ANALYSIS OF DEVONIAN BLACK SHALES IN KENTUCKY FOR POTENTIAL CARBON DIOXIDE SEQUESTRATION AND ENHANCED NATURAL GAS PRODUCTION

Final Report

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Abstract

Carbonaceous (black) Devonian gas shales underlie approximately two-thirds of Kentucky. In these shales, natural gas occurs in the intergranular and fracture porosity and is adsorbed on clay and kerogen surfaces. This is analogous to methane storage in coal beds, where CO_2 is preferentially adsorbed, displacing methane. Black shales may similarly desorb methane in the presence of CO_2.

Drill cuttings from the Kentucky Geological Survey Well Sample and Core Library were sampled to determine both CO_2 and CH_4 adsorption isotherms. Sidewall core samples were acquired to investigate CO_2 displacement of methane. An elemental capture spectroscopy log was acquired to investigate possible correlations between adsorption capacity and mineralogy.

Average random vitrinite reflectance data range from 0.78 to 1.59 (upper oil to wet gas and condensate hydrocarbon maturity range). Total organic content determined from acid-washed samples ranges from 0.69 to 14 percent. CO_2 adsorption capacities at 400 psi range from a low of 14 scf/ton in less organic-rich zones to more than 136 scf/ton in the more organic-rich zones. There is a direct linear correlation between measured total organic carbon content and the adsorptive capacity of the shale; CO_2 adsorption capacity increases with increasing organic carbon content.

Initial volumetric estimates based on these data indicate a CO_2 sequestration capacity of as much as 28 billion tons total in the deeper and thicker parts of the Devonian shales in Kentucky. In the Big Sandy Gas Field area of eastern Kentucky, calculations using the net thickness of shale with 4 percent or greater total organic carbon, indicate that 6.8 billion tonnes of CO_2 could be sequestered in the five county area. Discounting the uncertainties in reservoir volume and injection efficiency, these results indicate that the black shales of Kentucky are a potentially large geologic sink for CO_2. Moreover, the extensive occurrence of gas shales in Paleozoic and Mesozoic basins across North America make them an attractive regional target for economic CO_2 storage and enhanced natural gas production.

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Executive Summary

Increased emissions of carbon dioxide (CO_2), especially from the combustion of fossil fuels, are being linked to global climate change and are of considerable concern. These concerns are driving initiatives to develop carbon management technologies, including geologic sequestration of CO_2. One option for sequestration may be Devonian black shales, organic-rich rocks that are both the source and trap for natural gas (primarily methane). In gas shales, natural gas occurs as free gas in the intergranular and fracture porosity and is adsorbed on clay and kerogen surfaces, very similar to the way methane is stored within coal beds. It has been demonstrated in gassy coals that on average, CO_2 is preferentially adsorbed, displacing methane at a ratio of two for one or more. Black shale reservoirs may react similarly and desorb methane in the presence of adsorbing CO_2. If this is the case, black shales may serve as an excellent sink for CO_2 and have the added benefit of serving to enhance natural-gas production. A bibliography of Devonian shale has been compiled to identify previous work and provide supporting data for continued research.

Drill cuttings collected from recent shale wells were used as the primary material for analyses. The volume of material lost when cuttings were washed dictated a modification of the original sampling protocol; composite cuttings samples were collected before washing. Candidate samples were selected and prepared for total organic carbon, vitrinite reflectance, petrographic, and CO_2 adsorption analyses to determine the gas-storage potential of the shale and to identify shale facies with the most sequestration potential. For the Devonian shale, average total organic carbon is 3.71 (as received) and mean random vitrinite reflectance is 1.16.

Columbia Natural Resources (CNR) has provided access to a selected drill hole of opportunity for collecting sidewall cores and an elemental capture spectroscopy (ECS) logging suite for correlation and mineralogical analysis. A shale analysis integrating the standard nuclear log suite and ECS log data was acquired. The data from this log analysis and other digital logs were processed to determine TOC and adsorption capacity data.

Samples from the CNR well were submitted for TOC and CO_2 adsorption analyses. Additional samples from the New Albany Shale (Illinois Basin) and the Battelle deep well in Mason County, West Virginia (AEP #1) were acquired and submitted for determination of adsorption isotherms. Qualitative X-ray diffraction analyses were conducted to assist in mineral characterization and for correlating results from electron capture spectroscopy logging.

In cooperation with Interstate Natural Gas, Pikeville, Kentucky, another ECS log and 10 sidewall cores were acquired for a well in Martin County, Kentucky. The shale gas analytical model developed by Schlumberger was applied to the logs for this well. Five sidewall core samples were analyzed for quantitative x-ray diffraction, porosity, and permeability. Mineralogically, quantitative x-ray diffraction data from this well average 46% quartz and 39% clay minerals. Phyllosilicate minerals (clays and mica) include Illite, Kaolinite, and Chlorite. As received, porosity averaged 0.9 percent and permeability averaged 0.0005 millidarcys. CO_2 adsorption isotherm data using whole rock (not crushed) techniques and data have been received for one of 5 sidewall cores. The reported Langmuir volume is 174.75 scf/ton and the Langmuir pressure is 993.88 psia.

Sidewall cores were submitted for methane and CO_2 adsorption isotherms and methane displacement analyses. The results of the displacement and flow through experiments are pending.

Adsorption capacity reported as measured Langmuir volumes ranges from 37 to 2,078 standard cubic feet CO_2 per ton of shale (scf/ton) at Langmuir pressures ranging from 243 to 14,284 psia. These values represent the range of values for coefficients of the selected Langmuir model. At a constant pressure of 400 psia, the CO_2 adsorption capacity ranges from 14 to 136 scf/ton with a median value of 40 scf/ton. Methane adsorption capacity ranges from 2

to 38 scf/ton with a median value of 8 scf/ton. At 400 psia, CO_2 adsorption exceeds CH_4 adsorption by a factor of 5. These data were correlated with data from nuclear log suites for modeling TOC and CO_2 storage capacity for individual wells.

Gamma ray and density log data have been digitized for 18 wells in the Big Sandy Gas field. These data have been correlated and models are being developed to calculate CO_2 sequestration capacity as adsorbed gas in place from the shale density log data. ASCII text files of digital log data for 722 wells throughout Kentucky have been converted to log ASCII standard (LAS) format and loaded into mapping software for calculation and spatial analysis of TOC and CO_2 adsorption capacity.

Enhanced production of natural gas displaced by CO_2 injection remains to be demonstrated; the experiments to investigate enhanced gas recovery from the shale are continuing. These pending flow-through data and the data developed by this project will be expanded in research conducted through the Regional Carbon Sequestration partnerships active in the Illinois and Appalachian Basins. Two-phase dual-porosity reservoir modeling will be used to history match shale gas production and to study CO_2 injection. These efforts will result in a better understanding of continuous, low permeability shales as gas reservoirs, sequestration targets, and seals for sequestration.

General conclusions:

- Estimates using the distribution of gas storage capacity of CO_2 from TOC data indicate a sequestration capacity of 6.8 billion tonnes in the five-county area of the Big Sandy Gas Field of eastern Kentucky.
- Assuming a thickness weighted average adsorption capacity of 40 scf/ton (at 400 psia), as much as 28 billion tons total in the deeper and thicker portions of the Devonian shales in the Appalachian and Illinois Basins of Kentucky.
- These results indicate that Devonian black shales of Kentucky are a potentially large geologic sink for CO_2. The extensive occurrence of gas shales in Paleozoic and Mesozoic basins across North America would make them an attractive regional reservoir for economic CO_2 sequestration and enhanced natural gas production.

Introduction

Carbon dioxide (CO_2) is an efficient heat-trapping gas occurring in Earth's atmosphere. Over the past decades, there has been a growing concern that anthropogenic emissions of CO_2 are contributing to a systematic warming of Earth's climate; that is, global warming. The majority of anthropogenic emissions of CO_2 are from fossil fuel combustion. Electric power generation, transportation fuels, and industrial applications are highly dependent on coal, crude oil, and natural gas. It is estimated that the reliance on fossil fuel combustion will extend well into the 21st century (EIA, 2000). In Kentucky, 95 percent of the total electric generation capacity relies on fossil fuels (EIA, 2002, Table 4), with annual emissions of 87 million metric tonnes of CO_2 (EIA, 2002, Table 7).

CO_2 emissions can be decreased by increasing the efficiency of fossil fuel combustion processes, switching to alternate and renewable fuels (biomass, nuclear, solar, wind), and mitigated by capturing and sequestering CO_2. Each of these methods is currently being used in the world today to achieve goals for addressing global warming and meet increasing energy demands. For sequestering CO_2, marine and terrestrial options are being researched, but geologic sequestration is the focus of this project. Geologic sequestration includes long-term carbon storage in old oil and gas fields (with the incentive of enhanced recovery), unminable coals, deep saline aquifers, and unconventional reservoirs.

Usually considered to be the seal for conventional oil and gas reservoirs, carbonaceous gas shales warrant study as a possible sequestration target. Gas is commonly stored in carbonaceous shales as free gas in the pore and fracture systems and as adsorbed gas associated with the organic matter. This research tests the hypothesis that organic- and gas-rich black shales can adsorb significant amounts of CO_2. In carrying out the research, the Devonian black shales of Kentucky were tested in the laboratory to determine their CO_2 sorption capacity using powdered drill cuttings and sidewall cores. The ability of sorbed CO_2 to displace methane is also being tested on sidewall cores in order to assess the potential for enhanced natural gas production from the shales.

The organic matter in gas shales has large surface areas similar to that found in coal. Coal seams are currently being investigated as potential sequestering sites for CO_2, the most important greenhouse gas (IEA Coal Research, 1999). Naturally occurring organic matter (kerogen) is a microporous material that possesses a very high surface area and hence sorption capacity for gas. In the subsurface, coal commonly has economically significant amounts of sorbed methane (coalbed methane). Because organic matter has a greater sorption affinity for CO_2 than methane, injection of CO_2 with simultaneous production of methane may be viable (see Reznik and others, 1982; Bachu and Gunter, 1998). Currently there are three pilot projects testing CO_2 injection for enhanced coalbed methane (CBM) recovery. The Alberta Research Council and a consortium of petroleum companies is conducting a project in Alberta, Canada (Gunter and others, 1997). In the San Juan Basin, New Mexico, Amoco has carried out another pilot investigation (Reeves, 2003). Finally, Burlington Resources is also evaluating the utility of CO_2 injection (Reeves, 2003). Results from these tests have shown that CO_2 injection and co-production of coalbed methane is technically and economically feasible. Since 1996, over 57 million m^3 of CO_2 has been sequestered in Cretaceous coal of the San Juan Basin, New Mexico. The question is: can Devonian gas shales adsorb sufficient amounts of CO_2 to make them significant targets for CO_2 sequestration?

Study Area

The study area is primarily within the major gas-producing area of the Ohio Shale in the Big Sandy Gas Field, in the Appalachian Basin area of eastern Kentucky (Figure 1). In cooperation with the Indiana Geological Survey, the Devonian New Albany Shale in two Illinois Basin wells in Sullivan and Lawrence Counties, Indiana were sampled for comparison. Battelle also contributed drill cuttings through the Devonian Lower Huron Member of the Ohio Shale from their deep AEP CO_2 seqestration project well in Mason County, West Virginia.

Regional Geology

Thinly bedded, fissile gray and black (carbonaceous) shales of Early Mississippian and Late Devonian age occur in the subsurface of nearly two-thirds of Kentucky. In general, the shales are thicker and deeper in eastern and western Kentucky (Figure 2) and are absent in the Bluegrass Region of central Kentucky and the Mississippi Embayment Region in the Jackson Purchase area of extreme western Kentucky. Along the axis of the Cincinnati Arch in central Kentucky, the thickness of the shale is usually 15 meters (50 feet) or less. The shale thickens from a minimum of 0 meters in some locations along the crest of the Cincinnati Arch eastward to more than 518 meters (1,700) feet in Pike County. The shale is exposed in outcrop around the margin of the Jessamine Dome (along the perimeter of the Inner and Outer Bluegrass Regions of central Kentucky) and along the Cumberland River drainage in south-central Kentucky. A subcrop of the shale has been identified beneath the Cretaceous sediments of the Mississippi Embayment Region of western Kentucky. Figure 3 shows the elevation of the top of the Devonian shale in Kentucky and illustrates the progressive deepening of the shale east and west of the Cincinnati Arch area of central Kentucky.

Stratigraphy

Carbonaceous shales of Devonian age are present throughout the Appalachian Basin of the eastern U.S. Nomenclature is generally based on outcrop studies and varies across the Basin (Figure 4). The Devonian shales of the Illinois Basin areas of western Kentucky and southwestern Indiana are correlative to similar shales of the Appalachian Basin (Figure 5). Figure 6 shows the aerial limits of the nomenclature used for the Devonian shales in Kentucky, known variously as the New Albany (Illinois Basin), Chattanooga (central Kentucky, Cincinnati Arch area), and Ohio (Appalachian Basin) Shales. The Ohio Shale of eastern Kentucky is typically subdivided into seven recognizable units (Figure 7): Cleveland Shale, Three Lick Bed, Upper, Middle, and Lower Huron, Olentangy, and Rhinestreet. In the subsurface, these units have been differentiated based on gamma ray and density differences that are essentially related to the organic-matter content of the shale. The upper-most black, carbonaceous shales (Cleveland and Upper Huron) pinch out eastward into gray, more clastic sequences correlative to the Three Lick Bed. Where the Cleveland and Upper Huron are missing, the shale above the Lower Huron is designated in this report to be the Chagrin Shale. The Olentangy and Rhinestreet black shales correlate to the Java Formation of West Virginia (e.g. de Witt and others, 1993), and thin and pinch out westward toward the margin of the Appalachian Basin. Some authors (Ettensohn and others, 1979) have considered that the Olentangy and Rhinestreet are members of the Devonian Ohio Shale. Although they are not everywhere present in the subsurface in the study area, the units are included in the analyses where samples are available.

In the Illinois Basin, two members of the New Albany shale (Figure 5) were sampled in this study. The Selmier Member of the New Albany is the more organic-rich interval of those sampled and is correlative in part to the Olentangy and Rhinestreet Members (combined) of the Devonian Ohio Shale. The underlying Blocher Shale Member is the basal shale of the New Albany Shale in the Illinois Basin (Hasenmueller and Comer, 1994).

Reservoir integrity for CO_2 sequestration is a concern. Figure 8 provides a composite general geologic column illustrating more than 1,158 meters (3,800) feet of Mississippian and Pennsylvanian lithologies, including carbonate, sand, shale, and coal that have proven an effective seal for existing petroleum and gas resources. An assumption was made that sequestration will take place in the shale at depths of at least 305 meters (1,000 feet) to recognize the possible limitations of a fractured reservoir to act as an effective seal. Testing the integrity of this seal with respect to CO_2 is beyond the scope of this project and will be the subject of continuing research.

Lithology

The Ohio mudstone is a black to gray, thin-laminated, fissile, shale. Hosterman and Whitlow (1983) report the shales consist of clay (30 to 75 percent) and quartz (20 to 50 percent) with varying amounts of pyrite and calcite being the primary accessory minerals. Clay minerals are primarily mixed layer clays (Illite-Smectite and Illite-Chlorite), Chlorite, and Kaolinite. The shale color (and density) varies based on the organic matter content (bitumen) which ranges from less than 1 percent to 27 percent (Zielinski and McIver, 1982). Pyrite occurs throughout the unit, but tends to be better preserved in the more bituminous-rich intervals. Calcite often occurs as cementation at or near boundaries between the more and less organic-rich units.

Reservoir parameters for the Big Sandy Gas Field were summarized in the "Atlas of Major Appalachian Gas Plays" (Boswell, 1996). The average completed interval exceeds 152 meters (500 feet) in thickness. Average porosity is 4.3 percent, with a maximum of 11 percent. Reservoir temperature averages 29°C (84°F), with an initial reservoir pressure of 5.5 MPa (800 psi) or more. Current reservoir pressure averages 2.75 MPa (400 psi). Sidewall cores from the Interstate No. 3 Jude Heirs well (well number 19 this report), Martin County, eastern Kentucky, were analyzed using mercury injection and indicate an average matrix porosity was 0.9 percent. The highest observed porosity in the Jude well, 2.4 percent, occurred in the Lower Huron Member. Permeability to mercury determined from the sidewall cores averaged 0.5 microdarcys.

Production

The first Devonian shale gas wells in Kentucky were drilled between 1863 and 1865 in Meade County, west-central Kentucky. The produced gas was used as fuel to evaporate brines, for street lamps, and to provide heat in Louisville. Shale gas was discovered in eastern Kentucky circa 1892 in Floyd County (Hoeing, 1905). Overall, cumulative Devonian shale gas production in Kentucky probably exceeds 84.9 billion cubic meters (bm^3, 3 tcf); gas in place is estimated by various investigators to be between 26 trillion cubic meters (tm^3, 918 bcf) and 73 tm^3 (2.6 tcf, Hamilton-Smith, 1993, p. 5). According to production data on file at the Kentucky Geological Survey, the giant Big Sandy Gas Field of Floyd, Knott, Letcher, Martin, and Pike Counties produced 77 percent of the nearly 2.5 bm^3 (88 bcf) of natural gas produced in Kentucky in 2003.

Historic production data for individual wells is sparse. The only data available is a proprietary data set collected in the 1980's by the BDM Corporation for the Gas Research Institute (now Gas Technology Institute). Many of the wells in that data set exhibit exponentially inclining production rates over time. Figure 9 shows the average daily gas production in thousand cubic feet per day for an eastern Kentucky shale gas well over a 30-year history. This production increase over time, often decades, and the organic content of the shale suggests an appreciable adsorbed gas content in addition to the free gas in fractures and intergranular porosity.

Drilling and completions target organic-rich intervals with abundant natural fractures, mostly in the Lower Huron Member of the Ohio Shale (Figure 7) of eastern Kentucky. The completion often consists of multiple zones including the Sunbury to Upper Huron interval with the Lower Huron being completed separately. Completions in the gray, more clastic, shale intervals (Three Lick Bed/Chagrin and Middle Huron are typical only where temperature, density, and audio anomalies indicate fracturing of the shale. Nitrogen is typically used as the carrier fluid in hydraulic fracturing stimulations, which are intended to intersect with and enhance any natural fractures. Sand is employed as a proppant to maintain an open fracture system. The median open flow for shale wells is 5.2 Mm^3/d (184 Mcf/d) from data reported to the Kentucky Geological Survey. The industry rule of thumb is that shale wells can be expected to produce 8.5 MMm^3 (300 MMcf). Some wells produce from 14 MMm^3 (500 MMcf) to more than 28 MMm^3 (1 bcf) over a 50-years or longer time span.

Methods

Drill Cuttings

Drill cuttings on file at the Kentucky Geological Survey Well Sample and Core Library and sidewall cores are the main source of material for analysis. Unwashed sets of recently acquired drill cuttings were used to minimize weathering of material and to maximize volume of material for analysis. Drill cuttings are commonly collected during drilling in 1.5- to 3-meter (5- to 10-foot) intervals and consist of a mix of chipped rock fragments and powder. Distribution and stratigraphy of different facies members in the Devonian shale in eastern Kentucky were used to divide well cuttings into up to three samples for adsorption analysis. The upper part of the Ohio Shale from the Cleveland Member through the base of the Middle Huron Member is generally less organic-rich, as indicated by the gamma-ray response on standard geophysical well logs (Figure 7). Drill cuttings of this sequence generally have a lighter gray color and more recognizable quartz material than the darker gray to black samples with sparse pyrite that are characteristic of the Lower Huron Member. In some areas of the Big Sandy Gas Field, the Olentangy and Rhinestreet Members of the Ohio Shale are present but also have a somewhat lesser organic content as indicated by gamma-ray logs. Where present, these shales were composited as a separate sample. Most wells have an insufficient volume of cuttings available to analyze the individual members of the Ohio Shale; in these cases the entire shale sequence was aggregated into a single sample. A maximum of three samples from cuttings per well was used for analyses. The drill cutting samples were divided into two splits: one for TOC, vitrinite reflectance, and X-ray diffraction analyses, and one for determination of CO_2 isotherms. Each split was then milled and sieved to the specifications of the respective analytical technique. Figure 1 shows the location of wells sampled in eastern Kentucky, West Virginia, and the Illinois Basin area of western Indiana.

Total Organic Carbon

To investigate any relation between organic content and CO_2 sorption capacity, total organic carbon content (TOC) was determined. For total organic carbon analyses, samples were first crushed to a maximum particle size of 200 microns (–60 mesh). Samples were run in duplicate. One split was run “as is.” Another split was treated with 30 percent hydrochloric acid (HCl) for 12 to 24 hours to remove any carbonate minerals from the matrix, prior to analysis. Although carbonate minerals are typically a rare component of Devonian Shales, they do occur as noted and they present a possible bias in the calculation of TOC. Like organic material, carbonate minerals dissociate in the combustion chamber and form CO_2. The hydrochloric acid was removed by repeated washings with distilled water, followed by centrifugation. The samples were then placed in a drying oven (50^{o}C).

Total organic carbon was measured on a LECO SC-144 DR dual range sulfur and carbon analyzer, which is a nondispersive, infrared, digitally controlled instrument designed to measure sulfur and carbon in a wide variety of organic and inorganic materials. The unit combusts samples in a pure oxygen environment at 1,350ºC. Sulfur compounds are immediately oxidized and form sulfur dioxide (SO_2); carbon compounds are oxidized to CO_2. From the combustion system, sample gases pass through two tubes containing magnesium perchlorate ($MgClO_4$), which removes moisture, and then are routed to the infrared (IR) detection cells. A sulfur IR cell measures the amount of SO_2 present in the gas stream, and a carbon IR cell does the same for CO_2. All molecules, with the exception of bipolar species (e.g., N_2, H_2, O_2), absorb energy in the infrared region. As radiant energy is projected through the sample material an IR absorption spectrum is produced. Since no two molecules produce the same spectrum, the identity and quantity of a compound can be readily, and accurately, determined.

An anomaly was noted in the last group of samples submitted for TOC determination; the carbon content after acid washing was consistently higher than the content as received. A new TOC standard was selected and the samples were reanalyzed. It was determined that the observed difference in TOC content before and after washing were smaller than instrument error. This indicated that very little, if any, inorganic carbon was present in the samples.

Vitrinite Reflectance

Vitrinite reflectance is used as a measure of the maturity of the organic matter in shale and maturity of the shale may influence CO_2 sorption capacity. Mean random reflectance ($R_{0random}$) on dispersed vitrinite particles in the samples was determined on a Zeiss USMP incident light microscope calibrated using glass standards of known reflectance. Depending on the amount of vitrinite in the samples, 50 or 100 grains were measured at a magnification of 640x to determine mean reflectance. Mean random reflectance was used because it eliminates the need to rotate the stage to determine maximum and minimum reflectance values. As the vitrinite particles in the analyzed samples were quite small (usually less than 10 microns), stage rotation simply wasn't practical, because it often resulted in the reflectance measuring spot moving off the grain. Maximum vitrinite reflectance values (R_{0max}) can be estimated by multiplying the mean random measurements by 1.066 (Ting, 1978).

Adsorption Isotherms

The classic theory used to describe the Type I isotherm for microporous materials with small external surface area is based on the Langmuir equation (Langmuir, 1916). The Type I isotherm displays a steep increase in adsorption at low relative pressures due to enhanced adsorption caused by the overlapping adsorption potentials between the walls of pores whose diameters are commensurate in size with the adsorbate molecule. The Type I isotherm then flattens out into a plateau region at higher relative pressure, which is believed to be caused by the completion of a monolayer of adsorbed gas. The micropore volume is thought to then be filled by only a few molecular layers of adsorbate, and further uptake is limited by the dimensions of the micropores.

The Langmuir model assumes that a state of dynamic equilibirum is established between the adsorbate vapor and the adsorbent surface and that adsorption is restricted to a single monolayer. The adsorbend surface is thought to be composed of a regular array of energetically homogeneous adsorption sites upon which an adsorbed monolayer is assumed to form. The rate of condensation is assumed to be equal to the rate of evaporation from the adsorbed monolayer at a given relative pressure and constant temperature. The Langmuir equation was developed with these assumptions and takes the following form:

$$\frac{P}{V} = \frac{1}{BV_m} + \frac{P}{V_m}$$

where P is the equilibrium pressure, V is the volume of gas adsorbed at equilibrium, V_m is the volume of adsorbate occupying the monolayer, and B is an empirical constant. A plot of P/V vs. relative pressure should yield a straight line whose slope will yield V_m, from which the surface area may be obtained.

The Langmuir isotherm can be written:

$$V(P) = \frac{V_L P}{P_L + P}$$

P = gas pressure
$V(P)$ = predicted amount of gas adsorbed at P
V_L = Langmuir volume parameter
P_L = Langmuir pressure parameter

The difference between the measured amount of gas adsorbed ($V(P)$) and that predicted using the Langmuir equation ($V_i(P)$) is a measure of goodness of fit and is given as:

$$Err(P) = V_i(P) - V(P)$$

This measure of goodness of fit may be positive or negative. The square of the error statistic is always positive and is a measure of how well the calculated isotherm matches the data. This measure of the goodness of fit can be calculated for each point and summed giving a measure of the overall error:

$$SSE = \sum_{i=1}^{N} Err_i^2$$

N = number of measured points

The standard goodness of fit of the isotherm is expressed by calculating the correlation coefficient between the measured points and the calculated points. The results generally yield correlations that are better than $r^2 = 0.99$, and standard errors of Langmuir volumes of ±2 percent. The reported CO_2 sorption capacity and corresponding pressure are calculated coefficients of the Langmuir model and are used to determine the sorption capacity at reservoir-appropriate pressures.

Adsorption analyses were performed using a high-pressure volumetric adsorption technique similar to that described by Mavor and others (1990). Isotherms were measured on a custom-made apparatus modeled after a similar module designed and built at CSIRO in Lucas Heights, Australia. The apparatus is based on Boyle’s Law. In simple terms, a known volume of gas within a reference cell is used to dose a sample cell that contains the sample. The amount of gas adsorbed in the sample cell is then determined, based on a change in pressure in the sample cell using the Real Gas Law. Following dosing of the sample cell, the pressure drops until equilibrium is reached (i.e., no more gas can be adsorbed by a sample at a particular pressure). When equilibrium is reached, the sample is dosed at a higher pressure. Typically, 11 separate pressure points are selected and measured so that a Langmuir regression curve can be accurately generated. The pressures in the reference and sample cells are measured using pressure transducers that are interfaced to a computer equipped with special boards and software. The computer monitors the transducers and determines when equilibrium is reached; it also controls valves and switches for dosing and purging the cells.

Sidewall Cores for Adsorption and Methane Displacement

Laboratory investigation of methane displacement in the presence of CO_2 is being performed on whole rock core samples. In cooperation with Columbia Natural Resources, access to a well in Knott County, eastern Kentucky (Figure 10), was obtained for logging and collection of sidewall cores. Schlumberger Oilfield Services provided elemental capture spectroscopy logging for mineral identification and obtained the sidewall cores. The sidewall core plugs are being saturated with methane. To test the potential for enhanced natural gas production, the cores are being subjected to simulated injection of CO_2, and the amount of methane displaced during injection is being measured. Laboratory setup and analyses are similar to the standard procedure for obtaining adsorption isotherms. The results from this flow-thru experiment are pending.

Mineralogy: Elemental Capture Spectroscopy and X-Ray Diffraction

Elemental capture spectroscopy (ECS) is an advanced tool used for lithology and mineral determination that uses the same technology employed by NASA on the Mars Rover missions. An AmBe neutron source is used to activate a formation. Relative elemental yields are derived using fourier transform infrared spectroscopy analysis to identify 23 elements. Primary elements measured include: Si, Ca, Fe, S, Ti, Gd, Cl, and H. The relative abundance of these elements has been correlated with particular minerals and sedimentary lithologies (Herron and Herron, 1997 and Schlumberger, 2000). To supplement the ECS log, x-ray diffraction (XRD) data were acquired. Samples for XRD analysis are pulverized to 200 mesh or smaller and side packed.

Geophysical Logs

A gamma-ray density (GRD) log suite is typically available for shale wells drilled within the past few decades. More recently, the standard open-hole log suite has expanded to include temperature, audio, density porosity, and lithology (photoelectric effect) determinations. Schmoker (1979, 1993) developed a model for determining TOC of the shale from formation density log data. Shale can be considered a mixture of three components: clay minerals, quartz-feldspar-mica, and organic matter. Schmoker (1979) suggests the organic matter content is the main contributing factor to observed variations in shale density. Using Schmoker's (1993, p. J4) method, TOC for intervals can be estimated from density logs using the equation:

$$TOC = 55.822\left[\frac{\rho_B}{\rho} - 1\right]$$

ρ_B = maximum density of gray shale intervals (typically 2.67 to 2.72 g/cm^3)

ρ = observed formation density from log

Schlumberger Oilfield Services has developed a shale analysis model that uses data acquired from a standard nuclear log suite (Schlumberger Platform Express service) and an ECS log. This model provides detailed continuous lithologic and mineralogic interpretations, and TOC. The shale analysis presents TOC calculated from formation density data using a method analogous to Schmoker (1993) and from the ECS elemental analysis (ELAN).

Sequestration Capacity of the Shale

ArcView GIS software was used to develop a method to compile an estimate of the sequestration capacity of the shale. The method uses a cell-based approach that enables combines shale thickness information in the form of continuous grids with shale density and spatially variable CO_2 adsorption capacity data. Preliminary estimates were compiled using a uniform, minimum CO_2 adsorption capacity and include data projected into the Illinois Basin portion of western Kentucky. The details of this basic method are presented in Appendix D. Using density logs to estimate TOC (Schmoker, 1993), determining the net thickness of shale with greater than a particular TOC cutoff, and employing the TOC-CO_2 adsorption capacity relation developed by this research, the volumetric method of estimating sequestration capacity of adsorbed gas can be refined to be more representative of potential gas capacity and storage volumes.

Results

Fourty-three samples were collected from 11 wells, including up to three composite cuttings samples in some wells, 10 sidewall cores from the Columbia Natural Resources No. 24752 Elkhorn Coal Corporation well in Knott County (Figure 10), and 10 sidewall cores from the Interstate Natural Gas No. 3 John Jude Heirs in Martin County. Data for completed analyses are presented in Table 1. Appendix A provides a key to wells used in the cross section and samples acquired. In recognition of the regional nature of the potential reservoir, both the Midwest Geologic Sequestration Consortium (Illinois Basin, ISGS) and the Midwest Regional Carbon Sequestration Partnership (Appalachian Basin, Battelle) were contacted to obtain shale samples. Core samples from two Illinois Basin wells and drill cuttings from the Battelle AEP test well were acquired and analyzed for CO_2 adsorption capacity and TOC.

$R_{0random}$ values (Table 1) range from a minimum of 0.78 to 1.59 with a median of 1.1 and a mean of 1.2. This places the shale in the upper oil to wet gas and condensate maturity range as measured by reflectance. Figure 11. Mean random reflectance ($R_{0\ random}$) shows the distribution of $R_{0random}$ values.

Columbia Natural Resources (CNR) drills a number of Devonian shale gas wells in eastern Kentucky as a normal part of their resource development program. A drill hole of opportunity was identified and sidewall cores and logs were obtained from the CNR well number 24752 Elk Horn Coal Company, located in eastern Knott County (Figure 10). An elemental capture spectroscopy (ECS) log was also obtained. Appendix E includes sections of the litho-density and elemental capture spectroscopy logs acquired.

A second ECS log was acquired by Interstate Natural Gas Company, Pikeville, Kentucky for their No. 3 John Jude Heirs well in Martin County. For this well, ten sidewall cores were acquired in closely spaced (less than one vertical foot apart) pairs. One core of each pair was submitted divided into two parts for quantitative X-ray diffraction analysis and the other part for porosity and permeability analysis. The second core plug of each sample pair was submitted for whole rock CO_2 adsorption analysis. Available data are provided in Appendix F. As received, porosity averaged 0.9 percent and permeability averaged 0.5 microdarcys. CO_2 adsorption isotherm data using whole rock (not crushed) techniques and data have been received for one of 5 sidewall cores, in the Jude well. In the sidewall core sample from the Lower Huron at a depth of 922 m (3025.4 ft), the measured Langmuir volume of 174.75 psia and pressure of 993.88 psia were within the data ranges of those measured from drill cuttings. Analytical work on the other 4 samples continues.

An ECS log presents dry weight fractions of major lithologic components including silicates (quartz, feldspar, and mica), clay minerals, and carbonates. Figure 12 shows a portion of the ECS log through the Lower Huron Member of the Devonian Ohio Shale in the CNR well 24725 Elk Horn Coal. As measured on the ECS log through the complete Ohio Shale interval, the dry weight fraction of clay ranges from a minimum of 25 percent to a maximum of 71 percent. The mean clay content is 55 percent and the mode is 63 percent. A typical whole rock x-ray diffraction trace from drill cuttings is shown in Figure 13 and indicates the presence of Illite, Kaolinite, Pyrite, and Quartz. Another clay mineral (indicated by “M” in the figure) is most likely an authigenic Smectite (possibly Montmorillonite). Hosterman and Whitlow (1983) reported an Illite-Smectite mixed layer clay (consistent with Montmorillonite) in their analyses. Quantitative x-ray diffraction data from the Jude Heirs well average 46% quartz and 39% clay minerals. Identified phyllosilicate minerals (clays and mica) include Illite, Kaolinite, and Chlorite. These data are included in Appendix F and are consistent with compositional data reported in the literature (i.e., Hosterman and Whitlow, 1983). The Montage Well Shale Analysis from nuclear and elemental capture spectroscopy logs of both the CNR and Interstate wells indicate the more organic-rich intervals (with lesser clay contents) have higher adsorption capacities.

Relatively thin intervals of calcite cemented mudstones are noted on the Montage Well Shale Analysis logs. The sparse distribution of these zones indicate that inorganic carbon is not abundant (as a fracture filling cement, for example) and supports the conclusions reached concerning the problems encountered during TOC analysis. These zones may represent the occurrence of flooding surfaces as noted in studies by MacQuaker (2005) of the Mancos Shale, Book Cliffs, Utah.

Seven sidewall cores recovered from the CNR 24752 Elk Horn Coal well were submitted to assess the change in permeability as shale, initially saturated with methane, was flooded with CO_2. The available triaxial experiment flow-through apparatus was designed for full diameter core tests and was modified to accommodate the one inch diameter side wall cores. One new cell was initially constructed and subsequently two additional cells were made from modified

Hoek cells. Experimentation commenced with saturation of the samples under confining pressure (calculated from depth) in the one inch flow apparatus. Once saturation was obtained, we attempted to measure permeability to methane. The permeability of the samples proved too low to measure by conventional permeability tests. Hence it was necessary to build an additional module to the flow apparatus to measure permeability by pulse decay. The one sample tested to date with the pulse decay is essentially impervious and we are currently modifying the software to enable prolonged and automated dosing of the sample at various differential pressures. At the low permeability of at least our initial sample, it is not possible to differentiate diffusion from pressure driven flow. Diffusion of gases is concentration driven and pressure dependent so differentiating diffusion from permeability in these samples may prove to be a moot point. The flow-through experiments of the shale samples have proved challenging. We have made a number of major modifications to our experimental apparatus and our protocols. Not being able at this point to provide hard quantitative experimental results is of course disappointing. The experiments to date have provided insight as to transport mechanics of gas in the shales and have forced us to rethink our experimental protocols. These flow-through experiments will continue.

Adsorption isotherms are summarized in Figure 14. The Langmuir volume and pressure data reported in Table 1 must be compared on a uniform pressure basis by formation. Summary data are shown in Table 2 provides calculated adsorption capacities at three pressure values, that are expected to be typical of the range of observed Devonian shale gas reservoir conditions. To effectively compare capacity data derived from adsorption isotherms, three pressure conditions were selected: 1.4, 2.8, and 4.1 MPa (200, 400, and 600 psia). These comparison data are presented in Figure 15.

Adsorption capacity from drill cuttings reported as measured Langmuir volumes ranges from 1.1 to 65 cubic meters of CO_2 per metric tonne (37 to 2,078 standard cubic feet per ton) of shale at Langmuir pressures ranging from 1.7 to 98.5 MPa (243 to 14,284 psia, Table 2). These values represent the range of values for coefficients of the selected Langmuir model. At a constant pressure of 2.8 MPa (400 psia), the indicated CO_2 adsorption capacity ranges from 0.4 to 4.2 m^3/tonne (14 to 136 scf/ton) with a median value of 1.2 m^3/tonne (40 scf/ton). Methane adsorption capacity ranges from 0.1 to 1.2 m^3/tonne (2 to 38 scf/ton) with a median value of 0.2 m^3/tonne (8 scf/ton) (Table 3) at 2.8 MPa (400 psia). At the same pressure (2.8 MPa), CO_2 adsorption exceeds CH_4 adsorption by a factor of 5.3 (Figure 16). The reported Langmuir volume from whole rock obtained from the Interstate No. 3 Jude Heirs well was 174.75 scf/ton and the Langmuir pressure was 993.88 psia. Both values are within the range of data determined from powdered drill cuttings. When the average adsorption capacities of all data from drill cuttings are compared by formation, the adsorption capacity is highest for the more organic-rich Lower Huron shale (Figure 15).

A direct and linear relationship was observed between total organic content and the adsorption capacity of the shale. Figure 17 shows the relation by formation analyzed. It should be noted that the Indiana Selmeir (New Albany Shale) samples were specifically chosen for their high organic content. It was observed that two samples are enriched with respect to the amount of CO_2 that can be adsorbed based on organic carbon content. When these outliers are included in regression analysis, the correlation coefficient is 0.80 (at the 95 percent level of confidence). Excluding the outliers, the correlation coefficient improves to 0.96 (at the 95 percent level of confidence). The gas storage volume calculated for the Interstate No. 3 Jude heirs well at 2.8 MPa (400 psia) was comparable to the range of data from drill cuttings (see Figure 17). With only one whole rock analysis available, however, no further conclusions are warranted.

The least squares linear regression equation used for modeling CO_2 adsorption capacity is:

$$CO_2 \text{ scf/ton} = 7.9 * TOC + 20.7$$

Note that the storage volume of CO_2 returned by this equation is standard cubic feet per U.S. short ton. Calculations using this model and subsequent calculations involving geophysical logs are carried out in the units common to the logging industry as established by the American Petroleum Institute (API).

Gamma ray and density logs were digitized for 18 shale wells. These wells include all wells for which adsorption data were acquired and supplemental wells needed to construct a detailed cross section sub-parallel to regional dip through the main part of the Big Sandy Gas Field. The cross section, Figure 18, was compiled using the Petra software from GeoPlus Corporation and shows the facies transition from predominantly black, organic-rich shales in the west to predominantly clastic-rich gray shales toward the basin center (eastward). To determine the maximum gray shale density for using Schmoker's (1993) method to determine TOC, gamma ray versus density cross plots were made for these 18 wells. Two plots of this type are shown in Figure 19. With reference to the top plot in the figure, the general pattern for sandstone units, in this case the Mississippian Berea Sandstone, indicates a cluster between densities of 2.4 to 2.8 grams per cubic centimeter (g/cm^3) with the natural gamma-ray being less than 200 API units. Gray shales with little organic matter (the Three Lick Bed, Middle Huron, and Chagrin) cluster between densities of 2.55 and 2.82 g/cm^3 and a gamma-ray reading generally between 150 and 250 API units. The black, organic rich units, however, show a wide variation along a broad, linear trend supporting Schmoker's assumptions. The same pattern holds for individual wells (see bottom cross plot in Figure 19). For calculating TOC from the density curve using the method of Schmoker (1993) a bulk density of 2.82 g/cm^3 was determined from the cross plots for the maximum density of the gray shale sections of the Ohio Shale.[1] To facilitate spatial analysis of TOC and CO_2 adsorption capacity of the shale, digital log data for the shale interval in 109 wells (including the cross section wells) were converted to the LAS digital log format. These logs and stratigraphic data were imported into the Petra geologic software program for mapping and contouring.

Initial estimates of CO_2 sequestration capacity were calculated using shale volumetric data and an assumed CO_2 adsorption capacity of 40 scf/ton of shale indicate a sequestration volume of 25 billion metric tonnes in the areas of the Illinois and Appalachian Basins where the Devonian Shale is 1,000 or more feet deep and 50 or more feet thick (see Appendix D). A new estimate of sequestration capacity using the gas adsorption capacity data developed by this research has been compiled for the shale in the Big Sandy Gas Field of Floyd, Knott, Letcher, Martin, and Pike Counties. It is of note that differences in service companies, vintage of log, and logging tool sensitivity and calibration result in gridded data sets (and thus contours) that include multiple "bullseyes." Attempts to smooth or normalize the data generally resulted in featureless maps. Calculations were accomplished using a uniform grid cell size of 1 square kilometer. The net thickness in feet of the interval from the top of the Ohio Shale to the base of the Lower Huron with greater than 4 percent TOC is shown in Figure 20. Metric tonnes of shale were determined by multiplying this grid by a grid of average shale density data from digital logs. TOC data from density logs were used to calculate a gas storage capacity grid assuming the model of Figure 17.

[1] *The density value of 2.82 g/cm^3 equals or exceeds the density of the most common mineral components of the shale. Two things should be understood: 1) This density is derived from geophysical log data and is used in calculations involving log data. For more information, see for example Asquith and Krygowski (2004, p. 39-40). 2) Sufficient pyrite is dispersed in the shale matrix to account for the specified density value.*

The product of the gas storage capacity and tons of shale in place grids is shown in Figure 21. Totaling these data over the 5 county area yields a CO_2 sequestration capacity of 6.9 billion metric tonnes.

Conclusions

- TOC content of the shale can be estimated from density log data.
- TOC data can be used as a proxy to estimate adsorptive capacity of the shale.
- Within the Devonian shale of eastern Kentucky, the Lower Huron Member of the Ohio Shale has the greatest CO_2 adsorption capacity.
- Whole rock cores are more representative of in-situ conditions expected in the subsurface, but the low permeability of shale resulted in flow-through and adsorption isotherm experiments that took longer than expected.
- Limited data (one sample) suggests adsorption isotherm data determined from whole rock samples are comparable to that data derived from powdered drill cuttings.
- Limited data (four samples) from the Illinois Basin suggest the Devonian New Albany Shale has adsorption characteristics similar to those of the Ohio Shale of the Appalachian Basin.
- Estimates using the distribution of gas storage capacity of CO_2 from TOC data indicate a sequestration capacity of 6.8 billion tonnes in the five-county area of the Big Sandy Gas Field of eastern Kentucky.
- Assuming a conservative thickness weighted average adsorption capacity of 40 scf/ton (at 400 psia), as much as 28 billion tons total in the deeper and thicker portions of the Devonian shales in the Appalachian and Illinois Basins of Kentucky.
- Enhanced production of natural gas displaced by injected CO_2 would contribute to a long-term increase in the supply of what is considered a "greener" fuel.
- Adsorption data indicate that black, organic-rich gas shales can serve as targets for sequestration of significant volumes of anthropogenic CO_2.

Future

Enhanced production of natural gas displaced by CO_2 injection remains to be demonstrated; the experiments to investigate enhance gas recovery from the shale will continue. These pending flow-through data and the data developed by this project will be expanded in research conducted through the Regional Carbon Sequestration partnerships active in the Illinois and Appalachian Basins. Two-phase dual-porosity reservoir modeling will be used to history match shale gas production and to study CO_2 injection. These efforts will result in a better understanding of continuous, low permeability shales as gas reservoirs, sequestration targets, and seals for sequestration and provide data for the siting, design, and implementation of the field test required to test this concept.

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Conversion Factors

1 U.S. ton = 2,000 pounds = 0.907185 metric tonnes
17.25 thousand cubic feet (Mcf) of CO_2 at 60°F and 1 atmosphere = 1 U.S. ton of CO_2

Abbreviations and Units

bcf	billion cubic feet of gas (volume)
g/cm^3	grams per cubic centimeter (density)
Mcf	thousand cubic feet of gas = 28.317 m^3 (volume)
Mcf/d	thousand cubic feet of gas per day (rate)
Mm^3	thousand cubic meters of gas (volume)
MMm^3	million cubic meters of gas (volume)
Mm^3/d	thousand cubic meters of gas per day (rate)
MMcf	million cubic feet of gas (volume)
MPa	megapascals (pressure)
psi `	pounds per square inch (pressure)
tcf	trillion cubic feet of gas (volume)

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Tables

Table 1. **Gas storage capacity, total carbon (TC), total organic carbon (TOC), and vitrinite reflectance data for completed samples.**

Well ID	Sample	Formation	Langmuir Coefficients CH_4 scf/ton	CH_4 PSIA	Langmuir Coefficients CO_2 scf/ton	CO_2 PSIA	TOC (Acid*)	$R_{0random}$	Sulfur%
2	107928-1	Upper Ohio	4.6	377.8	37.5	681.1	0.69	1.55	
2	107928-2	Lower Huron	34.6	443.2	67.6	243.7	2.95	1.48	
2	107928-3	Lower Ohio	4.9	176.2	34.6	253.1	1.60	1.59	
7	121774-1	Ohio Shale			126.5	989.8	3.66	1.1	
15	124789-1	Upper Ohio			740.8	6419.1	3.26	0.78	
15	124789-2	Lower Huron			2077.6	14283.5	4.62	0.81	Not analyzed
15	124789-3	Lower Ohio			116.2	957.9	1.78	0.83	
8	123486-1	Upper Ohio	Not analyzed		228.9	2230.4	2.44	0.78	
8	123486-2	Lower Ohio			309.3	2106	4.13	0.82	
3	121162-1	Ohio Shale			164.2	1561.3	2.37	0.85	
6	121464-1	Upper Ohio			52.6	708.9	1.18	1.52	
6	121464-2	Lower Huron			248.7	751.2	3.60	1.52	
6	121464-3	Lower Ohio			108	819	2.31	1.51	
21	107310-1	Selmier Shale	172.6	1428.1	607.3	1390.3	14.7		2.26
21	107310-2	Blocher Shale	118.7	2097.6	408.5	1456.5	3.69		1.42
22	119139-1	Selmier Shale	109.5	1148.7	321	781.5	11.79		1.37
22	119139-2	Blocher Shale	68.4	1513.2	283	1444.1	5.37		1.63
13	123957-1	Upper Ohio	33.5	2170.8	218.7	1977.5	2.34	Not analyzed	2.4
13	123957-2	Lower Huron	43.7	1126.7	271	1742	4.73		2.5
17	125651-1	Upper Ohio	36.7	1497.9	90.7	455.4	1.96		2.06
17	125651-2	Lower Huron	22.7	1445.3	146.1	978.5	3.05		2.4
17	125651-3	Lower Ohio	4.5	936.4	79.5	493.4	0.73		1.79
20	AEP#1-1	Lower Huron	26	1566.7	111.7	810	1.54		1.87
19	128253-C9	Cleveland							
19	128253-C8	Chagrin							
19	128253-C5	Upper Huron	Not Analyzed		Analyses continuing		Not Analyzed		
19	128253-C3	Middle Huron							
19	128253-C2	Lower Huron			174.75	993.88			

See Appendix A for key to identification numbers
** Samples washed in HCl to remove carbonate (inorganic carbon)*
Scf/ton = standard cubic feet per ton
psia = pressure, pounds per square inch absolute

Table 2. Summary of CO_2 adsorption capacity in standard cubic feet per ton at selected pressures.

