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New models for determining thermal maturity and hydrocarbon potential in Marcellus Shale

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Progress in hydraulic fracturing and horizontal drilling techniques for shale gas production has revolutionized the US energy sector. Despite these advancements, there is a still a low recovery of gas in place (~20-30%) and a rapid decline in well productivity in unconventional shale gas wells. One of the major limitations in improving the production efficiency is the lack of understanding of molecular-level properties of shales, especially that of kerogen. Kerogen is an insoluble geo-macromolecule component of black shales that controls and the amount and type of hydrocarbons (HCs) generated and expelled. Significant advancements have been made recently to develop kerogen structural models using spectroscopic and molecular simulation techniques. However, a large gap still exists in understanding the evolution of structural components of kerogen with maturation and their HC generative potential. In this study, we characterized different molecular components (structural parameters) of kerogen in a Marcellus Shale maturity series (VRo ranging from 0.8 to 3) using ^{13}C solid-state NMR. The variations in these molecular components provided knowledge about the evolution of the nanostructure of kerogen with increasing thermal maturation and the key molecular contributors of HC generation. Additionally, we utilized the variations in kerogen molecular parameters of the maturity series to develop new regression models for accurate determination of thermal maturity and HC generative potential of Marcellus Shale.

Introducing a New Tool for Discussing the Complex Interactions of Petroleum Production and the Environment

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Concern about the environmental, climatic and public health risks of the energy sector has grown with the decade-long expansion of oil and gas production using hydraulic fracturing of horizontal wells. People are now debating whether oil and natural gas are essential to modern life and what their role should be in the future.

Strong and divergent views about oil and gas production and use reflect complex interactions of economics, politics, public health, even expectations for the distant future. Amid a flurry of potentially polarized news and opinion provided by the 24-hour media cycle, state and local decision makers seek understandable information from neutral sources.

The American Geosciences Institute, an association of varied geoscientist organizations, has a long history of providing accurate, unbiased information about human interactions with earth systems, from groundwater to landslides, and their impacts on the environment.

This year the American Geosciences Institute has updated it 2003 publication, “Petroleum and the Environment” as a web-hosted series of two dozen fact sheets on major elements of the modern petroleum industry, from land use to methane emissions, induced seismicity and oil refining. The sheets explain complexities and uncertainties of the issues and make the information accessible through clear writing, a series of interlinked webpages and many free references. The American Geosciences Institute aims to make this user-friendly and search engine-optimized reference suite a trusted source of information about modern issues in petroleum and the environment.

Coupling Low Salinity Water Flooding and CO_2 Flooding for Sandstone Reservoirs; Low Salinity-Alternating- Co2 Flooding (LSAGF)

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Low salinity water flooding and Co_2 flooding are two novel combination floods was coupled due to the important role of both of methods in increasing oil recovery. Low salinity was examined by many laboratory and field works and it showed an interesting result in increasing oil recovery. Co_2 was tested on increasing oil recovery and the oil recovery increased by improved wettability alteration effect towards more water-wet, and interfacial tension reduction. Although the Co_2 showed an improvement in oil recovery, the density difference between Co_2 and oil raised a gravity override, channeling, and early breakthrough problems. For that reason, we develop the low salinity alternating Co2 flood to gather the benefits of low salinity itself and to improve sweep efficiency by Co2 and prevented Co2 problems mentioned earlier as well as capturing the Co_2 from the atmosphere. This method can be considered as a low-cost method since it needs only water and Co_2.

Numerous Berean sandstone cores with analogous petrophysical properties were saturated with a synthetic formation water, the water was displaced with crude oil to Swi, and then allowed to age for three weeks at 90°C. These cores were then flooded with two pore volume (PV) high salinity (HS) and then followed by one PV low salinity (LS) water at room temperatures. The HS water was identical to the formation water, while the LS water was diluted 100x (symbolized d100HS) from the HS water. HS water was injected into the cores until (Sor) was reached. The new combined technology was conducted by five scenarios on five cores: (1) One PV Co_2 followed by two PV LS water. (2) 0.5 PV Co_2 + 1 PV LS water + 0.5 PV Co_2 + 1 PV LS water. (3) 0.25 PV Co_2 + 0.5 LS water + 0.25 Co_2+ 0.5 LS water (4) Huffed 0.9 PV Co_2 and puffed it after two hours, then 0.5 LS water was injected+ 0.5 Co_2 +0.5 LS water.

The laboratory experiments of all scenarios showed an incremental oil recovery, but the optimum scenario was the scenario (5) with incremental oil recovery 14.5% of OOIP. The two hours huffing make it easy for the following flooding LSASF. While scenario (3) was the second optimum with incremental oil recovery 11% of OOIP because the short cycle injected of LS water and Co_2. In this paper, simulation work was conducted to visualize the new coupling method.

This combination technology can solve the Co_2 flooding problems and support the Co_2 by LS water which is itself could increase oil recovery by altering the wettability towards more water-wet.

High Resolution XRF Stratigraphy of the Ordovician Utica Shale, Central New York State

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Bulk rock elemental concentrations were collected using a handheld X-ray fluorescence spectrometer at 5 mm resolution through 5 m of core collected from the Utica Shale in central New York State. These results provide a higher resolution context to previous measurements from this core taken at stratigraphic scale of 7.62 cm (3 inches). While the two datasets are consistent, higher frequency trends are now resolvable and help to better understand the "signal to noise ratio" of the lower frequency data that extends over a much longer stratigraphic interval. Additionally, undetected elemental trends have been recognized below the resolution of the coarser dataset. The data collected in this study was also analyzed using a software package developed by the EPA called EPA PMF which uses positive matrix factorization, a form of multivariate factor analysis, to unmix the elemental concentrations of each sample into a set of geologically identifiable components. The stratigraphic trends in the contribution of these components can then be plotted to investigate changes in carbonate and biogenic silica content, the composition of siliciclastic detritus, and redox proxies. The results of this study suggest that short intervals of core through the various members of the Utica Shale and the associated Trenton Group limestones should be analyzed at high resolution to better understand the lower frequency datasets. By combining short intervals of high frequency data with longer intervals of low frequency data, collection rate and geologic resolution are not compromised.

Cross-section framework for visualizing carbon capture utilization and storage potential in the Ohio-West Virginia-Pennsylvania portion of the Appalachian basin

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The Midwest Regional Carbon Sequestration Partnership (MRCSP), a consortium of ten states, funded by the U.S. Department of Energy through Battelle Memorial Institute, has been investigating and mapping the geology of various subsurface formations from the Michigan Basin to the Atlantic U.S. offshore for 15 years. Within the past five years, project team members have begun to generate regional geologic cross-sections that span multiple physiographic provinces across our study area. As this regional midwestern U.S. cross-section framework continues to march eastward to the sea, Pennsylvania has contributed to the effort by preparing two strategically placed cross-sections through a portion of the Appalachian basin. These cross-sections use available deep log control to identify reservoirs suitable for CO_2 storage, organic shales that may benefit from enhanced hydrocarbon recovery, and confining layers which function as seals. Deepening basinward from west-to-east and north-to-south over the tri-state area of eastern Ohio, southwestern Pennsylvania and northern West Virginia, the two sections incorporate gamma-ray with bulk density, neutron or density porosity log control to highlight geologic formations below 2500 feet depth suitable for miscible CO_2 storage. These potential storage reservoirs include, in order of increasing age, the Oriskany Sandstone, Lockport Dolomite, “Clinton”/Medina Group, Rose Run Sandstone and Cambrian basal sands. Reservoir potential is greatest in the northern and western portions of the study area, where the basin is shallower, although thin-skinned tectonics toward the east and south enhances trapping and permeability in the Oriskany Sandstone. Confining intervals, which develop CO_2 reservoir storage or enhanced hydrocarbon recovery locally, include the deltaic sands of the Venango and Greenland Gap groups as these intervals deepen basinward to the east and south; the Bass Islands Dolomite to the north; Tuscarora Sandstone where influenced by structure to the east and south; and Copper Ridge Dolomite toward the west. Potential to solution mine storage caverns in the Salina F4 Salt also exists locally. Several organic Upper Devonian shales, along with Middle Devonian Marcellus and Upper Ordovician Utica and Point Pleasant that exist throughout the cross-section study area are noted where they occur deeper than 2500 feet. To assist geologic evaluations, published data on basement faults, local cross-structural discontinuities and folding, which influence facies changes, reservoir quality and confining properties, have been incorporated, along with facies changes evidenced by log control and nomenclature variations from state stratigraphic columns.

Candidate Well Selection for Re-Fracturing in Tight-Gas Sand Reservoirs Using Artificial Intelligence

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Tight-gas sand reservoirs require large hydraulic-fracture stimulation treatments through horizontal wells to be able to recover economic volumes of gas. Characterizing the uncontrollable hydraulic-fracture properties along the horizontal wellbore to identify candidate wells for re-fracturing from limited data remains as a challenging and resource-demanding decision-making problem. In this study, an artificial-intelligence based decision-making protocol is developed to identify wells with relatively low hydraulic-fracture quality in terms of permeability, width and half-length. The methodology is based on fuzzy logic which is used to deal with imprecision and subjectivity through mathematical representations of linguistic vagueness. A fuzzy inference system is developed based on fuzzy *if-then* rules and fuzzy reasoning. The following key assumption is defined: wells with similar reservoir/hydraulic fracture characteristics and operational conditions are expected to display similar performance characteristics. Similarly, if two wells with similar reservoir and operational characteristics behave differently in terms of production, then the hydraulic-fracture quality must be different. Considering this assumption, we grouped all parameters related to a tight-gas horizontal well into the following categories: reservoir quality, initial conditions, operational constraints and hydraulic-fracture quality. For each category, we developed a rule-based fuzzy-inference system that quantifies the quality of that category (higher quality is better for well performance). Quality indices are calculated by inferring from 27 linguistic rules for 3 input parameters for each category. We also defined a performance index as a function of initial flow rate and cumulative recoveries after 3 and 5 years. Our final fuzzy-inference system for decision making had 4 inputs (reservoir, operational, initial conditions and performance indices) and 1 output (re-fracturing potential index). A total of 81 linguistic rules were developed to quantify the need for re-fracturing. Using available data, all rules are evaluated simultaneously to output the re-fracturing candidacy index for a given well. This approach was successfully validated using case studies from Granite Wash and Williams Fork tight-gas sand formations. These examples showed that the developed system can be used to quickly identify wells in which there is a room for improvement in terms of the hydraulic-fracture quality.

Methods to Assess Thermal Maturity of the Utica / Point Pleasant Play in the Appalachian Basin

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KEYWORDS: Thermal Maturity, Utica, Point Pleasant, Bitumen, Graptolites, Ordovician, CAI

Thermal Maturity has been a key component of the Utica play since its inception. The initial focus was determining the oil, condensate, wet gas, and dry gas boundaries in Eastern Ohio and Western Pennsylvania. While that aspect of the play is now well delineated, there is still work to do determining the effective extent of the dry gas play as it extends into Central and Northeastern Pennsylvania.

Vitrinite Reflectance (VRo %) measurements are the gold standard for assessing maturity in coals and source rocks. The Utica and Point Pleasant are Upper Ordovician in age, so unfortunately there is no vitrinite to measure. Conodont Alteration Index (CAI) maps

introduced by Harris and others (1978) and updated by Repetski (2008) have helped in determining the overall maturity patterns in the Appalachian Basin. However, the author believes the CAI is an unreliable metric to accurately define the boundary between the dry gas and over mature parts of the play.

Using logs, cuttings, and core samples collected throughout our 100+ year history in the Appalachian Basin, Seneca has undertaken a number of studies to further our knowledge of the extents of the deep, dry gas Utica play. These efforts include looking at bitumen and graptolite reflectance, resistivity logs, and Raman Spectroscopy, in addition to integrating shallower datasets from Devonian source rocks and Pennsylvanian coals. This presentation will detail the advantages, as well as issues, encountered with each of these methods.

Carbonate concretions in the Middle and Upper Devonian shales of the Appalachian Basin: Insights into origin, formation, and their effects on drilling efficiency

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Limestone “stringers” encountered while drilling horizontal Marcellus wells negatively impact drilling operations by reducing drilling rates, damaging bits, and requiring excessive steering corrections to penetrate or extricate the bit from the horizon. Analysis of cuttings, cores, and well logs reveals that the limestone “stringers” are often carbonate concretions. Observations of surface exposures of the Middle and Upper Devonian shale succession, including randomly tilted concretions and differential compaction of host sediment laminae around concretions, suggest early diagenetic formation in unconsolidated sediment. Estimates of pre-cementation host sediment porosity based on carbonate cement volume (74-93%), a consistency in center to edge laminae thickness, and the preservation of a card-house clay fabric within concretions is consistent with shallow, rapid diagenetic growth. Carbon isotopic composition of Rhinestreet and Marcellus concretions range from -16.33 ‰ to +1.7 ‰ indicating a carbon mix of depleted and isotopically heavy sources. These observations suggest that carbonate concretions form by the anaerobic oxidation of methane in a narrow zone perhaps just a few meters below the seafloor. Crucial to this mechanism is a slowing or pause in sedimentation rate that would have held the zone of carbonate precipitation at a fixed depth long enough for concretions to grow. A resumption in sedimentation and burial of the would have brought concretion growth to an end.

Using this model, we attempt to predict the size and location of concretions to avoid encountering them while drilling. The size of Marcellus concretions was predicted using measurements of their vertical thickness in core compared to the relationship of the vertical and horizontal length of Rhinestreet Shale concretions. These measurements suggest that concretions up to three feet in length are common in the Marcellus. The potential for encountering concretion horizons was predicted using uranium to organic carbon ratios to identify hiatuses in sedimentation. Since the attachment of uranium to organic carbon macerals occurs across the sediment-water interface, an increase in the abundance of uranium per unit organic carbon indicates a cessation in sedimentation and the potential for concretion growth. Indeed, when comparing well log response to core, uranium to organic carbon excursions predicted the location of two concretion horizons in the Marcellus Shale of southwestern PA.

Refined Lithostratigraphy of Upper and Middle Devonian Shales in West Virginia

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The evolution of the formal lithostratigraphy for the Middle and Upper Devonian strata in the central Appalachian basin has been complex. The original terminology (Chemung, Portage, Marcellus, Catskill, and others) was assigned late in the 19th century. However, by the 1930s, the realization that these units changed in nature dramatically when traced laterally resulted in a crisis in stratigraphy that forced the differentiation of chronostratigraphy from lithostratigraphy. Further, the sheer size of the basin creates challenges, as stratigraphic terminology defined by examination along the outcrop belts at the basin margins is difficult to extend into the subsurface due to the distances involved, the different nature of outcrop and subsurface data, the different perspective of workers attempting to extend units either from the north and west or from the east, and the complex facies changes within the strata. As a result, the facies architecture and associated lithostratigraphic nomenclature for many Middle and Upper Devonian units remained unsettled, particularly in the basin center.

This study uses log data from nearly 400 wells from West Virginia to produce detailed maps of the economically important, organic-rich facies and identifies various associated vertical and lateral lithostratigraphic unit boundaries. The study focuses on the Middle Devonian Hamilton Group and its constituent Marcellus and Mahantango formations. Within the Marcellus, a lower Union Springs Member, a middle Cherry Valley Member, and an upper Oatka Creek Member are defined within northeastern West Virginia only. Throughout the rest of the subsurface of the State, the Marcellus has no distinguishable members. In the Upper Devonian, the occurrence and limits of the Harrell Shale (and its basal Burket Shale Member), and its westward lateral transition into the largely-correlative Genesee Formation (with basal Geneseo Shale and upper West River Shale members) are mapped. Maps also detail the position at which the Sonyea Formation (with basal Middlesex Shale and upper Cashaqua Shale members), West Falls Formation (with basal Rhinestreet Shale and upper Angola Shale members), Java Formation (undifferentiated), and lower part of the Huron Member of the Ohio Shale transition eastward into age-equivalent strata of the Brallier Formation.

Assessing the Potential Helium Resources in Central Kentucky

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Helium (He) is a rare element essential to medical procedures, such as magnetic resonance imaging, and low temperature physics research. However, the decision to sell Federal helium supplies through the Helium Privatization Act of 1996 may make the United States dependent on foreign sources for its He supply. He is produced in the Earth's crust by radioactive alpha decay of uranium (U) and thorium (Th) isotopes in minerals. Radioactive decay of potassium (K) isotopes, common in crustal rocks, is by gamma decay and does not produce He.

