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Abstracts

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Abstracts

Preliminary Interpretation of Syn-Rift and Early Post-Rift Stratigraphy on the St. Lawrence Promontory, John S. Allen and William A. Thomas, University of Kentucky, Department of Earth and Environmental Sciences, Lexington, KY 40506, geowat@uky.edu, john-allen@uky.edu

The St. Lawrence promontory broadly defines the Laurentian rifted margin in western Newfoundland. There, Neoproterozoic through Early Ordovician clastic, volcanic, and carbonate successions indicate protracted continental rifting and passive-margin thermal subsidence followed by destruction of the passive margin during the Middle Ordovician in a westward progressing foreland basin and thrust belt. These rocks are host to an unknown quantity of oil and bitumen beneath the western coast of Newfoundland. Understanding the geologic framework of the Laurentian rifted margin is important to constraining the development of these potential hydrocarbon plays.

Rift facies rocks on the St. Lawrence promontory include conglomerate and red sandstones of the Bateau Formation (~0–242m), which lie directly on basement and are cross-cut by and interlayered with ca. 605 Ma tholeiitic basalts of the Lighthouse Cove Formation (~3–310m). A rift-to-drift transition is preserved in shelf sandstones of the Bradore Formation (~65–170m), which blankets most of the St. Lawrence promontory. These rocks contain an Early Cambrian fauna indicating a significant depositional hiatus between active rift and transition to passive margin. Anomalously thick foreland basin deposits near Port au Port bay suggest reactivated rift graben on the promontory.

The thickness and distribution of rift and transitional rocks indicate an upper plate configuration with local syn-rift graben on the St. Lawrence promontory. A hiatus between rift and rift-to-drift transitional rocks may reflect thermal uplift and passive margin mountains along the upper-plate boundary. Further geophysical investigation and palinspastic restoration of rift and early drift stratigraphy can confirm this new hypothesis.

Thickness and Extent of Saline Cambrian Reservoirs in the Ohio Region Is Controlled, in Part, by the Underpinning Precambrian Complex and Paleotopography, Mark T. Baranoski, Ohio Division of Geological Survey, 2045 Morse Rd., Building C-1, Columbus, OH 43229-6693, mark.baranoski@dnr.state.oh.us

Updated maps of the Precambrian complex (Granite Rhyolite and Grenville Provinces and the East Continent Rift Basin) unconformity surface in the Ohio region are essential when selecting potential sites for CO_2 sequestration into saline Cambrian reservoirs. Regional structural features and paleotopography controlled depositional facies and basin architecture of the proto-Illinois-Michigan and Appalachian Basins and Rome Trough. Thickness and extent of potential Cambrian reservoirs have been redefined with updated regional correlation and maps of Cambrian sub-Knox units for the Ohio region. The Mount Simon Sandstone was deposited in an area limited to western Ohio and the adjacent proto-Michigan-Illinois Basin. The eastern limit of the Mount Simon is redefined along a north–northwest-trending, broad, Precambrian paleotopographic arch (exposed Laurentian craton), which extends in the subsurface from an area north of presentday western Lake Erie, southward to the Ohio River, and corresponds to the northwestern Rome Trough boundary fault system. The Mount Simon subcrops along the northern portion of this north–northwest-trending arch. Along the southern portion of this trend, the Mount Simon thickness thins to the east, grading laterally with mixed clastic-carbonate Conasauga Group facies. An east–northeast-trending shoulder of the Rome Trough formed another regionally extensive paleotopographic barrier to Mount Simon deposition. Following Mount Simon deposition, the stable Ohio Platform developed, which was dominated by cyclical mixed clastic-carbonate sediments of Eau Claire Formation and Conasauga Group. The redefined sub-Knox of the Ohio region illustrates that the Mount Simon is not the regional basal "blanket sandstone," as traditionally mapped.

Hydrothermal Dolomite (HTD) in the Michigan Basin, USA, David A. Barnes, Michigan Geological Repository for Research and Education and Department of Geosciences, Western Michigan University, Kalamazoo, MI 49008, barnes@wmich.edu; T.M. Parris, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506; William B. Harrison III, and G. Michael Grammer, Michigan Geological Repository for Research and Education and Department of Geosciences, Western Michigan University, Kalamazoo, MI 49008

Previous investigations and new data from the St. Peter Sandstone, Trenton/Black River (T/Br), Niagaran, and Dundee formations in the Michigan Basin (> 1,600 MMBOE combined cumulative production) sug-

gest that genetically related, hydrothermal diagenesis was important in the origin of many petroleum reservoirs. Saddle dolomite occurs in all of these units as replacive intergranular cement, fracture/vug fill, and/or primary carbonate matrix replacement. Other important hydrothermal phases include pyrite; bitumen; quartz; fracture filling, sparry calcite; anhydrite; and rare fluorite. Petroleum reservoirs in the Ordovician T/Br Group have long been recognized as classic, fracture related, hydrothermal dolostone reservoirs. Stable isotope and fluid inclusion data indicate that fracture fill and replacive dolomite and late, sparry calcite fracture fill were formed from saline, δ18O enriched (+5–+12 δ18O) hydrothermal fluids at between 100°–160°C in T/Br reservoirs. The subjacent, Ordovician St. Peter Sandstone and related strata (AKA "PDC" Sands) contains a complex digenetic mineral suite including intergranular, replacive, saddle dolomite formed from saline, δ18O enriched (+9–+10 δ18O) hydrothermal fluids at between 120°–170°C. Although complex early diagenesis dominates secondary mineral assemblages in many Silurian Niagaran Reef reservoirs, a regionally significant suite of hydrothermal mineral cements also occurs. Saddle dolomite and late sparry calcite formed from saline, δ18O enriched (+2–+9 δ18O) hydrothermal fluids at between 85°–125°C. The Devonian Dundee Limestone formation contains numerous dolostone reservoirs with matrix replacive and fracture/vug filling saddle dolomite and late sparry calcite formed from saline, δ18O enriched (+4–+8 δ18O) hydrothermal fluids at between 120°–145°C. Each of these important hydrocarbon reservoirs as well as other, less productive formations share at least one and, in most cases, several important diagenetic mineral components resulting from at least one episode of fracture related, hydrothermal mineralization in the Michigan Basin.

Geological Carbon Sequestration (GCS) Potential in Upper Silurian to Middle Devonian Strata in the Michigan Basin, USA, David A. Barnes, William B. Harrison III, Amanda Wahr, Michigan Geological Repository for Research and Education, Department of Geosciences, Western Michigan University, Kalamazoo, MI 49008, barnes@wmich.edu; Phil Jagucki, and Neeraj Gupta, Battelle Memorial Institute, 505 King Ave., Columbus, OH 43201

The Core Energy, State-Charlton #4-30 well in Otsego County, Michigan, was drilled in late 2006 in conjunction with ongoing DOE/NETL funded, MRCSP Phase II studies of GCS potential in Upper Silurian to Middle Devonian saline reservoir and caprock units in the Michigan Basin. New downhole data from conventional and sidewall core and modern, wireline logs from the #4-30 well, along with an enhanced understanding of existing subsurface data from elsewhere in the the basin, have greatly improved the resolution of and confidence in regional estimates of GCS potential. Excellent, potential GCS saline reservoir targets are recognized in porous dolomite of the Upper Silurian Bass Islands Group. Uppermost Bass Islands strata in Michigan underlie the base-Kaskaskia unconformity surface, and correlative strata are present in much of the MRCSP region. Diverse and distinctly cherty lithofacies in the Middle Devonian Bois Blanc Formation in much of the Michigan Basin apparently lack suitable injectivity and are not considered a GCS reservoir target in the #4-30 well. Fossiliferous limestone of the Middle Devonian Amherstburg Formation contains minimal porosity throughout the basin and mostly non-detect permeability in the #4-30 well. The Amherstburg is a suitable caprock unit throughout most of the Michigan Basin. Using preliminary estimates of reservoir thickness and average porosity, GCS storage capacity in the Bass Islands in the Michigan Basin ranges from 1.4Gt to 6.8Gt of CO_2 at critical point conditions and equates to approximately 310–1,544 metric tons of CO_2 per hectare. Geologic data from the proposed pilot injection test well are being used with reservoir modeling to evaluate actual injectivity potential and develop permit and operational strategies for a geologic storage demonstration phase of the project to be conducted during 2007.

Aeromagnetic Gradient Anomalies Help Locate New Oil and Gas Reservoirs, Harold Robert Beaver, Saint Joseph Petroleum Inc., 7378 Cockrill Bend Blvd., Nashville, TN 37209, hrbeaver@comcast.net

Aeromagnetic measurements traditionally are used to provide basement structure, depth, and lithology data. Horizontal gradient studies of aeromag total field measurements can be used to map small direct current anomalies in the subsurface caused by chemically reduced zones above oil and gas reservoirs. These direct current anomalies can sometimes be seen on the spontaneous potential measurement of electric logs taken of wells drilled into oil and gas reservoirs. These small direct current anomalies also have a very small effect on the total earth magnetic field. With a special horizontal gradient operator, these effects can be filtered and mapped as a derivative anomaly.

Case histories using aeromag data flown in the 1950's with a fluxgate magnetometer prior to the discovery of oil and gas in certain areas are documented.

These studies disprove the possible contamination of aeromag data by oil field flow lines, tank batteries, or casing dipoles.

Other case histories using more recent aeromag data using a proton precession magnetometer after 1975 illustrate the method and its use over newer oil and gas reservoirs in the Appalachian Basin, Cincinnati Arch, and the Michigan Basin. Before and after case histories are provided proving the effectiveness of the theory and method.

Strengths and limitations of the method are presented in a detailed summary.

Carper Sandstone Potential in the Illinois Basin, James Blumthal, Independent Consultant, Olney, IL 62450, jblumthal@wabash.net

The Carper Sandstone has been a moderate producer in the Illinois Basin over the last 50 years. Previous production has been limited to 12 fields along the Mattoon-Louden-Salem trend of the western Fairfield Basin and minor areas on the LaSalle Anticline. Review of regional trends of sand development indicate potential for additional exploration in these areas. The sample database of the Illinois Geological Survey is an excellent source of well cuttings from old dry holes that may indicate production potential. This play may provide for significant activity in the future of the Illinois Basin.

Pennsylvania State Forests: Our Role in Basin Exploration and Development, Teddy W. Borawski, Nathan S. Bennett, and Amy E. Randolph, PA-DCNR, Bureau of Forestry, Harrisburg, PA 17105, tborawski@state.pa.us, nabennett@state.pa.us, arandolph@state.pa.us

Exploration and production of oil and natural gas on Pennsylvania State Forest lands began in 1945. Historically, a majority of the 1,300 wells drilled on State Forest land have targeted shallow, Upper Devonian gas reservoirs. However, notable production from moderately deep formations (e.g., 6,000–10,000 feet) has also occurred. Although somewhat limited in geographic extent, production from the Grugan Field, which lies almost entirely beneath State Forest land, continues to play a vital role in shaping natural gas production throughout Pennsylvania. If the past is any indication of the future, Pennsylvania's State Forests will continue to be a key component in Appalachian exploration and development.

This study serves to provide a historical look into the oil and gas program administered by the Minerals Section of the Bureau of Forestry. This comprehensive look at natural gas production will seek to establish not only statewide production volume(s) but also an inflation adjusted economic look into what natural gas production has provided to Pennsylvania conservation efforts. Additionally, production will be delineated by gas field to better establish where the most significant activity has occurred in relation to sub-surface geologic structures as well as what producing formation(s) have been the most prolific across State Forest lands. Lastly, the future of oil and gas development on State Forest lands will be examined with specific focus placed on exploration trends and how these trends may affect to an upcoming lease sale.

Producing and Potential Shale Gas Reservoirs of the Eastern United States, James L. Coleman, Christopher S. Swezey, Robert C. Milici, and Robert T. Ryder, U.S. Geological Survey, 12201 Sunrise Valley Drive, MS 956, Reston, VA 20192, jlcoleman@usgs.gov, cswezey@usgs.gov, rmilici@usgs.gov, rryder@usgs.gov

Efforts to acquire exploration and production leases for shale gas reservoirs have accelerated recently, coincident with increasing prices and decreasing supplies of domestic oil and natural gas. New leasing and drilling proposals typically cite the success stories of the Mississippian Barnett and Fayetteville shales in Texas and Arkansas to promote new investment opportunities. East of the Mississippi River, shale gas reservoirs that are currently being produced or undergoing testing in the Appalachian, Michigan, and Illinois Basins include the following: the Cambrian Conasauga Formation, the Ordovician Utica Shale, various Upper Devonian shales (e.g., Ohio, Chattanooga, Sunbury, Antrim, and New Albany), the Mississippian Floyd Shale, and various Pennsylvanian shales associated with adjacent coal beds. Other stratigraphic intervals in the region that may become shale gas reservoirs are the Precambrian Nonesuch Formation and generally equivalent shales of various Precambrian rift basins, the Silurian shale with a Gondwanan affinity in North Florida–South Georgia, the Triassic Lockatong Formation and generally equivalent shales in the Mesozoic rift basins, and the Cretaceous Eagle Ford Shale of the Gulf Coast Basin. All of these shale gas intervals may be considered as either identified or potential petroleum source rocks and reservoirs, although the reservoirs are unconventional or continuous in nature. Natural gas within these shale reservoirs may be thermogenic and (or) biogenic, and different exploration concepts may be needed for these different gas types. Examination of each potential interval and comparison with existing producing intervals show key commonalities and potential significant differences.

Palinspastic Reconstruction around a Recess in the Appalachian Thrust Belt in Georgia, B.S. Cook and W.A. Thomas, University of Kentucky, Department of Earth and Environmental Sciences, Lexington, KY 40506, b.cook@uky.edu, geowat@uky.edu

The characteristically sinuous map traces of orogenic thrust belts include salients and recesses. A distinct Appalachian recess in Georgia comprises an intersection between two regional strikes at an approximately 45° angle. Folds and faults from both structural trends intersect and include clearly defined interference folds, enabling the tracing of both strike directions through the intersection. The intersection and fold interference exemplify a well recognized problem in balancing palinspastic reconstructions of sinuous thrust belts. The palinspastic restoration of thrust belts around salients and recesses immediately applies to orogenic evolution and hydrocarbon exploration.

Palinspastic restorations around bends in thrust belts present difficulty in volume balancing. Cross sections generally are constructed perpendicular to structural strike, which corresponds to the assumed slip direction. An array of cross sections around a structural bend may be restored and balanced individually; however, restorations perpendicular to strike along intersecting thrust faults yield an imbalance in the along-strike lengths of frontal ramps. The restoration leads to a similar imbalance in the surface area of a stratigraphic horizon, reflecting a volume imbalance in three dimensions.

Three alternative solutions are suggested: (1) treating the ends of the fault segments as fault tips, so that displacement diminishes to zero toward the tip; (2) restoring a trapezoidal block (bounded by cross sections perpendicular, respectively, to two intersecting structural trends), so that higher order strains are accommodated within the block by superposed folds and/or faults, etc.; or (3) incorporating successive deformation episodes with contrasting slip directions that correspond to the two intersecting structural trends.

Flow in Porous Media: Experiments and Simulations with Application to CO_2 Sequestration, Dustin Crandall, Clarkson University, Department of Mechanical and Aeronautical Engineering, Potsdam NY 13669 and National Energy Technology Laboratory, Morgantown, WV 26507, meDustin@gmail.com; Goodarz Ahmadi, Clarkson University, Department of Mechanical and Aeronautical Engineering, Potsdam NY 13669; and Duane H. Smith, National Energy Technology Laboratory, Morgantown WV 26507

The amount of carbon dioxide that can be sequestered in reservoirs is dependent on fluid-fluid-solid interactions within porous rock. Displacement of an in-place fluid by a less viscous invading fluid does not evacuate 100 percent of the defending fluid, due to capillary and viscous fingering. This has been studied over the past decades experimentally and numerically with pore-throat flow cells and pore-level models, respectively. This current work examines immiscible two-phase displacements within a novel flowcell and extends this experimental work with a computational fluid dynamics model within the same random pore-throat geometry using the Volume of Fluid (VOF) method.

A new, experimental flowcell is described and experiments of constant-rate injection of air into the water-saturated cell are shown. The flowcell is weakly water wetting with a static contact angle measured as 76°. The motion of the invading fingers is shown to obey the well defined fingering structures observed in pore level numerical models of drainage; namely, dendritic fingers at high flow rates and a more stable invasion at low rates. An increase in the fractal dimension (D_f) of the interface and a decrease in the final saturation of invading air was noted with increasing flow rate.

VOF modeling within the same flowcell geometry is then discussed. Percent saturation and the D_f of the invading fluid were calculated from the numerical model and shown to be in good agreement with the experimental findings of air invasion into a water saturated domain. The fluid properties (viscosity and density) were than varied and the viscosity ratio (M) between fluids and capillary number (Ca) of the flow are shown to affect the percent of displaced fluid, with lower Ca and higher M displacing a greater amount of the wetting fluid.

Finally, the fluid-fluid-surface conditions of the numerical model were changed to show the effect on the percent saturation and D_f for the case of a weakly water repellent surface, the case of imbibition. The invading fluid is shown to preferentially move into small throats and displace a larger percent of the in-place fluid than observed in the drainage case. The interface was also observed to have a higher D_f, similar to 2.

This study has used porous media analogies and computational fluid dynamics to show the effect that pore-level interactions have on the motion of two fluids within a heterogeneous domain. The results indicate that a greater percent saturation of CO_2 can be achieved within geological reservoirs when a low injection rate is used to mitigate this greenhouse gas.

Methodology for Combining Old Log Suites with Modern Modeling Technology, Louden Oil Field, Illinois Basin, James R. Damico, Rex Knepp, and John P. Grube, Illinois State Geological Survey, 615 E. Peabody Dr., Champaign, IL 61820, damico@isgs.uiuc.edu

In mature fields lacking modern porosity logs, it is often difficult to obtain data necessary for the reservoir modeling and simulation that must precede EOR tests using CO_2. Louden Field is one such field, having been discovered in 1937 and developed in the 1930's and 1940's. Though wells form a tight, 10-acre grid, not all were logged and few have more modern logs than an SP-Resistivity suite. For 138 wells in the model area, 62 logs and 17 cores were available.

The first test of CO_2 EOR is a huff-n-puff technique applied to a Chesterian Cypress Sandstone producer, the Owens #1. Cypress reservoir bodies in the Illinois Basin are usually coalescing lenticular "pods" some 200 acres in area and 10 to 20 feet thick. According to geological mapping, Owens #1 lies near the southwestern extremity of a typical pod.

To generate a useful reservoir model it was necessary to convert SP—the log curve most nearly independent of hydrocarbon content—to a sand/shale curve through normalization. The normalized data were then used to characterize the reservoir using two different geostatiscal models: plurigaussian and turning bands. These models served as the basis for geological input to simulating CO_2 injection.

The normalized SP curves were cross-plotted against the 17 core analyses to obtain regression curves relating SP to permeability and permeability to porosity. Estimated values at cored wells were overwritten by analytical values during modeling. The permeability and porosity models were submitted to reservoir simulation along with the reservoir model after upscaling.

