text{C}$ [61°F], ash content = 9%, equilibrium moisture content = 32.17%).

A series of experiments with different gases and confining pressures indicated that permeability strongly depends on both stress state and presence of CO₂. Mechanical loading and unloading of the lignite confirmed its plastic behavior, which, in combination with other possible laboratory artifacts, could affect the measurements. Despite the artifacts, the measurements support the conclusion of relatively high matrix permeability of the lignite (up to 1 mD). The experiments also indicated that CO₂ is likely to cause significant swelling of the coal which can occur very fast: during one of the experiments an order of magnitude of permeability was lost in 10 minutes in response to CO₂ exposure.

Geophysical logging data from petroleum exploration and production wells and groundwater resource wells in the vicinity of the study site were obtained from the North Dakota Department of Mineral Resources and North Dakota State Water Commission. Specifically, data from wells drilled within approximately 5 miles of the study site were used to identify the target coal seam (the Burke County coal seam) and characterize its continuity and thickness across the expanded study area (Figure 11). Using ArcGIS, the data were then used to calculate a coal volume value for the target coal seam in the expanded study area. The coal volume value as well as coal density data, Langmuir CO₂ adsorption isotherm data, and the density of CO₂ at reservoir conditions were applied to the formula below, as described in (Nelson et al. 2005):

$$Q_{CO_2V} = A \cdot h \cdot \rho_{CO_2} \cdot \rho_{coal} \cdot SC_{CO_2} = 4 \cdot 10^9 m^3 \cdot 1.98 kg/m^3 \cdot 1468 kg/m^3 \cdot 0.011 m^3/kg = 128 \cdot 10^9 kg = 128MMt$$

where A = area, h = thickness, ρ_{CO_2} = density of CO₂ at reservoir conditions, ρ_{coal} = density of coal, and SC_{CO_2} = storage capacity of CO₂ in a given coal based on Langmuir isotherm data. For this evaluation, $(A \cdot h)$ were determined according to the thickness and extent map of the coal seam created using ArcGIS, while the other values were determined according to the measurements generated by core testing and analyses.

The application of the data generated by the research activities described in this report to the formula above resulted in an estimated theoretical maximum storage capacity for the Burke County lignite seam in the expanded study area of approximately 128 million metric tonnes (141 million short tons) of CO₂. Considering the expanded study area is approximately 300 square miles, this works out to 470,000 short tons/mi². It is important to note that geologic formations, including coals, are inherently heterogeneous with respect to their physical, chemical, and geomechanical properties. Because of this heterogeneity, it will never be possible to utilize 100% of the theoretical maximum storage capacity of any coal formation. The actual storage capacity will be significantly lower because of a variety of factors that will limit the ability of the injected CO₂ to come into contact with the bulk volume of a given coal seam. The multiplicative combination of volumetric parameters that affect the effectiveness of a coal seam to store CO₂ is referred to as the “efficiency factor” (U.S. Department of Energy, 2007). Efficiency factors that can be applied to storage capacity estimates for coals, and the methodology by which they were developed, are presented in the “Carbon Sequestration Atlas of the United States and Canada” (U.S. Department of Energy, 2007). Efficiency factors can reflect a variety of parameters, including the volumetric difference between bulk volume and coal volume and coal quality characteristics such as ash content, moisture content, heating value, vitrinite reflectance, maceral composition, and total organic content. The efficiency factors

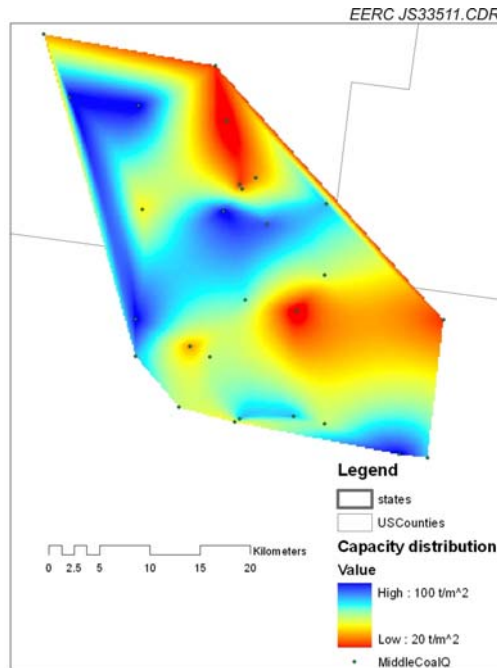


Figure 11. Map of expanded study area showing distribution of CO₂ storage capacity.

reported for coals range from 0.28 to 0.40, which means that anywhere from 28% to 40% of a given coal seam's maximum theoretical capacity may be available for CO₂ storage (U.S. Department of Energy, 2007). Applying these efficiency factors to the Burke County lignite seam in the expanded study area results in an estimated CO₂ storage capacity of approximately 39.5 million to 56.4 million short tons, or 132,000 to 188,000 short tons/mi². It is important to note that there have been no field-based CO₂ injection operations into lignite, so the accuracy and reliability of these estimates may be limited and should still be considered to be theoretical in nature.