He migrates and accumulates in porous rocks much like oil and natural gas. He concentrations exceeding 1.6 vol.%—three times the minimum concentration required for commercial development in western U.S. helium fields—have been found in oil and gas exploration wells drilled to the Rome Formation, at an average depths > 4500 ft, adjacent to the Kentucky River fault in the Rome Trough, Garrard and Clark Counties, Kentucky. There are, however, no data on He occurrences in the 20-mi gap between those locations.

He generation potential can be estimated by calibration of conventional gamma ray logs (GR) to U and Th concentrations measured by X-ray fluorescence (XRF) analyses of cuttings and core samples from wells in the areas of known He accumulation. These data can then be used as a guide for predicting commercial He accumulations. A spectral gamma ray log (SGR), a logging tool that measures U, Th, and K concentrations in formations penetrated in a wellbore, was run in the Kentucky Geological Survey 1 Hanson Aggregates well, Carter County, Kentucky, and XRF analyses of cuttings from the Conasauga shale and Grenville basement were performed for calibration of SGR and GR log data. SGR log values were a poor match to XRF data, with SGR values of U much lower and Th values higher XRF values in the Conasauga and SGR measured U values much higher and Th values much lower than XRF values in the Grenville. By calibrating SGR values to XRF measurements, however, calibration of GR log values to U and Th concentrations was possible. Net potential He source rock in the Rome Formation shales was determined using a 108 API units (APIu) cutoff. Average GR values in Rome Formation shales in the Rome Trough at the API unit cutoff increase from about 125 APIu in central Garrard County to more that 200 APIu in southern Clark County. This suggests that the Garrard-Clark counties region has a high likelihood for He generation. Additional XRF analyses of cuttings from the Rome Formation shales will be necessary to confirm this.

If the Garrard-Clark counties region is rich in He, central Kentucky may have a valuable commercial resource. The cost of drilling deeps wells to assess the He distribution, however, has discouraged exploration in the region.

Preliminary Assessment of the CO_2 Storage Capacity in the Lower Copper Ridge Dolomite (Upper Cambrian), Northeastern Kentucky

J. Richard Bowersox and Stephen F. Greb, and David C Harris, Kentucky Geological Survey

The Kentucky Geological Survey drilled its 1 Hanson Aggregates stratigraphic research well, Carter County, northeast Kentucky, to identify potential CO_2 storage reservoirs in the Knox Group and deeper strata, identify potential confining intervals, and test reservoir rock properties in the southern Appalachian Basin. The lower Copper Ridge Dolomite of the Knox (3313 - 4170 ft) was evaluated to determine porosity and permeability as a standalone CO_2 storage reservoir. The interval is composed almost exclusively of dolomite with occasional thin sandstone and shale interbeds. Average porosity calculated in the entire lower Copper Ridge is 5.8% and permeability measured in core plugs ranges from less than 0.001 mD to 34 mD.

A step-rate test was conducted in the Copper Ridge from 3695–3945 ft, an interval that showed substantial vugular porosity in cores. The interval was isolated at its base by a cast iron bridge plug and cement plug at 3945–3963 ft to prevent pressure communication and fluids loss to underlying strata during testing, effectively abandoning the wellbore below 3963 ft. The interval with swabbed through tubing in 19 runs prior to the step-rate test to recover formation water, recovering 43 barrels of water. Analysis of the water sample showed 114,900 mg/l residue total dissolved solids. A static bottomhole pressure was obtained followed by the step-rate test. The test featured stable pumping rates from 0.25 to 5.5 BPM in 5-minute steps, but was terminated when the supply of fresh drinking water test-fluid was exhausted. After completion of the final step the well was shut-in and pressure falloff monitored for about 12 hrs. The lower Copper Ridge test interval fractured at a pressure of 1979 psi, or a fracture gradient of 0.60 psi/ft. Average permeability of the test interval calculated from the falloff pressure was 15.3 mD.

Porosity and net reservoir thickness for calculating potential CO_2 storage volume in the lower Copper Ridge were determined using an industry-standard 7% porosity cutoff. Average reservoir thickness in the study area at the cutoff is 71 ft and porosity is 9.0%. Net lower Copper Ridge reservoir pore volume in the 615,450-acre potential storage area is about 4.0 million acre-feet.

CO_2 storage volume was determined using the methodology of the U.S. DOE, Office of Fossil Energy, National Energy Technology Laboratory. Estimated P_{50} CO_2 lower Copper Ridge storage volume is about 1320 metric tons/acre and 811 million metric tons in the study region. Thus, about 760 surface acres would be required to store 1 million metric tons of CO_2, the average annual CO_2 released by a coal-fired power plant in the Ohio River industrial corridor.

Evaluation of Thin Limestone Interlayers within Marcellus Shale in Southwestern Pennsylvania

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Marcellus Shale consists of organic-rich mudrocks with several thin limestone interlayers. The thickest interlayer is named Purcell Limestone, which separates the Marcellus Shale into the Upper Marcellus Shale (Oatka Creek Member) and Lower Marcellus Shale (Union Spring Member). The thickness of these limestone interlayers varies by location within the Appalachian Basin. Limestone interlayers can have an influence on hydraulic fracturing and production in the Marcellus Shale. Identifying the thin limestone interlayers within the Marcellus Shale is important to correctly estimate the thickness of the organic-rich zone within Marcellus Shale. The effects on hydraulic fracturing and production can be investigated by analyzing whether the mechanical properties change within the Marcellus Shale. Hydraulic fractures through the Purcell Limestone is an important area of study in which the thickness of the limestone layer can play a part in some effects. Understanding the varying thickness of the Purcell Limestone will be useful in order to evaluate the Marcellus further.

In southwestern Pennsylvania (including Westmoreland, Fayette, Washington and Greene Counties), the Purcell limestone varies in thickness. Analyzing wells that have been drilled in the Marcellus Shale Formation will allow to pick formation tops and consequently make isopach maps for these thin limestone layers and Marcellus Shale. The log data used in this research include gamma ray, bulk density, neutron, PE and resistivity. The thin limestone interlayers may be analyzed further in different wells to figure out the effects on hydraulic fracturing and production for this area. A 3-D structural model will be constructed based on the formation top data and the built maps of structure and isopach of the thin limestone layers and Marcellus shale.

Relationship Between Well Performance and Structural Setting in the Marcellus Shale of Greene County, Pennsylvania

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Analysis of horizontal Marcellus Shale wells in Greene County, Pennsylvania suggests a correlation between estimated ultimate recovery per thousand feet of lateral (EUR/1,000 ft) and structural setting. Basement-generated anticlines and synclines of Greene County seem to have a direct effect on well performance.

To test the relationship between EUR/1,000 ft and structural setting in the Marcellus Shale, 730 wells with adequate production, completion, and location information were categorized into four structural settings based on shallow residual mapping the base of the Big Injun Sand. The structural settings refer to the relative height above or below the residual trend surface of the Big Injun at a given location. The structural settings, from low to high, are (1) Below Trend (2) At or Near Trend (3) Above Trend, and (4) Well Above Trend. The Below Trend structural setting has the highest average EUR/1,000 ft and outperforms the worst structural setting, Well Above Trend, by 25%. The average EUR/1,000' decreases with each progressively shallower structural setting.

A similar relationship between horizontal well performance and structural setting has been observed in the Utica-Point Pleasant Shale (Utica Shale) in Ohio. In the Utica Shale, structurally low settings show higher total organic carbon (TOC) compared to structurally high settings. It is hypothesized that structurally low settings offer a better environment for the deposition and preservation of organics. The relationship between well performance and structural setting in the Marcellus Shale will be explored and compared to what has been observed in the Utica Shale. Further, the importance of filtering wells by structural setting prior to analyzing completion methods will be emphasized.

Resolving Predictable Reservoir Behavior in Heterogenous Carbonates using Integrated Rock Typing Methods: A Field Scale Case Study of a Michigan Basin Silurian-aged Niagaran Brown Reef

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The Silurian-aged pinnacle reef complex of the Michigan basin is a prolific hydrocarbon play and valued for its potential for carbon storage and CO_2 driven enhanced oil recovery. Recent work has aided in resolving reefal structure and facies relationships, however, prediction of rock properties remains difficult. This study strives to optimize existing field scale

workflows by implementing rock typing techniques that integrate geological, diagenetic and petrophysical attributes across scales into predictable profiles for static model population. The study area is limited to a single field along the northern reef trend in Otsego County, Michigan. The field is currently undergoing CO_2-EOR and features a characterization well cored through the leeward profiles of the lower A1 carbonate and Niagaran Brown formations. This characterization well served as the type well of the field to generate rock types and features 230 feet of whole core, 117 core plugs, 16 mercury capillary curves, and 21 thin sections. Conventional and specialized well logs, including borehole image logs were collected. Intervals were picked for mercury injection and thin section analysis post-core description such that each curve and thin section was matched to core plug intervals that best represented geologic and petrophysical characters of each lithofacies encountered and served as control points for normalization of data. The study workflow consisted of four stages: geological and diagenetic characterization, petrophysical and pore-typing characterization, rock type definition, and geophysical facies definition and correlation. Upon completion of characterization stages, data was pooled and normalized beyond control points to the remainder of the core plug database. Data was segmented by depositional environment and subjected to multivariate ordination techniques to identify rock types. Core-calibrated geophysical log data was subjected to descriptive and multivariate analytical techniques to resolve profiles of defined rock types. Preliminary results include: (1) successions of lithofacies observed along the proximal reef apron are consistent with tempestite facies models, (2) trends in diagenetic modifications and controls on the development of microporosity were observed, (3) lithofacies-specific characterization of pore systems revealed heterogeneities and trends that account for distinctly different pressure-saturation profiles, and (4) rock types segmenting major depositional zones yielded enhanced petrophysical predictability and provided insight on how best to populate static models of the field.

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Structure and isopach mapping of the Mississippian Black Hand Sandstone in eastern Ohio (northwest Appalachian Basin)

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Accurate mapping of the base of the deepest underground source of drinking water (USDW) is crucial for well planning and protection of aquifers in eastern Ohio, where oil-and-gas exploration is common. The deepest USDW in east-central Ohio is the Mississippian Black Hand Sandstone Member of the Cuyahoga Formation. In its type area, the Black Hand Sandstone is defined as a porous, medium- to coarse-grained sandstone with common conglomeratic lenses. Originally interpreted to be a deltaic deposit, more recent research suggests the Black Hand may be part of an incised fluvial system. In the subsurface, the Black

Hand is correlated to the drillers' "Big Injun," although this term is haphazardly applied to several Mississippian and Pennsylvanian units with low gamma signatures in eastern Ohio. Therefore, a more rigorous subsurface definition of the Black Hand is necessary for detailed mapping. Analyses of outcrop, geophysical well logs, and well cuttings were combined to define the Black Hand in the subsurface and to produce isopach and structure maps of the unit. Detailed subsurface maps of the Black Hand Sandstone will provide insight into its complex depositional system and can aid in the development of robust well-casing programs.

Numerical study of the role of critical dimensionless numbers associated with multiphase flow in 3D porous media using lattice Boltzmann modeling

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Multiphase flow in porous media is of great practical interest in many engineering fields, including geological CO_2 sequestration, enhanced oil recovery, and ground water contamination and remediation. In order to advance the fundamental understanding of multiphase flow in natural, 3D porous media, the role of the critical dimensionless numbers associated with multiphase flow, including contact angle, viscosity ratio, and capillary number, is investigated using lattice Boltzmann (LB) modeling. In this study, the pore structure information was extracted from micro computed tomography (Micro-CT) scanned images and then used as internal boundary conditions in a pore-scale LB simulator to simulate multiphase flows within the pore space. A Berea sandstone core sample was scanned in three sections, and then two phase flow simulations were performed for each section. The LB-simulated fluid distribution agreed well with Micro-CT scanned images, which validated the LB simulation capability. To the best of our knowledge, it is the first time that comprehensive interactions between contact angle, viscosity ratio, and capillary number are demonstrated in a real 3D sandstone rock. Simulation results showed that increasing contact angle causes an increase in wetting phase relative permeability and a reduction in non-wetting phase relative permeability. Increasing capillary number will increase both wetting phase and non-wetting phase relative permeabilities, because higher inertial force favors the mobility of both fluids. Increasing viscosity ratio (defined as the ratio of non-wetting phase viscosity to wetting phase viscosity) caused the distance between wetting phase relative permeability curves larger, whereas the distance between non-wetting phase curves smaller. This is because the lubrication effect was stronger when the wetting phase (brine) viscosity was reduced, leading to enhanced non-wetting fluid (CO2) relative permeability. We also simulated the relative permeabilities of both phases after the fluid injection direction and sample location were changed. The results showed that the change in non-wetting phase relative permeability was larger. This indicates that there is stronger spatial heterogeneity and anisotropy in larger pore networks because the non-wetting fluid tended to occupy larger pore space. . The combination of numerical simulation and experiment measurements is promising for advancing fundamental understanding of

relative permeability and providing guidance to the design and interpretation of experimental studies. Moreover, special attention should be paid to these micro-scale heterogeneities for relative permeability analysis; insight gained from the studies of small-scale heterogeneity will benefit the understanding of permeability upscaling in geological formations.

Sediment Provenance Study of the Marcellus Shale: An Analysis Between the Organic-Rich Facies and Their Depositional Histories

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Currently, no geological model exists to explain the variability and distribution of organic-rich facies in the Marcellus Shale. Within the central Appalachian basin, there are two "sweet spots", one in Northeast Pennsylvania and another in Southwest Pennsylvania/North-Central West Virginia. In these areas, the Marcellus Shale contains thick accumulations of organic matter and are highly productive for natural gas. In contrast, many studies and production reports have shown that in other areas, the Marcellus Shale is relatively organic-poor. One possible explanation for the lower organic content is that detrital dilution was greater in these areas compared to surrounding productive regions. This hypothesis will be tested by analyzing the provenance of inorganic detritus in the Marcellus Shale. Recent study of the MSEEL (Marcellus Shale Energy and Environmental Laboratory) well in north-central West Virginia revealed input from the Superior Craton decreased and input from the Acadian mountains increased as TOC in the Marcellus decreased up-section. This suggests detrital dilution of organic matter should exert a decreasing influence southward along the basin axis. To examine this idea further, a comparison will be made between the MSEEL well and two wells located in other areas of the basin. Facies classifications and provenance interpretations will be made in the Marcellus Shale intervals based XRD mineralogy and XRF/ICP-MS major/trace element geochemistry. These data will be combined with Sm-Nd analysis analysis to further constrain provenance. Raman spectral analysis will be used to evaluate thermal maturity and its relationship to organic richness of Marcellus facies. Ultimately, these data will be used to model the depositional environments, sediment provenance, and thermal maturity to explain the variation in organic matter content in the central Appalachian basin.

Midwest Regional Carbon Sequestration Partnership: Findings from the Michigan Basin Phase III Injection Test Monitoring Program

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KEYWORDS: Geologic carbon storage: monitoring, verification, and accounting

Carbon capture, utilization, and storage is a crucial technology for enabling the use of abundant and reliable fossil fuel resources with greatly reduced carbon intensity. The U.S. Department of Energy established the Midwest Regional Carbon Sequestration Partnership in 2003 to perform research and development on geologic storage of carbon dioxide in ten states spanning the Midwest and Mid-Atlantic region. The MRCSP is a consortium of industry, private companies, universities, non-governmental organizations and state agencies with a goal to assess the potential, economic viability, and public acceptability of carbon sequestration within its region.

The Michigan Basin Phase III Injection Test is designed to inject and monitor one million metric tons of anthropogenic carbon dioxide within a series of formations currently being used for enhanced oil recovery operations. The project is being carried out across ten pinnacle reefs in fields in different stages of their production life-cycle: one late-stage reef, six active reefs and three new reefs that have only experienced primary oil production (new carbon dioxide floods).

The project successfully injected and monitored the combined storage of one million metric tons carbon dioxide in March 2018. The late-stage reef served as the main test reef for application of monitoring, verification and accounting technologies. The closed carbonate reservoir provides an ideal system for testing the ability of technologies - such as pulsed neutron capture logging, borehole gravity surveys, vertical seismic profiling, and satellite monitoring - to record the behavior and fate of injected carbon dioxide in the subsurface.

Monitoring of carbon dioxide injection and oil production in active and new reefs at the test site include pressure and wireline logging and fluid flow mass balances, as well as metering of the injection volume, recycle of carbon dioxide gas produced with oil, and new compressed carbon dioxide from the natural gas processing plant. One new reef was selected for detailed characterization and additional monitoring, including fiber-optic based temperature and acoustic systems, multi-level pressure, and periodic logging in the injector and monitoring well.