Examining Stimulation Options in Light of Big Lime Geological Characterization, B.J. Davis, BJ Services Co. U.S.A., 11211 FM 2920, Tomball, TX 77375, brian.davis@bjservices.com

It is rare for E & P company geologists and engineers working in the Appalachian Basin to have detailed knowledge of actual reservoir properties and rock characteristics. A limited technical paper search returned nothing in literature pertaining to the etched acid conductivity resulting from fracture acidizing of the Mississippian age Big Lime formation in West Virginia. This is surprising because fracture acidizing is an everyday procedure used to enhance Big Lime hydrocarbon recovery. A Kanahwa County core of the entire Big Lime interval and the top of the Big Injun sandstone was obtained for geological and core flow study from the West Virginia Economic and Geological Survey.

The objectives of the core analysis were twofold: first, to characterize the framework mineralogy, cements, clays, and porosity types of the samples, and second, to evaluate that characterization in light of the laboratory effectiveness of hydrochloric acid to induce an etching pattern necessary for satisfactory reservoir stimulation.

Reservoir quality varied in the samples from poor to good due to variations in detrital carbonate sand size, degree of dolomitization, and the occurance of authigenic quartz. Natural fractures were noted in the upper limestone interval but not in the dolomitic section.

Acid solubiilties of select samples averaged 90 percent in 15 percent HCl. In practice nearly all operators pump foamed HCl acid as their stimulation fluid in the Big Lime. Laboratory tests evaluated the effectiveness of foamed versus non-foamed HCl in creating favorable etching patterns in dolomitic Big Lime cores.

You've Won Your Energy Trifecta—Now for Some Thoughts on Keeping Your Winnings, Rick Deery

With a degree of wisdom that is nonexistent in today's political climate, the Founders created our Federal system that, as James Madison put it in Federalist Ten, "breaks and controls the violence of Faction." Madison defined Factions as "a number of citizens amounting to a majority or a minority of the whole, who are united and actuated by some common impulse of passion, or of interest, adverse to the rights of other citizens, or to the permanent and aggregate interests of the community. To reduce the impact of "Factions" on all of us, Madison and the Founders gave us a Federal system that divides and disperses power to Federal and state levels and spreads it among many places inside the Federal government. It is a system that is deliberately designed to make things difficult for "Factions" to quickly drive damaging policies into law. For those who only rarely look into the world of Federal congressional activity, it is often a murky place. It fails to quickly respond to the cry, "There ought be a law!" Rejoice in that failure, because in today's world, "Factions" unite around impulses of passion or interest powered by the internet, often adverse to the permanent and aggregate interests of the community - the United States. Proposals to repeal EPAct 2005's "subsidies and tax breaks for Big Oil," fighting global warming induced by the use of fossil fuels and blocking federal oil and gas leasing to make sure the oil companies don't prevent hunting and recreation are just some of the impulses of passion and interest that rock the United States petroleum scene. We'll look at how the impulses of the moment play out in the House of Representatives. More importantly we'll look at how geologists and petroleum geologists in particular, can effectively deal with a body composed of 435 politicians, none of whom are geologists. These politicians are in turn supported by more than 7,000 staffers, most of who have only a minimal interest in science and probably even less interest in geology. This is a tough crowd to approach with the type of technical issues that make up your comfort zone and which in one sense insulate and even isolate geologists from the rest of the citizenry. Other speakers will reach out to you with pleas as to why you as geologists should get engaged in the political arena. I will start with the assumption that you do want to protect yourselves, but are not quite clear on how to proceed and so I'll offer some simple rules for getting engaged. After all if you are not engaged, you will find it hard to keep your winnings.

Palynologic Correlation of Late Middle Pennsylvanian Coal Beds in the Central Appalachian Basin, Cortland F. Eble and Stephen F. Greb, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506, eble@uky.edu, greb@uky.edu; Bascombe M. Blake, West Virginia Geologic and Economic Survey, Morgantown, WV

Late Middle Pennsylvanian strata in the Central Appalachian Basin contain some of the most economically important coal beds and coal zones in the region, including the Haddix, Hazard, Peach Orchard, Broas, Skyline, Kittaning, and Freeport coal beds. Palynological (spore and pollen) data can help with identification and correlation so that more accurate reserve assessments can be made. This is especially true where the interval thins, or coals split into multiple beds.

In eastern Kentucky, late Middle Pennsylvanian strata occur in the Four Corners and overlying Princess Formations of the Breathitt Group. In adjacent West Virginia, correlative rocks are assigned to the upper part of the Kanawha Formation and overlying Charleston Sandstone. In southwestern Virginia, age-equivalent strata occur at the top of the Wise and overlying Harlan Formations. Late Middle Pennsylvanian strata also are found in the Cross Mountain Formation of northestern Tennessee and the Allegheny Formation of southeastern Ohio.

Stratigraphically important palynomorphs in the late Middle Pennsylvanian include *Torispora securis, Murospora kosankei, Triquitrites minutus, Cadiospora magna, Mooreisporites inusitatus, Thymospora pseudothiessenii,* and *Schopfites dimorphus, Radiizonates difformis, Densosporites annulatus, Dictyotriletes bireticulatus, Vestispora magna,* and *Savitrisporites nux.* These forms help identify and correlate late Middle Pennsylvanian coal beds across the Central Appalachian region.

Coal palynology also helps with interbasinal correlation. Comparison with established spore and pollen assemblage zones indicate a late Atokan through Desmoinesian age for the U.S. Eastern and Western Interior Basins, and the upper part of the Bolsovian and Asturian sub-stages (Westphalian C–D) of western Europe.

CO_2 Re-Stimulation in the Michigan Basin: A Second Chance for the Prairie Du Chien, James T. Edwards, BJ Services Co., Dunbar, WV 25064, james_edwards@bjservices.com; and J.W. Crafton, Performance Sciences, Evergreen, CO 80437, jcrafton@performancesciences.com

The Michigan Basin is viewed by many as only having mature reservoirs with limited availability for new treatment designs. The latest re-stimulation program using CO_2 might give rise to opportunity of enhanced production in Michigan as well as the benefit for new completions.

Simulation treatment designs in the Prairie Du Chien (AKA PDC) over the past two decades since initial drilling have been marked by vast differences in natural gas productions numbers from wells within the same field. Re-stimulation treatments have included cross-linked fluid or nitrogen foam that have provided mixed results in terms of their success rate. Problems such as excessive surface treating pressure, limited downhole sand concentration, early screen outs, and water retention have been seen in the afore-mentioned stimulations. Many existing wells within established PDC fields have declining production numbers despite reasonable reservoir pressure still present.

The advantages of the CO_2 treatment design marked with increased fluid recovery capabilities by gas assist along with the hydrostatic advantages will be expanded upon. Treatment design details with pressure response along with production results from the first set of wells will be included.

This presentation will expand re-stimulation ideas as well as spur a desire for further investigation into the use of CO_2 in the Prairie Du Chien. It also hopes to change the perception of the Michigan Basin to that of a still viable and rediscovered source of natural gas in the ever tightening world supply.

Secondary Porosity Development in the Galena (Trenton) Dolomite of Northern Illinois: Implications for Regional Fluid Flow and Hydrocarbon Accumulation, Dean W. Ekberg, John P. Grube, and Joan E. Crockett, Illinois State Geological Survey, 615 East Peabody Dr., Champaign, IL 61820, ekberg@isgs.uiuc.edu

Secondary porosity in the Galena (Trenton) dolomite can be subdivided into three types: matrix, fracture, and conduit. All three types of secondary porosity have been enhanced by karst processes, either meteoric or hydrothermal. Meteoric karstification occurred along with subaerial exposure during post-Galena (mid-Ordovician) time. Hydrothermal karstification subsequently occurred in middle to late Paleozoic, with sulphur-rich hydrothermal fluids rising up through fracture conduits in the Galena dolomite until reaching the relatively impermeable overlying Maquoketa shale. Maximum dissolution occurred directly beneath the Maquoketa as well as along the vertical and horizontal conduits and fractures. Increased matrix porosity also resulted from shrinkage due to hydrothermal dolomitization.

Karst features such as caves, sinkholes, and springs are concentrated near synclinal axes as well as major faults and fractures. Sulphide mineralization is also coincident with synclines, faults, and fractures. Karst is evidenced by bit drops on drillers' logs as well as vugs and cavities in rock cores. Triple porosity pump drawdown curve analysis and spring hydrograph recession curve analysis also indicates karst. Horizontal karst conduits are found primarily at the junctions of vertical fractures and bedding plane fractures. Vertical conduits are found at the junctions of the northwest and northeast vertical fracture sets.

Hydrocarbon accumulation in the Trenton in both the Michigan and Illinois Basins occurs primarily in the top 50 feet, directly beneath the Maquoketa shale seal. Oil and gas occurrence is also associated with synclines and fractures that have resulted from solutional collapse and/or structural compression.

Horses, Kentucky Bluegrass, and the Origin of Upper Ordovician, Trenton-Age Carbonate Reservoir and Source Rocks in East-Central United States, Frank R. Ettensohn, University of Kentucky, Department of Earth and Environmental Sciences, Lexington, KY 40506, fettens@uky.edu

The central Kentucky Bluegrass Region is commonly touted as "The Horse Capital of the World," and the designation is clearly tied to the origin of the Trenton-age Lexington Limestone and its equivalents throughout east-central Kentucky and nearby areas. These argillaceous limestones weather, largely through solutional processes, to generate flat to gently rolling terrain with phosphate-rich soils that are important in generating solid skeletal framework and enhanced metabolism in the horses that graze on grasses in the area. All of this, however, is related to the tectono-stratigraphic framework during limestone deposition about 450 Ma ago.

Prior to deposition of Trenton-age carbonates, the region was characterized by widespread, peritidal deposition of pure pelletal carbonate muds on the very shallow Blackriver carbonate platform. Abruptly, however, the Blackriver platform collapsed along older Keweenawan, Grenvillian, and Iapetan structural trends and differentiated into structural highs like the Lexington and Galena-Trenton platforms and intervening structural lows like the Sebree Trough and foreland basin. This collapse event was coeval with initiation of the Taconic tectophase at the New York promontory and probably reflects cratonward movement of largely tensional, far-field, tectonic forces during early parts of the tectophase. The structural highs acted as foundations for the extensive buildup of carbonates that would become reservoir rocks in Lexington and equivalent limestones, whereas the intervening lows accumulated dark-mud source beds and were sufficiently depressed to make contact with open seas to the south, which in the existing paleogeographic-paleoclimatic setting, funneled deep, cold, phosphate-rich, oceanic waters into the craton and onto the platforms via upwelling. Later, however, during an apparent change in Taconian subduction polarity that resulted in change to an overall compression regime, the area experienced major deepening and regional tilting that allowed foreland-basin muds to flood the low areas and eventually inundate the carbonate platforms. Hence, the same phosphate-rich limestones that have generated the beautiful Bluegrass terrain and horse-raising industry in central Kentucky are clearly related to the hydrocarbon potential of similar rocks in the larger, east-central U.S. region; both reflect the unique interplay of tectonic, paleogeographic, and paleoclimatic conditions in the area nearly 450 million years ago.

Dropstones, Glaciation, and Black Shales: New Inferences on Black-Shale Origins from the Upper Ohio Shale in Northeastern Kentucky, Frank R. Ettensohn, University of Kentucky, Department of Earth and Environmental Sciences, Lexington, KY 40506, fettens@uky.edu; Thomas R. Lierman, Eastern Kentucky University, Department of Earth Sciences, Richmond, KY 40475, tom.lierman@eku.edu; and

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Recently, a nearly 3-ton, granitic boulder was found embedded within uppermost parts of the Upper Devonian (Famennian; *praesulcata* Zone) Cleveland Shale Member of the Ohio Shale in Rowan County, northeastern Kentucky. Other anomalous, igneous and metamorphic boulders have been found near Cleveland exposures in the area, but none were *in situ*, prompting previous workers to ascribe their origins most commonly to ice-rafting in proposed extensive Pleistocene proglacial lakes accompanying glaciation to the north. The *in-situ* nature of the new find, as well as compositional aspects of this and other boulders, strongly suggest an eastern Appalachian origin. Although Gondwanan glaciation was present far to the south at the time, the likely Appalachian sources suggest that ice rafting related to alpine glaciation in the newly elevated Acadian highlands 300–400 km to the east was more likely. This is supported, moreover, by probable tillites and other dropstone-bearing sequences in more proximal deposits of the same age in Pennsylvania and Maryland.

The co-occurrence of black shales and nearby glaciation also suggests yet another set of factors conducive to black-shale deposition. There is no doubt that the unique coincidence of temporal, tectonic, and paleoclimatic-paleogeographic factors at the time strongly favored black-shale deposition, but the presence of nearby glaciation indicated by the dropstones would have enhanced these factors through an influx of meltwater that intensified a salinity-stratified water column and amplified euphotic-zone bioproductivity by increasing levels of meltwater-derived nutrients. In fact, episodes of nearby waxing and waning glaciation in the Acadian highlands may have influenced the course of third- and fourth-order transgressions and regressions seen in the Appalachian black-shale sequence, with the most organic-rich black shales occurring during periods of deglacial melting and transgression.

Preliminary Study of a Producing, Late Mississippian, Low-Stand Sand Body at the Base of the Big Lime on and near the Pine Mountain Thrust Sheet in Southeastern Kentucky and Northeastern Tennessee: Relationships to Ouachita Tectonism, Frank R. Ettensohn, Department of Earth and Environmental Sciences, University of Kentucky, Lexington, KY 40506, fettens@uky.edu; and Matthew B. Vest, SAIC Inc., Oak Ridge, TN 37830

Exposures in southeastern Kentucky and northeastern Tennessee show the presence of a dolomitic sandstone unit at the base of the Big Lime (Newman Limestone), which unconformably overlies Fort Payne rocks. Study of the unit shows that it is the same as a gas-producing sandstone in the Mud Creek and Key Rock fields, just west of the Pine Mountain thrust fault. The unit occurs as fining-upward clastic-carbonate sequences in an apparent channel complex with thicknesses of 80 feet or more in channels and 30 feet or less in inter-channel areas. Porosity attains 15 percent in some intervals and permeability ranges from less than 1 mD to greater than 4,000 mD. Production in both fields is highly variable, with greatest production occurring in thicker channel sands. The sand body occurs just southeast of the Greenwood structural anomaly.

Stratigraphic and paleontologic evidence suggests that the unit is approximately equivalent to other early Chesterian sandstone and sandy-carbonate units (Warix Run Member, Loyalhanna Limestone, Keener Sandstone, and Greenbrier Big Injun) in the Appalachian Basin that occur on top of a post-Ste. Genevieve unconformity, which cuts down through earlier Middle Mississippian carbonate and clastic units near structural features. Post-Ste. Genevieve uplift and erosion, as well as uplift on regional structures, were probably related to Ouachita far-field tectonism from the south, and a subsequent influx of sands and sandy carbonates, partly eroded from the exposed surface, infilled adjacent low areas as peritidal, lowstand, sand bodies. These sand bodies seem to form the best reservoirs where they intersect subtle northwest–southeast-trending folds that can only be ascribed to later Ouachita compression. Hence, the sand body and its producing status may be wholly related to the influence of Ouachita tectonics in the Appalachian Basin. Future exploration should concentrate on the intersection of thick sand bodies with the subtle anticlines and on extensions of the sand body below the Pine Mountain thrust sheet.

How Far Did the Appalachian Thrusts Move? A Study of the Burning Spring and Pine Mountain Stuctures, S. Parker Gay Jr., Applied Geophysics Inc., Salt Lake City, UT 84111, spg@applgeo.com

In the Rocky Mountains where “thick-skinned” thrusting has created many anticlines that now contain oil and gas, well drilling and seismic data have mapped the geometry of these structures, and their basement roots (faults) are well known. They have also been mapped magnetically by the author. In the Appalachians, however, the “thin-skinned” thrusts have traveled a greater distance and are far removed from their roots, whose location is consequently unknown.

The author was intrigued by this problem and decided to apply the same technique used in the Rockies to determine the root locations of two Appalachian structures. In West Virginia, the Burning Springs anticline and adjacent anticlines form a pattern that was compared to the basement fault block pattern farther east along the possible transport path. This exercise yielded a remarkable fit to the fold pattern only 20 miles east of their actual location. A 10° rotation was required for a perfect match. The writer therefore proposes that the thrust/folds were originally formed at this easterly location and later shoved westerly while undergoing a slight rotation.

Following this success, the technique was tried on the Pine Mountain thrust. Here, the fault pattern is less well constrained, as we have only the one main thrust to compare to. Going east–southeast from the thrust's present location, there are no candidate basement faults until we encounter the Cranberry structure approximately 100 miles east. It is remarkably parallel to the Pine Mountain thrust (within 2°) and thus is the probable root of that structure.

Simulation of Sparging in Connection with Leakage of Sequestered Carbon Dioxide, E. Gessner, G. Ahmadi, Clarkson University, Department of Mechanical and Aeronautical Engineering, Potsdam, NY 13699, Eric.A.Gessner@gmail.com; G. Brohmal, and D. Smith, Department of Energy, National Energy Technology Laboratory, Morgantown, WV 26501

Sequestration of carbon dioxide is used to minimize exhaust of a known greenhouse gas to the atmosphere. One problem that can occur is the leakage of sequestered carbon dioxide. Leakage due to previous wells or permeable soil poses a real threat to the time and energy spent on sequestration. In order to determine if there is leakage in nature, tools for discovering emitting carbon dioxide are necessary. These tools are being developed in a controlled study in conjunction with sparging of carbon dioxide. Sparging is the insertion of a gas below the water table where the natural buoyancy is the driving force. Most often, sparging is a method often used to mitigate volatile chemical or petroleum based spills. This procedure alleviates the hydrocarbon concentration with enhanced aerobic biodegradation. Conventionally, air is pumped into a contaminated zone where the permeable soil allows passage to the chemicals. This study, however, has been performed by sparging the "toxic" carbon dioxide into a clean subsurface. There has been strong correlation between experimental sparging of carbon dioxide and numerical predictions using FLUENTTM. In addition, predictions about the quantity of carbon dioxide that can leak from abandoned wells has been studied. It has been shown that a rate of over 2,600 m^3/year of carbon dioxide can easily be emitted from a single 5-inch diameter pipe given typical reservoir conditions. This poses a serious threat considering there are millions of test wells across the country.

Characteristics of Hydrocarbon Reservoirs in Paleozoic Rocks in Kentucky, Patrick J. Gooding, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40511, gooding@uky.edu

Hydrocarbons in Kentucky occur throughout much of the Appalachian Basin, along the Cincinnati Arch, and in the Illinois Basin. More than 1,500 oil and gas pools produce from over 60 different formations throughout the Paleozoic. Most of the oil is produced from Mississippian limestones and sandstones in eastern and western Kentucky or from Ordovician limestones and dolostones in south-central Kentucky. Most natural gas is produced from the Devonian black shales of eastern Kentucky.

