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MEETING ABSTRACTS

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Analysis of finely bedded intervals in the Frontier Formation using high resolution logs

The Frontier Formation in the Powder River Basin contains a mixture of coarse-grained fluvial deposits interbedded with marine strata. The bedding can be on the order of a few tenths of a foot or less causing standard logging tools to average over the bedding response. High resolution logging suites have been recorded to calculate parameters such as net-to-gross and mechanical anisotropy to better delineate the reservoir.

Bedding density has been mapped along the reservoir section with an X-tended Range Micro Imager and compared with near-bit accelerometer estimates of mechanical properties at 0.017ft. and 0.1ft. resolution, respectively. Assuming the bedding density is correlated with sand volume, there is strong agreement between the two methods. By applying simple logical arguments to the high resolution measurements we can generate a new net-to-gross estimate. The updated net-to-gross is different than the estimate using low resolution logs, and may affect the lateral target and economic viability of the prospect.

The accelerometer measurements also suggest the bedding density is anti-correlated with mechanical anisotropy. Higher mechanical anisotropy will generate higher minimum horizontal stress, possibly affecting hydrofracture growth and completion strategy. The mineralogy has been estimated along the vertical pilot with an elemental analysis tool calibrated to cuttings measurements. The estimated mechanical anisotropy is well correlated along the vertical with clay content, and drifts toward higher anisotropy with increasing depth. This observation can be explained by the reorientation of clay particles with depth, generating a larger anisotropic response for the same clay volume as the clay platelets align under increasing stress. The anti-correlation between bedding density and mechanical anisotropy suggests the fine layering observed by the microimager is not generating a significant amount of mechanical anisotropy in comparison to the clay content. By applying Backus averaging to the mechanical properties we can confirm that fine layering of isotropic units is not sufficient to generate mechanical anisotropy on the order of observed values in shale core studies, suggesting the additional stress generated by mechanical anisotropy is driven primarily by clay content. This additional stress should be considered when planning lateral targets and completions.

Obtaining high resolution logs that can estimate stress and net-to-gross in finely laminated media is critically important for reservoir characterization and completions strategy, and should be considered best practice for finely layered media.

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Integrated subsurface evaluation of 'Doyin Field', shallow offshore Niger Delta, Nigeria

The Niger Delta basin is ranked among the world's prolific hydrocarbon provinces. The structures, stratigraphy and traps could be very subtle and complex and are therefore, difficult to map accurately. The degree of reliability and precision of the mapping can be greatly enhanced by integrating seismic data with well logs for hydrocarbon exploration and field development studies.

Seismic data and well logs were integrated to delineate the subsurface geometry, stratigraphic framework and hydrocarbon trapping potential of 'Doyin' field, offshsore Niger Delta, Nigeria. The objectives of this study is to utilize seismic data to image subsurface geology for hydrocarbon exploration and estimate the amount of hydrocarbon resources in place.

Seven reservoirs were correlated, mapped and analyzed for their varying petrophysical parameters using wireline logs. Seismic attribute analysis was used to enhance the quality of interpretation in all reservoirs mapped. Structure contour maps were generated in time and depth domain for the reservoirs and closures were delineated. This study also utilizes the various seismic attributes to investigate structural and stratigraphic elements within the study area to delineate lithology and hydrocarbon.

The trapping mechanism is mainly fault dependent and the accumulations are mainly on the hanging wall of an antithetic fault. Structural style is dominated by two parallel structure-building normal faults trending through the entire field. Hydrocarbon discovery in this field is estimated at 13.70 BCF for gas and 22.12 MMBO for oil.

AHERN, JUSTIN P., and CHRISTOPHER R. FIELDING, University of Nebraska, Lincoln, NE

Paleoenvironments of the Mississippian Heath Formation (Big Snowy Trough, central Montana) and their relevance to understanding late Paleozoic paleoenvironmental change and low-accommodation, unconventional petroleum systems

The late Mississippian Heath Formation is a paleotropical, cyclothemic succession that is an emerging tight oil play in the Big Snowy Trough of central Montana. More than 100 MMBO of oil produced from regional reservoirs are sourced from organic-rich Heath rocks. In 2013, oil production directly from Heath intervals confirmed it as a stand-alone petroleum system. The Heath

Formation is also notable for preserving a record of numerous sea-level fluctuations that may be related to Gondwanan glacial ice growth and decay cycles at the onset of the late Paleozoic Ice Age.

Despite recent exploration efforts, robust facies and sequence stratigraphic models, a well as a detailed paleoenvironmental analysis, are not yet available for the Heath Formation. This study focuses on the record of late Paleozoic paleoenvironmental change and paleo-water depth variability preserved in the Heath Formation in order to elucidate their influence on Heath petroleum system elements in the Big Snowy Trough. Wireline logs and cores from subsurface intersections are combined with outcrop data and 125 thin-sections to yield a robust depositional model for the Heath, in addition to an analysis of stacking patterns and stratigraphic changes in petroleum system elements within the succession.

Two recurrent stratigraphic motifs were observed in the Heath Formation, each composed of repetitive successions of facies. The motif in the lower Heath consists (from base to top) of: fossiliferous black laminated mudstone, fossiliferous calcareous siltstone with irregularly dispersed fine sandstone, wackestone, and packstone, calcareous siltstone with plant fragments, slickensides, pedogenic fabrics, and coal (overlain by the next black shale). The motif in the upper Heath consists of: fossiliferous dark grey laminated mudstone, fossiliferous, calcareous siltstone, sandstone, wackestone and packstone (as above), biolaminated micrite and dolomudstone, nodular to chicken-wire anhydrite, and a cap of fossiliferous black laminated mudstone.

Observed facies are consistent with a muddy, homoclinal carbonate ramp. Fossiliferous laminated black mudstones settled from suspension in offshore, basinal waters. Poorly fossiliferous, laminated and normally graded calcareous siltstones are outer ramp deposits, alternating fossiliferous siltstone, fine fossiliferous sandstone, wackestone, and packstone are mid ramp deposits. Biolaminated micrite and dolomudstone with variable proportions of anhydrite are inner ramp subtidal to peritidal deposits. Calcareous siltstones with plant fragments, slickensides, pedogenic fabrics, and coals are coastal plain and mire deposits.

Laterally persistent, repetitive vertical cycles of alternating marine and nonmarine facies (cyclothems) are interpreted as depositional sequences bounded by sequence boundaries that are represented by paleosols, and later by evaporites. Cycles record up to eight 3rd to 4th order sequences, with sea-level excursions up to 10s of meters that are likely a paleotropical, eustatic response to Gondwanan ice growth and decay cycles. Deposition of marine facies over coals and anhydrites in sequences as thin as ~2m suggests these units were formed in both a low accommodation and low sediment supply setting. The upward transition from paleosols and coals to limestone-anhydrite associations records a known paleotropical humid to arid climate shift, here identified as Serpukhovian in age, earlier than suggested by previous studies.

ANDERSEN, JENICA, BRIANNA BERG, CODY BOMBERGER, and MICHAEL H. HOFMANN, AIM GeoAnalytics, Missoula, MT

Dynamic integrated data analysis of a mature hydrocarbon basin -- A case study from the Bighorn Basin

When assessing mature hydrocarbon basins, objective evaluation of big data sets and large geographic areas can pose challenges. Namely, knowledge bias for an area can occlude a higher potential for production in another area.

This study presents results from an assessment of existing and undiscovered oil resources in the Bighorn Basin, using an original method to dynamically evaluate large data sets. The assessment is based on a range of geologic elements and historic production data for individual stratigraphic intervals and for the basin as a whole -- all available from public resources.

The Bighorn Basin contains 134 oil fields, seven of which fall within the state of Wyoming's top ten producing fields. Since its initial discovery in 1905, the Bighorn Basin has produced more than 2.67 billion barrels of oil, and in 2011 Bighorn Basin production accounted for 22 percent of Wyoming's oil production that year. The maturity of this basin, the complexity of the petroleum systems, and the vast amount of publicly available data make this basin an ideal case study for dynamic integrated data analysis (DIDA).

This dynamic evaluation tool allows for on-the-fly parameter adjustment and a virtual comparison of probability for success. Parameter significance can be based on many factors, including data density and quality -- which are key considerations in mature basins where data comes from a range of sources and vintages. For example, in the Bighorn Basin, basin-wide porosity data is limited. Although porosity has the potential to significantly influence reservoir quality, the sparsity of the data set demands a more careful handling of this parameter in a basin-wide evaluation process. Being able to dynamically adjust the importance of different geologic parameters in a spatial framework allows one to evaluate and visualize the effect these parameters have, and improves probability mapping.

Results from Bighorn Basin data evaluation show that the dynamic integration of large data sets is a successful screening tool for seeking areas of high potential, with the ability to visualize and select relative parameter importance. The findings and methods presented in this study provide a fast and objective evaluation of mature and data-rich hydrocarbon basins across North America and around the world, and can be implemented by individuals or companies during an early phase of basin evaluation

ANDERSON, DONNA S., Colorado School of Mines, Golden, CO, and MARK W. LONGMAN, QEP Resources, Denver, CO

Re-visiting the Bighorn Dolomite (Ordovician) and Darby (Devonian) subcrop geometry across southwestern Wyoming: New light from an old well

The eastward pinchout of the Upper Ordovician Bighorn Dolomite and Upper Devonian Darby Formation is well known from outcrops in mountain ranges surrounding the Greater Green River Basin (GGRB). Less studied, especially in the last 40 years, is the subsurface distribution of these two units. In addition, published isopach maps of the two formations mostly rely on pre-1972 data when well control was much less than today.

A new interpretation of the subsurface pinchout geometry of the Bighorn Dolomite and overlying Darby Formation comes from a well drilled on the crest of the Rock Springs Uplift in 1962. The Mountain Fuel Supply UPRR-11-19-104-4 well is one of only four wells that penetrate all or part of the Devonian-Ordovician succession in the subsurface of the GGRB between the Moxa Arch and the Rawlins Uplift. It was also almost completely cored from above the Mississippian Madison Limestone to PreCambrian basement, and the core is archived at the USGS CRC in Lakewood, CO. From a reinterpretation of the stratigraphy in the core, 25 feet of Bighorn Dolomite is recognized based on the characteristic Thalassinoides-bioturbation fabric in crinoidal-peloidal dolo-wackestone typical of Late Ordovician subtidal carbonate facies ranging from Nevada to Greenland. The Bighorn-like lithology is in complete contrast to the alternating dolomitic flat-pebble conglomerate and mudstone of the underlying Cambrian Gallatin Limestone and the brecciated anhydritic, sandy dolo-mudstone to coated-grain grainstone and quartz sandstone of the overlying Darby Fm. This re-interpretation impacts the isopach maps of the two units across the southwestern GGRB. The Darby Fm. isopach and pinchout geometry is slightly modified from past interpretations. The Bighorn Dolomite extent is substantially modified. It is more widespread than previously thought, and the eastward pinchout geometry is more consistent with that exposed in outcrop along the southeastern flank of the Wind River Range.

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Sequence stratigraphy of the Inyan Kara Formation, North Dakota

The Inyan Kara Formation of North Dakota is the lowermost unit of the Lower Cretaceous Dakota Group. The formation is the primary subsurface injection zone for produced water where over a million barrels/day is injected. This work examines the subsurface stratigraphy of the Inyan Kara within North Dakota to identify potential areas for produced water injection. A partial core from the Amerada Petroleum Corporation, Math Iverson #1 (NDIC: #165, API: 33-105-00097-00-00) in Williams County was used along with wireline logs from thousands of wells to map the Inyan Kara in the subsurface and develop a working sequence stratigraphic model. Five detailed 1:100,000 scale Inyan Kara sandstone isopach maps (Crosby, Parshall, Stanley, Watford City, and Williston) from the heart of the Bakken in northwestern North Dakota have been published to date, with three more (Grassy Butte, Kenmare, Killdeer) planned for 2017.

Numerous sedimentary structures and sequence stratigraphic surfaces are observed in both core and on logs. Gamma-ray signatures from well logs are characterized by a distinct, blocky pattern for coarser-grained sandstone deposits, commonly over 100 feet thick. These sandstones then grade upwards into finer-grained units of interbedded sand, silt, and clay. Based on these observations, the Inyan Kara can be subdivided into two units that reflect the overall sea-level rise of the Early Cretaceous. The lower half is interpreted to be a "fluvial-dominated, incised valley-fill complex that can be sub-divided into the following systems tracts: 1) initial incising of the lowermost valley during falling stage; 2) filling of the valley during low-stand and early transgression; 3) initial incursion of the seaway with subsequent flooding and development of estuarine deposits during transgression; and 4) progradational marine deposits of the highstand. This same depositional sequence is repeated in the upper Inyan Kara and into the overlying lower shales of the Skull Creek Formation, with the lower sequence capped by a subaerial unconformity.

The model shows coastline evolution through time and correlation of sequence stratigraphic surfaces basinward/landward from northwestern North Dakota. It can be used to predict the presence and extent of incised-valley-fill sandstone bodies for produced water disposal, as well as distinguishing such bodies from other coarser-grained units that have lesser potential for injection. Results indicate that sandstones of the valley fills are well connected along valley trends (10's of km) and within valleys (km); whereas, coarser deposits of the estuarine, marginal marine, and interfluve facies are not as laterally continuous or well connected.

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Uniformitarianism and the Laramide Orogeny of the Wyoming Craton: The present is the key to the past, and the past…

Seismic studies (COCORP, Deep Probe, and EarthScope BASE) have provided a better understanding of Laramide tectonism at deeper crustal levels. However, deformational mechanisms in the upper crust related to Laramide orogenisis remain unclear. Internal controls of Laramide tectonism in the upper crust have been proposed to be related to basement anisotropies, which may be linked to evolution of foreland arches at deeper crustal levels and structures seen at the surface.