Well ID	Sample ID	Formation	PSIA 200	PSIA 400	PSIA 600
7	121774-1	Ohio Shale	21.26	36.41	47.74
3	121162-1	Ohio Shale	18.65	33.49	45.58
20	AEP#1-1	Ohio Shale	22.12	36.93	47.53
	Average	**Ohio Shale**	**20.17**	**35.08**	**46.61**
2	107928-1	Upper Ohio	8.51	13.87	17.56
15	124789-1	Upper Ohio	22.38	43.45	63.32
6	121464-1	Upper Ohio	11.57	18.97	24.11
8	123486-1	Upper Ohio	18.84	34.81	48.52
13	123957-1	Upper Ohio	20.09	36.79	50.91
17	125651-1	Upper Ohio	27.68	42.41	51.56
	Average	**Upper Ohio**	**18.18**	**31.72**	**42.67**
2	107928-2	Lower Huron	30.47	42.01	48.07
15	124789-2	Lower Huron	28.69	56.60	83.75
6	121464-2	Lower Huron	52.29	86.41	110.44
13	123957-2	Lower Huron	27.91	50.61	69.43
17	125651-2	Lower Huron	24.79	42.39	55.53
	Average	**Lower Huron**	**32.83**	**55.60**	**73.45**
2	107928-3	Lower Ohio	15.27	21.19	24.33
15	124789-3	Lower Ohio	20.07	34.23	44.75
6	121464-3	Lower Ohio	21.20	35.44	45.67
8	123486-2	Lower Ohio	26.83	49.37	68.58
17	125651-3	Lower Ohio	22.93	35.59	43.63
	Average	**Lower Ohio**	**21.26**	**35.16**	**45.39**
21	107310-2	Blocher Shale	49.32	88.02	119.18
22	119139-2	Blocher Shale	34.43	61.38	83.07
	Average	**Blocher Shale**	**41.87**	**74.70**	**101.13**
21	107310-1	Selmier Shale	76.38	135.69	183.08
22	119139-1	Selmier Shale	65.41	108.68	139.41
	Average	**Selmier Shale**	**70.89**	**122.18**	**161.25**

Table 3. Summary of CH_4 adsorption capacity in standard cubic feet per ton at selected pressures

Well ID	Sample ID	Formation	PSIA		
			200	**400**	**600**
20	AEP#1-1	Ohio Shale	2.94	5.29	7.20
	Average	**Ohio Shale**	**2.94**	**5.29**	**7.20**
2	107928-1	Upper Ohio	1.59	2.37	2.82
13	123957-1	Upper Ohio	2.83	5.21	7.25
17	125651-1	Upper Ohio	4.32	7.73	10.50
	Average	**Upper Ohio**	**2.91**	**5.10**	**6.86**
2	107928-2	Lower Huron	10.76	16.41	19.90
13	123957-2	Lower Huron	6.59	11.45	15.19
17	125651-2	Lower Huron	2.76	4.92	6.66
	Average	**Lower Huron**	**6.70**	**10.93**	**13.92**
2	107928-3	Lower Ohio	2.60	3.40	3.79
17	125651-3	Lower Ohio	0.79	1.35	1.76
	Average	**Lower Ohio**	**1.70**	**2.37**	**2.77**
21	107310-2	Blocher Shale	10.33	19.01	26.40
22	119139-2	Blocher Shale	7.99	14.30	19.42
	Average	**Blocher Shale**	**9.16**	**16.66**	**22.91**
21	107310-1	Selmier Shale	21.20	37.77	51.06
22	119139-1	Selmier Shale	16.24	28.28	37.57
	Average	**Selmier Shale**	**18.72**	**33.02**	**44.32**

Figures

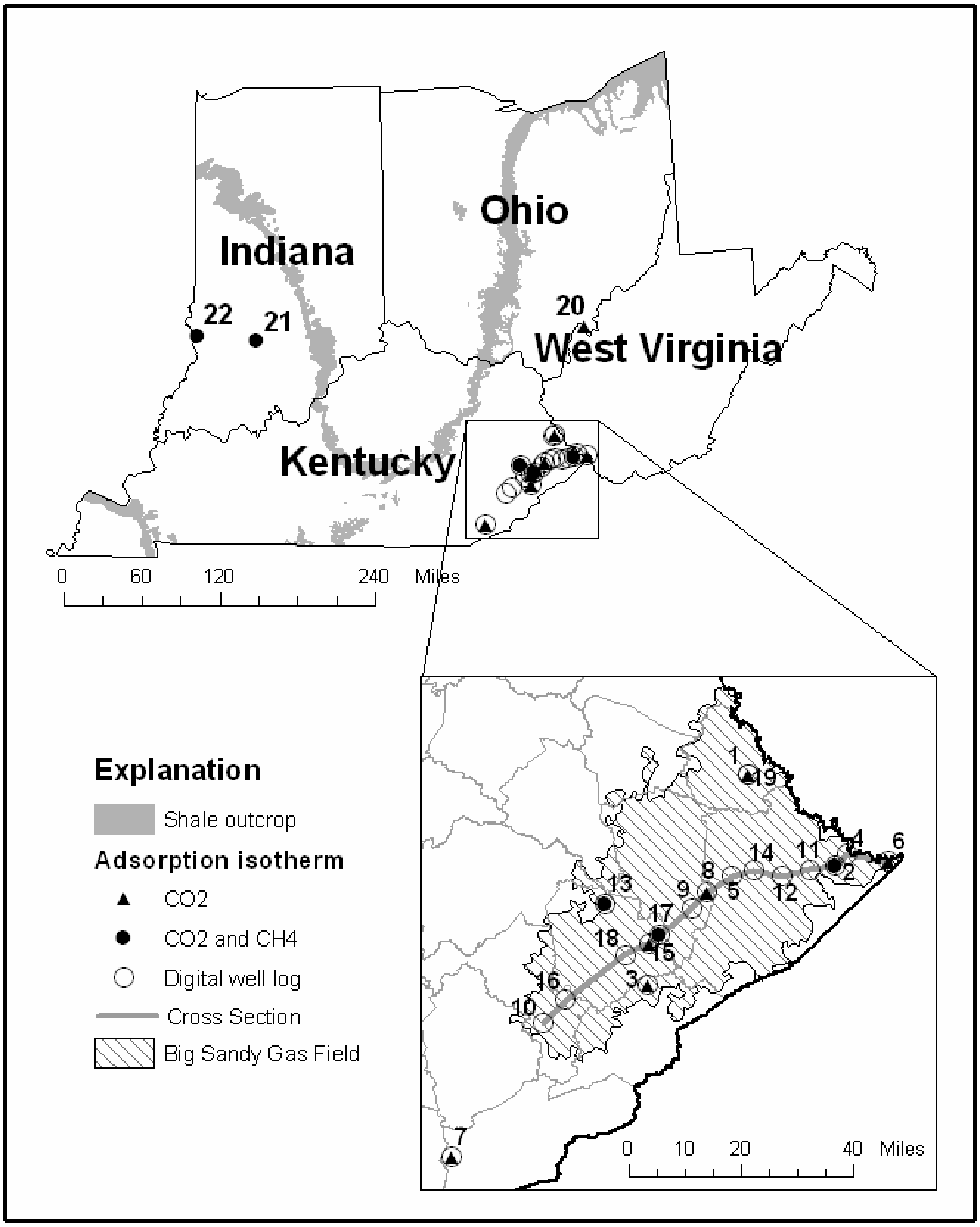


Figure 1. Location of wells used in study. See Appendix A for key to well identifications.

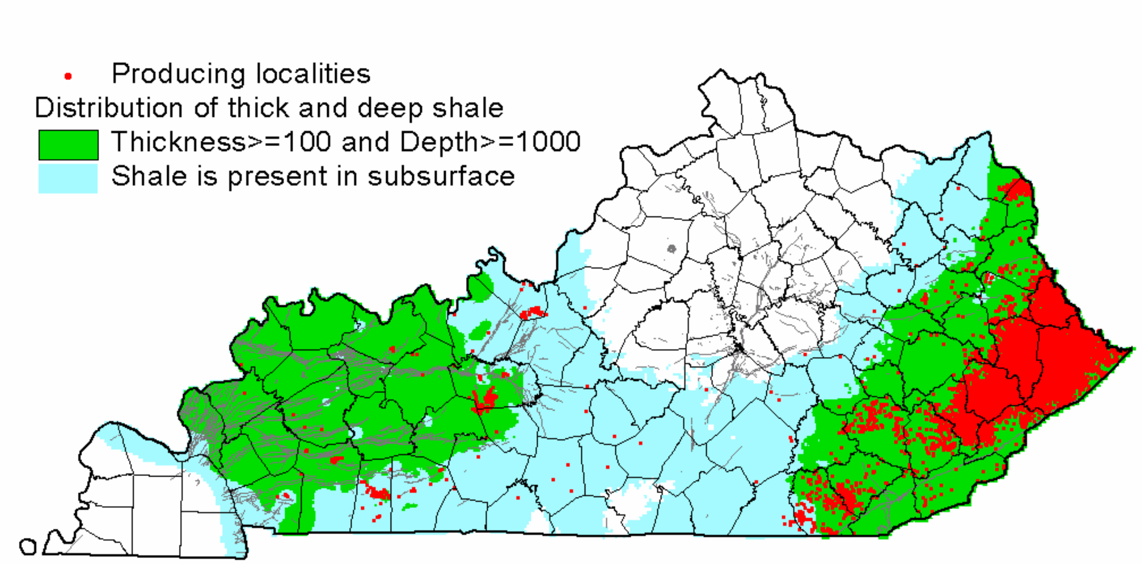


Figure 2. Distribution of the Devonian shale in Kentucky, showing the occurrence of deeper and thicker shale with possibly greater potential for geologic sequestration of CO_2.

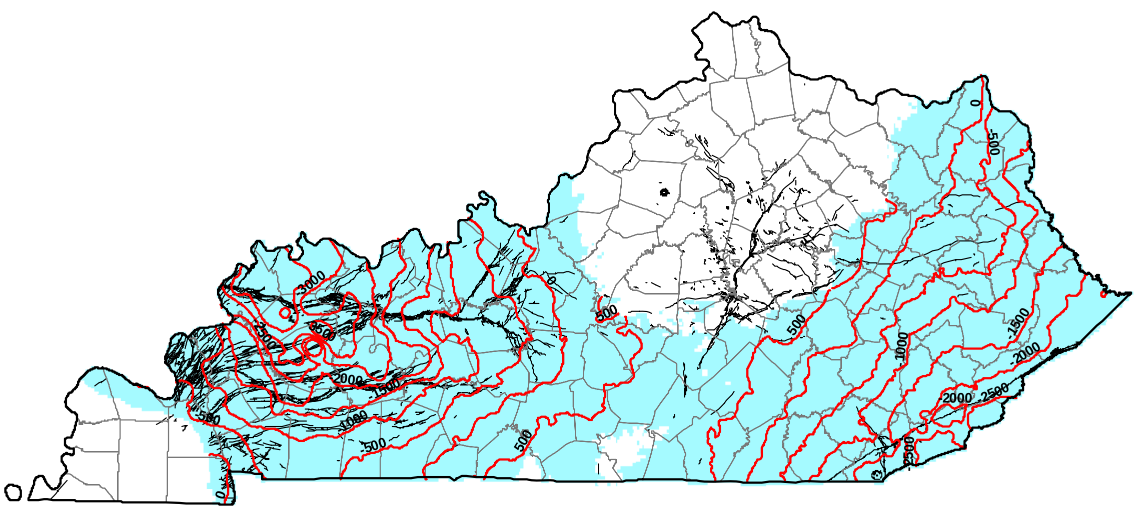


Figure 3. General structure of the Devonian shale, showing presence of shale in the subsurface (shading).

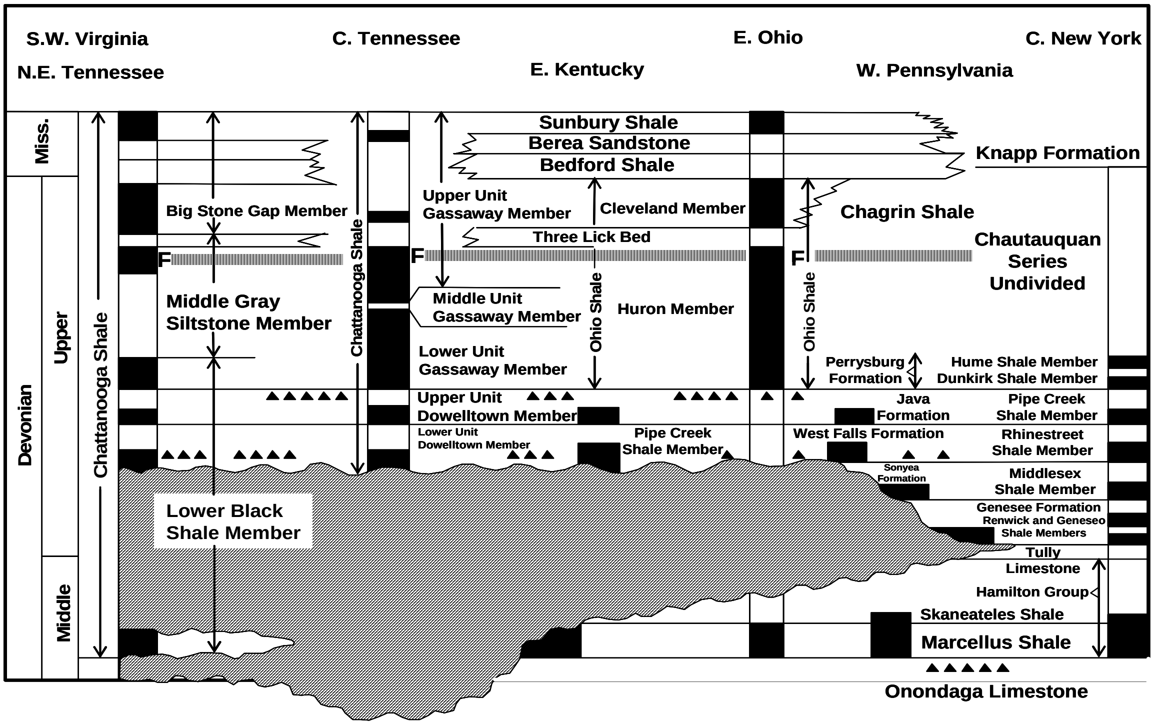


Figure 4. General stratigraphic nomenclature for the Middle and Upper Devonian black shales in the Appalachian Basin. Organic shales are shaded black. "F" indicates the Foerstia Zone. Black triangles indicate major ash beds. Redrawn from de Witt and others (1993). See also Roen and Kepferle, 1993, Plate 2, cross section A-A'.

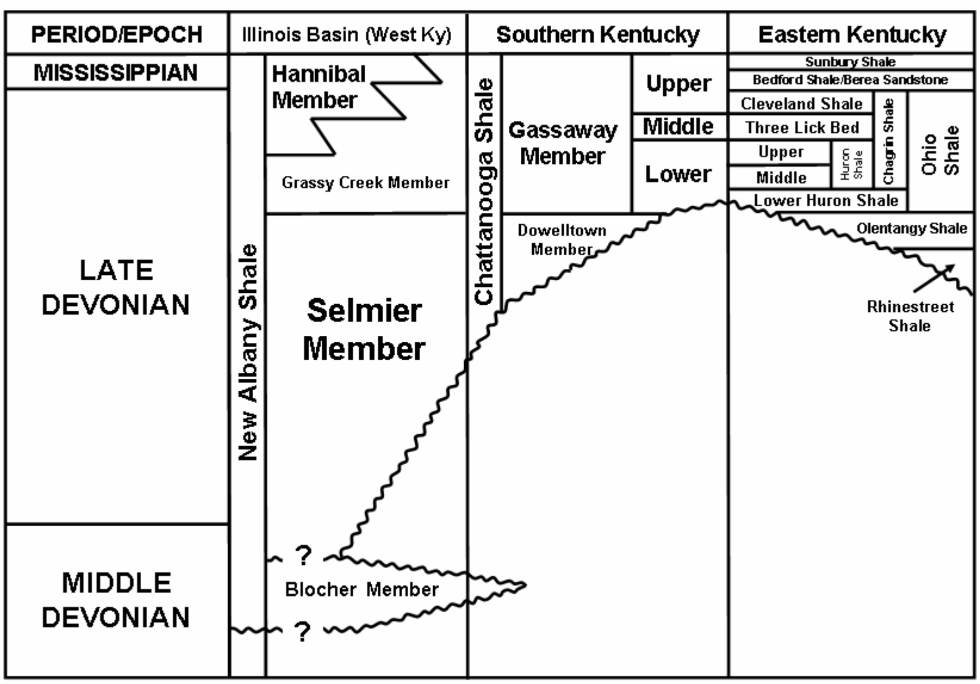


Figure 5. General stratigraphic nomenclature for Kentucky showing correlation of the Illinois Basin units used in this report. Modified from Hamilton-Smith (1993).

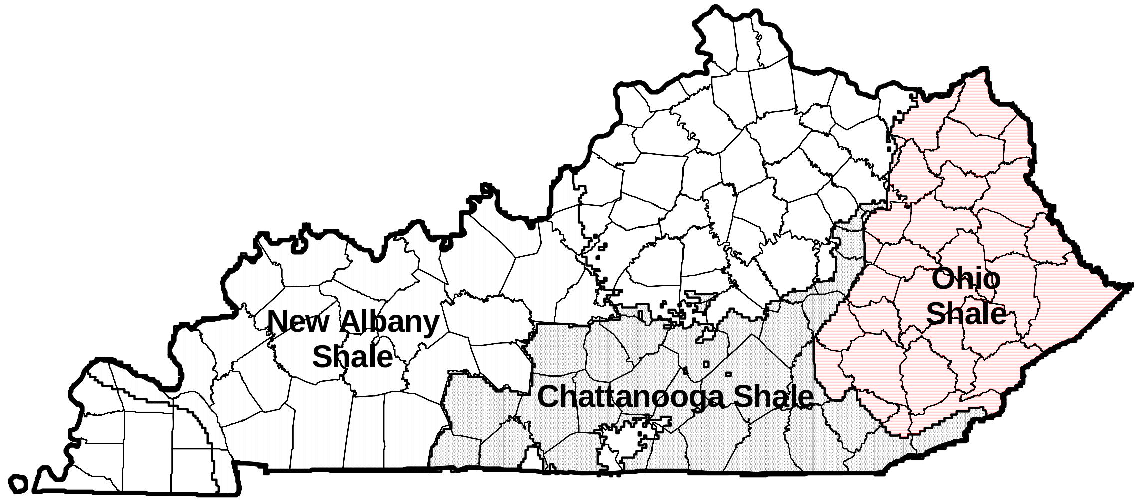


Figure 6. Distribution and nomenclature of Devonian shales of Kentucky (Hamilton-Smith, 1993, p. 3).

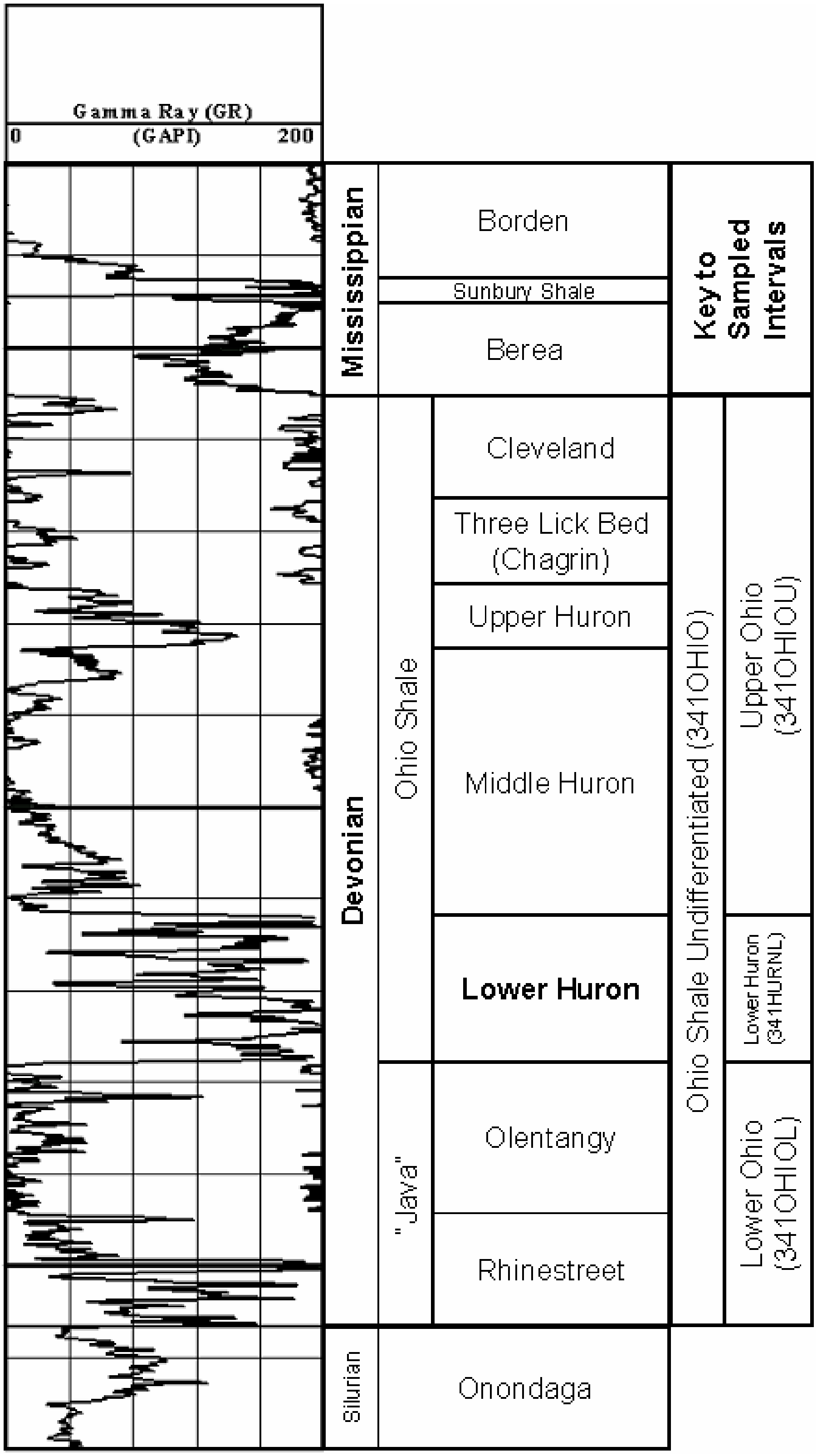


Figure 7. Nomenclature of Mississippian and Devonian shales of eastern Kentucky and key to names and codes used for intervals sampled.

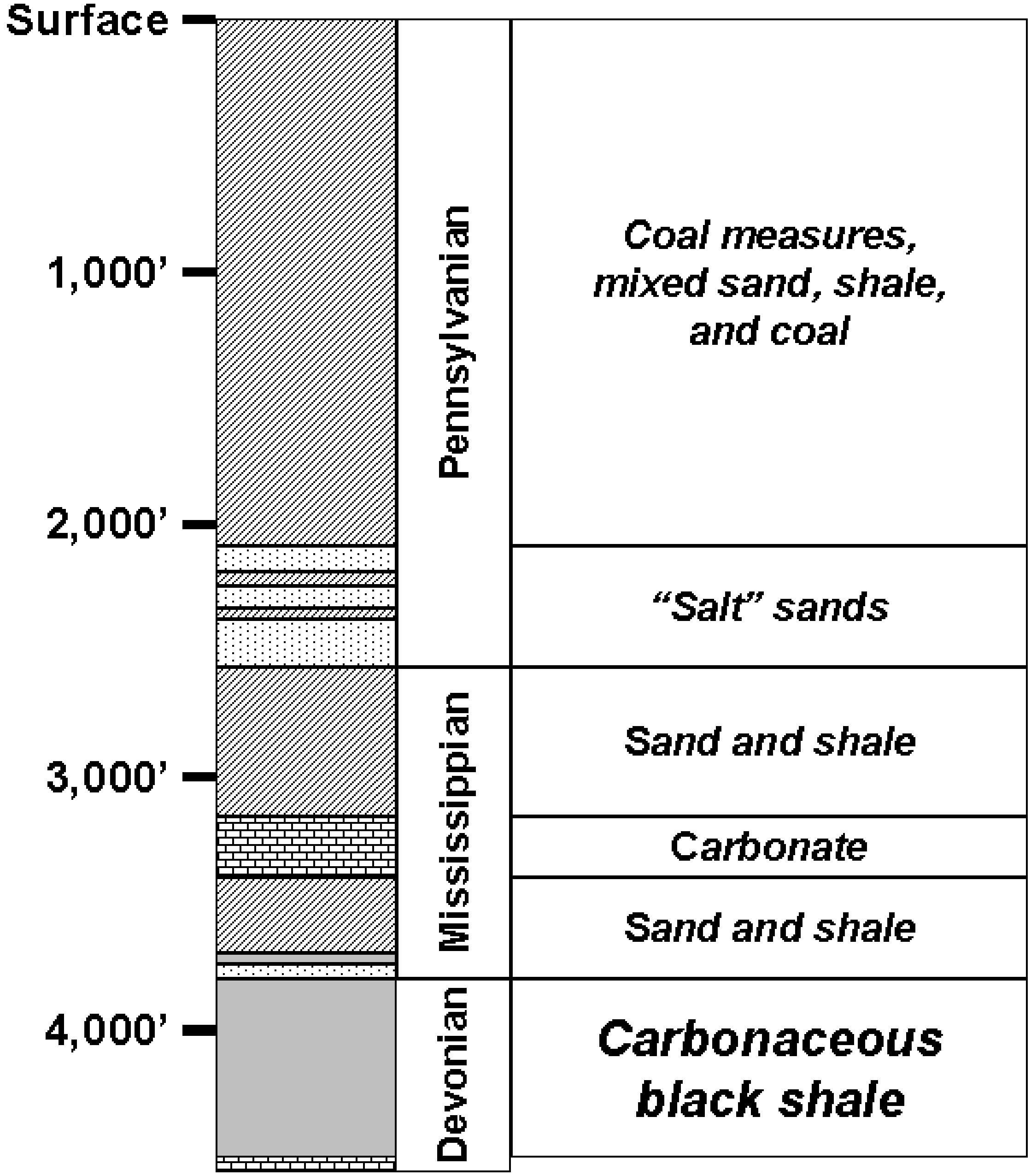


Figure 8. General geologic column showing approximately 3,800 feet of overlying Mississippian and Pennsylvanian lithologies adequate for ensuring reservoir integrity in the Devonian shale. Note: Devonian shale is underlain by Devonian carbonates.

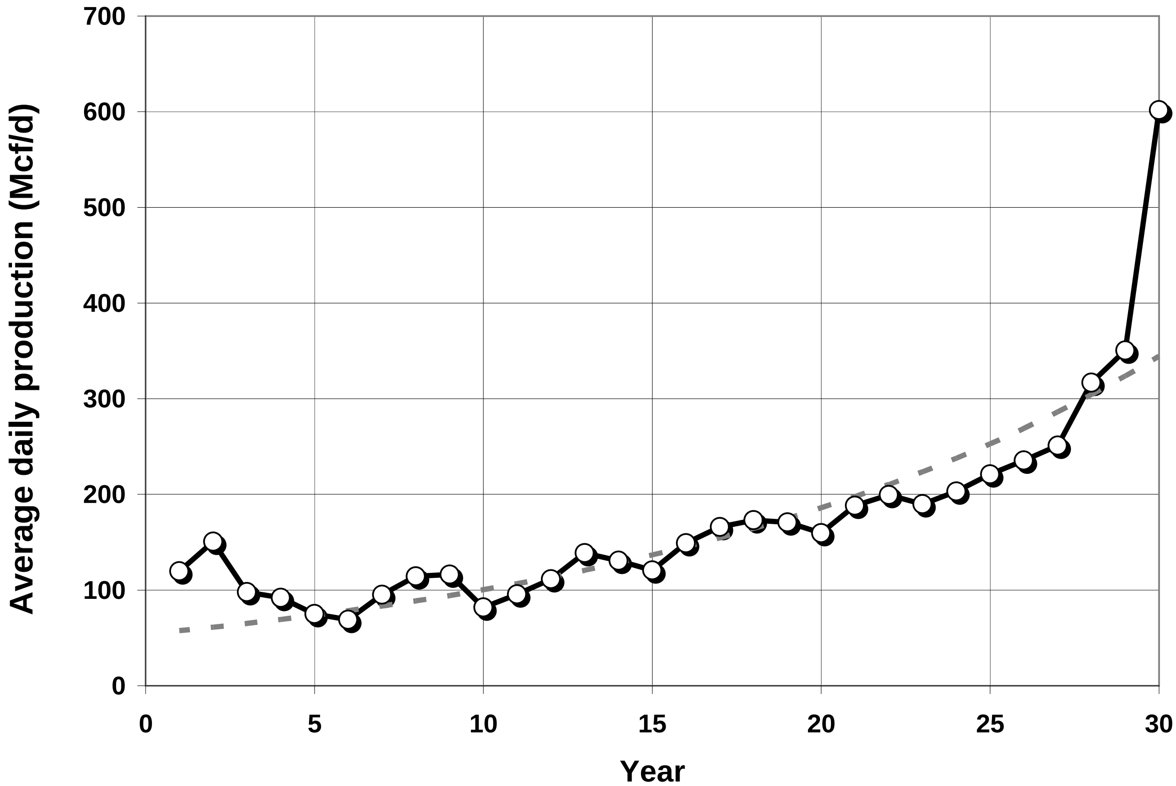


Figure 9. Eastern Kentucky Devonian shale natural-gas production (proprietary data), showing long-term increase. Dotted line is exponential best fit of observed rate-time data.

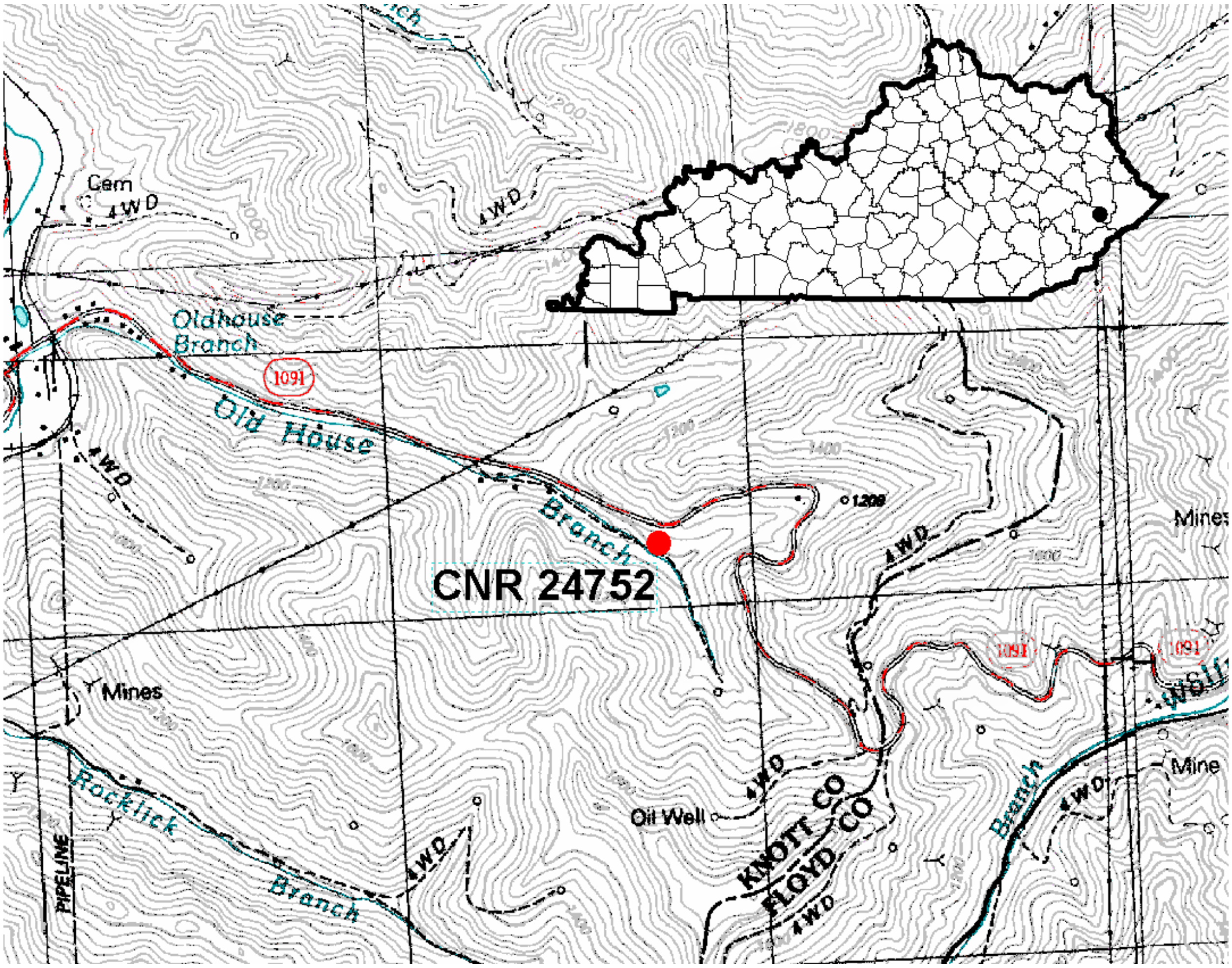


Figure 10. Location of the Columbia Natural Resources 24752 Elk Horn Coal Company well, permit 94539, Knott County, Ky., Carter coordinate 11-K-81, latitude 37.37019º N, longitude 82.76441º W (NAD 1983).

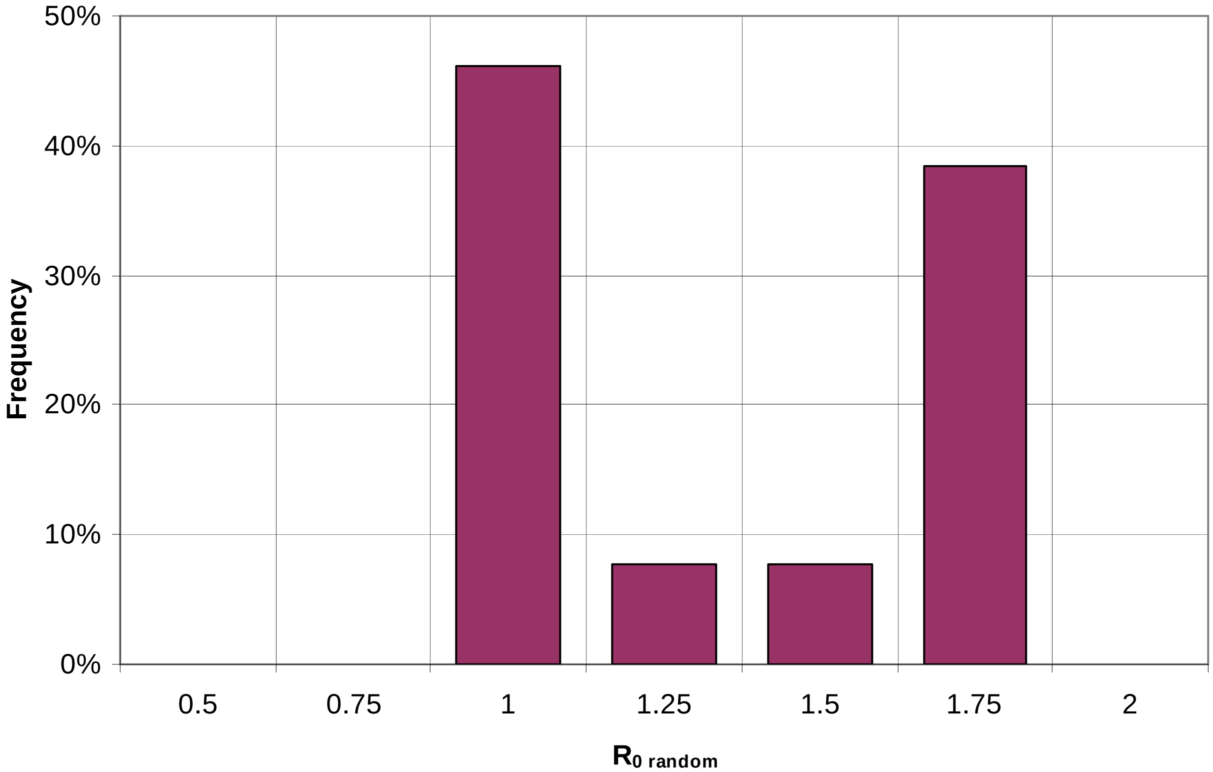


Figure 11. Mean random reflectance ($R_{0\ random}$)

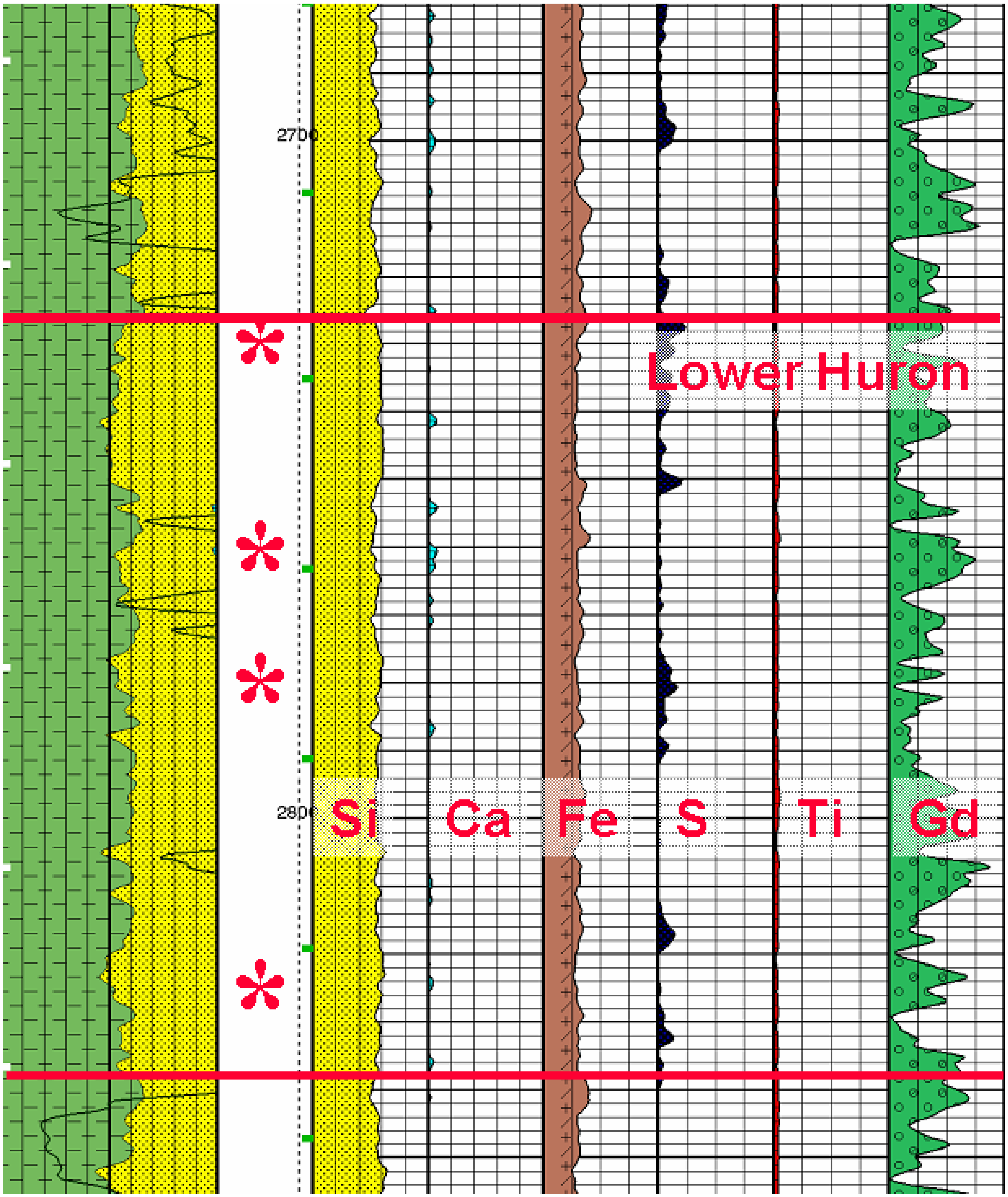


Figure 12. Section of elemental capture spectroscopy log through the Lower Huron section of the Columbia Natural Resources No. 24752 Elk Horn Coal well, Knott County, Ky., showing relative abundance of species related to mineral and lithologic identification. Asterisks denote depths where sidewall cores were recovered.

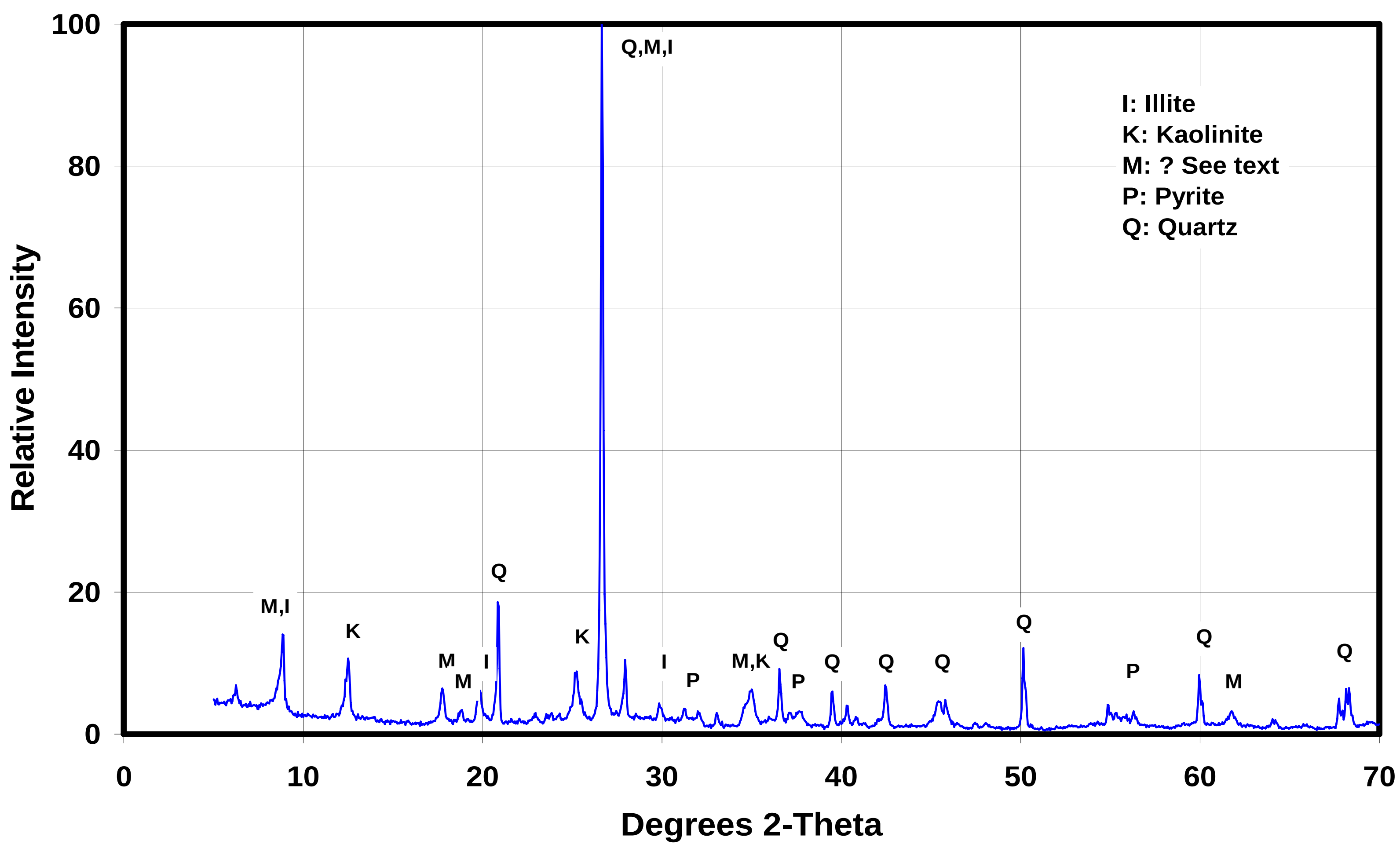


Figure 13. Typical whole rock X-ray diffraction trace of the Devonian shale (upper part, well id 2).