The composition and physical properties of the Paleozoic reservoir rocks across Kentucky are varied. Hydrocarbons commonly occur in a wide range of rock types and depositional settings ranging in age from Early Cambrian to Early Pennsylvanian. A much better understanding of the depositional and diagenetic history and geologic controls on reservoir development is being provided by geologic research, as well as new insights to porosity, permeability, maturation, generation, migration, and accumulation of hydrocarbons in Kentucky. New discoveries on the influence of structural activity and tectonic events, both regionally and locally, are coming to light.

Devonian black shale–sourced hydrocarbons have migrated both vertically and horizontally from deep within the Appalachian and Illinois Basins. They are transported both horizontally and vertically through faults, fractures, joints, weakened bedding planes, vugs, breccias, and unconformable surfaces throughout the basins and along the flanks of the arch to accumulate in the Paleozoic reservoirs of Kentucky.

New geochemical and geophysical data, the evolution of computer modeling, new and innovative drilling, stimulation, and completion techniques make it imperative to reexamine and reevaluate the basins.

Middle Ordovician Carbonates of Central Kentucky, Patrick J. Gooding and Robert R. Daniel, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40511, gooding@uky.edu, rdaniel@uky.edu

The predominantly carbonate sediments of the Middle Ordovician High Bridge Group and Wells Creek Dolomite are composed mainly of dolostone and limestone with minor amounts of shale and siltstone. These formations are of important economic significance because of their composition and association with hydrocarbon entrapment and localization of mineral deposits. Sedimentary structures, fauna, lack of fauna and the abundance of carbonate sediments, mainly mudstones, suggest regressive carbonate cycles deposited on tidal flats within the intertidal, supratidal, and shallow marine environments.

The core was drilled along the axis of the Cincinnati Arch, on the Jessamine Dome in central Kentucky. The area is associated with the Kentucky River and Lexington Fault Systems, and is underlain by basement structures, mainly the Rome Trough. An unconformity of regional extent is present at the base of the Middle Ordovician.

Polished core slabs show great detail and variety in sedimentary structures, colors, textures, contacts, and repetition of particular rock types and structures with increasing depth and influence from hydrothermal activity. Detailed examination re-emphasizes the important role that invertebrate organisms played. They generated fecal and skeletal material, which produced carbonate sediment of both mud and coarser particles. Algae also played an important role in producing carbonate mud.

Many interesting sedimentary structures and geologic features resulting from burrowing activity are observed. Bird's-eye structures; tubular and cylindrical holes; vertical, inclined, horizontal and dolomite-filled burrows; unusual color-mottled structures; fossil packstones; laminations; mudcracks; extensive deformed, disturbed and destroyed bedding; and stylolites are common.

Michigan's Antrim Shale Play—A Two-Decade Template for Successful Devonian Gas Shale Development, Wayne R. Goodman, Northern Lights Energy, Gaylord MI 49734-0218, wrgnle@alphacomm.net; and Timothy R. Maness, Maness Petroleum Corporation, Mount Pleasant, MI 48804-0313, tim@manesspetr.com

Although key wells drilled by early visionaries from the 1940's to 1960's proved play viability, it was not until the late 1980's that Michigan's Devonian Antrim Shale play established a strong economic foothold. The combination of improved completion technology, regional pipeline capacity seeking new gas in the twilight of the Niagaran pinnacle play, and non-conventional gas tax incentives led to a dramatic burst in Antrim development roughly 20 years ago. Today, over 9,000 completed wells in 700+ discrete projects across a 12-county northern Lower Michigan fairway bear testimony to a successful play that defines one of the 10 largest gas fields in the United States. Earlier in 2007, Antrim gas sales exceeded the 2.5 TCF mark.

The Antrim, while producing from the same Upper Devonian sequence that defines many North American non-conventional gas plays, has some fundamental differences from most of the others. Antrim gas pays are shallow (500–2,000 feet); the gas is chiefly biogenic, with Antrim thermal maturities generally below levels required for methanogenesis. Significant associated water is produced, particularly early in a well's history, resulting in a typical project design where multiple wells feed a central production facility for dehydration and compression.

While essentially all play fairway wells with a preserved Antrim section result in economic completions, areas of enhanced recovery are identifiable through geological and engineering studies. The ultimate performance level of Antrim wells and projects is defined by combining the innate regional geology and reservoir characteristics with surface topography, flowline mechanics, and operational astuteness.

Geology of the Planned Carbon Sequestration Demonstration Well, Boone County, Kentucky: A Test of the Mount Simon Sandstone on the Cincinnati Arch, Stephen F. Greb, James A. Drahovzal, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506-0107, greb@uky.edu, drahovzal@uky.edu; John A. Rupp, Wilfrido Solano, Indiana Geological Survey, Indiana University, Bloomington, IN 47405; Lawrence Wickstrom, Ohio Geological Survey, Ohio Department of Natural Resources, Columbus, OH 43229; Neeraj Gupta, Philip Jagucki, and Joel R. Sminchak, Battelle, Columbus, OH

The Midwest Regional Carbon Partnership (MRCSP) is part of DOE's regional carbon sequestration partnership program to evaluate CO_2 sequestration feasibility in the U.S.A. MRCSP researchers are conducting three small-scale injection demonstrations in Appalachian Basin, Michigan Basin, and Cincinnati Arch geologic provinces. The Cincinnati Arch test is being conducted at Duke Energy's East Bend Power Station, Boone County, Kentucky. The demonstration consists of site characterization, injection well construction, permitting and stakeholder outreach, injection of a few thousand tonnes of CO_2, monitoring, and site closure.

Bedrock at the surface of the East Bend site consists of Upper Ordovician carbonates. These are underlain by the Knox Supergroup (1,600–2,000 feet) including the Beekmantown, Rose Run Sandstone, and Copper Ridge Dolomite; Eau Claire Formation (500–550 feet); Mount Simon Sandstone (300–385 feet); and a thick sequence of Middle Run Precambrian sedimentary rocks. The Mount Simon is considered to have significant potential as a sequestration reservoir in the region, and is at depths of 3,400 to 3,700 feet at the well site. Analysis and interpretation of seismic data acquired in 2006 confirm the estimated depth and thickness and suggest that both the reservoir and confining interval are tabular with shallow northeast dip.

Pre-drilling site characterization has been completed. Construction of the test hole will include coring of injection zone and caprock layers, geophysical logging, and injection testing. The results of these tests and analyses will be used to design the CO_2 injection permit and monitoring program. Pre-test modeling suggests that the plume of injected CO_2 should not travel far beyond the well site (hundreds of feet).

Carbon Sequestration, CBM, and Coal-to-Liquids Conversion in Appalachia; Critical Need for Understanding Unmineable and Deep Coal Resources, Stephen F. Greb, Cortland F. Eble, and Gerald A. Weisenfluh, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506-0107, greb@uky.edu, eble@uky.edu, jerryw@uky.edu

As U.S. energy needs increase, Appalachian coal production is projected to increase. Yet much of the easy-to-exploit resources are gone or under development. More and more focus is being placed on deeper, below-drainage coals, some of which may be unmineable because of technological or economic restrictions. Deeper coal resources are being considered for coalbed methane potential; for geologic sequestration of carbon dioxide; and for coal-to-liquids conversion technology, which may be required to include a carbon sequestration component. Fundamental to each is an understanding of the deep and/or presently unmineable coals; the surrounding geology; proximity of favorable areas to existing and planned mines, CO_2 sources, water, and transportation corridors, as well as any environmental concerns.

Although deep saline reservoirs are currently being proposed for large-volume CO_2 sequestration, there are many areas in the Appalachians where coal beds are likely to be utilized because of their potential to generate enhanced coalbed methane, and favorable absorption mechanisms, which will allow for shallower injection depths than for many saline reservoirs. In some areas, it may be possible to use multiple beds as stacked reservoirs, whereas in others, there will be fewer options. There are large areas where little is known about the extent or thickness of deep coals, their permeabilities, water chemistry, cleating, and secondary cementation; all issues that will be important considerations for potential sequestration.

Production History and Reservoir Characteristics of the Antrim Shale Gas Play, Michigan Basin, William B. Harrison III, Michigan Geological Repository for Research and Education, Department of Geosciences, Western Michigan University, Kalamazoo, MI 49008, harrison@wmich.edu

The Upper Devonian Antrim Shale is a major gas producer in the Michigan Basin. Although there had been occasional Antrim producing wells since 1940, the recent development began in the late 1980's as a result of new technology, access to under-utilized Silurian Niagaran Reef play infrastructure, and a federal nonconventional fuels tax credit. To date, the Antrim Shale in Northern Michigan, has produced over 2.5 TCF of gas from over 8,800 wells. Production in 2006 was nearly 140 BCF. The Antrim Shale is a classic black shale that produces natural gas by desorption processes into a complex network of fractures. The distribution of high total organic carbon and natural fractures are keys to good productivity. Although thermally immature in the producing area, the large accumulation of natural gas has been generated mainly by biogenic processes.

Numerous cores in the collection of the Michigan Geological Repository for Research and Education (MGRRE) at Western Michigan University have been studied for facies distribution, organic content, and fracture characteristics. Cores show vertical and lateral facies variation through the basin and facies control on the distribution of natural fractures. Gas in place can be measured by geochemical rock analyses and suggest 0.5 to 1.0 BCF per 40 acres in the northern part of the basin. Variable production history of project areas can be explained by reservoir rock properties measurable from core, logs, and drill cuttings.

Facies and Rock Properties for Reservoir and Caprock Intervals in the Midwest Regional Carbon Sequestration Partnership (MRCSP) State-Charlton #4-30 Test Well, Otsego County, Michigan, William B. Harrison III, David A. Barnes, G. Michael Grammer, Michigan Geological Repository for Research and Education, Department of Geosciences, Western Michigan University, Kalamazoo, MI 49008, harrison@wmich.edu; and Phil Jagucki, Battelle Memorial Institute, 505 King Ave., Columbus, OH 43201

A CO_2 pilot injection test well, the State-Charlton #4-30, was drilled by Core Energy LLC in Otsego County, Mich., in conjunction with the Midwest Region Carbon Sequestration Partnership (MRCSP) as part of ongoing Phase II investigation to evaluate saline reservoir and caprock intervals in the Upper Silurian Bass Islands Group and Middle Devonian Amherstburg and Bois Blanc Formations. One hundred eighty feet of conventional core, eight sidewall cores, and a suite of modern wireline logs were collected through the zones of interest. Upper Bass Islands strata consists of nodular anhydrite overlain by 75 feet of shoaling upward, dolomitized, subtidal to peritidal strata present in meter-scale sedimentary cycles. Porosity and permeability averages 12.7 percent and 22.6 md in the Upper Bass Islands, although maximum measured core porosity and permeability is 37.3 percent and 684 md. Initial investigations suggested that the overlying Bois Blanc Formation was also a potential saline reservoir injection target, but core analysis revealed that bioturbated, cherty limestone to dolostone in the Bois Blanc are poor quality reservoirs with average porosity of 11.9 percent, but only a maximum of 0.01 md permeability. Highly fossiliferous, open marine, lime-wackestone to mud-rich lime-packstone of the Amherstburg Formation is the major caprock interval in the well. The Amherstburg has average porosity of 2.5 percent with all measured permeability below detection limits.

Geophysical Signature within the Northern Nile Delta, Egypt, Ahmad Muhammad Sobhy Helaly, Ain Shams University, Abbassia, Cairo, Egypt, 11566, Ahmad.Helaly@geologist.com

Nile River Delta, Egypt, is of great importance for hydrocarbon accumulation, as well as many near-surface targets of economic interest. Gravimetric data along a number of profiles within the area at the northern part of the Nile Delta were processed and interpreted to evaluate the regional structural setting, to delineate the sedimentary basins' distribution, and mapping the local structures, which are possible prospects, within these basins. That is through the separation of the regional anomalies which are related to great basement depth that can be correlated to sedimentary basins. A low-pass filter, represented by upward continuation, was applied to the available gravity data to delineate the regional anomalies. Filtering of high frequency anomalies related to shallow structures of interest were delineated using residual and specific high-pass filters, represented by the second vertical derivative technique. Depth to basement was calculated to determine the thickness of the sediments within each defined basin in the study area. The second vertical derivative results showed significant shallow anomaly sources, while the upward continuation revealed the deeper basins' distribution. Integration of processed profiles, maps, and geologic knowledge revealed the structural setting of the study area.

AAPG Invades Washington—What the Headlines Don't Tell You, Don Juckett, Director, AAPG Office of Geoscience and Energy

AAPG's Washington, DC office has been operational for about twenty months. The objective for establishing the office was to bring a greater presence for AAPG and the energy geosciences to the policy and legislative process in Washington including both domestic and international interests. In that time frame, AAPG is now recognized as a player in the science and policy arena. We will explore some of the activities of the office and highlight where we believe we have had an impact.

Critical to AAPG's presence is to develop an appreciation by Association members of the kinds of activities in which they can engage both locally and in Washington where their presence can make a difference. The art of bringing good science to bear on public policy and implementation of policy should be perceived by scientists as both a privilege and an obligation. Building, presenting and being comfortable with the message in non-science, political environments is not necessarily within most scientists "comfort zone". Science in and of itself is inarticulate - science, especially in the Washington sense needs a succinct and articulate translator. An appreciation of that need is important for it will not only improve the appreciation of oil and natural gas geoscience in policy circles, but it can and will impact on making good public policy.

The Mississippian Floyd Shale in the Black Warrior Foreland Basin, Alabama and Mississippi, Carrie A. Kidd and William A. Thomas, University of Kentucky, Department of Earth and Environmental Sciences, Lexington, KY 40506, carrie.kidd@uky.edu, geowat@uky.edu

The fill of the Black Warrior Basin is a middle Mississippian to Pennsylvanian southwest-thickening synorogenic clastic wedge, the lower tongue (Pride Mountain Formation, Hartselle Sandstone, and lower Floyd Shale) of which thins northeastward between the underlying Tuscumbia Limestone and overlying Bangor Limestone. The organic-rich Floyd Shale has recently gained attention by being comparable to the unconventional gas play in the Barnett Shale, Fort Worth Basin. Interpreting the sequence stratigraphy of the Lower Mississippian clastic wedge will be useful for describing the geometry and distribution of hydrocarbon reservoir sandstones in relation to the probable Floyd Shale source.

Sequence stratigraphy has recently been applied to foreland basins with some success, making it possible to interpret the balance between subsidence and sea level change, and to define a temporal framework for the filling of the foreland basin. Data from geophysical well log correlations and well cuttings support an interpretation of the sequence stratigraphy of the Pride Mountain Formation, Hartselle Sandstone, Floyd Shale, and Bangor Limestone. The Pride Mountain Formation and Hartselle Sandstone include stacked barrier-island and marine-bar facies that grade northeastward into carbonate-platform facies. The Pride Mountain and correlative lowermost Floyd Shale thin over the Lowndes-Pickens fault block in the southern part of the basin. The Bangor Limestone includes a southwest-sloping carbonate ramp, which is distinctly cyclic. The toe of the ramp passes into black shale, which represents a condensed section deposited in the deeper parts of the basin within the Floyd Shale. The Bangor ramp and Floyd black shale lap across the Lowndes-Pickens block with no thickness anomaly.

Geology and Public Policy—What? Why? How? Local, State, and Regional Efforts, John D. Kiefer, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506, kiefer@uky.edu

Geology and public policy is becoming one of those overused catch phrases. Perhaps the question should not be what and why, but why has it taken so long. The answer points right back to the geologists. Approximately 30 states now have geology registration laws on the books, meaning that, by statute, we are part of public policy. Geology, or the broader earth science, plays a fundamental role in many of our public policy decisions. Unfortunately, we have not done a good job of informing the public. We know how important geology is, but we continue to whine and "preach to the choir" that people should be using geology in making decisions in the public interest. We do little to explain to others just why it is important. To quote Thomas Jefferson, "Science (geology) is my passion, politics is my duty." Is it our duty also? We tend to hide behind worn-out excuses such as: I have no time; I'm a scientist, not a politician; most decisions are political anyway, not scientific; decisions are made behind the scenes, ignoring any outside input anyway. What is really meant by geology in public policy? How can you get involved? What are the consequences of not getting involved? Are we ever successful? How about locating energy resources, siting landfills, dealing with groundwater contamination, ensuring adequate water supplies, mitigating flooding, landslide, and earthquake damage, finding sources of sand, gravel, and limestone aggregate? Make no mistake about it, geology is critical to our survival on this planet, and making that known is critical to the survival of our profession.

Testing the Efficacy of CO_2 for Enhanced Oil Recovery in the Illinois Basin: Preliminary Results, Rex Knepp, James R. Damico, Scott M. Frailey, John P. Grube, and Beverly Seyler, Illinois State Geological Survey, 615 E. Peabody Dr., Champaign, IL 61820, knepp@isgs.uiuc.edu

Previous analyses of historical production in the Illinois Basin by the Midwest Geological Sequestration Consortium suggest that using CO_2 for EOR would yield incremental oil of 0.86 to 1.3 billion barrels, while sequestering a portion of injected gases from the atmosphere. To further evaluate CO_2's EOR potential in the basin's numerous mature producing fields, the consortium will conduct four tests under a variety of conditions. The first of these, a huff and puff, has recently been completed, while a second is scheduled for summer 2007.

The huff and puff test well, in Louden Field (Fayette County, Illinois), produces from the Mississippian Cypress Sandstone at 1,516 feet. After geological modeling, reservoir characterization, and simulation of production under immiscible conditions, an injection program was designed and implemented in spring 2007. Results of this well stimulation technique and comparison of pre- and post-injection reservoir models will be presented, as will details of environmental monitoring carried out during and after the test injection and subsequent production.

A second scheduled EOR test entails conversion of an existing water injector to CO_2 injection, with hydrocarbon production from adjacent wells in a classic five-spot pattern. This test will also be carried out on a reservoir under immiscible pressure and temperature conditions. Geological and geostatistical modeling and reservoir simulation will be used to make final site selection and then design the CO_2 injection program. Two future tests will evaluate EOR from other prolific producing formations under miscible conditions.

Recent Appalachian Basin Mergers and Acquisitions—2007, Tim Knobloch and Benjamin Thomas, James Engineering Inc., Marietta, OH 45750, tknobloch@jamesenginc.com, thomasb@marietta.edu

A presentation has been prepared of recent Appalachian Basin acquisitions to provide operators better insight into the historic basis for asset sales. The materials presented are drawn from public data sources, press releases, and Securities and Exchange Commission reports.

The presentation includes a discussion on "price drivers"—factors that influence a purchase or sale price—and "pricing yardsticks"—common methods for determining an asset's worth including quick look "rule of thumb" methods and reserve based methods. The presentation compares the historic impact of the prime interest rate and natural gas prices on oil and gas asset acquisition values. Historic average Appalachian Basin asset values are presented for the years 2000–2006 in dollars per mcfe of proved reserves and in dollars per mmcfdeq.

Details of acquisitions are presented including the asset size (dollars), annual cash flow, daily production, net proved reserves, geographic location, well count, miles of pipeline, and acreage.