This study presents a structural and tectonic analysis of Precambrian anisotropies of the Wyoming craton and provides a hypothesis on the potential role of these features in Laramide orogenisis. Anisotropies are generally oriented in three directions: north-northwest, west-northwest, and northeast. They have a complex and long history of deformation since the Precambrian, most recently, during the Laramide. This work provides evidence for development of long-lived Neoarchean zones of convergence dominantly directed from the southwest towards the craton forming north-northwest weakness zones, as shown from modern analogs. In addition, northeast-southwest-directed pure-shear compressional forces from convergence are postulated to have formed west-northwest- and northeast-trending anisotropies in the form of conjugate shears, again supported by modern convergence zone deformations. It is proposed that these structures were reactivated throughout Laramide contraction, forming discrete zones of transpression that were displaced along a southwest- to northeast-directed Laramide deformational front.

In the Wyoming transpressive zone, west-northwest structures were displaced as reverse/left-lateral oblique-slip faults and, where connected, acted as lateral ramps facilitating major arch development along the north-northwest-trending structures. In the Montana transpressive zone, where north-northwest basement anisotropies are not present, reverse-sinistral slip occurred along west-northwest basement-seated faults without the associated vertical slip seen in Wyoming.

Basement-seated faults are expressed at the surface as oblique, left-slip reverse faults (west-northwest deformational zones in Wyoming/Montana), high-angle right-slip faults (northeast deformational zones in Wyoming/Montana), and low-angle reverse faults/thrust faults (north-northwest arches generally only in Wyoming) that are interconnected in a convergent deformation system that likely includes the Black Hills. This deformation system is postulated to be a fundamental tectonic feature controlling formation of Laramide arches/uplifts of the Wyoming craton.

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Vaca Muerta: an Argentine resource play

East-West trending prograding sediments of Upper Jurassic age in the Neuquén Basin, Argentina, provide one of the largest productive self-sourcing reservoirs for oil and gas resources in South America. The Vaca Muerta Formation is the target reservoir in the basin with multiple companies actively drilling wells. Just as the participating companies continue to study the basin, our efforts will focus on utilizing well logs and 3-D seismic to evaluate a portion of the basin to better understand the depositional systems to optimize reservoir development, improve understanding of the petroleum system including migration pathways, seals, and source rocks. Mapping stratigraphic units in the basin is difficult due to the complexity of the steeply dipping progrades. By coupling wireline well logs and seismic data, we are able to more accurately identify and evaluate the depositional package that constitutes the Vaca Muerta Formation.

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Bakken, thinking about scalability of certain features in the Williston Basin

Companies choosing to ramp up drilling projects require a sophisticated understanding of noise or bandwidth in the performance of those assets. In the Williston Basin Bakken, our work found a tie to two features. One large in scale, paleo-topography. The second smaller in scale from identifying fracture distributions in a horizontal core.

This intracratonic basin, sourced by world class organic shale, is believed to have generated 300 billion barrels of oil within the thermal maturity boundary. It is projected to be a 7.4-billion-barrel resource underlying 14 million acres in the continental United States and 8.5 million acres below the Brockton-Froid sheer system. In the late 1980’s Billings Nose was the original ‘horizontal Bakken play’ in the basin. Operators commonly placed 4000 ft laterals in the shale interval as the Middle Bakken was thin (0-10 ft). These wells were completed using single stage gelled oil fracture treatments. IP’s were 200-400 BOPD with the ‘successful wells’ projected to make 200 to 250 MBOE.

Every horizontal play in North America has dealt with understanding well performance ties to completion schemes and targeting investigations. The Bakken is no exception. Notwithstanding a rich history in evolving completion designs that are anything but static the beginning prejudice in investigating the Bakken is that hydrocarbons are occupying both matrix and fracture porosity. The broken rock portion of the resource is dominating early and mid-term deliverability and therefore the economics of such. This idea is validated by the linear scale-up of lateral lengths to well performance and upgraded completion schemes that address longitudinal constraints. Post 2009 investigations of production in the Williston will quickly gravitate to the East Nesson sub-basin and the Parshall Field area. The efforts of EOG Resources and their geological team in Parshall is well documented. Their straight forward investigation of open-hole logs in that area supported the tests based upon comparison to logs in the more mature Elm Coulee Field in the West Nesson sub-basin.

We looked at interval isopaching of the Three Forks as representing paleo-topography with the idea that a paleo-low fostered optimal accumulation of organics in an oxygen deprived area. That work revealed that the Parshall Field, one of the largest fields in North America, was fully within that outline. In fact, emerging results within that paleo-low support such a linkage and expansion into areas previously underdeveloped.

Heat maps produced from 6-month cumulative oil numbers in the basin also coincided with the Parshall Field and this paleo-low. We determined that it requires around 6 months of production data before you can begin to define a well's usable performance. There are a lot of moving parts in the early flow period in vertical wells, let alone horizontal wells in unconventional reservoirs. Long term production from a Black Oil Model scaled up from core petrophysical data on Elm Coulee Field predicted higher IP’s than that seen in aggregate historical data. However, actual cumulative production syncs with that model at around 6 months with a strong tie to long term performance.

Finally, we examined eighty feet of horizontal core from a well in the Parshall Field measuring the 'small scale' fracture population and creating a histogram of spacing of those fractures. We found that histogram synced quite well with the spacing distribution of large scale production lineaments (contouring 6-month cumulative oil production within the field) and thus validating the use of that core in predicting spatial or geographic variability in the subsequent well results.

In conclusion, we found that a depositional low allowed for preservation of a large scale sweet spot wherein a quiet mini sub basin was subsequently fractured through tectonic events resulting in enhanced production. The subsequent development of the dominant field in that area was not uniform and, in fact, followed a distribution profile consistent with a limited small scale observation.

BERG, BRIANNA, CODY BOMBERGER, JENICA ANDERSEN, and MICHAEL H. HOFMANN, AIM GeoAnalytics, Missoula, MT

The use of unconventional spatial statistics as a predictive tool in conventional petroleum exploration: A case study from the Bighorn Basin, Wyoming

Exploring mature basins for overlooked or new opportunities can be a cumbersome and time consuming process that may be an impossible task for small companies and independents with limited resources and budgets. The use of spatial statistics to analyze basin-scale datasets may provide a solution to this problem. Spatial statistics is widely used in populating advanced reservoir models, but has rarely been applied when analyzing historic data in mature basins. This study aims to test the use of a variety of spatial statistics, including spatial Fourier analysis, Lomb-Scargle periodograms, and fault proximity analysis, to quickly and objectively analyze basin-scale datasets. The Bighorn Basin, located in north-central Wyoming and south-central Montana, is used as a case study for this project. The Bighorn Basin is a proven mature basin with a long production history, making it an ideal test case for these analyses. Since its initial discovery in 1905, the cumulative production in the Bighorn Basin has reached more than 2.67 billion barrels of oil with estimated conventional reserves of 61 million barrels of oil. The basin's long history as an oil province has resulted in a considerable quantity of publicly available data for the basin that could be analyzed with these innovative spatial statistical approaches. The basin-wide spatial data analysis revealed, for example, that known large petroleum accumulations in the Bighorn Basin are not randomly distributed, but follow statistically significant patterns that are not easily discerned from maps or by using other common exploratory tools. The spatial data analysis also allowed for the distinction of interesting spatial relationships between fault geometry and a characteristic spacing of high production along major structural trends. These patterns, while non-unique, become apparent with the methods in this study and aid in understanding historical production data and geologic controls. They provide an additional set of information when predicting opportunities in areas with little to no production or when identifying undiscovered or underdeveloped fields. The approaches taken in this study are repeatable statistical methods that can be applied to a variety of datasets and basins.

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Methodology for multi-scale shale lithofacies modeling: Case study from the Bakken Formation in North Dakota

Integrated shale lithofacies models are important to analyze multi-scale variation of geologic and petrophysical parameters of shale formations to interpret depositional and diagenetic environments, and manage the petroleum system. This study presents the results from the upper and lower shale members in the Bakken Formation of the Williston Basin in North Dakota. The major objectives of this study are to better understand geologic controls on mineralogy and organic matter content, and provide a quantitative framework for shale lithofacies characterization at core, well, and regional scales. Shale lithofacies is defined using a quantitative workflow based on mineralogy, Total Organic Carbon, and various petrophysical parameters derived from core (XRD, XRF, pyrolysis, and secondary X-ray emission spectroscopy) and advanced geochemical spectroscopy logs from 37 wells. Next, machine learning algorithms are used to recognize the pattern of different shale lithofacies and corresponding petrophysical parameters from ubiquitous conventional well logs from ~500 wells. After core and well log-based classification of shale lithofacies, geostatistical algorithm, such as Sequential Indicator Simulation, is used to generate 3D stochastic shale lithofacies models at regional scale (~13,000 sq. miles). The results show that upper and lower Bakken shale members are vertically and laterally heterogeneous at core, well, and regional scales, but can be classified into five different lithofacies. Organic-rich shale lithofacies outweigh the proportion of organic-lean gray shale lithofacies. Several factors, such as source of elements, paleo-redox conditions, and organic matter productivity appear to have controlled the depositional pattern of shale lithofacies. Silica in the Organic Siliceous Shale lithofacies is derived from both biogenic and eolian actions. Organic-rich shale lithofacies show positive correlation with hydrocarbon production.

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Detailed examination of transitional zones in Eocene Lake Uinta, Piceance Basin, using hyperspectral core scanning

Several major transitions in Eocene Lake Uinta are recorded in the oil shale deposits of the Eocene Green River Formation in the Piceance Basin of western Colorado. The Cow Ridge Member was deposited during freshwater conditions in the paleolake and transitioned into a more brackish phase that deposited the Garden Gulch Member. This sequence was followed by deposition of the saline to hypersaline Parachute Creek Member, which includes substantial deposits of nahcolite and halite as well as the regionally extensive, highly laminated organic-rich oil shales of the Mahogany zone. These distinctive zones can be readily identified from changes in organic richness and mineralogy. However, the transitional zones between these sections have not been examined in detail to assess how particular trends in paleolake chemistry affected subsequent mineralogical compositions occurring during the different stages of Lake Uinta. In this study, transitional zones between the different members of the Green River Formation and within the Parachute Creek Member were examined in two cores from the Piceance Basin center and margins. An imaging system integrating hyperspectral imagers (450- 2500 nm), an RGB camera, and a 3D laser profiler was used to characterize the mineralogy and geochemistry of core material from within these transition zones. Along the basin margins and in the basin center, spectral interpretation of the reflectance data indicates major differences in the mineralogy related to the depositional environment in different areas of the paleolake. Several authigenic indicator minerals were detected using hyperspectral analysis, including dawsonite, analcime, and buddingtonite. The presence or absence of these minerals in the basin center or margins provides information on water chemistry, particularly pH, Al mobility, and Na and Si activity. The results show similar trends to those observed in previous bulk mineralogy surveys using methods such as X-ray diffraction and elemental analysis. The Cow Ridge Member is clay-rich, transitioning to a more organic-rich section that includes some carbonate in the illitic Garden Gulch Member. The transition from the Garden Gulch Member to the dolomitic-feldspathic Parachute Creek Member marks the appearance of common dawsonite in the basin center and authigenic analcime in the basin margins. The middle part of the Parachute Creek shows the end of dawsonite as a common mineral in the basin center and the regular appearance of buddingtonite throughout the basin. In the upper part of the Parachute Creek, buddingtonite essentially disappears at the B-groove marker, which contains illite, calcite, and Mg-carbonate, while the dominant Na-Al silicate phase in the Mahogany zone is analcime. Organic matter was also readily detected in the cores due to the high concentration of aliphatic moieties in Green River oil shales, demonstrating the utility of hyperspectral imaging for examining organic richness in petroleum systems.

BIRDWELL, JUSTIN E., RONALD C. JOHNSON, and PAUL G. LILLIS, U.S. Geological Survey, Denver, CO

Paleogene lake-margin coals in early freshwater lacustrine sections of lakes in the Green River, Uinta, and Piceance Basins, Wyoming, Utah, and Colorado

Low-rank coals were deposited in lake-margin settings during the Paleogene in the Washakie, Uinta, and Piceance Basins during the early freshwater lake stages in the Green River Formation. The thickest, most extensive coals were deposited in broad marginal mires that developed during restricted phases of the lakes. Marginal lacustrine coal beds in the Uinta Basin were buried deeply enough to have generated hydrocarbons and are thought to have sourced some of the oil in that basin. Previous work has shown that immature samples of these Uinta coals can be relatively hydrogen-rich (hydrogen indices > 300 mg/g), contain bitumen with a high pristine/phytane ratio (> 3), and consist primarily of vitrinite macerals. Similar marginal lacustrine coal beds in the Piceance Basin may be the source of minor waxy oil deposits found there. It is possible that there may also be coal-generated oil in the Washakie Basin. These coals have been shown to be highly oil-prone as determined by the Fischer assay method, with liquid oil yields as high as 79 and 40 gallons per ton (GPT) in the Uinta and Washakie Basins, respectively. The Washakie coals are high in sulfur (up to ~9 wt. %), which is significantly higher than sulfur contents for coals from the other basins (~1 wt. % or less). Total organic carbon (TOC) content and programmed pyrolysis analyses of Washakie coals from core show that the hydrogen indices (HI, 150-360 mg/g) for many samples meet geochemical criteria for possible oil generation (HI > 200 mg/g). An example of relative source rock quality is highlighted in a 402 ft thick section of marginal (near zero oil yield) lacustrine rock within the Washakie 01A core. The section contains only 27.7 ft of scattered coal beds with an average Fischer assay oil yield of 23.1 GPT, but has the same potential as 122 ft of offshore lacustrine oil shale that continuously averages 5.25 GPT. These results reinforce previous reports of oil potential from Paleogene coals found in these and other lacustrine basins within the Rocky Mountain region and may warrant further investigation.