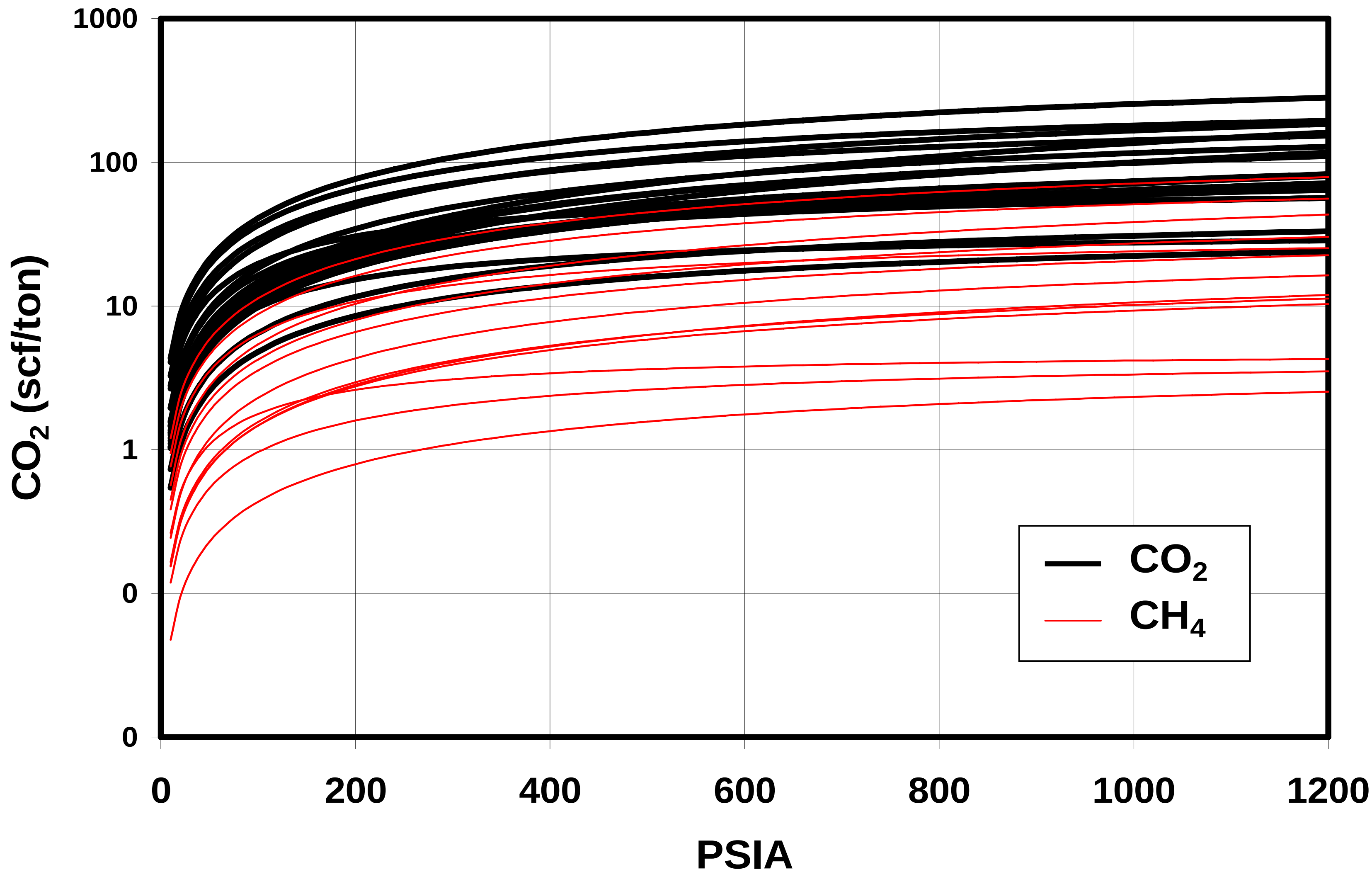


Figure 14. Summary of adsorption isotherms.

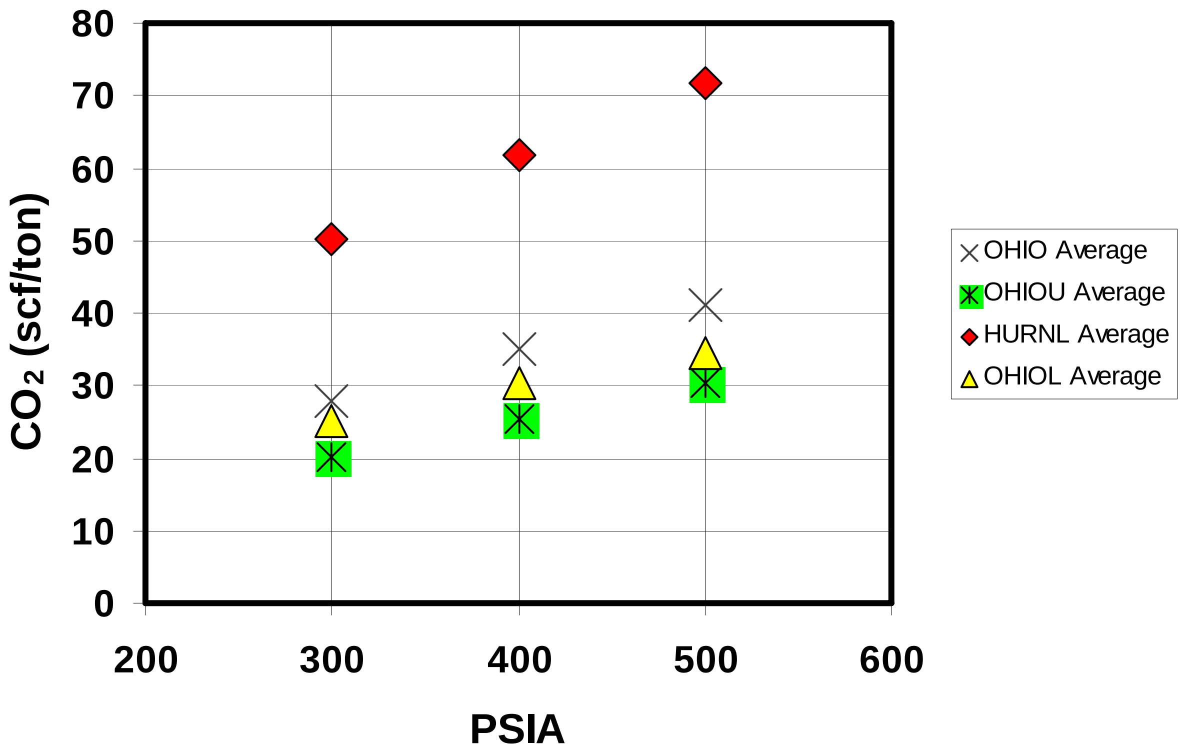


Figure 15. Average calculated adsorption capacities by formation at selected pressures.

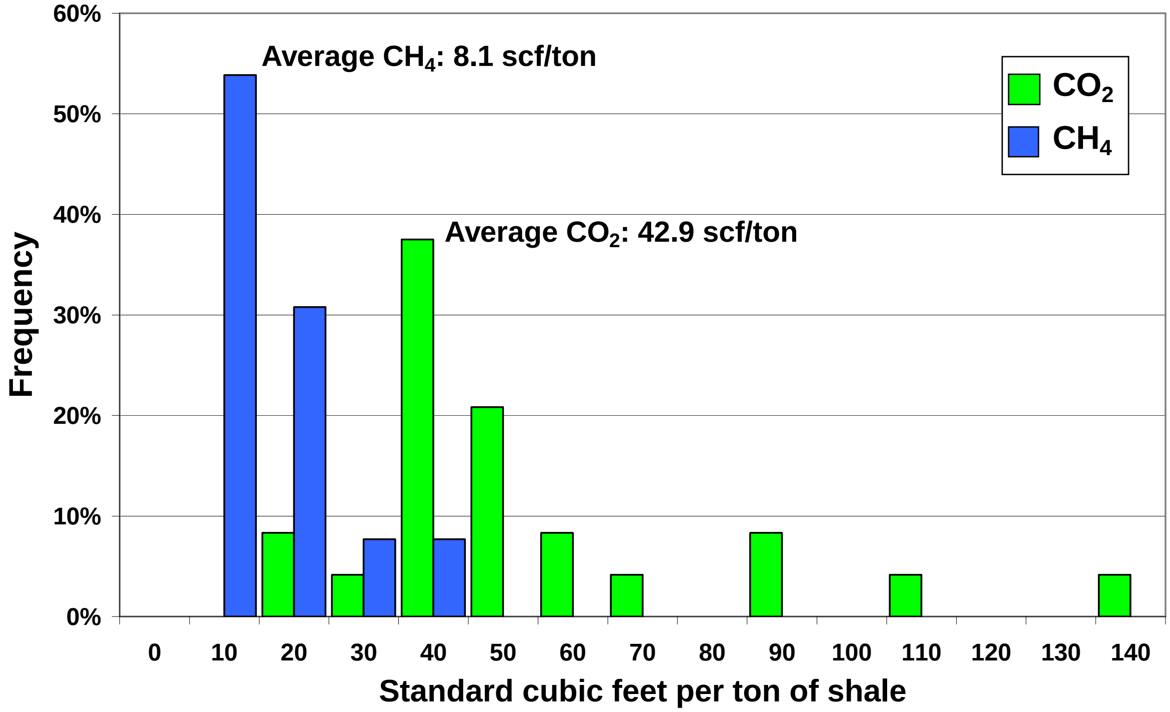


Figure 16. Distribution of observed CO_2 (green) and CH_4 (blue) adsorption capacity.

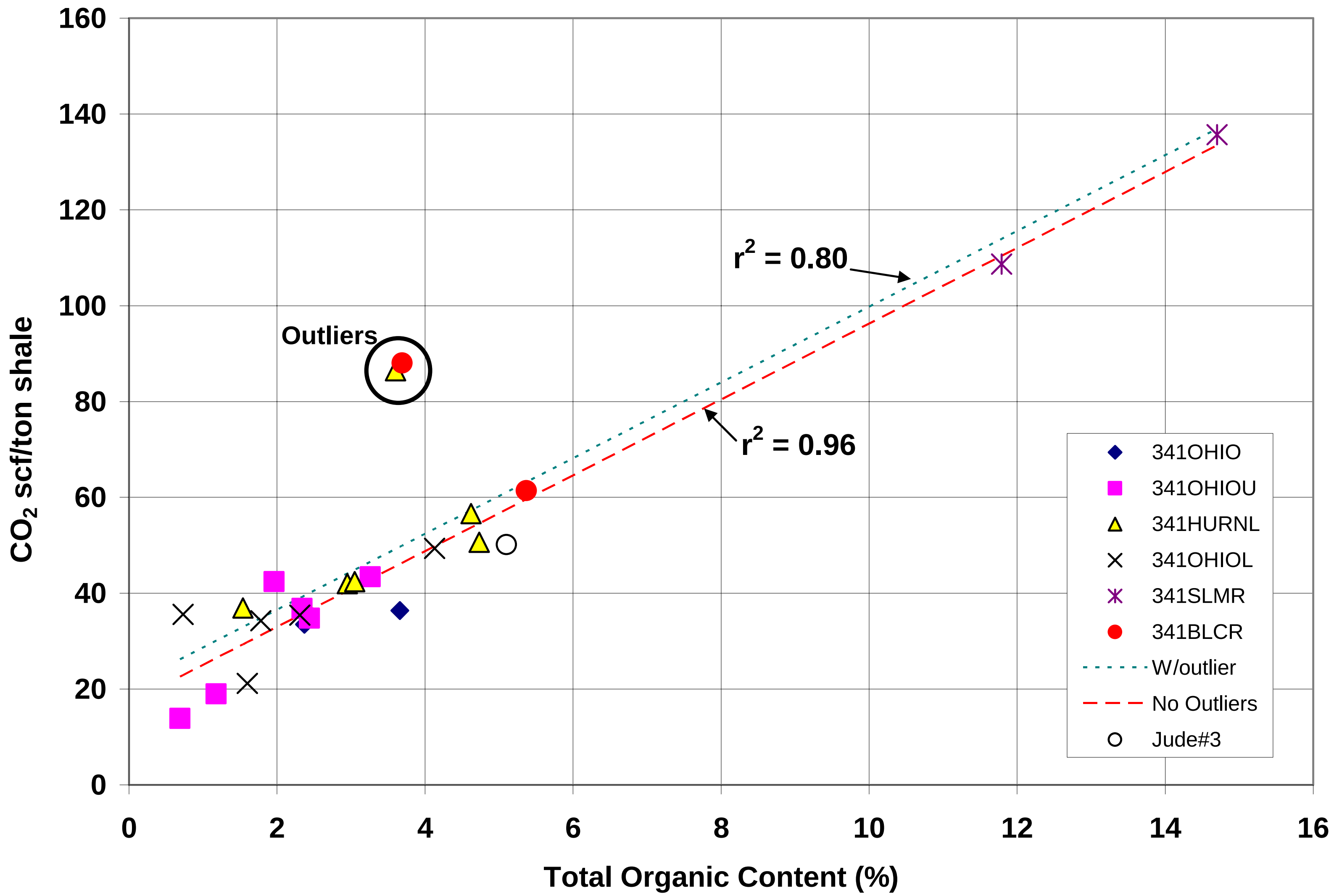


Figure 17. Relationship between total organic content and adsorption capacity of shale at 400 psia.

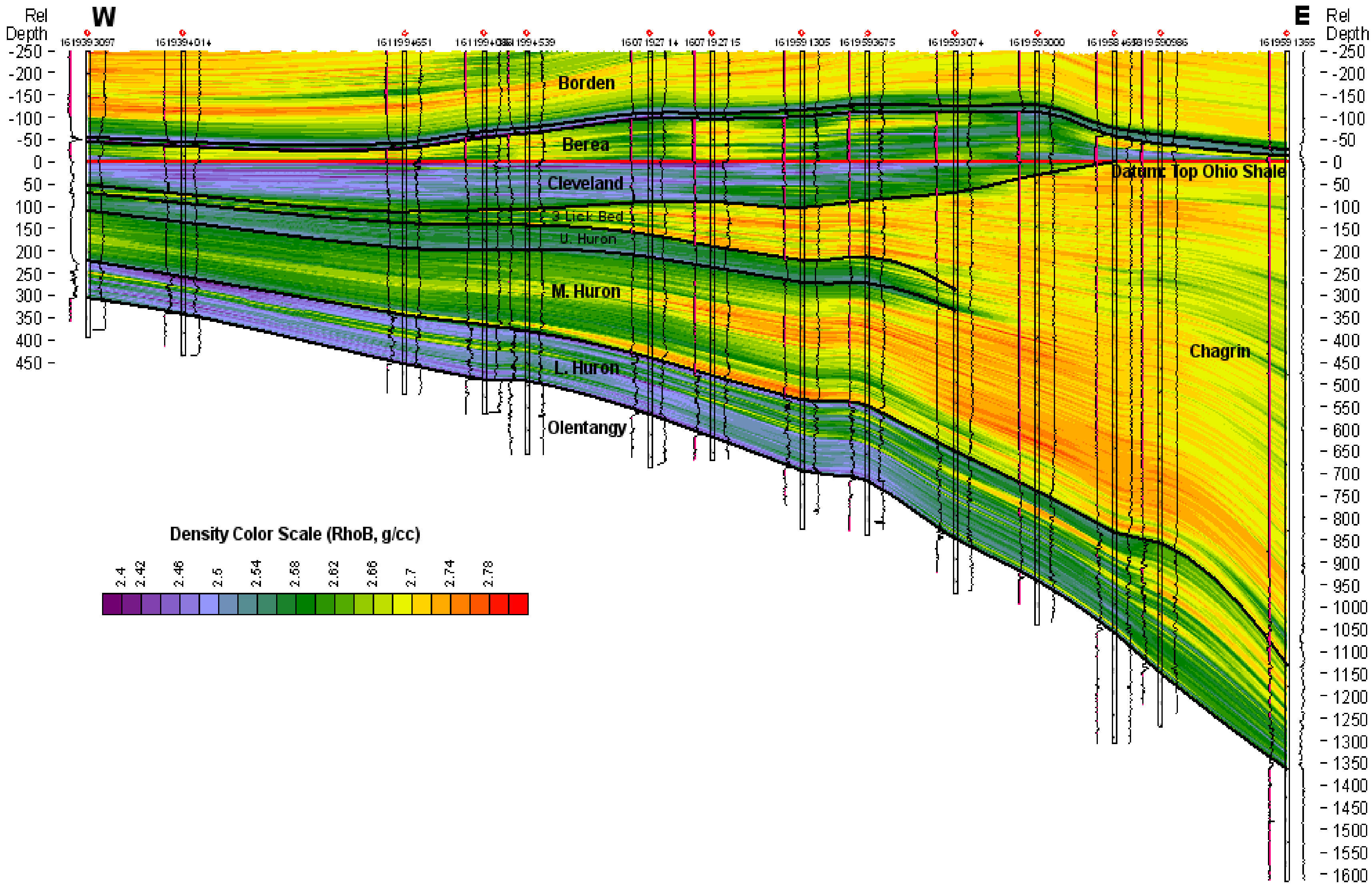
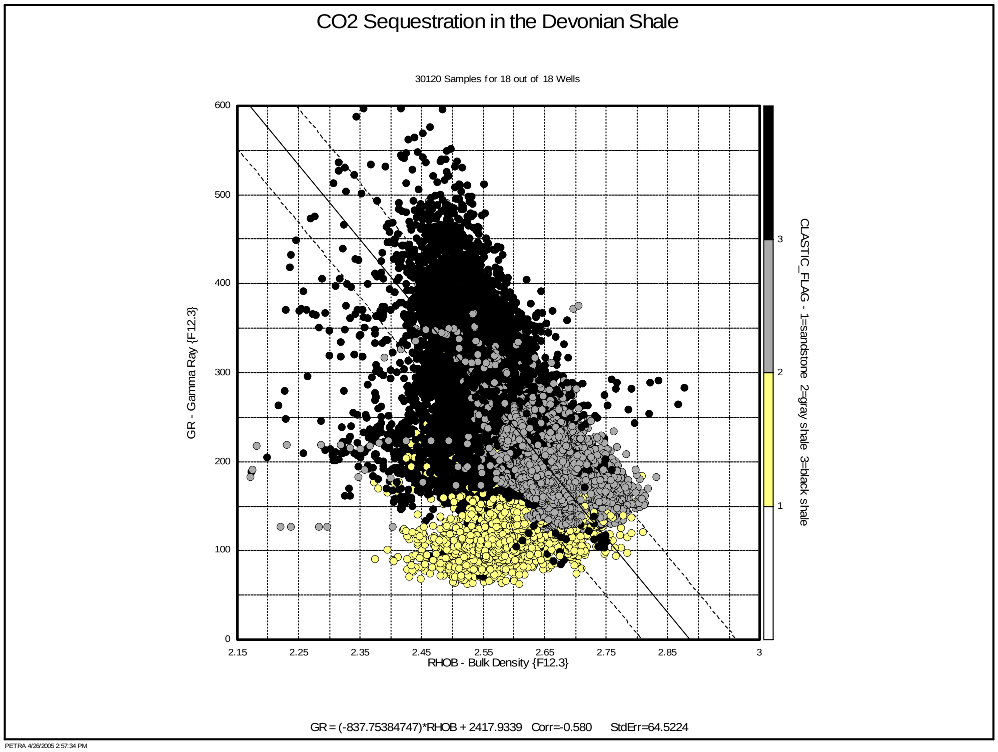


Figure 18: West (left) to east (right) cross section of Big Sandy Gas Field color-shaded based on density. Low densities (darker colors) indicate organic-rich zones. See Figure 1 for location of section.



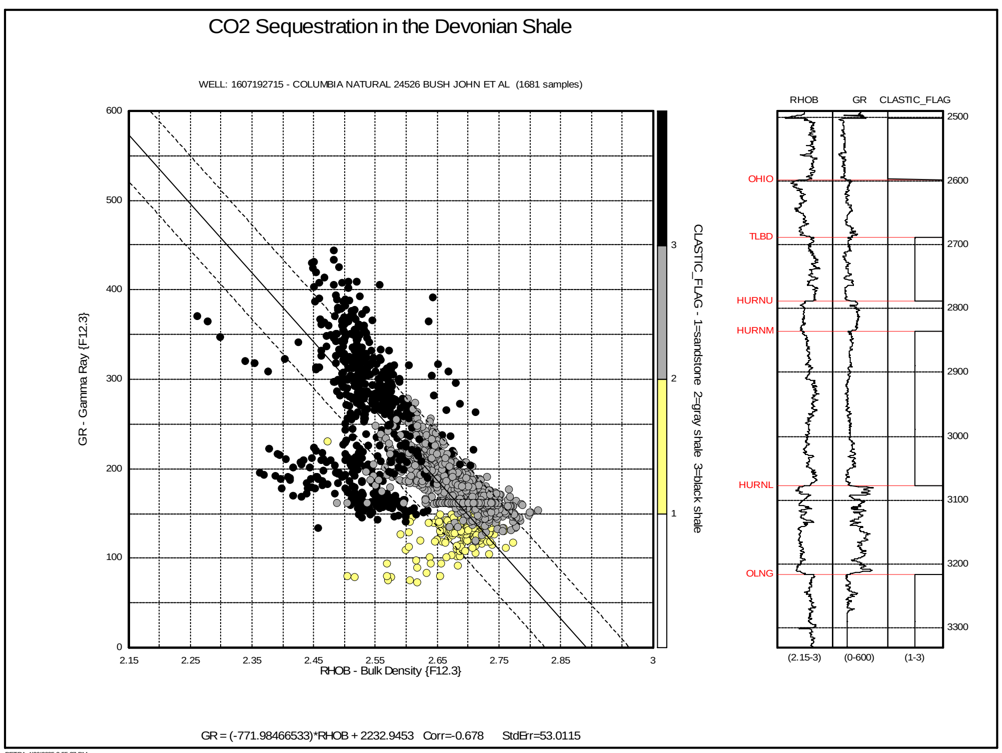


Figure 19. Gamma-ray density cross plots showing variation by general lithotype: all wells combined (top) and the CNR #24526 Bush (bottom).

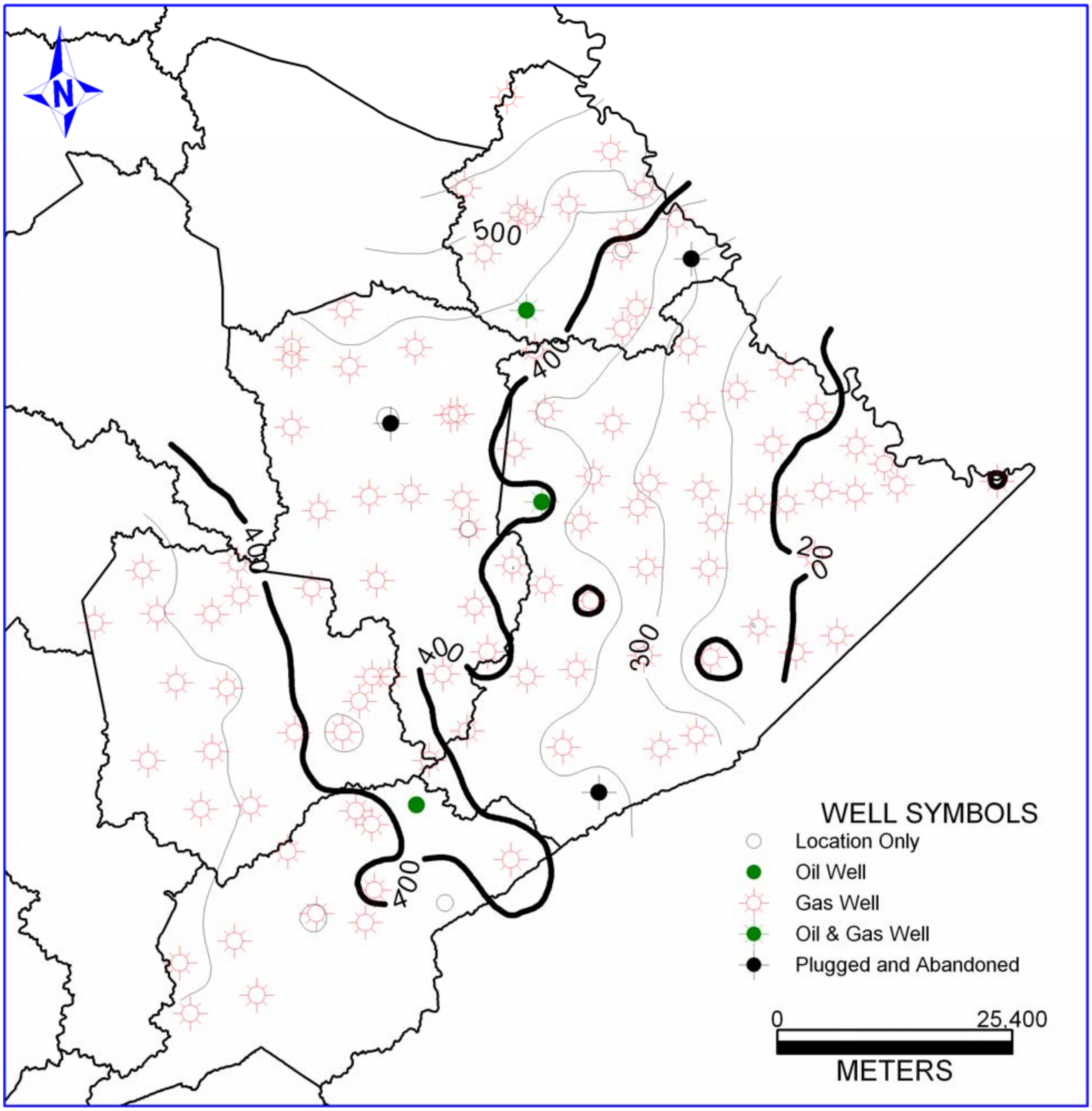


Figure 20. Net thickness in feet of the interval from the top of the Ohio Shale to the base of the Lower Huron with 4 percent or more total organic carbon. Contour interval is 50 feet.

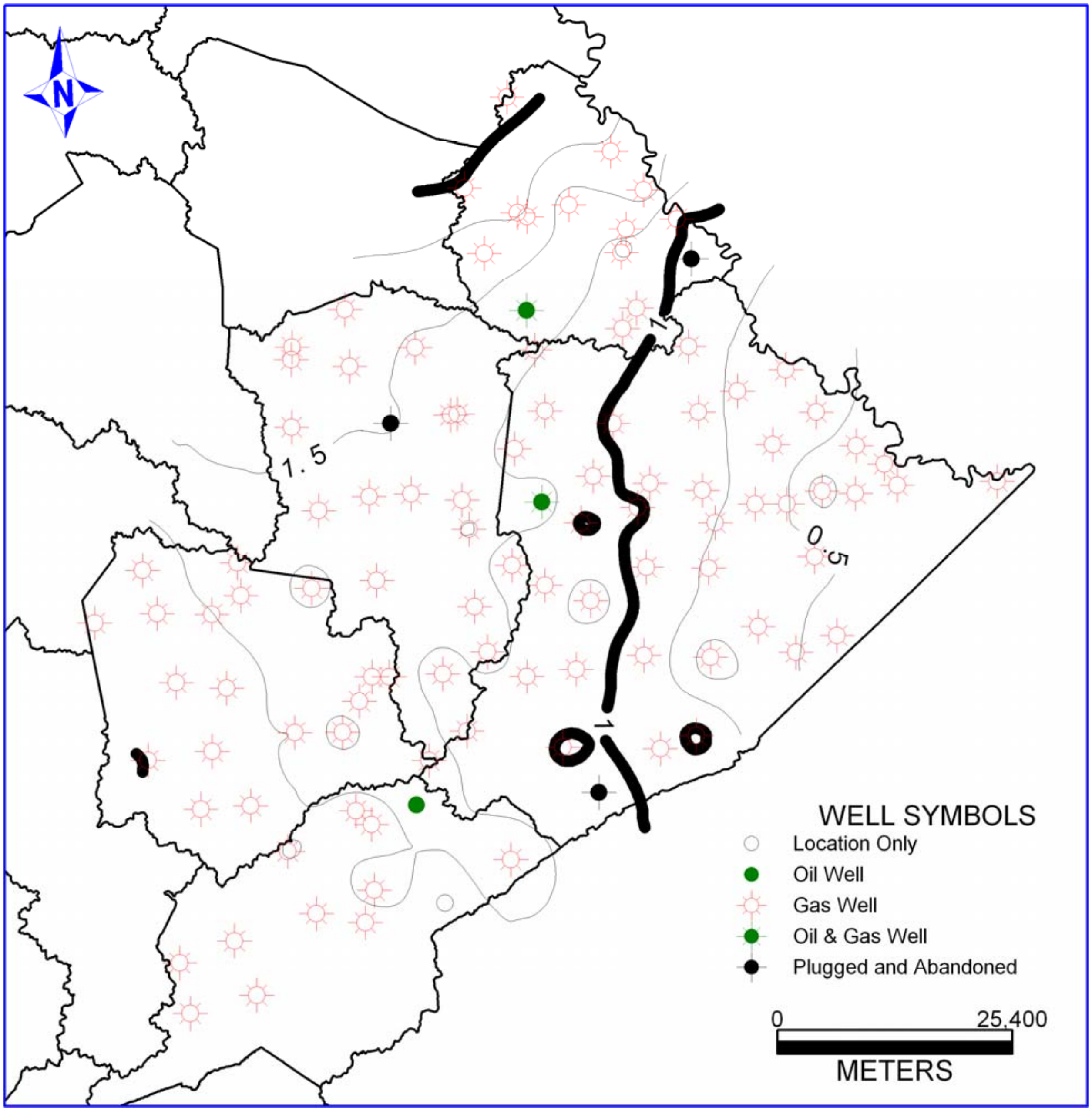


Figure 21. Million metric tonnes of carbon storage capacity per square kilometer in the Big Sandy Gas Field area. Contour interval is 0.25 million metric tonnes per square kilometer.

Appendix A: Key to Well Identification and Locations

Wells without a table providing identifying data for samples were selected for compiling digital logs for the cross section.

1) J M L OIL & GAS CO 117 HOWARD P H HEIRS

API: 1615900149 (KGS Record Number: 88596)
Kentucky Lat: 37.772824 Lon: -82.456355 (NAD83) Elev: 872 (ft)
12/9/1988 Total depth: 3350: Deepest formation: Ohio Shale

2) ASHLAND EXPLORATION INC 60 FORD MOTOR COMPANY

API: 1619502691 (KGS Record Number: 107928)
Kentucky Lat: 37.527149 Lon: -82.185245 (NAD83) Elev: 1261 (ft)
10/8/1993 Total depth: 6130: Deepest formation: Ordovician Sequatchie Fm
Drill cuttings:

Sample ID	Formation	Top (ft)	Base (ft)
107928-1	Upper Ohio	3600	4400
107928-2	Lower Huron	4400	4600
107928-3	Lower Ohio	4600	5000

3) KINZER J W 1003 PIKE LETCHER LAND CO

API: 1613300570 (KGS Record Number: 121162)
Kentucky Lat: 37.240961 Lon: -82.812138 (NAD83) Elev: 1590 (ft)
11/17/2000 Total depth: 3814: Deepest formation: Ohio Shale
Drill cuttings:

Sample ID	Formation	Top (ft)	Base (ft)
121162-1	Ohio Shale	3410	3810

4) EASTERN STATES OIL & GAS INC 1-285 EMPEROR COAL CO

API: 1619504276 (KGS Record Number: 121220)
Kentucky Lat: 37.554156 Lon: -82.147841 (NAD83) Elev: 1117 (ft)
4/25/2000 Total depth: 4600: Deepest formation: Olentangy Shale

5) EASTERN STATES OIL & GAS INC 4-142 WEDDINGTON HEIRS

API: 1619504343 (KGS Record Number: 121447)
Kentucky Lat: 37.511816 Lon: -82.521725 (NAD83) Elev: 971 (ft)
8/7/2000 Total depth: 3499: Deepest formation: Olentangy Shale

6) KINZER J W 1052 KINZER J W

API: 1619504361 (KGS Record Number: 121464)
Kentucky Lat: 37.531697 Lon: -82.011368 (NAD83) Elev: 853 (ft)
7/17/2001 Total depth: 5199: Deepest formation: Silurian Salina Fm
Drill cuttings:

Sample ID	Formation	Top (ft)	Base (ft)
121464-1	Upper Ohio	3200	4300
121464-2	Lower Huron	4300	4580
121464-3	Lower Ohio	4580	4980

7) PENN-VIRGINIA OIL & GAS CORP 11 KENTENIA

API: 1609500131 (KGS Record Number: 121774)
Kentucky Lat: 36.812600 Lon: -83.471295 (NAD83) Elev: 1196 (ft)
2/5/2001 Total depth: 4327: Deepest formation: Ordovician, Upper Part
Drill cuttings:

Sample ID	Formation	Top (ft)	Base (ft)
121774-1	Ohio Shale	3500	3720

8) COLUMBIA NATURAL RES INC 24526 BUSH JOHN ET AL
API: 1607102052 (KGS Record Number: 123486)
Kentucky Lat: 37.473379 Lon: -82.608091 (NAD83) Elev: 1019 (ft)
8/1/2001 Total depth: 3268: Deepest formation: Ohio Shale
Drill cuttings:

Sample ID	Formation	Top (ft)	Base (ft)
123486-1	Upper Ohio	2600	3070
123486-2	Lower Ohio	3070	3210

9) EQUITABLE PRODUCTION CO KL3-504714 NEWSOME HEIRS F W
API: 1607102053 (KGS Record Number: 123491)
Kentucky Lat: 37.434786 Lon: -82.65654 (NAD83) Elev: 1057 (ft)
10/5/2001 Total depth: 3274: Deepest formation: Olentangy Shale

10) EQUITABLE PRODUCTION CO KL6-504727 SIZEMORE MINING CORP
API: 1619300963 (KGS Record Number: 123783)
Kentucky Lat: 37.150352 Lon: -83.154888 (NAD83) Elev: 1183 (ft)
1/23/2002 Total depth: 3441: Deepest formation: Olentangy Shale

11) EQUITABLE PRODUCTION CO 504973 ROWE G C HRS & FORD MTR CO
API: 1619504597 (KGS Record Number: 123811)
Kentucky Lat: 37.520164 Lon: -82.269443 (NAD83) Elev: 1196 (ft)
12/21/2001 Total depth: 4445: Deepest formation: Olentangy Shale

12) EQUITABLE PRODUCTION CO 505022 EQUITABLE PRODUCTION CO
API: 1619504602 (KGS Record Number: 123846)
Kentucky Lat: 37.505420 Lon: -82.357811 (NAD83) Elev: 905 (ft)
1/9/2002 Total depth: 3925: Deepest formation: Olentangy Shale

13) EQUITABLE PRODUCTION CO 505045 EVANS E J
API: 1611901721 (KGS Record Number: 123957)
Kentucky Lat: 37.455559 Lon: -82.940952 (NAD83) Elev: 1283 (ft)
4/19/2002 Total depth: 2770: Deepest formation: Lower Huron Mbr, Ohio Shale
Drill cuttings:

Sample ID	Formation	Top (ft)	Base (ft)
123957-1	Upper Ohio	2450	2540
123957-3	Lower Huron	2640	2770

14) EQUITABLE PRODUCTION CO 504402 EQUITABLE PRODUCTION CO
API: 1619504758 (KGS Record Number: 124438)
Kentucky Lat: 37.524139 Lon: -82.451645 (NAD83) Elev: 1380 (ft)
10/3/2002 Total depth: 4030: Deepest formation: Olentangy Shale

15) INTERSTATE NATURAL GAS CO 4 DAVIS IDA

API: 1611901759 (KGS Record Number: 124789)
Kentucky Lat: 37.347355 Lon: -82.801601 (NAD83) Elev: 1271 (ft)
10/15/2002 Total depth: 3190: Deepest formation: Ohio Shale
Drill cuttings:

Sample ID	Formation	Top (ft)	Base (ft)
124789-1	Upper Ohio	2680	2990
124789-2	Lower Huron	2990	3110
124789-3	Lower Ohio	3110	3190

16) JOURNEY OPERATING LLC HFDV#4 EQUITABLE PRODUCTION CO

API: 1619300998 (KGS Record Number: 124814)
Kentucky Lat: 37.210278 Lon: -83.0824947 (NAD83) Elev: 1419 (ft)
9/24/2002 Total depth: 3600: Deepest formation: Olentangy Shale

17) COLUMBIA NATURAL RES INC 24752 THE ELK HORN COAL CORP

API: 1611901791 (KGS Record Number: 125651)
Kentucky Lat: 37.370201 Lon: -82.764414 (NAD83) Elev: 1004 (ft)
10/3/2003 Total depth: 3004: Deepest formation: Ohio Shale
Drill cuttings:

Sample ID	Formation	Top (ft)	Base (ft)
125651-1	Upper Ohio	2350	2730
125651-2	Lower Huron	2730	2840
125651-3	Lower Ohio	2840	3010

Sidewall cores:

Sample ID	Formation	Top (ft)	Base (ft)
125651-C10	Cleveland	2370	*N/A*
125651-C9	Three Lick Bed	2455	*N/A*
125651-C8	Three Lick Bed	2465	*N/A*
125651-C7	Upper Huron	2530	*N/A*
125651-C6	Middle Huron	2630	*N/A*
125651-C5	Lower Huron	2730	*N/A*
125651-C4	Lower Huron	2760	*N/A*
125651-C3	Lower Huron	2780	*N/A*
125651-C2	Lower Huron	2835	*N/A*
125651-C1	Lower Huron	2900	*N/A*

18) EQUITABLE PRODUCTION CO 565545 EQUITABLE PRODUCTION CO

API: 1611901930 (KGS Record Number: 125793)
Kentucky Lat: 37.319870 Lon: -82.882185 (NAD83) Elev: 1373 (ft)
4/28/2003 Total depth: 3295: Deepest formation: Ohio Shale

19) INTERSTATE NATURAL GAS CO 3 JUDE JOHN E HEIRS

API: 1615901485 (KGS Record Number: 128253)
Kentucky Lat: 37.776177 Lon: -82.453305 (NAD83) Elev: 844 (ft)
3/23/2005 Total depth: 3272: Deepest formation: Ohio Shale
Sidewall cores:

Sample ID	Formation	Top (ft)	Base (ft)
128253-C10	Cleveland	2492.4	*N/A*
128253-C9	Cleveland	2493	*N/A*
128253-C8	Three Lick Bed	2580	*N/A*
128253-C7	Three Lick Bed	2580.4	*N/A*
128253-C6	Upper Huron	2742.5	*N/A*
128253-C5	Upper Huron	2743	*N/A*
128253-C4	Middle Huron	2776.6	*N/A*
128253-C3	Middle Huron	2777	*N/A*
128253-C2	Lower Huron	3026	*N/A*
128253-C1	Lower Huron	3025.4	*N/A*

20) BATTELLE MEMORIAL INSTITUTE 1 AMERICAN ELECTRIC POWER

API: 4705300423
West Virginia Lat: 38.9761 Lon: -81.9383 (NAD83) Elev: 590 (ft)
7/3/2003 Total depth: 9192: Deepest formation: Precambrian granite
Drill cuttings:

Sample ID	Formation	Top (ft)	Base (ft)
AEP#1-1	Lower Huron	2820	3190

21) INDIANA GEOLOGICAL SURVEY SDH-193 ARMSTRONG

IGS ID: 107310
Indiana Lat: 38.930160 Lon: -86.633910 (NAD83) Elev: 591 (ft)
10/15/1969 Total depth: 1050: Deepest formation: Devonian Limestone
Core samples:

Sample ID	Formation	Top (ft)	Base (ft)
I107310-1	Selmier	940	941
I107310-2	Blocher	1020	1021

22) ENERGY RESOURCES OF INDIANA 1 PHEGLEY FARMS INC

IGS ID: 119139
Indiana Lat: 38.971520 Lon: -87.489070 (NAD83) Elev: 430 (ft)
9/6/1976 Total depth: 2847: Deepest formation: Devonian New Harmony
Core samples:

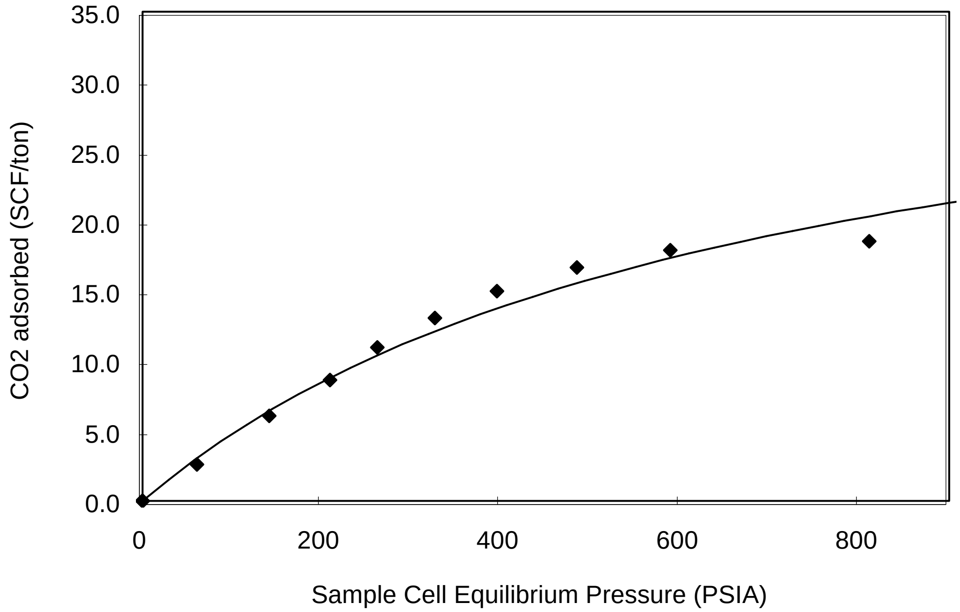
Sample ID	Formation	Top (ft)	Base (ft)
I119139-1	Selmier	2505	*N/A*
I119139-2	Blocher	2553	*N/A*

API numbers provided for Kentucky wells were assigned by the Kentucky Division of Oil and Gas and are the official API numbers for Kentucky oil and gas well data.

