Gee Whiz Geophysics…But What About the Log Data? Normalizing, Editing and Supplementing Log, Core and Production Data from 1935 to the Present

J.S. Arbogast, Petroleum Software Technologies, LLC

Geophysicists have been trying to squeeze as much useable information as possible from seismic data long before the discovery of bright spots. Today they display this information with 3D visualization software and 3D seismic is touted as the answer to all things. However, most log data (even ancient log data) have 10-25 times better vertical resolution than today’s seismic data however, many geoscientists treat log data much like it was treated in 1935. They obtain copies of the logs, display them in cross sections, correlate them, and map them. The use of mixed-vintage, incomplete, and/or poor quality log data however, can lead to serious problems in interpretation. Without accurate, normalized, high-resolution log data for every well in a study area, correlations, seismic ties and maps may be incorrect. As a result, 3D seismic interpretations based on these data may turn out to be amazing. But these 3D representations are grossly inaccurate and are becoming more common.

New Interest in Cores Taken Thirty Years Ago: The Devonian Marcellus Shale in Northern West Virginia

K.L. Avary, J.E. Lewis, West Virginia Geological and Economic Survey

In the late 1970’s, the US Department of Energy cored a series of wells as part of its Eastern Gas Shales Program. Seven of these cored wells were located in West Virginia. The first five wells in the program targeted the Lower Huron Member of the Ohio Shale in southwestern West Virginia. This black shale has produced from thousands of wells for many decades in southwestern West Virginia and adjacent eastern Kentucky. The last two cored wells in the program focused on the older and deeper shales, the Rhinestreet Shale Member of the West Falls Formation and the Marcellus Shale of the Hamilton Group. Recent interest in the Marcellus Shale in West Virginia, Pennsylvania and New York has prompted renewed interest in these cores. During the Eastern Gas Shales Program, a large body of data was collected for all of the cored wells. Recently, the US Department of Energy released a Natural Gas Program Archive on DVD which contains scanned versions of the documents from the Eastern Gas Shales and other unconventional gas resources programs. In an effort to make this information readily available for current evaluations, data from the two WV Marcellus cores, located in Monongalia and Wetzel counties, have been extracted from the reports and summarized. Average total organic carbon ranges from 6.19 to 6.79% while average vitrinite reflectance values range from 1.71 to 2.30 %R0 for the Marcellus in these two cores.

Regional Geology of the Middle Devonian Marcellus Shale, Appalachian Basin


The Middle Devonian Marcellus Shale is the oldest, thickest and most widespread of four formations in the Hamilton Group of central and eastern New York. This black shale unit extends from New York southward to Virginia and West Virginia, and westward into eastern Ohio where it pinches out beneath the Middle Devonian unconformity. In Ohio, the Marcellus Shale generally is not separated from younger rocks in the lower Olentangy Formation; in Virginia, the Marcellus usually is included in the basal portion of the thick Millboro Shale. Throughout the basin, the Marcellus Shale overlies the Onondaga Limestone or eastern facies equivalents, the Huntersville Chert or Needmore Shale.

The areal distribution of the Marcellus Shale is similar to other Lower and Middle Devonian black shale units in that it is thickest to the east, and thins to the west, whereas younger Devonian black shale tongues in the Rhinestreet and Lower Huron are thicker in the west and thin, then pinchout to the east. Thus, the thickest accumulation of this organic-rich black shale occurs along the eastern side of the basin from New York to Virginia where thermal maturity is the highest. This combination of thick, thermally mature (dry gas window) black shales with well-developed regional fracture sets makes the Marcellus Shale an attractive play along the eastern side of the basin far from historical shale play areas as well as in the center of the basin.

The eastern side of the basin also is structurally more complex, creating discrete areas where the Marcellus Shale is likely to be intensely fractured along major anticlines in the Valley and Ridge and High Plateau provinces. Thus, “sweet spots” would be expected within the broad regional extent of the Marcellus. Conversely, some of the current thinking is that these highly fractured areas should be avoided.

Assessment of Geological Carbon Storage Capacity in the Cambrian Mt Simon Sandstone; Regional Assessment to Site Characterization and Feasibility, an Example from the Michigan Basin

D.A. Barnes, MGRRE/Western Michigan University; D.H. Bacon, Battelle Pacific Northwest Division

Geological carbon storage (GCS) capacity in the Michigan basin, in excess of 86 billion metric tons of CO2, was reported in the DOE/NETL Carbon Sequestration Atlas of the US and Canada (CSAUS&C). Investigations were undertaken to refine estimates in the Cambrian Mt Simon Sandstone and establish the feasibility of GCS for a large, stationary emissions source, although capture facilities are not now in place. The Mt Simon may have little effective porosity in the central basin below approximately 1.8 to 2.0km due to diagenetic alteration. Lateral and vertical facies changes in the basin also result in substantial variation in fundamental rock properties and petrophysics. Using methodology modified from the CSAUS&C, estimates of storage capacity of the Mt. Simon Sandstone in Ottawa Co. are between 5000 and 14000 metric tons per acre. Numerical simulations of CO2 injection were conducted using the STOMP-CO2 simulator to assess the potential for geological sequestration at maximum theoretical injection rates. Injecting CO2 for 4 years at a rate limited by a fracture pressure gradient of 0.8 psi/ft results in injection rates that vary between 16 and 29 MMT/yr. After 4 years, the total amount of CO2 injected is 102.7 MMT.
with 99 MMT as supercritical CO₂ and 3.7 MMT dissolved into the brine. After 4 years of injection, the maximum radius of the supercritical CO₂ is 3 km and injection pressures at the bottom of the caprock (Eau Claire Formation) are below the fracture pressure limit. Although these results suggest that the Mt. Simon has the capacity to accept the large volume, CO₂ output of a typical coal-fired power plant in a small number of injection wells, further sensitivity analysis and field validation will be needed before such high injection potential can be verified.

The Effects of Hydrothermal Mineralization on Rock Properties and Reservoir Quality in Paleozoic Carbonate Reservoirs, Michigan Basin, USA

D.A. Barnes, W.B. Harrison III, G.M. Grammer, MGRRE/Western Michigan University

In carbonate-dominated successions, dolostone often forms the best reservoirs. Petrologic data, T_h, T_m, and oxygen isotopes in authigenic carbonates, indicate that fracture-related, hydrothermal alteration of primary limestone mineralogy and texture was an important mechanism in forming dolostone reservoirs in the Michigan basin; the Devonian Dundee-Rogers City, Upper Silurian Bass Islands, Middle Silurian Burnt Bluff, and Middle Ordovician Trenton/Black River formations. Hydrothermal dolomite in these units occurs as baroque intergranular cement, baroque fracture/vug fill, and micro-spar replacement of primary limestone matrix. Other late diagenetic phases include pyrite; bitumen; quartz; fracture-filling, sparry calcite; anhydrite; and rare fluorite. Hydrothermal mineralization apparently resulted from reoccurring interaction of primary limestone with formation fluids of high salinity (>30 wt %) and oxygen isotope compositions ranging from -5 to -12°/O (PDB) at minimum temperatures of 120°-170°C. Hydrothermal mineralization probably resulted from the interaction of primary limestone with high pressure/high volume brines of evaporatively modified sea water origin, which interacted with a significant heat source below the sedimentary succession in the basin. Hydrothermal mineralization in these reservoirs, including pervasive dolomitization and dissolution of primary limestone, had a fundamental impact on petrophysical properties and dolostone reservoir characteristics including extreme spatial discontinuity on a variety of scales. Hydrothermal dolostone reservoirs incorporate a heterogeneous, dual porosity system with high permeability/low porosity fracture pores and volumnetrically more important patchy (vuggy), intercrystalline meso-porosity in dolostone matrix. Recognition of these reservoirs provides a conceptual framework for understanding the flow properties, spatial distribution, and internal geometry inherent in these reservoirs.

Identifying Electrostatic Interactions in Aqueous and Non-Aqueous Media Using Atomic Force Microscopy and Extended DLVO Theory

M.J. Bower, T.L. Bank, R.F. Giese, Department Of Geology, SUNY-Buffalo

In non-aqueous media, such as petroleum products, colloidal stability is poorly characterized and modeled. However, an understanding of colloidal stability is vital to the petroleum industry as it influences the recovery and processing of unconventional resources, as well as the efficiency of engine oils. In this research we investigate the effects of different additives (i.e. surfactants, urea) on colloidal stability in decane, a major component of commercial oils. Some additives that improve oil efficiency contain Zn and Ca which generate electrostatic charges and decrease colloidal coagulation by increasing electrostatic repulsions. In some systems, urea is used as an additive to enhance colloidal coagulation and thus increase filtration and lengthen oil lifetimes. We have used Atomic Force Microscopy (AFM) to measure the interfacial forces between polystyrene colloids and a glass surface in decane and in water. Preliminary results show that electrostatic interactions, which dominate colloidal stability in aqueous solutions, were significantly reduced in the non-polar decane. In future experiments, we will measure iron-oxyhydroxide colloid stability in decane and decane treated with various chemical amendments in order to represent a more geologically relevant, engineered system. Extended-DLVO (XDLVO) theory will be used to describe the van der Waals, electrical double layer, and acid/base interactions based on the total free energy of each system. XDLVO modeling will utilize surface contact angles and zeta-potential measurements to determine the total free energy of the system. This research will improve our understanding of the fundamental mechanisms of various chemical amendments and recovery techniques in the petroleum industry.

A National Look at Carbon Capture and Storage - National Carbon Sequestration Database and Geographical Information System (NatCarb)

T.R. Carr, Department of Geology and Geography, West Virginia University

The DOE’s Regional Carbon Sequestration Partnerships (RCSPs) generated data for the layers displayed in the Carbon Sequestration Atlas of the United States and Canada. These key geospatial data (carbon sources, potential storage sites, transportation, land use, etc.) are required for efficient implementation of carbon sequestration on a broad scale. NatCarb is an online relational database and geographic information system (GIS) that integrates carbon storage data from the RCSPs and various other sources. The digital spatial database allows users to estimate the amount of CO₂ emitted by sources (such as power plants and other fossil-fuel-consuming industries) in relation to geologic units that can provide secure sequestration sites. NatCarb organizes and enhances the information about CO₂ sources and develops the technology to access, query, analyze, display, and distribute natural resource data. Data are maintained at the RCSP level, or at specialized data warehouses, and assembled through a single geoportal. NatCarb is a functional demonstration of distributed data-management systems that cross the boundaries between institutions and geographic areas. It forms the first step toward a functioning national carbon cyber-infrastructure. NatCarb provides access to the necessary information regarding the costs, economic potential, and societal issues of CO₂ capture and storage, including public perception and regulatory aspects. NatCarb is connected to all the RCSPs and to public servers including the U.S. Geological Survey-EROS Data Center and from the Geography Network. Data for major CO₂ sources are obtained from U.S. Environmental Protection Agency (EPA) databases, and energy data were obtained from the Energy Information Administration (EIA).


The Summit gas field, located along the Chestnut Ridge anticline in southern Fayette County, Pennsylvania, offers an appropriate setting to discuss the carbon sequestration potential of the Oriskany Sandstone, one of the most promising, laterally extensive saline aquifers in the Appalachian basin. Discovered in April 1937 with the drilling of New Penn Development Corporation’s No. 1 Leo F. Heyn well, the Summit field produced gas from roughly 300 feet of fractured Devonian Huntsville Chert and Oriskany Sandstone. The Heyn well produced an initial open flow of 1,800 MCF at a depth of 6,611 feet, and represents the first well ever drilled to produce from this combined, chert-sandstone reservoir. The original pool was eventually named North Summit as other Huntsville-Oriskany pools were discovered in separate fault blocks throughout the field. Reported intergranular porosities for these clastic rocks are generally low (1.5 to 3.5 percent), but secondary fracture porosity associated with multiple thrust faults greatly improved the reservoir’s productivity. The North Summit pool eventually produced 22 BCF before it was converted to natural gas storage in 1991.
Petrologic and petrophysical reservoir characterization data collected on behalf of the Midwest Regional Carbon Sequestration Partnership (MRCSP) serve to augment the North Summit storage pool’s existing data set and advance our understanding of the fractured Huntersville-Oriskany reservoir relative to its carbon sequestration potential. Existing geophysical data are used to evaluate whether other Huntersville-Oriskany pools have comparable reservoir properties and storage capacities, thereby showing promise for carbon sequestration.