Acquisition details are presented for Delta Petroleum selling their Appalachian Basin and East Texas properties, EXCO acquiring Power Gas Marketing, and EXCO acquiring some West Virginia properties. Historical acquisitions summaries are also provided for Linn Energy and Chesapeake. Finally, some recent press releases regarding the Appalachian Basin are also reviewed.

Characterization of Environmentally Sensitive Trace Elements in Coals and Fly Ashes from Bulgarian Power Plants, Irena J. Kostova, Sofia University "St. Kliment Ohridski," Department of Geology and Paleontology, 1000, Sofia, Bulgaria, irenko@gea.uni-sofia.bg; and James C. Hower, University of Kentucky, Center for Applied Energy Research, Lexington, KY 40511, hower@caer.uky.edu

The distribution of main and 17 trace elements (Ba, Mo, Rb, Sr, Co, Cr, Mn, Ni, V, As, Cd, Cu, Hg, Pb, Sb, Se, and Zn) considered as toxic and potentially hazardous air pollutants in the feed coals and fly ashes from four of the biggest power plants in Bulgaria (Maritza East 2, Maritza East 3, Republika, and Bobov Dol) were investigated. The feed coals are lignite and subbituminous, with high ash and high to moderate sulphur content.

Major oxides and trace elements, with the exception of Hg, were analyzed using X-ray fluorescence (XRF). Mercury analysis, on a whole coal or whole ash basis, was performed on a LECO AMS254 Advanced Mercury Analyzer.

Overall, the examined coals can be characterized as having high trace element contents. Some of them, such as Mo (up to 143 ppm), Cu (up to 207 ppm), and Pb (up to 48 ppm), display extremely high contents.

The mean values of trace element concentrations display relative enrichments in Co, Zn, V, Cr, Mn, Ni, Sr, Ba, and As in the investigated samples in comparison with other coals in the world. Cd, Se, Hg, and Rb are present in low to moderate concentrations in the feed coals.

The fly ashes from all investigated power plants have high molybdenum content (up to 178 ppm). Higher values than the world ashes were obtained for Cu, V, Zn, Se, Cr, Co, and Ni for all the investigated power plants, and for Mn and As for some of them.

Mercury in the Coals and Fly Ashes from Bulgarian Power Plants, James C. Hower, University of Kentucky, Center for Applied Energy Research, Lexington, KY 40511, hower@caer.uky.edu; Irena J. Kostova, Sofia University "St. Kliment Ohridski," Department of Geology and Paleontology, 1000, Sofia, Bulgaria, irenko@gea.uni-sofia.bg; Maria N. Marks, University of Kentucky, Center for Applied Energy Research, Lexington, KY 40511 and Engineering Consulting Services Inc., Lexington, KY; and Daniel J. Hedges, Engineering Consulting Services Inc., Lexington, KY

The concentration, distribution, mode of occurrence, and origin of mercury in feed coals and fly ashes from four of the biggest power plants in Bulgaria (Maritza East 2, Maritza East 3, Republika, and Bobov Dol) were investigated. This study is based on four average raw feed coal and eight fly ash samples, collected from bunkers and three rows of electrostatic precipitations from power plants. The feed coals are lignite and subbituminous, with high ash and high to moderate sulphur content.

Mercury analysis, on a whole coal or whole ash basis, was performed on a LECO AMS254 Advanced Mercury Analyzer.

The mercury content of the coals, reported in parts per million (ppm) in the ash, varies from 0.24 to 0.14. These values of mercury concentrations are below average in comparison with other coals in the world.

The amount of mercury in fly ashes exceeds 0.04 ppm. The highest concentration of 0.12 ppm was received for Republika fly ash.

In contrast with frequently observed positive correlation between Hg content and fly ash carbon content, the finest fly ash fractions had greater concentrations of Hg (0.24 ppm for Republika and 0.05 ppm for Bobov Dol) than the higher-carbon coarser fractions in the ashes from Republika (0.02 ppm) and Bobov Dol (0.04 ppm) power plants. In these cases, Hg capture by fly ash is dependent upon flue gas temperature and increases with a decrease in flue gas temperature.

Geology of the Kyrock and Nolin River Gorge Region, Edmonson County, Kentucky, Kenneth W. Kuehn and Michael T. May, Western Kentucky University, Department of Geography and Geology, Bowling Green, KY 42101, kenneth.kuehn@wku.edu

The Commonwealth of Kentucky contains a number of significant geologic sites, and the area surrounding the old asphalt rock mining community of Kyrock is no exception. This region, located near the western edge of Mammoth Cave National Park on the Dripping Springs Escarpment, affords excellent exposures of Mississippian (Chesterian) and basal Pennsylvanian (Morrowan) strata in the context of asphalt impregnated siliciclastics and both paleo and modern karst features. The best exposures are along the Nolin River at the Nolin Reservoir Dam where up to 60 meters of relief along the Mississippian-Pennsylvanian sequence boundary or unconformable surface can be noted. Geologic investigations have been numerous in the area over the past century and a half, and tar sands have been well known since the 19th century. There is a renewed interest in the 21st century for exploring for heavy oil resources and a concomitant interest in preserving karst resources and biota near the national park. This area is a distinguished geologic site because of the rich heritage associated with bitumen-rich strata and exploitation of these, and it is one of the few places were such great relief is traceable along a globally significant sequence boundary in the United States. It is a location where students of sequence stratigraphy can truly appreciate the sedimentologic complexity associated with tectonic, geomorphic, and climatic influences on the development of a sequence stratigraphic surface and its subsequent incised valley fill depositional sequence.

Late Middle Devonian Tectonic Activation of the Appalachian Basin, Western New York and Northwestern Pennsylvania, Gary G. Lash, Department of Geosciences, State University of New York–College at Fredonia, Fredonia, NY 14063, lash@fredonia.edu

The Middle and Upper Devonian succession of the Appalachian Basin of western New York (WNY) and northwestern Pennsylvania (NWPA) provides a record of repeated eustatic events. However, analysis of more than 500 wireline logs from this region of the basin reveals a strong but localized tectonic imprint that occurred over ~ 2 MY in the early half of the Givetian. This activity, initiated prior to deposition of the Tully limestone, resulted in as much as 40 m of the Moscow shale in the northeastern Chautauqua County–Cattaraugus County region of WNY. This was followed quickly by accumulation of a shaly limestone over the eroded Moscow shale. Soon after this, a second uplift event removed much of the limestone and perhaps more of the underlying Moscow shale. The Tully limestone was deposited over the eroded shaly limestone and Moscow shale and locally on the underlying Tichenor limestone. The final phase of uplift resulted in erosion of the Tully limestone over much the same region of the basin that the Moscow shale was most deeply eroded. The Tully limestone and its equivalent unconformity is sharply overlain by deposits of the Genesee Group, notably the Geneseo black shale, which mark the onset of Tectophase III and related collapse of the basin. However, results of this study suggest that the WNY-NWPA area of the Acadian foreland basin experienced the effects of thrust load-induced dynamics (i.e., development of a flexural welt) before widespread maximum subsidence of the basin.

Crosscutting versus Abutting Joints: A Reflection of Overburden-Induced Joint-Normal Stress in Devonian Black Shale, Western New York, Gary G. Lash, Department of Geosciences, State University of New York–College at Fredonia, Fredonia, NY 14063, lash@fredonia.edu; and Terry Engelder, Department of Geosciences, The Pennsylvania State University, University Park, PA 16802

The pervasive nature of joints in Middle and Upper Devonian black shale deposits exposed along the Lake Erie shoreline, western New York, has compelled some to suggest that jointing occurred principally as a consequence of glacial unloading. Studied black shale units of this area of the Catskill Delta host east–northeast-trending joints that either crosscut or abut cross-fold (CF) joints. These sets crosscut exclusively in the more proximal (Finger Lakes) region of the delta where slip on CF joints offsets east–northeast joints, indicating that the latter are older. However, in equivalent black shale in the shallower, distal delta (Lake Erie region), ~25 percent of the joint intersections are crosscutting whereas ~75 percent of the interactions are of east–northeast joints abutting CF joints. East–northeast joints in these deposits propagated first but were not as long or pervasive as in the deeper, proximal delta. Yet ~130 m deeper into the distal section, east–northeast joints are much better developed; all intersections are again crosscutting. CF joints propagated across east–northeast joints when both proximal and distal deposits had been buried deep enough (i.e., ≥ 3 km) such that a high joint-normal stress closed all east–northeast joints. Post-Middle Tertiary exhumation (i.e., burial depth ≤ 1 km) of the Catskill Delta caused reactivation of east–northeast joints by opening in the contemporary tectonic stress field. The reduction of joint-normal stress on CF joints in the distal black shale resulted in the reactivation of east–northeast joints into abutting intersections. In sum, post-glacial exhumation appears to have resulted only in reactivation of favorably oriented joints.

Petrologic and Petrophysical Evaluation of the Lockport Dolomite (Middle Silurian) for Geological Sequestration of CO_2 in the Central Appalachian Basin, Christopher D. Laughrey, Jaime Kostelnik, Kristin M. Carter, and John A. Harper, Pennsylvania Geological Survey, Pittsburgh, PA 15221, claughrey@state.pa.us

The Middle Silurian Lockport Dolomite is a potential target for geological sequestration of carbon dioxide (CO_2) in the Central Appalachian Basin. Lockport sediments were deposited as shallowing upwards facies on a broad carbonate platform across this region. Porous, permeable intervals mostly occur within thicker (> 4.5m) biohermal and biostromal lithofacies. Carbonate textures and fabrics indicate episodes of marine and freshwater phreatic diagenesis, syngenetic replacement of micrite by finely crystalline dolomite, evaporite mineralization, burial dolomitization, and late diagenetic formation of iron sulfides, galena, fluorite, saddle dolomite, calcite, quartz, bitumen, and hydrogen sulfide during thermochemical sulfate reduction. Anhydrite cement might increase CO_2 fugacity.

Vuggy, moldic, and intercrystalline voids dominate the Lockport reservoirs, yielding a dual porosity-permeability distribution. Dense crystalline dolostones have an average porosity of 3.4 percent and average horizontal and vertical permeabilities of <0.10 md and 0.88 md, respectively. Intervals with vuggy and moldic pores have an average porosity of 9.6 percent and respective horizontal and vertical permeabilities of 50.0 md and <0.10 md. Irreducible saturations in the vuggy and moldic intervals average 7 to 9 percent at water pressures of 97 to 284 psi. Resistivities for Lockport brines range from 0.032 to 0.045 ohm-m, with a mean R_w = 0.04 ohm-m. S_w calculated using the Archie formula is unreliable due to variability in the cementation exponent. Combined use of S_w as measured by the movable hydrocarbon index, the ratio method, and the Archie equation, in conjunction with estimates of bulk volume water, provide accurate calculations of fluid saturations in these rocks.

Petrology and Petrophysics of Middle Devonian/Middle Silurian Potential CO_2 Sequestration Reservoirs in the Central Appalachian Basin, Christopher D. Laughrey, Jaime Kostelnik, Kristin M. Carter, and John A. Harper, Pennsylvania Geological Survey, Pittsburgh, PA 15222, claughrey@state.pa.us

We are evaluating four subsurface stratigraphic units in the Central Appalachian Basin for potential geologic sequestration of carbon dioxide (CO_2). These include the Lower Devonian Oriskany Sandstone, Upper Silurian Bass Islands Dolomite, Middle Silurian Lockport Dolomite, and Middle Silurian Keefer Sandstone.

The Oriskany Sandstone interval consists of quartzarenite, calcareous sandstone, and arenaceous biosparite. Pore-filling cements include quartz, calcite, dolomite, glauconite, chalcedony, pyrite, and illite. Intergranular, moldic, and fracture porosity provide the fluid storage capacity of the rocks. Porosity ranges from less than 2 to 20 percent, and permeability ranges from less than 0.1 to 30 millidarcy (md).

The Bass Islands Dolomite consists of fine to medium crystalline planar-p dolostone and dolomitic packed biopelmicrite. Lithodensity logs indicate the rocks are often siliceous. Thin section analysis reveals that chert and quartz replace planar dolomite. Petrography and log analysis indicate moldic, vuggy, and fracture porosity in this unit. Porosity ranges from 1 to 6 percent and permeability is typically less than 0.1 md.

The Lockport Dolomite originated as shallowing upwards facies on a broad carbonate platform across the Central Appalachian Basin. The rock fabrics in the Lockport are the product of marine and freshwater diagenesis and hydrothermal burial dolomitization. Vuggy, moldic, and intercrystalline voids create a dual porosity-permeability distribution. Potential CO_2 sequestration reservoirs are limited to vuggy and moldic intervals in biohermal and biostromal lithofacies with an average porosity of almost 10 percent and mean horizontal permeability of 50 md.

The Keefer Sandstone consists of very fine- to coarse-grained sublitharenite and quartzarenite deposited in littoral to shallow marine environments. These sandstones are cemented by quartz, anhydrite, gypsum, calcite, and dolomite. Porosity ranges from 1 to 20 percent, but averages only 5 percent. Void types include primary and secondary intergranular porosity and open fractures.

Using a Petroleum System Approach for Evaluation of CO_2 Sequestration Potential in Saline Reservoirs, H.E. Leetaru, D.G. Morse, S.M. Frailey, Midwest Geological Carbon Sequestration Consortium, Illinois State Geological Survey, 615 E. Peabody Dr, Champaign, IL 61820-6964, leetaru@isgs.uiuc.edu, morse@isgs.uiuc.edu, frailey@isgs.uiuc.edu; and J. McBride, Department of Geological Sciences, Brigham Young University, P.O. Box 24606, Provo, UT 84602, john_mcbride@byu.edu

Evaluation of the CO_2 sequestration potential of a saline reservoir would benefit from methodologies developed to analyze a petroleum system. Petroleum system analysis emphasizes the importance of the: 1) seal, 2) trapping mechanism, 3) overburden, 4) reservoir rock, 5) source, 6) preservation, and 7) critical moment. This type of systematic approach is readily modified for analysis of the sequestration potential of a formation or region. The key differences in analytical methodologies are that: the source would refer to the surface potential of the site, preservation is the length of time CO_2 would be sequestered, and critical moment is the time sequestration starts.

The Cambrian Mount Simon sandstone of the Illinois Basin is used to illustrate how this approach could be used to define the sequestration fairway. For example, Mount Simon reservoir suitability is constrained by amount of overburden, depositional system, and the Precambrian topography. Sequestration traps may not necessarily be defined by structural or stratigraphic traps, but instead may also be found in areas of low structural dip and high reservoir preservation potential. The preservation potential of the reservoir is controlled by water salinity, reservoir heterogeneity, and lithology. The critical moment or first injection of CO_2 may become important when multiple injection sites in a basin become operational. Finally, the surface conditions, such as urban areas and water bodies may limit the location of CO_2 sources. These examples from the Mount Simon demonstrate an orderly approach to examining all pertinent data that should be considered when evaluating an individual site or a formation for its sequestration potential.

Use of Digital Log Analysis to Evaluate the Helderberg Group as a Confining Layer for CO_2 Sequestration, J. Eric Lewis, Ronald R. McDowell, and Katharine L. Avary, West Virginia Geological and Economic Survey, Morgantown, WV 26508-8079, elewis@geosrv.wvnet.edu, mcdowell@geosrv.wvnet.edu, avary@geosrv.wvnet.edu; and Kristin M. Carter, Pennsylvania Geological Survey, Pittsburgh, PA 15222-4745, krcarter@state.pa.us

The Midwest Regional Carbon Sequestration Partnership (MRCSP) has evaluated several categories of geologic reservoirs for potential carbon dioxide (CO_2) sequestration, but the reservoir type that has been determined to offer the greatest storage potential is deep, saline formations. One of the most promising formations evaluated by the partnership to date is the Devonian Oriskany Sandstone. As a sequestration target, this reservoir is generally confined by overlying and underlying limestones, chert, and shales, including those of the Siluro-Devonian Helderberg Group. Heretofore, the MRCSP had not performed detailed stratigraphic or reservoir evaluations of the Helderberg in the study area. However, a number of through-going faults intersect both the Oriskany and Helderberg throughout the Appalachian Basin, and suggest that the Helderberg Group may offer only limited potential as a confining interval, depending upon location and degree of faulting. A number of digital log analysis techniques, including electrofacies analysis, can be employed to evaluate the stratigraphy and reservoir characteristics (e.g., porosity, permeability, water saturation) of the Helderberg Group, identify heterogeneities in this sequence, and confirm the extent of fault offset.

Experimental Determination of Reaction Rates and Modeling of the Long-Term Fate of CO_2 in Deep Geological Formations, Peng Lu, Department of Geological Sciences, Indiana University, Bloomington, IN 47405, pelu@indiana.edu; Qi Fu, William E. Seyfried Jr., Department of Geology and Geophysics, University of Minnesota; Brian R. Strazisar, Sheila W. Hedges, National Energy Technology Laboratory, U.S. Department of Energy; Zuoping Zheng, and Chen Zhu, De-

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The injection of CO_2 into deep saline aquifers is a potential option for greenhouse gas mitigation. However, several key issues, such as underground storage time and the fate of the injected CO_2, must be studied before this option becomes economically and socially acceptable. In order to test the feasibility of CO_2 injection, we conducted feldspar dissolution experiments in CO_2 impregnated brines. Feldspars' dissolution rates were calculated based on temporal change in solution chemistry. Analysis of mineral reactants (SEM, TEM, and XPS) following the experiments confirmed the existence of abundant secondary mineralization associated with feldspar surfaces. The reaction path and secondary minerals precipitation kinetics were determined by reaction-path modeling. The slow kinetics of secondary minerals exert a strong control of feldspar dissolution. The experimental work was supplemented with one-dimensional reactive mass-transport modeling. The dissolution of the injected CO_2 into brine causes a sharp drop in pH, and consequently, the acidic brine aggressively reacts with aquifer minerals. Our model also predicts the dissolution of aluminosilicate minerals with the formation of secondary minerals and the precipitation and dissolution of carbonate minerals and is consistent with laboratory-scale CO_2 core-flooding experiments in the literature. The transport of carbon can be significantly retarded with respect to the flow of the brine itself, and a significant amount of injected CO_2 is immobilized because of mineral trapping. The carbon reactive transport is sensitive to the reaction rates used, illustrating the need for improved knowledge of reaction kinetics.

Evaluation of Coalbed Methane Potential and Gas Adsorption Capacity in the Western Kentucky Coalfield, Sarah M. Mardon, Department of Earth and Environmental Sciences, University of Kentucky, Lexington, KY 40506-0053, smmard0@uky.edu; Kathryn G. Takacs, Cortland F. Eble, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506-0107, ktakacs@uky.edu, eble@uky.edu; James C. Hower, Center for Applied Energy Research, University of Kentucky, 2540 Research Park Dr., Lexington, KY 40511-8433, hower@caer.uky.edu; and Maria Mastalerz, Indiana Geological Survey, Indiana University, 611 North Walnut Grove, Bloomington, IN 47405-2208, mmastale@indiana.edu

The Illinois Basin has not been developed for coalbed methane (CBM) production. It is imperative to determine both gas content and other parameters for the Kentucky portion of the Illinois Basin for exploration and production to occur in this area.