Kentucky online data — http://kgsweb.uky.edu/DataSearching/OilGas/OGSearch.asp
Indiana online data — http://igs.indiana.edu/pdms/

Appendix B: Summary of Adsorption Isotherms

107928-1 3600-4000 ft. Ohio Shale (upper part)



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)*** ***In-Situ Conditions (Equilbrium Moisture)***
61	2.6
141	6.1
209	8.6
262	11.0
326	13.1
395	15.0
484	16.7
589	17.9
811	18.6

Langmuir Parameters

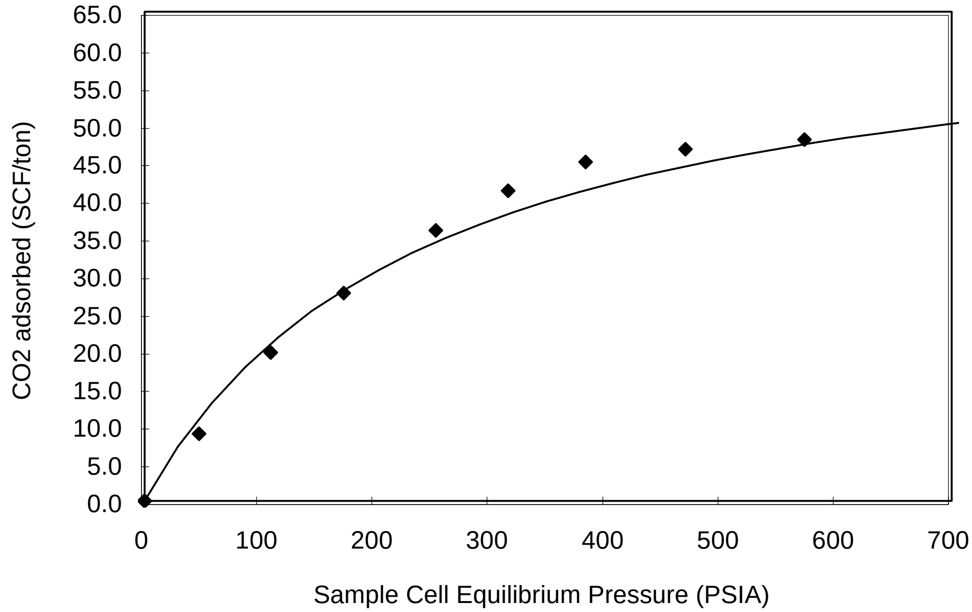
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	37.5
Pressure (PSIA)	681.1

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.88** **Density g/cc** **2.756**

107928-2 4400-4600 ft. Lower Huron Member



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)***
	In-Situ Conditions (Equilbrium Moisture)
47	8.9
109	19.7
172	27.6
252	35.9
315	41.2
383	45.1
469	46.8
572	48.0
803	48.7

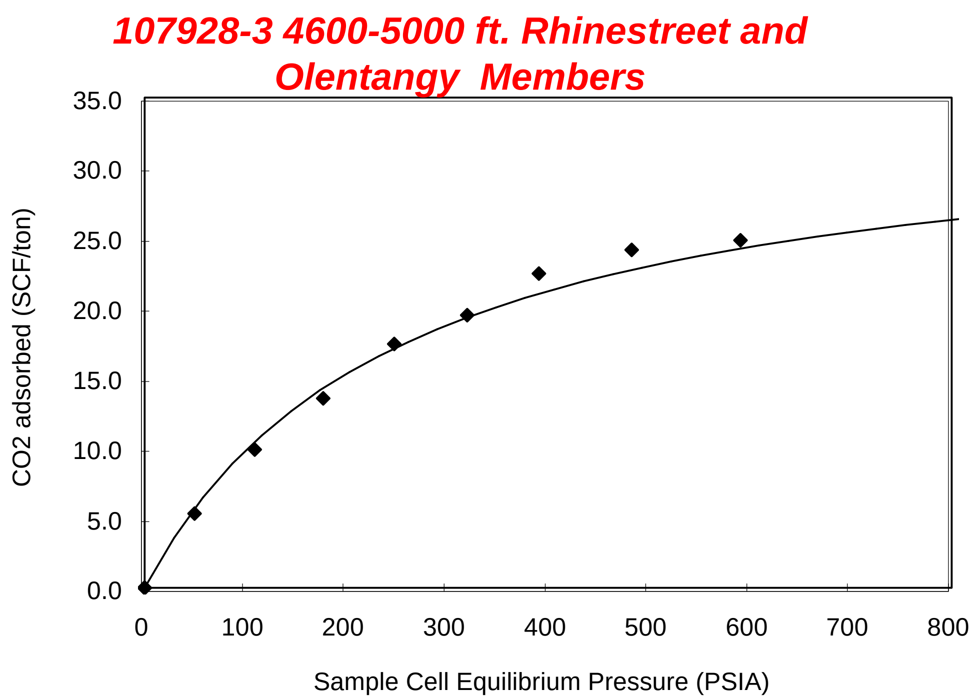
Langmuir Parameters

	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	67.6
Pressure (PSIA)	243.7

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 °F**

Goodness of fit of Langmuir regression: **0.97** **Density g/cc** **2.660**



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton) In-Situ Conditions (Equilbrium Moisture)***
49	5.3
109	9.9
177	13.5
248	17.4
320	19.5
391	22.4
483	24.1
590	24.8
806	25.0

Langmuir Parameters

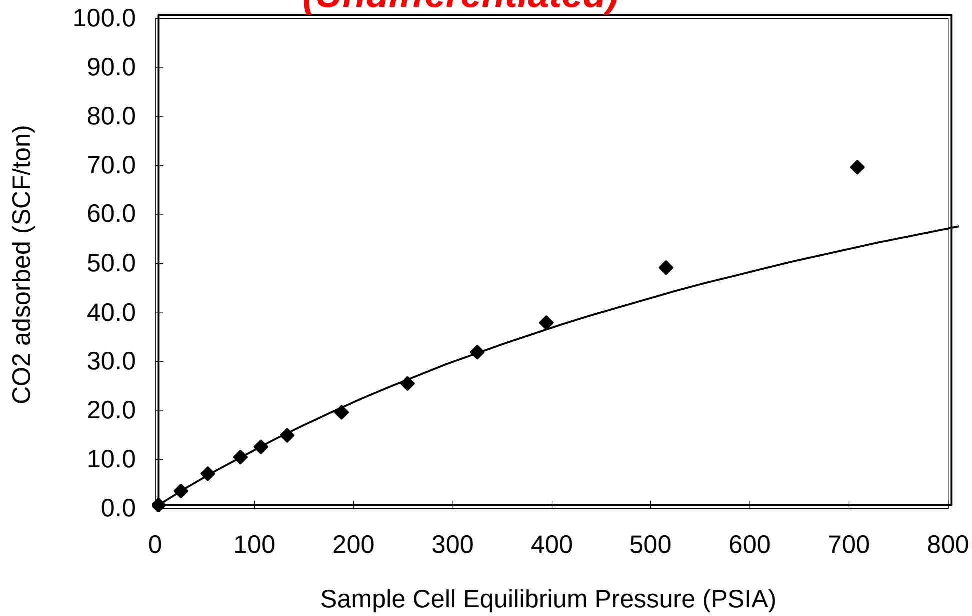
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	34.6
Pressure (PSIA)	253.1

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 °F**

Goodness of fit of Langmuir regression: **0.98** **Density g/cc** **2.749**

121774-1A 3500-3720 ft. Ohio Shale (Undifferentiated)



Pressure (PSIA)	Adsorbed gas (ft^3 /ton) In-Situ Conditions (Equilibrium Moisture)
23	2.9
50	6.4
82	9.8
103	11.8
130	14.2
185	18.9
251	24.8
321	31.3
392	37.2
512	48.4
705	68.9

Langmuir Parameters

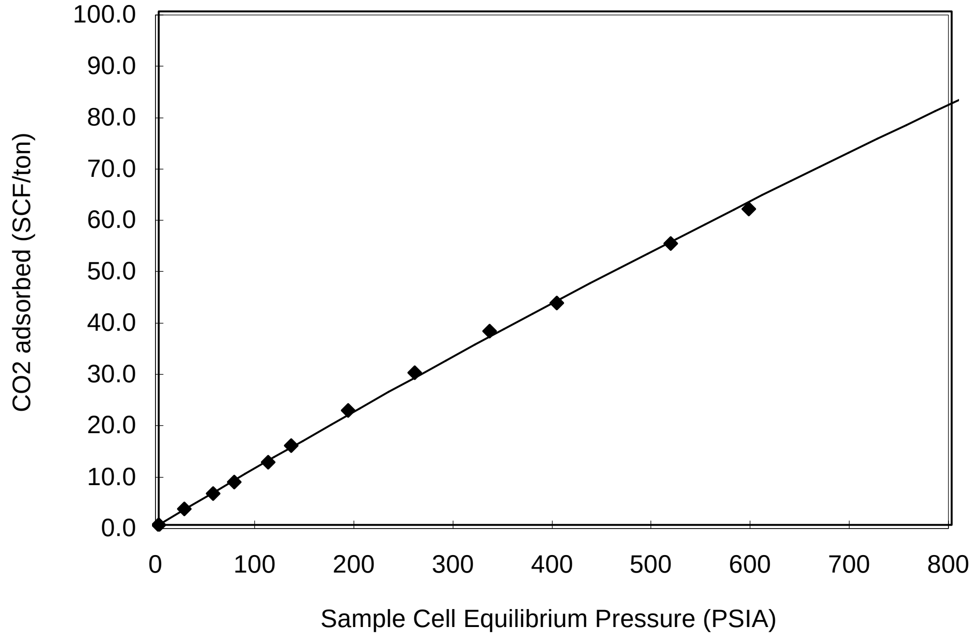
	In-Situ Conditions (Equilibrium Moisture)
Vol. (ft^3 /ton)	126.5
Pressure (PSIA)	989.8

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.91** **Density g/cc** **2.550**

RN124789 1A 2680-2990 ft.



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton) In-Situ Conditions (Equilbrium Moisture)***
26	3.1
55	6.2
76	8.3
111	12.1
133	15.4
191	22.3
259	29.6
334	37.7
402	43.2
517	54.9
595	61.6

Langmuir Parameters

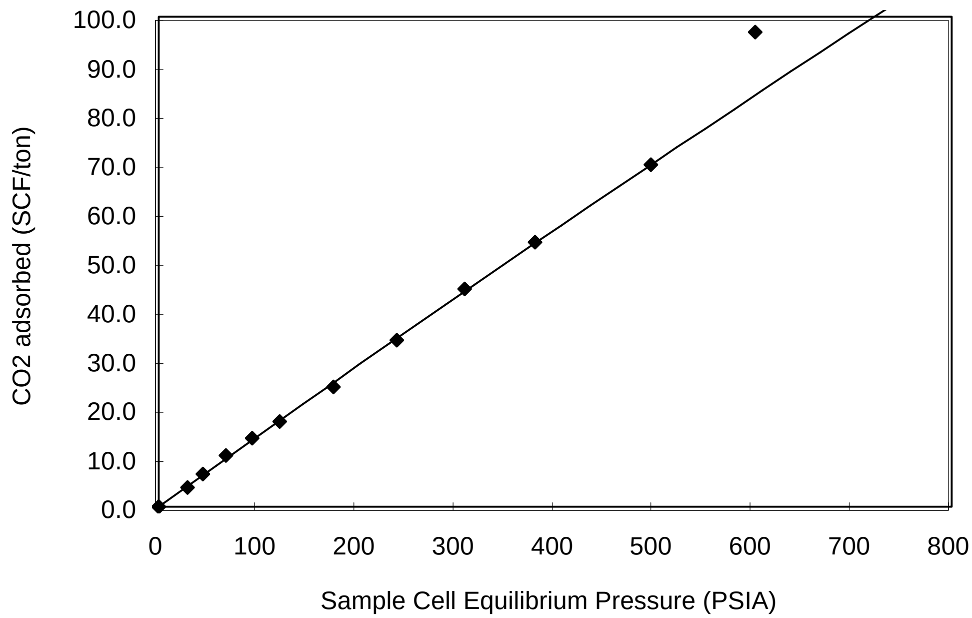
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	740.8
Pressure (PSIA)	6419.1

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.49** **Density g/cc** **2.597**

RN124789 S2A 2990-3110 ft.



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)***
	In-Situ Conditions (Equilbrium Moisture)
29	3.9
45	6.7
68	10.4
94	14.0
122	17.4
176	24.4
240	34.0
309	44.4
380	54.0
496	69.8
602	96.9

Langmuir Parameters

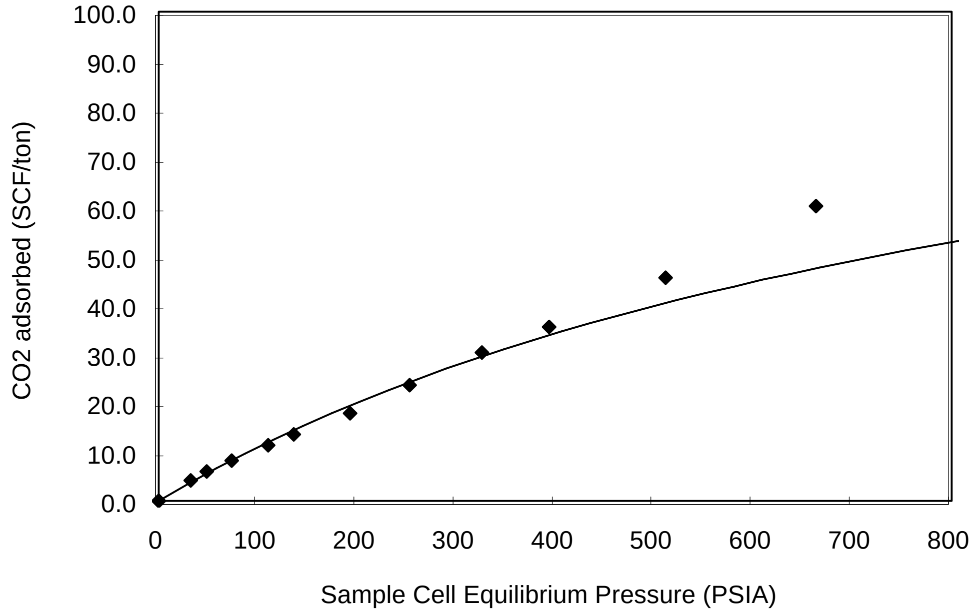
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	2077.6
Pressure (PSIA)	14283.5

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.04** **Density g/cc** **2.579**

RN124789 3A 3110-TD



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)***
	In-Situ Conditions (Equilbrium Moisture)
32	4.2
49	6.0
74	8.2
110	11.4
136	13.6
193	17.9
253	23.6
326	30.4
394	35.6
512	45.7
663	60.3

Langmuir Parameters

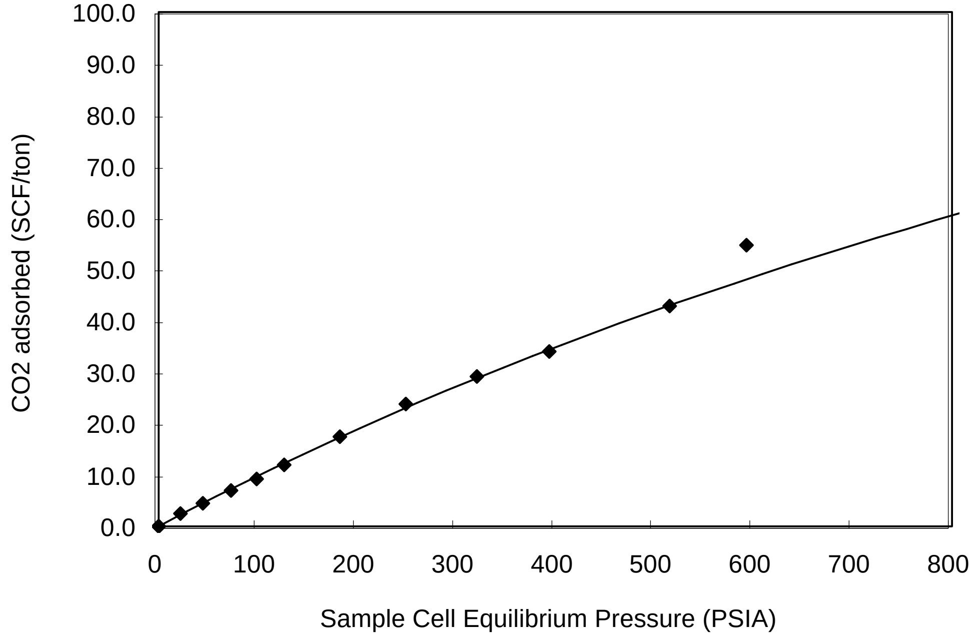
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	116.2
Pressure (PSIA)	957.9

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.77** **Density g/cc** **2.679**

RN123486 #1 341OHIOU 2600-3700 ft.



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)***
	In-Situ Conditions (Equilbrium Moisture)
22	2.4
45	4.5
73	7.0
99	9.2
126	12.0
183	17.4
249	23.8
321	29.2
394	34.0
515	42.9
593	54.7

Langmuir Parameters

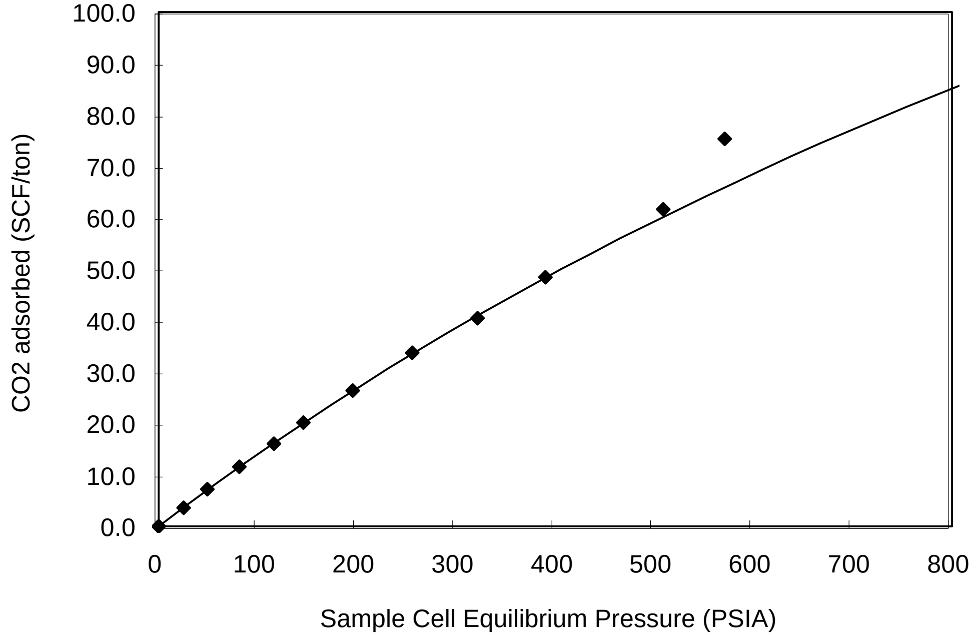
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	228.9
Pressure (PSIA)	2230.4

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.66** **Density g/cc** **2.631**

RN123486 S2 341OHIOL 3070-3210 ft.



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton) In-Situ Conditions (Equilbrium Moisture)***
25	3.6
49	7.2
82	11.6
116	16.1
146	20.1
196	26.4
256	33.7
321	40.5
390	48.4
508	61.6
571	75.3

Langmuir Parameters

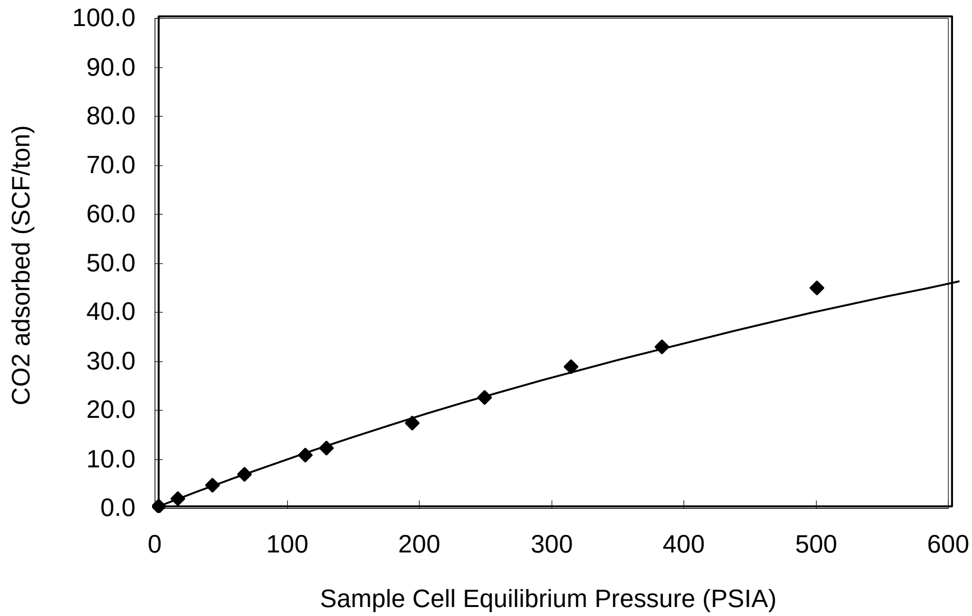
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	309.3
Pressure (PSIA)	2106.0

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.96** **Density g/cc** **2.573**

121162 OHIO UPPER 3410-3810 ft.



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)***
	In-Situ Conditions (Equilbrium Moisture)
14	1.6
40	4.3
65	6.6
111	10.5
127	11.9
192	17.0
247	22.2
312	28.6
381	32.6
498	44.5

Langmuir Parameters

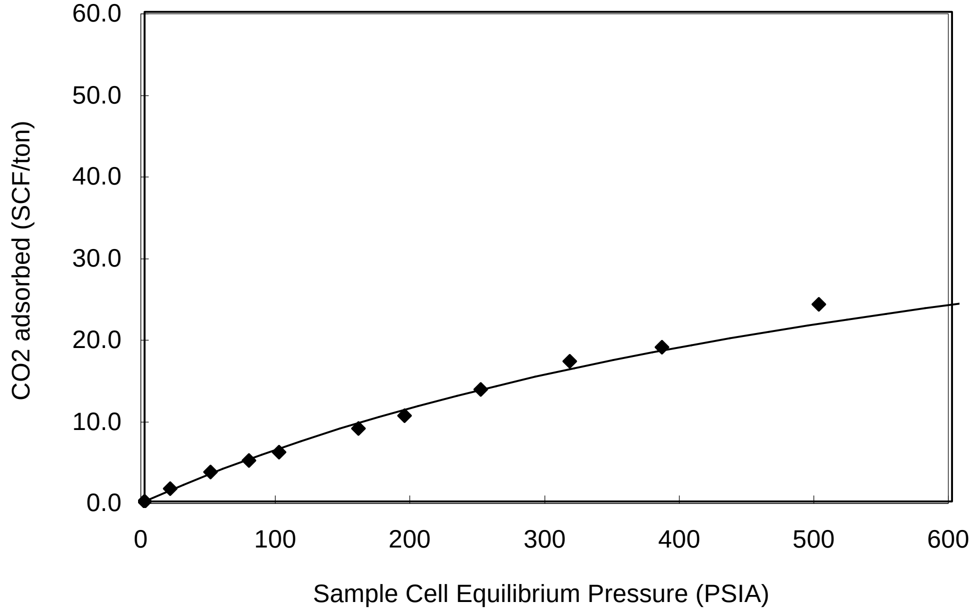
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	164.2
Pressure (PSIA)	1561.3

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.79** **Density g/cc** **2.669**

121464 OHIO Upper 3200-3300 ft,



Pressure (PSIA)	*Adsorbed gas (ft^3 /ton) In-Situ Conditions (Equilbrium Moisture)*
19	1.6
49	3.6
78	5.0
100	6.1
159	8.9
193	10.5
250	13.7
316	17.2
384	18.9
501	24.2

Langmuir Parameters

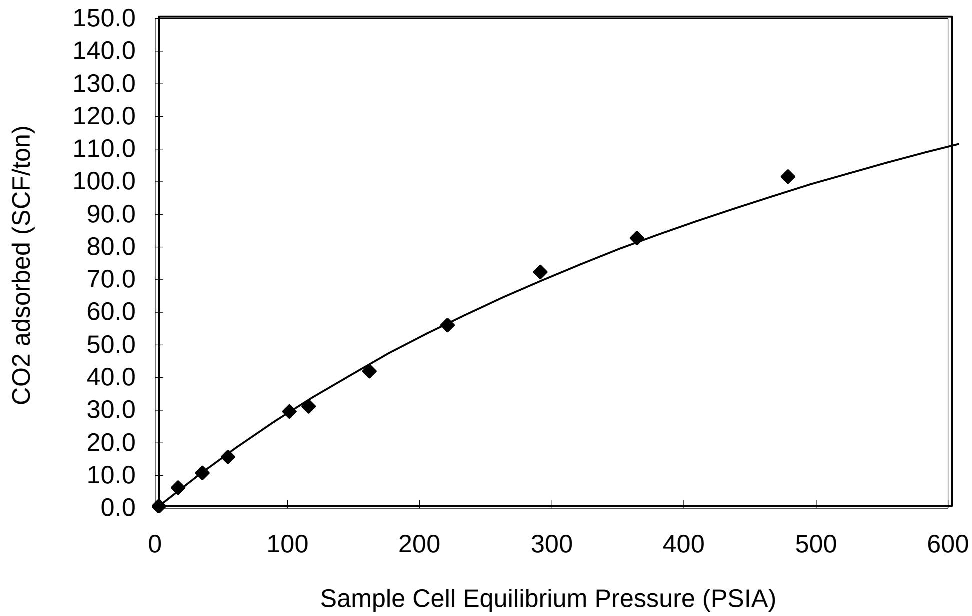
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	52.6
Pressure (PSIA)	708.9

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.82** **Density g/cc** **2.694**

121464 HURNL 4300-4380 ft.



Pressure (PSIA)	*Adsorbed gas (ft^3 /ton)*
	In-Situ Conditions (Equilbrium Moisture)
14	5.6
33	10.3
52	15.0
99	29.0
113	30.6
159	41.4
218	55.5
289	71.7
362	82.1
476	101.1

Langmuir Parameters

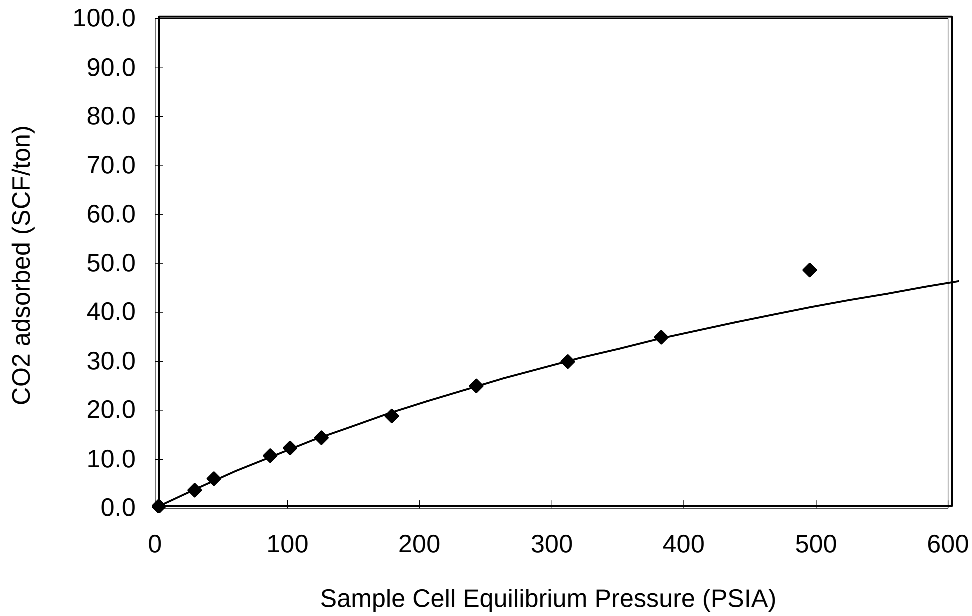
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	248.7
Pressure (PSIA)	751.2

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.79** **Density g/cc** **2.716**

121464 OHIO Lower 4580-4980 ft.



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton) In-Situ Conditions (Equilbrium Moisture)***
27	3.2
42	5.6
84	10.4
99	11.9
123	14.0
176	18.5
240	24.6
310	29.5
380	34.5
493	48.3

Langmuir Parameters

	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	108.0
Pressure (PSIA)	819.0

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

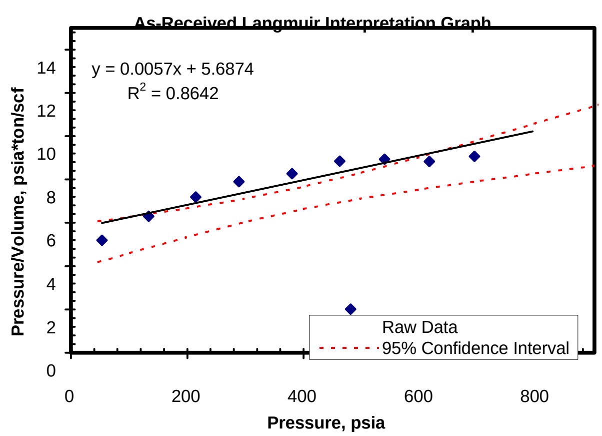
Goodness of fit of Langmuir regression: **0.93** **Density g/cc** **2.730**

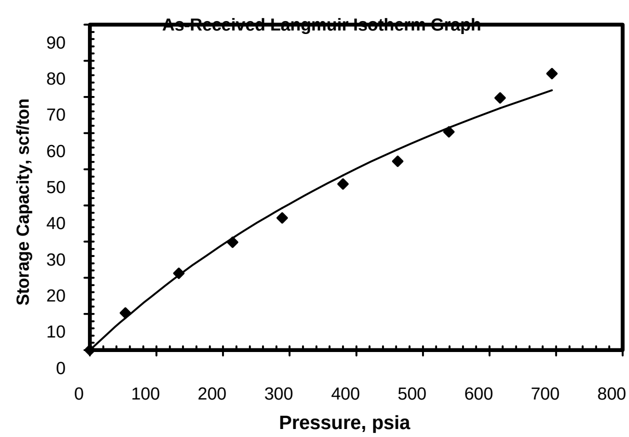
Carbon Dioxide Adsorption Isotherm Summary

Well: **#3 John Jude Heirs**
Reservoir: **Devonian Ohio Shale**
Sample Number: ISO054-1
Sample Type: Sidewall Core # 128253-C2
Drill Depth, feet: 3025.4
Temperature, °F: 86
Average Particle Size, inches: whole Sidewall Core
Experimental Moisture Content, fraction: 0.0000
Experimental Ash Content, fraction: 0.0000
"In-Situ" Moisture Content, fraction: #N/A
"In-Situ" Ash Content, fraction: #N/A
Notes:

Pressure	**Carbon Dioxide Storage Capacity, scf/ton**					
psia	As-Received		Dry, Ash-Free		In-Situ	
	Measured	Calculated	Measured	Calculated	Measured	Calculated
0.00	0.00	0.00	0.00	0.00	0.00	0.00
53.15	10.25	8.87	10.25	8.87	#N/A	#N/A
133.54	21.20	20.70	21.20	20.70	#N/A	#N/A
214.31	29.80	31.00	29.80	31.00	#N/A	#N/A
288.59	36.55	39.32	36.55	39.32	#N/A	#N/A
379.90	45.90	48.32	45.90	48.32	#N/A	#N/A
462.20	52.25	55.47	52.25	55.47	#N/A	#N/A
539.21	60.38	61.46	60.38	61.46	#N/A	#N/A
616.01	69.73	66.87	69.73	66.87	#N/A	#N/A
693.68	76.44	71.83	76.44	71.83	#N/A	#N/A

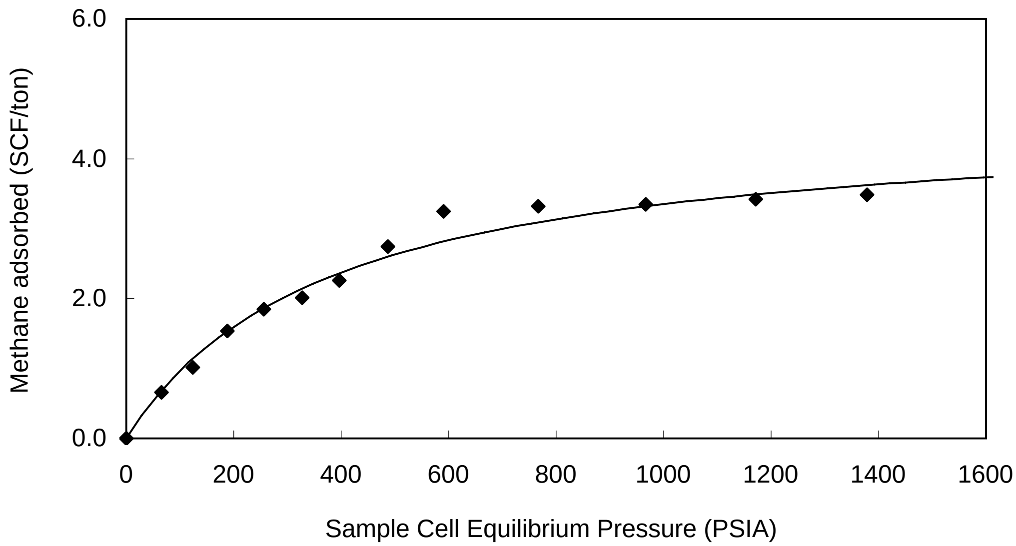
Parameters	**Carbon Dioxide Langmuir Parameters (U.S. Units)**		
	As-Received	Dry, Ash-Free	In-Situ
Slope:	0.0057	0.0057	#N/A
Intercept:	5.6874	5.6874	#N/A
Regression Coefficient (squared):	0.8642	0.8642	0.8642
Intercept Variation, psia*ton/scf:	1.0459	1.0459	#N/A
Slope Variation, ton/scf:	0.0024	0.0024	#N/A
G_{sL} Variation, scf/ton:	2.0673	78.8028	#N/A
P_L Variation, psia:	142.0096	508.1252	#N/A
Langmuir Volume, scf/ton:	174.75	174.75	#N/A
Langmuir Pressure, psia:	993.88	993.88	993.88
Langmuir Equation:	V=174.7*P/(P+993.9)	V=174.7*P/(P+993.9)	#N/A
Pressure (Midpoint), psia:	400.0	400.0	400.0
Storage Capacity, scf/ton:	50.15	50.15	#N/A





Methane Adsorption Isotherms

107928-1 3600-4400 ft. Ohio Shale (Upper Part)



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton) In-Situ Conditions (Equilbrium Moisture)***
66	0.7
123	1.0
188	1.5
256	1.9
327	2.0
397	2.3
487	2.7
591	3.3
767	3.3
967	3.4
1172	3.4
1378	3.5

Langmuir Parameters

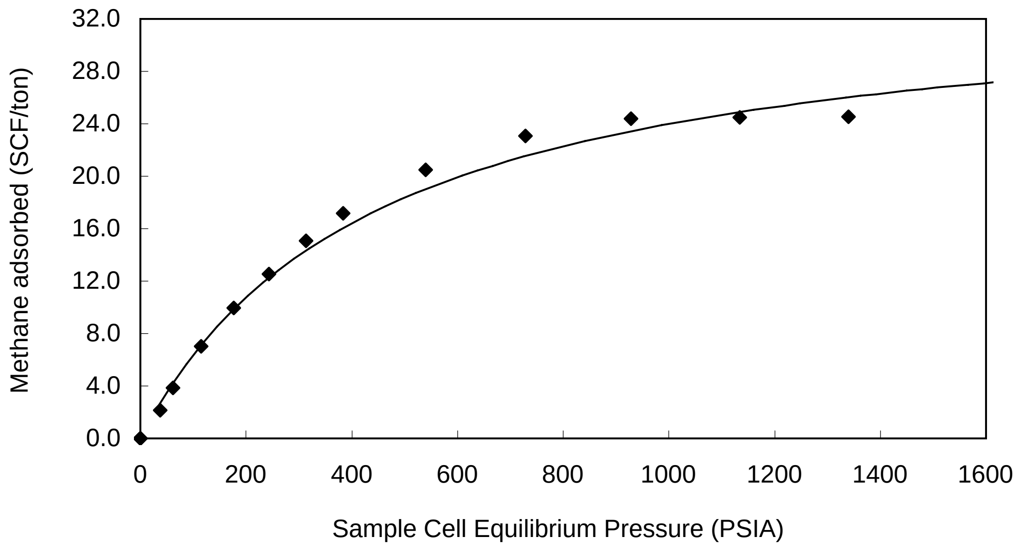
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	4.6
Pressure (PSIA)	377.8

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.98** **Density g/cc** **2.760**

107928-2 4400-4600 Ft. Lower Huron Member



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton) In-Situ Conditions (Equilbrium Moisture)***
37	2.1
62	3.8
115	7.0
177	10.0
244	12.5
314	15.1
384	17.2
540	20.5
729	23.1
928	24.4
1134	24.5
1340	24.5

Langmuir Parameters

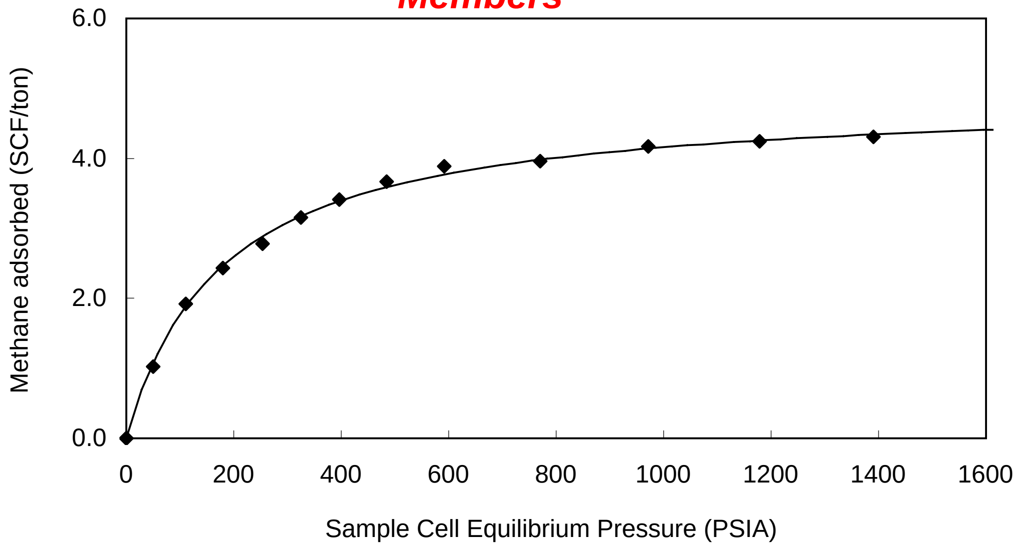
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	34.6
Pressure (PSIA)	443.2

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.98** **Density g/cc** **2.671**

107928-3 4600-5000 ft. Rhinestreet and Olentangy Members



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton) In-Situ Conditions (Equilbrium Moisture)***
49	1.0
111	1.9
180	2.4
253	2.8
325	3.2
396	3.4
484	3.7
591	3.9
770	4.0
971	4.2
1179	4.2
1390	4.3

Langmuir Parameters

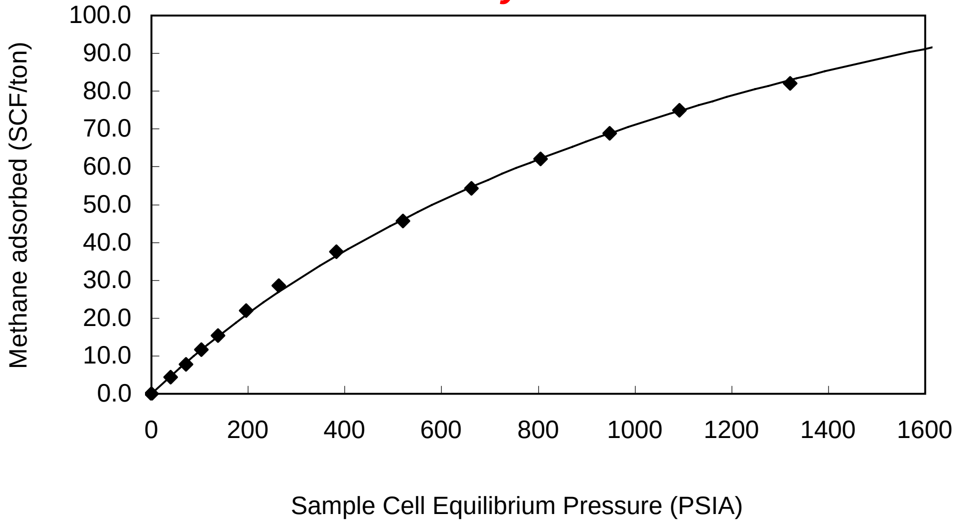
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	4.9
Pressure (PSIA)	176.2

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 °F**

Goodness of fit of Langmuir regression: **1.00** **Density g/cc** **2.749**

IGSID-107310-1A 940-941 ft. Seimer Mbr. New Albany Shale



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)***
	In-Situ Conditions (Equilbrium Moisture)
40	4.3
71	7.7
104	11.8
137	15.4
196	22.0
263	28.6
383	37.6
520	45.7
661	54.3
805	62.1
948	68.9
1092	74.9
1320	82.0

Langmuir Parameters

	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	172.6
Pressure (PSIA)	1428.1

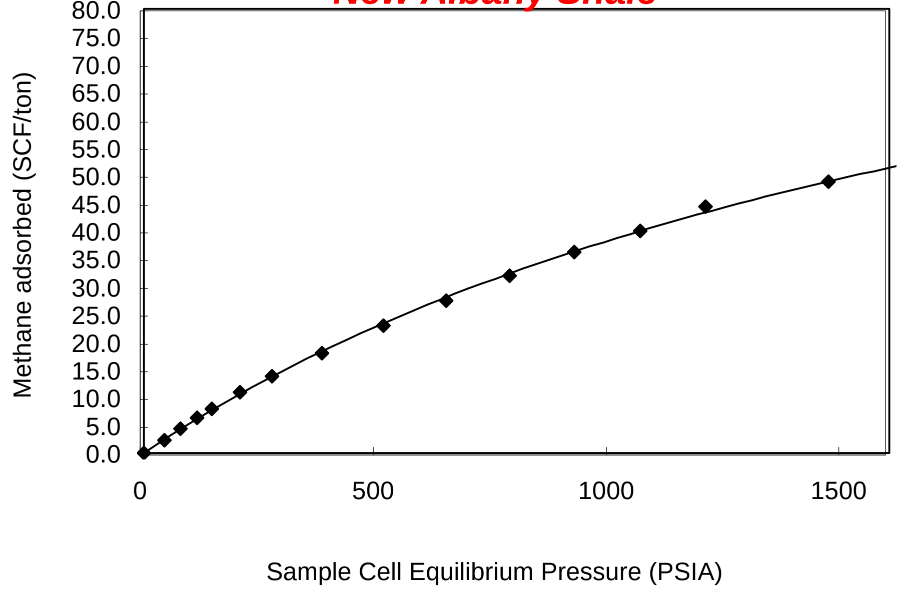
SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 °F**

Goodness of fit of Langmuir regression: **0.98** **Density g/cc** **2.121**

Moisture% **2.56**

IGSIG-107310-2A 1020-1021 ft. Blocher Mbr.
New Albany Shale



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton) In-Situ Conditions (Equilbrium Moisture)***
44	2.3
78	4.3
114	6.3
146	8.0
207	11.0
275	13.9
382	18.0
514	23.0
649	27.4
785	31.9
924	36.2
1065	40.0
1206	44.3
1469	48.9

Langmuir Parameters

	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	118.7
Pressure (PSIA)	2097.6

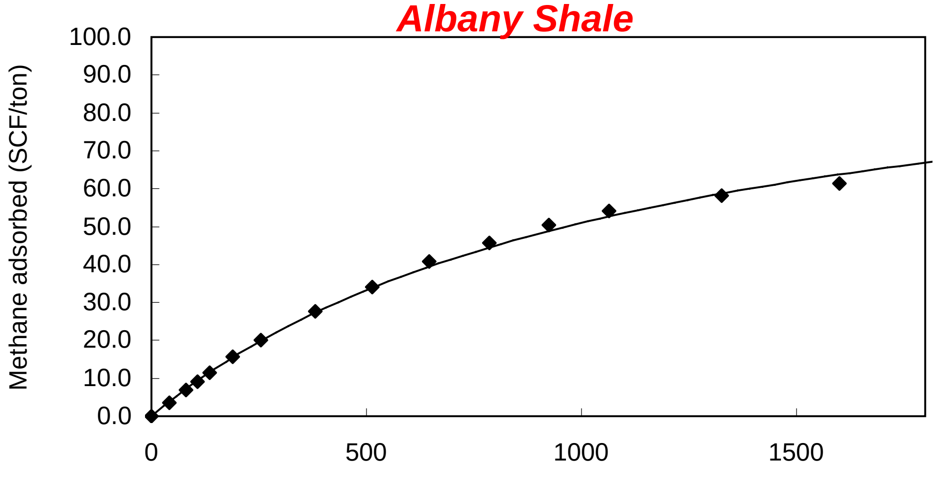
SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 °F**

Goodness of fit of Langmuir regression: **0.98** **Density g/cc** **2.534**

Moisture% **1.96**

IGSID 119139-1A 2505 feet Selmier Mbr. New Albany Shale



Pressure (PSIA)	*Adsorbed gas (ft^3 /ton)*
	In-Situ Conditions (Equilbrium Moisture)
41	3.6
80	6.9
107	9.1
135	11.5
189	15.6
255	20.1
381	27.6
513	34.0
646	40.8
786	45.6
925	50.4
1064	54.2
1327	58.2
1601	61.3

Langmuir Parameters

	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	109.5
Pressure (PSIA)	1148.7

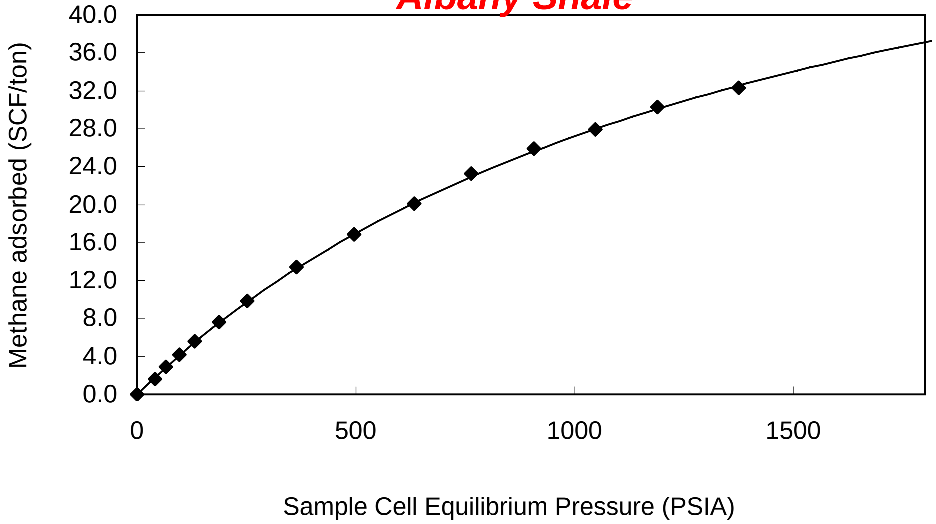
SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 °F**

Goodness of fit of Langmuir regression: **0.99** **Density g/cc** **2.304**

Moisture% **1.91**

IGSID 119139-2A 2553 ft. Blocher Mbr. New Albany Shale



Pressure (PSIA)	*Adsorbed gas (ft^3 /ton)*
	In-Situ Conditions (Equilbrium Moisture)
41	1.6
66	2.9
96	4.2
132	5.6
187	7.7
251	9.8
365	13.4
496	16.8
632	20.1
764	23.3
906	25.9
1047	27.9
1188	30.3
1374	32.3
1576	34.4

Langmuir Parameters

	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	68.4
Pressure (PSIA)	1513.2