The Ontario Phase of the Trenton-Black River Hydrothermal Dolomite Play: Historical Context and Contributions to a Modern Exploration Model

T.R. Carter, Ontario Ministry of Natural Resources; R. A. Trevail, Dallas Energy LLC

The Trenton-Black River play started in 1884 when oil and gas was discovered near Findlay, Ohio, leading to the drilling of nearly 100,000 wells in the giant Lima-Indiana trend. Discovery of the Deerfield oil field in 1936 expanded the play to Michigan and eventual discovery of the giant Albion-Scipio field in 1957. The first modern discovery well in New York was drilled in 1986 but development did not begin until 1996. The play has now expanded throughout Appalachia. In Ontario key events were the discovery of the Dover gas pool in 1917 and the Hillman and Dover 7-5-VE pools in 1983. Ontario was the focus of the entire play in the 1980’s and 1990’s. During that time innovations in seismic interpretation, including the first 3D survey, and improvements of the geological model greatly improved exploration success rates, leading to 39 new field discoveries between 1982 and 2004. The first horizontal wells in the play were drilled in Ontario. Lessons learned in Ontario have been applied with great success in New York State by Fortuna Energy. Cumulative production from Trenton-Black River reservoirs in Ontario totals 22.5 million barrels of oil and 40 bcf of natural gas to the end of 2007. Proven recoverable reserves in individual pools range up to 6 million barrels of oil and 13.6 bcf of natural gas at an average depth of 825 metres. A 2005 assessment estimates that 85% of the natural gas and 43% of the oil resources in this play are still undiscovered.

Reassessment of Devonian Reservoirs in Green County, Indiana

K. Chaudhary, B.D. Keith, Indiana Geological Survey at Indiana University

Devonian structures draped over Silurian reefs have long been targets for petroleum production and also for the underground storage of natural gas in the Stone Oak and Oriskany zones. The Oriskany reservoir relative to its carbon sequestration potential. Existing geophysical data are used to evaluate whether other Huntersville-Oriskany pools have comparable reservoir properties and storage capacities, thereby showing promise for carbon sequestration.

Comparison of Reservoir Characterization Approaches Used in Models for CO₂ Sequestration within the Illinois Basin


The Illinois State Geological Survey, as part of the Midwest Geological Sequestration Consortium, has designed a number of field pilots to test CO₂ injection as a means for enhanced oil recovery. The first pilot involved a huff-n-puff well stimulation technique in the Louden field in Illinois in 2007. In order to make useful predictions, a detailed model of the reservoir architecture was required to produce injection and transport simulations. Due to the plethora of work on reservoir modeling, there are a variety of different approaches available. One of the main challenges in selecting a model is finding a balanced approach that honors the data as well as the input from the theoretical depositional model. In this case, a pure stochastic approach was utilized in order to best honor all the data available. This approach allows the data to control the model interpretation. In order to perform a post-operation review, we will revisit this model using a deterministic facies modeling approach. This approach incorporates a conceptual model of the facies into the model, making more use of the geologist’s interpretation skills. The focus of this research will be to objectively evaluate the two methods and compare the results of modeling in a heterogeneous environment. The analysis will look at the variation produced among the realizations as well as the subsequent predictions from the injection simulations. Successful analysis will lead to better refined models for future tests as well as provide insight on model selection.

Imaging Extensional Fault Systems Along Foothill Trends

M.A. Davies, D.J. Bate, ARKeX Inc; W. Wheeler, JECBO Seismic LP

The foothills region of the Canadian Rocky Mountains is considered to be a prospective hydrocarbon province. To date relatively few wells have been drilled, this is primarily because exploration costs are prohibitively expensive. In 2005 ARKeX Ltd was contracted by JECBO Seismic (Canada) to acquire a multi-client BlueQube airborne geophysical survey over Muskwa-Kechika, British Columbia. The BlueQube survey, covering 3,000 sq km of the Rocky Mountain Foothills was completed in the winter of 2006/07 and the data acquired provides the explorationist with previously unattainable high resolution airborne gravity gradiometry imaging, magnetic gradiometry and LIDAR data. The recent commercialization of the previously classified defense technology gravity gradiometry has opened up a new and exciting genre of exploration in the oil, gas, and mining industries. The simultaneous acquisition of complementary data sets delivers a cost effective, multidisciplinary interpretation, of previously hard to reach areas. Gravity gradient imaging was used to map extensional faulting systems east and in front of the thrust front proper. A new methodology based on convolving end member inversion models was developed, which allowed the signal from rotated Triassic fault blocks (masked by overlying Cretaceous clastics) to be isolated from signals relating to deeper structures. This paper is a critique of the methodology used, the ability of gravity gradient imaging to identify targets of this nature and the success and failure of a blind inversion result to that of known producing / dry wells.
Tectonism, Estimated Water Depths, and the Accumulation of Organic Matter in the Devonian - Mississippian Black Shales of the Northern Appalachian Basin

F.R. Ettensohn, Department of Earth & Environmental Sciences, University of Kentucky

Water depths during deposition of the Devonian-Mississippian black shales of eastern North America have been estimated at anywhere from “knee-deep” to thousands of meters, but both end-member estimates are probably incorrect. Similarly, physical, paleontological, and geochemical bathymetric indicators suggest overall deepening with time, but offer little evidence of the depths involved. Nonetheless, occurrence of the black-shale sequence in the northern Appalachian Basin as alternating units of black shale and intervening coarser clastic wedges not only reflects the cyclic nature of Acadian tectonism in adjacent orogenic source areas, but also provides a means for approximating water depths during black-shale deposition. These black shales clearly accumulated in a foreland-basin setting in which each black-shale unit represents an episode of rapid, foreland, tectonic subsidence below the pycnocline (anaerobic conditions) and subsequent infilling of the basin with shales and coarser clastics into higher, dysaerobic and aerobic parts of the water column. Due to the largely, near-sea nature of any subsidence event, measuring the thickness of a clastic wedge from the top of the basal black shale to a sea-level datum in the overlying coarser-clastic counterpart provides an approximation of absolute depth. Because some basins were underfilled and because the varying effects of compaction cannot be easily considered, the estimates are minimal at best. Nonetheless, the exercise provides order-of-magnitude estimates and reflects depths ranging from 80 to 310 m during deposition of Lower Devonian - through-Lower Mississippian black shales in the northern Appalachian Basin. The estimates not only show a general deepening with time, but also reflect shallowing-upward, third-order cycles that coincide with the timing of unconformity-bound sequences containing one or more, black shale-clastic wedge cycles. To confirm the origin of the cycles, the distribution of black shales in each cycle was mapped in space and time, which showed that black-shale units clearly tracked the progress of Acadian tectonism as predicted by flexural models. Increasing depths over time probably in large part reflect the cumulative effects of tectonic loading, but the Devonian was also a time of eustatic sea-level rise, and this, together with a unique paleogeographic setting, probably ensured large areas of enhanced organic productivity and the deep, stratified waters necessary to preserve it. It is probably no accident that the youngest — and deepest — of the black shales contains the highest amounts of organic matter. Hence, attention to estimated depths, combined with the extent of respective black-shale basins, may provide information about the likelihood and location of the most organic-rich source rocks.

Gas Character Anomalies Found in Highly Productive Shale Gas Wells

K. Ferworn, J. Zumberge, Geomark Research, Ltd.; J. Reed, Reed Geochemical Consulting

Stable carbon isotopes measured in gases allow for numerous useful interpretations including the identification of “families”, observing seals and providing evidence of migrated thermogenic gas accumulations. In shale gas plays, where the source rock is also the reservoir, carbon isotopes of ethane and propane are strong thermal maturity indicators and accurately calibrated against measured vitrinite reflectance values. The calibration is particularly useful when coupled with mud gas isotope analyses (MGIA) where gas samples from the mud stream are collected at specific depths and used to generate a “thermal maturity” log. Stable carbon isotopes become increasingly heavier (more positive) with increasing maturity. However, in certain shale gas plays (including the Barnett, Fayetteville, Woodford and Appalachia) an interesting phenomenon occurs at high maturity where the ethane and propane isotope values begin to reverse and become lighter (more negative). In these highly mature shale environments, laboratory testing suggests that in-situ gas cracking is occurring where larger molecules like butanes and pentanes are cracking into smaller molecules with lighter isotopic signatures. A key observation is that many of these “isotopically reversed” wells appear to be the most productive. One possible advantage might be higher reservoir pressures associated with an increase in the concentrations of smaller gas molecules. Furthermore, if the shale has moved past the kerogen and oil cracking stages to reach the gas cracking maturity level, the shale is likely more brittle shale with increased porosity and permeability. The gas cracking behavior has not been observed in all high maturity shales, and perhaps not coincidentally, some of the early wells do not appear as productive as those exhibiting the isotope reversals.

Marcellus Shale Gas Well Development Produced Water Treatment

M. Gannon, P. Miller, Tetra Tech

New horizontal drilling techniques for developing the Marcellus Shale for natural gas extraction generate large quantities of produced water that includes the returned frac water and formation water. Both sources of water contain a variety of constituents which need to be addressed prior to discharge or reuse. The Pennsylvania Department of Environmental Protection (PA DEP) and applicable river basin commissions regulate the discharge and disposal of produced water. There can be many advantages to reusing the produced water for well development, provided the required water quality can be cost-effectively achieved. The unit operations for produced water treatment may involve:

- Source Water Pretreatment
- Collection and Equalization
- Filtration
- Oil and Grease Removal
- Organic Removal
- TSS Reduction
- Metals Removal
- TDS Reduction
- NORM Removal
- Reuse Conditioning

The poster session will compare and contrast available technologies for treating produced water to meet discharge or recycling requirements.

The Marcellus Shale Play in Pennsylvania - What's All the Fuss??


While exploring for Oriskany gas in New York and Pennsylvania in the 1930s, drillers found almost every well had a strong flow of gas in the Marcellus black shales that shut down drilling for several days. The Marcellus looked favorable until it became clear that the gas occurred in “pockets” (fractures) and that flows could not be sustained. Drillers learned to ignore these gas flows and soon stopped reporting them. During the 1970s/80s Eastern Gas Shales Project, the Pennsylvania Geological Survey correlated and mapped the Middle and Upper Devonian, generating technical reports, cross sections, and maps showing formation thicknesses and net feet of organic-rich shale throughout western and north-central PA. The Marcellus underlies most of Pennsylvania, but the organic-rich portion reaches its maximum development in the northeast. While Upper Devonian shales were thought to have excellent potential with expected development of better fracturing technology, the Marcellus was not considered promising until gas prices increased and technology advanced even further. Despite 70 years of high Marcellus gas flows, it took until recently for its potential as a commercial gas target to attract attention. Between 2003 and April, 2008, PA permitted more than 600 prospective Marcellus wells across the state. The actual value of the Marcellus as a gas reservoir has yet to be determined. Based on two years worth of available data from vertical wells, Marcellus production averaged only 43.7 Mcf/d. Data...
from horizontal wells are not yet available. Only time will determine just how productive and lucrative the Marcellus play truly is.

**Demonstrating Carbon Storage Options in Kentucky**

D.C. Harris, J.R. Bowersox, D.A. Williams, S.F. Greb, T.M. Parris, B.C. Nuttall, J.A. Drahozal, K.G. Takacs, Kentucky Geological Survey

Anticipating requirements to mitigate CO₂ emissions resulting from the use of coal, the Kentucky Legislature passed House Bill 1 in 2007. This bill authorizes funding for research by the Kentucky Geological Survey (KGS) in the areas of CO₂ enhanced oil and gas recovery, and permanent geologic storage of CO₂. To carry out these mandates, KGS partnered with energy companies and other agencies, and formed the Kentucky Consortium for Carbon Storage (KYCCS).