CONCLUSIONS AND RECOMMENDATIONS

The results of laboratory and field work at the Burke County, North Dakota, lignite site indicate that methane content and consequently methane production potential of the target lignite in Burke County is not promising. On the other hand, the results of CO₂ sorption studies indicate the seams are likely to provide good targets for CO₂ storage. Another expected challenge in the field is the possible absence of a well-developed cleat system, which would significantly influence fluid injection and transport in the lignite seam. This can be a common problem in lignite seams as cleat systems are known to develop with the maturity of coal. Thus specific attention should be paid in future project activities to understand the in situ transport properties of coal. This can be done by comparing the field-based data obtained by injection activities to the laboratory-derived parameters. Further research can be conducted in the direction of choosing techniques for the better characterization of coals at the stage of feasibility studies. For instance, it has been suggested that the existence of fractures, which weaken the mechanical integrity of

the borehole wall, can occasionally give anomalous gamma ray signals. These signals are often being interpreted as the washing out of the borehole across the coal-bearing interval (Charles Nelson, personal communication, 2007). It also can be suggested that regional vertical pore pressure profiles be evaluated to ensure that the reservoir pressure is favorable for higher original gas in place. The results of the project have been used to develop a petrophysical model of the coal seam (Figure 12).

Because there are no field-based data on the injection and subsequent adsorption and storage of CO₂ or production of methane from a lignite coal seam with which to conduct history-matching modeling, the usefulness and applicability of the petrophysical model are very limited and, thus, not a topic of detailed discussion in this report. However, creation of the model is an example of how the data generated by this research project can be used to facilitate the development of a future injection project, whether it be for potential ECBM exploitation or CO₂ storage as part of a greenhouse gas mitigation strategy for regional coal-fired utilities.

ACKNOWLEDGMENTS

The authors wish to express their gratitude to Mr. David Fischer, Mr. Ron Rovenko, Dr. Charles Nelson, Mr. Lynn Helms, Mr. Ed Murphy, Mr. Grant Bromhal, Mr. Dwight Peters, and Mr. Monte Besler for valuable discussions. We also appreciate the tremendous support provided by the North Dakota Department of Mineral Resources, Flatland Exploration, Fischer Oil and Gas, the Schlumberger Carbon Services team, U.S. Department of Energy National Energy Technology Laboratory researchers, Eagle Operating staff, and the Montana Board of Oil and Gas Conservation.

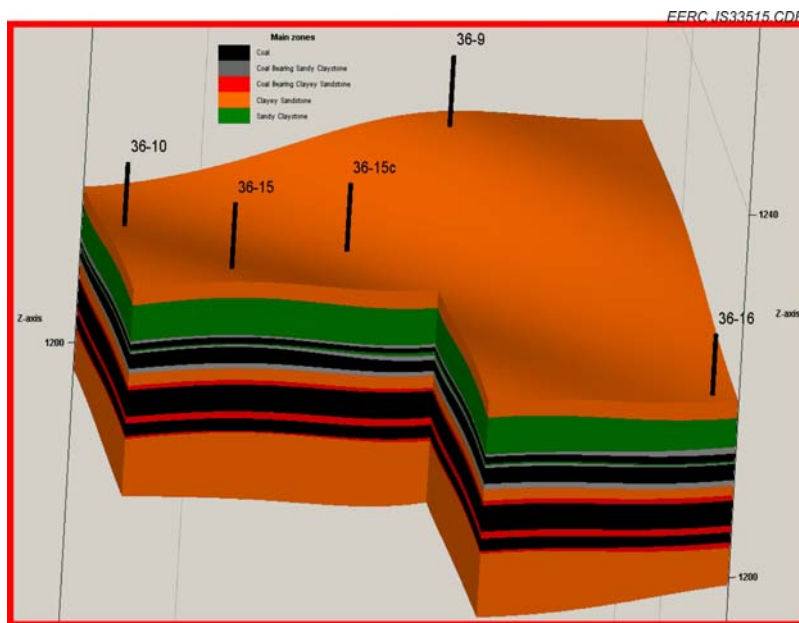


Figure 12. Three-dimensional image of the petrophysical model of the Burke County lignite test site.

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APPENDIX A
BUDGET SUMMARY

ENERGY & ENVIRONMENTAL RESEARCH CENTER
NASEO: Determination of CO₂ Storage and ECBM Potential of Lignite Coals
Prime Contract: DE-FC26-NT42592
Project-to-Date Financial Report at September 30, 2008

BUDGET AND EXPENDITURE SCHEDULE

Object Class Categories	Approved Budget BP One	Project Expenditures	
		This Quarter	Cummulative To Date
Personnel	73,921.00	30,238.25	100,448.71
Fringe Benefits	36,373.00	15,489.34	48,769.17
Travel	8,413.00	0.00	448.46
Equipment	0.00	0.00	0.00
Supplies	11,343.00	0.00	0.00
Contractual	40,000.00	0.00	141,430.00
Construction	0.00	0.00	0.00
Other	100,769.00	0.36	80.72
Total Direct Charges	270,819.00	45,727.95	291,177.06
Indirect Charges	129,181.00	21,811.75	83,353.84
Total Requested from DOE	400,000.00	67,539.70	374,530.90
Cost Share (Cash Equivalent)	100,000.00	0.00	106,591.80
Total Project Cost	500,000.00	67,539.70	481,122.70

COST SHARE CONTRIBUTIONS

Funding Source	Approved Cost Share		This Quarter		Cummulative To Date	
	Cash	In-Kind	Cash	In-Kind	Cash	In-Kind
ND Industrial Commission - Oil & Gas				0.00		50,000.00
ND State Land Department				0.00		28,420.00
Flatland Exploration				0.00		28,171.80
TOTAL		100,000.00	0.00	0.00	0.00	106,591.80
PERCENTAGE		0.20			0.00	0.21