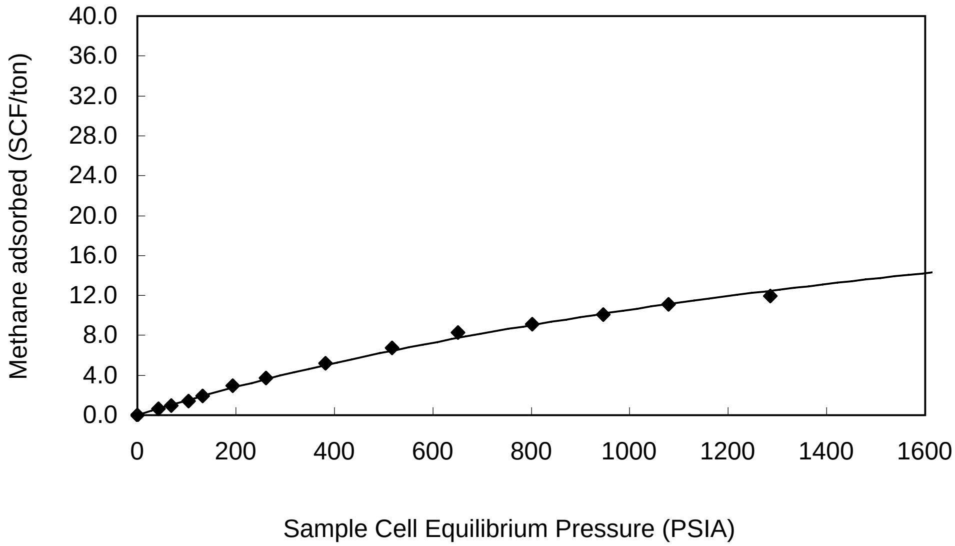
SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 °F**

Goodness of fit of Langmuir regression: **0.99** **Density g/cc** **2.455**

Moisture% **2.30**

123957-1A 2450-2640 ft. Ohio Shale (upper part)



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)***
	In-Situ Conditions (Equilbrium Moisture)
43	0.6
69	1.0
103	1.4
132	1.9
193	2.9
261	3.7
383	5.2
518	6.7
651	8.3
802	9.1
946	10.1
1079	11.1
1286	11.9

Langmuir Parameters

	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	33.5
Pressure (PSIA)	2170.8

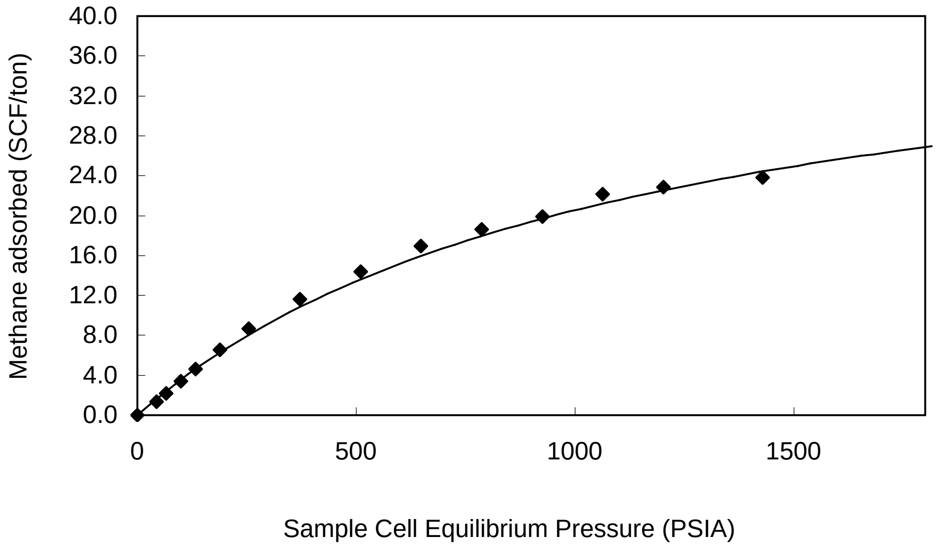
SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 °F**

Goodness of fit of Langmuir regression: **0.92** **Density g/cc** **2.556**

Moisture% **2.82**

123957-2A 2640-2770 ft. Lower Huron



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)***
	In-Situ Conditions (Equilbrium Moisture)
44	1.3
66	2.2
99	3.4
133	4.6
189	6.5
255	8.6
372	11.6
510	14.4
648	17.0
786	18.6
926	19.9
1063	22.1
1202	22.8
1429	23.8
1604	24.1

Langmuir Parameters

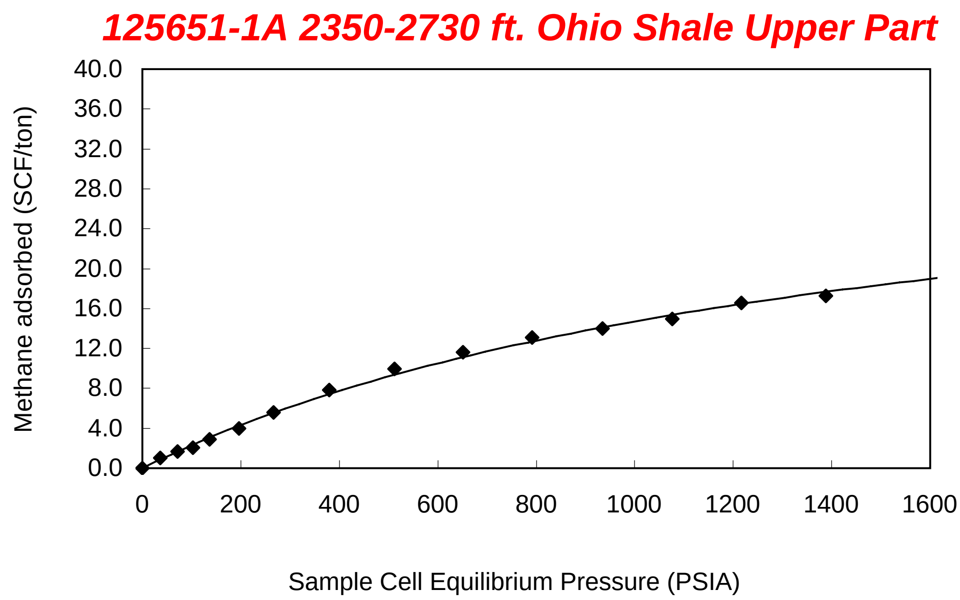
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	43.7
Pressure (PSIA)	1126.7

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.96** **Density g/cc** **2.443**

Moisture% **3.83**



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)***
	In-Situ Conditions (Equilbrium Moisture)
37	1.0
72	1.7
103	2.1
136	2.9
196	4.0
266	5.6
380	7.8
512	9.9
651	11.6
792	13.1
935	14.0
1076	15.0
1217	16.6
1389	17.2

Langmuir Parameters

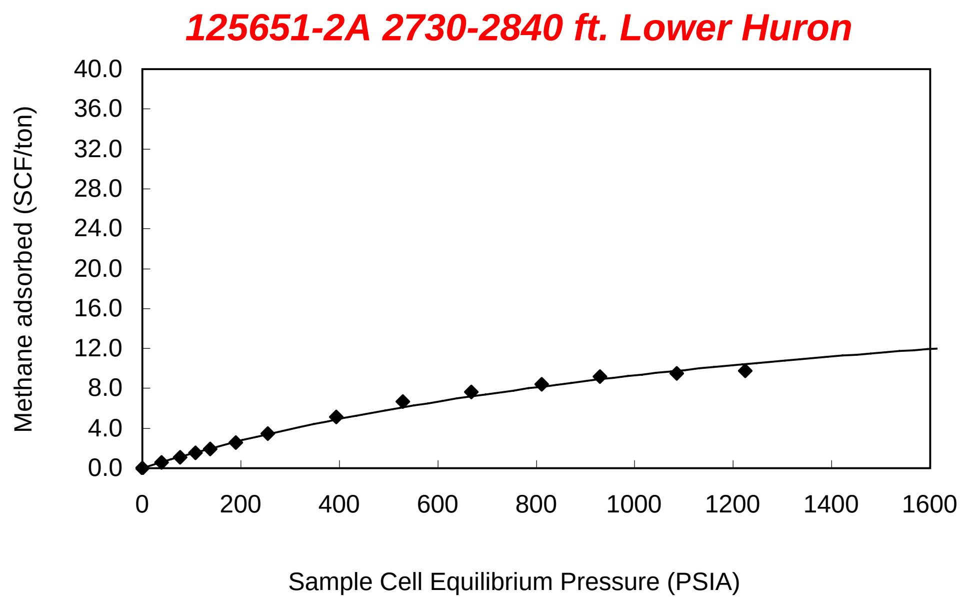
	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	36.7
Pressure (PSIA)	1497.9

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 ºF**

Goodness of fit of Langmuir regression: **0.94** **Density g/cc** **2.636**

Moisture% **1.98**



Pressure (PSIA)	Adsorbed gas (ft^3 /ton) In-Situ Conditions (Equilbrium Moisture)
39	0.6
76	1.1
108	1.5
137	1.9
190	2.6
255	3.5
394	5.2
529	6.7
668	7.6
811	8.4
929	9.2
1086	9.5
1225	9.7

Langmuir Parameters

	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	22.7
Pressure (PSIA)	1445.3

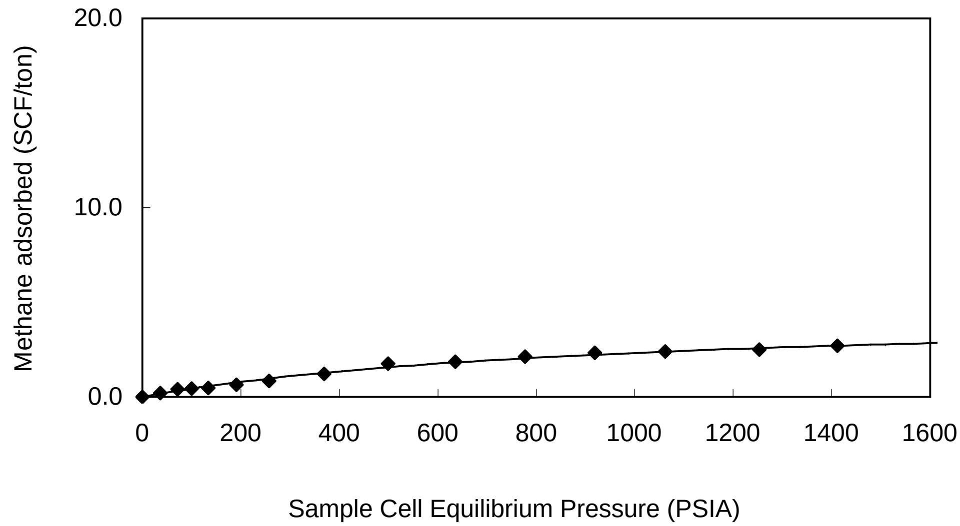
SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 °F**

Goodness of fit of Langmuir regression: **0.94** **Density g/cc** **2.631**

Moisture% **1.67**

125651-3A 2840-3010 ft. Ohio Shale (lowest part)



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)***
	In-Situ Conditions (Equilbrium Moisture)
36	0.2
71	0.4
101	0.4
134	0.5
191	0.6
257	0.9
369	1.2
499	1.7
636	1.9
778	2.1
919	2.3
1062	2.4
1253	2.5
1411	2.7

Langmuir Parameters

	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	4.5
Pressure (PSIA)	936.4

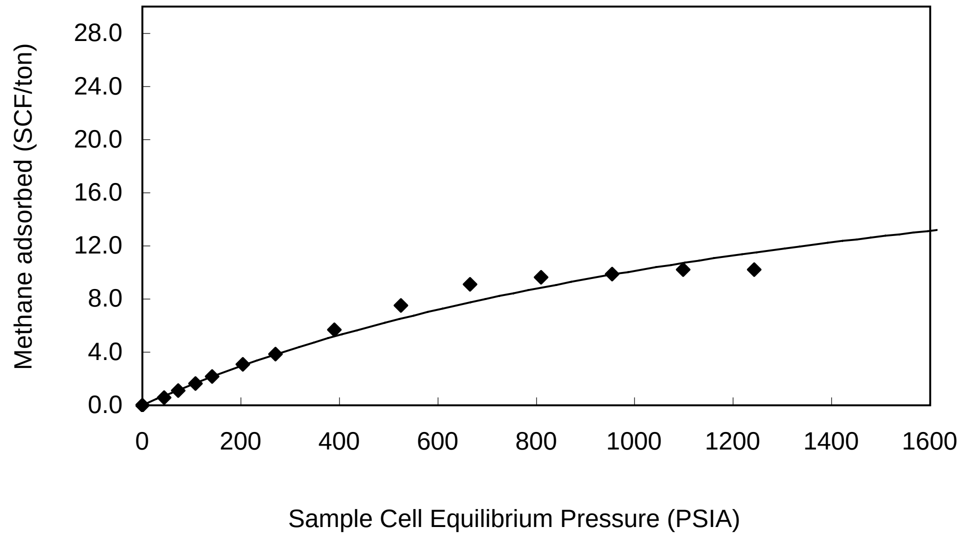
SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 °F**

Goodness of fit of Langmuir regression: **0.91** **Density g/cc** **n/a**

Moisture% **3.10**

AEP#1-1A 2820-3190 ft. Lower Huron



Pressure (PSIA)	***Adsorbed gas (ft^3 /ton)***
	In-Situ Conditions (Equilbrium Moisture)
44	0.6
73	1.1
107	1.6
141	2.2
204	3.1
271	3.9
390	5.7
525	7.5
666	9.1
809	9.6
954	9.9
1098	10.2
1243	10.2

Langmuir Parameters

	In-Situ Conditions (Equilbrium Moisture)
Vol. (ft^3 /ton)	26.0
Pressure (PSIA)	1566.7

SUMMARY OF ADSORPTION ANALYSES IMP. UNITS

Isotherm Temperature: **86.0 °F**

Goodness of fit of Langmuir regression: **0.77** **Density g/cc** **2.546**

Moisture% **1.96**

Appendix C: Technology Transfer Summary

- NE/SE Combined GSA Section Meeting, April 2-5, 2002, Lexington, KY
- 2nd National Conference on Carbon Sequestration (NETL), May 5-8, 2003, Alexandria, Virginia: (poster session)
- Kentucky Oil and Gas Association Annual Meeting, June 23-25, 2003, Louisville, Kentucky
- 2003 GSA Annual Meeting and Exposition, November 2-5, 2003, Seattle, Washington
- NE/SE Combined GSA Section Meeting, March 25-27, 2004, Washington, DC
- DOE/NETL Carbon Sequestration Project Review, March 29 to April 1, 2004, Pittsburgh, Pennsylvania
- AAPG Annual Meeting, April 18-21, 2004, Dallas, Texas.
- 3rd Annual Conference on Carbon Sequestration (NETL), May 2-6, 2004, Alexandria, Virginia.
- 7th International Conference on Greenhouse Gas Control Technologies, September 5-9, 2004, Vancouver, British Columbia, Canada
- AAPG Eastern Section, October 3-7, 2004, Columbus, Ohio
- Regional Carbon Sequestration Partnership Geologic Characterization Working Group Workshop, Houston, Texas
- 2004 GSA Annual Meeting and Exposition, November 7-10, Denver, Colorado
- 4th Annual Conference on Carbon Sequestration (NETL), May 2-5, 2005, Alexandria, Virginia
- AAPG Annual Meeting, June 19-22, 2005, Calgary, Alberta, Canada
- AAPG Eastern Section, September 18-20, 2005, Morgantown, West Virginia
- Midwest Geologic Sequestration Consortium, Carbon sequestration in the Illinois Basin, September 28, 2005, Evansville, Indiana

Appendix D: GIS Analysis of the Distribution and Estimated CO2 Storage Volume of the Devonian Shale in Kentucky

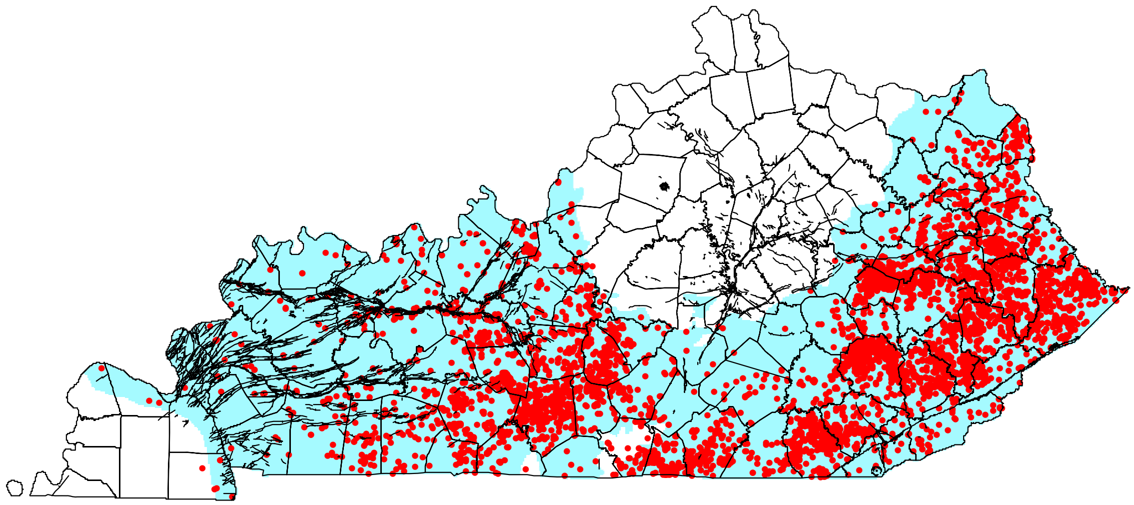
Note: Grid data sets are indicated in matrix notation using the courier type face, i.e., `[grid_data]`

Geographic information system (GIS) software was used to perform an analysis of the thickness and distribution of the Devonian black shale in Kentucky. The initial goal is to calculate the number of tons of shale in place by county for those areas with drilling depths to the shale of at least 1,000 feet and a shale thickness of at least 50 feet. These cutoffs were selected to ensure reservoir integrity (deeper than the expected depth of surface fracturing) and gas reservoir potential. With the number of tons of shale being determined, a series of factors to calculate the sequestration potential in tons of CO_2 are derived based on measured CO_2 storage capacity and shale density. For GIS, ESRI's ArcView 3.2 and Spatial Analyst were used. The Kentucky Geological Survey uses a server running SQL-2000 for data storage. Data are accessed with tables linked to a graphic user interface implemented using Microsoft Access 97. Access queries were composed to compile point data sets consisting of the locations and values of Devonian shale stratigraphic tops and thickness. The formation tops data were maintained as drilling depth to the top of the formation rather than elevations with respect to sea level. Open database connectivity (ODBC) services are available from ArcView. The Access query results were added to the GIS as tables using the SQL Connect facility and then converted to shape files.

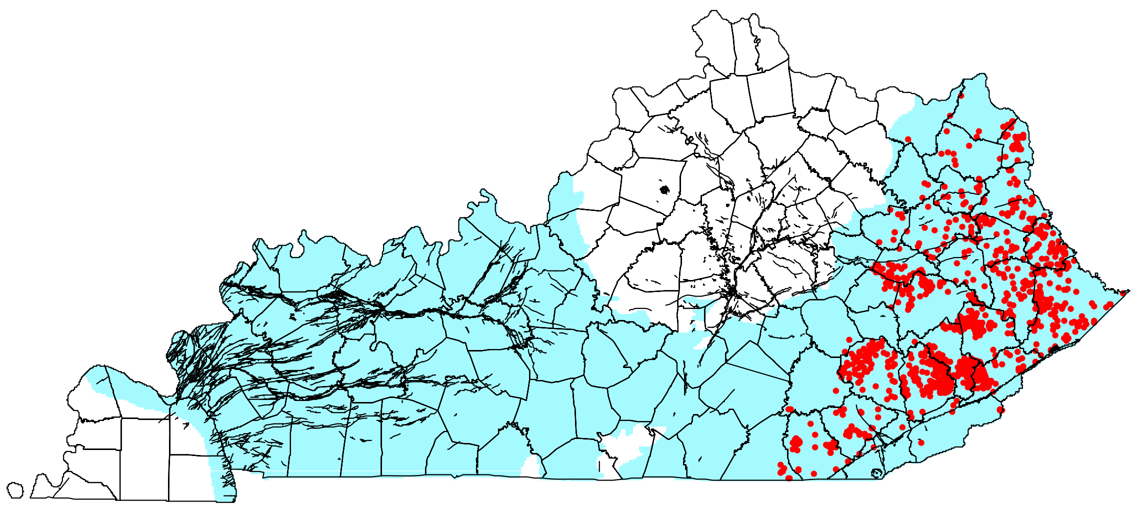
```
SELECT dbo_well_identification.record_number AS recno,
dbo_geographic_location.north_latitude AS lat,
dbo_geographic_location.west_longitude AS lon, dbo_formation_tops.pick_fm,
dbo_geographic_location.surface_elevation AS elev, dbo_formation_tops.fm_top,
dbo_formation_tops.fm_base, [fm_base]-[fm_top] AS thick
FROM ((dbo_geographic_location INNER JOIN dbo_geographic_region ON
dbo_geographic_location.location_index = dbo_geographic_region.location index)
INNER JOIN dbo well identification ON dbo geographic location.location index =
dbo_well_identification.location_index) INNER JOIN dbo_formation_tops ON
dbo_well_identification.record_number = dbo_formation_tops.record_number
WHERE (((dbo_formation_tops.pick_fm)="341OHIO" Or
(dbo_formation_tops.pick_fm)="341CHAT" Or
(dbo_formation_tops.pick_fm)="341NALB") AND ((dbo_formation_tops.fm_top) Is
Not Null) AND ((dbo_formation_tops.fm_base) Is Not Null) AND (([fm_base]-
[fm_top])>0) AND ((dbo_formation_tops.type_of_top)="s") AND
((dbo geographic location.ns feet)>0) AND ((dbo geographic location.n or s) Is
Not Null) AND ((dbo_geographic_location.ew_feet)>0) AND
((dbo_geographic_location.e_or_w) Is Not Null) AND
((dbo_geographic_location.carter_section)>0) AND
((dbo_geographic_location.carter_letter)>=" A") AND
((dbo_geographic_location.carter_number) Is Not Null));
```

Sample SQL query composed with the Access GUI for compiling Devonian shale stratigraphic and location point data.

Existing polygon shape files of the Kentucky counties, faults, and the subsurface distribution of the Devonian shale in Kentucky (`[Subsurf]`) were employed in the analysis. The shape file of the subsurface distribution of the shale was converted to a grid for use in the spatial analysis. Each cell of this grid contained a value of 1 (true) if the shale existed in the subsurface over the area of the cell. All other cells were set to null, the no data value. All grids were computed with 1,000-meter (1 kilometer) cell dimensions. Analyses were performed using the North American Datum of 1927 (NAD27) with the projection set to UTM zone 16.



Subsurface distribution of the Devonian shale (blue, shaded) with stratigraphic data points.



Subsurface distribution of the Devonian shale (blue, shaded) with stratigraphic data points for the Lower Huron Member of the shale.

For deriving drilling depth and thickness maps, grids were interpolated from point data using the inverse distance weighted (IDW) nearest neighbor method. The interpolated data were processed to establish which grid cells fit the selection criteria of 1,000 feet or deeper drilling depths and a shale thickness of at least 50 feet.

```
Interpolate grid, [Depth], using drilling depth from point file
Interpolate grid, [Iso], using thickness data from point file
Map Query [Depth]>=1000 = [Deep]
Map Query [Iso]>=50 = [Thick]
Calculate [Deep]*[Thick] = [Temp01]
Calculate [Temp01]*[Subsurf] = [Temp02]
([Temp02] = 0.AsGrid).SetNull([Temp02]) = [DeepThick]
```

Method for deriving a grid dataset indicating the distribution of shale at least 50 feet thick and 1,000 feet deep.

To restrict the volume calculations to the limits of the distribution of thicker and deeper shale, the `[Iso]` and `[DeepThick]` grid data sets were multiplied together to produce a new grid, `[Target]`.

To limit the number of calculation steps required to derive volume and sequestration potential estimates, conversion factors were derived to convert the thickness (isopach in feet) data in `[Target]` to million tons of shale and then directly to CO2 tons. Tons of shale in place is a function of shale volume and density, thus:

$$Tons_{shale} = volume * density$$

and

$$MMTons_{shale} = \frac{thickness * area * density}{1000000}$$

Assuming thickness in feet, a1 kilometer cell size, a density in *g/cc* million tons of shale in place can be calculated:

$$MMTons_{shale} = \frac{thickness * \frac{0.3048\,m}{ft} * (1000\,m)^2 * density * 1.102}{1000000} \qquad \text{Eq. 1.}$$

where:

$thickness$	= thickness of shale in feet
1000	= cell size in meters
$density$	= bulk density from compensated density log
1.102	= density conversion factor to convert from grams per cubic centimeter to tons per cubic meter

For a specified density, the constants in equation 1 can be combined to obtain a direct conversion factor that is a function only of shale thickness. Substituting different shale densities, a factor, `CfMMTons`, would be one of:

2.5 g/cc (log estimated density for Lower Huron)	= 0.840
2.6 g/cc (log estimated density for upper part of shale)	= 0.873
2.65 g/cc (log handbook typical shale density)	= 0.890

To calculate million tons of shale per cell, the ArcView grid calculation would be:

```
[Target]*CfMMTons.AsGrid = [MMTons]
```

Different conversion factors could be derived for standard reservoir analysis (as opposed to assuming adsorbed gas). Distributions of porosity, water or oil saturation data, and others could be gridded and used to derive oil or gas in place estimates.

Converting tons of shale in place to estimated tons of CO_2 sequestered requires an additional factor based on the gas content per ton of shale from CO_2 adsorption data. Using a gas content of 1 standard cubic foot of CO_2 per ton and 17.25[1] thousand cubic feet (Mcf) CO_2 per ton of CO_2, there will be 57.97 tons of CO_2 per million tons of shale.

$$TonsCO_2 = \frac{ft^3_{CO_2}}{ton_{shale}} * 1000000 * \frac{Mcf}{1000\, ft^3_{CO_2}} * \frac{ton_{CO_2}}{17.25 Mcf} = 57.97 \qquad \text{Eq. 2}$$

The sequestration volume in tons of CO_2 can now be considered a function of thickness, shale density, and adsorbed gas content, or:

$$TonsCO_2 = 57.97 * CfMMTons * thickness * gascontent$$

Multiplying the 57.97 and $CfMMTons$ provides a single factor that varies only with density:

Factor = 48.69 at density equals 2.5 g/cc
Factor = 50.61 at density equals 2.6 g/cc
Factor = 51.59 at density equals 2.65 g/cc

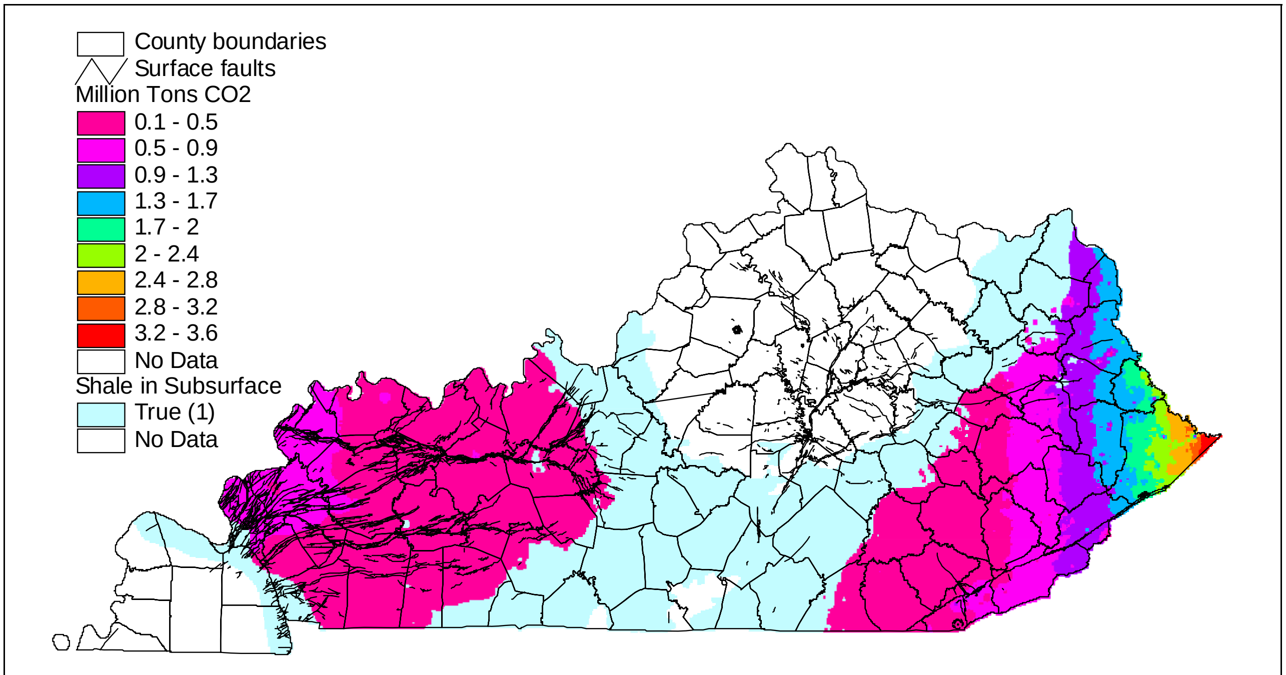
In lieu of gridding gas content data, multiplying a measured gas content by one of these factors yields a final selection of factors for use in converting shale thickness data directly to tons of CO_2 sequestered. For example, using a gas content of 40 scf/ton, a shale density of 2.6 g/cc, and a 1000-meter cell size, the tons of CO_2 per cell is 2024.3 per foot of shale thickness, thus:

```
[Target] * (2024.3).AsGrid = [CO2Tons]
```

[1] 17.25 Mcf CO_2 per ton CO_2 is the conversion factor used by the U.S. EPA. Conversion is derived from gas laws and is valid for 60°F and 1 atmosphere pressure.

As additional gas content data are acquired, examining the distribution and gridding the data as appropriate will be used to refine the sequestration volume calculations.

The values calculated for each cell require summation for specific regions to obtain totals. With the county polygon theme active, the ArcView Summarize Zones procedure (available from the Analysis menu command) was used to summarize the data by county. The field defining the zones was the county name and the `[CO2Tons]` grid theme was selected for summarizing. A table of summary statistics was computed that could be joined to the original county table for mapping and additional analysis.



CO2 storage capacity per square kilometer in million tons.

Summary by county of potential sequestration totals (gas content 40 scf/ton, shale density 2.6 g/cc, cell size 1,000 meters):

Name	Basin	Count	Min	Max	Mean	MMTonsCO2
BELL	160	949	0.24	1.52	0.51	486.8
BOYD	160	420	1.03	1.70	1.39	583.9
BREATHITT	160	1293	0.38	1.05	0.60	775.2
CARTER	160	329	0.34	1.26	1.05	346.6
CLAY	160	1236	0.24	0.48	0.35	433.2
ELLIOTT	160	292	0.29	1.14	0.92	267.2
FLOYD	160	1040	0.27	1.79	1.42	1,474.4
GREENUP	160	339	0.99	1.38	1.24	421.7
HARLAN	160	1211	0.31	1.17	0.76	918.6
JACKSON	160	275	0.21	0.34	0.25	69.4
JOHNSON	160	657	0.86	1.67	1.28	839.8
KNOTT	160	918	0.78	1.42	1.06	969.9
KNOX	160	1017	0.20	0.47	0.31	318.5

Name	Basin	Count	Min	Max	Mean	MMTonsCO2
LAUREL	160	1146	0.16	0.38	0.22	255.7
LAWRENCE	160	1089	0.20	1.85	1.37	1,490.6
LEE	160	232	0.22	0.50	0.35	81.6
LESLIE	160	1066	0.38	0.79	0.55	590.8
LETCHER	160	894	0.21	1.70	1.13	1,012.2
MAGOFFIN	160	793	0.63	1.20	0.92	730.8
MARTIN	160	631	1.23	2.32	1.76	1,113.1
MCCREARY	160	703	0.10	0.24	0.15	107.8
MENIFEE	160	16	0.37	0.42	0.39	6.2
MORGAN	160	710	0.25	1.19	0.70	496.8
OWSLEY	160	497	0.13	0.44	0.34	168.0
PERRY	160	892	0.37	1.04	0.71	630.4
PIKE	160	2056	0.82	3.60	2.17	4,467.3
POWELL	160	7	0.31	0.34	0.32	2.2
ROCKCASTLE	160	4	0.19	0.21	0.20	0.8
ROWAN	160	2	0.54	0.54	0.54	1.1
WHITLEY	160	1161	0.16	0.70	0.22	261.1
WOLFE	160	525	0.20	0.81	0.45	237.1
Appalachian	**160 Total**					**19,558.9**
MARSHALL	250	29	0.39	0.56	0.48	13.9
Jackson Purchase	**250 Total**					**13.9**
EDMONSON	300	670	0.12	0.40	0.24	157.5
HARDIN	300	220	0.13	0.18	0.16	35.3
HART	300	178	0.11	0.20	0.15	26.4
MEADE	300	106	0.18	0.22	0.20	21.6
PULASKI	300	58	0.14	0.18	0.16	9.3
WARREN	300	424	0.12	0.38	0.20	84.0
Cincinnati Arch	**300 Total**					**334.2**
BRECKINRIDGE	315	1426	0.10	0.26	0.19	274.8
BUTLER	315	1130	0.11	0.41	0.28	320.3
CALDWELL	315	898	0.27	0.67	0.48	430.0
CHRISTIAN	315	1870	0.11	0.58	0.25	470.0
CRITTENDEN	315	968	0.31	0.90	0.66	634.1
DAVIESS	315	1255	0.12	0.46	0.32	404.1
GRAYSON	315	1277	0.12	0.49	0.27	343.6
HANCOCK	315	516	0.15	0.54	0.29	150.5
HENDERSON	315	1233	0.11	0.64	0.45	560.8
HOPKINS	315	1464	0.14	0.64	0.41	595.7
LIVINGSTON	315	696	0.42	0.67	0.60	415.6
LOGAN	315	966	0.12	0.25	0.19	183.1
LYON	315	620	0.28	0.59	0.46	284.8
MCLEAN	315	671	0.14	0.56	0.39	259.9
MUHLENBERG	315	1266	0.12	0.59	0.34	425.4
OHIO	315	1549	0.16	1.09	0.37	573.4
TODD	315	879	0.10	0.31	0.18	156.9
TRIGG	315	848	0.16	0.34	0.24	200.6
UNION	315	953	0.57	0.81	0.69	657.7
WEBSTER	315	878	0.17	0.68	0.51	445.1
Illinois Basin	**315 Total**					**7,786.5**
	Grand Total					**27,693.5**
Years sequestration available at 80,000,000 tons CO2 per year						**346.2**

The values shown in this table are provided to illustrate an application of the estimation method described in this appendix. The numbers are subject to revision and do not represent final conclusions of this project. Additional CO_2 adsorption capacity data will be acquired to refine the estimates. Consideration will be given to other adjustments to the total that might include evaluating areas likely to have little or no sequestration potential even though they are mathematically included in the area of deep and thick shale. These areas will be excluded. For example, based on experience in oil and gas field exploration and development, Marshall, Pulaski, and Rockcastle counties are areas of marginal potential that have a relatively small likely-hood of being developed for carbon sequestration.

Appendix E: CNR 24752 Elk Horn Coal, Knott County

Recno: **125651** API: 1611901791
Permit: 94539
Name: **Columbia Natural Resources 24752 Elk Horn Coal Corp**
Loc: Knott County, KY, 1250 FSL 620 FWL 11-K-81
Lat: 37.370201 N (NAD83)
Lon: -82.764414 W

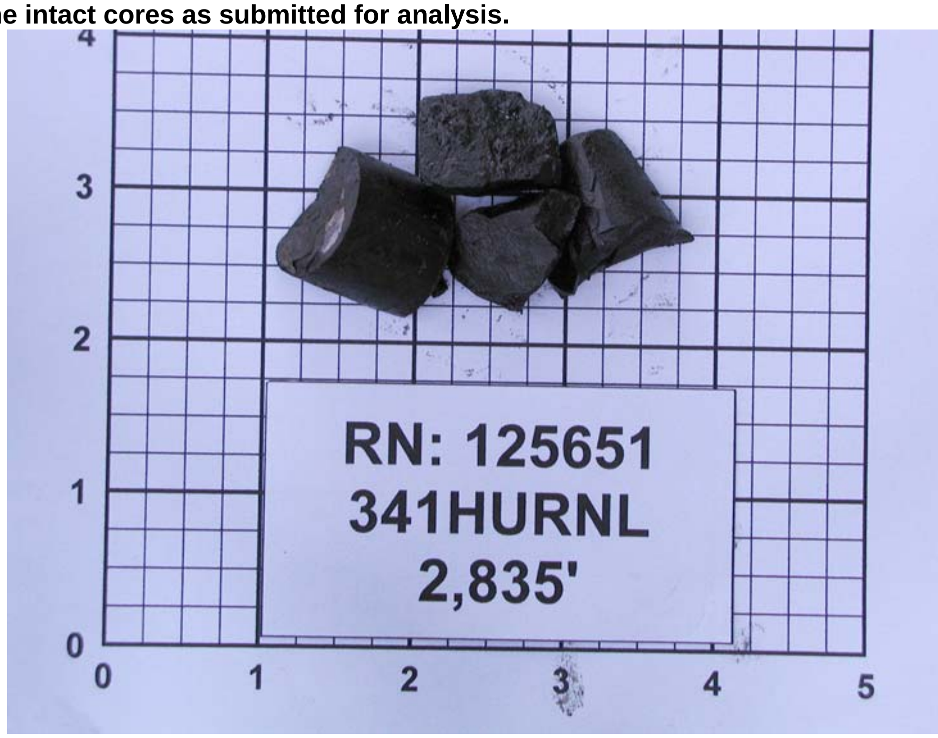
TD: 3004 feet

Log measured from KB @ 1011'

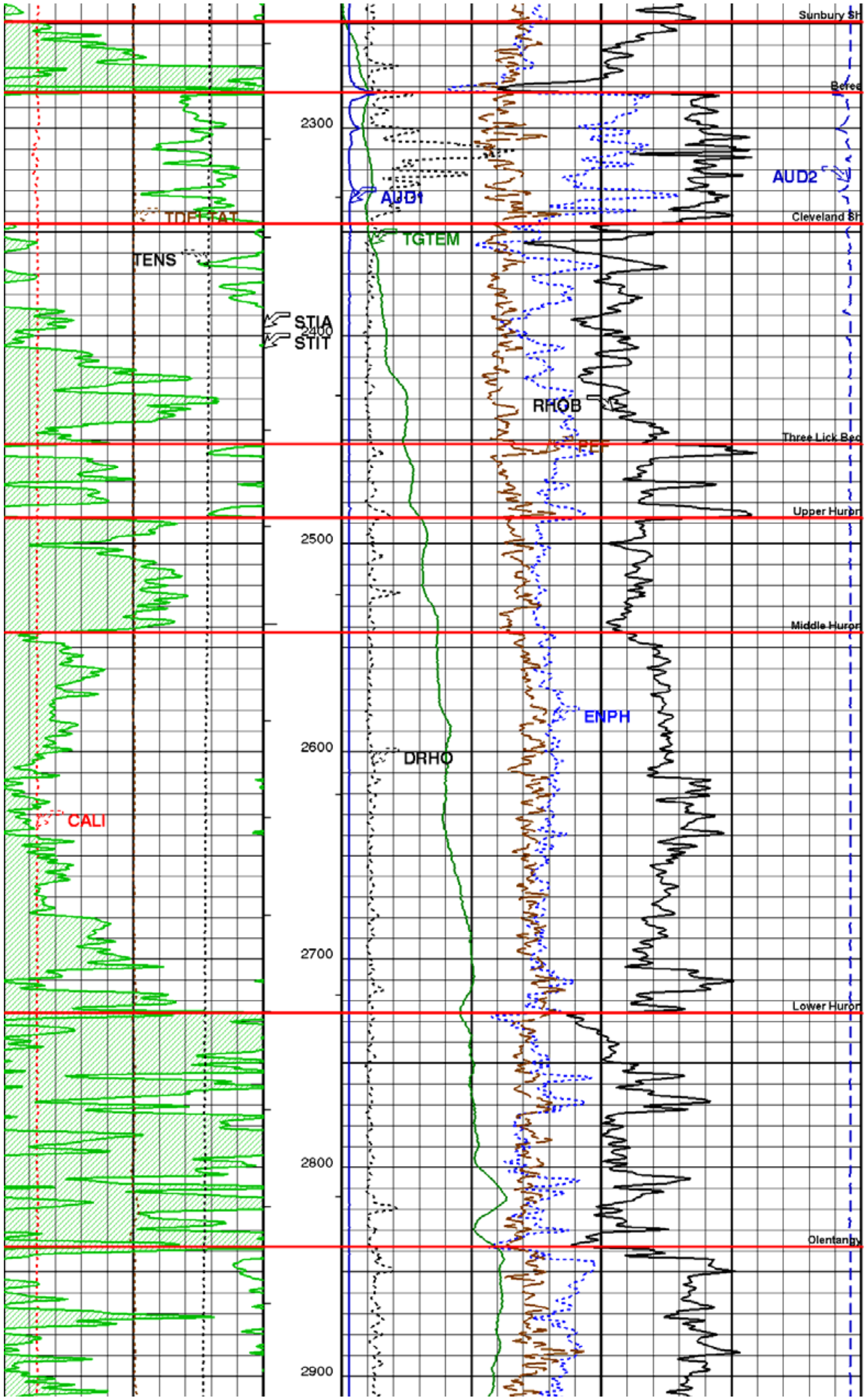
Era	Formation	Code	Top (feet)	Condition	Fluoresce	Comments	Shipped
Mssp	Little Lime	332LTLM	1698				
	Pencil Cave	332PCCV	1735				
	Big Lime	332BIGL	1739				
	Borden	337BRDN	1954				
	Sunbury	339SNBR	2249				
	Berea	339BREA	2283				
Devonian	Ohio Shale	341OHIO	2346				
	Cleveland Sh Mbr	341CLVD	2346				
	Core 10	341CLVD	**2370**	Intact	No	dry, faint odor	Yes
	Three Lick Bed	341TLBD	2452				
	Core 9	341TLBD	**2455**	Intact	No	light gray	Yes
	Core 8	341TLBD	**2465**	Intact	No	odor, dark oily black, slick, sticky feel, but not wet	Yes
	Upper Huron Mbr	341HURNU	2488				
	Core 7	341HURNU	**2530**	Intact	No	slight odor, dark oily black as in core 8	Yes
	Middle Huron Mbr	341HURNM	2543				
	Core 6	341HURNM	**2630**	Broken	No	slight odor, waxy feel, but not wet	No
	Lower Huron Mbr	341HURNL	2726				
	Core 5	341HURNL	**2730**	Intact	No	dry, somewhat mottled	Yes
	Core 4	341HURNL	**2760**	Intact	No	dry, somewhat mottled	Yes
	Core 3	341HURNL	**2780**	Intact	No	dry, approx. 0.5cm pyrite clast, possible faint odor	Yes
	Core 2	341HURNL	**2835**	Broken	No	oily, strong odor	No
	Olentangy	341OLNG	2838				
	Core1	341OLNG	**2900**	Broken	No	oily, strong odor	No

Core samples are identified by their respective measured depth from KB (i.e., Top value in **bold**)

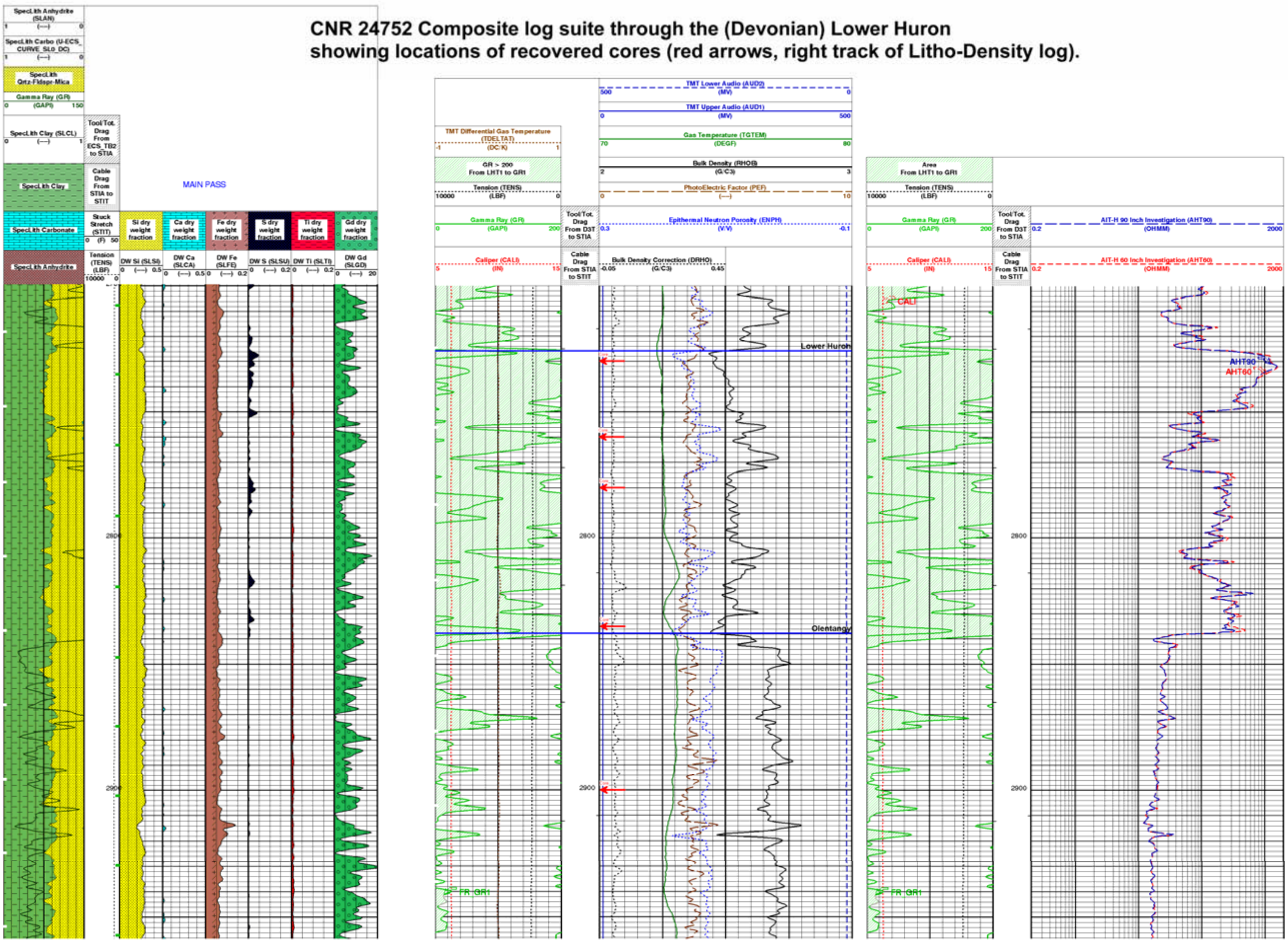
Sidewall core number 3 (0.25-inch grid).. This sample included a pyrite clast but is otherwise typical of the intact cores as submitted for analysis.