KYCCS projects will include deep CO₂ storage tests in eastern and western Kentucky, and CO₂ enhanced oil and gas recovery pilots. The Cambrian Mt. Simon Sandstone is an attractive sequestration target over much of the Midwest but its depth, questionable reservoir quality, and limited extent in western Kentucky will restrict its use for CO₂ storage. Cambrian sandstones in the Rome Trough of eastern Kentucky have excellent permanent geologic storage of CO₂. To carry out these mandates, KGS partnered with energy companies and other agencies, and formed the Kentucky Consortium for Carbon Storage (www.kyccs.org). KYCCS projects will include deep CO₂ storage tests in eastern and western Kentucky, and CO₂ enhanced oil and gas recovery pilots. The Cambrian Mt. Simon Sandstone is an attractive sequestration target over much of the Midwest but its depth, questionable reservoir quality, and limited extent in western Kentucky will restrict its use for CO₂ storage. Cambrian sandstones in the Rome Trough of eastern Kentucky have excellent permanent geologic storage of CO₂.

**Marcellus Shale Gas Well Development Water Management Planning**

S. Hughes, P. Miller, D. Skoff, Tetra Tech

Drilling techniques utilized for developing the Marcellus Shale formation for natural gas extraction are water intensive. As gas exploration and development has increased in the Commonwealth of Pennsylvania, increased focus has been placed on the supply of water for development activities; as well as the treatment and disposal of the produced water. In response, the Pennsylvania Department of Environmental Protection (PA DEP) recently issued an addendum to the Marcellus Shale Gas Well Application (5500-PM-OG0083) that mandates that a Water Management Plan be conducted as part of the application submittal process. The Water Management Plan requires that the following information be submitted with the application:

- Source of water
- Location of Proposed Source
- Public Water Supplier (if applicable)
- Amount of Water to be Withdrawn or Purchased
- Streams, Wetlands and Other Bodies of Water
- Safe Yield (to be completed by a Licensed Pennsylvania Professional Engineer)
- Act 220 Registration
- PA Natural Diversity Inventory
- Water Withdrawal/Use Evaluation
- Water Treatment, Reuse and Disposal
- Pits, Impoundments and Dams

The poster session will discuss these requirements and strategies to cost-effectively develop the Water Management Plan in a timely fashion.

**Reservoir Characteristics of the Bass Islands Dolomite in Otsego Co., Michigan - Results for a Saline Reservoir CO₂ Sequestration Demonstration**

W.B. Harrison III, D.A. Barnes, G.M. Grammer, Michigan Geological Repository for Research and Education, Dept. of Geosciences, Western Michigan University; P. Jagucki, Battelle Memorial Institute

As part of a Phase II plan to understand, test and evaluate the CO₂ sequestration potential for deep saline reservoirs in Michigan, a demonstration test well was planned, drilled and completed in late 2006 in Otsego County, Northern Lower Michigan. The well was drilled to 3630 feet and open hole logged. Selected conventional cores totaling 180 feet were taken in the saline reservoir (Bass Islands), the immediately overlying confining unit (Bois Blanc) and the overlying seal (Amherstberg). Additionally, 24 sidewall cores were taken in several well intervals. The whole core was drilled for 1-inch P&P plug analyses. Seventy-four horizontal plugs, 12 vertical plugs, 8 whole core and 17 sidewall core plugs were sent to Core Laboratories for routine P&P analyses. Also 15 blue-dyed, epoxy-impregnated thin sections made from selected P&P plugs. The whole core was slabbed for examination and description of lithology, sedimentary structures and facies characteristics. The immediately overlying confining unit, Bois Blanc Fm. is a very cherty limestone and dolostone with moderate porosity and low permeability. Thin sections show abundant microporosity. The target saline reservoir interval, Bass Islands, is a variably porous and permeable dolostone comprised of several tidal flat cyclic packages. It has a gross thickness of 70 feet with the reservoir interval over 40 feet of greater than 10% porosity and permeabilities exceeding 500 md. Average porosity over the entire Bass Islands is 12.5%. Average permeability is 22.4 md. CO₂ injection tests, utilizing the Bass Islands section were completed during February and March 2008.

**The Importance of Geological Variability on Petrophysical Properties When Estimating Geologic Storage Capacity in the Middle Devonian Dundee Limestone (Sensu Lato), Michigan Basin, USA**

J.P. Kirschner, D.A. Barnes, Western Michigan University & MGRRE

The Middle Devonian Dundee Limestone (sensu lato) has substantial Geologic Storage Capacity (GSC), estimated at 1.4-5.6 billion metric tons, in the Michigan Basin. Historically, the Dundee Limestone (s.l.) was separated into the Rogers City and Dundee (sensu stricto) Limestones only in outcrop. However, separation is also possible in much of the subsurface on the basis of wireline logs. The Dundee Limestone (s.s.) consists of evaporate prone peloidal facies in the western part of the basin, and predominantly shallow open marine patch reef, grainstone/packstone, and other facies in the east. The Rogers City Limestone is a mostly homogeneous, open marine, fissiliferous mudstone/wackestone that overlies the Dundee Limestone (s.s.). Localized fracture related dolomitization has significantly improved reservoir quality in both units. The petrophysical properties of the Rogers City and Dundee (s.s.) Limestones are intrinsically influenced by stark differences in lithology. Using statewide averages for porosity and thickness obscures GSC estimates even on the county scale. High end estimated GSC per unit area using statewide averages is 1,361 tons/ha for the Dundee (s.l.), 1,089 tons/ha for the Dundee (s.s.), and 139 tons/ha for the Rogers City. Estimated GSC per unit area using county averages for the respective units are 2,285 tons/ha, 2,080 tons/ha, and 12 tons/ha in Arenac county, and 575 tons/ha, 367 tons/ha, and 86 tons/ha in Osceola county. Thus, statewide GSC estimates misrepresent known lithologic and petrophysical variability, which must be taken into account for any geologically sound GSC estimate.
Optimal Development of Utica Shale Gas Wells

G.J. Koperna Jr., J. Kelafant, V.A. Kuuskraa, Advanced Resources International, Inc.

In 1820, the first commercial shale well was drilled in the State of New York,¹ which lead to the eventual gas production from the Basin’s Devonian Shale reservoirs. Today, thanks to successful and active development of the Barnett, Antrim and Fayetteville shales, along with the Devonian (Huron/Ohio) of the Appalachian Basin, shale gas now accounts for 6% of U.S. gas production, totaling, more than 1000 BCF annually. As a result, no two words are more attention grabbing than “shale gas” in today’s oil and gas marketplace. While the Fort Worth Basin’s Barnett Shale has garnered most of the news over the past decade, what was old is now new in the Appalachian Basin. Operators have improved technologies, developed and honed in the Fort Worth Basin, to thank for this resurgence as these technologies hold promise for developing the region’s large Marcellus and Utica Shale gas deposits. This paper will discuss and release an extensive database of previously unpublished geochemical source rock data. The analyses represent samples from 28 wells and a few outcrops in 21 different counties throughout Pennsylvania. Most of these wells are situated on the Appalachian Plateau, however, six are located in the Ridge and Valley province, and one well is in the Triassic rocks of the Newark basin in southeastern Pennsylvania. The 10 outcrop samples are from the Newark basin. The following analyses are presented in the database: (1) Total Organic Carbon (TOC); (2) Rock-Eval pyrolysis; and (3) visual kerogen, including vitrinite reflectance (Ro), thermal alteration index (TAl), kerogen type, and fluorescence. The data indicate the source rock potential of this unit. Geochemical logs for selected wells provide a useful tool for geologists working with the Marcellus Shale gas development. For this, the paper will conduct a parametric reservoir study for an example Utica Shale gas development project. The subject wells were drilled and completed with modest stimulation treatments. This review will review past performance and assess optimum stimulation strategies (in terms of size and intensity) when using vertical for vertical and horizontal wells to produce the Utica gas shale.

An Organic Geochemistry Database - Evaluating the Marcellus Shale and Other Potential Petroleum Source Rock in Pennsylvania

J. Kostelnik, C.D. Laughrey, Pennsylvania Geological Survey

Organic geochemistry is a key factor in evaluating and mapping petroleum source rocks and unconventional thermogenic shale-gas reservoirs, including the Marcellus Shale in Pennsylvania. The recent flurry of Marcellus activity has prompted the Pennsylvania Geological Survey to develop and release an extensive database of previously unpublished geochemical source rock data. The analyses represent samples from 28 wells and a few outcrops in 21 different counties throughout Pennsylvania. Most of these wells are situated on the Appalachian Plateau, however, six are located in the Ridge and Valley province, and one well is in the Triassic rocks of the Newark basin in southeastern Pennsylvania. The 10 outcrop samples are from the Newark basin. The following analyses are presented in the database: (1) Total Organic Carbon (TOC); (2) Rock-Eval pyrolysis; and (3) visual kerogen, including vitrinite reflectance (Ro), thermal alteration index (TAl), kerogen type, and fluorescence. The data indicate the source rock potential, the product expelled at peak majority, and the stage of thermal maturity. In addition to these data, we will be adding comprehensive stable gas isotope analyses to the database. Specific results from the Marcellus Shale illustrate the role these technologies, specifically, can utilize the raw data sets to evaluate the source rock and shale reservoir potential of this unit. Geochemical logs for selected wells provide a comprehensive look at how potential source rock intervals throughout the commonwealth are identified and evaluated. The data will provide a useful tool for geologists working with the Marcellus shale, and for identifying other potential black shale reservoirs in the state.

Unraveling the Stratigraphy of the Oriskany Sandstone: A Necessity in Assessing Its Site-Specific Carbon Sequestration Potential

J. Kostelnik, C.D. Laughrey, Pennsylvania Geological Survey

The Lower Devonian Oriskany Sandstone is considered a carbon sequestration target in the Appalachian basin due to its widespread distribution, favorable reservoir characteristics, and depth. The lithology of this saline aquifer, however, varies regionally, particularly in distal parts of the basin. This complicates stratigraphic interpretations of the Oriskany Sandstone and adjacent Bois Blanc Formation and Helderberg Group rocks. For this reason, the Midwest Regional Carbon Sequestration Partnership (MR CSP) has recommended detailed site assessments when evaluating the sequestration potential of the Oriskany Sandstone at a given injection site. The Oriskany Sandstone is a very fine to coarse-grained, monocrystalline quartz arenite. In many parts of the basin, however, the unit is considered a sandy limestone with abundant carbonate grains and cement. The Oriskany was deposited in several shallow-marine and paralic environments, and has been derived from numerous clastic sources. The formation is thickest in the structurally complex Ridge and Valley province, thins toward the northern and western basin margins, and is even absent in other parts of the basin (i.e., the “no-sand area” of northwestern Pennsylvania). We have evaluated the Oriskany Sandstone throughout the central Appalachian basin to characterize relationships among its lithology, reservoir characteristics, and potential carbon dioxide storage capacity. Oriskany samples collected from 15 wells represent regional variations in depositional and diagentic environments, as well as structural alteration of the rocks, all of which have impacted this reservoir’s porosity and permeability. Geophysical log analyses provide additional petrophysical data for localities where sample or core data are absent.

Six Days Burning: Geology & Petrology of an Upper Devonian Well Fire Jefferson County, Pennsylvania

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In December 1992, the Empire Exploration Maslowski #7221 well caught fire during logging. The rig was destroyed and the fire took six days to extinguish, consuming an estimated 9-13 MMcfgd. Fortunately, there were no injuries, the well was saved and it was eventually brought online. After a hydraulic fracture the open flow of the well increased to 3.1 MMcfgd. The Maslowski well is expected to ultimately produce 263 MMcfgd. Cumulative production is currently 253 MMcfgd. The source of the ignition is still unknown. The fire was an unforeseen event. But equally unforeseen was the quality of the reservoir, which led to the sustained open flow rates of 1.5 to 2.2 MMcfgd, which abundantly fed the fire and made the well difficult to kill. The main productive reservoir, the Cooper Sandstone, is part of a probable Upper Devonian estuary complex that developed following an erosional sea level lowstand. Cross-sections and mapping confirm this interpretation. Petrographic and X-ray Diffraction analyses confirm the favorable diagenetic history, which resulted in the preservation of extraordinarily primary porosity and permeability in this normally tight sandstone. Core-derived porosity in the Cooper reservoir exceeds 20 md. Natural fractures are not present. The superior porosity and permeability in this reservoir are the result of a favorable inverse relationship between diagenetic rim-chlorite and pore-filling silica cements. Prediction of the occurrence of this favorable relationship prior to drilling is difficult, but general rules guiding its likelihood can be formulated.