Data from these multiple fields has provided insight into the impact of geologic heterogeneity and hydrocarbon production history on CO_2 storage potential. This presentation will provide an overview of the key findings of the MRCSP monitoring program and how this information may be applied to future commercial storage sites.

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Central Kentucky Reservoirs Associated With the Cincinnati Arch Affected by Structure and Tectonics

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KEYWORDS: Fracturing, hydrocarbons, Cincinnati arch, structure, tectonic activity.

Central Kentucky structurally lies on the axis of the Cincinnati Arch, a major structural feature that separates the Appalachian Basin to the east from the Illinois Basin to the west. Structural features associated with the Cincinnati arch are the Jessamine dome to the north and the Nashville dome to the south. A structurally low feature, the Cumberland saddle, separates the two domes.

Sedimentary evidence suggests that basement faulting and uplift of the Cincinnati Arch occurred as early as the Cambrian and was reactivated several times during various periods in geologic time. An unconformity occurs at the top of the Cambrian-Ordovician rocks resulting in extensive karst topography including residual hills and sink holes.

The southern area along the arch has been extensively and successfully explored for hydrocarbons which are entrapped along an unconformity at the top of the Cambrian-Ordovician rocks. As a result of repeated uplift and shifting of the axis of the arch, numerous fractures occurred in the carbonates, both beneath and overlying the unconformity. Several extensive fault systems are present in the area, and many of them produce hydrocarbons on the upthrown side. The hydrocarbons were driven by fluids and gases and migrated along the eroded Cambrian-Ordovician surface laterally and upward onto topographic highs. Hydrocarbons generated from Devonian black shales migrated both vertically and horizontally from deep in the Appalachian and Illinois Basins through faults, fractures, joints, weakened bedding planes, vugs, breccias, unconformable surfaces, and along the flanks of the arch to accumulate in Cambrian, Ordovician, and Silurian reservoirs. Brecciated and fractured zones associated with the unconformity also serve as a host for hydrocarbons and sulfide mineralization containing varying amounts of galena, sphalerite, barite, calcite, and fluorite.

The porosity characteristics of the carbonates are secondary, caused by chemical and physical changes such as dolomitization, hydrothermal activity, solution channels, or fractures. Compaction and cementation also affect porosity. The porosity, permeability, and pore-space distribution observed in core samples are related to the depositional environment, changes that have occurred after deposition, and tectonic activity.

Regional Cross section beneath the Ohio River Valley for carbon storage evaluation

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The Ohio River Valley is a major industrial and electric-generation corridor. A cross section using logs from 25 deep wells is constructed from western Kentucky eastward to Pittsburgh, Pennsylvania to illustrate the changing depths of potential carbon storage units and confining strata within the valley in the Midwest Regional Carbon Sequestration Partnership region. All stratigraphic units from the surface to basement are correlated. Intervals below 2,500 ft. depth are color coded as (1) regional saline aquifers, (2) potential local reservoirs within larger confining intervals, (3) confining intervals, and (4) organic-rich shales, which are confining intervals, but also have potential for enhanced gas recovery with CO_2. The 2,500 ft depth approximates conditions at which injected CO_2 would be in its supercritical state for optimal geologic storage and for miscibility if used for enhanced oil production. Immiscible CO_2 could be used in some cases to repressure depleted reservoirs at shallower depths.

The Ohio River cross section extends from the western margin of the Illinois Basin, across the Cincinnati Arch, eastward into the Appalachian Basin. Precambrian basement shallows from –7,000 ft (subsea) on the western edge of the section, to less than –3,000 ft on the Arch, to more than –14,000 ft north of Pittsburgh. The section includes four Class V CO_2-test wells (Kentucky Geological Survey No. 1 Marvin Blan, Battelle No. 1 Duke Energy, AEP No. 1 Mountaineer, and First Energy Generation No. 1 FEGENCO), and two Class I wells previously drilled for underground waste injection. Carbon storage tests targeted the Mount Simon Sandstone where shallow on the Cincinnati Arch and the Gunter/New Richmond Sandstone, Rose Run Sandstone, and Copper Ridge Dolomite of the Knox Group in the basins. Additional local reservoirs occur in Silurian and Devonian limestones and sandstones in the Appalachian Basin. Parts of the Ohio, Rhinestreet, and Marcellus Shales might also be suitable to inject CO_2 for enhanced gas recovery.

Results from testing show large-volume storage is possible in certain units in some areas, but in other areas, stacked reservoirs or pipelines would be required. More analyses are needed to quantify actual reservoir characteristics away from the test wells for any of the potential reservoirs shown, but the section allows easy visualization of critical storage units, extent of confining intervals, and location of faults for future carbon storage planning.

Regional Characterization of an Oil-Bearing Reef Complex for Factors affecting Assessment of Associated CO_2 Storage

Autumn Haagsma, Amber Conner, Glenn Larsen, Mackenzie Scharenberg, Wayne Goodman, William Harrison, Joel Main, Valerie Smith, Ashwin Pasumarti, Allen Modroo, and Neeraj Gupta

There are over 800 identified Silurian-aged (Niagaran) Pinnacle Reefs in the northern Trend (NPRT) in the Michigan Basin. The complex internal architecture, production history, lithology, and diagenetic changes in these reefs strongly affect the storage capacity, pressure response, and ultimately the reservoir performance of each individual field. Therefore, these fields provide an excellent opportunity to evaluate the geologic variability in complex carbonate reservoirs and its impact on CO_2 storage configurations. The reefs have historically been studied on an individual scale which does not represent the potential of the entire trend. Under this project, workflows were established to characterize reefs from an individual scale to a regional scale, capturing the entire NPRT. The reefs are being analyzed in three parts: 1) geologic characterization using wireline logs, whole core, and production records, 2) assessment of EOR/CCUS feasibility and comparison between the reefs by constructing representative static earth models, dynamic models, and geomechanics models, and 3) estimates of CO_2 resources across the NPRT using three methods (fluid substitution, material balance, and dynamic modeling).

Results show the geologic variability in the reefs impacts the storage feasibility across the trend. Significant factors include lithology, diagenesis, and reef connectivity. A comprehensive dataset collected on this project successfully identified trends in the NPRT and characterized variability while also providing a resource and guide for future CCUS activities. New methodologies and techniques were developed which were used consistently and efficiently to analyze hundreds of fields. Some of the highlights are listed below:

1) Image analysis techniques were developed to statistically derive porosity indicators and to quantify diagenetic features in whole core using CT scan data
2) Petrophysical techniques were developed for complex carbonates and identified reefs better suited for CCUS
3) Reservoir characteristics changed across reef types and lithofacies, however the diagenetic overprint primarily controlled the reservoir performance through secondary porosity development or evaporite plugging
4) Reefs were ranked by CCUS feasibility using the results from dynamic modeling and storage resource calculations
5) Assessment of caprocks and geomechanical models showed the effectiveness of CCUS in reefs
6) An interactive database was established to quickly provide assessments of individual reefs as well as summaries across the entire NPRT

The study is part of the Midwestern Regional Carbon Sequestration Partnership (MRCSP) Michigan Basin Large-Scale Injection Project under DOE/NETL Cooperative Agreement # DE-FC26-0NT42589 with co-funding by Core Energy, LLC, and several other partners.

Statistical Analysis of Core and Wireline Log Data from the Northern Niagaran Pinnacle Reef Trend to Inform Static Earth Modeling for CO2 Storage Fields

Autumn Haagsma, Srikanta Mishra, Mackenzie Scharenberg, and Neeraj Gupta

The Northern Niagaran Pinnacle Reef Trend (NPRT) is composed of over 800 identified reefs in the Michigan Basin. Well coverage and data availability vary greatly between fields and create a significant challenge in characterizing and modelling. Methodology was established to statistically analyze core and wireline log data to determine characteristic property distributions of porosity and permeability for specific formations and facies that can be applied in areas of scarce data. The analysis was conducted in three parts: 1) descriptive statistics of formations and facies were run using wireline logs and core data, 2) correlations were developed between wireline log and core data to build predictors, and 3) results were applied to static earth models with different data availability to demonstrate the influence on modelling.

Core data was compiled for over 250 wells across the NPRT capturing a variety of reef types, including: dolomite, limestone, mixed carbonate, salt-plugged, vugular and fractured, oil producing, gas producing, and water filled. This included data for off-reef Niagaran rocks and overlying A-1 Carbonate. Associated wireline log data was digitized, key formation tops identified, and depth shifts between core and log data were corrected. A statistical analysis program, R, was used to establish distributions and apply machine learning techniques to develop predictors. Prediction models were validated by comparing predicted properties to actual measured properties. Static earth models were constructed for multiple reefs and results were applied to better populate properties within the reef structure. Additionally, results of models were compared between non-informed and informed property models.

Results show property distributions were controlled by facies, lithology, and diagenesis. Unique distributions were established to represent specific reef facies and were successfully applied to static earth models. Where data was scarce, the statistical results provided a solution for property modelling which better matched geologic and reservoir interpretations. Results of this study can be applied across the NPRT to better predict reservoir properties and aid in future modelling efforts.

The study is part of the Midwestern Regional Carbon Sequestration Partnership (MRCSP) Michigan Basin Large-Scale Injection Project under DOE/NETL Cooperative Agreement # DE-FC26-0NT42589 with co-funding by Core Energy, LLC, and several other partners. Data was provided by the Michigan Geologic Repository for Research and Education (MGRRE).

Reservoir Characterization of the Upper Silurian Bass Islands Formation in Northern Michigan for CO_2 Storage

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Recent research for evaluation of subsurface reservoirs in the northern Michigan Basin through a DOE–funded program called CarbonSafe (DE-FE0029276) identified the Bass Islands Formation as a potential CCS saline reservoir candidate throughout a large area of the northern half of Michigan's Lower Peninsula.

The Bass Islands Formation is a dolomitized brine-filled carbonate reservoir which is underlain by a thick anhydrite and overlain by a cherty carbonate of the Bois Blanc Formation. Porosity values as high as 30% and permeability of >900 md have been observed in core samples The Bois Blanc has high porosity (>15%), but very low permeability and can be considered a leak-off zone and an immediately overlying confining unit. Capillary trapping of CO_2 in the Bois Blanc porosity can occur after the pressure during injection diminishes post-injection. The ultimate caprock for the Bass Islands reservoir is the dense, tight limestone of the Amherstberg Formation.

Detailed mapping and reservoir analysis using wireline logs throughout a 21-county area in northern Lower Michigan shows relatively uniform thickness (greater than 60 feet) of the porous interval in at least 14 of these counties. Additionally, most of this area lies at depths greater than 2600 feet which is necessary for the CO_2 to be maintained in the supercritical phase. Thickness, average porosity, and areas were used along with DOE-NETL standard efficient factors for dolomite to estimate the CO_2 resources in Northern Michigan. Results produced a range of 3.5 GT (P10) to 12 GT (P90) with a P50 of 7 GT. The highest potential occurred in Antrim, Otsego, Grand Traverse, and Kalkaska counties. On average, prospective storage was 0.23 MT/km2 which equates to 220 km^2 to store 50 MT of CO_2. In the highest potential areas, this reduces to 100 km^2. There is significant storage potential in the Bass Islands dolomite in northern Michigan, however due to the thickness of the unit, a large radius would be needed to reach injection goals. The Bass Islands dolomite would be a suitable secondary storage zone in a stacked storage scenario.

GIS Compilation and Analysis of Near-Surface Structure Data from 707 Geologic Quadrangle Maps in Kentucky

John Hickman and Doug Curl, University of Kentucky, Kentucky Geological Survey

Between the years 1960 and 1978, the United States Geological Survey, in cooperation with the Kentucky Geological Survey (KGS), 196 professional geologists mapped the surface geology of the entire state of Kentucky at a scale of 1:24,000, and published 707 7.5-minute quadrangle maps. The geologic information from these maps were later digitized into vector-based GIS files by KGS staff between 1998 and 2005, making Kentucky the first US state to be entirely digitally mapped at a 1:24,000 scale.

For the majority of these Geologic Quadrangles, structural elevation contours based upon a local subsurface stratigraphic datum were included along with the stratigraphic contacts, fault locations, and other geologic information gathered during the original mapping effort. In an effort to create a seamless, statewide dataset, structural contours were interpreted for the remaining 36 quadrangles using currently available state records from oil, gas, and water wells, along with LiDAR high-resolution elevation data.

Although using a local datum for structural elevation data on individual quadrangles is necessary for detailed precision and ease of mapping, it presents a challenge when trying to merge the map data across a whole state. Because Kentucky straddles three separate continental basins (Appalachian, Illinois, and the Mississippi Embayment), 153 distinct datums were used for geologic quadrangle structural elevation data. Trying to create a statewide 3D display from this data produces 153 locally continuous surfaces, interrupted by vertical offsets at each datum boundary. In order to merge this dataset while retaining the relevant structural information, KGS researchers created dip and azimuth maps of the raster surfaces generated from the structure contours for each individual structural datum domain. Because displays convey only slope information (and not specific elevations), adjacent domains with different datums could then be merged into a seamless, statewide coverage. These new GIS products can now be used for the analysis of numerous geologic attributes. For example, locations of buried, previously unmapped faults can be interpreted from linear abrupt changes in dip (sediment drape across fault tip). Or, by comparing the structural dip with that of the LiDAR digital elevation model, estimations of relative erosional rates for various formations can be compared. This GIS layer will soon be available to the public for display or download from the KGS website.

2018 Update on the Emerging Rogersville Shale Play in Kentucky and West Virginia

John Hickman and David Harris, University of Kentucky, Kentucky Geological Survey

The 2013 Bruin Exploration #1 Silvia Young well, Lawrence County, Kentucky, was the first well to target the Cambrian Rogersville Shale as an unconventional reservoir. Speculation on the success of this well quickly spread through the industry, resulting in a regional oil and gas leasing boom in 2014 and 2015 across eastern Kentucky and southwestern West Virginia. Four additional Rogersville wells were drilled over the next 18 months; the Cabot Oil & Gas #50 Amherst Industries in Putnam County, West Virginia, the Horizontal Tech Energy #572360 EQT Production in Johnson County, Kentucky, the Chesapeake Appalachia #LAW-1 Janet Stephens and #LAW-1 JH Northup Estate wells in Lawrence County, Kentucky.

The most recent Rogersville well drilled was the Bruin Exploration #1H Walbridge, a horizontal well completed in the Rogersville with a 27-stage hydraulic fracture treatment. Logs and completion information from the #1H Walbridge were released in May of 2018. This well was tested for 68 days in early 2017, with average flowback rates of 21 BOPD, 797 MCFGD, and 2,494 BWPD. Total production volumes during testing were 54.2 MMCFG, 1,416 BO, and 169,571 BW. Based on these results, this well was temporarily plugged in mid-2017. Bruin is continuing to evaluate options for this well.

Other recently released data include both the logs and the 2015-2017 production data from the Cabot Oil & Gas #50 Amherst Industries well (as of this writing, the only Rogersville well put on production), as well as limited records (GR and completion info) from Horizontal Tech Energy #572360 EQT Production well. Total dry gas production through December 2017 from the vertical Rogersville completion in the Cabot well was 340 MMCF. Gas production declined from an initial monthly rate of 67.4 MMCF in May 2015 to 2.8 MMCF in September 2017. Although no new Rogersville wells have been permitted since September 2015, none of these six initial wells have been plugged and abandoned, signifying the possibility of future Rogersville Shale exploration and/or production activity.

Identifying Hazards and Enhancing Reservoir Models through interpretation of Hyperspectral Core Imaging for Carbonate and Unconventional and Carbonate Plays.

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An emerging analytical tool, with respect to oil and gas explorations, interpretation of Hyperspectral Core Imaging has been used in the mining industry to identify key lithological facies, mineral textures and alterations. Integration of traditional laboratory analysis and petrophysical interpretation allows us to accurately identify drilling and completion hazards as well as refine reservoir and fracture propagation models. In unconventional or carbonate plays, using cuttings, rotary side wall cores, and whole core to incorporate additional laboratory analyses such as X-ray diffraction, porosity/permeability analysis, rock mechanics, organic geochemistry, and thin sections interpretation with hyperspectral imaging analysis can clarify well log responses.

The critical component to using these images with respect to oil and gas, is accurate identification of the mineralogy and its relation to depositional fabric and textures within continuous conventional core. This allows for a more inclusive, cohesive grouping and correlation between log-derived electrofacies and sedimentological facies. Understanding this correlation will increase the operator's capability to identify drilling and fracking hazards such as that can cause costly drilling and completion delays, including bit-deviation and well instability. Differential cemented facies, recrystallized bedding or the widespread occurrence of expandable smectite are all common origins of drilling and fracking risks that can be better understood and mitigated by integrating hyperspectral imaging analysis with traditional energy exploration techniques.