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Trace element chemistry in Green River Formation oils shales from the Piceance and Uinta Basins: Implications for interpretation of redox conditions in lacustrine systems

The Eocene Green River Formation represents one of the largest accumulations of sedimentary organic matter in the world. The most recent U.S. Geological Survey assessment of oil shale resources in the Piceance and Uinta Basins indicates that rocks with yields of at least 15 gallons per ton represent over one trillion barrels of oil in place in Colorado and Utah. During deposition in Eocene Lake Uinta, low oxygen conditions in the bottom waters of the stratified lake have been proposed as a key factor in preserving the massive accumulation of organic material. In marine environments, bottom-water anoxia generally leads to accumulation of redox-sensitive trace metals, like molybdenum (Mo), vanadium (V), and nickel (Ni). Trace metal ratios calculated based on the concentrations of these metals and other elements in marine black shales have been correlated to particular depositional conditions, including ranges of dissolved oxygen concentrations and the presence of dissolved hydrogen sulfide. Examination of trace element concentrations in Green River oil shales reveals that parameters based on redox-sensitive metals do not consistently indicate anoxic conditions for core samples from the Piceance and Uinta Basins. Despite the high concentrations of hydrogen-rich, Type I kerogen present in much of the Green River oil shale, the ratios of Ni/Co and V/Cr indicate oxic and oxic-to-dysoxic conditions, respectively. The concentration of Mo is generally expected to correlate with organic carbon content, but in the Green River cores the relationship between Mo and total organic carbon content is much weaker than what is typically observed in marine shale deposits. One commonly reported parameter, V/(V+Ni), places the Green River oil shales in an anoxic depositional environment and also indicates euxinic conditions in some samples, which is consistent with expectations. The closed-nature of Lake Uinta along with the high alkalinity and pH, may explain the failure of various trace element ratios to indicate anoxia. These results show that trace element parameters used to interpret depositional conditions in marine systems may not necessarily be applicable to understanding the sedimentological origins of lacustrine mudrocks. Therefore, the application of these ratios to interpret lacustrine source rock data collected in chemostratigraphic surveys should be done cautiously.

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Imaging techniques in seismic geomorphology

Pattern recognition has long been a key to our understanding of geologic landforms and depositional regimes. Channels, dunes, reefs, debris flows, and karst regions all exhibit various geomorphic patterns that provide insight into their origins. In fact, much of the success or failure associated with a geologic investigation depends on our ability to identify and classify various depositional and/or erosional patterns.

For the geophysicist interested in reconstructing ancient landforms hidden within his or her 3D seismic amplitude data, there are many challenges that need to be addressed in order to accurately image the associated patterns. To begin with, the frequency content of traditional seismic data may not be appropriate for resolving certain geologic features. Subtle lithologic changes are not always apparent to the interpreter using traditional seismic data. And variably dipping seismic reflectors can often obscure the original depositional patterns required for in-depth analysis.

The purpose of this discussion is to highlight and discuss various imaging techniques in seismic geomorphology. Many different seismic attributes and spectral decomposition techniques are often able to enhance and bring out subtle features and/or lithologic changes that are still hidden within a traditional seismic amplitude display. Flattening and various slicing techniques can be used to help unravel complexities related to non-uniform horizons. Volume co-rendering of differing attributes can provide additional insights as compared to a single attribute. And finally, voxel body picking allows the interpreter to focus in on a specific range of attribute values which are useful in defining geobodies.

BOMBERGER, CODY W., BRIANNA BERG, JENICA ANDERSEN, and MICHAEL H. HOFMANN, AIM GeoAnalytics, Missoula, MT

Characterizing spatial deformation patterns in a Laramide Rocky Mountain basin

This study seeks to identify spatial patterns in structural deformation that are important to hydrocarbon exploration. Using techniques from Fourier analysis, expanded into two dimensions, we identify characteristic scales of structural deformation and map the locations of the most prominent patterns spatially. Previous applications of these methods include identifying the characteristic length scales of hillslopes with a high potential for landslides and mapping, along with determining patterns in topography and strain rates associated with active tectonics in the western United States to identify the characteristic scales of deformation and map their spatial variations.

In this study we use the mapped surface of the Cloverly formation as a proxy for the subsurface structures across the entire Bighorn Basin and is the input dataset for the analysis. Using the techniques from Fourier analysis, a power spectrum of the mapped Cloverly formation is created which shows amplitude (prominence of features) as a function of the spatial scales of structures. In the power spectrum two ranges of spatial scales are identified as prominent. Through creating a power summation map of these dominant frequencies, we show where the two prominent scales are most important in the basin. The spatial analysis of the power spectra allows for interpretations about which structures and deformation processes are most important in creating the patterns. Additionally, and most importantly for hydrocarbon exploration, the comparisons of structural pattern prominence to production data, produces predictive maps of potentially undeveloped areas that aid additional geologic analysis. This new and original re-tooling of established methods from signal processing is designed to complement the exploration for hydrocarbon resources in structurally complex basins away from current production, as well as help identifying underdeveloped areas in producing fields. These methods have the potential for future applications to a range of hydrocarbon basins across the Rocky Mountains and beyond.

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Recommended revisions to mid-Carboniferous stratigraphy of the Big Snowy Trough, Central Montana, USA

The Heath and Tyler Formations of central Montana have been the subject of much study and debate since the Tyler Formation was named in 1922 by Freeman and the Heath was named as the uppermost formation in the Big Snowy Group by Scott in 1935. Numerous workers in the 1950s and 1960s debated whether strata assigned to the Tyler are a mappable unit, the existence of an unconformity between beds assigned to the Tyler and the Heath, and the age of the Tyler.

Paleontological studies of the Bear Gulch Limestone began in 1968 and clearly document that it is latest Mississippian in age, and therefore the underlying units, including the Lower Tyler (or Stonehouse Canyon Member of the Tyler), must also be late Mississippian in age. Studies that have focused on outcrops in the Big Snowy uplift typically regard strata known to most workers as Lower Tyler and Bear Gulch Limestone as the uppermost beds of the Heath Formation. However, regional stratigraphic correlations document a sequence boundary with more than 400 feet of relief between clastic-rich sedimentary strata of the Lower Tyler and marine strata of the Heath. The Lower Tyler is largely confined to incised valleys cut into the underlying Heath, so this erosional relief and much of the Lower Tyler are only locally present. This study proposes modifications to existing stratigraphic correlation charts for the Carboniferous in central Montana. The base of the Heath Formation/top of the Otter Formation should be re-defined as the top of a laterally persistent oolitic limestone bed that is regionally correlative in the subsurface and is mappable at the surface (Scott, 1935). The current definition of the top of the Otter as the "first green shale" is neither consistent nor mappable. The top of the Heath Formation and the top of the Big Snowy Group should be defined as the sequence boundary above which fine to coarse-grained sandstones are present. The clastic-bearing unit above the Heath, largely present in incised valleys, and the Bear Gulch Limestone are late Mississippian in age and should be included in the Tyler Formation. Further paleontological studies should be undertaken to better define the ages of strata between the lower Heath and the Bear Gulch Limestone. The overlying Cameron Creek Member (upper Tyler) is separated from the Bear Gulch by at least one sequence boundary. These strata are Morrowan (Pennsylvanian) in age and are most closely affiliated with the overlying Alaska Bench. Paleontological data from the dark gray shales and sandstones within the Upper Tyler incised valley fills is lacking, and these could be either latest Mississippian or early Pennsylvanian. If these strata are included in the Tyler Formation, the Mississippian-Pennsylvanian Boundary is within the Tyler. Additional studies are needed to determine the true stratigraphic affiliations of the "Becket Beds" and the "Surenough Beds". New core data help subdivide internal strata within the Heath Formation. Past attempts at internal subdivision of the Heath have suffered from poor outcrops and limited core (lithological) control. Core to log calibrations and ensuing regional correlations allow informal definition, in ascending order, of the lower Heath, Van Dusen zone, Cox Ranch Oil Shale Interval (expanded from the original definition), Heath Carbonate unit (which has the Loco Ridge Gypsum bed at the top), a lowstand basin fill shale, carbonate, and gypsum unit, and the upper Heath.

BREHM, JEFFREY A., Alta Resources LLC, Houston, TX

Horizontal drilling in the Tyler Formation of the southern Williston Basin – First attempts at a new resource play?

The Tyler formation is one of several source-rich formations and one of the youngest oil producing formations in the Williston Basin. It has been suggested that "as well as conventional oil production … the Tyler Formation may be capable of forming a basin centered oil accumulation similar in style to the Bakken Formation" (Nordeng & Nesheim). It is also one of only two formations in the basin that exhibits significant geopressuring. In the southern extremity of the Williston Basin, the upper part of the Tyler has a single source-rich interval with 2-6% TOC. This region also has an anomalous geothermal gradient at a relatively shallow depth. Oil expulsion from the Tyler filled various sandstone reservoirs to the north which, to date, have produced about 90 million barrels of oil. Elsewhere, where permeabilities in adjacent rocks are very low, expulsion of oil from source beds has created an unconventional petroleum accumulation, unable to migrate away from the proximal source beds, within the Tyler and lower Amsden formations. Geopressuring, maturation-induced fracturing and significant oil recovery were recently confirmed by horizontal drilling in the Upper Tyler.

Marathon Oil Corporation tested the idea in two long fracture-stimulated horizontal wells in the Upper Tyler in Slope County, North Dakota in 2013 – 2014. Tyler core samples taken in a pilot hole confirmed the presence of TOC in the range seen elsewhere. Measured porosities were somewhat lower than initial electric log estimates, though they were about in the same range as the Bakken (2-10%). Permeabilities measured were somewhat better than those typically measured in the Bakken. Live oil was also observed both in core and while drilling. All of these are the basic ingredients which can make a potential large-scale resource play. As in the early completions in the Bakken, the first Slope County tests amounted to a discovery, which were also an economic failure. Total oil recovered from both wells was less than 5000 barrels, with final rates of 5-7 BOPD before production ceased in 2015. However, in the post-mortem analysis, the poor reservoir performance can be attributed to unsuitable completion methods – application of Bakken-style fresh water hydraulic fracturing in a reservoir to a reservoir with a lithologic make up unfavorable to this methodology. It remains to be seen whether further lithological analysis and improvements in completion technology can yield a recipe that will result in a new sustainable economic Tyler play for the southern Williston Basin.

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The Ohio Creek Conglomerate in the Piceance Basin near Rifle, Colorado: Results of an integrated surface-subsurface and laboratory undergraduate research project

The Paleocene Ohio Creek Conglomerate in the area of Rifle Gap, Colorado, is a conglomeratic sandstone that was deposited in the Piceance Basin and subsequently deformed during the Laramide Orogeny. The age and tectonic significance of the Ohio Creek Conglomerate have long been debated. This report is based upon nine independent undergraduate research projects that examined the physical stratigraphy, subsurface distribution, provenance, diagenetic and subsidence history of the formation, from field exposures on Grand Hogback and using well log data from the Rifle area and the Piceance basin regionally. Burial history modeling shows that the Ohio Creek Conglomerate was deposited during a period of markedly slow subsidence, compared to the underlying Williams Fork Formation. Provenance reflects a lithic recycled orogenic source and points to an unidentified volcanic arc component. The characteristic white clay matrix of the unit was identified by X-ray Diffraction studies as kaolinite, dickite, and nacrite. Thin-section petrography shows that these clays formed by in-situ weathering and diagenesis of a detrital arkosic component. The subsurface distribution of the unit reflects thickening along a southwest-northeast basin axis, which is consistent with slightly higher subsidence rates shown by subsidence modeling. Our studies show that in the Rifle Gap area, the Ohio Creek Conglomerate is a thin, coarse clastic unit derived from a relatively distant source area, which was deposited during a period of subdued subsidence.

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The Elko Basin: An unconventional basin in the hinterland of the Sevier Orogenic Belt

In the Sevier hinterland, from eastern Nevada to western Utah, Eocene terrestrial strata record the crustal and mantle dynamics of a high-elevation landscape prior to its collapse during Basin and Range-style extension. New decimeter-scale stratigraphy of the Elko Formation coupled with single-crystal sanidine 40Ar/39Ar geochronology and isotopic analysis of hydrated volcanic glass (δDglass), both extracted from tuffs deposited within the Elko Basin of northeastern Nevada, show a long-lived lacustrine system in this area hosted a wide variety of depositional environments while it formed atop a Paleogene orogenic plateau with elevations of ~2.5-3 km. Assessments of carbonaceous shales within the Elko Formation indicate the formation contains good to excellent source rocks with the potential to generate large amounts of oil and gas (TOC ~1.5-3.5). Oil and gas production, however, is hindered by difficulties in estimating the spatial extent, volume, and depositional timing of hydrocarbon source rocks in the Elko Formation. Here we use a multidisciplinary study of Eocene fluvial and lacustrine strata in northeastern Nevada to reconstruct the stratigraphic architecture of the Elko Basin through time and improve the predictive potential of this region.

Lacustrine lithofacies across the Elko Basin show two general lake-type progressions from overfilled to balanced-fill conditions between 49 and 41 Ma and are capped by proximal volcanic detritus from the ~40-39 Ma Tuscarora volcanic field. Preliminary XRD, δ13C, and δ18O analysis of the Elko Formation reveals shifts in carbonate geochemistry and mineralogy are correlative with increased Fischer assay oil yield as well as lake-type boundaries. Lake-type facies shifts are further highlighted by implementation of δDglass values for tuffs intercalated with lacustrine intervals, which show a strong correlation between geochemical measurements of lake water chemistry and independent lithostratigraphic estimates. Fluctuating profundal lithofacies that are indicative of saline waters have enriched δDglass values (-65 to -120‰), whereas fluvial lithofacies have distilled δDglass values (-150 to -180‰) that are consistent with regional paleoprecipitation waters. Chronostratigraphic correlations show an up-section increase in δDglass values and synoptic basin-wide lake-type changes suggesting middle Eocene lakes were regionally extensive and not confined to incised paleovalleys or isolated grabens.