Potential for Prolific Reef-Related Reservoirs in the Sangamon Arch, West Central Illinois

Y. Lasemi, B. Seyler, Illinois State Geological Survey

Hydrocarbon production along the Sangamon Arch, a broad southwest-trending structure in west-central Illinois, thus far has been chiefly from the non-reef carbonate reservoirs in the uppermost part of the Niagaran (Silurian) succession. To date, there have been no documented reports of any reef reservoirs in the Sangamon Arch area and there is a general lack of understanding of the occurrence, geometry and facies distribution of these potentially important reservoirs. Preliminary studies along the southern flank of the arch have revealed the presence of a reef interval in the lower part of the Niagaran succession. The reefs are composed mainly of coral skeletons, but their internal structure is poorly preserved as a result of pervasive dolomitization. They occur as patch reefs of...
limited lateral extent that grade laterally and vertically into impermeable, bioturbated and bioclastic mudstone to wackestone or to a very finely crystalline, argillaceous dolomite inter-reef facies. The reefs and associated facies display a shallowing-upward cycle and may occur in 1 to 3 horizons. The majority of wells in the study area have not tested the lower part of the Niagaran deposits that include the newly-recognized patch reefs, so the potential of these productive lower horizons has been mostly overlooked. Examination of a few highly productive wells indicates that the highest production is normally associated with this type of reservoir. The results of our study suggest that, there is an excellent possibility for finding more productive Niagaran patch reefs along a vast area of the Sangamon Arch.

Silurian Carbonate Reservoirs of the Mount Auburn Trend along the Sangamon Arch, West-Central Illinois

Y. Lasemi, B. Seyler, Illinois State Geological Survey

The Silurian succession of the Sangamon Arch in west-central Illinois is composed of hydrocarbon-bearing carbonate rocks. Over 12 million barrels of oil have been produced from these rocks in the Mount Auburn trend, along the southern flank of the arch, chiefly from dolomitized carbonate reservoirs in the upper part of the Niagaran series. To date, there has been no detailed study of the Niagaran reservoirs in the Sangamon Arch area; there is a general lack of understanding of the reservoir facies types, distribution, geometry, porosity development, petroleum entrapment and their controls. Detailed subsurface studies along the Mount Auburn trend have revealed the presence of permeability pinch outs at several horizons. They include dolomitized packstone-grainstone facies in the upper part and coral patch reefs in the lower part of the Niagaran succession. These reservoir facies are characterized by lenticular bodies of limited lateral extent that grade laterally and vertically into an impermeable limestone facies or a very finely crystalline, argillaceous dolomite facies. They were deposited along a southwest trending platform margin that was roughly parallel to the Sangamon Arch trend and graded basinward into muddy carbonates below wave base. This study shows that reservoir rocks in the study area are compartmentalized and productive facies display a shallowing-upward cycle that may occur at several horizons. However, most wells drilled thus far have only tested the uppermost part of the Niagaran succession; only a few wells have tested the lower reservoirs that include the newly-recognized patch reefs. A detailed subsurface facies analysis is currently underway to characterize the distribution of various porosity zones and assess the potential for finding additional productive pay zones in the Sangamon Arch area.

Marcellus Shale Subsurface Stratigraphy and Thickness Trends: Eastern New York to Northeastern West Virginia

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Recent interest in the Middle Devonian Marcellus Shale of the Appalachian Basin necessitates a more complete understanding of the subsurface stratigraphy of this emerging play. Tracing of the stratigraphy of the Marcellus Shale defined by outcrop studies in New York, which comprises two black shale intervals separated by a thin limestone horizon, yields information regarding basin evolution, notably differential uplift likely produced by development of a forebulge during the Acadian Orogeny. However, difficulty in identifying the Stafford Limestone at the top of the Marcellus over much of the subsurface of central and northeastern Pennsylvania and eastern-central New York precludes widespread use of this stratigraphy. Perhaps more meaningful to exploratorist is the total radioactive interval thickness of the Marcellus Shale. In most regions of the basin, the Marcellus comprises lower and upper radioactive intervals separated by a limestone or shaley-limestone interval of variable thickness. The total radioactive interval thickness of the Marcellus Shale increases to > 200 ft toward the center of the basin in the Lycoming County area of Pennsylvania. Mapping reveals a thick (locally > 200 ft) north-northeast-trending area of thick radioactive shale extending through western Susquehanna County, Pennsylvania, into Broome and Chenango counties, New York. Isopach trends in the Fayette County, Pennsylvania, region of the basin may reflect the influence of the Rome Trough, but not to the extent that depositional patterns of the Upper Devonian Rhinestreet and Huron organic-rich shale intervals were affected by subsidence of the trough.

Sulfate Mineralization, Thermochemical Sulfate Reduction, and Burial Diagenesis in Ordovician and Silurian HTD Reservoirs, Central Appalachian Basin

C.D. Laughrey, Pennsylvania Geological Survey

Hydrothermal dolomite (HTD) reservoirs in the Ordovician Trenton/Black River Limestone and Silurian Lockport Dolomite produce significant quantities of natural gas in the central Appalachian basin. The Lockport Dolomite also is a potential CO2 sequestration target. The aerial extent of dolomitization is significantly different in the two reservoirs. HTD in the Trenton/Black River is restricted to fractured rocks in structurally low synclinal sags oriented en echelon to basement faults. Dolomitization in the Lockport is regional over much of the central Appalachian basin. Dolomite textures, porosity fabrics, and associated mineralization, however, are essentially identical in the two units and reflect the dominance of mesogenetic and telogenetic processes during burial diagenesis. The emplacement of calcium sulfate as a by-product of dolomitization was an important component in the textural evolution of these rocks. Anhydrite and gypsum partially replace dolomite and occur as cements in both fabric selective and non-fabric selective pores. Gypsum is restricted to relatively shallow reservoirs where it is partially replaced by anhydrite. Deeper dolostone reservoirs contain anhydrite interpreted as either dewatered gypsum or as primary anhydrite. Authigenic pyrite, bitumen, and methane occur as inclusions within the sulfate minerals. H2S is produced from some of the dolomite reservoirs. The mean δ34S of this gas is 14.7 permil which suggests that thermochemical sulfate reduction (TSR) of gypsum and anhydrite is the source of the sour gas. Additional evidence for TSR includes the presence of late solid bitumen and pyrobitumen, replacement of CaSO4 by calcite, and reprecipitation of calcite and dolomite with Ca from dissolved sulfate minerals. Anhydrite and sulfur are sometimes concentrated on stylolite surfaces and authigenic metal sulfides are abundant in the dolostones. There is significant secondary porosity development associated with these burial diagenesis processes. Commercial gas accumulations in the Trenton/Black River and Lockport reservoirs are directly linked to the formation of this secondary porosity. These same diagenetic processes, however, also contribute to further cementation and porosity reduction as well as the generation of CO2 and the concentration of N2 in the rocks.

Thermal Maturity of Devonian Black Shale-Gas Reservoirs, Northwestern Pennsylvania - Evidence from Organic Petrology, Geochemistry and Mineralogy

C.D. Laughrey, Pennsylvania Geological Survey

Reliable interpretations of thermal maturation indicators (geothermometers) provide critical data needed for resource estimates in thermogenic shale-gas reservoirs. In the Appalachian basin, vitrinite reflectance (R0) is one the most commonly measured geothermometers used for mapping regional maturity patterns in the Devonian black shales. R0 values from distal Catskill delta mudrocks suggest that organic matter in these shales is immature. This observation contradicts hypotheses suggesting that regional joint sets in these rocks formed as natural hydraulic fractures induced by abnormal fluid pressures during catagenesis. Some workers suggest that the R0 values are suppressed. Analyses of several different geothermometers in cores of Huron through
Marcellus shale recovered from the EGSP-PA #3 well in Erie County, Pennsylvania indicate that the rocks actually are in the early to peak stage of catagenesis. The mean conodont alteration index (CAI) is 1.5. The mean illite crystallinity factor is 0.10, a value that approximates the observed CAI values. $T_{max}$ and production indices, from Rock-Eval pyrolysis, range from 439°C to 442°C and 0.05 to 0.10, respectively. The ratios of methane to TOC are 0.06 to 0.072. Several biomarker maturity indicators also imply that these shales are in the oil window. These include C1 homohopane isomerization, the Te/Ts + Tm ratio, C29 sterane isomerization, and the ratio of 5x20S/5x20R ($C_{(29)S}$). Carbon preference indices of 1.10 and isoprenoid/n-alkane ratios are consistent with catagenesis. Crossplots of the stable isotopes of methane ($^{13}C$ and $D$) indicate that associated gas was generated in the black shales. The $\delta^{13}C$ of methane, ethane, and propane are consistent with the oil window. The biomarker preference indices (TI) consistent with wet gas generation in the upper oil window. Burial modeling shows that the rocks entered the oil window approximately 190 Ma and were exposed to temperatures as high as 120°C over a period of 50 million years before uplift retrogressed organic maturation in the rocks.

Mississippi Valley-Type Lead-Zinc Ore Deposits, Hydrothermal Dolomite and Hydrocarbon Reservoirs

D. Leach, U.S. Geological Survey

Current interest in “hydrothermal dolomite” in the hydrocarbon industry and the resurgence in exploration for Mississippi Valley-type (MVT) lead-zinc deposits have led to renewed attention to the links between MVT deposits and hydrocarbon reservoirs containing “hydrothermal dolomite” or coarse, sparry dolomite. Some of the recent literature on hydrothermal dolomite commonly contains questionable fluid inclusion data on dolomite, as well as obtuse interpretations of dolostone fabrics, dissolution collapse breccias, and dolomite replacement features, which together obscure understanding of what is hydrothermal dolomite and what is not. New results in the field of economic geology help define the links between the formation of MVT deposits and the alteration and/or dissolution of carbonate rocks associated with MVT ores and sulfide-barren dolomite bodies that host hydrocarbon resources. The precipitation of dolomite in MVT deposits depends on the composition of the ore-forming fluids, the geochemical reactions that produce ore, and the carbonate host lithology. Fluid mixing in limestone can cause significant calcite dissolution and dolomite precipitation independent of ore deposition, thus explaining some massive hydrothermal dolomite bodies devoid of sulfides. This process may have played a role in porosity development in the Appalachian basin’s Trenton-Black River hydrocarbon play. Pervasive replacement of pre-existing dolostone by hydrothermal dolomite associated with mineralization in dolostone is typically limited to narrow zones (< several hundred meters) surrounding the ore deposits. Some large MVT ore systems deposited sparry dolomite cement in a variety of open spaces (e.g., fractures, vuggy porosity and carbonate dissolution features) for hundreds of kilometers in dolostone aquifers.

Development of a Large-Scale CO2 Sequestration Site in the Illinois Basin


One of the most important aspects of the development of a large-scale CO2 sequestration site is reservoir characterization. Because sequestration is most likely to occur under a cap-and-trade or carbon credit scenario, verification of long-term CO2 sequestration in geologic formations is critical. Consequently, characterization of the injection zone impacts the projections of injection rates and storage capacity at the site. Moreover, this initial geologic characterization creates the baseline in which to compare all models developed from data collected after CO2 injection begins. Key questions for locating a sequestration ready plant include: what are the seals, how thick is the reservoir, how permeable and porous is the reservoir, what is the reservoir heterogeneity, where will the CO2 migrate, and what is the ultimate fate of the CO2. The Mt. Simon Sandstone, a Cambrian age formation, is the most important sequestration target in the Western United States. Because few wells are drilled through the entire Mt. Simon, wells in the Loudon oilfield (Fayette County) and Manlove gas storage field (Champaign County) are used as analogues to model other sites in the Illinois Basin. Using these analog wells and data from Mt. Simon natural gas storage projects suggest that reservoir heterogeneity will be an important factor for evaluating storage capacity and CO2 plume migration.