Analysis of the Hyperspectral imaging is invaluable when developing models to characterize specific lithology packages. In turn, these packages are used to identify potential horizontal landing zones, hydrocarbon pay zones, drilling and completion hazards (borehole stability, and fracking hazards) and flow barriers. Identification and understanding these packages ultimately reduces operating costs, increases production and can ultimately impact reserves. For example, hyperspectrally-defined lithological packages combined with density and resistivity logs can reveal potential flow barriers that remained undetected in other wells. Hyperspectral imaging also identifies lithology where hydrocarbons and mineral-trapped hydrocarbons are located, further delineating preferable hydrocarbon pay zones across models. This same method of classification can be used to evaluate cores in producing wells for behind the pipe pay to be further pursued or to validate new calculations of reserve estimations.

U-Pb Calcite Ages and the Case for Acadian Structural Development in the Appalachian Basin: Implications for Oil and Gas Migration

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New U-Pb isochrons on calcite veins in the Middle Devonian (~ 400 Ma) Marcellus Formation in an EQT core raised in West Virginia are 317 +/- 20 Ma and 332 +/-20 Ma. One of the samples is from a low-angle, slickensided ("worked") Marcellus surface. These ages and their error bars primarily straddle the tectonically quiet time between the Neoacadian and the Alleghanian orogenies. The ages record the last time fluid migration occurred in the sampled vein-filled fractures. Thus, the veins record a Neoacadian or slightly later age, and are clearly not Alleghanian.

The Neoacadian to slightly post-Neoacadian age of the veins supports an earlier contention that the major folds and faults in the Appalachian basin began developing in the Neoacadian. This proposed age was originally based on 2-D seismic lines that appeared to display structural troughs that had Upper Devonian Elk and Bradford-time sediment infilling the structural trough (Jacobi et al., 2012). Because the data were relatively low resolution, a tectonic infill (mushwad), rather than a sediment infill, could not be completely ruled out (and thus, an Alleghanian time of development remained possible). However, a high –resolution 3D seismic volume in western PA confirms that there the infill is almost certainly depositional and of slightly pre-Elk time. Thus, these particular major Appalachian basin structures document Neoacadain initial development. We previously suggested that the initial structures were related to gravity "salt" tectonics (that involved silts, shales and limited salt of the Silurian Salina Group).

The ages of the veins and their error bars exactly correspond to the timing of early oil and gas generation that was determined from a subsidence curve constructed for the cored well in West Virginia. That the timing of early oil and gas mirrors the vein age is consistent with the observation of bitumen in the veins. Oil and gas migration up these early faults could have provided hydrocarbons for the Elk and Bradford sands. It is probable that the veins did block significant hydrocarbon migration in immediately post-Neoacadian time. The possible stress rotation near one of the thrusts (documented by the rotating orientation of J1 fractures observed on an image log in a lateral) suggests that the faults were again open during J1 (Alleghanian) time. This later reactivation of the thrust faults during the Alleghanian would have provided a second time of potential hydrocarbon migration.

FROM OUTCROP TO RESERVOIR, A COMPREHENSIVE DESCRIPTION TO LOWER SILURIAN LONGMAXI SHALE IN SICHUAN BASIN, CHINA

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Technical recoverable resources for Lower Silurian Longmaxi shale (S_1l) is estimated to be 286 tcf (EIA, 2016), showing prospective duplication of U.S shale gas revolution in China. Kerogen type, generation and accumulation patterns for Longmaxi shale have been reviewed by former researchers (Borjigin, 2017), which are conducive to resources evaluation. Whereas thorough appraisal to Longmaxi shale should be the foremost work for reservoir development from aspects of sedimentology, geochemistry, core sampling & description and well logging.

In this paper, we proposed our comprehensive approach from outcrop investigation, in-situ measurements to reservoir evaluation for detail description of the Longmaxi shale. Firstly, lithology, lithfacies and sedimentary sequences have been reviewed through outcrops. Mark stratigraphy, carbonate rocks containing shell fossil have been found and two periods of transgression and regression can be discriminated. Then depositional framework established from carbonate platform to deep shelf during latter Ordovician to early Silurian. Organic rich black shale developed in the quiet deep water environment with relatively low clay content is primarily identified as the favorable target zone for development. Secondly, further petrophysical properties evaluation for different lithofacies through in-situ measurement have been conducted. Organic rich black shale has total organic content between 3.0%-8.8% with vitrinite reflectance ranged from 2.3%-3.6%. It also has relatively high porosity with mean value of 7.3%, and mean gas saturation of 85%. Then Lower Silurian Longmaxi Group can be classified into two zones and lower zone which is much sweater is finally identified as the target for horizontal drilling. Thirdly, relationship between field survey, in-situ measurement and well logging has been connected and eletrofacies zonation has been established. The targeted lower zone has much higher natural gamma, higher resistivity, high interval acoustic transit time, lower density and thorium to uranium ratio.

Finally, sedimentary framework of Lower Silurian Longmaxi Group and detailed reservoir architecture have been established, and the sweat and the target zone has also been identified. Pilot drilling shows that horizontal wells with high penetration ratio of the identified target zone have the double outputs which reveals the meaning of our works.

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INTEGRATING PETROPHYSICAL AND GEOPHYSICAL DATA TO DELINEATE THE INTERNAL FACIES OF A PINNACLE REEF COMPLEX, MICHIGAN BASIN, USA

Austin M. Johnson, M.S., Western Michigan University

The Silurian Niagaran pinnacle reefs of the Michigan Basin have been extensively studied due to their significance as hydrocarbon producers. These carbonate buildups retain their relevance after primary recovery of hydrocarbons and are excellent candidates for carbon dioxide sequestration, natural gas storage, and enhanced oil recovery. Due to the nature of carbonate rocks, these reef complexes are heterogeneous and lateral interpolation between observations in wells, is ambiguous. Despite being extensively studied since the 1960’s, the ambiguity has led to large uncertainty and disagreement regarding reef architectures and their internal facies distributions. Previous models of these reef complexes have relied almost entirely on well logs and conventional core. This study focuses on integrating well logs with a 3D seismic reflection survey to reduce uncertainty when interpreting the internal and off-reef architectures. The focal point of this study is the Charlton 30-31 reef complex in the northern trend of the Michigan Basin. Specifically, I intend to determine whether this reef is symmetrical with unpredictable internal facies patterns or if it was influenced by paleowind during growth, resulting in a highly asymmetric architecture with predictable internal facies distributions.

In addition to a 3D seismic reflection survey, I have petrophysical data from 12 wells that penetrate the Charlton 30-31 reef complex. The facies log signatures of core, from the nearby Charlton 1-4 reef complex, were utilized to refine facies interpretations of the log signatures in the Charlton 30-31 reef. These interpretations will be used to generate at least 2 models of the reef with either random or leeward and windward based morphology. Synthetic seismograms will be generated for the Charlton 1-4 well using high- to low-frequency wavelets, to determine the frequency at which the synthetic seismic reflection can no longer distinguish the reef facies identified in the core. Synthetic seismograms of the Charlton 30-31 reef models will be generated at the lowest frequency that allows resolution of facies and at the frequency observed in the seismic survey. I anticipate that comparison of these synthetic profiles with the 3D seismic survey data will allow me to determine if there is an asymmetric, wind-influenced pattern to the reef facies.

Reservoir Characterization and 3D modeling of Silurian Fore-reef Slopes Exposed in the Pipe Creek Jr. Quarry: Grant County, Indiana

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Silurian reefs are significant hydrocarbon reservoirs in the Michigan Basin, having produced over 490 MMBO and 2.9 TCF of gas. Primary production from the reefs is typically low, averaging 20-25% due to the complex internal heterogeneity of the reservoir. To date, a majority of the exploration and development of these reservoirs has been directed towards the cores of the reefs, rather than the associated reef slope deposits. Slope deposits of the Pipe Creek Jr. reef complex exhibit many similarities to productive slope reservoirs in the rock record (e.g. Poza Rica trend in Mexico; Malampaya in the Phillipines; Tengiz and Karachaganak in the Caspian region). As such, the depositional processes and resulting geometries of potential reservoirs and seals in these Silurian fore-reef slopes, as well as early diagenetic modification and effect on reservoir quality, likely have many similarities to those found in other fore-reef reservoirs.

The current study is focused on the fore-reef slope deposits of the Pipe Creek Jr. reef complex and includes an in-depth analysis of the facies distribution and composition, bed geometries, stratigraphic architecture, and faunal abundance and distribution of the reef slope deposits, coupled with the development of a drone-based, georeferenced, 3D outcrop model developed in Agisoft Photoscan and Petrel. The Pipe Creek Jr. Reef has been previously studied with a focus on faunal assemblages, dolomitization of the reef, and the general depositional facies of the reef core. The reef complex has an inferred circular structure, with a minimum thickness of 48m, with original, pre-erosional relief of the reef complex speculated to be anywhere from 35 to 200 meters. The exposed fore-reef slope facies consist of a mixture of coarse skeletal grainstone-packstones, stromatactis and skeletal mudstone-wackestones, and argillaceous silty dolomitic mudstones. Similar to what is seen in other fore-reef deposits, lenticular bedding consisting of skeletal packstones and grainstones deposited by grainflow processes make up the majority of the 40-45° depositional slopes. In addition, slump scars and channels are common, as are resedimented blocks from the inferred reef crest. Synsedimentary (Neptunian) dikes filled with marine cements are also common.

Insights related to stratigraphic and reservoir architecture in the fore-reef slope facies of these Silurian reefs can potentially open up additional exploration and development opportunities and increase hydrocarbon recovery efficiencies in existing complex reef reservoirs.

Investigation of Potential Geochemical Reactions in Large-Scale Carbon Dioxide - Enhanced Oil Recovery (CO_2-EOR) Carbonate Reservoirs

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The Midwest Regional Carbon Sequestration Partnership (MRCSP) is responsible for the assessment of large-scale carbon dioxide (CO_2) storage associated with enhanced oil recovery (EOR) operations in oilfields that have undergone primary production. As part of this overall program, Battelle has collaborated with The Ohio State University (OSU) and Lawrence Livermore National Laboratory (LLNL) to perform studies investigating potential geochemical reactions caused by the injection of CO_2 and resulting changes to the hydrologic conditions (i.e., porosity and permeability) of the reservoir.

Initially, geochemical equilibrium modeling was performed using analytical data from brine samples collected from the EOR reservoirs. The models indicated that the brines were supersaturated with respect to several carbonate and sulfate minerals prior to the injection of CO_2. The model results also indicated that the saturation levels of these minerals increased with the injection of CO_2. Following the modeling efforts, rock (core) samples collected from the reservoirs were analyzed using scanning electron microscopy-energy dispersive x-ray spectroscopy (SEM-EDX) and powder x-ray diffraction (XRD) to investigate the elemental chemistry and mineralogy of the mineral precipitates present in the large pores and vugs of the core samples. Additionally, stable carbon isotope analyses were performed on the mineral precipitates to assess the origin of the carbon present in the carbonate minerals.

High-resolution micro x-ray computed tomography (XRCT) analysis of core samples collected following the injection of CO_2 was performed to investigate changes in the rock fabric, pore geometry, and fracture conditions resulting from the CO_2 injection. The XRCT scans did not find evidence of mineral dissolution along the fracture surfaces, nor were significant through-going connected fluid pathways observed in any of the core sub-samples. The most compelling evidence for CO_2-induced dissolution was subtle, comprised of localized areas of elevated porosity within regions displaying similar textures, or slight fracture widening in some cases. In contrast, the evidence of mineral precipitation, lining large pores and even fractures of one sample, was apparent throughout the sub-samples.

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Regional Distribution of Total Organic Carbon and Geochemical Characterization of the Maquoketa Shale Group within the Illinois Basin

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Stratigraphy of the Late Ordovician Maquoketa Shale Group in the Illinois Basin is complex and includes numerous reactivation surfaces and disconformities. In general, there are three intervals that can be correlated across the basin. These horizons correspond to the Brainard Shale (a dolomitic, locally organic-rich shale), the Fort Atkinson Limestone (a fossiliferous packstone and grainstone limestone) and the Scales Formation (a thinly interbedded limestone and shale interval).

Geochemical sampling of the Maquoketa Shale is limited to regionally restricted areas in the central and southeastern part of the Illinois Basin. As a consequence, the total organic carbon (TOC) distribution is unknown in most parts of the basin. Much of the sampling is limited to upper horizons within the Maquoketa Shale Group.

Petrophysical log data is used to calculate TOC from density, neutron, and sonic logs. Research involving the Maquoketa Shale indicates that TOC estimates from petrophysical data correlate to core/cuttings TOC measurements within 0.5 -0.75 wt.% TOC. Using well logs, the TOC distribution of each of the three horizons in the Maquoketa Shale Group were mapped individually to assess whether there is a pattern in the vertical distribution of TOC within the group. Rock extracts from the Maquoketa Shale were analyzed to characterize hydrocarbons produced from this interval.

Lithostratigraphy results indicate that the Brainard Shale has a maximum thickness of 150 to 160 ft. in north-central and thins to less than 40 ft. toward southern Illinois. In much of southeastern Illinois TOC content of Brainard Shale ranges between 1.0 to 1.2 wt.% percent, with higher values in the western parts of the basin. The Fort Atkinson Limestone contains TOC ranging between 0.4 to 1.2 wt.% percent. The lower Scales Shale Member has a maximum thickness of about 160 ft. in southeastern Illinois and contains TOC ranging from < 0.50 to 1.4 wt.% in western Indiana. Rock extracts indicate a low odd-carbon predominance in mid-range n-alkanes and a distribution of aryl isoprenoids that range from C_{13} to C_{24} (m/z 133) in the Upper Maquoketa Shale Group. Extracts taken from the lower shale interval contain geochemical markers consistent with a source rock rich in *G.prisca*, an organic-walled microfossil indicating that the Maquoketa Shale contains diverse organofacies.

Development of a Data-Driven Operational Design Tool for CO2 Sequestration in Shale Gas Reservoirs

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KEYWORDS: CO2 sequestration, shale gas reservoirs, stimulated reservoir volume, artificial intelligence, neural networks

Long-term sequestration of industrial CO2 in geological formations, such as shale, has been gaining interest to reduce the global greenhouse effects and its side effects on climate change. In this study, a data-driven operational design tool for CO2 sequestration in shale-gas reservoirs is developed and tested. The model described is based on artificial neural networks trained with a large number of numerical-simulation scenarios of natural gas production and CO2 injection. Numerical simulations were performed using PSU-SHALECOMP, a compositional dual-porosity, dual-permeability, multi-phase reservoir simulator developed at Penn State University. The simulator also incorporates the effects of water presence in the micropore structure and those of matrix shrinkage and swelling. The tool was designed in an inverse-looking fashion to estimate the necessary wellbore and hydraulic-fracture design characteristics in the form of stimulated-reservoir-volume (SRV), once known initial conditions, reservoir rock and fluid characteristics, and desired long-term natural gas production and CO2 injection profiles are input. During the gas-production period, the well is operated with a flowing bottom-hole pressure constraint. CO2 sequestration is performed with a constant injection rate, until a specified fracturing-pressure limit is reached. The profiles are input in the form of 12 equally-divided time steps, which are also specified explicitly as input parameters. After running a large number of different scenarios, an artificial neural network was trained and validated using the dataset obtained from simulation runs. To determine the optimum neural-network architecture, almost 100,000 different neural-network designs were tested with parallel-processing in UNIX clusters. Blind-testing of cases resulted in an average prediction error of 9.8% for output parameters, which would help to accurately design the wellbore and SRV characteristics needed for the planned sequestration process. Re-validating the testing cases using the numerical model resulted in an average error of 3.2% for cumulative gas production and an average error of 8.6% for cumulative CO2 injection. A graphical-user-interface application was also developed that enables using the model in a practical and efficient manner. Such kind of a tool would help operators to design CO2 sequestration projects in shale gas reservoirs in an efficient manner.

Understanding Public Perception of the Terms Clean Coal and Fracking

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Many in the mainstream media consider “clean coal” and “fracking” to be synonymous with the continued use of fossil fuels and that these technologies contribute the destruction of the environment. This negative perception has made these two technologies more difficult to implement in new regions of the U.S. and the world.