U-Pb-He double dating of detrital zircon and apatite from multiple stratigraphic levels within the Elko Formation shows the preponderance of Mesozoic-Precambrian cooling ages that signify minimal-no surface-breaching extension occurred during basin formation. These detrital minerals can also record burial reheating, providing further constraints on regional maturation trends prior to exhumation along Miocene normal faults. Double dating shows outcrop exposures of Eocene strata did not exceed the zircon closure temperature (~180°C), but locally surpassed the apatite closure temperature (~70°C) within parts of the Lamoille and Huntington valleys. In addition, isopach contouring shows these portions of the Elko Basin contain >75 m of finely-laminated kerogen-rich mudstones and marls that are correlative with high oil yield in fluctuating profundal zones across the basin. Further refinement of this basin evolution will greatly improve models of intermontane basin formation throughout the Rocky Mountain region.

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The role of grain size in unconventional reservoirs

Grain size affects fracture susceptibility, permeability, hydrocarbon saturation, and hydrocarbon recovery in clastic and carbonate sediments that are both water wet and overpressured. Grain size is critical to both natural and induced fracture susceptibility. Resistance to fracturing increases with decreasing grain size. Examples from the Williston Basin illustrate the effect of grain size on fracture stimulation. Grain size is also directly related to permeability. Permeability decreases by a factor of four as grain size decreases. Decreasing grain size limits hydrocarbon saturation. Smaller grain size typically has smaller pores and smaller pore throats that decrease the storage volume and migration of hydrocarbons into the sediment. Therefore, hydrocarbon recovery efficiency is also directly related to grain size. Decreasing grain size results in lower hydrocarbon recovery.

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Major oil plays in Utah - An overview

One of the benefits of Utah's diverse geology is a wealth of petroleum resources. Utah oil fields have produced over 1.6 billion bbls of oil and hold 510 million bbls of proved reserves at current prices, indicating significant oil remains to be produced. Three main oil-producing provinces exist in Utah--the thrust belt, Uinta Basin, and Paradox Basin, in the northern, eastern, and southeastern parts of the state, respectively. Oil is produced from eight major "plays" within these provinces, where we define a play as a geographic area with known oil accumulations or potential, sharing similar favorable combinations of source rocks, migration paths, reservoir characteristics, trapping mechanisms, and hydrocarbon types. Utah is also unique because there are outcrop analogs for most of the producing oil reservoirs in the state.

The most prolific oil plays in the thrust belt produce from the eolian Triassic-Jurassic Nugget Sandstone and marine Jurassic Twin Creek Limestone. Traps are discrete subsidiary closures along large ramp anticlines formed during the Sevier orogeny. These heterogeneous reservoirs are also extensively fractured. Hydrocarbons were generated from sub-thrust Cretaceous source rocks.

The Laramide-age (Late Cretaceous-Oligocene) Uinta Basin represents Utah's greatest petroleum province and has the best potential for adding new reserves, especially with the advancement of horizontal drilling techniques. Oil is mostly produced from stratigraphic traps in fluvial-deltaic sandstones and lacustrine carbonate reservoirs in the Paleocene and Eocene Green River and Colton/Wasatch Formations, which were deposited in and around ancestral Lake Uinta. The source rock for the Uinta Basin plays is kerogen-rich shale of the Green River Formation.

The Paradox Basin includes Utah's largest oil field, Greater Aneth, and numerous smaller fields that produce oil from the Pennsylvanian Paradox Formation. The cyclic Paradox Formation was deposited on a shallow-water carbonate shelf (often restricted) that locally contained carbonate buildups, commonly phylloid-algal mounds and ooid banks. Trap types are typically stratigraphic, some having structural or diagenetic influences. The Paradox Formation has heterogeneous reservoir properties due to lithofacies of varying porosity and permeability, and a variety of positive and negative diagenetic effects. The fractured organic-rich Cane Creek shale in the Paradox Formation has the potential to add significant reserves using horizontal drilling. The Cane Creek and other organic-rich shales in the Paradox are the source for the hydrocarbons in the formation.

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Geologic interpretation of Turner Sandstone integrating core data, Powder River Basin, southwest Campbell County, Wyoming

The Upper Cretaceous Turner Sandstone Member of the Carlile Shale and stratigraphically equivalent Wall Creek Member of the Frontier Formation are currently attractive targets for horizontal drilling and multi-stage fracture stimulation completions in the deeper portions of the Powder River Basin. Large undeveloped prospective areas with few Wall Creek or upper Turner penetrations remain within the confines of the horizontal play. These hydrocarbon reservoirs in the area of interest are interpreted in the literature as storm-generated shelf sand ridges that were deposited below fair-weather wave base. They produce hydrocarbons from alternating layers of bioturbated sandy mudstone, bioturbated muddy sandstone, and cross stratified and structureless sandstone which are stacked in upward-coarsening sequences. Most upper Turner vertical producers were completed in the cleaner sandstone intervals that accumulated in elongated marine sand bodies. The emerging horizontal play has focused completions not only on the cleaner sandstone intervals, but also on lower resistivity, lower permeability, pervasively bioturbated, muddy sandstones that were deposited in areas surrounding the central sand ridges. Reliable open hole log interpretation of the muddy sandstone facies is problematic. Sidewall core samples acquired from the Iberlin #1-4H well, located in an area of southwest Campbell County with sparse Turner well control and virtually no Turner core data, have helped determine basic rock properties and fluid saturations, calibrate shaly-sand log analysis models, and validate interpretation of depositional environment.

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Petroleum potential of the Codell Sandstone, Northern Denver Basin

The Upper Turonian Codell Sandstone Member of the Carlile Shale in the northern Denver Basin is a hydrocarbon-bearing sandstone that has produced primarily from the Wattenberg Field, northeastern Colorado, since the early 1980s. Until recently, attempts to produce from the Codell Sandstone north of Wattenberg Field have resulted in promising hydrocarbon shows with minimal to no economic value. Current horizontal drilling and multistage fracturing technology is proving the Codell Sandstone can be produced from outside of Wattenberg Field with exceptional potential hydrocarbon recoveries. A significant area between Wattenberg Field and Silo Field in southeast Wyoming remains unproven. The Codell Sandstone is a low resistivity, low porosity, and low permeability argillaceous sandstone. The large clay content of the Codell Sandstone is responsible for masking typical well log readings of sandstones and hydrocarbon rich zones. The clays are also the cause for the difficulty in completing and producing from the sandstone by conventional means. Understanding the properties of the Codell Sandstone and the clays within its matrix is crucial to deciphering well logs and determining where the sandstone is rich in hydrocarbons in the northern Denver Basin. Outcrops along the Colorado Front Range and multiple cores deeper in the basin illustrate how the Codell Sandstone was deposited in a shallow marine environment.

A series of storm events during the Turonian separated the Codell Sandstone into three facies. Tempestite laminae are sandwiched between lower and upper heavily bioturbated facies of the skolithos ichnofacies. The three facies can be recognized in well logs and mapped as three individual lithofacies. Thin section analysis, SEM imaging, and regional mapping show that the Codell Sandstone did not travel great distances during deposition from a northwestern source. XRD measurements characterized authigenic clays, which further explains high gamma and neutron density readings in the argillaceous sandstone and suppressed resistivity measurements in hydrocarbon-bearing zones. Analysis of heat distribution and synthetic vitrinite reflectance throughout the region more accurately identify where Niobrara Formation source beds have the greatest potential to generate oil and gas and where migration is occurring. Basin modeling of structure, burial depth, thickness, and effective porosity in proximal relation to source rocks within the vicinity of anomalously high heat and thermal maturity designate zones of greater probability for the successful production of hydrocarbons north of the Wattenberg Field.

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Characterization of Rocky Mountain Paleozoic oils - Not the usual suspects!

Most of the oil in the U. S. Rockies is considered to have been generated from Cretaceous (e.g., Niobrara, Mowry & Greenhorn), Tertiary (Green River), Ordovician (Red River), Devonian (Bakken), and Permian (Phosphoria) sediments. While the geochemistry of several Paleozoic petroleum systems has recently been well-characterized (e.g., Phosphoria, Central Montana Heath, and Williston Basin Bakken, Madison Group and Red River), this presentation addresses the detection and characterization of Paleozoic petroleum systems that have not been the focus of recent exploration efforts. Paleozoic source units have received limited attention because of their depth, but where they exist may represent economically attractive resource opportunities.

The presence of an oil sample is indisputable proof that a petroleum system exists, with the source rock generally deeper than the reservoir location of the oil. The molecular and isotopic composition of produced oil may be used to predict various geological and geochemical aspects of the oil's corresponding source rock, including organo-facies, lithology, depositional environment, source rock age, thermal maturity, and, at times, migration distance and relative direction. Biomarkers, such as terpanes and steranes, function as molecular fossils, and even though the oil may have migrated from its source, fossil evidence as to the nature of the source is carried with the oil.

A detailed analysis of 242 oil samples that have been generated from Rocky Mountain Paleozoic source rocks is the basis for this study. By evaluating this suite of Paleozoic-sourced oils we have a) documented their presence, b) established and mapped the extent of coverage (footprint), c) determined the character (e.g., %S, oil vs. gas, thermal maturity), d) identified the probable source rock, and e) made an initial assessment of the overall economic significance. This identification resulted from multivariate statistical analyses of genetic-specific terpane and sterane biomarker ratios (molecular fossils) as well as stable carbon isotope values of the C15+ hydrocarbon fractions.

Examples will be presented from three (of five) study areas that have been evaluated:

- Covenant-like oils in central Utah and northwest Colorado
- Pennsylvanian-sourced oils in southeastern Powder River Basin
- Pennsylvanian and Mississippian-sourced oils in the SE Denver Basin and the Las Animas Arch region

DOMENICK, MICK, Slick Oil Limited, Wheat Ridge, CO

Relation of reservoir petrophysical properties to horizontal Codell production in Colorado and Wyoming

A collaborative geologic, engineering, and data mining effort has yielded insights into Codell production in the northern DJ. Data mining facilitated the access and download of over 6,500 public domain .las files for modern vertical wells in the Wattenberg/Silo corridor. Raster logs were used to supplement the .las data, net sandstone pay was picked based on a bulk density cutoff of 2.525 gm/cc, and a grid was constructed using values from over 8,000 wells. Using the top of the Codell and the base of net sandstone pay as depth limits, and an 8 - 25% density porosity calculation range (based on matrix and fluid density of 2.68 and 1.0 gm/cc, respectively), phih was computed in Petra for over 5,000 wells with .las files only, and a phih grid constructed.

Both grids were "sampled" to over 900 horizontal Codell producers within the study footprint, and the assigned petrophysical values were cross-plotted against length-normalized production data. Phih correlates better than net sandstone with length-normalized production. However, both correlations vary with geographic area, and break down to some extent outside of Wattenberg Field. Normalized production in the Silo, Fairway-Brensee, and Redtail areas displays relatively poor correlation with net sandstone and phih. In contrast, the Codell horizontal production in all areas (including Wattenberg) shows a consistent, inverse, correlation with water-oil ratios from vertical and horizontal producers (Figure 2), suggesting an important role for thermal maturity in Codell productive potential.

Cross-plots of normalized production with hydrocarbon pore volume show the best overall correlation, and support the hypothesis that thermal maturity may be a more important production driver than mechanical reservoir properties in some areas. This conclusion informs the consideration of Codell sourcing, and whether migrated portions of the play may exist. While mainly a subject for follow-on study, preliminary analysis of elemental Uranium log data (from over 300 .las files) has also been conducted for this study. The analysis outlines possible subdivision of the play into thermal maturity categories, even within Wattenberg. The northern DJ Codell play has evolved in a very rich data environment, with respect to both geologic and engineering data. Optimization and expansion of the play will surely benefit from further analysis of this wealth of existing data.

DOMENICK, MICK, Slick Oil Limited, Wheat Ridge, CO

The northern DJ Codell: Distribution of rock properties as an indicator of provenance

Since the early 1980s, the Codell Sandstone member of the Carlile Shale has received much attention from the petroleum industry for its productive potential in the Northern DJ Basin. Academic focus has been on the depositional environment of the Codell, and its place in the Turonian Stage Greenhorn Marine Cycle. There have been differences of opinion regarding the sediment source and depositional environment of the Codell, with an eastern source and shelf area favored mostly by recent petroleum industry workers. Also complicating the provenance interpretation is the relatively contemporaneous deposition of Frontier Formation clastic wedge sediments sourced from the west. Vertical juxtaposition of Codell and Frontier units is seen across several unconformable sequence boundaries dividing both units.

The purpose of this study is to add to the understanding of regional Codell Sandstone distribution, particularly with respect to discriminating Codell facies from those of the Frontier. A brief review of the existing literature is provided, and used to inform the construction of fence diagrams using open-hole well logs. Log correlations benefitted from the presence of laterally extensive bentonite markers, as well as relatively unambiguous log properties seen for shale and carbonate units in the lower part of the Carlile Shale, underlying the Codell Sandstone.

Log correlations were augmented by data from public domain cores, from over 50 wells. The integrated data were used to categorize the Codell and associated facies into 5 general rock types, as follows:

1) Bioturbated sandstone- This rock type is dominant at Wattenberg, and southern Wyoming. The original depositional bedding has been disturbed by burrowing organisms, but the sandstone retains 12+ percent porosity, and thicknesses > 15-20 feet for much of the Wattenberg area. Poor log response due to high clay content and high bound water volume has contributed to the belated development of the play outside of Wattenberg field, but vertical production of bioturbated Codell has been ongoing since the 1980s.