Geologic Characterization of the Helderberg Group as a Confining Layer for CO2 Sequestration


The Midwest Regional Carbon Sequestration Partnership (MRCCSP) has determined that multiple units offer potential for carbon dioxide sequestration in West Virginia. The Siluro-Devonian Helderberg Group is situated stratigraphically between the Oriskany Sandstone and the Salina Group evaporites. Formed in an ancient “sea way,” the Helderberg is predominantly limestone, but contains some interbedded sand and shale shed from the eastern uplifts of the Taconic Orogeny. Ranging in thickness from 50 – 150 m, available data on the Helderberg include geophysical logs, sample descriptions, sidewall cores, and outcrop observations. Although extensive faulting suggests limited potential as a seal, a detailed geologic evaluation of the Helderberg may help to identify heterogeneities in this sequence and evaluate its effectiveness as a confining layer.

Integrated Rock Physics Studies and 3D Seismic Surveys to Evaluate CO2 Sequestration in the Sacroc Field, Texas

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The SACROC field is located in Scurry County, Texas and lies on the northeastern edge of the Permian Basin. It is the seventh largest onshore oil field in North America containing approximately 2.73 Billion Bbls of original oil in place. The main producing units are the Pennsylvanian aged Cisco and Canyon Formations. These are highly heterogeneous reef complexes that contain massive amounts of bedded bioclastic limestone and thin intercalated shale beds. The average porosity is 7.1% with a permeability of approximately 31 mD. The depth to this reef complex is approximately 2040 meters. These units are a part of the larger carbonate platform called the Horseshoe Atoll. The site is the oldest CO2 enhanced oil recovery site in the United States with over 140 million metric tons of CO2 injected since 1972. Recently, the National Energy Technology Laboratory of the United States Department of Energy has funded a combined carbon sequestration and enhanced oil recovery project at the site. In the first phase of the study, laboratory measurements of reservoir properties were collected at varying reservoir conditions. These measurements were then used to model the anticipated seismic response of the reservoir, which was then compared to 3D seismic data collected before a CO2 flood. In the final phase of the study, successive surveys will be used to map CO2 migration and assess the integrity of the overlying caprock, which are marine shale units of the Permian aged Wolfcamp Formation.
A Genetic Link between Hydrothermal Dolomite and MVT Mineralization in Eastern Wisconsin

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Paleozoic dolostones along the western margin of the Michigan basin preserve abundant evidence of a Late Devonian to Mississippian hydrothermal system that was distinct from the Upper Mississippi Valley ore district. Field, petrographic, and geochemical evidence suggests a genetic link between pervasive dolomite, MVT mineralization, and K-silicate mineralization in eastern Wisconsin Paleozoic rocks. Constraints were placed on the conditions of water-rock interaction using fluid-inclusion methods, cathodoluminescence and plane-light petrography, isotopic analyses, and organic maturity data. Water-rock interaction occurred in the presence of dense Na-Ca-Mg-CI-H2O brines (13 to 28 weight%, NaCl equivalent) at temperatures between 65°C and 120°C. These hydrothermal dolomites are unusual because they display planar instead of saddle shaped crystal morphology. Radial fluid flow out of deeper portions of the basin along Cambrian and Ordovician sandstone aquifers is inferred from this and other studies. In addition, a significant component of vertical advection from the Precambrian basement is required to satisfy lead-isotopic data from galena throughout the region stretching from eastern Wisconsin to the Upper Mississippi Valley ore district. Stratigraphic reconstructions and vitrinite reflectance on Devonian materials (R0 = 0.5 – 0.62%) indicate low thermal maturity for these sediments and are consistent with short-term heating rather than long-term sustained burial. Limited mechanisms can accomplish radial fluid flow rates high enough to preserve elevated temperatures while under low burial conditions. A proposed mechanism includes a combination of gas-displacement and pressure-solution compaction in deeper parts of the basin, aided by vertical advection out of the Precambrian basement beneath the study area.

Hydrothermal Dolomitization - Yet Another Overblown Bandwagon?!

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The latest bandwagon to roll through the dolomite research community is the “hydrothermal dolomite model”. This bandwagon originated in Canada in the late 1990s and is founded on four major assumptions: all saddle dolomite is hydrothermal; matrix dolomite is hydrothermal on a regional scale; saddle and matrix dolomites are co-genetic; hydrothermal activity was basin-wide. In Western Canada, all four assumptions have been shown to be incorrect or correct only locally. Rather, most dolostones south of the Peace River Arch formed under normal burial conditions. The few hydrothermal dolomite bodies are related to faulting and are not of regional extent. However, north of the Peace River Arch regional heat flow has been higher than normal, and several large dolostone bodies are hydrothermal. Yet even here it is contentious just how much dolomite was formed from hydrothermal fluids. Petrography and geochemistry show that hydrothermal fluids often are initially undersaturated with respect to dolomite and thus dissolve older dolomites, with concurrent generation of porosity and solution collapse brecciation. These fluids may evolve toward dolomite supersaturation and form saddle dolomite, which often form conspicuous but volumetrically minor amounts of cement. Thus, many so-called “hydrothermal dolomite” hydrocarbon reservoirs are not cases of hydrothermal dolomitization. Rather, they acquired their high porosities and permeabilities from hydrothermal karstification of older, relatively low-temperature dolomites, and the actual hydrothermal dolomite formation destroyed rather than formed porosity and permeability. These findings have important implications for hydrocarbon exploration. Also, like many other bandwagons before, the hydrothermal dolomite bandwagon is very much overblown.

The Utica Shale Play of Eastern New York

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Exploratory drilling is underway to begin producing the Utica Shale of eastern New York State. When developed, this field will represent the easternmost natural gas field in the United States. The prospective fairway includes a 17 county region bounded to the by the Hudson River, the Finger Lakes, the Mohawk Valley and the Pennsylvania border. The Utica is a massive, fissile, organic-rich, thermally-mature black to gray-black shale deposited in a subsiding trough that generally trended north-south. The Dolgeville, interpreted as a slope facies peripheral to the Trenton platform, interfingers with the basal Flat Creek black shale member. Source rock for the organic-rich black shale was supplied from the eroding Taconic highlands to the east. As the deep marine trough was filled in, the deposition of the lower members of the group onlapped westward over the carbonate platform. The basal Flat Creek member thickens considerably in the eastern half of New York and uppermost Indian Castle member spreads widely across the Appalachian Basin. The exploration fairway has been defined though an analysis of cuttings and cores defining unit properties. Rock-Eval parameters S2, T max, HI (Hydrogen Index), and TR (Transformation Ratio). Current drilling activity to date has concentrated on the shallower northern areas but technical evidence supports much deeper drilling depths. Hydraulic fracture designs include the use of acid to take advantage of the high calcite component. Since this play is within the eastern gas market, producers can expect a price premium for their gas.

New York’s Response to Climate Change on New York: Monitoring, Reducing and Sequestering Carbon Dioxide

J.P. Martin, A.D. Stevens, New York State Energy Research and Development Authority

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. The program targets the direct and indirect aspects of climate change on the state, including its energy infrastructure. Through the Environmental Monitoring and Evaluation Program, NYSERDA is developing a strategy to monitor the direct impacts of climate change, quantify the potential ecological, public health, infrastructure, and economic impacts of climate change in New York State, and identify mechanisms to manage and mitigate risk. The major indirect impact of climate change will likely be the alteration of traditional energy consumption. Gas demand is becoming bimodal with a winter heating peak and a summer electricity generation peak. This is forcing a reevaluation of the natural gas delivery infrastructure. The development of the Regional Greenhouse Gas Initiative (RGGI) will directly impact the energy delivery system. 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, the reduction of methane emissions in the natural gas delivery system will be an offset. NYSERDA is working on the quantification and verification of methane emissions from the natural gas production and distribution infrastructure. Finally, programs to help develop carbon capture and sequestration in New York are now in place.
Detailed Surface Structure - Starting Point for Understanding Deep Appalachian Geology

P.L. Martin

Many continuous bench-forming sandstones of the Permian(?), Pennsylvanian, Mississippian, and Upper Devonian formations exposed at the surface in the Appalachian Plateau lend themselves very well to accurate stereo-tracing on aerial photos. The penciled traces of these units are accurately posted from the photos to USGS 7.5' Topographic Maps, where the many intersections of these traces with topographic contours provide a myriad of elevation control points on any selected datum unit. Interval-conversion from the datum to other traces above and below expands control beyond the outcrop area of the datum. This elevation control is then contoured to produce surface structure maps which reveal many previously unmapped features and structural relationships. The diligent and on-going application of this mapping technique in the Appalachian Plateau of Western Pennsylvania has produced very detailed surface structure maps of ninety one 7.5' Quads so far, covering an area from Cameron, Clinton, and Lycoming Counties in the north to Fayette, Somerset, and Bedford Counties in the south. The structure contours, faults, and fold axes, plus political boundaries, have been digitized and can be layered in with seismic, isopach, production, and other maps. Such a display often reveals surprising relationships between subsurface geology and surface structure. “Look-alike” surface anomalies in areas of no subsurface control then can become prospective exploration or extension targets. All maps also are available as scanned images on CD’s in tif format, or as color or black and white prints. Also, all maps are protected by Copyright.

Re-Os Isotopic Evidence for Cenozoic Mineralization in the Central Pennsylvania Valley and Ridge Province


Hypotheses concerning processes and timing of hydrothermal sulfide mineralization in the central Pennsylvanian Appalachians utilize Mississippi Valley-type (MVT) models with Paleozoic ages. To examine this model, we studied sulfide-bearing veins from seven sulfide occurrences that contain pyrite < galena < sphalerite and occurs in central Pennsylvania, USA. Fault breccia pyrite from the Skytop occurrence (central PA) along with pyrite and chalcopyrite from the Perkiomen Creek (western PA) forms a nine point Re-Os isochron yielding an age of 33.8 ± 4.8 Ma and an \( \text{Re}^{187}/\text{Os}^{188} \) initial ratio of 0.18 ± 0.05. Three pyrites from the Keystone mine (central PA) and Thompson mine (central PA) form a trend that suggests an age of 35 Ma. Veins of sulfide (pyrite predominantly) from the Logan Valley, Albright and Scrub quarry do not fall on any trends and contain less Re and Os. The Re-Os isotope data do not fit current models for sulfide generation in central Pennsylvania that invoke MVT hydrothermal processes. These MVT models imply that mineralization in the area formed in the late Paleozoic at relatively low temperatures (120x40°C) with metals originating from surrounding sedimentary rocks. The data from the present study indicates that a younger mineralization event overprinted the MVT type mineralization (represented by the vein pyrite) across the whole orogen. This hydrothermal activity had not previously been hypothesized or recognized. The timing of the younger mineralization event coincides with two Cenozoic events in the Appalachian Basin: the Chesapeake Bay impact and Eocene volcanism in the southern portion of the Nittany anticlinorium.

Facies and Depositional Setting for the Speechley Sandstone of the Upper Devonian Lock Haven Formation in the Subsurface of Western Pennsylvania


The Speechley Sandstone is a driller’s name for a natural gas reservoir in the Upper Devonian Bradford Group in the Pennsylvania subsurface. The Bradford Group is equivalent to the Lock Haven Formation on the Pennsylvania outcrop. The Bradford Group represents an important drilling target in the active shallow natural gas drilling play in Indiana County, Pennsylvania and parts of adjacent counties in western Pennsylvania. Core sampling Bradford Group natural gas reservoirs like the Speechley for facies and depositional setting control is a rarity in the study area due to the increased cost associated with coring. Correlating borehole geophysical log signature to outcrop presents a lower cost alternative to acquiring core. In this study, Speechley geophysical log signatures are characterized by stacking pattern and reservoir log attributes and then correlated to described Lock Haven Formation outcrop. Facies and depositional settings are mapped for the study area and inferences made on the distribution of reservoir attributes relative to facies and depositional setting.