Sidewall core number 2 (0.25-inch grid). This sample exhibits an oily sheen characteristic of cores collected that were saturated with light hydrocarbons. This core is typical of the broken samples.



Annotated section of the litho-density log for the CNR 24752 Elk Horn Coal well, Knott County.

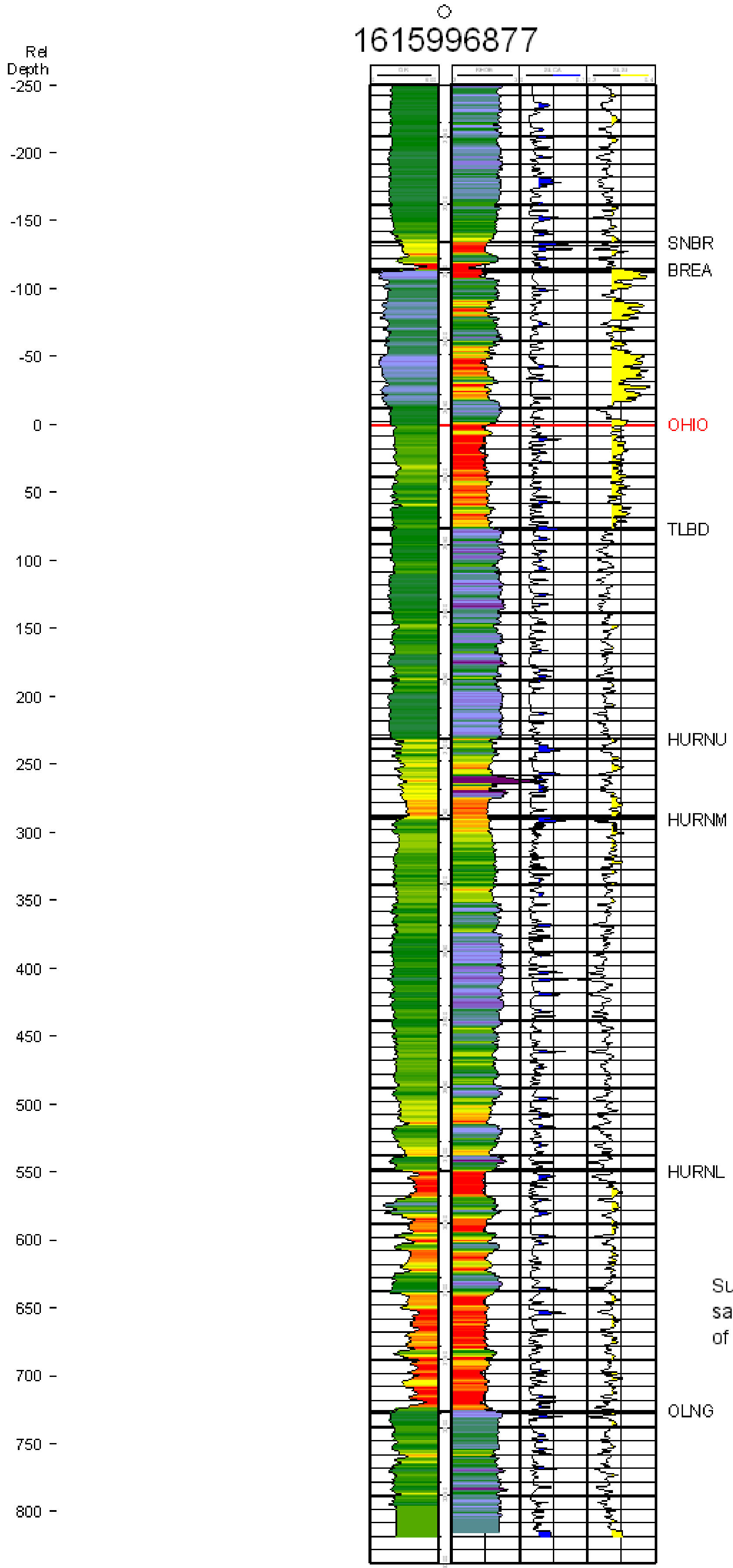


CNR 24752 Composite log suite through the (Devonian) Lower Huron showing locations of recovered cores (red arrows, right track of Litho-Density log).

Appendix F: Interstate Natural Gas No. 3 John Jude Heirs, Martin County

Note, this well was not part of the original contract. Only those items obtained with public funds contributed by the Kentucky Geological Survey or for which the operator has granted release to the public are included. The staff of the Survey are grateful to Interstate for allowing access to this well for inclusion in this project.

KGS Recno 128253
Martin Co., 18-P-85



Sidewall Cores

Sample ID (depth)

128253-C9 (2493 ft)

Intact. Nothing distinctive between this plug and plug recovered at 2492.4. Selected for adsorption.

128253-C8 (2580.4 ft)

Fractured. Scalloped fracture face indicates probable coring induced fracture. Gray powder on sample indicates higher clay content (confirmed on ECS log). Largest piece selected for adsorption.

128253-C5 (2743 ft.)

Intact, no significant difference with core collected at 2742.5. Selected for adsorption

Correlates to high open flow zone in offset well. Selected for adsorption.

128253-C3 (2777 ft.)

128253-C1 (3025.4 ft)

Intact. Small density correction below and temp anomaly across zone may indicate natural fractures. Selected for adsorption.

Summary of sidewall core samples sent for determination of adsorption isotherms.

GR: blue=low, red=high=more organic matter
RhoB: blue=high, red=low=more organic matter
Ca%: ECS weight% calcium, blue where >=3%
SI%: ECS weight% silicon, yellow where >= 27.5%

PETRA 4/13/2005 4:17:57 PM

X-ray Diffraction Mineralogy

James Talbott

K/T GeoServices, Inc.

http://www.ktgeo.com/

Interstate #3 John Jude Heirs, Martin Co., Kentucky, Permit 96877

K/T Sample #	1	2	3	4	5
Depth	3025.4	2776.6	2742.5	2581	2492.4
Formation	Lower Huron	Middle Huron	Upper Huron	Chagrin-Three Lick Bed	Cleveland
Whole Rock Mineralogy					
(Weight Percent)					
Quartz	48 %	47 %	51 %	34 %	49 %
Plagioclase	5.4%	7.0%	7.5%	8.1%	8.1%
Calcite	0.3%	1.1%	0.3%	0.3%	0.3%
Fe Dolomite	5.4%	1.3%	4.4%	0%	0%
Pyrite	8.6%	6.2%	5.4%	0%	5.0%
Gypsum	0.3%	0.3%	0.5%	0%	0.4%
Barite	1.1%	0.6%	0.7%	0.4%	0%
Total Phyllosilicates	31 %	37 %	31 %	57 %	38 %
Total	100%	100%	100%	100%	100%
Phyllosilicate Mineralogy					
(Relative Abundance)					
Illite & Mica	82 %	80 %	83 %	76 %	82 %
Kaolinite	4.3%	6.9%	7.4%	7.3%	6.0%
Chlorite	13 %	14 %	10 %	17 %	12 %
Total	100%	100%	100%	100%	100%
Summary Mineralogy					
(Weight Percent)					
Quartz	48 %	47 %	51 %	34 %	49 %
Plagioclase	5.4%	7.0%	7.5%	8.1%	8.1%
Calcite	0.3%	1.1%	0.3%	0.3%	0.3%
Fe Dolomite	5.4%	1.3%	4.4%	0%	0%
Pyrite	8.6%	6.2%	5.4%	0%	5.0%
Gypsum	0.3%	0.3%	0.5%	0%	0.4%
Barite	1.1%	0.6%	0.7%	0.4%	0%
Illite & Mica	25 %	29 %	25 %	43 %	31 %
Kaolinite	1.3%	2.5%	2.3%	4.2%	2.3%
Chlorite	4.1%	5.0%	3.1%	9.8%	4.5%
Total	100%	100%	100%	100%	100%

Online Records:
http://kgsweb.uky.edu/DataSearching/OilGas/OGResults.asp?farmname=jude&farmtype=wild&limiter=AND&opername=interstate&opertype=wild&yearlmt=equal&month1=&day1=&year1=&month2=&day2=&year2=&srchType=oil&areatype=operfarm

6-8-05

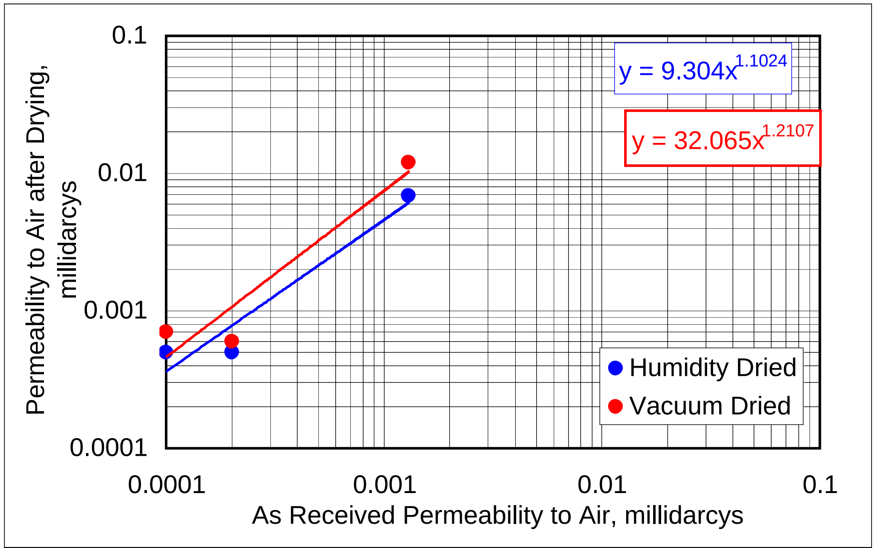
Omni Laboratories, Inc.

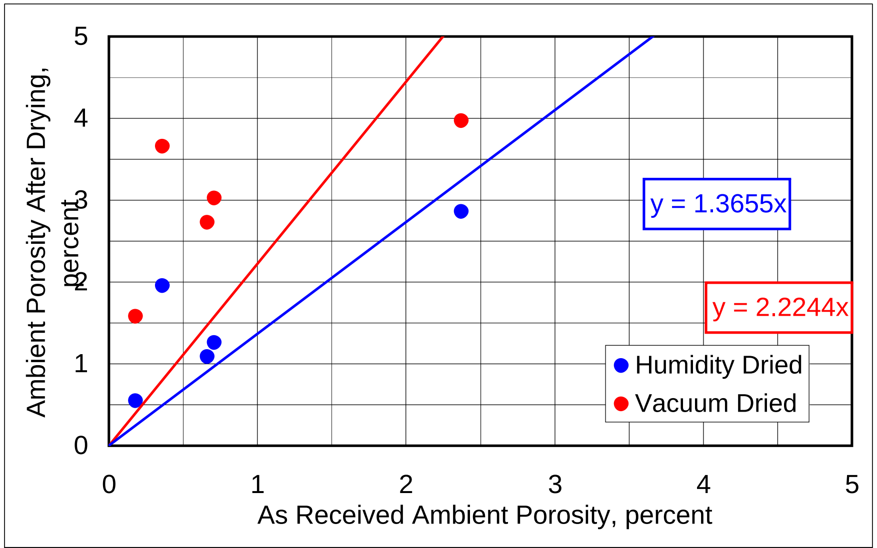
PERMEABILITY AND FLUID SATURATIONS VERSUS POROSITY

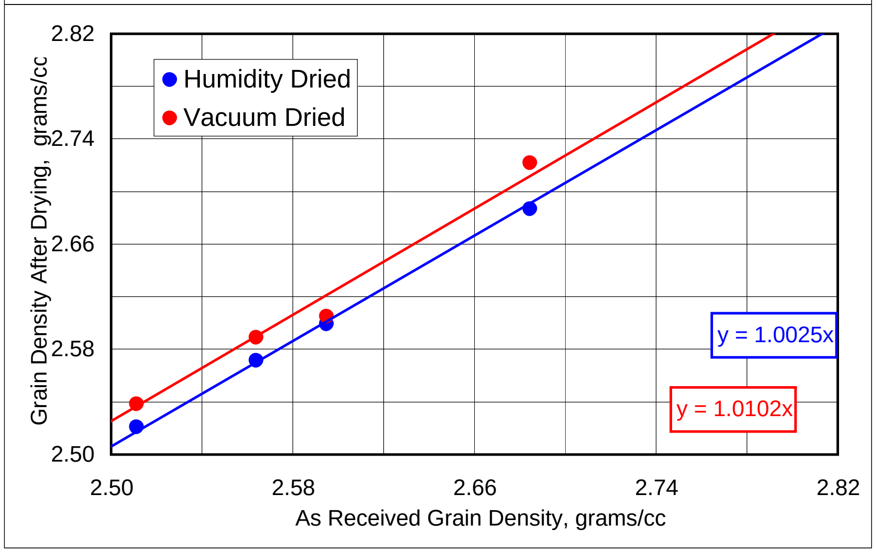
Drying Method As Noted Net Confining Stress As Noted

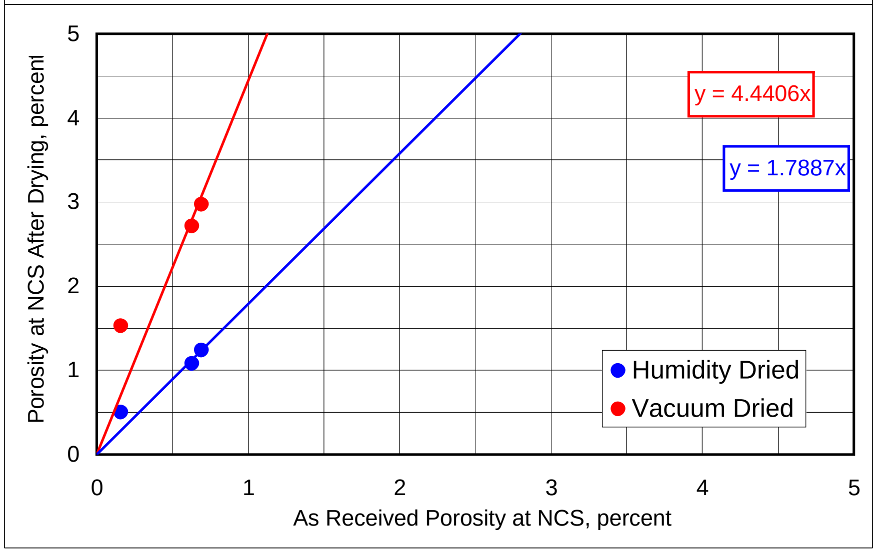
University of Kentucky
Jude No. 3 Well

Big Sandy Field
File: H-33385









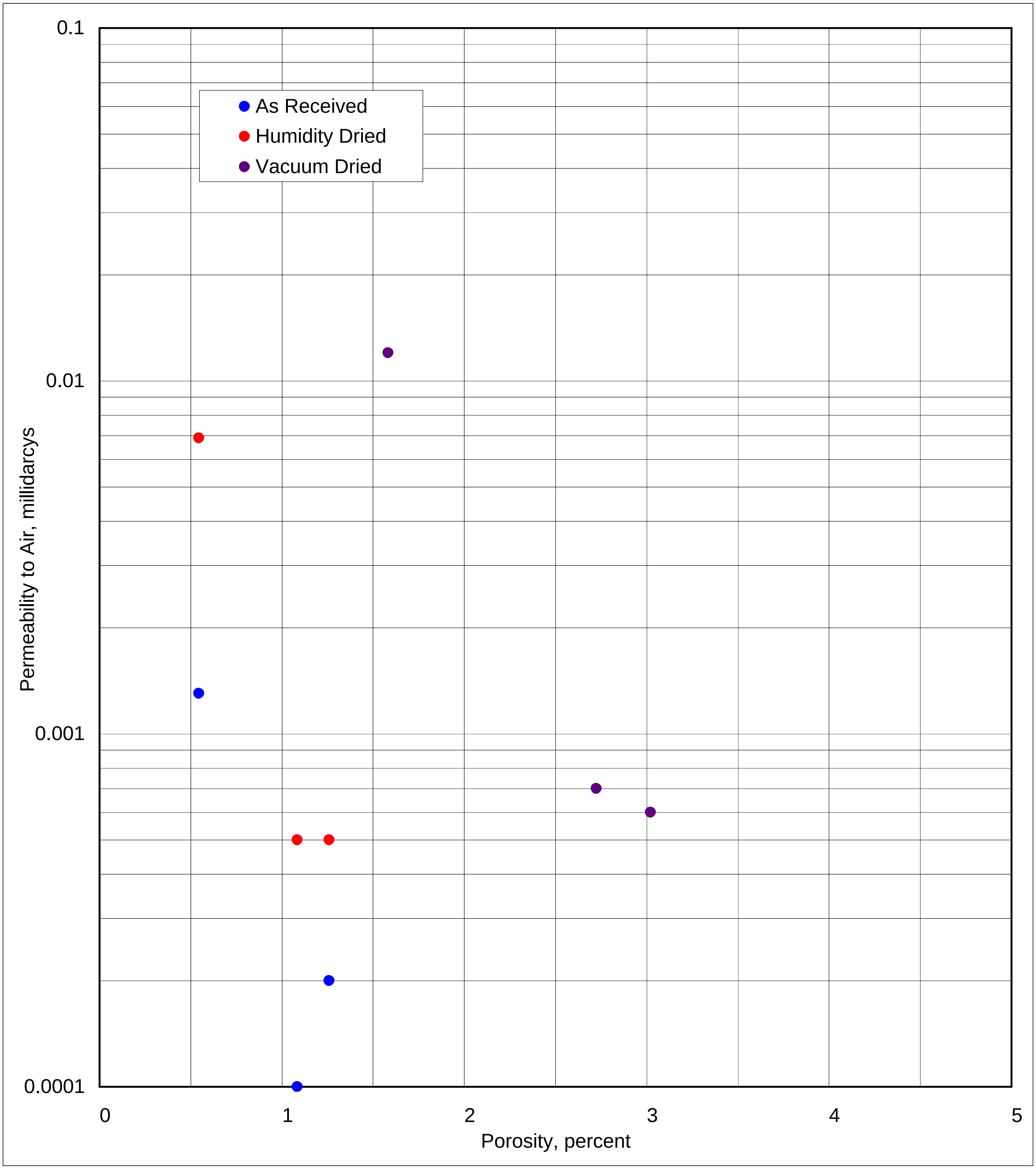
OMNI Laboratories, Inc.

PERMEABILITY VERSUS POROSITY

Drying Method As Noted Net Confining Stress As Noted

University of Kentucky
Jude No. 3 Well

Big Sandy Field
File: H-33385



SUMMARY OF ROTARY CORE ANALYSES RESULTS

Drying Method As Noted Net Confining Stress As Noted

University of Kentucky
Jude No. 3 Well

Big Sandy Field
File: H-33385

			Permeability, millidarcys						Porosity, percent						Grain Density, gm/cc			
			to Air			Klinkenberg			Ambient			800 psi						
Run Number	Sample Number	Sample Depth, feet	As Received	Humidity at 140°F	Vacuum at 180°F	As Received	Humidity at 140°F	Vacuum at 180°F	As Received	Humidity at 140°F	Vacuum at 180°F	As Received	Humidity at 140°F	Vacuum at 180°F	As Received	Humidity at 140°F	Vacuum at 180°F	Lithological Description
1	1	2492.4	0.0002	0.0005	0.0006	0.00002	0.0001	0.0001	0.7	1.3	3.0	0.7	1.2	3.0	2.420	2.428	2.450	in progress
1	2	2581.0				+			0.4	1.9	3.7				2.684	2.687	2.722	in progress
1	3	2742.5	0.0001	0.0005	0.0007	0.0001	0.0001	0.0001	0.7	1.1	2.7	0.6	1.1	2.7	2.564	2.571	2.589	in progress
1	4	2776.6	0.0013	0.0069	0.012	0.0002	0.0022	0.0043	0.2	0.5	1.6	0.2	0.5	1.5	2.595	2.599	2.605	in progress
1	5	3025.4				+			2.4	2.9	4.0				2.511	2.521	2.539	in progress
		Average values:	0.0005	0.0026	0.0044	0.0001	0.0008	0.0015	0.9	1.5	3.0	0.5	0.9	2.4	2.550	2.560	2.580	

+ Denotes sample unsuitable for measurement at net confining stress

OMNI Laboratories, Inc.

6-30-05

SUMMARY OF MERCURY INJECTION TEST RESULTS

University of Kentucky
Jude No. 3 Well

Big Sandy Field
File: H-33385

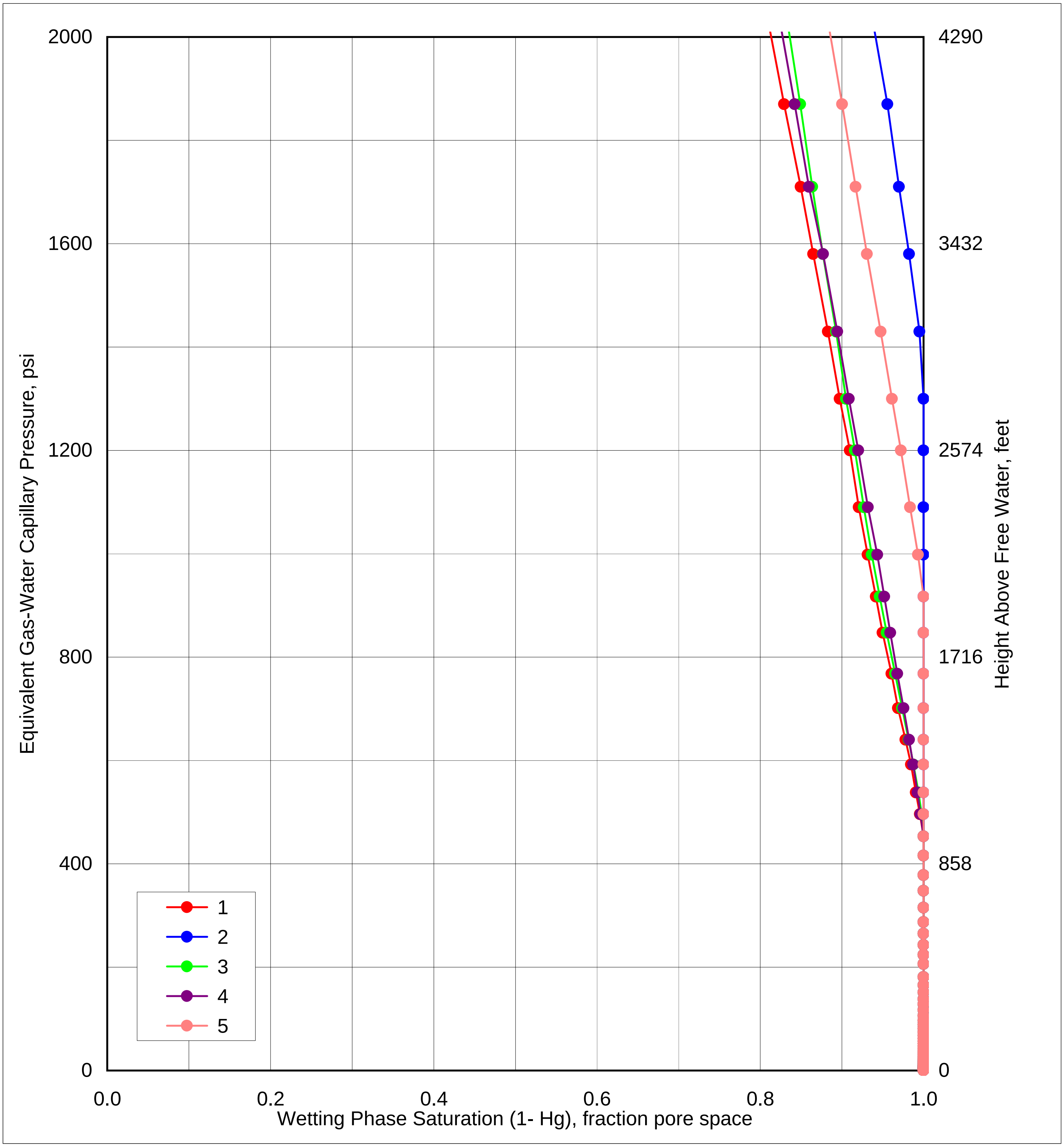
Sample Number	Sample Depth, feet	Permeability to Air, millidarcys		Porosity, fraction		Grain Density, grams/cc		Median Pore Throat Radius, microns	Fluid Saturation at 2000 psi Equivalent Gas-Water Capillary Pressure, fraction pore space
		plug	calculated*	plug	Hg Inj	plug	Hg Inj		
1	2492.40	0.0006	0.000029	0.030	0.029	2.45	2.45	0.0042	0.814
2	2581.00	+	0.000036	0.037	0.035	2.72	2.72	0.0036	0.941
3	2742.50	0.0007	0.000026	0.027	0.029	2.59	2.59	0.0037	0.836
4	2776.60	0.012	0.000020	0.016	0.020	2.61	2.61	0.0042	0.827
5	3025.40	+	0.000048	0.040	0.044	2.54	2.54	0.0036	0.886

+ Denotes sample unsuitable for measurement at net confining stress
* Calculated from mercury injection data per SPE paper 8234

EQUIVALENT GAS - WATER CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Composite of All Samples

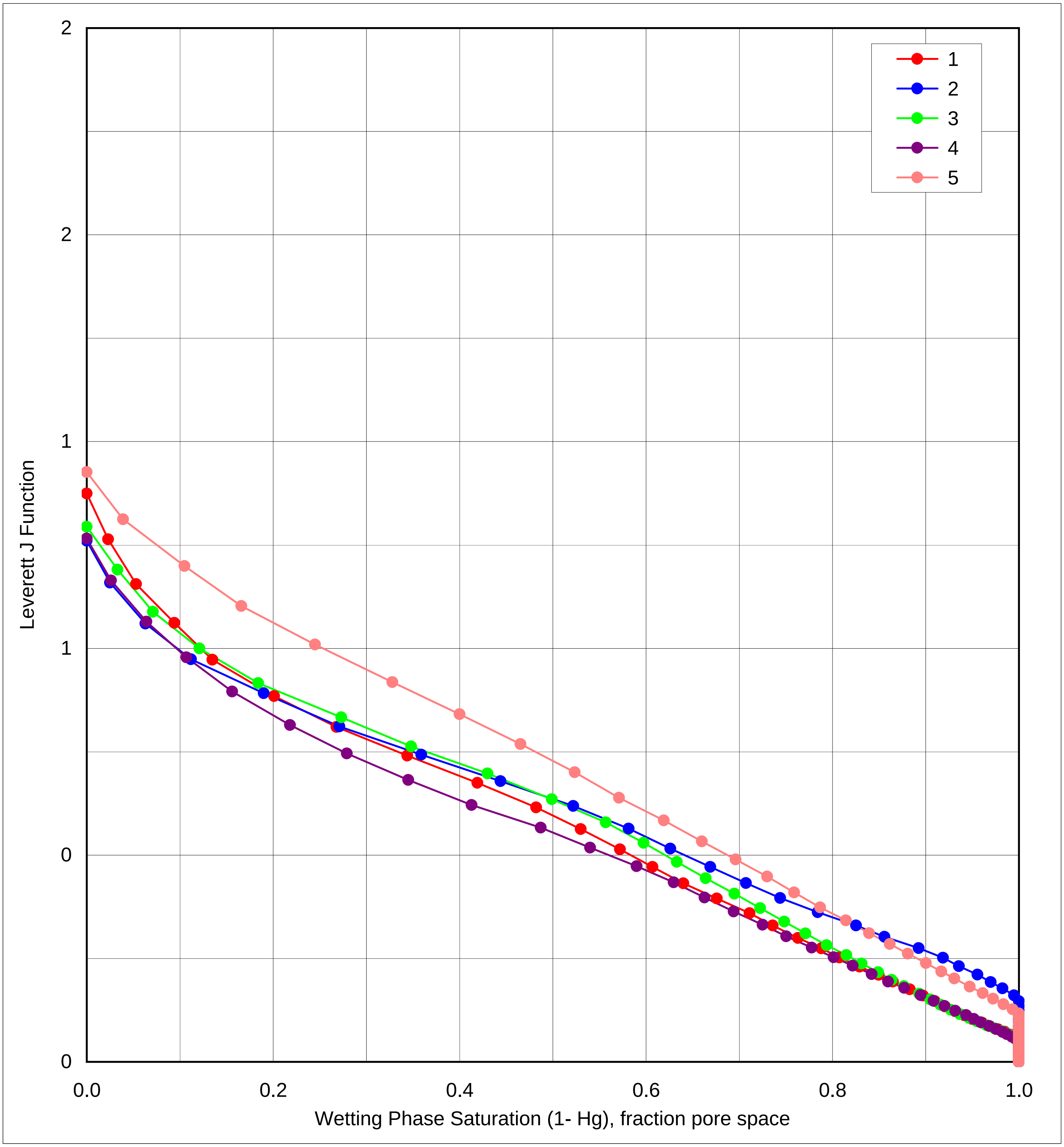


6-30-05

LEVERETT J FUNCTION

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Composite of All Samples

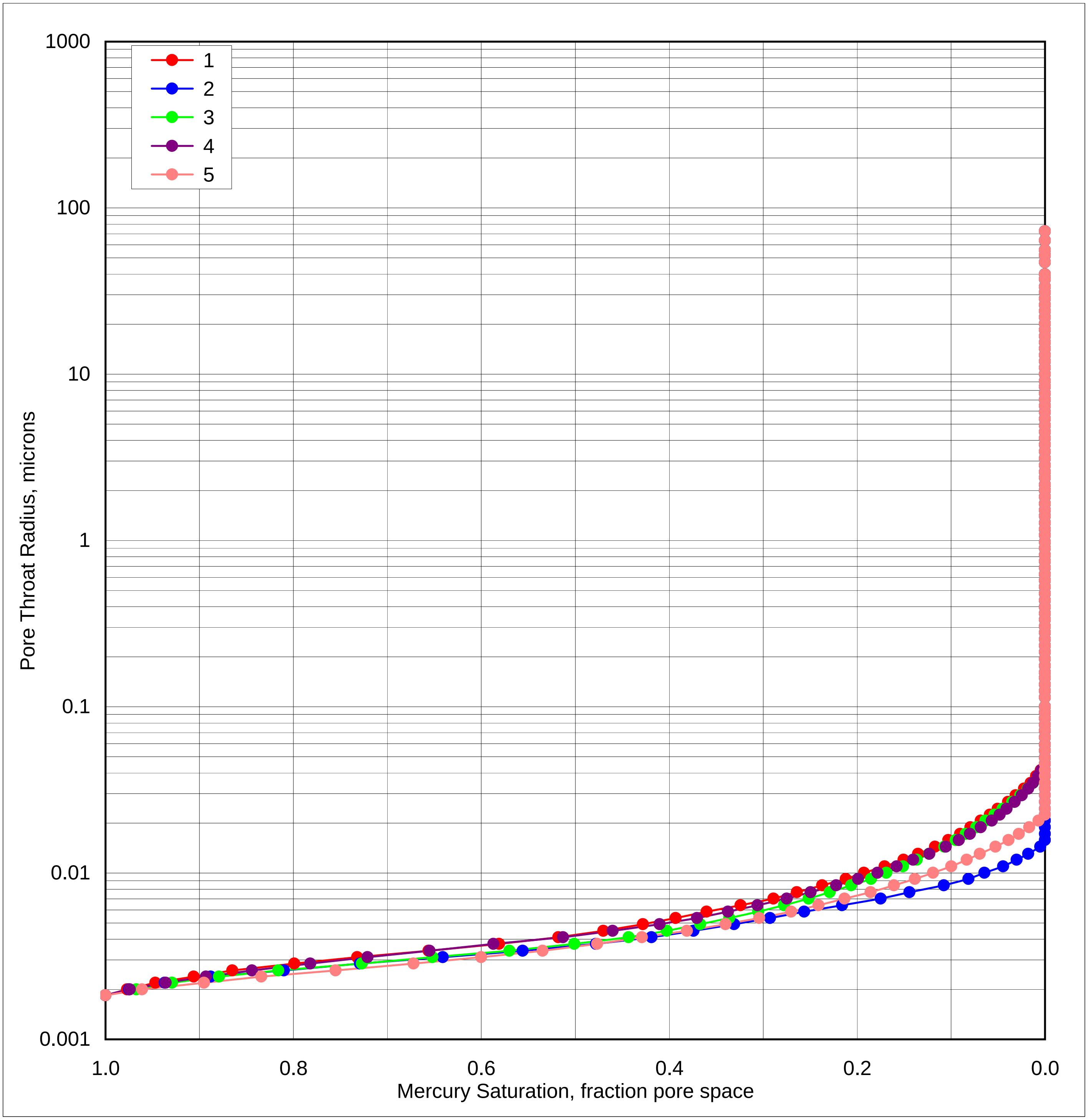


6-30-05

PORE THROAT RADII

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Composite of All Samples

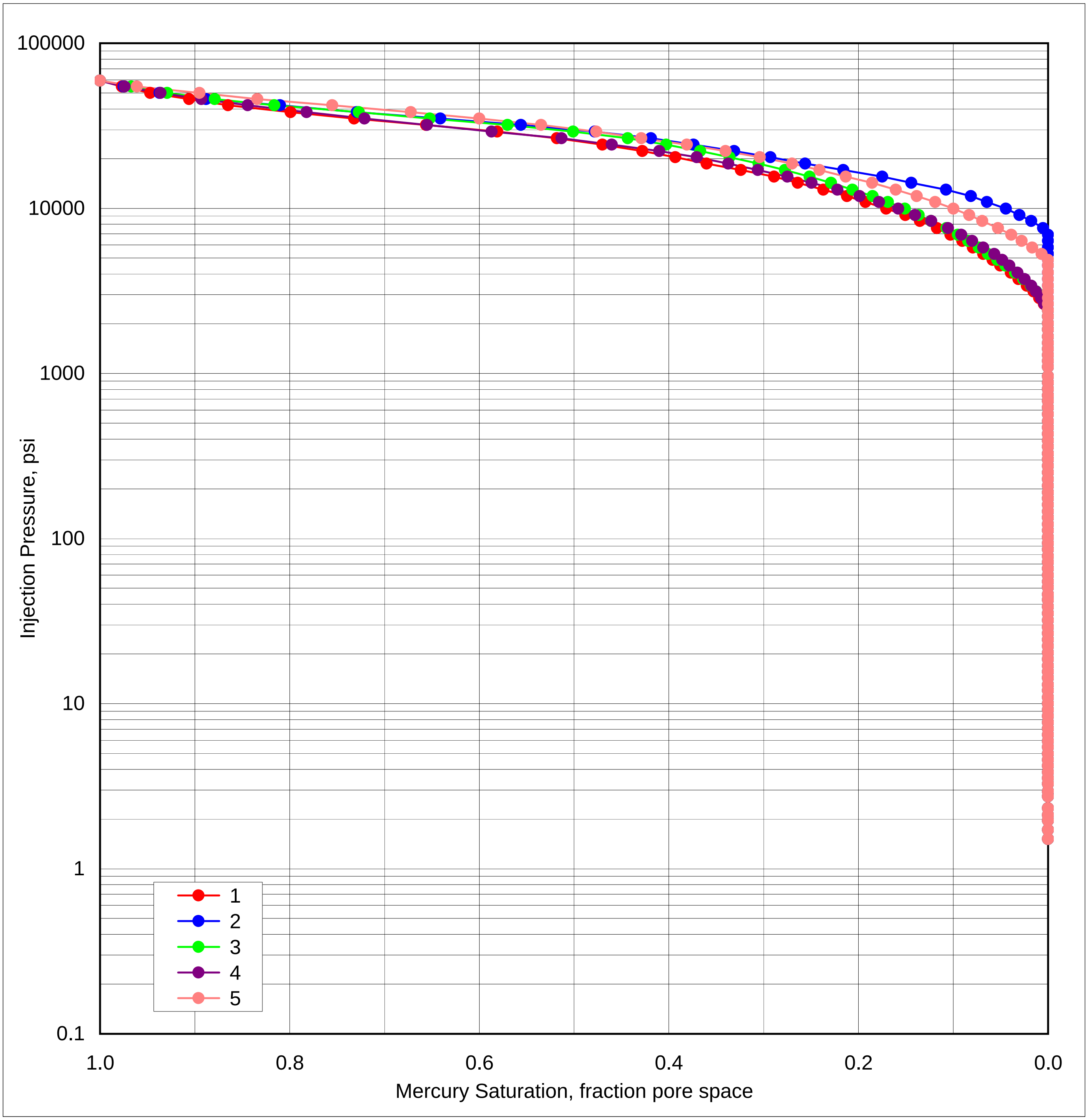


6-30-05

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Composite of All Samples



MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Composite of All Samples

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft G-W	O-W
1.51	0.000	1.000	72.34	0.00	0.28	0.10	0.12	0.61	1.01
1.72	0.000	1.000	63.51	0.00	0.32	0.11	0.14	0.70	1.15
1.96	0.000	1.000	55.73	0.00	0.37	0.13	0.16	0.79	1.31
2.11	0.000	1.000	51.77	0.00	0.40	0.14	0.17	0.85	1.41
2.32	0.000	1.000	47.08	0.00	0.44	0.15	0.19	0.94	1.55
2.74	0.000	1.000	39.87	0.00	0.52	0.18	0.22	1.11	1.84
2.93	0.000	1.000	37.28	0.00	0.55	0.19	0.24	1.18	1.96
3.26	0.000	1.000	33.51	0.00	0.61	0.21	0.27	1.32	2.18
3.53	0.000	1.000	30.94	0.00	0.67	0.23	0.29	1.43	2.36
3.84	0.000	1.000	28.45	0.00	0.72	0.25	0.31	1.55	2.57
4.20	0.000	1.000	26.01	0.00	0.79	0.27	0.34	1.70	2.81
4.56	0.000	1.000	23.95	0.00	0.86	0.29	0.37	1.84	3.05
4.97	0.000	1.000	21.98	0.00	0.94	0.32	0.41	2.01	3.33
5.44	0.000	1.000	20.08	0.00	1.02	0.35	0.44	2.2	3.64
5.91	0.000	1.000	18.48	0.00	1.11	0.38	0.48	2.39	3.96
6.47	0.000	1.000	16.88	0.00	1.22	0.42	0.53	2.61	4.33
7.04	0.000	1.000	15.52	0.00	1.33	0.45	0.57	2.85	4.72
7.67	0.000	1.000	14.24	0.00	1.45	0.50	0.63	3.1	5.14
8.40	0.000	1.000	13.00	0.00	1.58	0.54	0.69	3.39	5.63
9.15	0.000	1.000	11.94	0.00	1.72	0.59	0.75	3.7	6.13
10.00	0.000	1.000	10.923	0.00	1.88	0.65	0.82	4.04	6.7
10.91	0.000	1.000	10.012	0.00	2.06	0.70	0.89	4.41	7.31
12.00	0.000	1.000	9.103	0.00	2.26	0.78	0.98	4.85	8.04
12.99	0.000	1.000	8.409	0.00	2.45	0.84	1.06	5.25	8.7
14.27	0.000	1.000	7.655	0.00	2.69	0.92	1.16	5.77	9.56
15.56	0.000	1.000	7.020	0.00	2.93	1.01	1.27	6.29	10.4
16.94	0.000	1.000	6.448	0.00	3.19	1.09	1.38	6.85	11.3
18.55	0.000	1.000	5.888	0.00	3.49	1.2	1.51	7.5	12.4
20.32	0.000	1.000	5.376	0.00	3.83	1.31	1.66	8.21	13.6
22.25	0.000	1.000	4.909	0.00	4.19	1.44	1.82	8.99	14.9
24.32	0.000	1.000	4.491	0.00	4.58	1.57	1.98	9.83	16.3
26.60	0.000	1.000	4.106	0.00	5.01	1.72	2.17	10.8	17.8
28.99	0.000	1.000	3.768	0.00	5.46	1.87	2.37	11.7	19.4
31.90	0.000	1.000	3.424	0.00	6.01	2.06	2.6	12.9	21.4
35.14	0.000	1.000	3.108	0.00	6.62	2.27	2.87	14.2	23.5
38.59	0.000	1.000	2.831	0.00	7.27	2.49	3.15	15.6	25.8
42.43	0.000	1.000	2.574	0.00	7.99	2.74	3.46	17.1	28.4
45.86	0.000	1.000	2.382	0.00	8.64	2.96	3.74	18.5	30.7
50.60	0.000	1.000	2.159	0.00	9.53	3.27	4.13	20.4	33.9
54.69	0.000	1.000	1.997	0.00	10.3	3.53	4.46	22.1	36.6
59.86	0.000	1.000	1.825	0.00	11.3	3.87	4.88	24.2	40.1
65.71	0.000	1.000	1.662	0.00	12.4	4.24	5.36	26.6	44.
71.74	0.000	1.000	1.5226	0.00	13.5	4.63	5.85	29.	48.1
77.86	0.000	1.000	1.4029	0.00	14.7	5.03	6.35	31.5	52.2
85.75	0.000	1.000	1.2738	0.00	16.2	5.54	7.	34.7	57.4

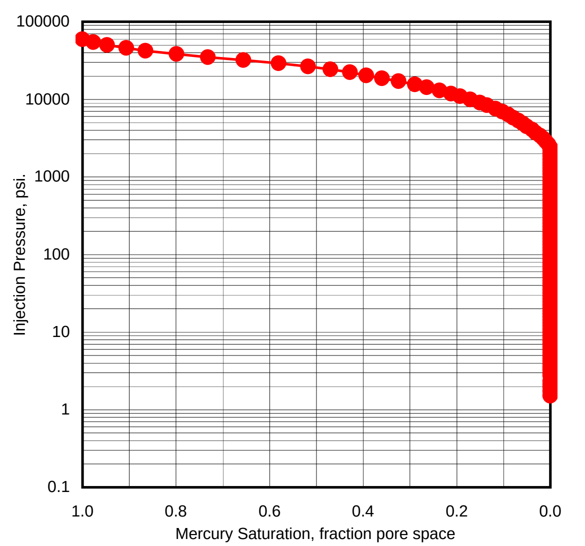
Laboratories, Inc.