2) Bedded sandstone- This rock type is similar to the bioturbated facies in mineralogical composition, but retains depositional bedding. In southern Wyoming, the bedding is generally horizontal to hummocky cross-stratified, usually associated with storm beds. These "laminated" facies are seen to exhibit higher permeability than the adjacent bioturbated facies. In Goshen County and north, the sandstone bedding is more commonly cross-stratified or crypto-bioturbated, and beds are more "massive" and lighter in appearance, which points to their deposition in an upper to middle shoreface environment, or gradational delta front to delta plain environment.

3) Mud Drape- The dominantly mud-draped sandstone rock type typically occurs beneath, or within, the shoreface Bedded sandstone. As such, the Mud Drape rock type is seen as related to and deposited with other shoreface facies, supported by the fact that they are not seen in association with the Bedded or Bioturbated rock types to the south and east. The Mud Drape facies has not been identified to any significant extent east into Nebraska.

4) Layered sandstone- The Layered sandstone rock type consists of alternating thin (~1" thick) layers of sandstone and shale, and is generally devoid of bioturbation. The Layered sandstone rock type is seen primarily in Wyoming and has tentatively been identified in the lower portions of southwestern Nebraska cores. The preserved bedding in these rocks and lack of bioturbation is taken to indicate relatively rapid deposition in a pro-delta environment.

5) Shale - The Shale rock type has been identified in the most general of ways, principally to discriminate the facies from other rock types with easily identifiable sandstone components, as identified above.

The Codell of the Wattenberg Field area in Colorado is dominated by the Bioturbated rock type. Thickening and reservoir quality improvement to the west is believed to be an expression of increased shelf energy, and not necessarily an indication that these rocks were sourced from the west. Very little Layered rock type has appeared to have reached as far south as the Colorado State line, into the Wattenberg area. In southern Colorado however, outcrop studies verify the presence of Layered rock type in association with Bedded/Mud Drape rock type. These rock types in southern Colorado are believed to be associated with an eastern sediment source. Relevant features of the paleo-shelf are surmised to be related to some of the same processes which created the Wattenberg High and Morrill County High. General southeastward thickening of the Carlile, off the flanks of the aforementioned features, also supports this hypothesis.

In contrast, Bedded/Mud Drape and Layered rock types are dominant in the northernmost DJ Basin, in Goshen and Platte Counties, Wyoming. Together with isopach mapping of key units, rock type distribution suggests that the rocks in Wyoming show a greater influence from a western source area. This study supports the hypothesis that these northernmost DJ facies, generally identified as Codell in earlier work, are actually equivalent to the (Frontier) Wall Creek of the Powder River Basin.

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Novel new method for the acquisition of high resolution outcrop gamma ray profiles that replicate well logs and allow for seamless integration of the two

We present a new method for rapid and efficient acquisition of outcrop-based gamma ray profiles with the same resolution and statistical qualities as subsurface well logs.

Gamma ray scintillometers in both hand-held units and sondes acquire gamma ray data in the time domain, using gamma ray counts from the isotopes of U, Th, K , per unit time to determine rock radioactivity. Each measurement is recorded in the instrument as counts/unit time. Gamma ray production is statistical, so acquisition times are varied in order to achieve meaningful counting statistics depending on rock radioactivity.

Outcrop measurements are done at discrete depth intervals (e.g. 1 foot) on a measured section. This requires tedious measurement of each depth and starting and stopping the instrument at each location. Many users record the measurements by hand, further increasing the time for each measurement point. The resulting gamma ray profiles lack detail and are woefully under sampled relative to the variability in rock radioactivity and subsurface data sets, which are the linchpin of stratigraphic correlation and analysis in subsurface data sets.

Subsurface gamma rays are acquired with essentially the same instruments that convert unit time to depth by using a sensor that measures the cable as it winds on the spool in the logging truck. Key components of the subsurface method are that the instrument records continuously at some short time step and that it travels at a constant rate from the bottom to the top of the well bore. Thus, subsurface datasets are characterized by small sampling intervals that are typically averaged to a larger interval for analysis and interpretation.

Our method is based on the recognition that a measuring depth for subsurface acquisition is potentially superfluous because if the starting and ending depths and times are known and travel rate is constant , the depth of each measurement can be calculated. We use this principle to create outcrop datasets which closely replicate subsurface datasets (which is really the aim of surface datasets).

In our approach, the measured section is divided into 1.5 meter intervals and/or between important lithologic contacts. The instrument is set on a short acquisition window (1 second) and data recorded continuously across each interval at a spacing of 3" (10cm), pausing at each point for 4 seconds. The data are stored in the memory of the instrument which records the starting and ending times of each interval's acquisition. The instrument MUST move at the same rate throughout the entire measurement interval in order to determine the correct depth for each measurement. To post-process the data we simply convert instrument-time to distance along the stratigraphic section. Because intervals might be measured at different rates, we then use cubic spline interpolation to present all section with a uniform sampling interval, usually about 0.25 feet. This resultant series can be resampled at any desired interval and subsequently converted to API units.

Using this method, outcrop gamma ray profiles capture all of the detail seen in well logs and have very similar statistical properties. Detailed bed-by-bed correlations between surface and subsurface datasets are possible and the link between the two datasets is seamless. A method for the acquisition of spectral data is currently under development.

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Assessment of undiscovered oil and gas resources in the Heath Formation, central Montana and western North Dakota

The Mississippian Heath Formation occurs across north-central Montana and western North Dakota and was deposited in a mostly-marine depositional environment. The Heath Formation is a heterogeneous mix of lithologies that includes grey to black mudstones, dolomite, limestone, anhydrite, and coal. The primary source rock, informally called the Cox Ranch oil shale bed, lies within the middle section of the Heath Formation and has total organic carbon contents as high as 26 weight percent. Production from the Heath Formation began in 1919 when oil was discovered in the Devil's Basin oil field on the Central Montana Uplift. Currently, oil and gas are being produced mostly from horizontal drilling within the Heath Formation. The U.S. Geological Survey (USGS) recently completed a geology-based assessment of the undiscovered, technically recoverable petroleum resources in the Heath Formation. For this assessment, two continuous (unconventional) assessment units (AUs) were defined: (1) the North-Central Montana Heath Continuous Oil AU; and (2) the Williston Heath Continuous Oil AU.

The North-Central Montana Heath Continuous Oil AU lies within the Big Snowy trough of central and eastern Montana. The AU boundary extends west to the lateral extent of the Heath Formation near Judith Gap, Montana and to the Cedar Creek anticline to the east. Within the AU, the Heath Formation is thermally mature and occurs at depths of 300 to 7400 ft. The Williston Heath Continuous Oil AU is located along the eastern side of the Cedar Creek anticline in the western Williston Basin. The Heath Formation is present only in a limited area and is thickest (>300 ft) along the east side of the Cedar Creek anticline; it was eroded during the Early Pennsylvanian on the west side of the Cedar Creek anticline. These newly defined AUs were used in a recently completed USGS quantitative assessment of technically recoverable, continuous oil and gas resources of the Heath Formation and results are expected to be released in mid-2017.

FARZANEH, MICHAEL, University of North Dakota,
Grand Forks, ND

Enhanced oil recovery in the Tyler Formation (early Pennsylvanian) using miscible phase carbon dioxide flooding

The Tyler/Heath pool production has dropped significantly despite a boom in the Williston Basin. Due to its high paraffin content and high viscosity, unconventional exploitation has not been shown to be advantageous for the Tyler pool. Carbon dioxide is frequently used as an enhanced oil recovery method in oil and gas plays and can possibly be used in the Tyler. Several samples taken from various depths within the Tyler are saturated with Tyler oil and then flooded with carbon dioxide to determine if a carbon dioxide and kerogen miscible phase is possible. If miscibility is observed it may be possible to use carbon dioxide flooding as an enhanced oil recovery method in the Tyler Formation.

FIELDING, CHRISTOPHER R., University of Nebraska, Lincoln, NE, ANDREW J. HUTSKY, George Mason University, Fairfax, VA, and JESSE T. KORUS, University of Nebraska, Lincoln, NE

Tectonic controls on Cenomanian and Turonian deltaic successions in the Western Cordilleran Foreland Basin of Wyoming and Utah, USA

The geometry, orientation, and spatial distribution of coastal to shallow marine sandstone bodies in the Cenomanian/Turonian succession of Utah and Wyoming has proved difficult to rationalize, with numerous plausible explanations proposed. This paper integrates results from recent studies of several such stratigraphic units, notably the Frontier Formation of the northern Bighorn Basin, the Frontier Formation of the Uinta Mountains region, and the Ferron Sandstone of the Henry Mountains. These successions preserve diverse evidence for tectonic controls on sediment dispersal and stratal stacking patterns. All examined delta complexes show fluvially-dominated to fluvially- and wave-influenced characteristics, in contrast with the more wave-dominated deltas of the later, Santonian to Campanian succession (e.g., Emery Sandstone, Blackhawk Formation). Most show evidence of planform asymmetry, driven by southward deflection of delta lobes and to a lesser extent by southward longshore drift currents. All show evidence of diversion around subsurface growth structures, particularly but not exclusively related to the growth and migration of the forebulge. The locations of Frontier deltas in the Vernal area of northern Utah were also influenced by early growth of the east-west-trending Uinta Mountains. Elsewhere, clear stratigraphic evidence is preserved of early growth on other "Laramide" structures such as the Sheep Mountain Anticline in the Bighorn Basin and the Moxa Arch in the Green River Basin. All of the documented successions show preferential preservation of falling stage and lowstand sandstone bodies, some of which were further modified during transgressions to form enigmatic, isolated sandstone bodies. Offlapping and downlapping stratal stacking patterns, together with descending regressive shoreline trajectories, demonstrate the importance of falling stage deposits in units such as the Ferron Sandstone of the Henry Mountains. The growth of anticlines, particularly those related to forebulge dynamics, created topographic barriers to sediment dispersal. This is invoked as a major control on the process balance in Cenomanian/Turonian deltas (fluvial dominance due to limited wave fetch), delta planform, and delta lobe deflection. Differential structural growth, moreover, led to situations wherein accommodation varied both temporally and spatially, leading to complex sediment distribution patterns.

FINLEY, ANDREW, Goolsby, Finley & Associates, Casper, WY

Update of horizontal plays in Wyoming

Since the mid 2000's, the application of horizontal drilling and the development of horizontal completion technology has allowed for the significant rise in daily oil and gas production across the US. Wyoming and the Rocky Mountains have benefited from the development and application of these technologies and daily production has grown as a result. This presentation will review the recent activity, history and results of horizontal drilling and completion technologies within Wyoming on a formation/play basis.

FISHER, THOMAS R., Escalante Mines, Inc., Evergreen, CO, WILLIAM W. LITTLE, Brigham Young University - Idaho, Rexburg, ID, and LISA R. FISHER, Escalante Mines, Inc., Evergreen, CO

Lower Cretaceous sequences at Dinosaur Ridge, Jefferson County, Colorado: New perspectives on their sedimentary history, correlation, and sequence architecture

The Lower Cretaceous stratigraphic succession at Dinosaur Ridge, west of Denver, Colorado, has been a center of geologic interest and research since ca. 1936 when it was first exposed by road construction. The succession is well known for its numerous saurian trackways and ichnofossil complexes and is of interest as an analog for hydrocarbon exploration in foreland basin deposits. The purpose of this report is to present our recent results and review those of others, including new and previously unpublished radiometric dates, and introduce a new high-resolution stratigraphic section and photomosaic facies maps for the area.

Five formations are present at Dinosaur Ridge with at least three stratigraphic sequences that are separated by apparent lowstand surfaces of erosion (LSEs). Sequence 1, the Lytle Sandstone, rests unconformably on the Jurassic Morrison Formation and is separated from the Plainview Sandstone by an apparent disconformity. The Lytle Sandstone is a fluvial channel and flood plain deposit that is fully continental in origin. Sequence 2 is composed of the estuarine Plainview Sandstone, which is separated from the Lytle Sandstone by a local (?) disconformity or transgressive surface of erosion (TSE) and overlain by the marine Skull Creek Shale. The uppermost sequence, Sequence 3, is an incised valley-fill comprised of the upper units of the South Platte Formation (a.k.a., Muddy "J" Sandstone) and is overlain by a marine transgression and highstand succession of the Mowry Shale.

Our study, combined with previously published reports, seeks to address, clarify, and potentially resolve some of the geologic problems associated with the Lower Cretaceous section along the Front Range, including:

- Definition of a more precise contact between the Jurassic Morrison Formation and the Cretaceous Lytle Sandstone;
- Timing, depositional setting, and regional correlation of the Lytle Sandstone and how it relates physically to the initiation of the Western Interior foreland basin;
- Apparent differences in depositional timing and initiation of geological processes across the developing foreland basin;
- Different interpretations of the Plainview Sandstone and Skull Creek Shale contact as a TSE versus a gradational facies change, and regional variations in this contact;

- Conflicting lithostratigraphic, biostratigraphic, and radiometric correlations of presumably equivalent formations on either side of the Western Interior seaway; and
- Reconciliation of published facies successions which now show disagreement in terms of number, order, and stacking patterns of parasequences.

FREDERICK, JOHN B., Red Leaf Energy, La Veta, CO, and STEVEN G. FRYBERGER, Steven Fryberger Petroleum LLC, Laramie, WY

Seismic expression of eolian sandstone "build-and-fill" deposition stimulates the search for new reserves in the Minnelusa oil play, Powder River Basin, Wyoming

The Minnelusa eolian sandstone oil play in the Powder River Basin, Wyoming (Figure 1) is a mature play which has produced over 500 MMBO. The depositional sequence of alternating porous eolian sandstones and intervening evaporites, dolomites, and carbonates provides a strong acoustic impedance contrast that allows porous sandstones to be readily mappable (Figure 2). Minnelusa hydrocarbon traps are primarily stratigraphic.