Depth Relationships in Porosity and Permeability in the Mount Simon Sandstone of the Midwest Region: Applications for Carbon Sequestration

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A comparison of porosity and permeability values (conventional core analyses data) from the Upper Cambrian Mount Simon Sandstone indicate a predictable relationship with depth owing to diagenetic changes in the pore structure. This predictive relationship is useful for evaluating and quantifying the geological carbon sequestration capacity in Indiana and Michigan. Image analyses of thin sections and porosity logs from wells in the study area provide additional sources of petrophysical data. The regional trend of decreasing porosity with depth is described by the equation: \( \phi (d) = 12,789,166 * d^{-0.897} \), where \( \phi \) equals porosity and \( d \) is depth in feet. This equation indicates that porosity typically falls below 5 percent below 7,000 ft. The correlation between burial depth and porosity is useful for prediction of the petrophysical character of the Mount Simon in more deeply buried and largely undrilled portions of the basins. Understanding the relationship between porosity, permeability, and depth also provides information that can be used in numerical models that simulate supercritical carbon dioxide flow within the Mount Simon. The fundamental relationship of decreasing porosity and permeability with depth generally holds true on a basinwide scale, but localized stratigraphic and areal variations in sedimentary facies also affect reservoir quality of the unit such that, in some areas, a reversal in the porosity/depth relationship is observed. Careful documentation of the mineralogical and sedimentological characteristics of the reservoir are critical to successfully predict the petrophysical attributes of deep saline aquifer systems and how they will perform at a given locality. This work is part of the regional carbon sequestration assessment being conducted by the MRCSP.

Horizontal Development in the Appalachian Basin Devonian Shale

L.J. Morris, Equitable Production Company

Equitable Resources began a horizontal drilling pilot project in mid 2006, initially targeting the Lower Huron Shales in eastern KY. Equitable has drilled over 170 horizontal wells in this play, expanding the project into adjacent states and also targeting additional Devonian Shale zones and some non-shale reservoirs. Techniques such as multi-lateral drilling
were also tested. This paper examines the results of this program, including the geologic setting of the target zones, the development strategy utilized by Equitable, and some of the results to date.

Carbon Dioxide Sequestration in Coal at the Illinois Basin Tanquary Site


The potential for sequestering CO2 in the largest bituminous coal reserve in the United States (Illinois Basin) is being assessed in southeastern Illinois as part of the DOE’s Regional Sequestration Partnership program. The main objectives of this test are to determine CO2 injection rates and storage capacity. At the Tanquary site, the Springfield Coal is 7 ft thick, 900 ft deep, and has a coal gas content of 150 to 195 scf/ton (dmmf). Desorbed Springfield Coal gases (normalized air-free vol %) are 88-96% methane, 2-9% nitrogen, 1-3% CO2 and trace amounts of C2+. The carbon and hydrogen isotopes of the methane indicate primarily a biogenic origin. Results of injecting up to 600 tons of gas-phase CO2 over a period of 40-80 days are presented. Pre-injection DST’s, pressure transient analyses, and pulse tests indicate initial coal permeability averages 6 md. COMET 3 reservoir simulation was used to determine well spacing, track anticipated CO2 movement and to evaluate enhancing coalbed methane recovery potential. Based on tests and model results, one injection and three observation wells oriented relative to the cleat directions and spaced approximately 50 to 100 ft apart, were drilled, cased and perforated. Lab measurements of CH4, CO2 and N2 adsorption capacities, as well as coal shrakng and swelling accompanying methane removal and CO2 adsorption, respectively, have been completed. In addition, changes in the mesopore and micropore characteristics (specific surface areas, volumes, and size distribution) as a result of CO2 adsorption have been analyzed in coals of varying petrographic composition.

Trade-Offs for Injecting Carbon Dioxide

P.R. Neal, Y. Cinar, W.G. Allinson, Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC), School of Petroleum Engineering, The University of New South Wales

A critical factor in shaping the final design of a carbon capture and storage process is a rigorous understanding of how the costs of transport and injection behave. Frequently, the supply of nearby good quality storage formations is limited, and the CCS project might therefore involve using low quality local reservoirs, with low net pay, low permeabilities, low fracture pressures, or high initial reservoir pressures. In contrast, good quality formations would have high mobility and pressure gradients with high contact areas for wells. However, they might be remote from the source. Ultimately, therefore analysing the relative economic merits of the different storage options should help us to decide which site is preferred. In this paper we analyse the effects of sites with contrasting conditions — a nearby, poor quality sink and a very distant, high quality sink. The analysis involves a combination of numerical reservoir simulation and economic modelling. A commercial compositional simulator is used for reservoir simulations and the economics are assessed using an internally developed techno-economic model. We investigate the sensitivity of the reservoir behaviour and the economics of CCS to such parameters as — the distance between the source and the sink, the pressure difference between the fracture and formation pressures, the formation thickness, the economic effect of fracturing the formation to increase injectivity and the risks of fracturing.

Analysis of Pore Architecture within a Sequence Stratigraphic Framework and Correlation to Sonic Velocity Values in Silurian (Niagaran) Reefs of the Michigan Basin

A.K. Noack, G.M. Grammer, Michigan Geologic Repository for Research and Education, Western Michigan University

The relationship between porosity and permeability in carbonate rocks is complex due to variability in pore type and architecture. Porosity/permeability transforms are of limited value when evaluating carbonate reservoirs because permeability is controlled by pore type. Middle Silurian (Niagaran) Reef reservoirs of the Michigan Basin are being evaluated to better understand pore types and related permeabilities. In addition, pore types and associated geometries are thought to have direct correlation with sonic velocity values. As a result, Niagaran reef wells with both core and sonic logs were evaluated. Petrophysically significant facies and related pore types were identified through core analysis. Key facies were made into thin sections and photomicrographs were imported into an image analysis program where pore abundance and geometries were determined. Facies and related pore geometries were compared to sonic velocity values to identify the relationship of velocity and pore architecture. Facies with greater rigidity contain more rounded pores and have higher velocities whereas facies with less rigidity contain more irregular shaped pores and have slower velocities. To confirm the relationship between pore architecture, permeability, and acoustic impedance, x-ray computed tomography will be used on key facies to visualize three-dimensional pore networks. Creating an integrated study that incorporates evaluation of the relationship of pore types, facies, and recognizing the affect of pore geometry and connectivity on rock acoustics, makes it possible to determine permeability. As a result, understanding rock and well log data relationships allows for better prediction of reservoir quality with logs in the absence of rock data.

Integrated Characterization and Potential of the Utica Shale in New York State: Is it the Next Big Thing??

R.E. Nyahay, L.B. Smith, J. Leone, Reservoir Characterization Group, New York State Museum; J.P. Martin, New York State Energy Research and Development Authority

The Ordovician Utica Shale may provide another major opportunity for shale gas production in New York. Recent announced discoveries in Quebec to the north strongly suggest that the Utica may also be an economic shale gas reservoir in New York and points south. Utica Energy has announced plans to drill four vertical Utica wells and a one horizontal well in New York this year. From top to base, the Utica Shale is composed of the Indian Castle Shale, the Dolgicle Limestone and the Flat Creek Shale Members. The Flat Creek and Dolgicle Members in the east are time-equivalent to the uppermost Trenton Limestone in the west. The highest TOC values are in the basal Flat Creek Member (2-3%), moderate TOC values occur in the Dolgicle (1-2%) and the Indian Castle Member has relatively low TOC values of less than 1%. Synthetic TOC logs were constructed using density logs (lower density = higher TOC) and calibrated with actual TOC measurements. Zones of higher TOC appear to correlate regionally in the Dolgicle and Flat Creek Members. XRD analysis is underway will be presented at the meeting. The TOC data, thermal maturation data, and other Rock Eval analysis and geologic mapping have helped to delineate a fairway for possible shale gas exploration which roughly coincides with the presence of the Flat Creek and Dolgicle Members of the Utica. This NE-SW trending fairway extends from the Eastern Finger Lakes to the Catskill Mountains and from the Mohawk Valley to the Pennsylvania border.
Origin and Distribution of Natural Gas in Devonian Black Shales, Northern Appalachian Basin

S. Osborn, J. McIntosh, Hydrology and Water Resources, University of Arizona

Geochemical and microbial studies of Devonian black shales in the Michigan and Illinois basins have shown that methane is generated dominantly by microbial processes at the shallow basin margins and by thermogenic processes at depth. Distinguishing the origin of natural gas is important for exploration, production, and resource assessments. The adjacent Appalachian Basin contains age-equivalent organic-rich shales with copious natural gas resources. This on-going study evaluates the origin and distribution of natural gas and formation water geochemistry in Devonian shales across the northern Appalachian Basin margin. Gas samples were collected from oil and gas wells producing from Devonian formations in NY, OH, PA, and Ontario (Spring 2007 and 2008), and analyzed for composition, and C and H isotopes of CH₄, C₂, and CO₂. Co-produced formation waters were analyzed for cation, anion and isotope (O,H,C) chemistry. Chloride concentrations generally increase with depth and position within the basin from about 125 to 10 mD and 20 to 5 percent, respectively. The thickness of the Eau Claire confining unit was also varied. CO₂ was introduced at over 31 sites in close proximity to existing power plants in our model. We found that the gentle slope on the Mount Simon did not promote long-distance lateral migration of CO₂. The relatively tight conditions at depth (greater than 2000 m) required using dozens of wells at individual power plant sites to avoid fluid pressures exceeding lithostatic levels near the wells. Pressure anomalies produced by injection extended out about 5 to10 km from injection sites before dissipating. A substantial superposition of pressure cones from adjacent injection wells was observed. Surprisingly, the position of the freshwater-saltwater interface did not move appreciably toward the margins of the basin. Future work will attempt to validate these findings using multi-phase serial (FEHM) and parallel (PFLOTRAN) multiphase codes.

Using ArcGIS to Estimate Thermogenic Gas Generation Volumes by Upper and Middle Devonian Shales in the Appalachian Basin

J.R. Reed, Jackie Reed Geochemical Consulting, D. Dunbar, S. Brown, Geomark Research

Using ArcGIS and a geochemical database from GeoMark’s Appalachian Basin Petroleum System Study, we estimate the volume of high maturity thermogenic gas generated by both the Marcellus and the Ohio sections of the Appalachian Devonian Shale. A new parameter, TOCgen, that represents the amount of organic carbon attributable to hydrocarbon generation, was calculated using TOCpd (present day TOC) and TOCo (original TOC) maps for the Devonian Marcellus and Ohio Shales. The TOCgen represents carbon expelled as oil and gas during oil window maturities as well as carbon in oil and gas that remained in the shales. The remaining carbon, converted to gas at high levels of maturity constitutes the bulk of the unconventional shale gas resource. A map of the generated gas volume of this resource was made using TOCgen, Devonian shale generation kinetics, expulsion efficiencies, and shale thicknesses. Based on these geochemical parameters, our map shows an area from central New York trending southwest into northern West Virginia as a favorable shale gas production fairway. Maps of gas wetness and BTUs show the overall quality of thermogenic gas generated from the Devonian shales is good. Typically, these gases have BTU values greater than 1000. The values decrease somewhat to the east in the basin reflecting the drier gas associated with the increasing thermal maturity of the generating shales.