This research is part of a larger project conducted by the Kentucky Geological Survey to evaluate the CBM production of Pennsylvanian-age western Kentucky coals in Ohio, Webster, Hopkins, and Union Counties using methane adsorption isotherms, direct gas desorption measurements, and chemical analyses of coal and gas. This research investigates relationships between CBM potential and petrographic, surface area, pore size, and high pressure gas adsorption isotherm analyses of the coals. Maceral and reflectance analyses are conducted at the Center for Applied Energy Research. Surface area and pore size of the coals are analyzed using a Micrometrics ASAP 2020, and the CO_2 high pressure isotherm analyses are conducted using a volumetric adsorption apparatus in a water temperature bath.

The aforementioned analyses are used to determine site-specific correlations for the Kentucky part of the Illinois Basin. The data collected is compared with previous work in the Illinois Basin and correlated with data and structural features in the basin. Gas composition and carbon and hydrogen isotopic data suggest mostly thermogenic origin of coalbed gas in coals from Webster, Hopkins, and Union Counties, Kentucky, in contrast to the dominantly biogenic character of coalbed gas in Ohio County, Kentucky.

Climate Change and Carbon Sequestration Programs in New York, John P. Martin and Amanda Stevens, New York State Energy Research and Development Authority, Albany, NY, jpm@nyserda.org

The New York State Energy Research and Development Authority (NYSERDA) is providing technical support for a number of initiatives that represent the foundation for New York's climate change policy. Foremost to this effort is the Regional Greenhouse Gas Initiative (RGGI). Nine northeastern and Mid-Atlantic states, including New York, comprise RGGI, with the goal of reducing greenhouse gas emissions in the region. Key to this discussion is the possible development of a cap and trade program. A number of models have been developed to provide input into this effort. Under the RGGI framework, carbon sequestration will be an important element. Through NYSERDA and the New York State Museum, New York has recently become a member state of NETL's Midwest Regional Carbon Sequestration Partnership. With the MRCSP, NYSERDA and the museum are characterizing New York's geology with respect to sequestration potential. NYSERDA is also pursuing novel technological solutions such as mineralization, ocean sediment CO_2 storage, using algae to capture CO_2, and oxyfuel combustion separation technology. Though the New York Advanced Clean Coal Powerplant Initiative, NYSERDA will be involved in a large-scale CO_2 capture and sequestration project.

Sequence Stratigraphy of the Pottsville Formation in Southern Ohio, Ronald L. Martino, Andrew McCormick, and Charles Sorden, Marshall University, 1 John Marshall Dr., Huntington, WV 25755-2550, martinor@marshall.edu

A sequence stratigraphic framework has been developed for the Lower–Middle Pennsylvanian Pottsville Formation in southern Ohio. Core data from more than a dozen wells, and over 200 geophysical logs have been used along with outcrop data from southern Ohio and eastern Kentucky. The Pottsville Formation extends from the base of the Sharon Sandstone to the base of the No. 4 coal and varies in thickness from 91 to greater than 137 m (300 to > 450 feet). Greater thicknesses occur where infilling of paleovalleys occurred along the regional Mississippian-Pennsylvanian unconformity. Six incised-valley fills (IVF's) ranging from 18–30 m (60–100 feet) thick have been identified. The fluvio-estuarine IVF's truncate and are laterally equivalent to packages of coarsening upward shale-to-sandstone parasequences which are usually capped by paleosols and coals. These CU-units average about 9–12 m (30–40 feet thick) and contain *Lingula* and shallow to marginal marine trace fossils. High frequency base level changes were likely due to eustatic sea level changes, which combined with longer term tectonically induced transgressions from thrust loading to control facies architecture.

Although shows of hydrocarbons are frequently reported in Pottsville strata, only limited production has occurred to date in Lawrence and Gallia Counties. Wireline logs indicate that reservoir quality sands are common. A more comprehensive understanding of the stratigraphic framework and depositional systems may facilitate future discoveries of bypassed Pottsville hydrocarbons bound in stratigraphic or combination traps.

CBM Gas Composition Trends—Central and Northern Appalachian Basin, Michael G. McClure and Matthew W. Frost, Marshall Miller & Associates, 534 Industrial Park Rd., P.O. Box 848, Bluefield, VA 24605, mike.mcclure@mma1.com, matt.frost@mmal.com

As analysis of coalbed gas (CBM) content within the Carboniferous coal-bearing strata of the Central and Northern Appalachian Basin has progressed during the past decade, gas composition data (fractional analyses and a few carbon isotopes) have likewise become available. Utilizing public and proprietary sources, data from approximately 30 coal beds within five states (Virginia, West Virginia, Ohio, Pennsylvania, and Maryland) and 25 counties provide a glimpse into some regionally observable patterns. Seams analyzed extend from the stratigraphically deepest Pocahontas No. 3 seam (Pocahontas Formation) to the upppermost Jollytown seam (Dunkard Group). Gas components of interest within this investigation include: methane, ethane, carbon dioxide, and nitrogen. Preliminary assessment of the data suggests: (1) apparent relationships to both thermal maturity (coal rank) and depth, and (2) a thermogenic origin for CBM within the coal beds analyzed.

A New Application of Low Altitude Airborne Multispectral Mapping of Rock Microfractures and Joint Systems to Maximize Conventional and Unconventional Hydrocarbon Production and Related Sequestration Injection of Carbon Dioxide, Bruce R. Moore, University of Kentucky, Department of Earth and Environmental Sciences, Professor Emeritus, Lexington, KY 40506, and Geoflite Technology Inc., Technical Director, Lexington, KY 40511

This method generates low altitude airborne multispectral data to detect and map microfractures and joint systems, and has been developed and tested over the past 20 years as the Geoflite System. The method maps joints and fractures through soil cover and vegetation, by imaging and measuring geochemical leakage in the soil directly above the joint systems.

These microfracture systems have been shown to control the production of methane gas from black shales and coal seams, and drilling the fracture intersections is the key to rapid dewatering of the rocks to achieve maximum production. Furthermore, the trace element leakage geochemistry at these intersections has been shown to be indicative of the potential hydrocarbon production. This same data also indicates the best locations on the fracture sets for the injection of fluids and gases, to achieve maximum carbon sequestration from carbon dioxide, and the most efficient related enhanced hydrocarbon recovery anticipated from these formations.

Geology and Development of Devonian Shale in Eastern Kentucky, Joe Morris and Jim Pancake, Equitable Production Company, 225 North Shore Dr., Pittsburgh, PA 5212-5861, LJMorris@eqt.com

The Devonian shale of the Big Sandy Field in eastern Kentucky has been a major gas producer in eastern Kentucky for many years. This paper examines the Devonian shale of the Big Sandy Gas Field of eastern Kentucky, and the favorable geological setting, both with regard to reservoir and structural position, that results in the presence of this gas play. Completion methods and strategy employed by Equitable Resources are discussed, along with the potential for new techniques such as horizontal drilling.

Predicting Cumulative Production of Devonian Shale Gas Wells from Early Well Performance Data, Appalachian Basin of Eastern Kentucky, Brandon C. Nuttall, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506-0107, bnuttall@uky.edu

Middle and Late Devonian strata of the Appalachian Basin in the eastern United States are dominated by black and gray shales. These low-permeability, organic-rich units are both hydrocarbon source beds and reservoirs. These shales are not ubiquitously productive, and there are areas with more prolific gas production and "better" wells. Two sets of gas production volumes by well are available: yearly data (GTI, proprietary) and monthly data (Kentucky Division of Oil and Gas, public). These production data, initial open flows, and reported rock pressures are being analyzed to classify shale wells and investigate their performance. The spatial relation of production to geologic controls will also be investigated.

Devonian shale gas initial open flow and cumulative production data are log normally distributed. Data indicate that over 10 years, 50 percent of shale wells produce at least 100 MMcf. Cumulative shale gas production data for 1, 5, 10, 25, and 50 years suggest classification into four groups at the 25th, 50th, and 75th percentile breaks. For the first year, these breaks are at 5.35, 10.04, and 18.83 MMcf. Both 5-year and 10-year cumulative production demonstrate statistically significant relations with first-year cumulative production. The initial open flow exhibits a weak, but statistically significant, relation to 5- and 10-year cumulative production. No relationship is observed between initial open flow and rock pressure. Most shale wells exhibit hyperbolic decline. A Python script has been developed to investigate the best-fit hyperbolic decline parameters; the objective is to develop a type decline curve.

Update on Regional Assessment of Gas Potential in the Devonian Marcellus and Ordovician Utica Shales of New York, Richard Nyahay, James Leone, Langhorne B. Smith, Reservoir Characterization Group, New York State Museum, Albany, NY; J.P. Martin, New York State Energy Research and Development Authority, Albany, NY; and D.J. Jarvie, D.J., Humble Geochemical Services, Humble, TX

There are at least two potential gas shale plays in New York in the Devonian Marcellus and the Ordovician Utica. A program was initiated to try to characterize both organic rich shales geochemically in New York. To date we have sampled 15 outcrops, 70 wells with well cuttings, and five cores from over 15 counties for our geochemical database. New isopach and structure contour maps have been constructed along with TOC, transformation ratio, and hydrogen index maps. These maps will help define fairways to explore.

Preliminary results show that the Utica has TOC values between 1.5 to 3 percent. The Devonian Marcellus Shale has TOC values between 0.3 and 11 percent. The Utica is a Type III to Type IV kerogen, while the Marcellus is a Type II to Type III kerogen. Fractures are being characterized in outcrop to see what orientations exist to determine the stress field at the time of deposition. XRD data is being run on some samples to determine mineralogy. Samples will also be examined with an SEM to determine if there is any microporosity. All work will be summarized in a final report that will include a database, cross sections, and defined fairways.

The Marcellus may be more favorable to newer completion techniques because of the high-silica Stony Hollow member that overlies the more organic rich Union Springs member. The Utica might have zones of higher porosity at a reasonable depth to create pore pressure in the quartz rich units of the Indian Castle and Dolgeville.

Fluid and Gas Geochemistry of Organic-Rich Shales in the Appalachian Basin, Stephen Osborn and Jennifer McIntosh, Department of Hydrology and Water Resources, University of Arizona, Tucson, AZ 85721, sosborn@hwr.arizona.edu, mcintosh@hwr.arizona.edu

Accumulations of microbial methane in shallow coal beds and organic-rich shales account for a significant portion of the U.S. annual natural gas production. Research conducted on Upper Devonian organic-rich shales in the Michigan and Illinois Basins has shown that secondary microbial gas generation was enhanced by Pleistocene glaciation. Loading and unloading of kilometer thick ice sheets extended the natural shale fracture network and depressed the salinity of basinal brines by recharge of dilute glacial meltwater. Recharge occurred at the basin margins through the underlying carbonate regional aquifer system. The lack of published geochemical data from organic-rich shales in the Appalachian Basin has precluded comparative studies with adjacent basins aimed at understanding the lateral and vertical distribution of microbial methane. The northern margin of the Appalachian Basin has a similar glacial history to the Michigan and Illinois Basins. Differences in the thermal maturity, tectonic setting, and stratigraphy of the organic-rich formations in the three basins may elucidate the environmental controls on microbial methane generation.

Gas and formation waters were collected from active Upper Devonian oil and gas wells throughout the northern Appalachian Basin during the spring of 2007. Major, minor, and trace elemental analyses, alkalinity, stable isotopes (O, H, and C), and 14CDIC, were performed on formation waters. Gas composition and compound specific isotopes of CH_4, CO_2, and C^2 were also measured. Preliminary results will be used to investigate the fluid migration history at the basin margin, as well as the origin and distribution of natural gas accumulations.

Optimization of Hydraulic Fracturing Performance in the Fractured Utica Shale of Northeastern United States, J. Paktinat, Joe Pinkhouse, Jeff Little, Universal Well Services, Meadville, PA 16335 javad.paktinat@univwell.com; Gary G. Lash, SUNY-Fredonia, Department of Geosciences, Fredonia, NY 15767; and Michael A. Forgione, Great Lakes Energy Partners LLC, Carlton, PA 16311

The primary purpose of stimulating fractured shale reservoirs is the extension of the drainage radius via creation of a long fracture sand pack that connects with natural fractures, thereby establishing a flow channel network to the wellbore. However, there is limited understanding of a successful method capable of stimulating Utica shale reservoirs. Indeed, most attempts to date have yielded undesirable results. This could be due to several factors, including formation composition (40 percent dilemmatic), entry pressure, and premature pad fluid leak-off. Furthermore, stimulation of Utica shale reservoirs with acid alone has not been successful due to the plugging of pore throats by post acid fines and sludge. This treatment method leads to a fracture length and drainage radius less than expected, resulting in poor well productivity.

This study describes new methods of stimulating Utica shale utilizing an in situ acid treatment to dissolve dolomite while reducing entry pressures, followed by gelled acid, and finally with crosslinked fracturing treatment. Application of multi-phase surfactant to reduce emulsion tendencies and improve leak-off is also addressed. These treatments were tested by use of parallel Utica shale plates and 6-foot-long Utica shale packed columns. Leak-off efficiencies and adsorption properties of surfactant treatments were investigated by the injecting of treatment fluids into the Utica shale packed column.

The results of this study demonstrate exceptional stimulation penetration, leak-off efficiencies, well cleanup improvements that can be used to optimize fracturing treatments of fractured Utica shale reservoirs in the Appalachian Basin.

Characterizing Soil Gas Chemistry in Advance of Carbon Sequestration and Enhanced Oil Recovery in Eastern Kentucky, T. M. (Marty) Parris, Michael P. Solis, Kathryn G. Takacs, Brandon C. Nuttall, and James A. Drahovzal, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506-0107, mparris@uky.edu, msolis@uky.edu, ktakacs@uky.edu, bnuttall@uky.edu, drahovzal@uky.edu

Soil gas flux and shallow soil gas chemistry (< 1 m) was measured under winter and summer conditions at two active oil and gas fields and relatively undisturbed forests in eastern Kentucky. The measurements apportion the biologic, atmospheric, and geologic influences on soil gas composition under varying degrees of human surface disturbance. They also constitute a heretofore absent geochemical baseline critical for recognizing reservoir leakage (i.e., microseepage) that might result from CO_2 injection in carbon sequestration and enhanced oil recovery projects in and near the study sites.

Soil gas fluxes were measured using closed-chamber methods. Positive fluxes of CO_2 were measured at all locations, and summer flux magnitudes were three to four times greater than winter fluxes. Soil gas CO_2 concentrations one to two orders of magnitude greater than atmospheric CO_2 provided the driving force for positive flux. Summer and winter δ13C composition of soil gas CO_2 was depleted in 13C, which suggests a dominant biologic influence on soil gas CO_2 relative to atmospheric and geologic sources. Soil gas CH_4 concentrations, in contrast, were slightly less than atmospheric CH_4, and the difference suggests a low magnitude negative flux for CH_4.

Microseepage anomalies were defined by positive CH_4 fluxes, soil gas CH_4 concentrations exceeding atmospheric CH_4, or positive shifts in the δ13C CO_2 values. Microseepage was detected along two normal faults that are part of the Rome Trough fault system. A notable false microseepage anomaly was detected at a location where the surface cover consisted of reclaimed coal mine material.

Hydrodynamic Control of Coalbed Methane Reservoir Performance in the Black Warrior Basin, Jack C. Pashin, Geological Survey of Alabama, P.O. Box 869999, Tuscaloosa, AL 35486-6999, jpashin@gsa.state.al.us

The Black Warrior Basin of Alabama hosts a prolific coalbed methane play in the Pottsville Formation (Pennsylvanian), with 4,180 wells producing 3.4 Bcm of gas in 2004. Gas is produced from five to 25 bituminous coal seams at depths between 150 and 1,200 m. Reservoir coal beds are exposed in a steep fold limb that marks the southeast basin margin. A broad range of geologic, hydrologic, and production data indicate that this folded basin margin is a site of meteoric recharge that dominates basin hydrodynamics and influences reservoir performance. Fresh-water plumes containing bicarbonate waters with low TDS extend from the recharge area into the interior of the basin. Northwest of the plumes, coal beds contain mainly chloride waters with moderate to high TDS. Carbon isotopic data indicate that fresh water facilitates bacterial methanogenesis and high gas content, and production operations have been most successful where TDS content is less than 10,000 mg/L.

The recharge system apparently controls the pressure regime and the production characteristics of the reservoirs. Initial reservoir pressure is typically normal near recharge, and underpressured distal to recharge. Water production is characteristically high proximal to recharge and minimal distal to recharge. Gas production throughout the basin is highly variable, reflecting significant reservoir heterogeneity, but a correlation exists between original reservoir pressure and production-decline characteristics. In normally pressured, water-wet reservoirs, production can increase for up to 4 years before exponential decline is established. In drier, underpressured reservoirs, peak production rates are typically achieved within the first year of production. Accordingly, low water production rate and short time to peak gas production favor reservoirs that contain fresh water and are distal to recharge areas.

Silurian Shelf Sequences, Wabash Platform, Mid-Continent North America: Records of Global Climate Change, J. Fred Read and Alison Spengler, Virginia Tech, Department of Geosciences, Blacksburg, VA 24061, jread@vt.edu, spengler@vt.edu

Global climate and amount of polar ice has an impact on the stacking patterns of carbonate parasequences and sequences during deposition. Platforms that developed under greenhouse conditions should show evidence of small high frequency sea level changes of low amplitude, if shallow, or non-cyclic subtidal successions where water depths are below the influence of the sea level fluctuations. In contrast, with increasing amounts of ice, waxing and waning of moderate sized ice sheets is likely to cause significant sea level changes that should be reflected in the sedimentary pile. Such glacio-eustasy can significantly affect the compartmentalization of potential reservoirs of the accumulating sedimentary succession.

The Late Ordovician and Early Silurian were characterized by significant glacial pulses, which apparently waned into the later Silurian. This research is focused on documenting detailed sequence and parasequence stacking patterns on the mid-continent Silurian Wabash Platform to evaluate the effects of glacio-eustacy on the accumulating sedimentary succession. The platform succession away from the margin is only 100 meters thick, consists of five depositional sequences, which appear to be largely conformable, and remained subtidal throughout. At the margin where thick pinnacle reef capped bank developed, it is up to 200 meters thick. It will also compare the successions to those in the Appalachian Basin and the Great Basin, western U.S. The field data will be used with computer modeling to evaluate which phases of the Silurian are compatible with times of greenhouse ice-free world versus moderate ice on Gondwana. This study will also evaluate controls on the very low accumulation rates that typified the Silurian Wabash Platform, especially with relation to sediment starvation due to distance from the oceanic carbonate reservoir.