Early seismic exploration for Minnelusa fields relied on identification of high amplitude negative impedance integrated with existing well control. In this early stage of exploration many high amplitude anomalies were drilled based upon 2D seismic data often without the benefit of a clear understanding of the regional and sub-regional sandstone depositional trends. The small footprint (1-3 mi^2) of many early 3D seismic surveys focused on imaging the distribution of the productive or prospective sand body. However, the small 3D survey size did not allow an adequate aperture to place the targeted sand in context with adjacent Minnelusa eolian sandstones or the erosional trapping facies.

3D seismic surveys targeting Minnelusa oil accumulations have grown larger in size, and these larger surveys facilitate a more robust mapping of the potential eolian reservoirs and trapping configuration. Yet, for a 3D survey that is located in an area of sparse well control, a keen understanding of the Minnelusa depositional seismic response greatly improves the chance of economic success.

Fryberger & Hern (2014) proposed the terminology "build-and-fill" to describe a geometric approach to the analysis of global eolian hydrocarbon reservoirs. Minnelusa eolian sandstone deposition may be characterized by this build-and-fill model whereby younger dune complexes are often deposited on the flanks of the underlying sandstones (Figure 3). Seismic data may image these offset dune complexes depending upon formation thickness and seismic frequency spectrum bandwidth (Figure 4.)

In order to seismically detect lateral changes that reflect stacked eolian sandstones of differing ages, seismic acquisition and processing must be optimized to provide a broad bandwidth seismic dataset. Detecting lateral formation changes with broadband data is a key to properly identifying productive and potentially productive sandstones.

Integrating a build-and-fill geologic model into the seismic interpretation (Figure 5) not only (1) reduces the risk of drilling an unproductive dune complex, but (2) provides opportunities for new discoveries in adjacent eolian sandstones, whether they be older or younger.

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Modern and ancient analogues for complex eolian petroleum reservoirs

Complex dunes such as linear, star, reversing and parabolic are common in modern depositional environments (Breed et al, 1979, Fryberger and Goudie, 1981). For example, there are more linear dunes (31%) in the world’s deserts than barchanoid dunes (24%). Despite this natural occurrence, most eolian petroleum reservoirs are interpreted using models based on barchanoid dunes, whether they are simple or compound in nature. While it is true that there are many such reservoirs, we suggest that there are also many eolian dune reservoirs that are built from linear, reversing or star dunes, and that many of them may remain unrecognized in subsurface work. If true, this presents opportunities in both production and exploration.

The performance of linear, and reversing dune reservoirs, for example, might be sub-par if they are wrongly interpreted using a model based on migrating barchanoid dune forms. An assumption of barchanoid bedforms with a unidirectional permeability structure can lead to a reservoir model that is far too optimistic. The result in practical terms is a low recovery factor, perhaps due to early water breakthrough and/or bypassed production. It is possible, however, to adjust well spacing and other aspects of primary and secondary recovery to optimize such complex reservoirs.

On the other hand, it is also possible that some fields remain undiscovered because DST or other evaluation techniques have mis-understood the eolian reservoir. For example, due to cross bedding permeability contrasts a test may wrongly evaluate the size or extent of a field. In linear dune reservoirs, it might be possible to miss a field entirely by testing tight ripple strata on the flank of a large dune while missing the avalanche strata of the good reservoir. There would seem to be an upside in exploration for those who understand eolian reservoir complexity in formation evaluation.

In our poster we present examples of the internal structure (cross bedding and lamination) of linear dunes in Saudi Arabia and Australia; reversing dunes at Great Sand Dunes, Colorado and Killpecker Dunes, Wyoming; and coastal parabolic/reversing barrier dunes at Hawk’s Nest, Australia. We also describe ancient linear dunes in Lyons Formation of the Colorado Front Range (USA), and at Auk oil field in the Northern North Sea Basin of the United Kingdom.

We hope the examples presented in our poster encourage others working ancient eolian dune reservoirs to consider the many possible dune types that exist in nature, and possibly in their producing eolian reservoir. For example, a pattern of opposing, relatively low dips, accompanied by a high proportion of ripple strata may reveal the presence of linear dunes. We suspect that careful interpretation of dune type in eolian reservoirs will result in improved recovery strategies or exploration outcomes in some eolian reservoirs in the Rockies of the USA, and worldwide.

GERAGHTY, ENNIS P., Stillwater Mining Co., Columbus, MT

Variation in tectonic style along the Beartooth Mountains front Laramide triangle zone, south-central Montana

The Stillwater Complex (SC) portion of the Beartooth Mountains front Laramide triangle zone provides a unique opportunity to observe the resultant structural behavior of crystalline basement. The beautifully layered Archean SC has a distinctive "igneous stratigraphy" that allows for unraveling structural and stratigraphic relationships not normally observed in crystalline terrain. Prominent marker units in both the SC section and Phanerozoic sedimentary section record interpreted west-northwest-trending forethrusts (southwest over northeast) and backthrusts (northeast over southwest), as well as lateral ramping in both the sedimentary and crystalline sections. Classic triangle zone geometries have been interpreted for over 45 km (28 mi) along strike on the basis of detailed surface outcrop and underground drift mapping coupled with abundant underground and surface drill holes. Regional forethrusts and backthrusts tip out and are replaced along strike by other fore and backthrusts that conserve shortening. Numerous transverse, "strike-slip faults that don't go anywhere" are interpreted as lateral ramps present in both the crystalline and sedimentary section. Dramatic variation in structural architecture is observed at some transverse faults. In one instance, a forethrust with 3.2 km (2 mi) of estimated dip-slip offset tips out and is immediately replaced to the east by backthrusts that stack and repeat the Cambrian/Archean Great Unconformity up to 11 times. Oblique slip (left lateral) is significant; up to 50% is estimated from surface mapping interpretation. The east-west variation in architecture is accompanied by vertical variation (stacking of thrusts and individual, discrete triangle zone packages) over 3.2 km (2 mi).

GILHOOLY, MURRAY G., Husky Energy, Calgary, AB, and JOHN A. W. WEISSENBERGER, ATW Associates, Calgary, AB, Canada

Preliminary sequence stratigraphic framework for a Mississippian shelf margin, Madison Group, south Boulder Canyon, Southwest Montana

A well-exposed, near depositional-dip oriented, Mississippian carbonate shelf margin outcrop was studied and is placed into a sequence stratigraphic framework for the first time. The exposure is situated on southwest facing slopes above the South Boulder River, 11 kilometres south of Cardwell, Madison County, Montana.

Lithostratigraphically, Mississippian Madison Group strata at South Boulder Canyon are comprised of generally poorly-exposed Lodgepole Formation calcareous shales and argillaceous carbonates grading upward into more resistant Mission Canyon Formation carbonates. Two complete and several partial stratigraphic sections were measured, the Madison Group section at South Boulder Canyon being over 300m thick.

The paleogeographic setting of the carbonate shelf appears to reflect a margin facing north-northwest into the Central Montana Trough. Regionally, outer shelf and basinal deposits existed both to the north and west (Rose, 1976; Sando et al., 1981).

The Madison Group at the studied outcrop is described in the context of Sonnenfeld’s (1996) regional sequence stratigraphy. This defined the Madison and related strata as a second-order depositional sequence comprising five third-order component sequences, of which parts of the upper four are recognized at South Boulder Canyon. The base of the outcrop exposes the highstand (HST) of Sonnenfeld’s Sequence II: cherty wackestones of the outer ramp shoaling upward into coarse skeletal and oolitic grainstones of the ramp margin. The base of Sequence III has restricted ramp interior deposits abruptly onlapping open marine facies of the uppermost Sequence II. A skeletal-oolitic grainstone complex dominates the lower half of Sequence III (lowstand to early transgressive); the late transgressive to highstand is dominated by outer to mid-ramp wackestones. A thin, in situ lowstand (LST) comprising skeletal grainstones resting abruptly on Sequence III, forms the base of Sequence IV. The remainder of this sequence consists of middle to outer ramp strata. Restricted inner ramp deposits of the basal Sequence V sharply overly these units. Above this ramp interior LST, the remainder of Sequence V comprises skeletal-oolitic units and tidal flats.

The third order depositional architecture of the Madison Group at South Boulder Canyon provides a useful analogue for the subsurface. It serves to provide a better stratigraphic understanding of reservoir and non-reservoir facies relationships.

GREENHALGH, BRENT, Wexpro Company, Salt Lake City, UT

Company myths and field extension opportunities, examples from Cretaceous reservoirs in the Greater Green River Basin

For the purpose of this presentation, a myth is an over-simplified, but seemingly reasonable, explanation for a particular aspect of a field's productive behavior. Myths are common to most producing fields and generally increase in number as fields age. Myths begin as reasonable hypotheses to explain patterns of well results, field limits, water production, stimulation results, or any other characteristic observed during field development activities. The transformation from hypothesis to myth occurs when a hypothesis is accepted by technical disciplines, and/or management, without rigorous scientific testing. With ready acceptance, the myth begins a life of its own as development and operating strategies are implemented around it. Myths are perpetuated by anecdotal stories that pass through generations of geologists, engineers, and management. Myths are detrimental to field development because they are over-simplified explanations for complex petroleum systems. Acceptance of myths inhibits, or at least delays, the critical thinking and data collection activities required to understand the details of a petroleum system operating in a field. Understanding the details of a particular petroleum system is often the key to identifying additional field development opportunities. Identifying company myths and rigorously evaluating them can provide valuable insights into field redevelopment and extension opportunities. Four examples of myths from the Green River Basin illustrate field development opportunities generated by identifying, and critically evaluating company myths.

GUSTASON, EDMUND R., and TOPHER LEWIS, Enerplus Resources, Denver, CO, and MARSHALL DEACON, Edge Oil and Gas, LLC, Denver, CO

Facies and facies architecture of the Codell Sandstone, northern Colorado Front Range and adjacent Denver Basin, Colorado

The Codell Sandstone Member (Codell) of the Carlile Shale has been producing large quantities of oil and gas in the northern Denver Basin, Colorado since the early 1980s. Until recently, the Codell was developed as a vertical play in Wattenberg Field. Today, aided by 3D seismic data, operators have successfully drilled horizontal wells up to two miles long in Wattenberg and throughout the northern Denver Basin. However, very little is known about the vertical and lateral facies changes or facies architecture of the Codell over these distances and the impact they have on production.

In the northern Denver Basin, the Codell unconformably overlies the Fairport Member of the Carlile Shale and is unconformably overlain by the Niobrara Formation. The Codell ranges in thickness from approximately 40 feet in outcrops north of Fort Collins, CO to 0 feet along the southeastern part of Wattenberg Field; largely due to the interplay (truncation and/or preservation) between the two unconformities. Based on descriptions of more than 60 cores and several outcrops, the Codell consists predominantly of bioturbated sandy mudstone and muddy sandstone with rare thin beds of planar parallel laminated (SPPL) to low angle laminated (HCS) sandstone and ripple cross lamination over much of Wattenberg Field. To the north and northeast of Wattenberg Field, in northern Weld County, Colorado and Laramie County, Wyoming, SPPL and HCS facies are more common. Recent workers have demonstrated that these laminated sandstone facies have significantly better reservoir properties, especially permeability, than bioturbated sandstone and bioturbated muddy sandstone facies. Thicker, more complete vertical facies successions suggest the Codell was deposited by a prograding marine shoreline. The application of Walther's Law to predict the continuity and connectivity of facies, especially the better reservoir quality facies, and facies architecture along a horizontal wellbore is dependent on an accurate interpretation of these vertical facies successions. For example, if clinoforms are present, what is their dip angle and azimuth?

In addition to measured sections of outcrops from widely spaced road cuts, gullies, and irrigation ditches, we present the results of a detailed characterization of a three-mile-long, north-south oriented, continuous outcrop of the Codell, located north of Fort Collins, where the authors used photomosaics and closely spaced measured sections to trace out facies and their bounding surfaces and create a database of the dimensions, continuity and connectivity of facies. Inasmuch as most horizontal wells in the northern Denver Basin are also oriented north-south, the results of this study could provide operators with a direct analog for the facies and facies architecture of the Codell in the adjacent subsurface.

HOFFMAN, B. TODD, and JOHN EVANS, Montana Tech, Butte, MT

EOR pilot projects in the Bakken Formation

Unconventional formations such as the Bakken, Niobrara and Eagle Ford have made a significant impact on the petroleum industry over the last decade, almost doubling the US domestic oil production. These types of reservoirs contain hundreds of billions of barrels of oil in US and Canada alone, but primary recovery factors are still low, typically less than 10%. The need for enhanced oil recovery (EOR) has been documented, but most studies have focused on simulation models and lab tests. The next logical step includes field trials (aka pilot projects).

Over the last 8-9 years, there have been a number of pilot tests for both water and gas injection in the Bakken. Results from these small pilots were reported to state agencies, and the first part of this presentation analyzes the available public data on these pilots. Injectivity of gas or water does not appear to be an issue in the Bakken; however, the projects, in general, show early breakthrough times and poor reservoir sweep efficiencies. There was only minor additional oil recovery, but the pilots were limited in scope and duration. No mitigating procedures were implemented to deal with the problems that occurred.

This presentation also proposes methodologies for implementing second generation pilots for unconventional reservoirs. Methods are devised to improve understanding of the near well formation before injection starts, detect where fluids are entering and leaving along the lateral and correct for any associated poor sweep efficiency. We also propose long term information collecting strategies and contingency plans to deal with difficulties that may arise during the pilot.