Tools to Evaluate the Hydrocarbon Potential of the Mesozoic Basins, North Carolina, USA

J.C. Reid, K.B. Taylor, North Carolina Geological Survey

The North Carolina Geological Survey (NCGS) has compiled a comprehensive data package of public records to evaluate the hydrocarbon potential of on-shore Mesozoic basins in North Carolina. This will provide industry with a consistent data entry point. The data include organic geochemistry: seismic lines; well locations – well cuttings, core samples and logs; other geophysical data; and permitting information. State and federal digital geologic maps provide a geologic framework. Organic geochemistry shows source rocks are oil and gas prone. TOC are above the lower limit of 0.4 wt.% required before hydrocarbon can be expelled from source rocks. Elevated thermal maturity is from intrusive Jurassic dikes and sills. About 75 line-miles of seismic (1980’s vintage) are located in Lee, Moore, Chatham, Wake
Evidence for Paleo-Fluid Flow Westward from the Appalachian Basin


We present a fluid and heat flow model of a cross-section through the Appalachian basin, extending from the deformation front in West Virginia to the Findlay arch in Ohio. The model was constructed to investigate the geologic conditions that produced elevated fluid inclusion (FI) temperatures on the Findlay arch. The passage of warm (>110°C) fluids is recorded by aqueous and hydrocarbon FI in fracture-filling and vug-lining fluorite, sphalerite, calcite, and dolomite cements in Silurian-Ordovician strata, including saddle dolomite from oil/gas reservoirs in the Trenton Limestone. Erosional truncation of Pennsylvanian-Divonian coal and shale limits the availability of vitrinite reflectance (Ro) data at the Appalachian basin’s western margin; however, conodont color alteration index (CAI) data from Ordovician carbonate strata, continuous over the Findlay arch, help to constrain thermal maturity. Low CAI values (<1.5) on the arch indicate that only a modest thickness, probably <1.5 km, of additional overburden (now eroded), was present at maximum burial. Burial alone appears incapable of explaining the elevated FI temperatures, however, burial combined with a relatively brief interval of fluid flow may be consistent with both the FI and CAI data. A pulse of updip groundwater migration onto the Findlay arch from deeper in the Appalachian basin is proposed and tested in our model. Paleomagnetic and radiometric age dating studies indicate a widespread, late Paleozoic episode of diagenesis in the Appalachian basin resulting from regional-scale groundwater circulation; it has also been shown that Alleghanian orogeny-related topography could plausibly have driven regional-scale groundwater flow through the Appalachian basin.

GeochemoRisk Assessment of the Marcellus Shale - A Case Study of the House Unit #1, Clearfield County, Pennsylvania

T.E. Ruble, Weatherford Laboratories

The Appalachian Basin is the largest onshore basin in the United States and is now experiencing a major resurgence in exploration as an unconventional shale gas play. GeochemoRisk techniques that have been previously used to successfully understand the prolific Barnett Shale in the Fort Worth Basin are now applied to the Marcellus Shale. Thermogenic shale gas systems can be segregated into various types depending upon geochemistry and geology. Both the Barnett and Marcellus Shales are considered to be high thermal maturity systems. However, differences in source rock potential and maturity can play key roles in the generation, retention, storage and potential destruction of hydrocarbons. In this case study, a geochemoRisk assessment has been conducted to evaluate the Marcellus Shale interval in the Houser Unit #1 well located in Clearfield County, Pennsylvania. Cuttings from this well were analyzed by a variety of geochemical techniques, including total organic carbon, programmed pyrolysis and organic petrology with measured vitrinite reflectance (Ro). This source interval is interpreted to represent a low to moderate geochemoRisk for thermogenic shale gas production. TOC in the basal Marcellus Shale averages 2.85%, which exceeds the recommended minimum of 2%. Measured vitrinite reflectance of 2.64% Ro indicates thermal maturity in the dry gas window and is sufficient for significant secondary gas generation. Average estimated cracked gas generation potential for the 100’ thick basal Marcellus Shale interval in the Houser Unit #1 well is 2500 mcf/a-ft, as compared to 3200 mcf/a-ft for the zone of productive Barnett Shale.
A Regional Geologic Cross Section Through the Appalachian Basin from near the Findlay Arch, Erie County, North-Central Ohio, to the Valley and Ridge Province, Bedford County, South-Central Pennsylvania


A new geologic cross section through the Appalachian basin provides a regional perspective for evaluating petroleum systems, thermal maturity patterns, and burial history models. The cross section is constructed from eleven wells, three of which bottom in Grenville-age crystalline basement rocks. Sedimentary rocks along the cross section span most of the Paleozoic Era and their approximate preserved thicknesses range from 3,000 ft near the Findlay arch to 32,000 ft near the Rome trough and Laurel Hill anticline in Fayette County, southwestern Pennsylvania. These rocks are broadly classified as follows: 1) Lower Cambrian to Upper Ordovician rift and passive margin siliciclastic and carbonate deposits; 2) Upper Ordovician to Lower Silurian Taconic orogeny foreland basin siliciclastic deposits; 3) Lower Silurian to Middle Devonian shallow marine carbonate and evaporite deposits; 4) Middle Devonian to Lower Mississippian Acadian orogeny foreland basin siliciclastic deposits; 5) Upper Mississippian shallow marine carbonate deposits; and 6) Upper Mississippian, Pennsylvanian, and Lower Permian Alleghanian orogeny foreland basin siliciclastic deposits. Regional unconformities, such as the Knox unconformity, are caused by falls in eustatic sea level and (or) tectonic uplift. Styles of deformation illustrated are: 1) thin-skinned contractional structures of Alleghanian origin in the Valley and Ridge province (Wills Mountain and Evitts Mountain anticlines) and in the adjoining Allegheny Plateau province (for example, Laurel Hill and Chestnut Ridge anticlines) and 2) basement-scale such as multi-stage extensional faults of the Rome trough. Several deeply rooted anticlines show aspects of both thin-skinned and basement-involved styles of deformation.

Recent Improvements in Production Methods in Nora Coaled Methane Field Southwestern Virginia

L. Schanken, M.J. Kovarik, T. Vactor, C.A. Eckert, Equitable Resources

Since the first well was drilled in 1988, coaled methane production in the Nora field has steadily increased to a current rate of 70 MMcfpd. Many factors are responsible for this increase such as multi-staged completions, infill drilling, efficient field operations, and rapid development and dewatering of new parts of the field. In addition, aggressive pipeline and compression planning and installation have allowed for maximum production benefit of the completed coal seams. Most recently, larger fracs and horizontal drilling may take production rates to levels not attainable through recent practices.

Facies Control on Reservoir Quality, Albion-Sipio Trend, Michigan Basin

J. Schulz, G.M. Grammer, Michigan Geological Repository for Research and Education, Western Michigan University

The Ordovician Trenton and Black River limestones of the Michigan Basin are significant hydrocarbon reservoirs characterized by hydrothermal dolomitization. Production has exceeded 124 million barrels of oil with twenty new discoveries made in the past year. The giant Albion-Scipio Trend is often used as a model for other prolific hydrothermal dolomite reservoirs around the world with current models focused on the distribution of reservoir quality dolomite being controlled by the pattern of regional faults and fractures. A general trend of lateral variability in the reservoir dolomite away from the major faults, however, cannot be explained simply by the distribution of faults and fractures.


B. Selleck, Department of Geology, Colgate University; M. Williams, M. Jercinovic, Department of Geosciences, University of Massachusetts

Upper Cambrian – middle Ordovician Beekmantown Group carbonates of eastern New York are extensively dolomitized. Fluid inclusion and stable isotope data from exposures near Ticonderoga, New York indicate dolomitization occurred at temperatures locally exceeding 200°C and involved high-salinity fluids typical of those implicated in the development of HTD carbonate reservoirs and MVT mineralization. This carbonate sequence is underlain by quartz sandstone and arkose of the Potsdam Sandstone, which non-comformably overlies Proterozoic basement. The arkoses of the Potsdam have undergone diagenetic alteration that includes dissolution of feldspar minerals (e.g. ilmenite, plagioclase, garnet, hornblende and biotite are nearly completely dissolved) and precipitation of Fe-chlorite, quartz, K-feldspar and anatase cements. Bulk chemical analyses suggest that the diagenetic alteration resulted in export of Mg$^{2+}$ from the sandstones. High initial permeability in the sandstones, and availability of fault conduits allowed the Mg$^{2+}$ -rich fluids exported from the basal sandstones to dolomitize the overlying carbonate sequence. Authigenic monazite overgrowths on detrital monazite grains, and authigenic xenotime overgrowths on zircon are abundant and well-developed in the arkosic facies of the basal Potsdam Sandstone in the Ticonderoga area. Petrographic study documents that monazite and xenotime overgrowths formed contemporaneously with other diagenetic phases during burial alteration and export of magnesium. Preliminary electron microprobe U-Pb-Th chemical dating of monazite overgrowths constrains authigenic monazite growth to the early Paleozoic, possibly pre-dating the medial-late Ordovician Taconic Orogeny. Additional data will document the timing of monazite and xenotime growth, and provide insights into the timing of hydrothermal dolomitization in eastern New York State.

Carbon Sequestration Potential and Natural Gas Plays in Cambrian Strata of Western New York State

B. Slater, A. Stolorow, L. Smith, R. Nyahay, New York State Museum

The Cambrian sandstones of western New York present one of the better opportunities for carbon sequestration in the State and some have significant potential to produce natural gas. The lowermost unit is the Potsdam Sandstone which is a feldspathic sandstone that directly overlies the basement in western New York. The formation thickens to the southwest from 0 to as much as 180 feet. Porosity in the Potsdam is patchy – some wells have little or no porosity while others have intervals up to 35 feet thick of sandstone with > 5% porosity. The Potsdam is overlain by the Galway Formation which is composed of interbedded sandstone, dolomite-cemented sandstone, sandy dolomite and dolomite.
The Galway is overlain by the Beekmantown carbonates (Upper Cambrian Little Falls and Lower Ordovician Tribes Hill Formations) and the Knox Unconformity which cuts down into progressively older units to the west with more than 1100 feet of relief. The Knox Unconformity overlies the Tribes Hill Formation in the east and cuts all the way down into the Potsdam Sandstone in the westernmost part of the State. The uppermost sandstone unit in the Galway is equivalent to the Rose Run Sandstone of Ohio and currently has several producing fields and new discoveries and significant remaining potential for natural gas. As in the Potsdam, porosity is patchy in the Rose Run - some wells have tens of feet of >5% porosity and some have little or no porosity. There is a second sand-rich interval in the middle of the Galway that is likely equivalent to the B-sand in Ohio that also has some porosity in very thin beds of dolomite-cemented sandstone. The Potsdam and Rose Run Sandstones do not present the same opportunities for carbon sequestration in New York but the patchiness of the porosity introduces a level of heterogeneity that may make planning for sequestration more problematic.

Hydrothermal-Seawater Mixing Zone Dolomite: A Hypothetical Model for Widespread, Pervasive Dolomitization

L. Smith, Reservoir Characterization Group, New York State Museum; G. Davies, GDGC Ltd.

There is significant potential for dolomitization in hydrothermal-seawater (or modified seawater) mixing zones. Seawater has high Mg/Ca ratios, but does not readily precipitate dolomite due to kinetic barriers to formation at low temperatures. Supersaturated hydrothermal fluids > 60°C readily precipitate dolomite, but there is a question of the source of the magnesium necessary to make large volumes of dolomite. A hydrothermal-seawater mixing zone dolomitization model might help to overcome these kinetic and mass balance problems. Hot fluids (up to 200°C or warmer) might flow up faults, mix with in situ magnesium-rich seawater and precipitate dolomite. Hydrothermal dolomitization appears to occur very near the surface – commonly within the first 500 meters of burial. One of the reasons it may preferentially occur at these shallow depths is that where hydrothermal fluids might most easily mix with seawater. Fluid inclusion and geochemistry results suggest that in many cases both matrix and later pore-filling saddle dolomite form at temperatures greater than the ambient burial temperature. Matrix dolomite might form in the hydrothermal-seawater mixing zone, while the later saddle dolomite might be precipitated from hydrothermal fluids alone after continued burial and compaction of overlying seals has cut off the supply of seawater. There is a common spread in homogenization temperatures and salinities in fluid inclusion data from these dolomites that might be explained by different degrees of mixing. This is a hypothetical model that requires further analysis but it could eventually be applied to the Trenton Black River and many other dolomitized reservoirs worldwide.