Far from a recent term, clean coal was first used in the nineteenth and early twentieth century because coal producers were increasingly "diluting" their product by adding dust, stones, wood, and other substances to artificially inflate its volume. The term has been continually repurposed every few decades to address a perceived "dirtiness" of coal at the time. By the 1940's, "clean coal" referred to coal that reduced soot and ash emissions in household use.

In 1970 the first reference to "acid rain" appeared followed quickly by a series of articles connecting industrial pollution (coal-fired in particular) to highly acidic rainfall. Clean coal was reinvented the following decade with the implementation of sulfur-reducing pollution controls to reduce the air pollution of coal burning. By 2007, the term clean coal was being used to describe the creation of coal fired power plants that do not emit carbon dioxide and hence do not contribute to climate change.

Although hydraulic fracking has been used to improve oil and gas recovery since the 1940's, the term "fracking" first entered mainstream media consciousness in Fall 2009. By 2012, comic Scott Adams' Dilbert character listens as the CEO outlines project "Fracking Awesome" to trigger earthquakes and pollute the water under a competitor's headquarters, highlighting the rapid spread of negative perception towards fracking in American popular culture. Online imagery of fracking emphasizes the perceived risk of drinking water contamination. In short, from its debut in the public consciousness, fracking has been synonymous with the image of deadly chemicals poisoning the public's water, while earthquakes have received comparatively little attention, though media and web focus appears to be shifting from water to broader perceived environmental risks.

It is important to understand public perception given that energy projects more often die through public perception than technological feasibility. The industry thus needs to better understand how the public sees energy projects in order to better explain their benefits and address the public's fears.

Influence and Regression Model of Long-term Waterflooding on Reservoir Petrophysical Properties

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Keywords: Long-term waterflooding, Petrophysical properties, Large pore channel, Multiple linear regression model

After waterflooding treatments over several decades, the petrophysical properties of the producing reservoir can change in many aspects. Because the hydrocarbon potential of certain reservoirs is still promising, it is crucial to identify the variation of these petrophysical properties after the long-term waterflooding treatments. Therefore, several groups of core samples, which came from an old oilfield in the northeastern region of China, were collected to investigate the variation in these properties in the reservoir. These samples were drilled and extracted from four different types of inspection wells and thus can represent the different stages of the reservoir during the development history of nearly forty years. A series of tests and experiments were conducted on the samples in order to measure properties such as porosity, permeability, three types of sensitivity, wettability, and internal pore structure. Moreover, the data of experimental results were classified and analyzed using statistical methods. The multiple linear regression model was applied with the predictors such as porosity and sensitivity index. The results showed that certain variables can predict the permeability. Furthermore, both the mean values and standard deviations of the porosity and permeability increased after the long-term waterflooding treatment. The variation of sensitivity, wettability, and pore structure all presented significant directionality. Moreover, the CT scanning experiment directly showed the forming process of large pore channel. Improved understanding of the reservoir properties after long-term-waterflooding treatments will provide valuable guidance for the follow-up production design.

The Use of Multivariate Analysis and Raman Spectroscopy for the Assessment of Thermal Maturity

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Vitrinite reflectance (VRo) is a standard petrographic method for evaluating thermal maturity (rank). The vitrinite reflectance protocol, however, requires significant petrographic proficiency, can be labor-intensive, and may be biased on an analyst-to-analyst basis.

Correlations between thermal maturity and Raman spectra present an enticing option that can remove some of the weaknesses in the VRo protocol. Our previous research, and other published studies have shown that traditional peak-fitting methodologies for quantifying metrics from Raman spectra can be correlated to thermal maturity, however, these approaches also are inhibited by analyst subjectivity which can affect correlations between analyte and spectral properties.

In this study, we have combined Raman spectroscopy with multivariate analysis (MVA) to create calibration models for the prediction of coal rank using VRo values and atomic O/C ratios. MVA techniques eliminated the ambiguity prevalent in peak-fitting Raman data by evaluating the full Raman spectrum, and identifying the spectral regions relevant to the construction of accurate thermal maturity models. Partial least squares (PLS) regression models were created using Raman spectra of 68 geographically diverse coal samples and VRo values (0.23 to 5.23%) or atomic O/C ratios (0.027-0.206) for 39 samples. The calibration set was validated by reserving half of the samples to serve as “unknowns” thereby assessing the model's predictive accuracy. Both models exhibited linear correlations, with coefficients of determination (R^2) for the validation set of 0.99 (VRo) and 0.93 (atomic O/C), despite the geographic and rank diversity of the samples. This study demonstrated the applicability and power of using PLS models for thermal maturity prediction calibrated to complete Raman spectra as opposed to Raman-derived parameters. More recently, our focus has turned to developing a predictive model for evaluating the thermal maturity of shale.

This quantitative MVA protocol provides a Raman-based alternative to the VRo industry benchmark for coal rank that mitigates the limitations and subjectivity of peak-fitting methods.

Estimating CO_2 storage resource volumes using a Static Earth Model of the St. Peter Sandstone in the Northern Michigan Basin

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The St. Peter sandstone in the Michigan Basin has been identified through previous studies as a potential storage reservoir due to its thickness (205-1180 ft.), porosity (0-38.5 %), permeability (0-124 mD), and lateral extent. However, few wells have been drilled, limiting detailed studies of the reservoir. Three lithofacies (L1, L2, and L3) within the St. Peter sandstone were identified using core and wireline logs and further investigated using 2D maps and cross sections to characterize each lithofacies' structure, petrophysical properties, and CO_2 resource estimate. Regional 3D static earth models (SEM) allow valuable insights into the geologic heterogeneity of potential CO_2 reservoirs that cannot be derived from 2D analyses in regions with sparse datasets, like the Ordovician St. Peter sandstone. Integration of wells tops, petrophysical logs, whole core, and expert knowledge of the geology went into developing the first regional 3D SEM of the St. Peter sandstone lithofacies in northern Michigan. The model has been built to facilitate current CCS project efforts and serve as a foundation for future site feasibility assessment and selection. Using Petrel™ software, a 3D structural framework of the St. Peter sandstone was created and populated with key petrophysical properties such as porosity and permeability. Pore volumes were calculated for each cell using bulk volume and porosity to determine available associated CO_2 storage quantities and identify areas with high geologic storage potential in the St. Peter sandstone. Preliminary deterministic estimates for the potential mass of CO_2 equivalent to the net pore volume were calculated in the regional SEM. These range from 1.5– 5.2 GT (gigatonnes) for the p10-p90 values with a p50 of about 3 GT. The p50 values for the LF1, LF2, and LF3 are 0.6, 1.4, and 0.9 GT, respectively. The highest injectivity and largest connected reservoir volumes are seen in LF3 in the northeastern and southwestern regions of the study area and are promising prospects for CO_2 sequestration.

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Pennsylvania Coalbed Methane Update

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Interest in the economic value and development of natural gas from coal beds in Pennsylvania was stimulated by federal research on deep mine safety practices through methane drainage and recovery during the 1970s and 1980s. This resulted in a dramatic increase in coalbed methane production a decade later, leading to major growth from 1999 to 2008. This occurred in part because of increased knowledge of the coalbed methane reservoir, improvement in drilling technology, higher gas prices, more favorable national economic conditions, and the need to expand our domestic energy resources. Since then, the number of new well permits decreased in 2009 due to a global recession and focus on the Middle Devonian Marcellus shale gas play. However, commercial quantities of coalbed methane are still being produced in the southwestern Main Bituminous field.

According to the Pennsylvania Geological Survey Wells Information System and the Pennsylvania Department of Environmental Protection as of December 2012, there were 1,275 coalbed methane wells in various stages of completion and status. About 985 of these wells were classified as producing, active, and inactive. The following coals of the Monongahela Group, Conemaugh Group, Allegheny Formation, and Pottsville Formation are among the principal targets for methane production: Sewickley, Pittsburgh, Bakerstown (Upper and Lower), Brush Creek, Mahoning, Freeport (Upper and Lower), Kittanning (Upper, Middle, and Lower), Clarion, Brookville, and Mercer (Upper, Middle, and Lower). At this writing, figures are being updated through our new Exploration and Development Well Information Network oil and gas database and available statistics from the Pennsylvania Department of Environmental Protection.

Various resource estimates were quantified by the following sources: (1) Geomega, Inc. (1983 unpublished report)—2,654 billion cubic feet (2.7 trillion cubic feet) for Pennsylvania anthracite and bituminous coal; (2) Gas Research Institute (1988)—51 trillion cubic feet gas-in-place for southwestern Pennsylvania and northwestern West Virginia; and (3) United States Geological Survey (1996)—11.5 trillion cubic feet economically recoverable for the Northern Appalachian coal basin (Pennsylvania, Ohio, Maryland, and northern West Virginia). Coalbed methane, an energy source that rivals conventional natural gas in composition and heating value, continues to be an important part of our domestic energy mix on state and national levels.

Relationships between natural fractures and chemical composition: Marcellus Shale, Appalachian Basin

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Within mudrock and shale reservoirs, brittle zones undergo plastic deformation during hydraulic stimulation, creating numerous artificial fractures through which hydrocarbons can permeate. Natural fractures in mudrock and shale reduce the tensile strength of the host rock, and because of this, are hypothesized to become reactivated during hydraulic stimulation. Combined, brittleness and natural fractures contribute to creating more abundant and complex fracture networks during hydraulic stimulation. Research efforts towards quantifying rock brittleness have resulted in numerous mineral/compositional-based indices, which are utilized during petrophysical analysis to predict zones most conducive to hydraulic stimulation. In contrast, investigations on the relationship between chemical composition and core-scale natural fractures are limited.

High-resolution energy-dispersive X-ray fluorescence (XRF) data, calibrated with a wave-dispersive XRF, were collected from a Marcellus shale core. Core-scale natural fractures were characterized in terms of length, width, in-filling material or lack thereof, and orientation. Natural fracture data were transformed into a continuous P10 curve, the lineal fracture intensity, which is expressed as fractures per a one foot window. Utilizing these datasets, we investigated the relationship between rock composition and natural fracture intensity. Regression analyses recorded positive relationships between natural fracture intensity and calcium, silicon/aluminum, and total organic carbon, and negative relationships with silicon and aluminum. Aluminum recorded the strongest (negative) relationship (r^2=0.379) with natural fracture intensity. Least partial squared analysis, a multivariate method, was used to assess the degree to which natural fractures can be predicted by chemical composition, and recorded an r^2=0.5255. This study illustrates that, while numerous factors are responsible for natural fracture genesis, such fractures predictively concentrate in areas of similar chemical composition, largely in zones depleted in aluminum.

Residual Oil Zone EOR Potential in the Northern Pinnacle Niagaran Reef Trend

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The primary goal of this study was to identify and evaluate the potential for a regionally pervasive residual oil zone (ROZ) in the Northern Pinnacle Niagaran Reef trend (NPRT) that could provide a viable enhanced oil recovery (EOR) play for operators and a CO_2 sink for carbon capture, utilization, and storage (CCUS) projects. Data available for analysis included downhole well logs, core analyses, literature, maps, and input from ongoing regional geologic characterization.

Structural complexity and well log data from ten reefs in Otsego County were used to evaluate the subregional petroleum systems evolution, leading to the following conclusions:

- There is no evidence to support the presence of a regionally extensive ROZ in the NPRT.
- Geographically isolated capillary pressure transition zones are present in all reefs, but they are unlikely to be in hydraulic communication with other reefs.
- Changes in carbonate pore geometry with depth or other variables may impact interpreted water saturation (S_w) curves, generating expanded apparent transition zones where the water saturation remains constant.
- Continuous bottom hole pressure (BHP) measurements collected before, during, and after CO_2 injection in the Charlton 30-31 reef confirm hydraulic communication between the north and south reef pods on short time scales.
- The combination of one-way analysis of variance and Tukey Grouping analysis show that gamma ray and neutron porosity validate the separation of the Brown Niagara formation into three statistically different zones based on log properties; the main pay zone (MPZ), the transition zone (TZ), and the water zone (WZ). The sonic and bulk density logs distinguished the WZ from the two other zones.

This study is part of the Midwestern Regional Carbon Sequestration Partnership (MRCSP) Michigan Basin Large-Scale Injection Project under DOE/NETL Cooperative Agreement # DE-FC26-0NT42589 with co-funding by Core Energy, LLC, and several other partners.

Potential for Recovery of Uranium from the Marcellus Shale

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Organic-rich shale has been recognized in the United States as a potentially significant resource of uranium since the early 1950's, with investigations of the Chattanooga oil shale. Processes have been demonstrated to recover oil and uranium by retort, and uranium has been recovered by acid dissolution. The Chattanooga shale is recognized as a major world uranium province, with estimated reserves of 5,000 t of uranium, but there has been no commercial production. Internationally, uranium has been produced from organic-rich shale, in Sweden and Germany. The Marcellus Shale has not been studied as a potential resource of uranium. This paper takes a semi-quantitative look at the potential uranium resource that could be developed because of drilling the Marcellus shale for natural gas. Currently, the cuttings from Marcellus wells are being disposed of in landfills, losing potentially recoverable uranium. It is estimated that a typical horizontal lateral will produce about 178,000 kg (392,423 lbs) of cuttings. From this volume of cuttings, it is feasible to recover around 4.6 kg (10.1 lbs) of Uranium. At current prices (US$23/lb), this amount of Uranium is worth US$232.00 (gross) per well. To date, around 5,900 horizontal Marcellus wells have been drilled. Potentially 27,140 kg (59,833 lbs.) of uranium have been discarded in landfills, a potential unrealized revenue of over US$1.4 MM (gross.) Consistently drilling in the zones of highest gamma ray readings, typically the lower Marcellus, could more than double the amount of uranium recovered. Other high value elements, e.g., cobalt, vanadium and molybdenum, could also be recovered from the Marcellus, increasing the potential revenue stream.

Storage Resource Estimates and Seal Evaluation of Cambrian-Ordovician Units in the MRCSP Region

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To evaluate the carbon storage potential of the Midwest Regional Carbon Sequestration Partnership (MRCSP) region, petrophysical analyses of Cambrian-Ordovician strata were conducted, resulting in new estimates of the reservoir targets for carbon storage and the effectiveness of overlying units to serve as seals. The carbon storage resource estimates (SRE) were evaluated using a hierarchy of methods that resulted in different SRE values based on a series of increasingly complex portrayals of the pore system. The simplest analysis follows the United States Department of Energy (USDOE) methodology, whereby a SRE is calculated using a single 'best estimate' of the average porosity of the assessed formations. Additional estimates employ variable porosity models based on a depth-based diagenesis function and effective porosity values derived from geophysical logs. Results from this approach not only illuminate the magnitude of uncertainty that should be expected in SREs as a function of data availability, but also suggest a high potential for storage in deeper Cambrian-Ordovician units.

Capillary pressure data from mercury porosimetry (MICP) were used to evaluate the seal capacity of the Upper Ordovician Maquoketa Group and equivalent units. Geophysical logs (gamma-ray, density, and neutron porosity logs) from multiple well locations in the MRCSP region were used to develop a lithofacies model consisting of five units, revealing a high degree of regional variability within the Maquoketa Group. The distribution of clay-rich lithofacies defines areas having higher potential for effective confinement. Further characterization of porosity, permeability, and the micro- and meso-pore size distribution from MICP suggest high sealing and capillary trapping potential of the Maquoketa Group.

The research was performed under the MRCSP program led by Battelle and funded under USDOE/NETL Cooperative Agreement # DE-FC26-0NT42589.

From the Tuscarora Sandstone to the Bubbles in Your Beverage: Naturally-Occurring CO_2 in the Indian Creek Field, Kanawha County, WV.

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The Tuscarora Sandstone in the Indian Creek field produces commercial volumes of food-grade carbon dioxide (CO_2) as a constituent of the natural gas stream. Presence of naturally-occurring CO_2 presents a unique opportunity to examine an analog for long-term carbon storage, but the mechanisms of its generation and trapping are not fully understood. As part of a research project funded by the U.S. Department of Energy, geoscientists from Battelle Memorial Institute and the West Virginia Geological Survey examined thin sections, well logs, drilling and completion reports, and core from wells inside the Indian Creek field and compared these data to wells from nearby fields that do not produce significant amounts of CO_2 in gas accumulations. Geologic cross-sections and isopach maps of the Tuscarora were augmented with Computed Tomography (CT) scans of the cores to assess potential fracture networks and migration pathways.