Using EOR to increase recovery from unconventional oil fields is important for the continued success of these plays, and this presentation provides a thorough analysis of implementing pilots to help do just that.

HOFMANN, MICHAEL H., AIM GeoAnalytics, Missoula, MT, SARAH EDWARDS, SM Energy, Denver, CO, and RILEY BRINKERHOFF, Newfield Exploration, Houston, TX

The Pronghorn Basin – a precursor of the Bakken Basin

In the Williston Basin, the Pronghorn Member of the Bakken Formation is known to be composed of silty sandstone, sandy siltstones, silty mudstones, and mudstones. Facies and trace fossil assemblages suggest an overall open marine depositional environment. This largely lithostratigraphic correlation limits the Pronghorn deposition to a well-known, thick lithologic succession recognized in the central and southern Williston Basin that pinches out in all directions. Hydrocarbon production from the Pronghorn in North Dakota mimics this Pronghorn thick and is limited to the Sanish, Parshall, and Billings Nose Fields; in other areas the Pronghorn is largely unproductive or untested.

We present results of detailed (sub-centimeter scale) facies descriptions from 26 cores from North Dakota and Saskatchewan. This high-resolution stratigraphic framework resulted in the recognition of a thin regional marker horizon (bioclastic lag) of distinctive geochemical, paleontological, and sedimentologic characteristics – reworked phosphatized and pyritized bioclasts – that varies in thickness from several centimeters to just a few millimeters and from which we were able to build a regional Pronghorn correlation.

We suggest that the Pronghorn Member was more widespread across the basin and was more lithologically complex than previously recognized. To the south this bioclastic lag overlies the classic bioturbated Pronghorn facies, but to the north, this lag overlies an organic rich mudstone with intermediate TOC content, with some resemblance of the Lower Bakken Shale facies. Thick, lithologically repetitive successions are challenging to correlate regionally because of the recurrence of just a few fine grained rock types. In the absence of recognizing the very thin lag deposit in the middle of a thick stack of organic rich mudstone, the organic rich mudstones of the Pronghorn are naturally lumped together with the Lower Bakken Shale. However, based on our detailed facies work, we suggest that the Pronghorn transitions from a more proximal facies in the southern part of the Williston Basin to a more distal facies in northern North Dakota and into Saskatchewan. There, the contemporaneous organic rich Pronghorn facies underlies the similar looking Lower Bakken Shale facies, only separated by the bioclastic lag deposit. In addition to the generally deepening to the north, the Pronghorn Basin was also influenced by inherited tectonic elements. We observe in some areas where the Pronghorn Member pinches out onto paleogeographic highs that follow well known lineaments in the Williston Basin.

HOHMAN, JOHN C., Retired, Houston, TX , JOHN M. GUTHRIE, AARON P. RODRIGUEZ, and NICHOLAS J. HOGANCAMP, Hess Corporation, Houston, TX, P. TED DOUGHTY, and GEORGE W. GRADER, PRISEM Geoscience Consulting, Spokane, WA

Bakken and Pronghorn geology of Montana: Comparing the Williston, South Alberta, and Sappington Basins

Montana is located in a crucial geographic position for studying the greater Bakken-Pronghorn stratigraphic section. This distinctive section is characterized by a succession of late Devonian to early Mississippian siltstones alternating with black shales that host a prolific petroleum system and unconventional oil play. Three principle accumulations of these deposits converge in Montana, including the Williston Basin in the east, the South Alberta Basin in the northwest, and the Sappington Basin in the southwest. Comparing observations from all three of these basins allows for a greater appreciation of the breadth of this distinctive depositional succession and a more comprehensive understanding of the stratigraphy and sedimentology associated with the Bakken-Pronghorn and its laterally equivalent sections.

The key to this comparison is the construction of a sequence stratigraphic framework that links the basins together. Continuous rock information, such as cores and outcrops, provides the critical information that leads to the identification of a progression of correlative depositional sequences and systems tracts that comprise the greater Bakken-Pronghorn section. In the Williston Basin, the sequences in ascending stratigraphic order include the Lower Pronghorn, Upper Pronghorn, Lower Bakken, Lower Middle Bakken, Upper Middle Bakken, and Upper Bakken. In the same ascending order, the Sappington Basin sequences include the Knoll, Trident, Lower Sappington, Middle Sappington and Upper Sappington (Cottonwood Canyon), while the South Alberta Basin sequences include the Knoll, Trident, Lower Exshaw, Upper Exshaw and Banff.

Linking the basins, the Lower Pronghorn correlates westward with the Knoll while the Upper Pronghorn correlates with the Trident. Similarly, the overlying Lower Bakken correlates westward with the Lower Sappington and Lower Exshaw. However, the Lower Middle Bakken appears to only correlate with the Middle Sappington and Upper Exshaw. At present, an equivalent sequence to the Upper Middle Bakken which is common in the Williston Basin has not been observed westward in the Sappington or South Alberta Basins. The Upper Bakken is correlative to the Upper Sappington (Cottonwood Canyon) and Banff.

This presentation displays Montana cores from each of the Williston, South Alberta, and Sappington Basins to illustrate how these sequences and systems tracts that comprise the Bakken-Pronghorn section are expressed regionally throughout the state. It includes and describes examples of both the surfaces and facies successions that define the sequence stratigraphic units in each of the three basins. Of particular significance, note the recognition of the unconformities that define the sequences. These inter-basin surfaces help establish the chronological context of deposition both within and between the basins while illuminating the missing sections that characteristically complicate Bakken-Pronghorn stratigraphy. Examining the differences and similarities encountered in the greater Bakken-Pronghorn section within a multi-basin framework of chrono-stratigraphically significant sequences and systems tracts provides a comprehensive context for maximizing the understanding of its depositional history.

HOHMAN, JOHN C., Retired, Houston, TX , JOHN M. GUTHRIE, AARON P. RODRIGUEZ, and NICHOLAS J. HOGANCAMP, Hess Corporation, Houston, TX, P. TED

DOUGHTY, and GEORGE W. GRADER, PRISEM Geoscience Consulting, Spokane, WA

Regional stratigraphy of the Bakken, Pronghorn, and Three Forks in the Williston Basin and equivalent sections in the South Alberta and Sappington Basins

The construction of a regional stratigraphic framework provides insight into how the Bakken, Pronghorn and Three Forks unconventional plays of the Williston Basin extend into the South Alberta Basin. This regional framework includes the three primary basins for these units in the northern Mid-Continent and Rocky Mountain area: the Williston Basin, the South Alberta Basin, and the Sappington Basin. The regional stratigraphic framework is characterized by ten depositional sequences that are separated into two distinct groups by the Acadian Unconformity. The lower group, below the unconformity, consists of four sequences dominated by dolostones or evaporites. The upper group, above the unconformity, consists of six sequences dominated by fine-grained clastics.

Originally defined in the Williston Basin, the lower group consists of four sequences that comprise the dolostone-dominated Three Forks (TF4, TF3, TF2 and TF1 in ascending stratigraphic order). The upper group consists of six sequences characterized by either sandy siltstone or shale that comprise the Pronghorn and Bakken. The basal sequence of the Pronghorn is called the lower Pronghorn and is subdivided into two systems tracts: the Lower Pronghorn siltstone and the overlying Lower Pronghorn limestone. The Upper Pronghorn sequence is characterized by brown, silty shale. The third sequence in the upper group is the Lower Bakken which is characterized by black, organic-rich shale. The fourth and fifth sequences are both characterized by sandy siltstones and comprise the Middle Bakken. These two sequences partition the Middle Bakken into two parts: the Lower Middle Bakken and the Upper Middle Bakken. Both of these sequences are further subdivided into three systems tracts each. The sixth sequence of the upper group is the Upper Bakken, which marks a return to black, organic-rich shale deposition.

The Williston Basin sequences can be correlated northwest into the South Alberta Basin. The sequence boundary between the TF1 and TF2 is among the key stratigraphic relationships identified. This unconformity marks the top of the Potlatch/Stettler evaporitic section with the TF1 corresponding to the basal, dolomitic part of the overlying Big Valley. The boundary between the dolomitic Big Valley and the succession of limestones and shales that comprise the remaining portion of the Big Valley marks the Acadian Unconformity. This overlying section is partitioned into two sequences: a lower, carbonate-dominated sequence and an upper, shale-dominated sequence that are correlated to the Lower and Upper Pronghorn, respectively. The overlying Exshaw, with its lower black shale and upper siltstone, resembles the Lower and Middle Bakken, while the Lower Exshaw is correlated with the Lower Bakken. However, in South Alberta the Upper Exshaw is only correlative to the Lower Middle Bakken. The section of shale and siltstone overlying the Exshaw, often referred to as Banff, is correlated with the Upper Bakken black shale.

In the Sappington Basin, the Acadian Unconformity has been identified within the Logan Gulch. It is expressed by the characteristic change from dolostones and evaporites below the unconformity to a succession of limestones and shales above. The boundary itself is placed at the base of the informally named Knoll limestone which forms the top of the Logan Gulch. The Knoll limestone is correlated to the Lower Pronghorn and the lower carbonate sequence of the upper Big Valley. The overlying shale-dominated Trident is correlated with the Upper Pronghorn and the upper shale sequence of the upper Big Valley. The Sappington overlies the Trident and consists of three parts: a black shale-dominated Lower Sappington that is correlated with the Lower Bakken and Lower Exshaw; a sandy siltstone-dominated Middle Sappington that is correlated with the Lower Middle Bakken (and is similarly subdivided into three systems tracts) and the Upper Exshaw; and a black shale-dominated Upper Sappington/Cottonwood Canyon that is correlated with the Upper Bakken and Banff.

HORNE, JOHN C., Orion International Ltd., Golden, CO, RYAN G. FISHER, Manitou Consulting, Golden, CO, SEAN C. HORNE, Texas Christian University, Ft. Worth, TX, and GEORGE M. CARLSTROM, Cross Exploration Co., Centennial, CO

The D Sandstone: A record of a sea-level cycle

The D Sandstone of the Colorado portion of the Denver-Julesburg basin is an excellent producer of hydrocarbons from numerous isolated reservoirs (>50). Porosity and permeability pinch outs counter to regional dip are the primary structural controls on these reservoirs. It is only within the context of the entire basinal fluvial to shoreline depositional system and sea-level cycle that the distribution of reservoirs becomes understandable.

Using a database of more than 20,000 well logs, 900 mudlogs, and 160 cores, internal correlations of the reservoir sandstones of the D Sandstone interval were documented. Valleys eroded during the falling stage of sea level and a variety of sediment fill accumulated during the subsequent sea-level rise. This variety of fill was defined from the distal shore setting to the more proximal fluvial setting. In the interfluves, abrupt-based, forced-regressive shoreline sandstones document the base of the D Sandstone, while transgressive lags cap the tops of the interval. Organic-rich source shales of the lower Graneros accumulated laterally basinward and atop the D Sandstone.

Paleogeographically, the D Sandstone prograded westward into the southeastern portion of the Western Interior Seaway from source areas of low-lying hills on the continental interior. The sediments were predominantly recycled Paleozoic sands and muds. Because of offshore winds and minimal tides, the D Sandstone sediments were deposited along a low-energy part of the seaway. Storm-related deposits dominated the more distal parts of the valley fills, while fluvial deposits accumulated more commonly in the proximal valleys.

Right-angle bends in the D Sandstone valleys suggest contemporaneous basement-block movements controlled the local direction and fill of these valleys. Numerous authors have alluded to these block movements and documented them on a regional scale. More recently, High-resolution aeromagnetics have defined the margins of these blocks in more detail.

Understanding the heterogeneity of the D Sandstone deposits provides valuable insights into reservoir compartmentalization that must be addressed during the design of efficient enhanced recovery methods. Knowledge of the tectonic controls on the distribution and orientation of the D Sandstone valleys offers exploration opportunities for discovering by-passed pay and new fields in an already mature play.

JOHNSON, ERIC H., Johnson Geophysical, Billings, MT

Lodgepole mounds and turtle structures in Montana and western North Dakota

Paleo-depositional maps indicate that broad areas of Montana and western North Dakota were favorable for the development of Waulsortian-type carbonate mounds during Early Mississippian (Lodgepole) Time. In addition to the oil-filled Lodgepole mounds near Dickinson, North Dakota, similar mounds have been found in a number of locations across Montana. Lodgepole mounds crop out in the Big Snowy Mountains of central Montana and in the Bridger Range near Bozeman. Lodgepole mounds have been imaged by seismic data in northern Montana's Blaine County and in northeastern Montana's Valley County, buried 4,000 and 7,000 ft deep, respectively.

There are no commercially productive Lodgepole mounds in Montana but, the fact is, very few mounds have been drilled. In Blaine County, drilling has focused on commercial oil production from Jurassic Sawtooth strata in drape closures overlying Lodgepole mounds. One example is Weygand Field (CUM. 500,000 BO). Drape closures developed above the mounds because the mound-core facies were more resistant to compaction by overburden than the off-mound carbonaceous mud areas. A review of the Dickinson mounds indicates that total off-reef compaction can be up to one-half the mound height. The Sawtooth drape features can be up to 50 ft high and appear to reflect less than half the total compaction that occurred within the Lodgepole Formation. The mound-drape closures are clearly imaged by both 2D and 3Dseismic data. Even where the mounds themselves are not evident, their presence is unmistakable because of definitive drape features in the overlying strata.

Some Lodgepole mounds are associated with underlying turtle structures (salt dissolution structures) suggesting that Lodgepole mounds could have developed anywhere throughout the Devonian Prairie Salt depositional basin in western North Dakota and northeastern Montana. The turtle structures created sea floor topographic highs that were the nuclei for the growth of Lodgepole mounds. Julie LeFever and others (1995) postulated that the Lodgepole Mounds at Dickinson were initiated by turtle structures that developed in the upper Bakken Formation. In northeastern Montana, Lodgepole mounds also appear to be coincident with turtle structures.