Integrated Characterization of the Devonian Marcellus Shale Play in New York State

L. Smith, R. Nyahay, J. Leone, New York State Museum; J. Martin, NYSERDA

The Marcellus Shale has the potential to produce economic quantities of gas across south-central New York State. The Marcellus thickens from west to east (from 20 to >800 feet) and is composed of three members. The basal Union Springs Member is a black shale up to 70 feet thick with a few thin limestone beds that has TOC values from 3-12% with the highest values in the eastern side of the basin. The middle Cherry Valley Member is a limestone up to 80 feet thick with thin black shale beds that have TOC values up to 6%. The overlying Oatka Creek Member is a black and gray shale up to 650 feet thick with TOC values up 7% that increase toward the base. Thermal maturity increases from west to east. The TOC, vitrinite reflectance and other rock eval data suggest that the fairway extends in an east-west sense about 150 miles from the western Finger Lakes across 12 counties to the Catskill Mountains in the east. The northern limit is the outcrop belt or the critical depth at which pressures are insufficient to sustain economic flow rates. Burial depths are up to 5000-6000 feet along the Pennsylvania border. X-ray diffraction analysis should be ready for this presentation. There are natural fractures associated with deep basement faults some of which are expressed as surface lineaments as well as intra-Marcellus fractures. The intra-Marcellus fractures may be beneficial, but those related to basement faults may complicate drilling, completion and production.

The Making of a High-Porosity, High-Permeability Reservoir - The Murrysvilles Sandstone of Pennsylvania

R. Smosna, West Virginia University; M.L. Sager, Dominion Exploration & Production Inc.

Reservoir characteristics of the Upper Devonian Murrysville Sandstone in southwestern Pennsylvania are outstanding: porosity exceeds 20% and permeability approaches 1000 md. The purposes of our study are to document the petrographic features of this sandstone—interpreted as a high-energy braided delta—and to explain the origin of its very good porosity and permeability. The porosity is so very good for a number of reasons. (1) Delta-plain sands were moderately sorted and well washed. Original porosity was thus high. (2) Currents also destroyed many mechanically unstable lithic grains, and the resulting sediment became quartz-rich. Consequently, during shallow burial the sandstone suffered just a moderate degree of compaction and porosity loss. (3) The mixing of river water and sea water in the deltaic environment allowed iron mineralization to take place during deposition and early diagenesis, creating thin chlorite coatings on the detrital grains. Access of fresh water to the Murrysville, however, soon ended because of an ensuing transgression. Nevertheless, chlorite coatings proved effective in preserving much of the remaining porosity in that they inhibited the precipitation of destructive quartz overgrowths. (4) Leaching of chemically unstable lithic grains and feldspars in the deep subsurface generated additional porosity. (5) Porosity reduction by late-stage calcite cement was volumetrically unimportant because of the limited amount of carbonate imported from outside the formation. Permeability in the Murrysville Sandstone is so very good because of the rocks' very good porosity, course grain size, and the low clay content, both detrital matrix and authigenic chlorite.

Regional Geochemical Evaluation of the Ordovician Utica Shale Gas Play in Quebec

R. Thériault, Quebec Ministry of Natural Resources and Wildlife

The Ordovician Utica Shale was deposited throughout the Appalachian Basin during the Taconian Orogeny. In the Province of Quebec, where it covers over 10 000 square kilometers, the Utica Shale occurs at depths ranging from surface (northwest) down to over 4 km (southeast). Its thickness generally varies from 75 to over 350 meters in the deeper parts of the basin. The Utica is a thermally mature, organic-rich black shale that is considered to be the source rock for Devonian to Ordovician hydrocarbon production and shows in Quebec. Based on well log data, well samples and outcrops, the Utica Group has been informally subdivided into different formations, as is the case in Ontario and New York. Rock-Eval analyses were performed on 50 outcrops and more than 60 wells (>700 cuttings samples) to evaluate the regional geochemical variability of the Utica Shale, and ultimately to identify "sweet spots". XRD analyses were also carried out to determine the mineralogical composition of the shales. Preliminary results show that the Utica has TOC values generally ranging between 0.3 and 5 percent (average of 1.2% TOC), with 25% of the values being above 1.5% TOC. The mineralogy consists mainly of illite, calcite and quartz, which suggests good "fracturability" potential. Isopach and isocountour maps (i.e. TOC, Hydrogen Index, Transformation Ratio) have been produced in order to identify exploration fairways. Complete results of this work will be presented later in the year.
be published in a final report by the end of 2008, which will include a database, coloured maps and composite logs.

Analogs to the Marcellus Shale Provide Effective Methods for Determining Gas Shale Properties

L. Utley, Utley Petrophysics, M. Franklin, Rocky Mountain Petrophysics

Unconventional gas shale reservoirs are the hottest play in the United States. The Marcellus Shale is quickly becoming an important target for domestic exploration. Experience in the Barnett and Fayetteville Shales, analogs to the Marcellus Shale, provide effective methods for utilizing core and log data to their fullest extent. Traditional log analysis has not yielded acceptable results in these reservoirs. Service companies recommend extensive logging suites. Consequently, when the operators rely on the service companies to integrate their core data with logs, the correlations are dependent on the complete and modern log suites. This practice ignores the wealth of log data that already exists, and adds unnecessary cost to the evaluation of these reservoirs. This presentation will show how innovative techniques are used to calculate TOC, porosity, water saturation, and gas-in-place using conventional logging suites. Mechanical rock properties such as Young’s Modulus and Poisson’s Ratio are also determined from standard log suites. A tremendous benefit of these techniques is the ability to map important petrophysical parameters, resulting from the application to existing log data over large areas. These techniques have been successfully applied to the Marcellus Shale.

Log Analysis of Legacy Marcellus Borehole Logs

J. Ward, PetroEdge Resource Partners

Regional mapping of facies within the Marcellus Shale in the Appalachian Basin in the early phase of drilling the formation depends on the availability of good quality borehole log data sets and applicable software for evaluation. PetroEdge Resource Partners LLC. embarked on a regional study of the Marcellus to locate areas for lease acquisition in late 2006. Public log data bases in New York, Pennsylvania, and West Virginia were reviewed for neutron, density, gamma ray, and photoelectric logs. When these logs were supplemented by proprietary logs, the result was a data set that is sparse, but suitable for regional facies mapping. The search for analysis software started with published equations developed by the Gas Research Institute in the early 1990’s. The algorithms, developed and published by the GRI, were modified and adapted for application to the Marcellus Formation. One critical modification of the programs involved calculation and application of varying kerogen density based on log crossplots. Comparison of log derived kerogen density maps, or Ro derived from kerogen density, are a close match to laboratory measurements of these variables. Uniform application of the programs and pay cutoffs converted the regional image log data set into a digital database with calculated volume of silt, heavies, kerogen, and clay. Using standard cutoffs, the pay volume was derived for all wells that had resistivitity logs. Maps of individual variables, or combinations of the variables allow the construction of regional facies maps. These facies maps serve to illustrate regional depositional characteristics of the Marcellus Formation. They also serve to explain the regional changes in the relationship between gamma ray deflection and apparent porosity on neutron and density logs. Lastly, the maps provide important clues concerning the distribution of gas in place in the Marcellus.

Enhanced Oil Recovery Potential and CO₂ Sequestration in the Michigan and Northern Appalachian Basins Region


The U.S. DOE-funded Midwest Regional Carbon Sequestration Partnership (MRCSP) is currently involved in an examination of potential carbon dioxide (CO₂) sequestration reservoirs, including oil and gas fields, for eight states. The Appalachian and Michigan Basins contain some of the largest historic oil-and-gas-producing areas in the conterminous United States. This region has produced over 5 billion barrels of oil and more than 50 trillion cubic feet of natural gas; however, secondary and especially tertiary recovery attempts have been spotty at best within the two basins. Since 1972, more than 1 billion barrels of incremental oil have been produced using CO₂-assisted enhanced oil recovery (EOR) techniques in the Permian Basin and other areas of the western United States. Large sources of CO₂ for EOR have not been available within the eastern United States to enable this technology. Should CO₂ become available via capture from large anthropogenic sources, could this region take advantage of this technology to produce hundreds of millions of barrels of additional oil while sequestering CO₂? Past EOR projects in the region and select case histories have been summarized. Using this information and a new regional oil and gas fields GIS, a high-level screening for potential CO₂-EOR candidates is underway.

Integration of Structural Analysis with Microseismic Fracture Mapping

S. C. Williams-Stroud, Microseismic, Inc.

Mapping of microseismic events generated during a hydraulic fracture treatment allows identification of fracture trends as they develop in response to reservoir stress changes during treatment. In an isotropic rock where the stress state is known, the ideal orientation of tensile fracture formation can be predicted. When the microseismic signals are strong, or when the event locations appear to mark the expected fracture orientation, the uncertainty in the location of events is less problematic leading to a high confidence of the results by geoscientists and engineers. When the results diverge from the expected and /or do not identify clear trends, additional constraints can be applied to the processing to illuminate trends. The natural fractures that are present in every rock will have varying impacts on the character of the induced fracturing and seismic events, but prediction of the locations and orientations of those natural fractures also can have a high uncertainty. This using an example from the Uinta Basin in Utah, this study shows how that uncertainty can be reduced by integrating structural analysis and rock mechanics information with the microseismic event mapping to identify orientations and locations of fractures generated and reactivated in the reservoir during the hydraulic fracturing treatment, as well as how the near-wellbore induced fractures may be connecting to the natural fracture network.
Sequence Stratigraphy and 3-D Reservoir Characterization of a Silurian (Niagaran) Reef - Ray Reef Field, Macomb County, Michigan

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Silurian age (Niagaran) reefs in the Michigan Basin have long been interpreted as relatively homogeneous units, despite production histories that strongly suggest the reefs are heterogeneous in both lateral and vertical dimensions. In an attempt to better illustrate reservoir heterogeneity in these reefs, a 3-D sequence stratigraphic model was produced for the Ray Reef Field. The Petrel model incorporates twenty-eight wells in the field using a combination of gamma ray and neutron logs, porosity and permeability data from whole core analysis, and facies descriptions. Six depositional facies were determined by analyzing rock fabric, depositional attributes, and faunal changes in eight full length cores evenly distributed within the reef complex. Comparison of porosity and permeability values within the various depositional facies clearly show trends related to the individual facies. The mud dominated bioherm (deep marine) and restricted environment (shallow) intervals have low porosity and permeability values related to low initial porosities in the primary depositional fabrics, whereas higher porosity and permeability values are observed in the framework reef and grainstone facies. Incorporating the sequence stratigraphic framework into the 3-D model illustrates the episodic nature of reef growth as exhibited by the stacked nature of reef and capping grainstones, often separated by well-developed exposure horizons. Utilization of the sequence stratigraphic approach also illustrates that the vertical reservoir heterogeneity often observed in these reefs, may be controlled in large part by the combination of the vertical stacking patterns of facies, especially framework reef and capping grainstones, and with the development of significant bounding exposure horizons.

Marcellus Shale - Regional Overview from an Industry Perspective

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The Middle Devonian Marcellus was tested in less than a dozen wells in Pennsylvania and West Virginia prior to the recent surge in drilling. These early wells were completed by explosive stimulation or fractured using nitrogen or foam and all had consistently poor results. Range Resources is the leader in modern exploration and development of the Marcellus beginning with their first wells located in Washington County, Pennsylvania in 2005. Public announcements by several companies of high IP’s and large reserves in the Marcellus have led to a boom in leasing, permitting and drilling in the heart of the Marcellus Fairway. The majority of the wells drilled to date have been vertical; however permits for horizontal wells in the Marcellus have been increasing at a rapid rate. Based on regional mapping, the area in which the Marcellus Shale could be productive may exceed 30,000,000 acres in portions of six (6) states. It is likely that less than 25% of this productive area may eventually be found to be economic. Factors affecting and controlling production include reservoir pressure, thickness of pay, porosity, permeability, geologic hazards, and thermal maturation. The most important of these factors may be reservoir pressure, as the Marcellus is not considered to be a viable primary target in areas with an abnormally low pressure gradient, while those proposed economically productive areas are projected to be normally or over-pressured. Geologic hazards to be avoided include structurally complex areas with deep seated faulting and also the lack of upper or lower frac boundaries. In addition, the sloughing nature of the shale can pose a drilling hazard if trying to drill horizontally into the formation.