Pores in thin sections of Tuscarora taken from a well drilled inside the field exhibit thin, incomplete, linings of calcite that appear to be an early cement partially dissolved by later pore fluids to produce CO_2. A second possibility for CO_2 generation is suggested by the presence of pores lined with framboidal pyrite typically associated with bacterial degradation of organic matter such as hydrocarbons. Thin sections taken from a core outside the Indian Creek field are characterized by bedding-parallel stylolites, often filled with heavy minerals and/or clays, as well as thick quartz overgrowths, and sutured grain contacts. Sediments in this core are burrowed; the burrows are backfilled with very fine to silt-sized quartz. Porosity is fracture-enhanced and contained within burrows rather than the matrix. Though there are multiple areas of gas production from the Tuscarora Sandstone, commercial production of the CO_2 is unique to the Indian Creek field in the Appalachian basin, providing a natural laboratory for the effects of potential carbon storage.

Explorations in TOC for Assessment of CO_2 Storage and Enhanced Gas Recovery for the Middle Devonian Marcellus and Upper Ordovician Utica Shales for the Midwest Regional Carbon Sequestration Partnership

Brandon C. Nuttall, Thomas N. Sparks, Stephen F. Greb*, Kentucky Geological Survey, University of Kentucky, Lexington, Kentucky

The potential for carbon storage and enhanced gas recovery in the Middle Devonian Marcellus and Upper Ordovician Utica organic-rich shales in the Appalachian Basin is being investigated using methods developed during investigation of the Upper Devonian Ohio Shale. Laboratory analysis of core and well cuttings provides baseline data for modeling TOC content in shale. In general, continuous resource plays exhibit relationships between measured TOC and wireline log data. TOC is in turn related to gas content and storage capacity. Wireline-based petrophysical models for estimating TOC have been proposed by many authors, but choice and application of a model depends on data availability. Only those based on total gamma-ray and bulk-density log data were used in this study, because they are most regionally available.

For the Marcellus, multiple models were analyzed to estimate TOC from log data. The simplest model for estimating TOC is a linear regression of a density and TOC cross plot based on laboratory data because TOC is generally regarded as the main control on density changes in an organic-rich shale. Gamma-ray- and density-based models use the slope of the gamma ray–density cross plot. A median TOC curve (P50) was calculated using multiple models to provide a probabilistic summary of TOC by well, which was used as input to geospatial modeling.

The Utica Shale was deposited in a carbonate-dominated open-marine shelf setting, suggesting that organic matter types and their mode of preservation differ significantly from those of the Marcellus. Classic models to estimate TOC for organic-rich shale may not provide acceptable results. Laboratory TOC and digital well-log data were compiled by the Utica Shale Consortium. Leco TOC data were depth-matched with gamma-ray and bulk-density data from logs. Neutron-porosity and photoelectric effect data were collected, but limited digital data precluded their use. Gamma-ray and density data were used to assess existing TOC models and formulate new ones. Two new models for calculating TOC from well-log data are proposed based on best-fit correlations to the distribution of laboratory TOC data.

*Speaker

Mapping Storage and Enhanced Gas Recovery for Organic Shale in the Midwest Regional Carbon Sequestration Partnership

Brandon C. Nuttall, Thomas N. Sparks*, Stephen F. Greb, Kentucky Geological Survey, University of Kentucky, Lexington, Kentucky

Midwest Regional Carbon Sequestration Partnership teams are investigating the potential for CO_2 storage and enhanced gas recovery in organic shales such as the Middle Devonian Marcellus Shale and Upper Ordovician Utica Shale in the Appalachian Basin. This work builds on past research on the Upper Devonian Ohio Shale in eastern Kentucky. For the Ohio Shale, Schmoker's density model was found to accurately estimate total organic carbon (TOC) from density in downhole geophysical logs. Because there are always more logs than sample analyses, determining if TOC can be reasonably estimated from logs is beneficial for regional mapping. For the Ohio Shale, density logs could then be used to map regional TOC distribution and thereby calculate potential CO_2 storage volume when used to enhance gas production. When Schmoker's density model was tested on Marcellus and Utica Shale data, however, results were more variable. Different models were developed to estimate TOC from downhole log data for each shale.

The Marcellus structure was mapped from 8900 well-log tops from southern New York southeast into Ohio and West Virginia. A net thickness map of the Marcellus Shale with net gamma ray greater than 180 API was constructed from 1,559 wells with gamma logs. A subset of 575 wells with density logs was used to model organic distribution. Mean (P50) TOC was contoured from an average of multiple wireline-based models. A gridded net thickness of shale with calculated TOC > 4% was mapped using the same data. General trends in the calculated TOC > 4% map compare well with the 180 API cutoff map, although a broader area of net organic-rich shale in northeastern Pennsylvania and southern New York is estimated from the TOC > 4% map. A potential Marcellus Shale volume of 2 billion acre-ft with a storage capacity of

1.1 to 3.7 billion tons of CO_2 is estimated from the TOC > 4% map. CO_2 storage capacity in the shale is based on the potential to use CO_2 for enhanced gas recovery and retention of CO_2 by adsorption on the organic-rich matrix.

A similar set of maps is being generated for the Upper Ordovician Utica–Point Pleasant play and potential CO_2 storage capacities will be estimated from the maps developed. Results to date show that different models are needed for estimating TOC in different organic-rich shales. Regional mapping of net organic thickness of the various shales will provide insight into the potential for CO_2 storage with enhanced gas recovery across the region.

***** Poster Presenter

Fracture Impact on Reservoir Performance near Fault Damage Zone

Karam Pierre, An XiaoXuan, Yang Junjie, Geoscience and Petroleum Engineering, Baker Hughes, a GE Company.

Fault Damage zone are known to have complex fault geometry with abundant presence of natural fracture ranging from cores to outcrops scale. The distribution of those fractures correlates with the width of the fault, observed displacement, faulting mechanism, and the formation thickness and properties. As many faults can act as barriers or conduit, natural fractures on the reservoir scale can be open conduit for fluid, hydrocarbon or water, or cemented and calcite filled. Answering those questions impacts reservoir development plans in regards to well placement, landing zone, and completion strategy.

This paper presents a study for two reservoirs, a silica and clay rich, tight, thin shale reservoir overlain by a thick, dolomitic, and brittle carbonate reservoir. Both of those formations have low permeability and are hydrocarbon bearing such that staggering wells are needed to maximize reservoir production. The study area is within the vicinity of a major fault line that runs north to south on the east of the field. No other faults have been seen or mapped within the field. However, the carbonate reservoir is highly fractures with some conductive and other resistive faults. The fracture density in the shale layer is extremely low with the majority of those fractures being completely closed. The work consisted of studying the variation of facies along the lateral and the relation of fracture density and facies within the carbonate layers. Facies were examined using image log data coupled with mud log data and cuttings information.

After examining the fracture density for multiple wells in the area, a map showing the distribution of natural fractures indicates a decrease of fracture density away from the fault line. The density correlates with the distance to the fault line. Knowing the distribution, a statistical model was used to populate the fracture in a 3D reservoir model such that those fractures are assumed to increase reservoir permeability. The static model is then moved to dynamic simulation to study the communication impact that those fractures have on the production.

It was observed that natural fracture contributes significantly to the well productivity. With higher fracture density, the carbonate reservoir drains more efficiently than the shale formation. In lateral direction, well drainage area correlates with spatial variation of fracture density, indicating potentially different optimal well spacing from east to west part of the field. Consequently, Inter-well interference is expected to be more pronounced on the east side than the west side of the field. In addition, sensitivity studies show that wells landing in shale are able to drain both formations effectively, given that hydraulic fractures propagate upward into carbonate formation associated with dense natural fractures.

Growth in Appalachia region hydrocarbon production driven by drilling efficiency. U.S. EIA expects plays in the East to lead production of domestic natural gas from shale resources.

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KEYWORDS: natural gas, crude oil and condensate, domestic production, Appalachian region, Marcellus, Utica/Point Pleasant

Shale gas production in the Appalachia region has increased rapidly since 2012, driving an overall increase in U.S. natural gas production. According to EIA's Drilling Productivity Report, natural gas production in the Appalachia region—namely the Marcellus and Utica shale plays—has increased by more than 15 billion cubic feet per day (Bcf/d) since 2012. Overall Appalachian natural gas production grew from 7.8 Bcf/d in 2012 to 22.1 Bcf/d in 2016 and was 24.0 Bcf/d in 2017, based on EIA data. Drilling wells in the Appalachia region has become very productive. EIA attributes this increase to efficiency improvements in horizontal drilling and hydraulic fracturing in the region, which include faster drilling, longer laterals, advancements in technology, and better targeting of wells. For example, in West Virginia, the average lateral length per well has increased from about 2,500 feet in 2007 to more than 9,000 feet in 2017. Some operators have recorded lateral lengths as long as 18,000 feet in the Marcellus and 19,000 feet in the Utica. Along with longer horizontal drilling, the days it takes for completion have decreased from about 30 days in 2011 to 4 days in 2017.

Dry natural gas production from shale gas plays in February 2018 accounted for 50.6 Bcf/d, or 64% of total U.S. natural gas production. Natural gas production from shale plays is expected to increase through 2040 in EIA's Annual Energy Outlook 2017 Reference case. The two Appalachian shale plays, the Marcellus and Utica/Point Pleasant, have factors favorable for production including proximity to consuming markets. Both Appalachian shale plays have remained resilient to the low natural gas prices and are projected to continue to drive total U.S. production in the long term. Dry natural gas production in these plays is expected to reach more than 40 Bcf/d by 2040, providing just over half of U.S. total shale gas production. EIA's Short-Term Energy Outlook is forecasting further growth in the Appalachia region through the rest of 2018. Natural gas processing capacity is also expected to increase by 2.5 Bcf/d over the next two years to support the continued growth in production. Rising natural gas and natural gas liquids production in Appalachia—Kentucky, Ohio, Pennsylvania, and West Virginia—has transformed this U.S. region's importance as a key supplier and a potential market for these energy commodities.

Offshore Stimulations with Portable Equipment: Operational Flexibility for Time and Cost Reduction

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OBJECTIVES/SCOPE: The advantages of performing stimulations and other pumping treatments with portable equipment are presented compared with Stimulation Vessels on offshore operations and how these can help to reduce operational times.

METHODS, PROCEDURES, PROCESS: Conventionally, the marine offshore stimulations in Mexico have been carried out with stimulation vessels, which transport everything necessary to mix and prepare in situ the necessary treatment systems designed for the pumping, such as the base acid and base solvent, additives, mixing pumps and recirculation tanks, as well as the pumping equipment necessary to perform the operations, among others, however, this operational scheme entails certain disadvantages with respect to operational times and risks involved. The treatment operations we have performed with portable equipment avoid these disadvantages and improve operational times, having as an additional benefit the reduction of costs.

RESULTS, OBSERVATIONS, CONCLUSIONS: Perform the stimulations with portable equipment installed directly on the platform or structure, reduces the operational disadvantages of stimulation vessels and makes them advantages. This paper shows those differences based on multiple historical cases of operations of acidizing matrix stimulation, Wellbore and Near-Wellbore Clean out and cleaning of tubing among others, accumulated for more than two years operating with this scheme in the fields of naturally fractured carbonates and some in consolidated sands oil producers and injectors in the marine region of Mexico, without sacrificing quality in the treatment systems or in the operational execution, including monitoring and transmission of data in real time to shore customers.

Petroleum systems of coastal North Carolina: What we know, what we think we know, and the range of uncertainty in the interpretation of geochemical data

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As part of a regional analysis of oil and gas occurrences in eastern North Carolina, the North Carolina Geological Survey initiated a comprehensive geochemical project using samples and cores from Esso Hatteras Light #1 (HL#1), and Mobil State of North Carolina #3 (NC#3). These were two of at least 19 exploration wells drilled in coastal North Carolina where oil/gas shows were reported. The study objective was to determine if the shows were *in situ* or represented migrated hydrocarbons.

The wells are located in a local depression on an otherwise elevated regional basement complex extending from the Cape Fear Arch on the south to the Fort Monroe High on the southern flank of the Salisbury Embayment on the north. In the downdip-adjacent U.S. Atlantic OCS, sea-surface hydrocarbon seepage slicks are identified on satellite synthetic aperture radar images and hydrocarbon-related diagenetic zones and "chimneys" interpreted on seismic data indicate vertical hydrocarbon migration.

Geochemical sampling and analyses concentrated on intervals where hydrocarbons were reported in the two wells. Biomarkers in aggregated samples appear to originate from marine shale source rocks at immature/early maturity levels of thermal maturity. Oleanane suggests the hydrocarbons are Cretaceous or Jurassic age. Analytical data indicate sampled intervals are too thin, organically lean, and immature to source commercial hydrocarbons in either conventional or resource plays in coastal North Carolina. However, possible occurrences of mobile hydrocarbons were detected in Tertiary strata (~815') and solid bitumen and migrabitumen were reported from Cretaceous rocks. The sporadic nature of the bitumen, lack of viable source rock and low level of thermal maturity suggested that these bitumen occurrences probably lie on a migration pathway(s) rather than being *in situ*. Better potential may exist offshore in deep water Assessment Units interpreted by the Bureau of Ocean Energy Management.

Stratigraphy, Geochemistry, and Organic petrology data from the Esso Hatteras Light #1 and the Mobil State of North Carolina #3 and their effect on hydrocarbon prospectivity in coastal North Carolina

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The North Carolina (NC) Geological Survey undertook a geochemical study to determine: (1) if hydrocarbons reported in a fluid inclusion stratigraphic study in the Mobil State of North Carolina #3 (NC#3) (**Coleman *et al.*, 2014**), and oil shows reported in post-drilling examination of cuttings and cores in the Esso Hatteras Light #1 (HL#1) well were *in situ* or migrated: and (2) to provide new data on the petroleum potential of the U.S. OCS offshore NC.

Drilling for oil/gas in coastal NC began in 1921. Oil and/or gas shows have been reported in wells, and oil occurrences were described in local, early 20th century newspapers. No reports of oil/gas have been found in wells in similar settings in VA, SC, and GA.

The study focused on intervals where hydrocarbons had been reported. Analyses included %TOC, %Ro, programmed pyrolysis, organic petrology, and biomarkers. The NC#3 penetrated 7,222' of Tertiary and Cretaceous strata overlying Precambrian granite. The down-dip HL#1, the deepest well drilled on the NC Atlantic Coastal Plain, encountered 9,878' of Tertiary and Cretaceous strata above granite.

Geological and geochemical data indicate sampled intervals are too thin, organically lean, and immature to source commercial conventional or unconventional hydrocarbons in the onshore or state waters of NC. Anomalously high %Ro values in the HL#1 may be due to allochthonous kerogen from nearby exposed Triassic rift basins of the Piedmont. Analyses of these basins indicate ~3,300' – ~10,000' of syn-rift strata were removed during their inversion, exhumation, and erosion.

The *in situ* or migrated nature of the hydrocarbons remains problematic. Biomarkers suggest an *in situ* origin. However, in the HL#1, interpreted mobile hydrocarbons were detected at ~815' in Tertiary strata, and solid bitumen and migrabitumen sporadically were identified in Cretaceous rocks. These, the lack of viable source rocks, and low level of thermal maturity suggest their relation to a migration pathway(s), the *"Carolina Ridge Comple*x". Both interpretations suggest better hydrocarbon source rock potential and generation–expulsion–migration may have existed farther offshore in deep waters of the Atlantic OCS. Sea-surface hydrocarbon seepage slicks identified on satellite synthetic aperture radar images, and hydrocarbon-related diagenetic zones and "chimneys" interpreted on reflection seismic data suggest vertical hydrocarbon migration in this area (**Post *et al.*, 2018**).

Underground Storage of Refrigerated Natural Gas in Granites of the Southeastern U.S.

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Conventional underground storage sites for natural gas (salt caverns, depleted gas and oil reservoirs, and aquifers) are either rare or absent along the U.S. eastern seaboard. The potential exists for underground storage of refrigerated natural gas in mined caverns (RMC) in granite*. We identified eleven pipeline-granite intersections in NC and southern VA along the Williams/Transco pipeline (completed) and the Atlantic Coast Pipeline (initial construction stage).

We used the conceptual design for a mined cavern in granite in the Maryland piedmont developed by PB-KBB (1998) in a U.S. DOE sponsored study as an example of a natural gas storage cavern that could potentially be adapted for use in NC and VA granites*. In that study, a RMC plant with 5 BCF design capacity and storage cavern at a 3,000-ft. depth was estimated to cost $173 million ($1998). RMC facilities provide high deliverability and multiple injection/withdrawal cycles per year to meet multiple peaking and other short-term demands, and have a small above-ground footprint. RMCs would have a high level of physical security and could provide emergency supplies during natural or manmade supply disruptions. Liquefied

Natural Gas (LNG) plants might have lower capital cost, but would be less physically secure, and more limited in their cycle time.