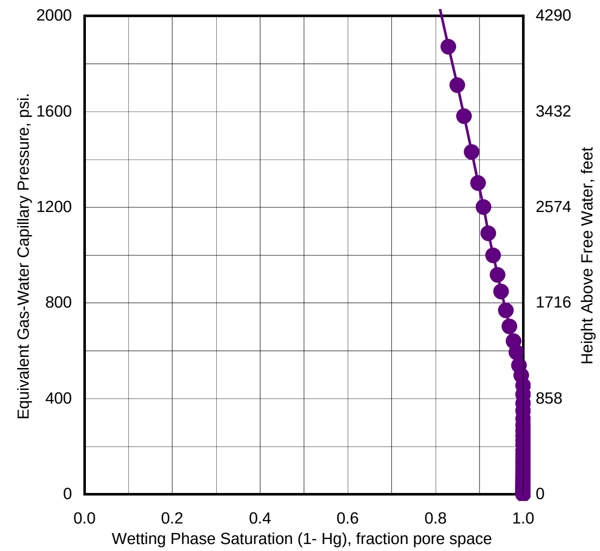
University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

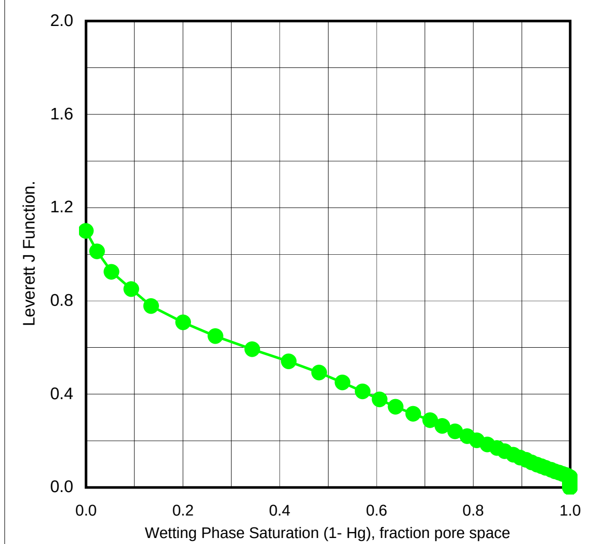
MERCURY INJECTION CAPILLARY PRESSURE

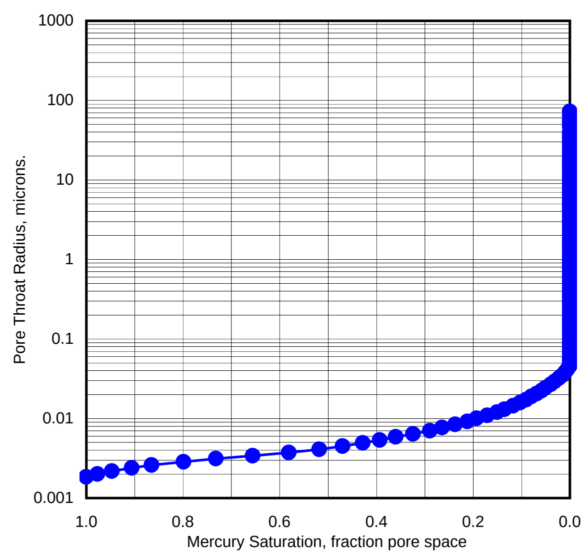
6-30-05

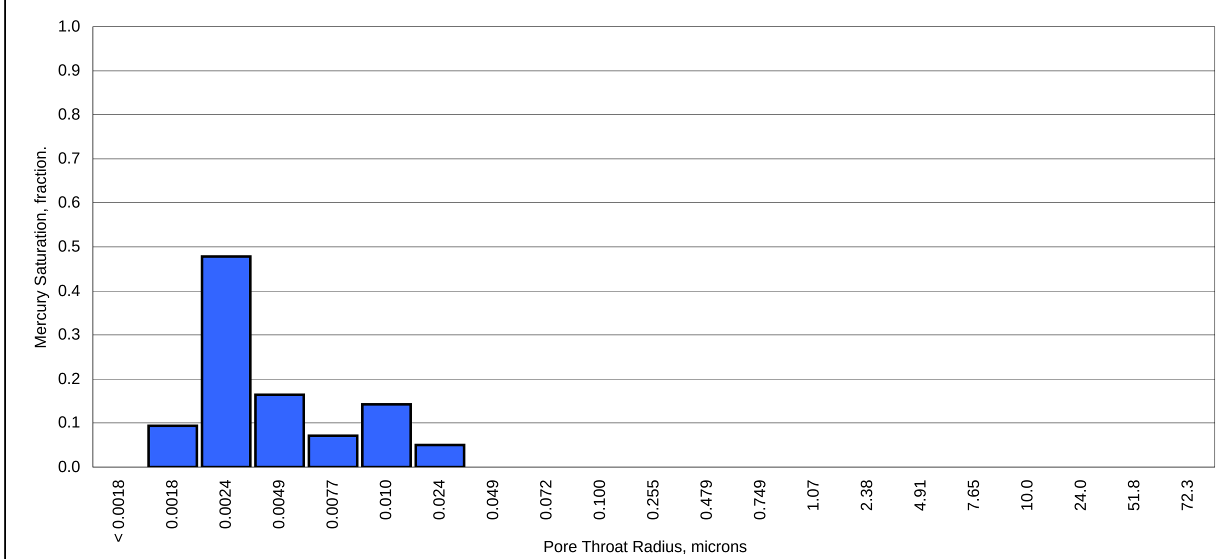
Sample Number:	1
Sample Depth, feet:	2492.40
Permeability to Air (calc), md:	0.000029
Porosity, fraction:	0.029
Grain Density, grams/cc:	2.45
Median Pore Throat Radius, microns:	0.004











OMNI Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 1
Sample Depth, feet: 2492.40
Permeability to Air (calc), md: 0.000029
Porosity, fraction: 0.029
Grain Density, grams/cc: 2.45
Median Pore Throat Radius, microns: 0.0042

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems: Gas-Water, psia	Other Laboratory Systems: Gas-Oil, psia	Other Laboratory Systems: Oil-Water, psia	Estimated Height Above Free Water, ft: G-W	Estimated Height Above Free Water, ft: O-W
1.51	0.000	1.000	72.3	0.000	0.28	0.10	0.12	0.61	1.01
1.72	0.000	1.000	63.5	0.000	0.32	0.11	0.14	0.70	1.15
1.96	0.000	1.000	55.7	0.000	0.37	0.13	0.16	0.79	1.31
2.11	0.000	1.000	51.8	0.000	0.40	0.14	0.17	0.85	1.41
2.32	0.000	1.000	47.1	0.000	0.44	0.15	0.19	0.94	1.55
2.74	0.000	1.000	39.9	0.000	0.52	0.18	0.22	1.11	1.84
2.93	0.000	1.000	37.3	0.000	0.55	0.19	0.24	1.18	1.96
3.26	0.000	1.000	33.5	0.000	0.61	0.21	0.27	1.32	2.18
3.53	0.000	1.000	30.9	0.000	0.67	0.23	0.29	1.43	2.36
3.84	0.000	1.000	28.4	0.000	0.72	0.25	0.31	1.55	2.57
4.20	0.000	1.000	26.0	0.000	0.79	0.27	0.34	1.70	2.81
4.56	0.000	1.000	24.0	0.000	0.86	0.29	0.37	1.84	3.05
4.97	0.000	1.000	22.0	0.000	0.94	0.32	0.41	2.01	3.33
5.44	0.000	1.000	20.1	0.000	1.02	0.35	0.44	2.20	3.64
5.91	0.000	1.000	18.5	0.000	1.11	0.38	0.48	2.39	3.96
6.47	0.000	1.000	16.9	0.000	1.22	0.42	0.53	2.61	4.33
7.04	0.000	1.000	15.5	0.000	1.33	0.45	0.57	2.85	4.72
7.67	0.000	1.000	14.2	0.000	1.45	0.50	0.63	3.10	5.14
8.40	0.000	1.000	13.0	0.000	1.58	0.54	0.69	3.39	5.63
9.15	0.000	1.000	11.9	0.000	1.72	0.59	0.75	3.70	6.13
10.00	0.000	1.000	10.9	0.000	1.88	0.65	0.82	4.04	6.70
10.91	0.000	1.000	10.0	0.000	2.06	0.70	0.89	4.41	7.31
12.00	0.000	1.000	9.10	0.000	2.26	0.78	0.98	4.85	8.04
12.99	0.000	1.000	8.41	0.000	2.45	0.84	1.06	5.25	8.70
14.27	0.000	1.000	7.65	0.000	2.69	0.92	1.16	5.77	9.56
15.56	0.000	1.000	7.02	0.000	2.93	1.01	1.27	6.29	10.4
16.94	0.000	1.000	6.45	0.000	3.19	1.09	1.38	6.85	11.3
18.55	0.000	1.000	5.89	0.000	3.49	1.20	1.51	7.50	12.4
20.32	0.000	1.000	5.38	0.000	3.83	1.31	1.66	8.21	13.6
22.25	0.000	1.000	4.91	0.000	4.19	1.44	1.82	8.99	14.9
24.32	0.000	1.000	4.49	0.000	4.58	1.57	1.98	9.83	16.3
26.60	0.000	1.000	4.11	0.000	5.01	1.72	2.17	10.8	17.8
28.99	0.000	1.000	3.77	0.001	5.46	1.87	2.37	11.7	19.4
31.90	0.000	1.000	3.42	0.001	6.01	2.06	2.60	12.9	21.4
35.14	0.000	1.000	3.11	0.001	6.62	2.27	2.87	14.2	23.5
38.59	0.000	1.000	2.83	0.001	7.27	2.49	3.15	15.6	25.8
42.43	0.000	1.000	2.57	0.001	7.99	2.74	3.46	17.1	28.4
45.86	0.000	1.000	2.38	0.001	8.64	2.96	3.74	18.5	30.7
50.60	0.000	1.000	2.16	0.001	9.53	3.27	4.13	20.4	33.9
54.69	0.000	1.000	2.00	0.001	10.3	3.53	4.46	22.1	36.6
59.86	0.000	1.000	1.82	0.001	11.3	3.87	4.88	24.2	40.1
65.71	0.000	1.000	1.66	0.001	12.4	4.24	5.36	26.6	44.0
71.74	0.000	1.000	1.52	0.001	13.5	4.63	5.85	29.0	48.1
77.86	0.000	1.000	1.40	0.001	14.7	5.03	6.35	31.5	52.2
85.75	0.000	1.000	1.27	0.002	16.2	5.54	7.00	34.7	57.4
93.64	0.000	1.000	1.17	0.002	17.6	6.05	7.64	37.8	62.7
101.68	0.000	1.000	1.07	0.002	19.2	6.57	8.30	41.2	68.1

OMNI Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 1
Sample Depth, feet: 2492.40
Permeability to Air (calc), md: 0.000029
Porosity, fraction: 0.029
Grain Density, grams/cc: 2.45
Median Pore Throat Radius, microns: 0.0042

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems: Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft: G-W	O-W
111.98	0.000	1.000	0.975	0.002	21.1	7.23	9.14	45.3	75.0
121.70	0.000	1.000	0.898	0.002	22.9	7.86	9.93	49.1	81.5
133.85	0.000	1.000	0.816	0.002	25.2	8.65	10.9	54.1	89.5
145.76	0.000	1.000	0.749	0.003	27.5	9.42	11.9	59.0	97.7
159.69	0.000	1.000	0.684	0.003	30.1	10.3	13.0	64.6	107.
174.53	0.000	1.000	0.626	0.003	32.9	11.3	14.2	70.6	117.
190.06	0.000	1.000	0.575	0.004	35.8	12.3	15.5	76.8	127.
208.09	0.000	1.000	0.525	0.004	39.2	13.4	17.0	84.1	140.
228.16	0.000	1.000	0.479	0.004	43.0	14.7	18.6	92.2	153.
250.43	0.000	1.000	0.436	0.005	47.2	16.2	20.4	101.	167.
274.98	0.000	1.000	0.397	0.005	51.8	17.8	22.4	111.	184.
300.38	0.000	1.000	0.364	0.006	56.6	19.4	24.5	121.	201.
326.89	0.000	1.000	0.334	0.006	61.6	21.1	26.7	132.	219.
359.50	0.000	1.000	0.304	0.007	67.7	23.2	29.3	145.	241.
392.11	0.000	1.000	0.279	0.007	73.9	25.3	32.0	159.	263.
429.16	0.000	1.000	0.255	0.008	80.9	27.7	35.0	174.	287.
469.55	0.000	1.000	0.233	0.009	88.5	30.3	38.3	190.	314.
511.94	0.000	1.000	0.213	0.009	96.5	33.1	41.8	207.	343.
564.96	0.000	1.000	0.193	0.010	106.	36.5	46.1	227.	378.
620.04	0.000	1.000	0.176	0.011	117.	40.1	50.6	251.	415.
681.09	0.000	1.000	0.160	0.013	128.	44.	55.6	275.	456.
734.02	0.000	1.000	0.149	0.014	138.	47.4	59.9	296.	492.
802.95	0.000	1.000	0.136	0.015	151.	51.9	65.5	324.	538.
878.32	0.000	1.000	0.124	0.016	165.	56.7	71.7	354.	589.
961.21	0.000	1.000	0.114	0.018	181.	62.1	78.4	388.	644.
1093.16	0.000	1.000	0.100	0.020	206.	70.6	89.2	442.	732.
1187.15	0.000	1.000	0.092	0.022	224.	76.7	96.9	480.	796.
1288.19	0.000	1.000	0.085	0.024	243.	83.2	105.	521.	862.
1403.88	0.000	1.000	0.078	0.026	265.	90.7	115.	568.	944.
1524.88	0.000	1.000	0.072	0.028	287.	98.5	124.	616.	1020.
1670.75	0.000	1.000	0.065	0.031	315.	108.	136.	676.	1120.
1845.94	0.000	1.000	0.059	0.034	348.	119.	151.	746.	1240.
2006.45	0.000	1.000	0.054	0.037	378.	130.	164.	811.	1350.
2207.35	0.000	1.000	0.049	0.041	416.	143.	180.	892.	1480.
2405.54	0.000	1.000	0.045	0.045	453.	155.	196.	972.	1610.
2633.98	0.004	0.996	0.041	0.049	496.	170.	215.	1064.	1770.
2856.54	0.009	0.991	0.038	0.053	538.	185.	233.	1150.	1910.
3139.69	0.015	0.985	0.035	0.058	592.	203.	256.	1270.	2100.
3396.42	0.022	0.978	0.032	0.063	640.	219.	277.	1370.	2270.
3721.82	0.031	0.969	0.029	0.069	701.	240.	304.	1500.	2500.
4076.88	0.039	0.961	0.027	0.075	768.	263.	333.	1650.	2730.
4494.61	0.050	0.950	0.024	0.083	847.	290.	367.	1820.	3010.
4868.08	0.059	0.942	0.022	0.090	917.	314.	397.	1970.	3260.
5294.34	0.068	0.932	0.021	0.098	998.	342.	432.	2140.	3550.
5788.25	0.079	0.921	0.019	0.107	1090.	374.	472.	2340.	3880.
6348.76	0.090	0.910	0.017	0.117	1200.	410.	518.	2570.	4250.

Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number:	1
Sample Depth, feet:	2492.40
Permeability to Air (calc), md:	0.000029
Porosity, fraction:	0.029
Grain Density, grams/cc:	2.45
Median Pore Throat Radius, microns:	0.0042

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems: Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft: G-W	O-W
6916.75	0.103	0.897	0.016	0.128	1300.	447.	564.	2790.	4630.
7582.32	0.117	0.883	0.014	0.140	1430.	490.	619.	3070.	5080.
8388.55	0.135	0.865	0.013	0.155	1580.	542.	684.	3390.	5620.
9092.58	0.150	0.850	0.012	0.168	1710.	587.	742.	3670.	6090.
9946.89	0.171	0.829	0.011	0.184	1870.	643.	812.	4010.	6670.
10903.76	0.193	0.807	0.010	0.202	2050.	704.	890.	4400.	7310.
11861.34	0.212	0.788	0.0092	0.219	2230.	766.	968.	4780.	7950.
12956.73	0.237	0.763	0.0084	0.240	2440.	837.	1060.	5230.	8700.
14248.70	0.264	0.736	0.0077	0.264	2680.	920.	1160.	5750.	9520.
15552.78	0.289	0.711	0.0070	0.288	2930.	1000.	1270.	6280.	10400.
17067.33	0.324	0.676	0.0064	0.316	3220.	1100.	1390.	6910.	11400.
18661.64	0.360	0.640	0.0059	0.345	3520.	1210.	1520.	7550.	12500.
20377.39	0.393	0.607	0.0054	0.377	3840.	1320.	1660.	8240.	13600.
22206.38	0.428	0.572	0.0049	0.411	4180.	1430.	1810.	8970.	14900.
24318.84	0.470	0.530	0.0045	0.450	4580.	1570.	1980.	9820.	16300.
26587.99	0.518	0.482	0.0041	0.492	5010.	1720.	2170.	10700.	17800.
29159.12	0.581	0.419	0.0037	0.540	5490.	1880.	2380.	11800.	19500.
32006.60	0.656	0.344	0.0034	0.592	6030.	2070.	2610.	12900.	21400.
35009.34	0.732	0.268	0.0031	0.648	6600.	2260.	2860.	14200.	23500.
38239.29	0.799	0.201	0.0029	0.708	7200.	2470.	3120.	15400.	25600.
42031.89	0.865	0.135	0.0026	0.778	7920.	2720.	3430.	17000.	28200.
45901.07	0.906	0.094	0.0024	0.849	8650.	2970.	3740.	18600.	30700.
49947.95	0.947	0.053	0.0022	0.924	9410.	3230.	4070.	20200.	33400.
54638.68	0.977	0.023	0.0020	1.011	10290.	3530.	4460.	22100.	36600.
59405.26	1.000	0.000	0.0018	1.099	11190.	3840.	4850.	24000.	39800.

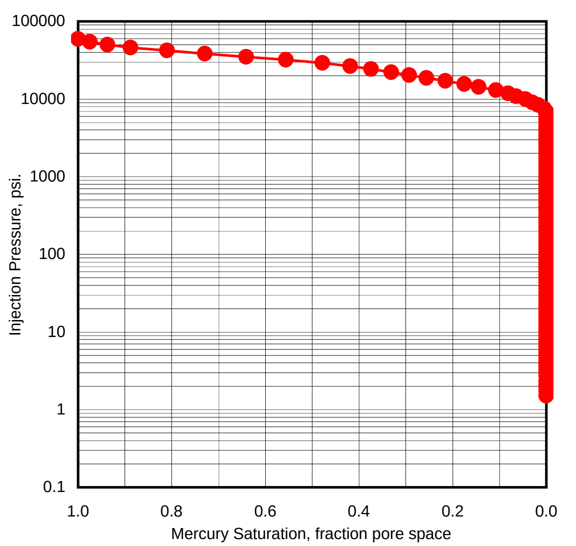
Laboratories, Inc.

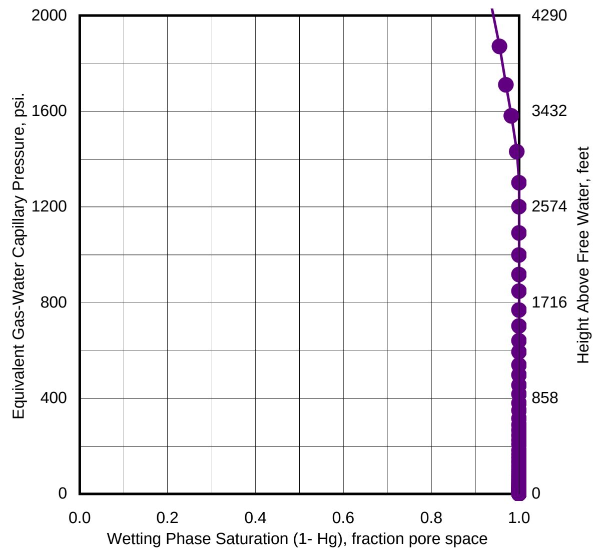
MERCURY INJECTION CAPILLARY PRESSURE

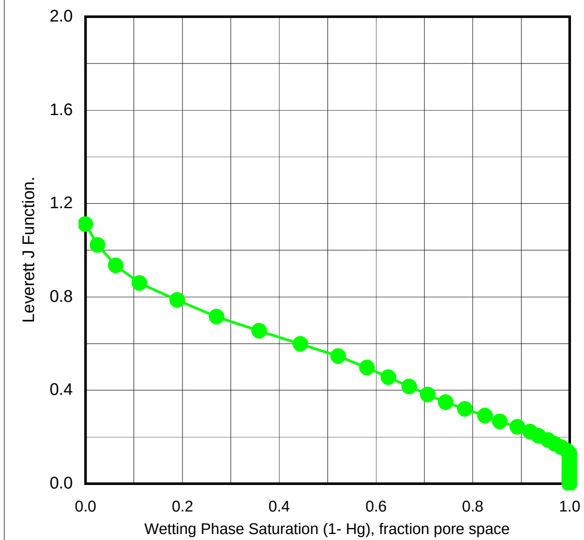
6-30-05

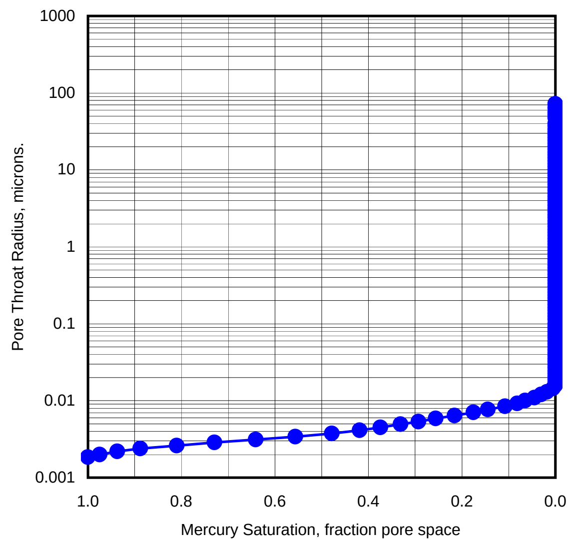
University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

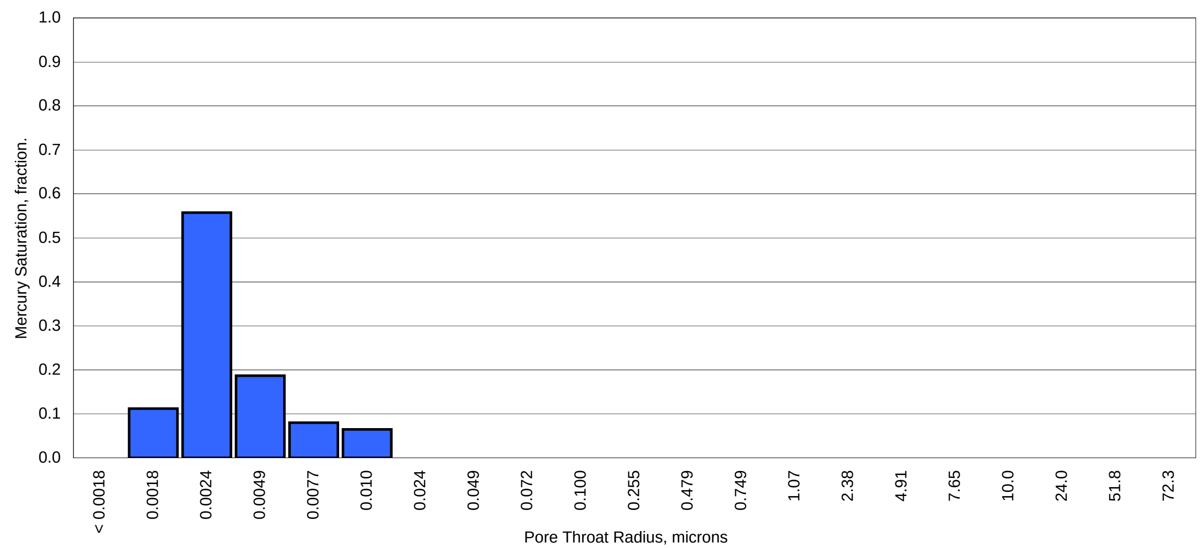
Sample Number:	2
Sample Depth, feet:	2581.00
Permeability to Air (calc), md:	0.000036
Porosity, fraction:	0.035
Grain Density, grams/cc:	2.72
Median Pore Throat Radius, microns:	0.00











OMNI Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 2
Sample Depth, feet: 2581.00
Permeability to Air (calc), md: 0.000036
Porosity, fraction: 0.035
Grain Density, grams/cc: 2.72
Median Pore Throat Radius, microns: 0.0036

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft G-W	O-W
1.51	0.000	1.000	72.3	0.000	0.28	0.10	0.12	0.61	1.01
1.72	0.000	1.000	63.5	0.000	0.32	0.11	0.14	0.70	1.15
1.96	0.000	1.000	55.7	0.000	0.37	0.13	0.16	0.79	1.31
2.11	0.000	1.000	51.8	0.000	0.40	0.14	0.17	0.85	1.41
2.32	0.000	1.000	47.1	0.000	0.44	0.15	0.19	0.94	1.55
2.74	0.000	1.000	39.9	0.000	0.52	0.18	0.22	1.11	1.84
2.93	0.000	1.000	37.3	0.000	0.55	0.19	0.24	1.18	1.96
3.26	0.000	1.000	33.5	0.000	0.61	0.21	0.27	1.32	2.18
3.53	0.000	1.000	30.9	0.000	0.67	0.23	0.29	1.43	2.36
3.84	0.000	1.000	28.4	0.000	0.72	0.25	0.31	1.55	2.57
4.20	0.000	1.000	26.0	0.000	0.79	0.27	0.34	1.70	2.81
4.56	0.000	1.000	24.0	0.000	0.86	0.29	0.37	1.84	3.05
4.97	0.000	1.000	22.0	0.000	0.94	0.32	0.41	2.01	3.33
5.44	0.000	1.000	20.1	0.000	1.02	0.35	0.44	2.20	3.64
5.91	0.000	1.000	18.5	0.000	1.11	0.38	0.48	2.39	3.96
6.47	0.000	1.000	16.9	0.000	1.22	0.42	0.53	2.61	4.33
7.04	0.000	1.000	15.5	0.000	1.33	0.45	0.57	2.85	4.72
7.67	0.000	1.000	14.2	0.000	1.45	0.50	0.63	3.10	5.14
8.40	0.000	1.000	13.0	0.000	1.58	0.54	0.69	3.39	5.63
9.15	0.000	1.000	11.9	0.000	1.72	0.59	0.75	3.70	6.13
10.00	0.000	1.000	10.9	0.000	1.88	0.65	0.82	4.04	6.70
10.91	0.000	1.000	10.0	0.000	2.06	0.70	0.89	4.41	7.31
12.00	0.000	1.000	9.10	0.000	2.26	0.78	0.98	4.85	8.04
12.99	0.000	1.000	8.41	0.000	2.45	0.84	1.06	5.25	8.70
14.27	0.000	1.000	7.65	0.000	2.69	0.92	1.16	5.77	9.56
15.56	0.000	1.000	7.02	0.000	2.93	1.01	1.27	6.29	10.4
16.94	0.000	1.000	6.45	0.000	3.19	1.09	1.38	6.85	11.3
18.55	0.000	1.000	5.89	0.000	3.49	1.20	1.51	7.50	12.4
20.32	0.000	1.000	5.38	0.000	3.83	1.31	1.66	8.21	13.6
22.25	0.000	1.000	4.91	0.000	4.19	1.44	1.82	8.99	14.9
24.32	0.000	1.000	4.49	0.000	4.58	1.57	1.98	9.83	16.3
26.60	0.000	1.000	4.11	0.000	5.01	1.72	2.17	10.8	17.8
28.99	0.000	1.000	3.77	0.001	5.46	1.87	2.37	11.7	19.4
31.90	0.000	1.000	3.42	0.001	6.01	2.06	2.60	12.9	21.4
35.14	0.000	1.000	3.11	0.001	6.62	2.27	2.87	14.2	23.5
38.59	0.000	1.000	2.83	0.001	7.27	2.49	3.15	15.6	25.8
42.43	0.000	1.000	2.57	0.001	7.99	2.74	3.46	17.1	28.4
45.86	0.000	1.000	2.38	0.001	8.64	2.96	3.74	18.5	30.7
50.60	0.000	1.000	2.16	0.001	9.53	3.27	4.13	20.4	33.9
54.69	0.000	1.000	2.00	0.001	10.3	3.53	4.46	22.1	36.6
59.86	0.000	1.000	1.82	0.001	11.3	3.87	4.88	24.2	40.1
65.71	0.000	1.000	1.66	0.001	12.4	4.24	5.36	26.6	44.0
71.74	0.000	1.000	1.52	0.001	13.5	4.63	5.85	29.0	48.1
77.86	0.000	1.000	1.40	0.001	14.7	5.03	6.35	31.5	52.2
85.75	0.000	1.000	1.27	0.002	16.2	5.54	7.00	34.7	57.4
93.64	0.000	1.000	1.17	0.002	17.6	6.05	7.64	37.8	62.7
101.68	0.000	1.000	1.07	0.002	19.2	6.57	8.30	41.2	68.1

OMNI Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 2
Sample Depth, feet: 2581.00
Permeability to Air (calc), md: 0.000036
Porosity, fraction: 0.035
Grain Density, grams/cc: 2.72
Median Pore Throat Radius, microns: 0.0036

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems: Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft: G-W	O-W
111.98	0.000	1.000	0.975	0.002	21.1	7.23	9.14	45.3	75.0
121.70	0.000	1.000	0.898	0.002	22.9	7.86	9.93	49.1	81.5
133.85	0.000	1.000	0.816	0.003	25.2	8.65	10.9	54.1	89.5
145.76	0.000	1.000	0.749	0.003	27.5	9.42	11.9	59.0	97.7
159.69	0.000	1.000	0.684	0.003	30.1	10.3	13.0	64.6	107.
174.53	0.000	1.000	0.626	0.003	32.9	11.3	14.2	70.6	117.
190.06	0.000	1.000	0.575	0.004	35.8	12.3	15.5	76.8	127.
208.09	0.000	1.000	0.525	0.004	39.2	13.4	17.0	84.1	140.
228.16	0.000	1.000	0.479	0.004	43.0	14.7	18.6	92.2	153.
250.43	0.000	1.000	0.436	0.005	47.2	16.2	20.4	101.	167.
274.98	0.000	1.000	0.397	0.005	51.8	17.8	22.4	111.	184.
300.38	0.000	1.000	0.364	0.006	56.6	19.4	24.5	121.	201.
326.89	0.000	1.000	0.334	0.006	61.6	21.1	26.7	132.	219.
359.50	0.000	1.000	0.304	0.007	67.7	23.2	29.3	145.	241.
392.11	0.000	1.000	0.279	0.007	73.9	25.3	32.0	159.	263.
429.16	0.000	1.000	0.255	0.008	80.9	27.7	35.0	174.	287.
469.55	0.000	1.000	0.233	0.009	88.5	30.3	38.3	190.	314.
511.94	0.000	1.000	0.213	0.010	96.5	33.1	41.8	207.	343.
564.96	0.000	1.000	0.193	0.011	106.	36.5	46.1	227.	378.
620.04	0.000	1.000	0.176	0.012	117.	40.1	50.6	251.	415.
681.09	0.000	1.000	0.160	0.013	128.	44.	55.6	275.	456.
734.02	0.000	1.000	0.149	0.014	138.	47.4	59.9	296.	492.
802.95	0.000	1.000	0.136	0.015	151.	51.9	65.5	324.	538.
878.32	0.000	1.000	0.124	0.016	165.	56.7	71.7	354.	589.
961.21	0.000	1.000	0.114	0.018	181.	62.1	78.4	388.	644.
1093.16	0.000	1.000	0.100	0.020	206.	70.6	89.2	442.	732.
1187.15	0.000	1.000	0.092	0.022	224.	76.7	96.9	480.	796.
1288.19	0.000	1.000	0.085	0.024	243.	83.2	105.	521.	862.
1403.88	0.000	1.000	0.078	0.026	265.	90.7	115.	568.	944.
1524.88	0.000	1.000	0.072	0.029	287.	98.5	124.	616.	1020.
1670.75	0.000	1.000	0.065	0.031	315.	108.	136.	676.	1120.
1845.94	0.000	1.000	0.059	0.035	348.	119.	151.	746.	1240.
2006.45	0.000	1.000	0.054	0.038	378.	130.	164.	811.	1350.
2207.35	0.000	1.000	0.049	0.041	416.	143.	180.	892.	1480.
2405.54	0.000	1.000	0.045	0.045	453.	155.	196.	972.	1610.
2633.98	0.000	1.000	0.041	0.049	496.	170.	215.	1064.	1770.
2856.54	0.000	1.000	0.038	0.053	538.	185.	233.	1150.	1910.
3139.69	0.000	1.000	0.035	0.059	592.	203.	256.	1270.	2100.
3396.42	0.000	1.000	0.032	0.064	640.	219.	277.	1370.	2270.
3721.82	0.000	1.000	0.029	0.070	701.	240.	304.	1500.	2500.
4076.88	0.000	1.000	0.027	0.076	768.	263.	333.	1650.	2730.
4494.61	0.000	1.000	0.024	0.084	847.	290.	367.	1820.	3010.
4868.08	0.000	1.000	0.022	0.091	917.	314.	397.	1970.	3260.
5294.34	0.000	1.000	0.021	0.099	998.	342.	432.	2140.	3550.
5788.25	0.000	1.000	0.019	0.108	1090.	374.	472.	2340.	3880.
6348.76	0.000	1.000	0.017	0.119	1200.	410.	518.	2570.	4250.

Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 2
Sample Depth, feet: 2581.00
Permeability to Air (calc), md: 0.000036
Porosity, fraction: 0.035
Grain Density, grams/cc: 2.72
Median Pore Throat Radius, microns: 0.0036

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft G-W	O-W
6916.75	0.000	1.000	0.016	0.129	1300.	447.	564.	2790.	4630.
7582.32	0.005	0.995	0.014	0.142	1430.	490.	619.	3070.	5080.
8388.55	0.018	0.982	0.013	0.157	1580.	542.	684.	3390.	5620.
9092.58	0.030	0.970	0.012	0.170	1710.	587.	742.	3670.	6090.
9946.89	0.044	0.956	0.011	0.186	1870.	643.	812.	4010.	6670.
10903.76	0.064	0.936	0.010	0.204	2050.	704.	890.	4400.	7310.
11861.34	0.081	0.919	0.0092	0.222	2230.	766.	968.	4780.	7950.
12956.73	0.108	0.892	0.0084	0.242	2440.	837.	1060.	5230.	8700.
14248.70	0.144	0.856	0.0077	0.266	2680.	920.	1160.	5750.	9520.
15552.78	0.175	0.825	0.0070	0.291	2930.	1000.	1270.	6280.	10400.
17067.33	0.216	0.784	0.0064	0.319	3220.	1100.	1390.	6910.	11400.
18661.64	0.256	0.744	0.0059	0.349	3520.	1210.	1520.	7550.	12500.
20377.39	0.293	0.707	0.0054	0.381	3840.	1320.	1660.	8240.	13600.
22206.38	0.331	0.669	0.0049	0.415	4180.	1430.	1810.	8970.	14900.
24318.84	0.374	0.626	0.0045	0.455	4580.	1570.	1980.	9820.	16300.
26587.99	0.419	0.581	0.0041	0.497	5010.	1720.	2170.	10700.	17800.
29159.12	0.478	0.522	0.0037	0.545	5490.	1880.	2380.	11800.	19500.
32006.60	0.556	0.444	0.0034	0.599	6030.	2070.	2610.	12900.	21400.
35009.34	0.641	0.359	0.0031	0.655	6600.	2260.	2860.	14200.	23500.
38239.29	0.729	0.271	0.0029	0.715	7200.	2470.	3120.	15400.	25600.
42031.89	0.810	0.190	0.0026	0.786	7920.	2720.	3430.	17000.	28200.
45901.07	0.888	0.112	0.0024	0.858	8650.	2970.	3740.	18600.	30700.
49947.95	0.937	0.063	0.0022	0.934	9410.	3230.	4070.	20200.	33400.
54638.68	0.975	0.025	0.0020	1.022	10290.	3530.	4460.	22100.	36600.
59405.26	1.000	0.000	0.0018	1.111	11190.	3840.	4850.	24000.	39800.

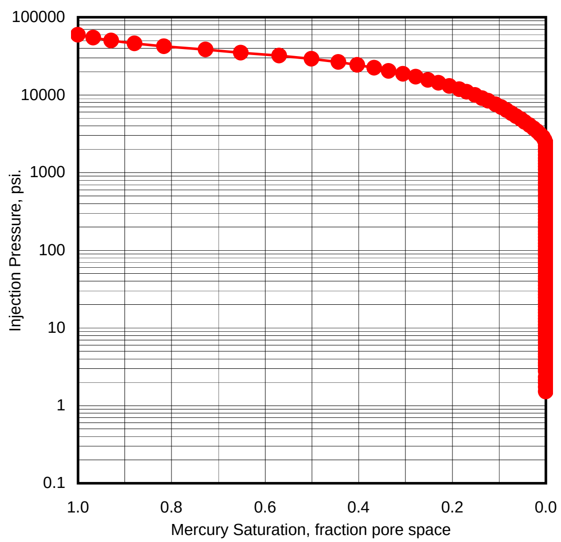
OMNI Laboratories, Inc.

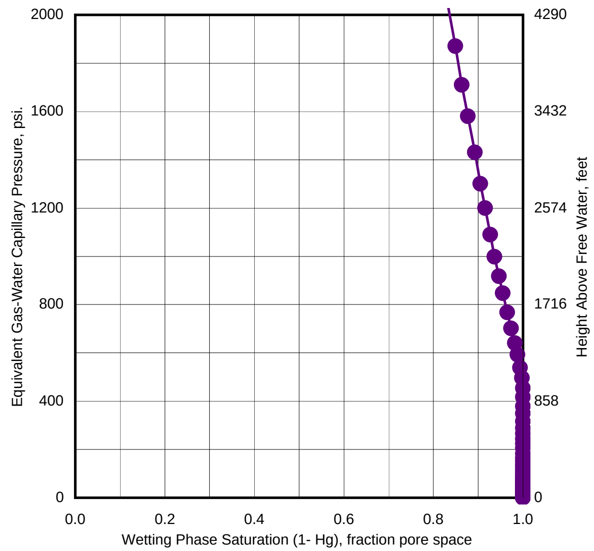
University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

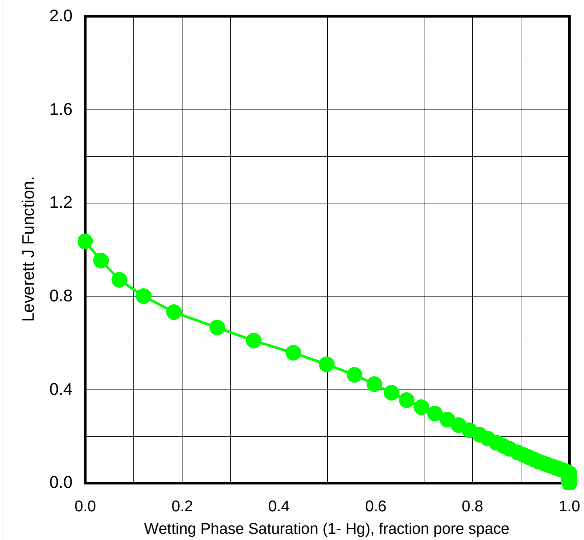
MERCURY INJECTION CAPILLARY PRESSURE

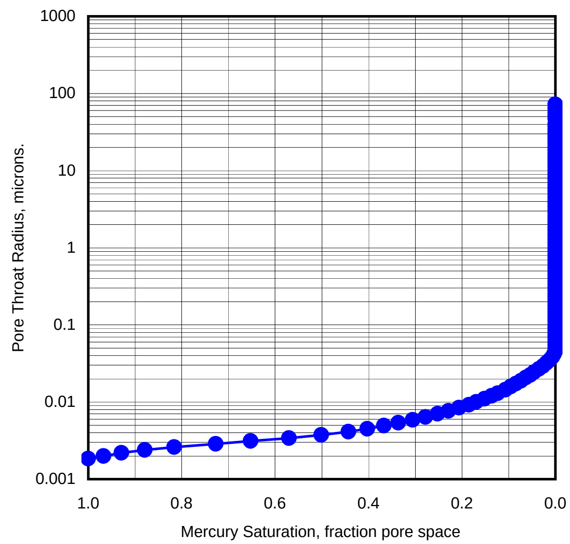
6-30-05

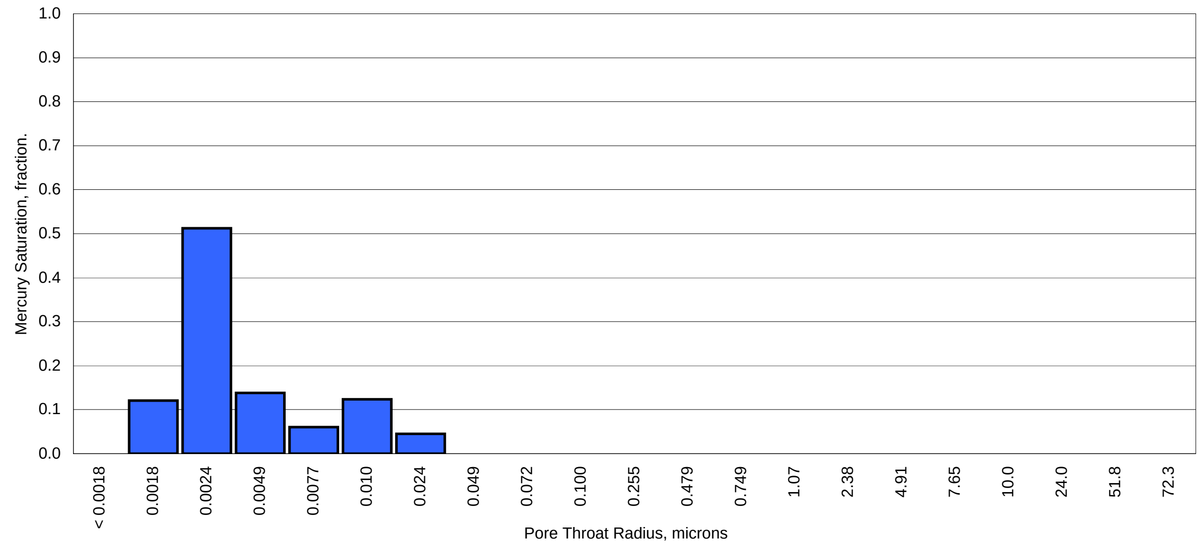
Sample Number:	3
Sample Depth, feet:	2742.50
Permeability to Air (calc), md:	0.000026
Porosity, fraction:	0.029
Grain Density, grams/cc:	2.59
Median Pore Throat Radius, microns:	0.0037











OMNI Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 3
Sample Depth, feet: 2742.50
Permeability to Air (calc), md: 0.000026
Porosity, fraction: 0.029
Grain Density, grams/cc: 2.59
Median Pore Throat Radius, microns: 0.0037

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft G-W	O-W
1.51	0.000	1.000	72.3	0.000	0.28	0.10	0.12	0.61	1.01
1.72	0.000	1.000	63.5	0.000	0.32	0.11	0.14	0.70	1.15
1.96	0.000	1.000	55.7	0.000	0.37	0.13	0.16	0.79	1.31
2.11	0.000	1.000	51.8	0.000	0.40	0.14	0.17	0.85	1.41
2.32	0.000	1.000	47.1	0.000	0.44	0.15	0.19	0.94	1.55
2.74	0.000	1.000	39.9	0.000	0.52	0.18	0.22	1.11	1.84
2.93	0.000	1.000	37.3	0.000	0.55	0.19	0.24	1.18	1.96
3.26	0.000	1.000	33.5	0.000	0.61	0.21	0.27	1.32	2.18
3.53	0.000	1.000	30.9	0.000	0.67	0.23	0.29	1.43	2.36
3.84	0.000	1.000	28.4	0.000	0.72	0.25	0.31	1.55	2.57
4.20	0.000	1.000	26.0	0.000	0.79	0.27	0.34	1.70	2.81
4.56	0.000	1.000	24.0	0.000	0.86	0.29	0.37	1.84	3.05
4.97	0.000	1.000	22.0	0.000	0.94	0.32	0.41	2.01	3.33
5.44	0.000	1.000	20.1	0.000	1.02	0.35	0.44	2.20	3.64
5.91	0.000	1.000	18.5	0.000	1.11	0.38	0.48	2.39	3.96
6.47	0.000	1.000	16.9	0.000	1.22	0.42	0.53	2.61	4.33
7.04	0.000	1.000	15.5	0.000	1.33	0.45	0.57	2.85	4.72
7.67	0.000	1.000	14.2	0.000	1.45	0.50	0.63	3.10	5.14
8.40	0.000	1.000	13.0	0.000	1.58	0.54	0.69	3.39	5.63
9.15	0.000	1.000	11.9	0.000	1.72	0.59	0.75	3.70	6.13
10.00	0.000	1.000	10.9	0.000	1.88	0.65	0.82	4.04	6.70
10.91	0.000	1.000	10.0	0.000	2.06	0.70	0.89	4.41	7.31
12.00	0.000	1.000	9.10	0.000	2.26	0.78	0.98	4.85	8.04
12.99	0.000	1.000	8.41	0.000	2.45	0.84	1.06	5.25	8.70
14.27	0.000	1.000	7.65	0.000	2.69	0.92	1.16	5.77	9.56
15.56	0.000	1.000	7.02	0.000	2.93	1.01	1.27	6.29	10.4
16.94	0.000	1.000	6.45	0.000	3.19	1.09	1.38	6.85	11.3
18.55	0.000	1.000	5.89	0.000	3.49	1.20	1.51	7.50	12.4
20.32	0.000	1.000	5.38	0.000	3.83	1.31	1.66	8.21	13.6
22.25	0.000	1.000	4.91	0.000	4.19	1.44	1.82	8.99	14.9
24.32	0.000	1.000	4.49	0.000	4.58	1.57	1.98	9.83	16.3
26.60	0.000	1.000	4.11	0.000	5.01	1.72	2.17	10.8	17.8
28.99	0.000	1.000	3.77	0.001	5.46	1.87	2.37	11.7	19.4
31.90	0.000	1.000	3.42	0.001	6.01	2.06	2.60	12.9	21.4
35.14	0.000	1.000	3.11	0.001	6.62	2.27	2.87	14.2	23.5
38.59	0.000	1.000	2.83	0.001	7.27	2.49	3.15	15.6	25.8
42.43	0.000	1.000	2.57	0.001	7.99	2.74	3.46	17.1	28.4
45.86	0.000	1.000	2.38	0.001	8.64	2.96	3.74	18.5	30.7
50.60	0.000	1.000	2.16	0.001	9.53	3.27	4.13	20.4	33.9
54.69	0.000	1.000	2.00	0.001	10.3	3.53	4.46	22.1	36.6
59.86	0.000	1.000	1.82	0.001	11.3	3.87	4.88	24.2	40.1
65.71	0.000	1.000	1.66	0.001	12.4	4.24	5.36	26.6	44.0
71.74	0.000	1.000	1.52	0.001	13.5	4.63	5.85	29.0	48.1
77.86	0.000	1.000	1.40	0.001	14.7	5.03	6.35	31.5	52.2
85.75	0.000	1.000	1.27	0.001	16.2	5.54	7.00	34.7	57.4
93.64	0.000	1.000	1.17	0.002	17.6	6.05	7.64	37.8	62.7
101.68	0.000	1.000	1.07	0.002	19.2	6.57	8.30	41.2	68.1

OMNI Laboratories, Inc.