Appalachian Devonian Gas Isotopes Suggest Lower Maturity Plays than in the Fort Worth Basin Barnett Play, Jackie Reed, Reed Geochemical Consulting, Hilton Head Island, SC 29926, jreed0301@aol.com; John Zumberge and Stephen Brown, GeoMark Research, Houston, TX 77095, jzumberge@geomarkresearch.com

Gas and source rock analyses from more than 150 wells in the Appalachian Basin indicate that the thermal maturity criteria for successful Devonian shale gas wells is much different than that for wells in the Barnett Shale in the Fort Worth Basin. Regional production data, gas isotopes, and vitrinite reflectance measurements show that liquid cracking, that is, high maturity conditions, are not necessary for gas production within the Appalachian Devonian shales. In addition to thermogenic gas, many of the successful wells are interpreted to show a substantial contribution from biogenic gas that has been previously unrecognized in the basin. Stable isotope compositions for these gases, unlike many other biogenic gases, are relatively isotopically heavy and indicate methanogenesis in a CO_2 limited system. Collectively, these data suggest that a geologically wider range of exploration opportunities may exist in the Appalachian Basin than in the Fort Worth Basin.

Shale Plays Revitalize Northeast Gas Activity, David D. Reimers, IHS, Houston, TX 77056, david.reimers@ihs.com

Old and new companies are showing renewed interest in the northeastern U.S., largely due to unconventional resource plays in the Appalachian, Illinois, and Michigan Basins. Higher prices for gas have created an economic incentive to develop shale gas resources to help meet demand. The number of shale gas well completions in the basins of the northeastern U.S. has increased during each of the past 5 years. Of particular importance is a strong increase in activity in the Devonian shales, accompanied by a lesser, but steady increase in the Antrim Shale. The Devonian shale production continues to increase, but the overall total gas production from shales decreased slightly during the same time period. Generated maps illustrate the active basins of these plays and the expansion during this 5-year period. The recent innovations in shale production treatments and the rising price of natural gas have been instrumental in this increase, and drilling in 2007 should continue to follow this trend.

Thermal Maturity Maps Based on Conodont CAI for the Central Appalachian, Illinois, and Michigan Basins, J.E. Repetski, R.T. Ryder, E.L. Rowan, J.A. East, U.S. Geological Survey, MS 926A National Center, Reston, VA 20192, jrepetski@usgs.gov; R.D. Norby, Illinois State Geological Survey, Champaign, IL; C.B. Rexroad, Indiana Geological Survey, Bloomington, IN; T.H. Shaw, Illinois State Geological Survey, Champaign, IL; S.M. Bergström, The Ohio State University, Columbus, OH 43210; M.H. Trippi and D.J. Weary, U.S. Geological Survey, MS 926A National Center, Reston, VA 20192

New thermal maturation maps have been constructed for Paleozoic rocks of the central part of the Appalachian Basin (New York to central Kentucky) and for the Michigan and Illinois Basins using conodont color alteration index (CAI). New CAI values were derived from drill cuttings from several hundred wells throughout the region and from outcrops along the edges of the Illinois Basin. Ordovician, Devonian, and Carboniferous carbonate intervals were chosen for CAI where they are within or near probable hydrocarbon source beds and oil and gas reservoir zones in these basins. The new maps show thermal patterns that are aligned with, and probably causally related to, structural/geophysical features such as the Rome Trough and selected basement fault systems. Also, the CAI isograds show differing levels of compatibility with known hydrocarbon accumulations, suggesting that accumulations originating from local migration may be distinguished from ones originating from longer-distance migration.

As in other paleothermal investigations, e.g., vitrinite reflectance (%Ro), the CAI isograds indicate higher paleotemperatures than can be explained by present burial depths over the region. Possible sources of additional heating vary from region to region but include burial and insulation of lower Paleozoic rocks by Devonian black shale and Pennsylvanian coal, migration of hot geothermal fluids, local emplacement of mantle-derived rocks along reactivated extensional structures during post-Paleozoic time, and crustal thinning. These data and maps will aid in resource assessments and the development of burial/thermal history, hydrocarbon generation, and fluid flow models for this region.

Reducing Methane Emissions and Improving Profits in Upstream Oil and Gas, James E. Rice, ICF International, 33 Hayden Ave., Lexington, MA 02421, jrice@icfi.com; and Donald Robinson, ICF International, 9300 Lee Highway, Fairfax VA 22031, drobinson@icfi.com

The Natural Gas STAR program, introduced by U.S. EPA in 1993, is a voluntary partnership that encourages member companies to adopt cost-effective technologies and practices that improve operational efficiency and reduce emissions of methane. Best management practices in production, gathering, and processing, and transmission and distribution are shared with member companies through technology transfer workshops and case studies. Within the production sector, studies have identified specific reservoir factors and common well operating practices that lead to excessive methane emissions, and Gas STAR partners are reducing those emissions cost-effectively. This presentation discusses several such technologies, including hydraulic fracturing tight formations and the excessive gas venting or flaring during flow-back where Gas STAR partners are employing "green completions" or "reduced emissions completions" to maximize gas recovery and sales during flow-back. The problem of downhole liquid loading suppressing gas production in mature fields was addressed by Gas STAR partners by employing "smart automation well venting" in conjunction with "plunger lifts" to minimize well venting to the atmosphere to expel liquids. The Gas STAR partners have identified several other wellhead practices that have economic alternatives to gas venting now that the price of natural gas is much higher than recent past, including vapor recovery of casinghead gas, aerial optical leak imaging of remote wells and flowlines, and solar powered pumps in remote, non-electrified locations.

Assessing the Potential for CO_2-Enhanced Oil Recovery in the MRCSP Region, Ronald A. Riley, Ohio Division of Geological Survey, Columbus, OH 43229, ron.riley@dnr.state.oh.us; Brandon Nuttall, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506, bnuttall@uky.edu; John A. Harper, Pennsylvania Geological Survey, Pittsburgh, PA 15222, jharper@state.pa.us; Lee Avary, West Virginia Geological and Economic Survey, Morgantown, WV 26508, avary@geosrv.wvnet.edu; John A. Rupp, Indiana Geological Survey, Indiana University, Bloomington, IN 47405, rupp@indiana.edu; David A. Barnes, and G. Michael Grammer, Department of Geosciences, Western Michigan University, Kalamazoo, MI 49008, barnes@wmich.edu, michael.grammer@wmich.edu

The Midwest Regional Carbon Sequestration Partnership (MRCSP) is investigating the potential for CO_2 sequestration for enhanced oil recovery (EOR) in the Appalachian and Michigan Basins, and the Cincinnati and Findlay Arches region. This phase II regional partnership project is funded, in part, by the U.S. DOE and includes the states of Indiana, Kentucky, Michigan, Ohio, Pennsylvania, West Virginia, and Maryland. The primary objective of this task is to create an initial screening of those oil fields in the MRCSP region that are the best candidates for CO_2 miscible-flooding for EOR. As part of the EOR evaluation, detailed data are being collected on selected historical and ongoing secondary recovery operations to report as case histories.

Important screening criteria in evaluating potential candidates for CO_2 miscible floods include depth, API gravity, cumulative production, net pay, and minimum miscibility pressure. A minimum reservoir depth of 2,500 feet was established as screening criteria, based on an estimated depth at which CO_2 will be in the supercritical phase. Data collected on selected EOR projects and case histories will document reasons for success or failure on attempted secondary recovery operations. Within the project area, ongoing CO_2 injection projects include the Niagaran reef reservoirs (Silurian) in the Dover Field in Michigan and the Keefer Sandstone reservoir (Silurian) in the Big Andy Field in Kentucky. Pilot CO_2 floods in the Big Injun and Berea Sandstone (Mississippian and Devonian) were conducted in the late 1970's and early 1980's in West Virginia. This investigation will provide industry with digital maps, databases, and case histories to better assess potential areas for CO_2–EOR projects throughout the region.

Organic Matter Preservation in Devonian-Mississippian Marine Black Shales of Central Kentucky (U.S.A.), Susan M. Rimmer and Harold D. Rowe, Department of Earth and Environmental Sciences, University of Kentucky, Lexington, KY 40506-0053, srimmer@email.uky.edu, hrowe@email.uky.edu

Geochemical and petrographic analysis of black shales of Middle Devonian age through Lower Mississippian age suggests that multiple controls influenced organic matter accumulation, including primary productivity, sediment influx, redox conditions, and variations in organic-matter type. The role of inorganic input was evaluated using Ti/Al, K/Al, and Si/Al as proxies for clastic input; C-S-Fe relationships, Mo, V/(V+Ni), Ni/Co, V/Cr, and trace-metal enrichment ratios were used to assess paleo-redox conditions; and C/P was used as a proxy for paleoproductivity. Organic-matter type was evaluated using organic petrography, carbon-isotopic composition, and Rock-Eval pyrolysis.

C-S-Fe relationships and trace-element data suggest anoxic conditions prevailed during deposition of a significant proportion of this interval. However, bottom-water conditions were intermittently dysoxic and possibly oxic, particularly during accumulation of the Huron (especially the lower Huron). Productivity appears to have been an important factor in the accumulation of organic carbon: high C/P ratios are consistent with a productivity-anoxia feedback mechanism. In addition, nutrients from increased terrestrial weathering may have contributed to enhanced productivity.

Other factors include variations in sediment influx and in the source of organic matter. Whereas most of the interval consists of Type II kerogen, terrestrial organic matter is seen to increase up-section, a trend that may reflect vegetative changes occurring on land. Most of this change is attributable to increases in inertinite, much of which appears to be fusinite ("fossil charcoal"). This latter observation has implications for the expansion of land plants and for Late Devonian atmospheric oxygen levels.

Provenance of Oil on the Findlay Arch Based on Geochemistry and Basin Modeling (Illinois, Appalachian, and Michigan Basins), Elisabeth L. Rowan, Joseph R. Hatch, Robert T. Ryder, and John E. Repetski, U.S. Geological Survey, Reston, VA 20192, erowan@usgs.gov, jrhatch@usgs.gov, rryder@usgs.gov, jrepetski@usgs.gov

Geochemical analyses of oils produced from the Ordovician Trenton Formation on the Findlay Arch in northeastern Indiana indicate a Middle–Upper Ordovician age for the hydrocarbon source rock. Regional-scale, reconnaissance, multi-1D modeling, calibrated with CAI data, provides burial/thermal histories for the potential Ordovician oil source rocks. The Upper Ordovician Maquoketa Shale (Illinois Basin) and its approximate stratigraphic equivalents, the Utica Shale (Appalachian Basin) and Collingwood Shale (Michigan Basin), are thermally immature to marginally mature on the Findlay Arch in northwestern Ohio and northeastern Indiana and thermally mature in adjacent deeper parts of the Illinois, Appalachian, and Michigan Basins.

Thermally mature Middle–Upper Ordovician strata in the Michigan Basin have generally higher total organic carbon (TOC) contents than equivalent strata in the Appalachian Basin; TOC data are not available for equivalent strata in the eastern Illinois Basin. While richer source rocks would favor the Michigan Basin as an oil source, the saturated hydrocarbon and tricyclic terpane (m/z=191) distributions in oils produced from the Findlay Arch in northeastern Indiana are similar to distributions in oils produced in central Ohio, suggesting an Appalachian Basin provenance, and are dissimilar to distributions in Ordovician oils produced in the southern Michigan and eastern Illinois Basins. Evidence for topographically driven westward regional fluid flow out of the Appalachian Basin at approximately maximum burial (mid-Permian) further supports an Appalachian Basin provenance. Hydrodynamic drive would enhance migration by buoyancy, particularly in areas of shallow dip.

Talking about Earth to Policy Makers: The Real Big Picture, Linda Rowan, Director of Government Affairs, American Geological Institute, Alexandria, VA 22302

Natural resources, natural hazards, climate change, and environmental issues are regular topics of discussion for policy-makers and their constituents. The federal government plays a vital role in supporting, regulating, and managing all of these interests and they regularly need the knowledge and help of geoscientists. Geoscientists need to communicate more often and more effectively with policy-makers at the federal level, particularly now, when the federal government is working on a growing number of measures related to energy resources and climate change. The American Geological Institute, the American Association of Petroleum Geologists, the American Geophysical Union, and many other geoscience societies have active public policy programs in Washington, D.C. These programs provide good opportunities for geoscientists to communicate with policy-makers and can help geoscientists become active citizen scientists without expending significant amounts of time and resources. For example, geoscientists can participate in congressional visits with hundreds of other scientists and engineers in the spring and the fall, they can participate in congressional briefings on geoscience topics for members and staff, they can prepare letters of support for research and science education at critical times in the legislative calendar, and they can provide needed expertise by serving as witnesses at hearings or answering specific questions posed by congressional staff. There are many other ways that geoscientists can and should get involved. Sound federal policy requires the big picture, and geoscience is an essential part of the decision-making process.

Stratigraphic Framework, Structure, and Thermal Maturity of Cambrian and Ordovician Rocks in the Rome Trough and Adjoining Cumberland Plateau, Eastern Kentucky, East-Central Tennessee, and Western West Virginia, Robert T. Ryder, Robert D. Crangle Jr., John E. Repetski, and Michael H. Trippi, U.S. Geological Survey, Reston, VA 20192, rryder@usgs.gov

A new southwest- to northeast-trending cross section from the Sequatchie Anticline in east-central Tennessee through parts of the Rome Trough in eastern Kentucky and westernmost West Virginia shows the stratigraphic framework of Cambrian and Ordovician rocks and their style of deformation. The cross section covers a distance of about 288 miles and is constructed from 17 wells that range in depth from about 5,405 to 19,591 feet. The strata consist of intertongued carbonate (limestone and dolomite) and siliciclastic deposits, and the Middle Ordovician Knox unconformity is present across the entire cross section. Structures in the Rome Trough are dominated by a complex array of normal faults, the larger of which are the Irvine–Paint Creek and the Rockcastle River Faults. These normal faults offset Mesoproterozoic basement and overlying lower Paleozoic rocks, and they had variable growth histories that probably included reversals in relative offset. In contrast, the Middle and Upper Ordovician rocks at the southern end of the cross section in Tennessee have been cut by thrust faults of thin-skinned origin.

Drill cuttings from several wells have yielded conodont elements. The identifiable conodonts are used to differentiate strata of Late Cambrian, Early Ordovician, and Middle Ordovician age, and their color alteration index (CAI) values are used to establish the thermal maturity of the rocks. The CAI 1–1.5 values in the Middle Ordovician rocks are consistent with local oil production from rocks of this age in the Cumberland Plateau, whereas the CAI 2–3 values in the Lower Ordovician rocks are consistent with local gas production from Lower Ordovician and Upper Cambrian rocks in the Rome Trough.

Using a Field Experience to Communicate Natural Resource Issues to Policy Makers: The Kansas Field Conference, Robert S. Sawin, Rex C. Buchanan, and Shane A. Lyle, Kansas Geological Survey, University of Kansas, 1930 Constant Ave., Lawrence, KS 66047, bsawin@kgs.ku.edu

Policy makers are an important, but difficult-to-reach audience for scientific information. As part of its public outreach effort, the Kansas Geological Survey (KGS) initiated the Kansas Field Conference in 1995 to communicate directly with policy makers about natural resource issues in Kansas. The conference targets state legislators, governmental agency officials, business leaders, environmental leaders, and others in positions that make or influence state policy. The primary objective is to present policy makers with balanced, unbiased information about Kansas's natural resources through a field experience that visits sites where natural resources are produced or used, or where there are important environmental issues. Participants gain first-hand knowledge from local operators, regulators, and others who are affected by, or carry out, their decisions.

The conference is 3 days of site visits, presentations, hands-on activities, and panel discussions. Participation is by invitation. Participants pay a small fee, but cosponsors (usually other state agencies) help defray expenses and broaden the conferences' topics. Travel is by chartered bus, and lodging, meals, and a guidebook are provided. Conferences have focused on topics (such as water or energy) or issues specific to various regions of the state.

The field conference has affected policy in many ways. Legislators regularly use conference information and contacts during the law-making process. Conference information played a direct role in decisions related to underground natural-gas storage rules, water-rights buy-back legislation, sand and gravel dredging regulations, and mining-related subsidence legislation. The conference also benefits the KGS and other agencies by raising the KGS's visibility within the legislature and improving relationships with other state agencies.

Geoscientists want to be involved in public policy decisions, but often don't know how to reach policy makers. The Kansas Field Conference is a highly effective way of communicating scientific information about natural resource-related issues to this audience. The concept has been adopted by other state geological surveys and is applicable to other earth-science organizations.

New Techniques for New Discoveries—Results from the Lisbon Field Area, Paradox Basin, Utah, David M. Seneshen, Vista Geoscience, 130 Capital Dr., Suite C, Golden, CO 80401; Thomas C. Chidsey Jr., Craig D. Morgan, and Michael D. Vanden Berg, Utah Geological Survey, P.O. Box 146100, Salt Lake City, UT 84114

Exploration for Mississippian Leadville Limestone-hosted hydrocarbon reservoirs in the Paradox Basin is high risk in terms of cost and low documented success rates (~10 percent based on drilling history). Only 100 wells have penetrated the Leadville over an area of the 7,500 mile^2, which equates to about one well per township. The potential for more hydrocarbon reserves is thus enormous, but the high cost of 3-D seismic exploration methods in environmentally sensitive areas deters small independents from exploring for Leadville hydrocarbon reservoirs.

This study was therefore initiated to evaluate the effectiveness of low-cost, innovative, non-invasive, surface geochemical methods for predicting the presence of underlying Leadville hydrocarbon reservoirs. Lisbon was chosen for testing because it is the largest Leadville oil and gas producer in the Paradox Basin, and a nearby recently discovered Leadville field (Lightning Draw Southeast) is also available for comparison. Surface soils (n=400), outcrop fracture-filled soils (n=33) and lichen (n=29), and 6-foot-deep free gas samples (n=40) were collected at intervals ranging from 50 to 500 meters over productive and barren parts of the Lisbon and Lightning Draw Fields. The soil and lichen samples were analyzed for thermally desorbed hydrocarbons in the C_1–C_{12} range, heavy aromatic hydrocarbons (C_6–C_{40}), organic carbon, 53 major and trace elements, and seven anions. Free gas samples were analyzed for hydrocarbons (C_1–C_8), hydrogen, helium, carbon dioxide, carbon monoxide, oxygen, and nitrogen. The data were interpreted using multivariate statistical methods. The main conclusions of the study are:

(1) The microseepage over the gas cap, oil leg, and water-leg at Lisbon is distinguished based on hydrocarbon, fluorescence, and metal associations in surface soil and outcrop fracture-fill soil and lichen samples. Important variables for distinguishing productive and barren areas are light alkanes and aromatics (C_1–C_6), uranium, vanadium, cadmium, molybdenum, and lead. Heavy aromatic hydrocarbon anomalies observed over productive areas could represent biodegraded Lisbon condensate and oil seeps.

(2) Productive "Lisbon-type" microseepage signatures are observed over the recently discovered Leadville Lightning Draw Southeast gas condensate field southwest of Lisbon. Compositional signatures over the Lightning Draw Field also predict productive parts of Lisbon.

(3) Light alkane (C_1–C_6) and hydrogen anomalies in 6-foot-deep free gas are spatially associated with production at the Lightning Draw Field.

(4) Recommendations for future geochemical surveys in the Paradox Basin are:

(a) Reconnaissance exploration should include the collection of surface soils (outcrop fracture-fill media where applicable) for hydrocarbon and major/trace element analyses.

(b) Anomalous areas identified in reconnaissance soil surveys should be followed up with the extraction and hydrocarbon analysis of deep free gas samples collected at short intervals (<100 meters).