GIS and Google Earth Pro were used to intersect granite outlines from USGS digital state geologic maps with pipelines. USGS search engines provided additional information on the granites identified. The USGS' National Geologic Map Database provided search results for geological, geophysical, and geochemical maps.

Existing geological knowledge of granite rock locations with potentially suitable geotechnical properties in NC and southern VA, and modern advances in hard rock excavation technology, argue for the overall technical viability of the RMC concept. Commercial viability will depend on site specific conditions, market analysis, and other considerations.

If the need for underground storage along the U.S. eastern seaboard justifies the higher costs of underground excavations, such as the type described by PB-KBB corporation, the granites would warrant further consideration as underground storage sites. The same argument might apply to granite terrains in other global regions undergoing an expansion in natural gas use.

*Granite as used herein is a broad term for massive and isotropic rock bodies with physical and mechanical properties capable of sustaining large underground openings.

Spatial distribution of chlorite in the Marcellus Formation and its relationship with static reservoir properties and well production

Rothfuss, J.L., Malizia, T.R., and Carson, B.E.

The objective of this study is to evaluate the relationship of chlorite to static reservoir properties and horizontal well production in the Marcellus Formation. A series of multivariate petrophysical models were built to predict chlorite content (as measured in weight percent (wt%) from x-ray diffraction (XRD) of core samples) from 68 wells in Pennsylvania, West Virginia, Ohio, and New York using basic wireline log data (gamma ray, neutron porosity, bulk density, deep resistivity, photoelectric effect). The petrophysical models were high-graded using residual error analysis and blind testing, resulting in two separate optimized models for use with laterologs and induction logs, respectively. The models were applied to 300+ wells without XRD data, and the modeled results were mapped across the spatial extent of the dataset.

The petrophysical models and the XRD data reveal similar trends in chlorite wt% in most areas. The models over-predict chlorite in distal parts of the basin, particularly the West Virginia panhandle and surrounding areas, which is attributed to a hydrocarbon phase change from dry gas to wet gas and its associated impact on resistivity readings.

In general, chlorite wt% increases up-section in the Marcellus and decreases basinward. Chlorite wt% is highest in central Pennsylvania in the proximal part of the basin. While chlorite in the Union Springs (basal Marcellus) can average >10 wt% in central Pennsylvania, it is virtually absent from the main play fairways of southwest Pennsylvania and northeast Pennsylvania. Chlorite is present in the Oatka Creek (upper Marcellus) across the entire study area, gradually transitioning from an average of 1 wt% in the west to 20 wt% in the east.

Increased chlorite wt% in the Oatka Creek relative to the underlying Union Springs records progradation of the Acadian clastic wedge during Middle Devonian. Cratonward migration and uplift of the Acadian orogenic belt led to unroofing of Lower Paleozoic and Precambrian greenschist facies, sourcing an influx of chlorite into the basin.

Statistical analysis reveals a significant inverse correlation (p-value=0.003) between chlorite wt% and total organic carbon (TOC) in the southwest Pennsylvania play fairway. This corroborates the prevailing view that high clastic influx dilutes TOC and increases clay content. Hence, the relationship between chlorite wt% and TOC is correlation, not causation, resulting from allocyclic controls. No significant relationships exist between chlorite wt% and other static reservoir properties (water saturation, permeability, and porosity). Well productivity (720-day cumulative production, normalized for lateral length) significantly correlates with TOC (p-value=0.048) and has no relationship to chlorite wt% (p-value=0.649).

Multivariate Analysis to Identify Variables Controlling Production and Quantify Their Economic Impact - Midland Basin, Texas

Patrick Rutty, Drilling Info

Objective/Scope: The Wolfcamp formation in the Midland Basin of Texas has long been a hotbed of activity, with a recent dramatic increase in horizontal well development. Operators are now focused on optimizing their development efforts, but the number of variables that control production can make the problem seem intractable. This study demonstrates the use of multivariate non-linear regression techniques to identify and rank the variables controlling production and presents the economic impact of design changes.

Methods/Procedures/Process: It is widely acknowledged that multiple variables control production in unconventional plays. In this multivariate analysis, we include both geological variables such as porosity, resistivity, thickness, and source rock maturity, as well as engineering variables, such as lateral length, proppant, fluid, wellbore orientation, and well spacing. Further, the model also allows for quantification of each variable's relative contribution to this production. We then use this predictive model to estimate the future productivity and economic returns of various optimized drilling and completion scenarios.

Results/Observations/Conclusions: There are many seemingly logical ways to increase unconventional production from horizontal wells. Theoretically, longer laterals, increased proppant loading, and increased proppant concentration should lead to improved performance. Similarly, wells in reservoir rock with higher porosity or pressure should outperform. However, in the study area, our model indicates that while some of these factors have the expected impact, others have surprisingly little. Further, the combinations of variables that do optimize production may or may not result in improved economic returns. Indeed, in some cases, we find that the best returns can be realized from wells with moderate – but not the best – production, because of their low cost. Complicating matters more, depending on the metric to be maximized – rate of return, return on investment, net present value, or even estimated ultimate reserves – the optimal development design varies.

Novel/Additive Information: This work is notable in that it moves us from using educated guesses to optimize development, to the use of a data-driven mathematical model that allows for quantification of our design change impacts. However, its most valuable conclusion may be even simpler: the days of bivariate analysis are over. The multivariate nature of unconventional (or complex conventional) reservoir development demands multivariate tools to optimize.

Investigating the geochemical relationship between the Ordovician Guttenberg Carbon Isotope Excursion and the Trenton and Point Pleasant reservoirs

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The Trenton Limestone and Point Pleasant interval of the Utica Shale of the Appalachian Basin are prolific oil- and gas-bearing zones, and although the Trenton reservoir appears to be conventional, thin organic-rich shale beds of this unit may have contributed to its hydrocarbon inventory. In southeastern, Ohio methane carbon isotopes (δ13C) recorded within the Trenton reservoir display a sharp 2‰ increase making the Point Pleasant and Trenton reservoirs isotopically distinguishable. Hydrocarbon δ13C values can serve as unique geochemical fingerprints controlled in part by thermal maturity due to enrichment of 13C with increasing thermal stress. However, hydrocarbon δ13C values are also known to be impacted by the isotopic value of the precursor organic matter (δ13Corg); i.e., as δ13Corg values become enriched so too do hydrocarbon δ13C values. A global isotope excursion known as the Guttenberg Carbon Isotope Event (GICE) recognized in Ordovician deposits as a sharp positive shift of both carbonate (δ13Ccarb) and δ13Corg can be traced throughout the basin immediately above the Millbrig Ash bed. It is thought that increased global productivity influenced the exchange of 13C enriched pCO2 with the global ocean, which may have been connected with the Appalachian Basin through the Sebree Trough. The introduction of seawater recorded by the transition of tropical to temperate carbonates is readily observed in wireline logs. The GICE has been documented throughout Ohio and δ13Corg values recorded from a core located in Highland county display a sharp increase at the stratigraphic horizon we observe the anomalous δ13C methane signature. Also, long chain hydrocarbon (n-C17, n-C20, n-C28) δ13C values have been observed to mimic the isotopic trend of the parent material (δ13Corg) from the GICE interval throughout the Appalachian Basin and from the Kahula and Variku formations of Estonia. The positive covariance of hydrocarbon δ13C and δ13Corg suggests the GICE not only impacted isotopic values recorded by carbonate and organic matter, but isotopic values of hydrocarbons as well. What remains to be determined then, is the reason for the anomalous δ13C methane signature documented from southeastern Ohio. Did hydrocarbons migrate into the Trenton reservoir from a location that experienced greater thermal stress, or were they self-sourced from organic matter that was affected by the positive excursion resulting in the anomalous signature we observe today?

Oil and Gas Fields Trends and Its Main Controls on the Occurrence in Onshore Simenggaris Area, Tarakan Basin, Indonesia

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Key words: Tarakan basin, oil and gas distribution, hydrocarbon distribution control

Oil and gas fields in Simenggaris distributed in a unique trend that can recognized based on its lineation. There are two major trends, the NW-SE trend, which dominated by oil accumulation and the NE-SW trend, which dominated by gas accumulation. The occurrence of those behaviours mainly controlled by three main constraints; those are (1) time of source rock expulsion and (2) time of trap formation and (3) position of trap to the potential kitchen location.

In this paper, we integrated numerous data from geology (biostratigraphy and depositional environment), geophysics (2D seismic interpretation), and geochemistry (gas isotope, oil biochemistry, and burial history) to support and generate comprehensive interpretation. We trying to get a robust perspective on how those three constraints interplay and create the trends of oil and gas accumulations, particularly for Onshore Simenggaris area.

Computed Tomography Scan Image Analysis of Michigan Niagaran Reef Cores for Improved Reservoir Characterization

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Whole core is a valuable dataset that facilitates a better understanding of variations in geology, environmental setting, and reservoir properties. Many core analyses provide single, localized measurements that are not representative of highly heterogeneous reservoirs. In recent years, image analysis of computed tomography (CT) scans has emerged as a mechanism for reservoir characterization and allows for examination of reservoir properties in 3-dimensions (3D). However, CT data analyses are often constrained to qualitative assessments and limited by software catered specifically to medical applications. Battelle has developed an interactive tool for CT scan data that allows the interpreter to process, view, and analyze core data for reservoir characterization in both 2-dimensions (2D) and 3D. Battelle’s CT scan analysis tool also quantifies the volume of selected features, generates a curve of percent of the selected features with depth and displays digital well log data.

Battelle was involved in the collection of two whole cores from reservoirs in the Northern Niagaran Pinnacle Reef Trend (NNPRT) that are currently undergoing carbon dioxide enhanced oil recovery (CO_2-EOR). With the objective of enhancing CO_2-EOR operations via

improved geologic characterization and understanding of the reef systems, dual energy CT scan data was collected over both cores and processed in Battelle's CT scan analysis tool. Density thresholds were identified to denote selected features such as secondary porosity, salt, anhydrite, and carbonate matrix. Volumes were rendered for the features of interest and statistics were calculated for each resulting feature volume. Results were then compared to wireline logs and other core-measured properties. The CT scan analysis tool successfully captured variability in the heterogeneous reservoirs which improved understanding of the reservoir properties. Understanding the variability in reservoir properties is critical when constructing geologic models and when analyzing the differences in CO_2-EOR performance among reefs along the NNPRT, as it allows for optimization of CO_2 storage and oil production.

This study is part of the Midwestern Regional Carbon Sequestration Partnership Michigan Basin Large-Scale Injection Project under DOE/NETL Cooperative Agreement # DE-FC26-0NT42589 with co-funding by Core Energy, LLC, and several other partners.

Correlating reported hydrocarbon production and published thermal maturity maps for organic-rich shales in Pennsylvania

Katherine Schmid and Robin Anthony

The capacity of a shale well to produce oil, natural gas or natural gas liquids is controlled in part by the thermal maturity of the source rock. Publicly available data on 6,500 wells from completion through the end of 2017 allow for comparison between reported hydrocarbon production and predictions from previously published thermal maturity maps. Sixty percent of these wells have reported production for at least four years. Results were obtained using a gas/liquids ratio (MCF/BBL) to classify well production into four categories (dry gas, wet gas, condensate or oil) for the Upper Devonian Geneseo/Burket, Middle Devonian Marcellus and Upper Ordovician Utica shales. Production values follow general trends illustrated by published thermal maturity maps (that is, westward decreasing maturities in Pennsylvania, with the trend shifting northward for shallower shales). However, some notable deviations do exist, namely the abundance of Marcellus and Utica wells with dry gas production in areas defined as "overmature", and little to no oil production in the northwestern part of the state where thermal maturities belong in the oil window. The lack of oil production in the northwest may be due to the type of organic matter present in the shales or as an artifact of the few wells that have been drilled in this part of the state. Dry gas production in the "overmature" areas may result from structural controls and hydrogen availability in those areas. This study examines possible geologic and geochemical controls, but does not consider possible bias resulting from non-verified operator reporting or from well facilities design.

Carbon Storage and Static Earth Model Development for Pennsylvanian Cyclic Carbonates of Southwestern Nebraska

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The Pennsylvanian Lansing – Kansas City (LKC) Group constitutes a regional succession of interbedded carbonates and shales. Located within the Cambridge Arch of Nebraska, these interbedded units were evaluated for carbon storage potential. Understanding the occurrence of carbonate porosity among the confining shale units in the LKC Group is key for developing a CO_2 storage strategy for the Integrated Midcontinent Stacked Carbon Storage (IMSCS) Hub Project as part of DOE-NETL's Carbon Storage Assurance Facility Enterprise (CarbonSAFE) initiative. This project seeks to develop a regional carbon storage hub where captured carbon would be piped to existing oilfields for carbon storage and enhanced oil recovery (EOR). Petrophysical analysis of wireline logs from 205 wells was used for reservoir characterization and building a static earth model (SEM) for Sleepy Hollow Field in Red Willow County, southwest Nebraska. Existing core samples from Sleepy Hollow and neighboring oilfields were studied and show that porosity occurs in packstone and grainstone units with further porosity development likely associated with meteoric water infiltration during periods of subaerial exposure. Gamma ray (GR) log response clearly indicated the depositional cyclicity and was employed in SEM facies development to delineate high, moderate, and low-energy environments using GR-thresholds. Storage resource estimates were based on the resulting porosity model while considering CO_2 storage opportunities in saline zones vertically-stacked with potential EOR reservoirs in oil-bearing carbonate intervals. This presentation will provide an overview of the Phase 1 SEM development which is applicable to future commercial stacked storage sites along the Cambridge Arch and the Central Kansas Uplift.

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A Comparison of Different Geomodeling Approaches in the Context of CO_2 Injection and Flow Simulations for the Mt. Simon Sandstone

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One million tonnes of CO_2 was injected into the Mt. Simon Sandstone, a deep saline reservoir, during the Illinois Basin – Decatur Project (IBDP), a large-scale carbon dioxide (CO_2) injection and storage demonstration project. During the life of the project, several different Static Earth Models (SEM) were developed for this reservoir, each using different modeling strategies and conceptual geologic models. This study describes four of these SEMs and

examines their properties in the context of CO_2 injection and flow simulation results. Unlike the original work for IBDP, we did not apply calibration or history matching to the CO_2 monitoring data. Thus, CO_2 plume development and changes in formation pressure reflect modeling differences, with no intention to replicate the IBDP simulation efforts. Furthermore, for simulation purposes, we introduced an injection well with a 90-ft perforated injection zone above the base of the Lower Mt. Simon and increased the injection rate to one million tonnes of CO_2 per year for 3 years. The four models are classified as object based (emulated densely spaced fluvial streams described by various stream geometries); stochastic based (employed neural networks and well logs to derive lithofacies); multipoint facies simulation (implemented a braided-fluvial training image); and porosity mapping (lateral heterogeneity prepared through use of a three-dimensional seismic inversion porosity cube). Considering the differences in facies and petrophysical modeling methodologies, flow simulation results showed that the CO_2 plumes were generally constrained to a 762-m (2500-ft) radius around the injection well within the Lower Mt. Simon. At 3 years and 3 million tonnes, the CO_2 saturation was compared against porosity and permeability models. This poster will describe the four SEM methods and showcase, side-by-side, flow simulation results depicting the CO_2 plume, CO_2 saturation, and formation pressure perturbation. We have illuminated the resulting differences among these modeling methods so that geomodelers and reservoir engineers can better understand the benefits and tradeoffs between these SEM approaches.

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Developing an Efficient Workflow to Utilize Geo-modeling in order to Predict Unconventional Hydrocarbon Production and Maximize Operational Efficiency

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Subsurface teams can determine unconventional reservoir performance drivers affecting operational efficiency by creating a workflow that integrates structural, stratigraphic, petrophysical, drilling, completion, and production data into a 3-D geologic model. When using these data to build a model, it is critical to construct a geologically detailed volumetric model from existing well data (e.g., well log, drilling, completion, and production data). In particular, it is essential that the entire length of the horizontal portion of the wellbore is stratigraphically placed into the correct model layer to accurately represent subsurface geology and engineering data.

For this study, a workflow was developed to efficiently integrate data into a sequence stratigraphic-framed geologic model, which also incorporates structural data collected from geosteering results. Petrophysical properties were normalized and geostatistically distributed throughout the model, and drilling and completion parameters - including rate of penetration, treating pressure, water used, and proppant delivered - were also distributed in a similar fashion. This model allowed the subsurface team to visualize how stratigraphic sequences/systems tracts and faults affect production and engineering parameters. Further, the model can be used to provide recommendations regarding field planning, drilling, and completion recommendations, as well as highlight “big levers” affecting operations and production in an unconventional well field.