6-30-05

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 3
Sample Depth, feet: 2742.50
Permeability to Air (calc), md: 0.000026
Porosity, fraction: 0.029
Grain Density, grams/cc: 2.59
Median Pore Throat Radius, microns: 0.0037

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems			Estimated Height Above Free Water, ft	
					Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	G-W	O-W
111.98	0.000	1.000	0.975	0.002	21.1	7.23	9.14	45.3	75.0
121.70	0.000	1.000	0.898	0.002	22.9	7.86	9.93	49.1	81.5
133.85	0.000	1.000	0.816	0.002	25.2	8.65	10.9	54.1	89.5
145.76	0.000	1.000	0.749	0.003	27.5	9.42	11.9	59.0	97.7
159.69	0.000	1.000	0.684	0.003	30.1	10.3	13.0	64.6	107.
174.53	0.000	1.000	0.626	0.003	32.9	11.3	14.2	70.6	117.
190.06	0.000	1.000	0.575	0.003	35.8	12.3	15.5	76.8	127.
208.09	0.000	1.000	0.525	0.004	39.2	13.4	17.0	84.1	140.
228.16	0.000	1.000	0.479	0.004	43.0	14.7	18.6	92.2	153.
250.43	0.000	1.000	0.436	0.004	47.2	16.2	20.4	101.	167.
274.98	0.000	1.000	0.397	0.005	51.8	17.8	22.4	111.	184.
300.38	0.000	1.000	0.364	0.005	56.6	19.4	24.5	121.	201.
326.89	0.000	1.000	0.334	0.006	61.6	21.1	26.7	132.	219.
359.50	0.000	1.000	0.304	0.006	67.7	23.2	29.3	145.	241.
392.11	0.000	1.000	0.279	0.007	73.9	25.3	32.0	159.	263.
429.16	0.000	1.000	0.255	0.007	80.9	27.7	35.0	174.	287.
469.55	0.000	1.000	0.233	0.008	88.5	30.3	38.3	190.	314.
511.94	0.000	1.000	0.213	0.009	96.5	33.1	41.8	207.	343.
564.96	0.000	1.000	0.193	0.010	106.	36.5	46.1	227.	378.
620.04	0.000	1.000	0.176	0.011	117.	40.1	50.6	251.	415.
681.09	0.000	1.000	0.160	0.012	128.	44.	55.6	275.	456.
734.02	0.000	1.000	0.149	0.013	138.	47.4	59.9	296.	492.
802.95	0.000	1.000	0.136	0.014	151.	51.9	65.5	324.	538.
878.32	0.000	1.000	0.124	0.015	165.	56.7	71.7	354.	589.
961.21	0.000	1.000	0.114	0.017	181.	62.1	78.4	388.	644.
1093.16	0.000	1.000	0.100	0.019	206.	70.6	89.2	442.	732.
1187.15	0.000	1.000	0.092	0.021	224.	76.7	96.9	480.	796.
1288.19	0.000	1.000	0.085	0.022	243.	83.2	105.	521.	862.
1403.88	0.000	1.000	0.078	0.024	265.	90.7	115.	568.	944.
1524.88	0.000	1.000	0.072	0.027	287.	98.5	124.	616.	1020.
1670.75	0.000	1.000	0.065	0.029	315.	108.	136.	676.	1120.
1845.94	0.000	1.000	0.059	0.032	348.	119.	151.	746.	1240.
2006.45	0.000	1.000	0.054	0.035	378.	130.	164.	811.	1350.
2207.35	0.000	1.000	0.049	0.038	416.	143.	180.	892.	1480.
2405.54	0.000	1.000	0.045	0.042	453.	155.	196.	972.	1610.
2633.98	0.002	0.998	0.041	0.046	496.	170.	215.	1064.	1770.
2856.54	0.006	0.994	0.038	0.050	538.	185.	233.	1150.	1910.
3139.69	0.013	0.988	0.035	0.055	592.	203.	256.	1270.	2100.
3396.42	0.018	0.982	0.032	0.059	640.	219.	277.	1370.	2270.
3721.82	0.026	0.974	0.029	0.065	701.	240.	304.	1500.	2500.
4076.88	0.035	0.965	0.027	0.071	768.	263.	333.	1650.	2730.
4494.61	0.045	0.955	0.024	0.078	847.	290.	367.	1820.	3010.
4868.08	0.054	0.946	0.022	0.085	917.	314.	397.	1970.	3260.
5294.34	0.063	0.937	0.021	0.092	998.	342.	432.	2140.	3550.
5788.25	0.073	0.927	0.019	0.101	1090.	374.	472.	2340.	3880.
6348.76	0.084	0.916	0.017	0.111	1200.	410.	518.	2570.	4250.

OMNI Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number:	3
Sample Depth, feet:	2742.50
Permeability to Air (calc), md:	0.000026
Porosity, fraction:	0.029
Grain Density, grams/cc:	2.59
Median Pore Throat Radius, microns:	0.0037

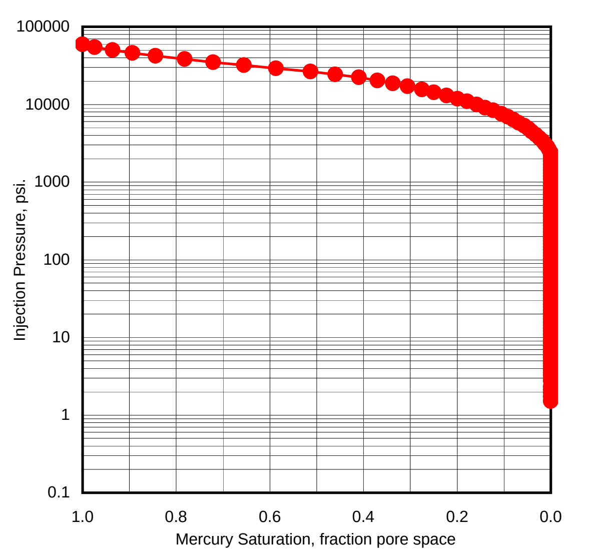
Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems			Estimated Height Above Free Water, ft	
					Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	G-W	O-W
6916.75	0.095	0.905	0.016	0.121	1300.	447.	564.	2790.	4630.
7582.32	0.107	0.893	0.014	0.132	1430.	490.	619.	3070.	5080.
8388.55	0.123	0.877	0.013	0.146	1580.	542.	684.	3390.	5620.
9092.58	0.136	0.864	0.012	0.158	1710.	587.	742.	3670.	6090.
9946.89	0.151	0.849	0.011	0.173	1870.	643.	812.	4010.	6670.
10903.76	0.169	0.831	0.010	0.190	2050.	704.	890.	4400.	7310.
11861.34	0.185	0.815	0.0092	0.207	2230.	766.	968.	4780.	7950.
12956.73	0.206	0.794	0.0084	0.226	2440.	837.	1060.	5230.	8700.
14248.70	0.229	0.771	0.0077	0.248	2680.	920.	1160.	5750.	9520.
15552.78	0.252	0.748	0.0070	0.271	2930.	1000.	1270.	6280.	10400.
17067.33	0.278	0.722	0.0064	0.297	3220.	1100.	1390.	6910.	11400.
18661.64	0.305	0.695	0.0059	0.325	3520.	1210.	1520.	7550.	12500.
20377.39	0.336	0.664	0.0054	0.355	3840.	1320.	1660.	8240.	13600.
22206.38	0.367	0.633	0.0049	0.387	4180.	1430.	1810.	8970.	14900.
24318.84	0.403	0.597	0.0045	0.424	4580.	1570.	1980.	9820.	16300.
26587.99	0.443	0.557	0.0041	0.463	5010.	1720.	2170.	10700.	17800.
29159.12	0.501	0.499	0.0037	0.508	5490.	1880.	2380.	11800.	19500.
32006.60	0.570	0.430	0.0034	0.558	6030.	2070.	2610.	12900.	21400.
35009.34	0.652	0.348	0.0031	0.610	6600.	2260.	2860.	14200.	23500.
38239.29	0.727	0.273	0.0029	0.666	7200.	2470.	3120.	15400.	25600.
42031.89	0.816	0.184	0.0026	0.732	7920.	2720.	3430.	17000.	28200.
45901.07	0.879	0.121	0.0024	0.800	8650.	2970.	3740.	18600.	30700.
49947.95	0.929	0.071	0.0022	0.870	9410.	3230.	4070.	20200.	33400.
54638.68	0.967	0.033	0.0020	0.952	10290.	3530.	4460.	22100.	36600.
59405.26	1.000	0.000	0.0018	1.035	11190.	3840.	4850.	24000.	39800.

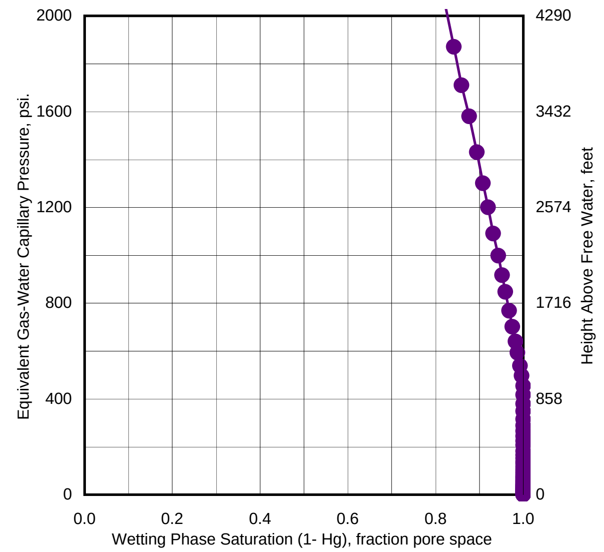
MERCURY INJECTION CAPILLARY PRESSURE

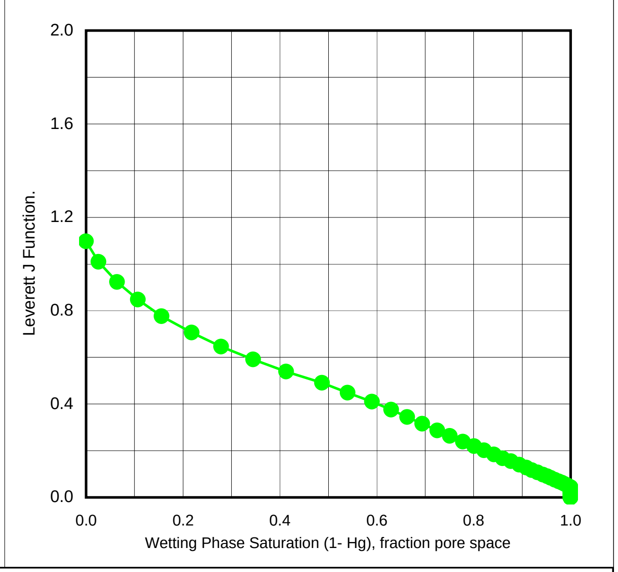
6-30-05

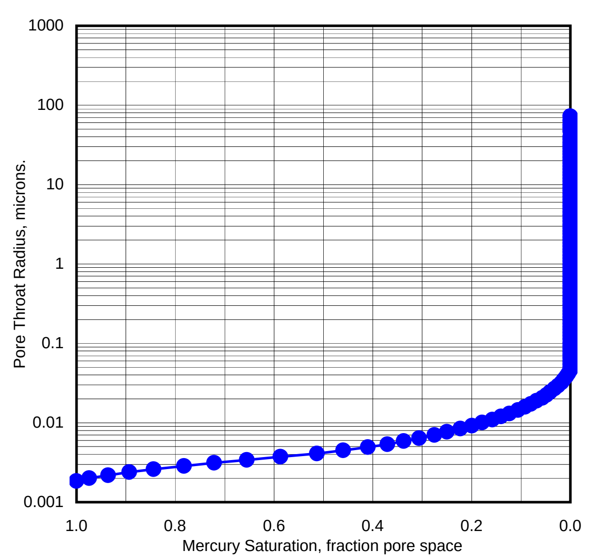
University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

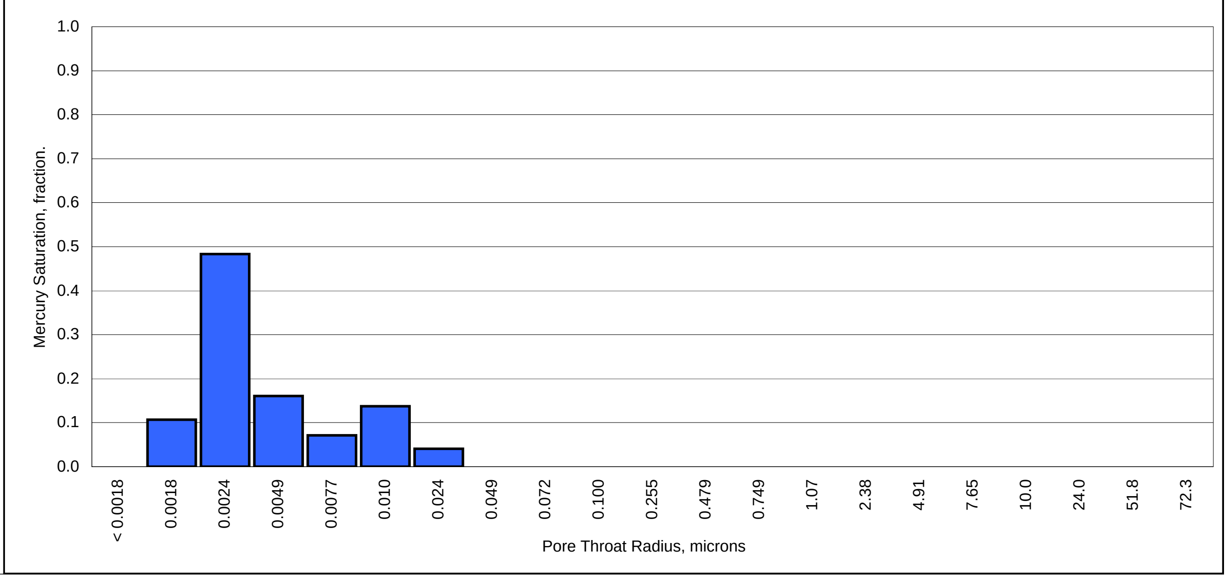
Sample Number:	4
Sample Depth, feet:	2776.60
Permeability to Air (calc), md:	0.000020
Porosity, fraction:	0.020
Grain Density, grams/cc:	2.61
Median Pore Throat Radius, microns:	0.004











OMNI Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number:	4
Sample Depth, feet:	2776.60
Permeability to Air (calc), md:	0.000020
Porosity, fraction:	0.020
Grain Density, grams/cc:	2.61
Median Pore Throat Radius, microns:	0.0042

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems: Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft: G-W	O-W
1.51	0.000	1.000	72.3	0.000	0.28	0.10	0.12	0.61	1.01
1.72	0.000	1.000	63.5	0.000	0.32	0.11	0.14	0.70	1.15
1.96	0.000	1.000	55.7	0.000	0.37	0.13	0.16	0.79	1.31
2.11	0.000	1.000	51.8	0.000	0.40	0.14	0.17	0.85	1.41
2.32	0.000	1.000	47.1	0.000	0.44	0.15	0.19	0.94	1.55
2.74	0.000	1.000	39.9	0.000	0.52	0.18	0.22	1.11	1.84
2.93	0.000	1.000	37.3	0.000	0.55	0.19	0.24	1.18	1.96
3.26	0.000	1.000	33.5	0.000	0.61	0.21	0.27	1.32	2.18
3.53	0.000	1.000	30.9	0.000	0.67	0.23	0.29	1.43	2.36
3.84	0.000	1.000	28.4	0.000	0.72	0.25	0.31	1.55	2.57
4.20	0.000	1.000	26.0	0.000	0.79	0.27	0.34	1.70	2.81
4.56	0.000	1.000	24.0	0.000	0.86	0.29	0.37	1.84	3.05
4.97	0.000	1.000	22.0	0.000	0.94	0.32	0.41	2.01	3.33
5.44	0.000	1.000	20.1	0.000	1.02	0.35	0.44	2.20	3.64
5.91	0.000	1.000	18.5	0.000	1.11	0.38	0.48	2.39	3.96
6.47	0.000	1.000	16.9	0.000	1.22	0.42	0.53	2.61	4.33
7.04	0.000	1.000	15.5	0.000	1.33	0.45	0.57	2.85	4.72
7.67	0.000	1.000	14.2	0.000	1.45	0.50	0.63	3.10	5.14
8.40	0.000	1.000	13.0	0.000	1.58	0.54	0.69	3.39	5.63
9.15	0.000	1.000	11.9	0.000	1.72	0.59	0.75	3.70	6.13
10.00	0.000	1.000	10.9	0.000	1.88	0.65	0.82	4.04	6.70
10.91	0.000	1.000	10.0	0.000	2.06	0.70	0.89	4.41	7.31
12.00	0.000	1.000	9.10	0.000	2.26	0.78	0.98	4.85	8.04
12.99	0.000	1.000	8.41	0.000	2.45	0.84	1.06	5.25	8.70
14.27	0.000	1.000	7.65	0.000	2.69	0.92	1.16	5.77	9.56
15.56	0.000	1.000	7.02	0.000	2.93	1.01	1.27	6.29	10.4
16.94	0.000	1.000	6.45	0.000	3.19	1.09	1.38	6.85	11.3
18.55	0.000	1.000	5.89	0.000	3.49	1.20	1.51	7.50	12.4
20.32	0.000	1.000	5.38	0.000	3.83	1.31	1.66	8.21	13.6
22.25	0.000	1.000	4.91	0.000	4.19	1.44	1.82	8.99	14.9
24.32	0.000	1.000	4.49	0.000	4.58	1.57	1.98	9.83	16.3
26.60	0.000	1.000	4.11	0.000	5.01	1.72	2.17	10.8	17.8
28.99	0.000	1.000	3.77	0.001	5.46	1.87	2.37	11.7	19.4
31.90	0.000	1.000	3.42	0.001	6.01	2.06	2.60	12.9	21.4
35.14	0.000	1.000	3.11	0.001	6.62	2.27	2.87	14.2	23.5
38.59	0.000	1.000	2.83	0.001	7.27	2.49	3.15	15.6	25.8
42.43	0.000	1.000	2.57	0.001	7.99	2.74	3.46	17.1	28.4
45.86	0.000	1.000	2.38	0.001	8.64	2.96	3.74	18.5	30.7
50.60	0.000	1.000	2.16	0.001	9.53	3.27	4.13	20.4	33.9
54.69	0.000	1.000	2.00	0.001	10.3	3.53	4.46	22.1	36.6
59.86	0.000	1.000	1.82	0.001	11.3	3.87	4.88	24.2	40.1
65.71	0.000	1.000	1.66	0.001	12.4	4.24	5.36	26.6	44.0
71.74	0.000	1.000	1.52	0.001	13.5	4.63	5.85	29.0	48.1
77.86	0.000	1.000	1.40	0.001	14.7	5.03	6.35	31.5	52.2
85.75	0.000	1.000	1.27	0.002	16.2	5.54	7.00	34.7	57.4
93.64	0.000	1.000	1.17	0.002	17.6	6.05	7.64	37.8	62.7
101.68	0.000	1.000	1.07	0.002	19.2	6.57	8.30	41.2	68.1

OMNI Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 4
Sample Depth, feet: 2776.60
Permeability to Air (calc), md: 0.000020
Porosity, fraction: 0.020
Grain Density, grams/cc: 2.61
Median Pore Throat Radius, microns: 0.0042

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems			Estimated Height Above Free Water, ft	
					Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	G-W	O-W
111.98	0.000	1.000	0.975	0.002	21.1	7.23	9.14	45.3	75.0
121.70	0.000	1.000	0.898	0.002	22.9	7.86	9.93	49.1	81.5
133.85	0.000	1.000	0.816	0.002	25.2	8.65	10.9	54.1	89.5
145.76	0.000	1.000	0.749	0.003	27.5	9.42	11.9	59.0	97.7
159.69	0.000	1.000	0.684	0.003	30.1	10.3	13.0	64.6	107.
174.53	0.000	1.000	0.626	0.003	32.9	11.3	14.2	70.6	117.
190.06	0.000	1.000	0.575	0.004	35.8	12.3	15.5	76.8	127.
208.09	0.000	1.000	0.525	0.004	39.2	13.4	17.0	84.1	140.
228.16	0.000	1.000	0.479	0.004	43.0	14.7	18.6	92.2	153.
250.43	0.000	1.000	0.436	0.005	47.2	16.2	20.4	101.	167.
274.98	0.000	1.000	0.397	0.005	51.8	17.8	22.4	111.	184.
300.38	0.000	1.000	0.364	0.006	56.6	19.4	24.5	121.	201.
326.89	0.000	1.000	0.334	0.006	61.6	21.1	26.7	132.	219.
359.50	0.000	1.000	0.304	0.007	67.7	23.2	29.3	145.	241.
392.11	0.000	1.000	0.279	0.007	73.9	25.3	32.0	159.	263.
429.16	0.000	1.000	0.255	0.008	80.9	27.7	35.0	174.	287.
469.55	0.000	1.000	0.233	0.009	88.5	30.3	38.3	190.	314.
511.94	0.000	1.000	0.213	0.009	96.5	33.1	41.8	207.	343.
564.96	0.000	1.000	0.193	0.010	106.	36.5	46.1	227.	378.
620.04	0.000	1.000	0.176	0.011	117.	40.1	50.6	251.	415.
681.09	0.000	1.000	0.160	0.013	128.	44.	55.6	275.	456.
734.02	0.000	1.000	0.149	0.014	138.	47.4	59.9	296.	492.
802.95	0.000	1.000	0.136	0.015	151.	51.9	65.5	324.	538.
878.32	0.000	1.000	0.124	0.016	165.	56.7	71.7	354.	589.
961.21	0.000	1.000	0.114	0.018	181.	62.1	78.4	388.	644.
1093.16	0.000	1.000	0.100	0.020	206.	70.6	89.2	442.	732.
1187.15	0.000	1.000	0.092	0.022	224.	76.7	96.9	480.	796.
1288.19	0.000	1.000	0.085	0.024	243.	83.2	105.	521.	862.
1403.88	0.000	1.000	0.078	0.026	265.	90.7	115.	568.	944.
1524.88	0.000	1.000	0.072	0.028	287.	98.5	124.	616.	1020.
1670.75	0.000	1.000	0.065	0.031	315.	108.	136.	676.	1120.
1845.94	0.000	1.000	0.059	0.034	348.	119.	151.	746.	1240.
2006.45	0.000	1.000	0.054	0.037	378.	130.	164.	811.	1350.
2207.35	0.000	1.000	0.049	0.041	416.	143.	180.	892.	1480.
2405.54	0.000	1.000	0.045	0.044	453.	155.	196.	972.	1610.
2633.98	0.004	0.996	0.041	0.049	496.	170.	215.	1064.	1770.
2856.54	0.007	0.993	0.038	0.053	538.	185.	233.	1150.	1910.
3139.69	0.013	0.987	0.035	0.058	592.	203.	256.	1270.	2100.
3396.42	0.018	0.982	0.032	0.063	640.	219.	277.	1370.	2270.
3721.82	0.025	0.975	0.029	0.069	701.	240.	304.	1500.	2500.
4076.88	0.032	0.968	0.027	0.075	768.	263.	333.	1650.	2730.
4494.61	0.041	0.959	0.024	0.083	847.	290.	367.	1820.	3010.
4868.08	0.048	0.952	0.022	0.090	917.	314.	397.	1970.	3260.
5294.34	0.057	0.943	0.021	0.098	998.	342.	432.	2140.	3550.
5788.25	0.068	0.932	0.019	0.107	1090.	374.	472.	2340.	3880.
6348.76	0.080	0.920	0.017	0.117	1200.	410.	518.	2570.	4250.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 4
Sample Depth, feet: 2776.60
Permeability to Air (calc), md: 0.000020
Porosity, fraction: 0.020
Grain Density, grams/cc: 2.61
Median Pore Throat Radius, microns: 0.0042

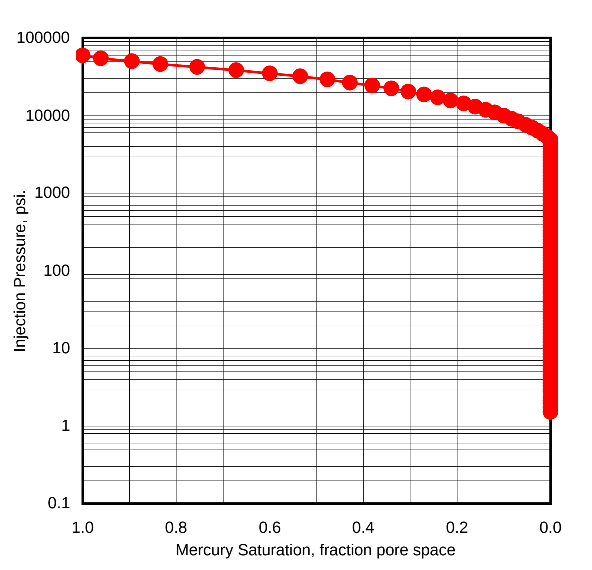
Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft G-W	O-W
6916.75	0.092	0.909	0.016	0.128	1300.	447.	564.	2790.	4630.
7582.32	0.106	0.895	0.014	0.140	1430.	490.	619.	3070.	5080.
8388.55	0.123	0.877	0.013	0.155	1580.	542.	684.	3390.	5620.
9092.58	0.140	0.860	0.012	0.168	1710.	587.	742.	3670.	6090.
9946.89	0.158	0.842	0.011	0.184	1870.	643.	812.	4010.	6670.
10903.76	0.178	0.822	0.010	0.201	2050.	704.	890.	4400.	7310.
11861.34	0.199	0.801	0.0092	0.219	2230.	766.	968.	4780.	7950.
12956.73	0.222	0.778	0.0084	0.239	2440.	837.	1060.	5230.	8700.
14248.70	0.250	0.751	0.0077	0.263	2680.	920.	1160.	5750.	9520.
15552.78	0.275	0.725	0.0070	0.287	2930.	1000.	1270.	6280.	10400.
17067.33	0.306	0.694	0.0064	0.315	3220.	1100.	1390.	6910.	11400.
18661.64	0.337	0.663	0.0059	0.344	3520.	1210.	1520.	7550.	12500.
20377.39	0.370	0.630	0.0054	0.376	3840.	1320.	1660.	8240.	13600.
22206.38	0.410	0.590	0.0049	0.410	4180.	1430.	1810.	8970.	14900.
24318.84	0.460	0.540	0.0045	0.449	4580.	1570.	1980.	9820.	16300.
26587.99	0.513	0.487	0.0041	0.491	5010.	1720.	2170.	10700.	17800.
29159.12	0.587	0.413	0.0037	0.538	5490.	1880.	2380.	11800.	19500.
32006.60	0.655	0.345	0.0034	0.591	6030.	2070.	2610.	12900.	21400.
35009.34	0.721	0.279	0.0031	0.646	6600.	2260.	2860.	14200.	23500.
38239.29	0.782	0.218	0.0029	0.706	7200.	2470.	3120.	15400.	25600.
42031.89	0.844	0.156	0.0026	0.776	7920.	2720.	3430.	17000.	28200.
45901.07	0.893	0.107	0.0024	0.847	8650.	2970.	3740.	18600.	30700.
49947.95	0.936	0.064	0.0022	0.922	9410.	3230.	4070.	20200.	33400.
54638.68	0.974	0.026	0.0020	1.009	10290.	3530.	4460.	22100.	36600.
59405.26	1.000	0.000	0.0018	1.097	11190.	3840.	4850.	24000.	39800.

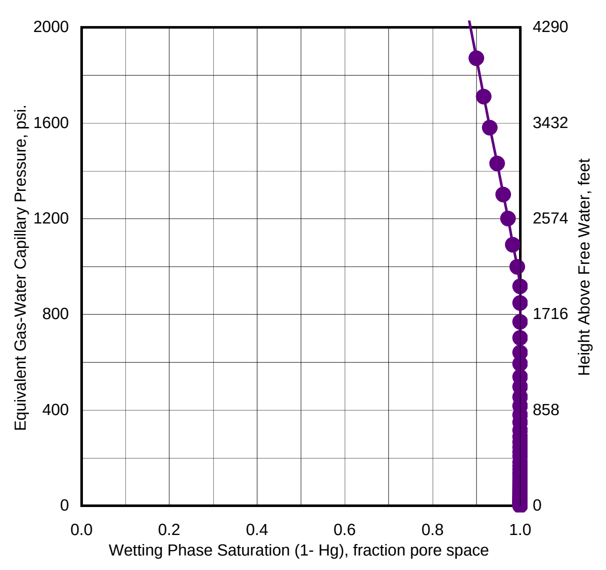
MERCURY INJECTION CAPILLARY PRESSURE

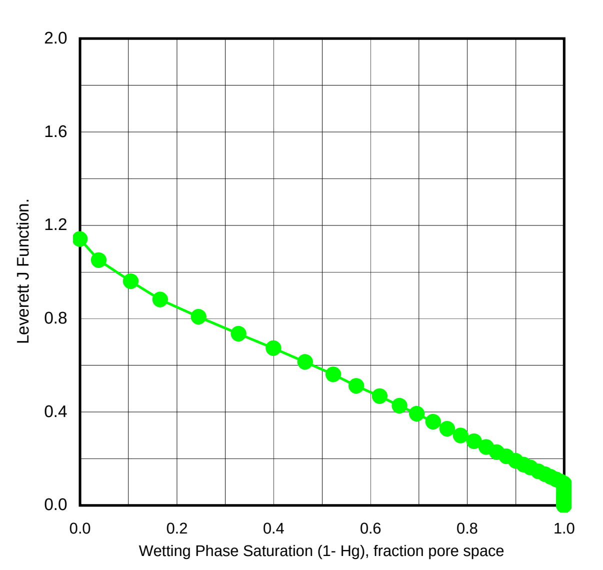
6-30-05

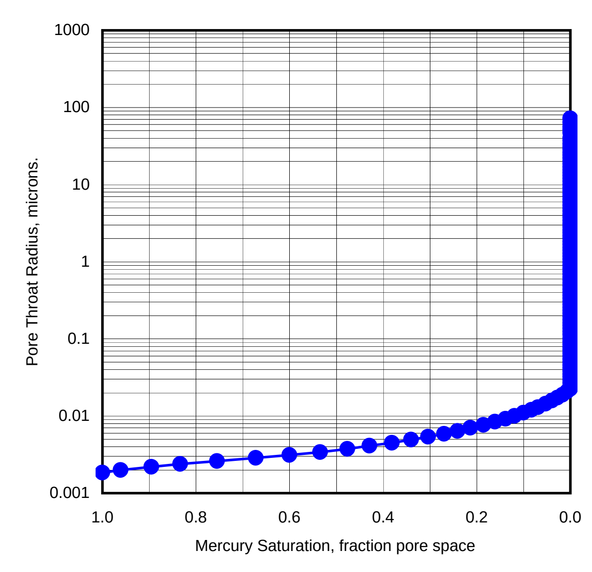
University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

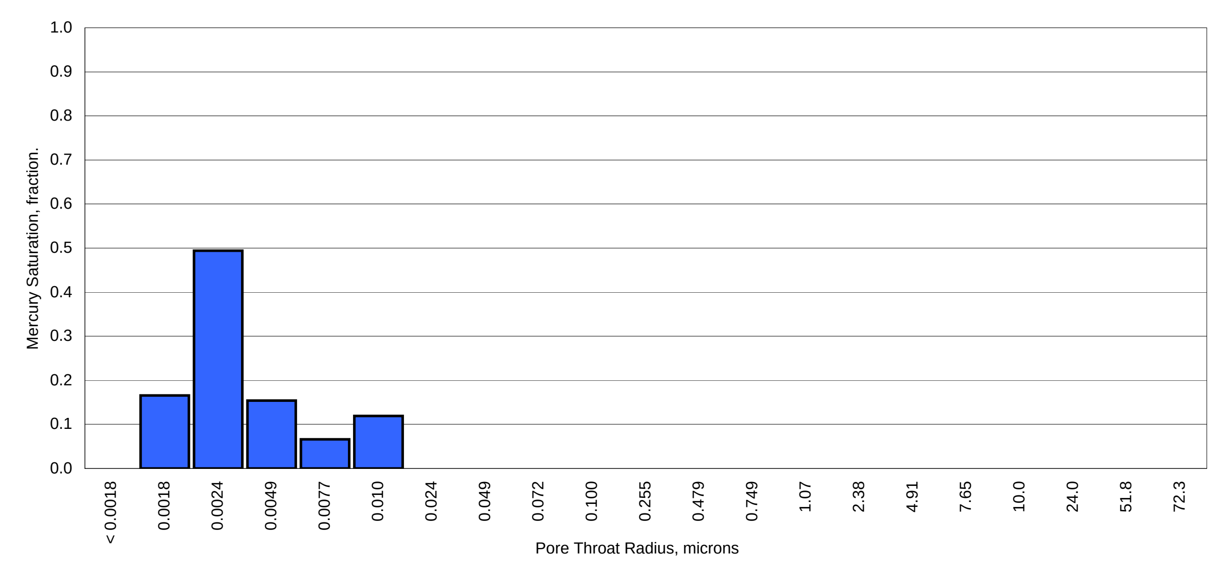
Sample Number:	5
Sample Depth, feet:	3025.40
Permeability to Air (calc), md:	0.000048
Porosity, fraction:	0.044
Grain Density, grams/cc:	2.54
Median Pore Throat Radius, microns:	0.0036











OMNI Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 5
Sample Depth, feet: 3025.40
Permeability to Air (calc), md: 0.000048
Porosity, fraction: 0.044
Grain Density, grams/cc: 2.54
Median Pore Throat Radius, microns: 0.0036

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft G-W	O-W
1.51	0.000	1.000	72.3	0.000	0.28	0.10	0.12	0.61	1.01
1.72	0.000	1.000	63.5	0.000	0.32	0.11	0.14	0.70	1.15
1.96	0.000	1.000	55.7	0.000	0.37	0.13	0.16	0.79	1.31
2.11	0.000	1.000	51.8	0.000	0.40	0.14	0.17	0.85	1.41
2.32	0.000	1.000	47.1	0.000	0.44	0.15	0.19	0.94	1.55
2.74	0.000	1.000	39.9	0.000	0.52	0.18	0.22	1.11	1.84
2.93	0.000	1.000	37.3	0.000	0.55	0.19	0.24	1.18	1.96
3.26	0.000	1.000	33.5	0.000	0.61	0.21	0.27	1.32	2.18
3.53	0.000	1.000	30.9	0.000	0.67	0.23	0.29	1.43	2.36
3.84	0.000	1.000	28.4	0.000	0.72	0.25	0.31	1.55	2.57
4.20	0.000	1.000	26.0	0.000	0.79	0.27	0.34	1.70	2.81
4.56	0.000	1.000	24.0	0.000	0.86	0.29	0.37	1.84	3.05
4.97	0.000	1.000	22.0	0.000	0.94	0.32	0.41	2.01	3.33
5.44	0.000	1.000	20.1	0.000	1.02	0.35	0.44	2.20	3.64
5.91	0.000	1.000	18.5	0.000	1.11	0.38	0.48	2.39	3.96
6.47	0.000	1.000	16.9	0.000	1.22	0.42	0.53	2.61	4.33
7.04	0.000	1.000	15.5	0.000	1.33	0.45	0.57	2.85	4.72
7.67	0.000	1.000	14.2	0.000	1.45	0.50	0.63	3.10	5.14
8.40	0.000	1.000	13.0	0.000	1.58	0.54	0.69	3.39	5.63
9.15	0.000	1.000	11.9	0.000	1.72	0.59	0.75	3.70	6.13
10.00	0.000	1.000	10.9	0.000	1.88	0.65	0.82	4.04	6.70
10.91	0.000	1.000	10.0	0.000	2.06	0.70	0.89	4.41	7.31
12.00	0.000	1.000	9.10	0.000	2.26	0.78	0.98	4.85	8.04
12.99	0.000	1.000	8.41	0.000	2.45	0.84	1.06	5.25	8.70
14.27	0.000	1.000	7.65	0.000	2.69	0.92	1.16	5.77	9.56
15.56	0.000	1.000	7.02	0.000	2.93	1.01	1.27	6.29	10.4
16.94	0.000	1.000	6.45	0.000	3.19	1.09	1.38	6.85	11.3
18.55	0.000	1.000	5.89	0.000	3.49	1.20	1.51	7.50	12.4
20.32	0.000	1.000	5.38	0.000	3.83	1.31	1.66	8.21	13.6
22.25	0.000	1.000	4.91	0.000	4.19	1.44	1.82	8.99	14.9
24.32	0.000	1.000	4.49	0.000	4.58	1.57	1.98	9.83	16.3
26.60	0.000	1.000	4.11	0.001	5.01	1.72	2.17	10.8	17.8
28.99	0.000	1.000	3.77	0.001	5.46	1.87	2.37	11.7	19.4
31.90	0.000	1.000	3.42	0.001	6.01	2.06	2.60	12.9	21.4
35.14	0.000	1.000	3.11	0.001	6.62	2.27	2.87	14.2	23.5
38.59	0.000	1.000	2.83	0.001	7.27	2.49	3.15	15.6	25.8
42.43	0.000	1.000	2.57	0.001	7.99	2.74	3.46	17.1	28.4
45.86	0.000	1.000	2.38	0.001	8.64	2.96	3.74	18.5	30.7
50.60	0.000	1.000	2.16	0.001	9.53	3.27	4.13	20.4	33.9
54.69	0.000	1.000	2.00	0.001	10.3	3.53	4.46	22.1	36.6
59.86	0.000	1.000	1.82	0.001	11.3	3.87	4.88	24.2	40.1
65.71	0.000	1.000	1.66	0.001	12.4	4.24	5.36	26.6	44.0
71.74	0.000	1.000	1.52	0.001	13.5	4.63	5.85	29.0	48.1
77.86	0.000	1.000	1.40	0.001	14.7	5.03	6.35	31.5	52.2
85.75	0.000	1.000	1.27	0.002	16.2	5.54	7.00	34.7	57.4
93.64	0.000	1.000	1.17	0.002	17.6	6.05	7.64	37.8	62.7
101.68	0.000	1.000	1.07	0.002	19.2	6.57	8.30	41.2	68.1

OMNI Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 5
Sample Depth, feet: 3025.40
Permeability to Air (calc), md: 0.000048
Porosity, fraction: 0.044
Grain Density, grams/cc: 2.54
Median Pore Throat Radius, microns: 0.0036

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft G-W	O-W
111.98	0.000	1.000	0.975	0.002	21.1	7.23	9.14	45.3	75.0
121.70	0.000	1.000	0.898	0.002	22.9	7.86	9.93	49.1	81.5
133.85	0.000	1.000	0.816	0.003	25.2	8.65	10.9	54.1	89.5
145.76	0.000	1.000	0.749	0.003	27.5	9.42	11.9	59.0	97.7
159.69	0.000	1.000	0.684	0.003	30.1	10.3	13.0	64.6	107.
174.53	0.000	1.000	0.626	0.003	32.9	11.3	14.2	70.6	117.
190.06	0.000	1.000	0.575	0.004	35.8	12.3	15.5	76.8	127.
208.09	0.000	1.000	0.525	0.004	39.2	13.4	17.0	84.1	140.
228.16	0.000	1.000	0.479	0.004	43.0	14.7	18.6	92.2	153.
250.43	0.000	1.000	0.436	0.005	47.2	16.2	20.4	101.	167.
274.98	0.000	1.000	0.397	0.005	51.8	17.8	22.4	111.	184.
300.38	0.000	1.000	0.364	0.006	56.6	19.4	24.5	121.	201.
326.89	0.000	1.000	0.334	0.006	61.6	21.1	26.7	132.	219.
359.50	0.000	1.000	0.304	0.007	67.7	23.2	29.3	145.	241.
392.11	0.000	1.000	0.279	0.008	73.9	25.3	32.0	159.	263.
429.16	0.000	1.000	0.255	0.008	80.9	27.7	35.0	174.	287.
469.55	0.000	1.000	0.233	0.009	88.5	30.3	38.3	190.	314.
511.94	0.000	1.000	0.213	0.010	96.5	33.1	41.8	207.	343.
564.96	0.000	1.000	0.193	0.011	106.	36.5	46.1	227.	378.
620.04	0.000	1.000	0.176	0.012	117.	40.1	50.6	251.	415.
681.09	0.000	1.000	0.160	0.013	128.	44.	55.6	275.	456.
734.02	0.000	1.000	0.149	0.014	138.	47.4	59.9	296.	492.
802.95	0.000	1.000	0.136	0.015	151.	51.9	65.5	324.	538.
878.32	0.000	1.000	0.124	0.017	165.	56.7	71.7	354.	589.
961.21	0.000	1.000	0.114	0.018	181.	62.1	78.4	388.	644.
1093.16	0.000	1.000	0.100	0.021	206.	70.6	89.2	442.	732.
1187.15	0.000	1.000	0.092	0.023	224.	76.7	96.9	480.	796.
1288.19	0.000	1.000	0.085	0.025	243.	83.2	105.	521.	862.
1403.88	0.000	1.000	0.078	0.027	265.	90.7	115.	568.	944.
1524.88	0.000	1.000	0.072	0.029	287.	98.5	124.	616.	1020.
1670.75	0.000	1.000	0.065	0.032	315.	108.	136.	676.	1120.
1845.94	0.000	1.000	0.059	0.035	348.	119.	151.	746.	1240.
2006.45	0.000	1.000	0.054	0.039	378.	130.	164.	811.	1350.
2207.35	0.000	1.000	0.049	0.042	416.	143.	180.	892.	1480.
2405.54	0.000	1.000	0.045	0.046	453.	155.	196.	972.	1610.
2633.98	0.000	1.000	0.041	0.051	496.	170.	215.	1064.	1770.
2856.54	0.000	1.000	0.038	0.055	538.	185.	233.	1150.	1910.
3139.69	0.000	1.000	0.035	0.060	592.	203.	256.	1270.	2100.
3396.42	0.000	1.000	0.032	0.065	640.	219.	277.	1370.	2270.
3721.82	0.000	1.000	0.029	0.071	701.	240.	304.	1500.	2500.
4076.88	0.000	1.000	0.027	0.078	768.	263.	333.	1650.	2730.
4494.61	0.000	1.000	0.024	0.086	847.	290.	367.	1820.	3010.
4868.08	0.000	1.000	0.022	0.094	917.	314.	397.	1970.	3260.
5294.34	0.007	0.993	0.021	0.102	998.	342.	432.	2140.	3550.
5788.25	0.017	0.983	0.019	0.111	1090.	374.	472.	2340.	3880.
6348.76	0.028	0.972	0.017	0.122	1200.	410.	518.	2570.	4250.

Laboratories, Inc.

MERCURY INJECTION CAPILLARY PRESSURE

University of Kentucky
Jude No. 3 Well
Big Sandy Field
File: H-33385

Sample Number: 5
Sample Depth, feet: 3025.40
Permeability to Air (calc), md: 0.000048
Porosity, fraction: 0.044
Grain Density, grams/cc: 2.54
Median Pore Throat Radius, microns: 0.0036

Injection Pressure, psia	Mercury Saturation, fraction	1.0-Mercury Saturation, fraction	Pore Radius, microns	J Function	Other Laboratory Systems Gas-Water, psia	Gas-Oil, psia	Oil-Water, psia	Estimated Height Above Free Water, ft G-W	O-W
6916.75	0.039	0.961	0.016	0.133	1300.	447.	564.	2790.	4630.
7582.32	0.053	0.947	0.014	0.146	1430.	490.	619.	3070.	5080.
8388.55	0.069	0.931	0.013	0.161	1580.	542.	684.	3390.	5620.
9092.58	0.083	0.917	0.012	0.175	1710.	587.	742.	3670.	6090.
9946.89	0.100	0.900	0.011	0.191	1870.	643.	812.	4010.	6670.
10903.76	0.119	0.881	0.010	0.209	2050.	704.	890.	4400.	7310.
11861.34	0.139	0.861	0.0092	0.228	2230.	766.	968.	4780.	7950.
12956.73	0.161	0.839	0.0084	0.249	2440.	837.	1060.	5230.	8700.
14248.70	0.186	0.814	0.0077	0.274	2680.	920.	1160.	5750.	9520.
15552.78	0.213	0.787	0.0070	0.299	2930.	1000.	1270.	6280.	10400.
17067.33	0.241	0.759	0.0064	0.328	3220.	1100.	1390.	6910.	11400.
18661.64	0.270	0.730	0.0059	0.358	3520.	1210.	1520.	7550.	12500.
20377.39	0.304	0.696	0.0054	0.391	3840.	1320.	1660.	8240.	13600.
22206.38	0.340	0.660	0.0049	0.427	4180.	1430.	1810.	8970.	14900.
24318.84	0.381	0.619	0.0045	0.467	4580.	1570.	1980.	9820.	16300.
26587.99	0.429	0.571	0.0041	0.511	5010.	1720.	2170.	10700.	17800.
29159.12	0.476	0.524	0.0037	0.560	5490.	1880.	2380.	11800.	19500.
32006.60	0.535	0.465	0.0034	0.615	6030.	2070.	2610.	12900.	21400.
35009.34	0.600	0.400	0.0031	0.672	6600.	2260.	2860.	14200.	23500.
38239.29	0.672	0.328	0.0029	0.734	7200.	2470.	3120.	15400.	25600.
42031.89	0.755	0.245	0.0026	0.807	7920.	2720.	3430.	17000.	28200.
45901.07	0.834	0.166	0.0024	0.882	8650.	2970.	3740.	18600.	30700.
49947.95	0.895	0.105	0.0022	0.959	9410.	3230.	4070.	20200.	33400.
54638.68	0.961	0.039	0.0020	1.049	10290.	3530.	4460.	22100.	36600.
59405.26	1.000	0.000	0.0018	1.141	11190.	3840.	4850.	24000.	39800.