Update of New Albany Shale Potential in Illinois, Beverly Seyler and Joan E. Crockett, Illinois State Geological Survey, 615 East Peabody Dr., Champaign, IL 61820, seyler@isgs.uiuc.edu

To date there is no known commercial production of oil or gas from the New Albany Shale in Illinois. However, Illinois well records indicate gas well completions in the New Albany Shale in two areas: from two wells in Westfield in Clark County and three shut-in, subsequently plugged wells in Russelville Field in Lawrence County. Additionally, completed oil zones have been reported in the New Albany Shale in single wells in four fields: Clay City Consolidated Field in 8-5N-10E Jasper County, Johnsonville Field, 4-1S-6E, Lawrence Field in Lawrence County 29-4N-12W, and in Salem Field, Marion County, 20-2N-2E. In each instance other zones were also completed or well records are very old and incomplete; therefore, production from the New Albany Shale cannot be verified. Previous workers have identified that the potential natural gas resources in the New Albany Shale of the Illinois Basin may be related to the following four key factors: organic content of the shale, thickness of the organic-rich shale, thermal maturity as related to depth of burial, and presence of natural fractures. These same factors are pertinent to recent discoveries in several Devonian black shale plays in North America. Total organic carbon values and maturity indicators are within the range of recently developed Devonian black shale plays, suggesting that the emerging black shale play taking place in Indiana and Kentucky may have similar potential in Illinois. This presentation will provide a review and update of these factors in Illinois.

Reprocessing the United States Magnetic Anomaly Map Using the Comprehensive Model, Adam Shaw, Joseph Batir, Matthew McIndoo, Dhananjay Ravat, Department of Geology, Southern Illinois University, Carbondale, IL 62901-4326, adam1385@siu.edu, jbatir33@siu.edu, mmcindoo@siu.edu, ravat@geo.siu.edu; Peter Milligan, Geoscience Australia, Peter.Milligan@ga.gov.au; Thomas G. Hildenbrand, Robert Kucks, and Patricia Hill, U.S. Geology Survey, tom@usgs.gov, rkucks@usgs.gov, pathill@usgs.gov

We have improved the magnetic anomaly map of the United States using National Uranium Reconnaissance and Evaluations (NURE) aeromagnetic surveys collected during the 1970's. Previous versions of these data sets processed using IGRF/DGRF do not mesh well at the survey boundaries because of leveling artifacts. Similarly, the U.S. component of the North American magnetic anomaly map has long wavelength errors caused by warping of hundreds of state and local aeromagnetic surveys during the merging process. The main difference in our processing that has allowed us to retain proper baselevels is the use of the continuous main field Comprehensive Model (CM4). The advantage of using the NURE surveys is that most of these surveys have time information and diurnal variation observed with base station magnetometers is removed from them. Furthermore, we have cleaned the NURE data by removing many spurious values through visual inspection. Some NURE surveys did not have total field values or time information. For these surveys, we reintroduced the IGRF for their approximate date and removed the core field determined by CM4. We compare the results of our processing and improvements with the U.S. aeromagnetic anomaly data prepared by different merging techniques. The improved map is more suitable for regional geologic and geodynamic interpretations.

Revisiting Some Carboniferous Stratigraphic Correlations in Ohio, Ernie R. Slucher, Ohio Division of Geological Survey, Columbus, OH 43229-6693, ernie.slucher@dnr.state.oh.us

The stratigraphic succession of Carboniferous-age rocks in Ohio possesses a long and established pedigree. The type sections of several Lower Mississippian units are located in Ohio, as are many of the widely recognized beds in the Pennsylvanian sequence of the Appalachian Basin. Regionally, some of these Mississippian units serve as the foundation of the stratigraphic nomenclature used in large portions of the Appalachian Basin (i.e., Sunbury Shale and Cuyahoga Formation). Similarly, the Pennsylvanian sequence in Ohio has long been deemed as a practical reference section when Pennsylvanian depositional sequences are correlated regionally, particularly the Middle and Upper Pennsylvanian portions. This notion is based on the premise that this portion of the basin was a relativly stable platform that received lesser amounts of the coarser clastics that contributed to variable intervals between key stratigraphic units, particularly when compared to strata deposited further eastward, in the axis of the subsiding Appalachian Basin. However, several recent geologic investigations for carbon dioxide sequestration, and a new interest in coal as a source for CBM in Ohio, suggest some of these long established correlations and stratigraphic relationships may be inappropriate. The Sunbury Shale, for instance, thickens and grades laterally into the Cuyahoga Formation, a relationship very dissimilar to most published stratigraphic sections that show the unit thinning and being overlain by the Cuyahoga. Likewise, some coals thought to be synchronous most likely are diachronous beds in different parts of Ohio. These and other stratigraphic profiles will be illustrated in a series of cross sections.

Exploring New Geosequestration Horizons in the Appalachian Basin: Midwest Regional Carbon Sequestration Partnership R.E. Burger Test Site, Joel Sminchak, Phil Jagucki, Jackie Gerst, and Neeraj Gupta, Battelle, Columbus, OH 43201, jagucki@battelle.org, sminchak@battelle.org, gerstj@battelle.org, gupta@battelle.org

Geological sequestration targets were identified and explored in a 2,555-meter-deep test well drilled at the Midwest Regional Carbon Sequestration Partnership R.E. Burger test site outside of Shadyside, Ohio. The well was drilled to the Queenston Shale at the FirstEnergy R.E. Burger power plant to facilitate CO_2 injection testing. Wireline logging, mud logging, and sidewall coring were completed to characterize geological sequestration potential and caprocks in the well. Well-known targets were present in the Oriskany Sandstone and the "Clinton"-Medina sandstone. However, drilling events and subsequent analysis of test data suggested that less-obvious rock formations such as the Hamilton Group and Lockport-Newburg should be considered for injection intervals in the test well. Information obtained from regional sequestration exploration wells was utilized to refine sequestration potential in the new horizons. Additional analysis and test procedures were developed to evaluate the units along with the more established rock formations. Overall, the project suggests that new horizons may hold additional potential for geological sequestration in the Appalachian Basin.

Analyzing the Deep Coal Resources of Eastern Kentucky for their Carbon Sequestration Potential, Michael P. Solis and Stephen F. Greb, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506-0107, msolis@uky.edu, greb@uky.edu

The Lower Pennsylvanian CBM plays of southwestern Virginia and Alabama occur in coal beds that are largely absent in southeastern Kentucky due to truncation by thick quartzarenites and updip loss of accommodation space. In Kentucky, however, there are coals at depth that may contain CBM, or could be utilized for carbon sequestration with the potential for enhanced CBM production. Lower Pennsylvanian coals of the Grundy Formation, and lower parts of the Pikeville Formation are preserved at depths of more than 500 and 1,000 feet below drainage in parts of the Middlesboro and Eastern Kentucky Synclines. There are, however, few coal exploration boreholes at these depths.

As part of the SECARB partnership, subsurface oil and gas wells are being used to better understand the stratigraphy of the Lower Pennsylvanian and lower Middle Pennsylvanian strata in the synclines. There are few density logs of the deeper coal-bearing strata, but there are many gamma and neutron logs. These logs are being used in combination with the existing density data to correlate Lower Pennsylvanian depositional sequences and determine areas where deep coals might be evaluated in the future for CBM or carbon sequestration. Useful stratigraphic markers include major marine flooding surfaces at the top of the Bee

Rock–Middlesboro Sandstone and Betsie Shale, the base of the Bee Rock–Middlesboro Sandstone, and a series of minor flooding surfaces in the lower Grundy Formation.

Geochemical Constraints on the Origin and Volume of Shale Gases in the Eastern Illinois Basin, Dariusz Strąpoć, Indiana University, Department of Geological Sciences, Bloomington, IN 47405-1405; Maria Mastalerz, Indiana University, Indiana Geological Survey, Bloomington, IN 47405-2208; Arndt Schimmelmann, Indiana University, Department of Geological Sciences, Bloomington, IN 47405-1405; and John Rupp, Indiana University, Indiana Geological Survey, Bloomington, IN 47405-2208

Gases from the New Albany Shale (Upper Devonian–Lower Mississippian) and Maquoketa Group shales (Ordovician) from Indiana were investigated compositionally and for carbon stable isotope ratios ($\delta^{13}C$ values). The shales were characterized by total organic carbon (TOC) and total nitrogen, $\delta^{13}C_{kerogen}$ and $\delta^{15}N_{total\ nitrogen}$ values, and petrographic composition of organic matter. Surface area plus micropore and mesopore volumes were also determined and compared to desorbed and residual gas contents. The New Albany Shale was sampled across depth intervals of 410–425 m and 825–851 m in two locations, and TOC content ranges from <1 to 13 wt. percent. New Albany Shale samples range from immature (R_o = 0.55 percent) to mature (R_o = 0.8 percent). The Maquoketa shale contains ~1.3 to 1.6 wt. percent TOC at a depth of 1,305–1,322 m. The total gas content in shales ranges from 0.15 to 2.2 cm^3/g (5 to 70 scf/t) and is strongly correlated with the TOC content, indicating that the organic fraction is dominantly responsible for generation and storage of gas. There is a strong positive correlation between micropore volumes and TOC content, suggesting that micropore volume controls total gas content. There is no consistent relationship between mesopore volume, TOC content, and gas content. The New Albany has a uniform $\delta^{13}C_{TOC}$ value of –29.6‰ (st. dev. 0.3‰, n=37) and the Maquoketa –30.0‰ (st. dev. 0.1‰, n=29). $\delta^{15}N_{total\ nitrogen}$ values for the New Albany and Maquoketa are +1.0 (st. dev. 0.5‰, n=29) and +2.6 (st. dev. 0.2‰, n=29), respectively. Mean elemental $C_{organic}/N_{total}$ ratios in the New Albany and Maquoketa are ~26 and ~18, respectively; higher total nitrogen content in the Maquoketa shale's rock coincides with a higher N_2 content in its gas (average 13 percent versus 4 percent, both n=3). Chemical composition and $\delta^{13}C_{methane}$ values of gases indicate a thermogenic origin of hydrocarbon gases in both New Albany and Maquoketa shales at depth; hydrocarbon gases from a shallower New Albany site resulted from ~1:1 vol:vol mixing of thermogenic and microbial gases.

Compound-Specific Carbon and Hydrogen Stable Isotope Ratios of Coalbed Gases in Southeastern Illinois Basin, Dariusz Strąpoć, Department of Geological Sciences, Indiana University, 1001E 10th St., Bloomington, IN 47405-1405; Maria Mastalerz, Indiana Geological Survey, Indiana University, 611 N. Walnut Grove, Bloomington, IN 47405; Cortland Eble, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506-0107; Arndt Schimmelmann, Department of Geological Sciences, Indiana University, 1001E 10th St., Bloomington, IN 47405-1405; and John Rupp, Indiana Geological Survey, Indiana University, 611 N. Walnut Grove, Bloomington, IN 47405

Coalbed gases and associated waters from exploratory and production gas wells in the Springfield and Seelyville Coal Members of the southeastern Illinois Basin (Indiana and western Kentucky) were sampled to geochemically assess the origin of coalbed gases. Spectroscopic analyses of hydrocarbon gases (C_1, C_2, C_3, n-C_4, i-C_4) yielded chemical concentrations, δD, and $\delta^{13}C$ values that suggest a spectrum from purely biogenic to thermogenic gas. The low thermal maturity of Indiana coals (R_o ~ 0.6 percent) is in agreement with the observed biogenic isotopic signature of coalbed gas (≥ 96 percent methane generated via bacterial CO_2-reduction). In contrast, thermogenic gas was generated by the stratigraphically equivalent coalbeds in western Kentucky (Rough Creek Graben), where higher maturities of R_o ~ 0.8 percent resulted from tectonic and hydrothermal activity. The lack of secondary biogenic methane observed in Kentucky coalbed gases probably resulted from greater burial depths and limited recharge of meteoric water.

Soil Gas Hydrocarbons: A Dual Purpose Geochemistry that Locates REDOX Cells and Identifies Specific Organic Signatures in Petroleum Exploration, Dale A. Sutherland, Activation Laboratories Ltd., 1336 Sandhill Dr., Ancaster, ON L9G 4V5, dalesutherland@actlabsint.com

Soil gas hydrocarbons (SGH) is an extractive procedure which releases organic compounds adsorbed on surficial samples such as soil, peat, humus, and lake-bottom sediments. These samples act as long-term collectors of organic compounds that migrate to the surface from deep hydrocarbon based plays. SGH has been researched and developed for over 10 years and analyzes for hydrocarbons in the C5–C18 range. These hydrocarbons are very robust to sampling, shipping, and handling procedures. Analysis of the sample extracts with gas chromatography–mass spectrometry provides a highly selective and sensitive method with detection limits in the trace parts-per-trillion (ppt) range for over 160 specific hydrocarbons.

Geochemical anomalies of hydrocarbons over petroleum bodies have been noted in the literature for several decades. These anomalies arise from oxidation-reduction (REDOX) cells that can be found for both hydrocarbon and mineral bodies. Researchers also suggest that hydrocarbons migrate as micro-gas bubbles through thousands of metres of cover, as seen with SGH case studies. SGH has the ability to vector to the vertical projection of a target as well as identify the type of buried target present by using forensically determined hydrocarbon signatures. Survey results are typically very clean, with easily interpretable anomalies.

SGH surveys have been conducted over several petroleum fields in southwestern Ontario and southeastern Saskatchewan, Canada, having depth to the play at up to 10,000 feet. Some case studies will be shown in this presentation.

Log-Derived Lithostratigraphy and Digital Mapping of Ste. Genevieve Oolite Bodies at Owensville North Consolidated Field, Gibson County, Indiana, Katy J.G. Swan, Indiana University, Department of Geological Sciences, Bloomington, IN 47405, kjswan@indiana.edu; and Brian D. Keith, Indiana Geological Survey, Indiana University, Bloomington, IN 47405, keithb@indiana.edu

The Mississippian (Valmeyeran) Ste. Genevieve Limestone is the second most productive petroleum reservoir within the Illinois Basin. The highly complex internal stratigraphy of the Ste. Genevieve makes detailed lithologic correlation difficult both on a field and basinwide scale. The Ste. Genevieve consists largely of interbedded wackestone, skeletal grainstone, calcareous mudstone, packstone, dolostone, and shale, with laterally discontinuous zones of highly porous oolite grainstone bodies that form prolific petroleum reservoirs.

Dual induction, formation density, and gamma-ray log data were used to interpret the depositional setting of the Ste. Genevieve at Owensville North Consolidated Field (Gibson County, Indiana). Examination, analysis, and correlation of 250 well logs across the field were used to generate lithofacies logs. A series of depth slices, on 2-foot intervals, were created from the data to provide an insight into the spatial distribution of lithofacies within the field. Three-dimensional imaging was used to gain an understanding of the spatial extent and orientation of derived lithofacies along with specific lithologic features within the field, in particular, the distribution of high-porosity oolitic grainstone bodies. The application of this newly developed lithofacies interpretative technique promotes effective prediction of the presence of high quality reservoirs within a carbonate depositional system.

The U.S. Geological Survey 2007 Oil and Gas Assessment of the Illinois Basin, C.S. Swezey, U.S. Geological Survey, Reston, VA 20192, cswezey@usgs.gov; J.R. Hatch, U.S. Geological Survey, Lakewood, CO 80225, jrhatch@usgs.gov; S.T. Brennan, J.A. East, J.E. Repetski, and E.L. Rowan, U.S. Geological Survey, Reston, VA 20192, sbrennan@usgs.gov, jeast@usgs.gov, jrepetski@usgs.gov, erowan@usgs.gov

In 2007, the U.S. Geological Survey (USGS) completed an assessment of the undiscovered, technically recoverable oil and gas resources in the Illinois Basin. In this assessment, the USGS identified four total petroleum systems (TPS), which are named according to their primary source rocks as follows: (1) the Precambrian to Cambrian TPS, (2) the Ordovician Ancell/Maquoketa TPS, (3) the Devonian-Mississippian New Albany TPS, and (4) the Pennsylvanian coal and shale TPS. The most prolific of these source rocks is the Devonian-Mississippian New Albany Shale, which has supplied petroleum to most of the Silurian through Pennsylvanian reservoirs. However, throughout most of the basin the New Albany source rock has only been buried deeply enough to enter the window of oil generation. Consequently, most of the reservoirs are oil reservoirs that contain very little thermogenic gas. In addition to identifying source rocks, the USGS delineated 19 reservoir intervals or assessment units (AU's). Most of the undiscovered oil is estimated to be in the Ordovician Dutchtown to Galena AU and in the Upper Silurian carbonates (reefs) AU. In contrast, most of the undiscovered gas is estimated to be in the Devonian-Mississippian New Albany continuous gas AU and in the Pennsylvanian coal bed gas AU. The gas in these two AU's is primarily biogenic gas, although some thermogenic gas is also present.

Reservoir Analysis of the Cypress Sandstone (Chesterian) for Enhanced Oil Recovery and Carbon Sequestration, Henderson County, Kentucky, Kathryn G. Takacs and T.M. Parris, Kentucky Geological Survey, University of Kentucky, Lexington, KY 40506-0107, ktakacs@uky.edu, mparris@uky.edu

The Cypress Sandstone in Euterpe Field in Henderson County is being evaluated for possible CO_2 injection and enhanced oil recovery. Geophysical well log analysis and mapping suggest that oil is structurally and stratigraphically trapped at subsea depths of –1,486 to –1,466 feet; injected CO_2 will thus reside in the reservoir as an immiscible gas. Log analysis further shows an oil-water contact at variable subsea depths, suggesting the reservoir might be compartmentalized. Using an average core porosity of 17 percent, the calculated reservoir pore volume is approximately 26,951 acre-feet. Microscopic and X-ray diffraction analysis shows that the Cypress is a fine-grained, quartz-rich sandstone with smaller amounts of kaolinite (~5 percent), calcite (~4 percent), and ankerite (~2 percent) cements. Overlying seal rocks of the Golconda Formation are composed of siltstone and mudstone. Golconda rocks are mineralogically more diverse and contain significant amounts of feldspar (~6 percent), calcite (~7 percent), siderite (~7 percent), illite (~10 percent), and chlorite (~3 percent). Future sampling and analysis of Cypress waters will provide data to model geochemical reactions between formation waters, minerals in the reservoir and seal rocks, and injected CO_2. Further study of the Cypress Sandstone will examine how reservoir characteristics at Euterpe compare to other Cypress and Mississippian sandstone reservoirs in the Illinois Basin of western Kentucky for suitability for enhanced oil recovery and carbon sequestration.

Trenton/Black River Hydrothermal Dolomite Reservoirs in Québec: The Emergence of a New and Highly Promising Play along the St. Lawrence Platform, Robert Thériault, Québec Ministry of Natural Resources, Hydrocarbon Branch, Québec, QC G1H 6R1, Canada, robert.theriault@mrnf.gouv.qc.ca

The prolific Trenton/Black River hydrothermal dolomite (HTD) play extends across North America, from Texas all the way through to Newfoundland. Although the play has been very successful in the United States and in Ontario, it remains virtually untested in Québec. However, recent exploration work point towards the emergence of this play along the St. Lawrence Platform of Québec.