Specific to this study, model results suggest that stratigraphic well placement and structural complexity affect drilling, completion, and production trends, and drilling and completion trends vary greatly among different stratigraphic systems tracts. Production is affected by structure and stratigraphic sequence placement but not necessarily by individual systems tract placement within a sequence. By utilizing a workflow to integrate and analyze geologic, engineering, and production data in an accurate and timely fashion, we can: 1) optimize efficiency in the planning and operational phases, 2) provide recommendations during drilling and completion operations, 3) predict drilling, completion, and production trends based on geologic structure and the stratigraphic placement of the wellbore, and 4) foster supportive relationships among disciplines.

Use of Iodine for Petroleum Exploration

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Iodine is highly mobile so is transient and highly variable in concentrations in the soil environment. Increased concentrations of iodine and bromine are often associated with oil and gas fields; however, there is a debate as to whether the halogens migrate with the hydrocarbons or are already present in the soil and what process causes the halogen association with the hydrocarbons. Nevertheless, surface geochemical surveys of iodine concentrations have been used as a ‘pathfinder’ for locating oil and/or gas accumulations for more than 40 years. Background values of iodine appear to range from 0.1 to 15 ppm while anomalous concentrations appear to range from approximately 3.5 to 10.5 ppm, which would be one to two standard deviations from the mean.

Iodine surveys have been conducted in many regions of the US including: 1) California, 2) Rocky Mountain, 3) Texas, 4) Mid-West, and the 5) Appalachian Basin. One survey has been reported from the Thrace Basin in the European portion of Turkey. The wide range of geologic and climatic regions that iodine surveys have been used in suggests that they can be an effective exploration method, but the data do not provide any type of correlation between anomalous concentrations of iodine in the surface environment and exploration success. One advantage of this exploration method is that one person can collect samples using a standard soil probe, so the method is quick and cost-effective. Tedesco (1995) suggests that the use of the iodine surveys along with other exploration methods can increase the exploration success rate by about 25 percent. Leaver and Thomasson (2002) used crosstab plots and Chi-square statistics to suggest that the association between iodine anomalies and oil and gas fields is not random.

Traverse Group Reservoirs in the Michigan Basin: A Second Look

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Keywords: Long-term waterflooding, Petrophysical properties, Large pore channel, Multiple linear regression model

Traverse Group reservoirs have been a prolific source of hydrocarbons in the Michigan Basin since the 1930's. Early exploration targeted structural traps in these relatively shallow reservoirs (300 to 900 meters). The reservoirs in these fields consists of dolomitized, vuggy carbonates sealed by argillaceous and organic shales of the overlying Antrim Shale.

The Traverse Group in the subsurface of Michigan includes the argillaceous shales of the Bell Shale and shales, dolomites and limestones of the Traverse Limestone. The facies of the Traverse Limestone reflect a shallow water carbonate bank present over much of the Lower Peninsula of Michigan. Facies include grainy oolitic and skeletal sand shoals, patch reefs and reef-associated rubble, muddy lagoonal carbonates, and open shelf deposits consisting of interbedded tempestites and bioturbated, cherty carbonates. Overlying the Traverse Limestone are argillaceous carbonates and dolomitic shales of the Squaw Bay Formation. The contact between the Traverse Limestone and the Squaw Bay Formation is a hardground with pyrite mineralization marking a period of relative sea level rise in the basin. The Squaw Bay Formation was deposited in the outer shelf under more reducing conditions. Up section, the Squaw Bay Formation becomes more argillaceous and exhibits higher gamma ray signatures. This zone transitions into the overlying Antrim Shales.

In productive reservoirs, dolomitization preceded up to the Squaw Bay Formation, which acted as a partial seal to these fluids. Dolomitization generated significant secondary porosity including vuggy and intercrystalline porosity (up to 12% in the Smith-Gerard #1). Grainy carbonates (reef rubble; skeletal, pelletal and oolitic sands) provided permeable pathways for dolomitizing fluids to migrate through the Traverse Limestone if not cemented early.

Historic Production in Traverse Group reservoirs through 1986 was 115 million barrels of oil. Renewed interest in overlooked hydrocarbons is already driving exploration and speculation on the underlying Dundee-Rogers City Formations. These Middle Devonian Reservoirs were exploited prior to modern advances in technology and geologic principles – perhaps it is time to look at Traverse Group reservoirs again as well!

High-resolution subsurface mapping of depositional cycles within the lower part of the Huron Member of the Ohio Shale: detailed snapshots of basin development in central and eastern Ohio

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As part of the collaborative Midwest Regional Carbon Sequestration Partnership project, administrated by Battelle Memorial Institute and funded by the U.S. Department of Energy, the Ohio Department of Natural Resources, Division of Geological Survey evaluated the utility of strata in the Appalachian Basin for carbon utilization and sequestration. Research focused partially on developing a high-resolution stratigraphic framework for the numerous Upper Devonian black shale units in Ohio to help characterize their potential for carbon sequestration via adsorption of CO_2 molecules onto organic particles. The lower part of the Huron Member of the Ohio Shale (Famennian Stage, Devonian System) is one potential target for carbon storage. It has a high average total organic carbon (TOC) concentration, but the distribution of TOC within the unit varies depending on both stratigraphic position and geographic location. Subdividing the lower Huron into chronostratigraphically meaningful units is useful for future work to precisely characterize the spatial distribution of TOC in the lower Huron, and to understand the geological factors that contributed to TOC deposition and preservation. The stacked gray and black shale layers of the lower Huron provide excellent markers for high-resolution correlation—they appear to be cyclical and were likely caused by glacio-eustatic sea-level variation. Eight high-frequency cycles superimposed on two third-order depositional sequences were identified in 789 wells across eastern Ohio using gamma-ray and bulk-density geophysical logs. Isopach maps created for each cycle illustrate that the location and size of depocenters within the study area changed during the deposition of the lower Huron. The close association of depocenter development and evolution with basement structural features indicates considerable structural control of basin bathymetry. On a broad scale, regional depositional strike became parallel to the Akron magnetic boundary and the Cambridge Cross-Strike Structural Discontinuity during cycles 4–8, indicating that these features localized movement during intervals of widespread basin subsidence. Several smaller, local-scale bathymetric characteristics appear to have been controlled by basement faults. A zone of thin strata in northwest Columbiana County during seven of the eight depositional cycles likely represents a bathymetric high caused by contractional overstepping between the Smith Township, Suffield, and Akron fault systems and the Highlandtown Fault. Subsidence along three unnamed basement faults in Belmont County appears to have led to the development of a sub-basin during cycles 5–8. The cycles likely represent the long eccentricity orbital variation, but additional chronostratigraphic data combined with orbital tuning is required to determine the duration of the cycles with more certainty.

Organic Matter Deformation in Overmature Mudrocks

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Pores within organic matter (OM) are strongly linked to hydrocarbon generation and primary migration in fine-grained source rocks and are very important for evaluating hydrocarbon storage and flow in shale reservoirs. Under overmature stage, abundant pores are formed within the OM. The porous and ductile OM should be deformed when the original equilibrium of stress condition is altered. OM deformation at the nano- or micro-scale has rarely been discussed due to the lack of associated evidence. This research documents evidence of OM deformation observed in scanning electron microscope (SEM) images of seven overmature samples from the Longmaxi Shale, Sichuan Basin. Deformation processes of OM-hosted pores were qualitatively analyzed with assumptions. To further discuss the features of OM deformation and its effect on OM-hosted pores, the OM deformation is classified into three types (I, II and III) according to the amount of additional forces, and deformation sub-types are recognized according to the contact area of OM particles and mineral grains along which the additional force applied to the OM and overlapping of displacement fields. Two OM particles subjected to Type I deformation were analyzed quantitatively for such parameters as pore size, geometry, and orientation of long axes of elliptical pores. The reduction of OM-hosted pore volume, specific surface area and organic porosity was calculated using the two OM particles suffering from Type I deformation.

Issues of Horizontal Well Log Interpretation: an example Longmaxi-Wufeng Shale in Fuling Gas Field of Eastern Sichuan Basin

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The wireline logs in horizontal wells provide a great opportunity to estimate the lateral variation of reservoir properties. This is a big benefits compared to the log data from vertical wells. But the interpretation of horizontal well log data also brings many new issues. One major issue arises from the data acquiring of log data in horizontal wells. Due to the difference of detection depth and detection direction of various logging tools, the measured zones are not the same. This is not a significant problem for vertical wells, but it has caused some abnormal phenomenon that were observed in horizontal well log data. In this research, we summarized these abnormal phenomenon, then explained the reasons, and finally proposed the methods to deal with it. Another issue is the instability of horizontal wells in mudrocks reduced the quality of logging data in multiple parts of the horizontal section. To generate a reliable assessment of shale reservoir, this researched proposed a methods to detect the low-quality data by caliper logs. The third issues is related to identify the formation tops in the horizontal section of horizontal wells. Repeat of formation tops become common in horizontal wells, especially in the areas where the structure is complex. This makes it a challenge to pick the formation tops in horizontal wells for shale reservoirs.

Longmaxi-Wufeng Shale in Fuling Gas Field is a high-quality, organic-rich mudrock. Shale gas production from this formation has been significantly increased in the last three years. In Fuling Gas Field, horizontal wells have been predominantly drilled with a few vertical wells, which is typical for shale reservoirs. In this research, we use it as an example to discuss the issues of petrophysical analysis of horizontal wells. First, we carried out the log correlation primarily based on gamma ray and the set of porosity logs, to estimate the spatial distribution

of Longmaxi-Wufeng Shale. Then, log normalization and quality control were completed to improve the reliability of the interpretation results. Uranium log with the differences among density, neutron and acoustic logs were combined together to interpret TOC content, which was verified by core-measured TOC content. Finally, the volume percentage of clay minerals were estimated by CGR (gamma ray from thorium and potassium only) log and neutron log in aid of XRD data and ECS logs, as an intermediate step to proximately estimate the brittleness of organic shale.

Utilizing Horizontal Drilling to Enhance Oil Production from the Devonian Geneva Dolomite at Plummer Field, Indiana, and Its Application in Carbonate Reservoirs

Thomas Ward, Citizens Energy Group

Plummer Field, a characteristic reef-induced anticline, was discovered in 1969. There are three oil bearing units in the overlying “draped” strata: Mississippian McCloskey and Salem Limestones and Devonian Geneva Dolomite. The Geneva Dolomite is a member of the Jeffersonville Limestone, and it is characterized as chocolate brown, rather soft, granular, and vuggy. At Plummer Field the formation has a depth ranging from 1500 to 1600 feet. The primary oil-bearing zone has gross and net thicknesses of 15.4 feet and 8.9 feet respectively, with average porosity of 10% maintained laterally throughout the field. Original oil in place is 6.6 MMBO. Production thru April 2014 totaled only 0.75 MMBO with a daily average of 30 BOPD from 40 wells. It is assumed, the low cumulative production value is due to poor connectivity of the vugular porosity. In May 2014 a horizontal test, Patterson-Schaar-Hemmerlein #4-H, was completed without stimulation and had an IP of 268 BOPD flowing. In December of that year two more horizontal wells were completed with IPs of 587 BOPD and 450 BOPD pumping. These three wells were drilled between active and plugged vertical Geneva oil wells, and no production loss was monitored in nearby producing wells. Since completion three years ago these three wells have produced over 140,000 barrels of oil accounting for 15% of the total oil production from the Geneva. Though the Geneva had been producing for 45 years at Plummer Field, the new horizontal wells proved very successful, and as a result, further drilling is planned for the approximately two square mile field. It is believed that this method could be applied to other mature fields containing thin (less than 10 feet) and laterally continuous carbonate reservoirs.

The Stacked Play North Outside of Pittsburgh “SNOOP”

Matthew Weinreich, Laurel Mountain Energy

The combination of population density and topography has prevented unconventional shale development in the metropolitan Pittsburgh area. The lack of activity in this area segments the southwest Pennsylvania shale plays into two areas. Exploration and development continues to extend from the original core of the Marcellus play located south of Pittsburgh in Washington

County, PA. Recent activity north of Pittsburgh reveals new economic opportunities in multiple unconventional strata. Comparing these geographic, somewhat-arbitrary segments provides insight into the unique reservoir characteristics of the stacked play north outside of Pittsburgh (SNOOP).

Similar to the original core of the southwest Pennsylvania Marcellus, SNOOP development began with vertical wells and progressed towards horizontal drilling. Build-out of wet-gas midstream infrastructure has allowed for further exploration in the play. Subtle changes in reservoir properties north of Pittsburgh are shown to have significant impacts on production. Operational practices and new technologies have proven critical to producing favorable economics in the SNOOP. The combination of wet gas Marcellus, wet gas Upper Devonian, and dry gas Utica/Point Pleasant provides economic flexibility and mitigates risk in the area. A systematic analysis of reservoir properties in these plays reveals the economic margins and ultimate resource available in southwest Pennsylvania.

Critical questions of hydrocarbon generation: fluid composition and maturation determined from new techniques using maturity proxies

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KEYWORDS: transformation ratio, maturity proxies

Assessment of unconventional shale reservoirs and potential source rock intervals rely on estimates of thermal maturity and extent of kerogen transformation to hydrocarbons.

Vitrinite reflectance (%R_o), bitumen reflectance (%B_{ro}), TMAX, hydrogen index (HI), transformation ratio (TR), and calculated $R_{o\ (eq)}$ values based upon time/temperature relationships are used to determine maturity indices. Problems can arise in applicability and interpretation of maturity proxies that are used to estimate hydrocarbon generation. Vitrinite suppression, bitumen inclusion in S2 peaks, heterogeneity in organic richness, and inaccurate time/temperature relationships can contribute to problematic maturity estimates.

Experimental closed-system pyrolysis and modeling suggest that the TR-HI relationship is non-linear and deviates from a linear relationship in areas with oil-prone and elevated original HI source rocks. Potential unconventional reservoirs containing excellent oil-prone kerogens, have calculated transformation ratios (from HI values) that significantly underestimate the conversion of organic matter to hydrocarbon. Combining a new approach in the assessment of original HI in heterogeneous organic facies with a TR calculation that accounts for the curved relationship would result in a maturity proxy that is more reliable in hydrocarbon generation estimates.

Source rock pyrolysis data from the New Albany Shale (NAS) in the Illinois Basin was used to evaluate the new techniques. Preliminary results indicate that calculated TR values expanded the range of incipient oil generation by 10 – 25 percent. In addition, zones of increased maturity within the NAS were postulated in the central/northern La Salle anticlinorium by HI maturity proxies and confirmed by TR estimates. Preliminary modeling suggest that at TR of roughly 50% is equivalent to a maturity estimate of 0.60 – 0.65 %R_o, early oil generation window.

Linkage of the TR estimates with predicted fluid compositions was attempted using KINEX and GENESIS Zetaware modeling. In the Illinois Basin, preliminary results indicate intervals of predicted high-volatile oil in the southern Wabash Valley Fault zone, Fairfield Basin and southern La Salle anticlinorium.

Ultrasonic Detection of Fracture Propagation and Complexity in Hydraulic Fracturing Experiments

Tim E.H. Witham, Dr. Chris Marone, Dr. Parisa Shokouhi, The Pennsylvania State University

Hydraulic fracturing is a proven method used to enable the recovery of hydrocarbons from tight reservoirs and source-rock plays. More complex fractures have larger surface areas, which is thought to help maximize recovery. However, measuring the degree of complexity and interconnectedness of fractures is a challenging problem, even with microseismic data. Here, we use laboratory-scale hydraulic fracturing experiments in conjunction with active and passive source compressional waves to evaluate how seismic waveform responses can be used to better constrain fracture development. Piezoelectric transducers were used to send waveforms through a confined, isotropic acrylic block as it fractured within a biaxial testing apparatus. Acoustic emissions were passively recorded during the fracturing process in certain experiments. Fracking fluids are delivered to the sample at a constant stress rate in all cases. Initial results show that detection of propagating fracture fronts is possible by analyzing the relative attenuation differences in active compressional wave amplitudes as a function of time. Further experiments test whether there is an observable difference in attenuation values based upon the compositions of fracking fluids or gasses used, and how variable compositions influence the complexity of the resultant fracture surface. In order to apply these methods at the field scale, deconvolving multiple seismic signals would be necessary to back out attenuation changes. Our experimental results suggest that fracture development can be observed by analyzing the relative attenuation changes in compressional waveforms.