The Trenton/Black River succession forms part of the Cambro-Ordovician St. Lawrence Platform, which spreads over approximately 1,000 km in length from southern Québec (St. Lawrence Lowlands) through to Anticosti Island. In March 2007, Questerre Energy Corporation (minority partner) announced a significant discovery of natural gas from the Talisman Energy Gentilly #1 well, located 30 km to the east of Trois-Rivières on the south shore of the St. Lawrence River. Preliminary testing yielded flow rates of up to 4.5 million cubic feet per day. Regional time-structure maps of the top of the Trenton Group reveal the presence of several sub-parallel grabens (structural sags) in this area. These linear depressions appear to measure 500–1,000 m in width by up to 50 km in length, a scale which is comparable to that of the world-class Albion-Scipio Field (Michigan), and recent gas discoveries in the Finger Lakes area (southern New York) by Talisman Energy. Similar structures also occur in the Trenton/Black River interval on Anticosti Island, where hydrothermal dolomites associated with significant secondary porosity have been documented.

Conasauga Mushwad Shale Gas Play in the Appalachian Thrust Belt in Alabama, William A. Thomas, Department of Earth and Environmental Sciences, University of Kentucky, Lexington, KY 40506-0053, geowat@uky.edu

The Conasauga shale gas play in the Appalachian thrust belt in Alabama focuses on the Gadsden mushwad, which is a tectonically thickened, ductile duplex of shale-dominated Conasauga Formation. The regional décollement of the Appalachian thrust belt in Alabama is in a Lower to Middle Cambrian (Rome and Conasauga Formations) shale-dominated weak layer. A regional stiff layer (Upper Cambrian and Lower Ordovician Knox Group) of massive carbonate rocks controls the structural geometry of thrust sheets. The floor of the Gadsden mushwad is the regional décollement; the roof is the broken, deformed, and partly eroded Dunaway Mountain thrust sheet. The leading edge of the mushwad formed over a frontal ramp, where the regional décollement rises northwestward over the down-to-southeast Birmingham basement fault in the footwall.

The Conasauga Formation (now in the Gadsden mushwad) is palinspastically restored as the fill of the Birmingham basement graben, where the formation is a thick succession of dark-colored shale and thin-bedded limestone. In contrast, both northwest and southeast of the basement graben, the Conasauga Formation is thinner and is a shallow-marine, massive carbonate. Thickness and facies of the Conasauga Formation reflect synsedimentary Middle Cambrian extension along the boundary faults of the Birmingham basement graben.

During late Paleozoic thrust translation, ductile deformation and accretion of the weak layer from the footwall into the allochthon further thickened the already thick shale-dominated Conasauga Formation in the Birmingham basement graben as the mushwad nucleated and enlarged along the large-scale frontal ramp over the Birmingham basement fault at the northwest boundary of the graben. Two circumstances led to the shale gas resource: (1) deposition of a thick succession of shale and thin-bedded limestone in the Birmingham basement graben and (2) nucleation and tectonic thickening of the Gadsden mushwad at a frontal ramp over the Birmingham basement fault, which provided a buttress to thrust propagation.

CO_2 Sequestration Potential of the North Michigan Silurian Reef Trend, Brian Toelle, Chaoqing Yang, and Tracee Imai, Schlumberger Data & Consulting Services, Pittsburgh, PA, toelle1@slb.com

The Northern Silurian Reef trend of the Michigan Basin was developed within the stratigraphic unit historically referred to as the Niagaran Brown. Within the past few years this unit was renamed the Guelph Formation. Over 700 reefs make up this trend, with some of these being over 300 acres in size and having produced more than 5 MMBbl of oil. Estimates of the total amount of hydrocarbons produced for the entire trend have been reported as high as nearly a half a billion barrels.

The U.S. Department of Energy has funded a study of an ongoing enhanced oil recovery project being conducted on a reef within this trend using the injection of CO_2. The Charlton 30/31 reef, located in Otsego County, like many other reefs in the play, was discovered and developed during the 1970's and 1980's. This field has completed its primary production phase, during which six wells produced 2.6 million of the field's estimated 7 million barrels of oil in place. This reservoir is characterized as a low porosity, low permeability limestone matrix with irregular dolomitized intervals providing a secondary network of higher porosity and permeability, which controls fluid flow throughout the reservoir. The estimated average porosity in this reef is just slightly over 6 percent. As part of this study the reservoir attributes identified at the Charlton 30/31 reef were extended to the entire Northern Reef Trend in order to determine its CO_2 sequestration capacity. Additionally, the potential oil recovery has been estimated.

Residence Time of Light Alkanes in Soils, Daniel H. Vice, Hazleton Campus, Pennsylvania State University, 76 University Dr., Hazleton, PA 18202; and Philip M. Halleck, Pennsylvania State University, 152 Hosler Building, University Park, PA 16802

Four surveys of 25 closely spaced soil samples each were conducted over a leak in a natural gas pipeline to study the lack of repeatability of surface geochemical surveys. These surveys were over a gas field in Centre County, Pennsylvania. The first survey was conducted 2 days before a leak in the pipeline was repaired. The second survey was conducted 6 days after the leak was repaired; the third 29 days afterwards; and the fourth 97 days afterwards. Approximately 50 cubic centimeters of soil were collected using an oakfield hand sampler and placed in a glass vial and sealed with a Teflon cap. These samples were analyzed in a gas chromatograph for the light alkanes, methane, ethane, propane, butane, and pentane, using a modified headspace method.

A one-way analysis of variance of the sample data suggested that two statistical populations of light alkanes were present. Next the data were compared using Fisher's pairwise comparisons, which show that the first survey represents one population while the latter three surveys represent a second population.

Graphical presentation of the light alkane concentrations from the four surveys versus time shows a rapid decline after the leak was repaired. Methane concentrations declined the most rapidly, while pentane showed a slight increase before declining. Light alkanes in the fourth survey were similar both in concentrations and in composition to samples previously collected over the Sabinsville gas storage reservoir. This suggests that the light alkanes have a residence time of approximately 3 months in the soil environment.

Asset Protection in a Politicized Environment: Drilling and Production in the 21st Century, James H. Viellenave and David Seneshen, Vista Geoscience, 130 Capital Dr., Suite C, Golden, CO 80401

The recent run-up in oil and gas prices has vastly expanded the footprint of oil and gas development in rural and suburban areas of the United States and Canada. That footprint, combined with price increases at the pump, visions of intangible damages to property values, and occasional severed estate problems, has increasingly politicized the process for orderly and economical development of petroleum resources. Industry has found enough difficult operating conditions securing qualified drillers, geophysical and geochemical contractors and other support even without considering the uncertain impacts of such a "non-scientific" range of external influences. Industry compliance with laws and regulations has not blunted the effects of citizen groups, working committees, legislative audits, and election year rhetoric.

The solution is an environmental risk management program, fully integrated with operations, which when implemented, identifies and reduces risks, saves money, and dramatically lessens the potential for litigation, which is the single most powerful source of inefficiency in the industry today. Case studies and lessons learned from several basins in the Rocky Mountain West are presented, including coal bed methane production in the San Juan, Raton, and Powder River Basins and tight gas in the Piceance and Green River Basins.

Enhanced Oil Recovery (EOR) and Geological Carbon Sequestration (GCS) Potential in the Middle Devonian Richfield Member of the Detroit River Group, Michigan Basin, USA, Amanda Wahr and David A. Barnes, Michigan Geological Repository for Research and Education, Department of Geosciences, Western Michigan University, Kalamazoo, MI 49008, amanda.wahr@wmich.edu

The Middle Devonian Richfield Member of the Lucas Formation (Detroit River Group) is an important oil producer in the Michigan Basin. Previous studies indicate that the Richfield Member consists primarily of alternating layers of anhydrite and high porosity low permeability algal laminated dolomite mudstone reservoirs. Anhydrite formation is thicker in younger strata, making the lower, stratigraphically isolated, dolomicrite reservoirs ideal drilling targets (Sullivan, 1985). The Richfield Member occurs in the subsurface across most of the central Michigan Basin and extends to a subcrop in the north, below glacial till, near the Straits of Mackinac. Initial production of the Richfield began in 1939. The Richfield Member is productive in over 30 fields, with cumulative production in excess of 55 Mbbl. Secondary recovery in several larger fields has been very successful. Cumulative oil production during water flooding ranges from 83 percent to 16 percent of cumulative primary production. CO_2 floods are the fastest growing EOR technique in the United States, and Richfield producing fields that were previously water flooded are still receptive to CO_2 flooding. Fields that have yet to be flooded for secondary recovery have higher potential for doubling cumulative production. Dual CO_2/EOR and regional saline reservoir geologic carbon sequestration in the Richfield has great potential in the Michigan Basin. Sequestration of CO_2 in deep saline formations does not produce direct byproducts of value to offset the cost, but it has another advantage. The estimated storage capacity of saline formations is extremely large, and emissions trading around the world is becoming more popular. Given the transitory state of energy today, the Richfield Member shines as a reservoir of various possibilities.

From Clastic to Carbonate Facies: Borden Delta Destruction and Evolution of the Slade Carbonate Platform: Tectonics versus Eustasy, D. Brent Wilhelm and Frank R. Ettensohn, University of Kentucky, Lexington, KY 40506, brent.wilhelm@uky.edu, fettens@uky.edu

Clastic and carbonate depositional systems are generally well understood, but the cause of transition from one to the other are sometimes unclear. In some cases, why these changes occur and why they are so abrupt are still uncertain. One such example occurs in eastern Kentucky, where the Mississippian Nada and overlying Renfro members of the Borden and Slade formations, respectively, form a transition from deltaic, clastic environments to shallow-water carbonate environments. The change is generally accompanied by little or no transitional sequence, and in places, the contact is probably unconformable. Why and how this transition occurred is still debated.

Approximately 50 outcrops were examined for sedimentological, paleontological, and stratigraphic detail and correlated with well log data from the Appalachian Basin. The transition is generally sharp in east-central Kentucky where distal, deep-water, deep- to mid-ramp mudstones in the Nada are overlain by shallow upper ramp subtidal to supratidal dolomatized carbonates in the Renfro. However, in northeastern Kentucky the contact is generally gradational where shallow-marine, proximal delta-platform limestones with a diverse fauna grade upwards into lagoonal and peritidal dolostones in the Renfro. This contrast is probably best explained by the position and activity of two structural features, the Kentucky River Fault Zone, which bounds the Rome Trough to the north, and the Waverly Arch that is situated mostly north of the fault zone. Both structural features were active during late Paleozoic time and may have been reactivated in Mississippian time as a result of bulge moveout. Hence, synsedimentary activity on local structures may explain the changing nature of the clastic-carbonate, Nada-Renfro transition in different areas.

Seismic and Sedimentary Facies Distribution of the St. Bernard Lobe, Mississippi Delta, D. Brent Wilhelm and Paul Howell, University of Kentucky, Lexington, KY 40506, brent.wilhelm@uky.edu, phowell@uky.edu

The St. Bernard is the easternmost of seven recognized delta lobes in the Quaternary Mississippi Delta. The St. Bernard was active between 4,000–1,000 years ago and is located in the inner-shelf area of the Gulf of Mexico along the eastern Louisiana, Mississippi, and Alabama coast. Acquisition of more than 6,700 line-km of seismic reflection data and 77 vibracore samples at a maximum depth of 12 m provides a strong database to explore the depositional and erosional record of the St. Bernard lobe.

We employed a GIS database to construct facies maps where seismic profiles and vibracore reports were available. Seismic profiles provide spatial control of geometries associated with depositional environments. The aerial extent of the prodelta, delta front, and delta plain seismic facies of the St. Bernard lobe were mapped. Vibracore logs and core photos provided lithology, percent sand, stratification, bed thickness, color, and average grain-size from which the database was prepared. Lithofacies maps created from the database were compared to seismic facies to better constrain correlations of depositional environments. The data reveal significant spatial variations on the amount of transgressive erosion during the destructive phase of delta abandonment. Prodelta muds are overlain by transgressive sand sheets, then vertically stacked units of deltaic successions, and surficial sands and muds as noted by previous authors.

The resulting data provides constraints on facies distributions and relative fluctuations in Quaternary sea-level. Moreover, as coastal awareness and the efforts to restore storm damaged coastlines in Louisiana increases, sand becomes an important resource. Preparation of digital databases will aid in providing this necessary information.

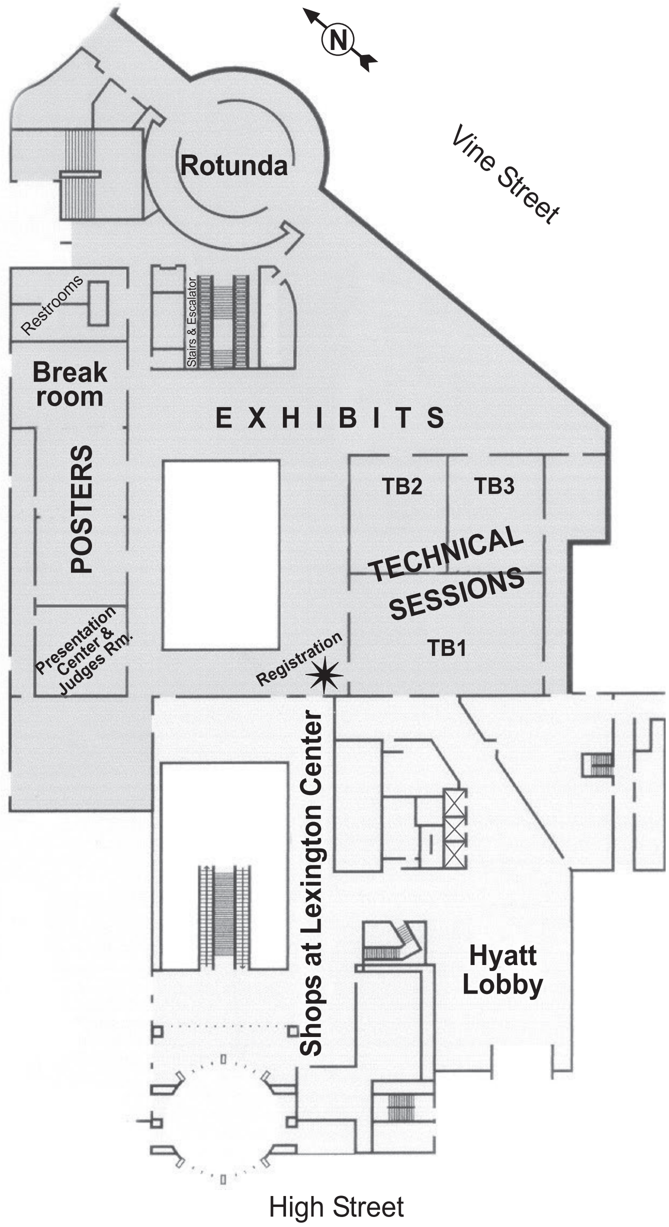
Sequence Framework of Mississippian Carbonates, Kentucky, West Virginia, and Virginia, U.S.A., Thomas C. Wynn, Department of Geology and Physics, Lock Haven University, Lock Haven, PA 17745, twynn@lhup.edu; Aus Al-Tawil, Saudi Aramco, Dhahran, Saudi Arabia, aus.tawil@aramco.com.sa; and J. Fred Read, Department of Geosciences, Virginia Tech, Blacksburg, VA 24061, jread@vt.edu

The sequence framework of the Mississippian Greenbrier-Newman carbonates (Meramecian-Chesterian) was documented using outcrops, well cuttings, and wireline logs in conjunction with limited core data in Kentucky, West Virginia, and Virginia. The major sequences are fourth-order sequences, a few meters to over a hundred meters thick. They consist of updip red beds and eolianites, lagoonal muddy carbonates, ooid and skeletal grainstone-packstone shoal complexes, open-ramp skeletal wackestone and slope-basinal laminated silty lime mudstone. The sequence boundaries are overlain downdip by lowstand sandstones and calcareous siltstones, and locally on the ramp by basal transgressive shales, eolianites, and redbeds; few sequence boundaries are calichified downdip, compared with updip sections in Kentucky. Transgressive systems tracts on the ramp are siliciclastic prone. Maximum flooding surfaces on the ramp slope occur beneath slope or basinal facies that overlie lowstand to transgressive complexes; on the ramp, maximum flooding surfaces occur beneath widespread grainstones that overlie nearshore shale or lime mudstone. The highstand systems tracts contain significant grainstone units and are relatively free of siliciclastics. Fourth-order sequences are arranged into weak third-order composite sequences. Correlation of the sequences with third-order global sea-level curves, and high-frequency sequences in the Illinois Basin (Smith 1999, 2001) indicates that the eustatic signal driven by moderate ice sheets on Gondwana generated the sequences, whose thicknesses were controlled by foreland basin tectonics.

Palynofacies Analysis, Source Rock Evaluation, and Organic Thermal Maturation of the Gray Fossil Site, Gray, Tennessee, Mohamed K. Zobaa, Michael S. Zavada, East Tennessee State University, Department of Biological Sciences, Johnson City, TN 37614, zobaa@etsu.edu, zavadam@etsu.edu; and Michael J. Whitelaw, East Tennessee State University, Department of Astronomy, Physics, and Geology, Johnson City, TN 37614, whitelaw@etsu.edu

The Gray fossil site (GFS), Gray, Tenn., preserves a paleolake sequence that contains a well preserved faunal and floral biota. It occurs as Miocene aged fill, up to 42 m thick and 3.5 ha in area, which occupies a karst feature developed within Ordovician carbonates. The palynofacies analysis of 28 subsurface core samples has revealed the presence of large amounts of diverse and well preserved particulate organic matter. Samples were counted and data plotted on an “Amorphous Organic Matter (AOM)-Phytoclast-Palynomorph” ternary plot to characterize the kerogen assemblages. Phytoclasts and opaques are the most abundant organic constituents and have diluted both the palynomorphs and AOM. This suggests an oxidizing depositional paleoenvironment or a localized high flux of charcoal following wildfires and subsequently increased runoff. The information provided by estimated vitrinite reflectance, spore/pollen coloration and visual petrographic kerogen analysis is used to define source rock potential as well as organic maturation level. The studied section contains kerogen type III to IV indicative of gas prone source rocks. These rocks are thermally immature and not suitable for natural gas generation. Palynofacies analysis indicates that wildfire was an important and periodic element during deposition of the GFS sediments.

Lexington Center



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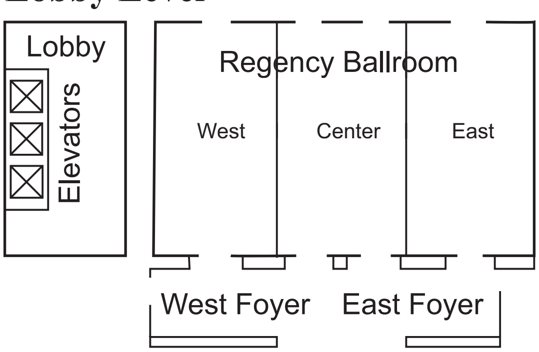

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