JOHNSON, RONALD C., JUSTIN E. BIRDWELL, TRACEY J. MERCIER, and MICHAEL E. BROWNFIELD, U.S. Geological Survey, Denver, CO

Impact of mass-movement processes on mineralogy and organic richness trends in the lacustrine Eocene Green River Formation, Piceance Basin, western Colorado

The lacustrine Eocene Green River Formation in the Piceance Basin of western Colorado is widely known for its laminated oil shales. Less known are the interbedded brecciated or "blebby" oil shales that were deposited by mass-movement processes, accounting for more than 50% of the rocks in some sections. Blebby oil shales generally consist of mineral-rich rip-up clasts in an organic-rich fine-grained matrix. Transgressive-regressive cycles, as well as seismic activity including earthquakes, may have been the cause of the mass-movement events that formed blebby oil shale beds. In this study, the mineralogy and organic richness of blebby and laminated oil shales in the different stratigraphic sections are compared to assess how the influx of material from marginal areas of Eocene Lake Uinta affected the distribution and properties of the oil shale resource in the Piceance Basin. We also use the recently published and extensive U.S. Geological Survey mineral occurrence database compiled, in part, from data collected by the former U.S. Bureau of Mines to assess mineralogical trends related to these mass-movement deposits. Previous analysis has shown that organic matter content, inferred from Fischer assay oil yield, is generally greater in mass-movement deposits when compared to adjacent laminated units, with the laminated Mahogany oil shale zone being a notable exception. This indicates that large amounts of organic matter from marginal areas were entrained with mineral matter as unconsolidated sediments moved into the paleolake depocenter. In fact, the Piceance Basin would not be the most concentrated oil shale deposit in the world without the contribution of organic matter in the central part of the lake from more marginal areas by mass-movement processes.

JOHNSON, RONALD C., JUSTIN E. BIRDWELL, and PAUL G. LILLIS, U.S. Geological Survey, Denver, CO

Stratigraphic sections for oil and tar sand deposits in the Uinta Basin, Utah

In order to better understand oil and bitumen generation and migration in the Paleogene lacustrine source rocks in the Uinta Basin, Utah, the productive intervals were assigned to a well-established stratigraphic framework. This includes transgressive and regressive sequences represented in the early freshwater lacustrine section of Lake Uinta as well as the overlying organic-rich and organic-lean zone oil shale framework which defines the sections deposited during the later brackish to hypersaline conditions in the lake. Most oil fields and tar sand deposits occur in marginal lacustrine facies and the goal here was to correlate these intervals to sources within the various lacustrine sections. The early freshwater stage is subdivided into three intervals in ascending order: (1) the Flagstaff Member, containing the earliest lake deposits in the basin; (2) the Uteland Butte member, representing a period of lake expansion; and (3) the Castle Peak interval (also known as the Wasatch/Colton tongue) representing a major lake regression. Detailed stratigraphic studies of marginal lacustrine areas and isopach maps of oil shale zones generated for the recently published oil shale assessment of the Uinta Basin facilitated correlation of the marginal sections into the 18 organic-rich and organic-lean zones previously identified in the upper brackish to hypersaline section based on Fischer assay oil-yield data. Samples from one hundred and eighty-two oil wells and tar-impregnated sections from 82 core holes at the Sunnyside and PR Spring-Hill Creek tar sands deposits were examined for this study. The Sunnyside tar sands deposit extends from above the Mahogany bed to just below the base of the freshwater Uteland Butte member. Tar-impregnated sandstones in the PR Spring-Hill Creek tar sand deposit are more restrictive stratigraphically, varying from above the Mahogany bed to approximately the R-4 through L-5 oil shale zones. Stratigraphically, most oil samples are from the freshwater stages to the early brackish-saline stages (R-0 through L-1 oil shale zone) of Lake Uinta. A limited number of samples are from the later saline to hypersaline lake stages. Oil typing based on bulk and molecular geochemistry will be compared to the stratigraphic interpretation and possible migration pathways will be discussed.

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Geological characterization of hydrothermally altered reservoirs and future exploration potential in eastern Michigan

Michigan Basin carbonates contain abundant strata that are hydrothermally overprinted based on their morphology, distribution, and geochemical signature. The hydrothermal overprint is controlled by the migration of hot diagenetic fluids along fractured and faulted plumbing networks into the Precambrian Basement and/or basement derived clastic sediments. Dolomitization by hydrothermal fluids is not always related to reservoir favorable processes, however, in highly productive examples like Albion Scipio and Deep River Fields the hydrothermal activity is accompanied by structural enhancement related to basement derived wrench faulting, reidel shear sags, replacement by dolomite, aggressive dissolution by corrosive fluids, and partial cementation by saddle/baroque dolomite. Radiogenic isotopes using 87Sr/86Sr and 144Nd/143Nd of the saddle and replacive dolomites from these fields indicates that the dolomitizing fluids derived from old (> 1 BY) Rb-rich rocks such as granites, gneisses, and/or their reworked sedimentary equivalents. Empirical temperature derivation of δ18O values from these dolomites indicate that dolomitization occurred from 80-180 °C, and is therefore geothermal-to-hydrothermal in origin. The association of reservoir favorable hydrothermal activity with northwest-southeast trending basement rooted faults across Michigan has implications for future hydrocarbon exploration along similar structural trends.

Two-D seismic interpretations in the relatively underdeveloped Sanilac County also map northwest-southeast faults that project towards known resources like Deep River and Akron fields to the northwest. The 87Sr/86Sr, 144Nd/143Nd, and δ18O analysis of Ordovician, Silurian, and Devonian carbonate strata from this county also confirm the presence of hydrothermal dolomitization. The relatively underexplored nature of Sanilac County and the presence of reservoir favorable structural trends coupled with hydrothermal geochemical signatures demonstrate the future potential for exploration of hydrothermally altered reservoirs in eastern Michigan.

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Discovery, petroleum geology and the early implementation of a high-pressure gas injection EOR in the “Alberta Bakken” play; Sweetgrass area, Alberta

The success of the Williston Basin Bakken development spawned renewed interest in the potential for contemporaneous, analogous deposits in the Alberta Basin. As a result, southern Alberta saw a rapid expansion in resources and the exploration of the evocatively named Alberta Bakken Formation; theretofore unceremoniously grouped into the widely known Big Valley-Exshaw-Banff system. Results of this exploration were largely unfruitful and proved uneconomic compared to its sister Basin. In December of 2010, however, Deethree Exploration Ltd. (now Granite Oil Corp.) discovered what has developed into the only economic early Mississippian Alberta Bakken pool in the province. Since discovery, the extent of the productive zone has been identified over a strike extending 36 miles with a primary producing pool that has been estimated to contain in excess of 470 million barrels of original oil-in-place.

Upon initial oil production, details of undersaturated fluid properties, reservoir variabilities and sediment deposition and their relationship to production have become extremely important contributing factors to the ongoing development of this unique oil resource. Rapid pressure depletion and low GOR ratios sturdily pointed to an undersaturated reservoir fluid and the decision was made early in the producing life to commence a high-pressure gas injection enhanced oil recovery (EOR) scheme. Further and ongoing evaluations through complex production modelling and field observations are extremely encouraging; greatly increasing the reserves and ultimate recovery of the original oil-in-place. This early life oil play is constantly undergoing geological and production evaluation with exceptional economics, even in today’s oil price reality.

Granite will walk through the evolution of a large scale oil discovery, current geologic understanding (ignoring the

International Border to the north), the implemented high-pressure gas injection process and its practicality.

LA FONTAINE, NATHAN, University of Montana, Missoula, MT, and MICHAEL H. HOFMANN, AIM GeoAnalytics, Missoula, MT

Quantifying architectural controls on reservoir behavior in the Turonian Wall Creek Member of the Frontier Formation in the Powder River Basin, Wyoming

Inter-well heterogeneities controlling fluid migration in deltaic reservoirs exist as low permeability beds within a hierarchical stratigraphic system. The vertical stacking and spatial extent of these low permeability facies within a three-dimensional stratigraphic architectural framework greatly influences connectivity and flow behavior in a reservoir. The estimation of effective reservoir properties, as influenced by these low permeability beds, is a significant source of uncertainty in modeling the subsurface, as common subsurface tools cannot resolve their spatial distribution and continuity. This study aims to address this subsurface conundrum by quantifying heterogeneities in a mixed delta system spatially and stratigraphically. To accomplish this, an integrated sedimentological, stratigraphic, and geocellular modeling approach is employed on the Wall Creek Member (WCM) of the Upper Cretaceous Frontier Formation. Exceptional exposures of the WCM in the Tisdale Anticline, on the western limb of the Powder River Basin, are cross-cut by a series of intersecting canyons, providing the three dimensional control necessary to adequately quantify these parameters. A 1kmx1km digital outcrop model (DOM) of the WCM was constructed using photogrammetric methods and georeferenced using field survey data. In addition, stratigraphic sections were measured in ~150m intervals providing facies constraint in both depositional strike- and dip-oriented outcrops. Within the DOM, surfaces bounding depositional elements of different hierarchies are mapped and quantified into categories. For example, thickening upward tidal bars (~5m thick bed sets), the highest order depositional element included in this study, are bound by low permeability surfaces spanning >500m across the study area; conversely surfaces bounding dunes (beds to bed sets) typically extend <50m. Initial measurements of dunes show width to length ratios that on average are 1:1 or greater, putting them in stark contrast to the higher order hierarchical elements (tidal bars) that are commonly much longer than wide. The stratigraphic interpretations traced in the DOM, and constraint by the measured sections, are directly exported into a Petrel geocellular model to help resolve progressive levels of stratigraphic hierarchy and their respective influences on reservoir flow. Results from this study are intended to assist with well placement and completion strategies. In addition, derived effective properties can also educate groundwater and CO_2 sequestration modelling efforts.

LE, TUAN TRAN, and B. TODD HOFFMAN, Montana Tech, Butte, MT, GREG HILTON, and BRENT BUNDY, SM Energy, Denver, CO

Flow simulation model of the Wall Creek Member in the Frontier Formation: Powder River Basin, Wyoming

The Frontier formation in the Powder River Basin has been re-discovered for oil and gas potential with the development of long horizontal wells and multi-stage hydraulic fracturing. Over the last decade, the Wall Creek member of the Frontier formation has proven to be a successful hydrocarbon-producing target, yet a full understanding of this complex structure has not been achieved. The complexity of the Wall Creek depositional environment has challenged geologists to understand the vertical and lateral heterogeneity of the play; furthermore, the fluid and rock properties have uncertainty and are not well defined. To develop better recovery strategies, an integrated reservoir model using geologic, petrologic, petrophysical, and geophysical data is created to evaluate different scenarios of how the play may occur in the reservoir.

The work started by using a representative horizontal well to create a single-well flow simulation model including properties of the reservoir such as porosity, permeability, relative permeability, capillary pressure, and water saturation. Using the three offset well logs, a 32 feet interval was selected to represent the net pay zone of the Wall Creek member. The porosity was estimated by averaging the neutron and density porosities, and permeability was established by applying a correlation of porosity and permeability found from the core data. By matching a PVT report from the well, a black oil model was created to represent the reservoir fluid. The production history was matched by modifying the initial fluid saturations and the rock physics parameters such as relative permeability and capillary pressure. As a result, representative fluid and rock physics models were obtained for the reservoir.

Sensitivity analysis was conducted to observe the effect of changing reservoir properties and hydraulic fracture properties on production. Well spacing and fracture spacing studies were also performed. Overall, this work allows for a better understanding of what is happening in this reservoir and provides a range of possible production rates for a number of reservoir properties in the field.

One of the most important outcomes from this model is the determination of reasonable fluid and rock physics parameters, which can be used in geologic models that capture the complex small-scale structural heterogeneity observed in outcrops. For the future work, this model will be combined with an outcrop study of Wall Creek heterogeneity to determine the appropriate method to upscale the complex, heterogeneous models to the well scale models. Different geologic scenarios will be evaluated to help determine the best strategy for field development.

LI, XIAOPENG, HAZIM ABASS, and TADESSE TEKLU, Colorado School of Mines, Golden, CO

Modeling on matrix and fracture permeability alteration by fluids imbibition and its impacts on post-frac well performance

Multi-stage hydraulic fracturing has been one of the key techniques for commercial development of shale formations. Tremendous amount of fracturing fluids are injected during the treatment with only a small fraction recovered by flowback. The retained water is believed to interact with formation rocks during the imbibition process. New observations from laboratory measurements showed different impacts of water imbibition on permeability in matrix and fracture media. Thus, it is critical to understand how the dynamic fracturing fluids distribution and near-fracture-face permeability alteration affect the performance of hydraulic fractured wells.

A series of alternating spontaneous imbibition tests and permeability measurements were performed on shale samples from three different formations to establish a relationship between imbibed fluid volume and permeabilities of matrix and fracture media. In this work, a numerical simulation model was constructed to properly capture the laboratory results through specially designed relative permeability curves and investigate the effects of permeability change caused by fracturing fluid imbibition on well productivity. Matrix media follow the relative permeability curves during the imbibition process driven by capillary and hydraulic forces. The fracture network created during the fracturing treatment may experience both relative permeability and stress-dependent permeability effects. However, some of the sealed fractures can be reactivated by imbibition through physical or chemical interactions between water and fracture filling materials after the treatment.

The simulation results showed that most of the near-fracture-face imbibition occurs within the first day and that different porous media behave differently. The shale matrix exhibited significant permeability reduction within a short period and the damage due to imbibition can lead to water blockage problems. Hydraulic fracture induced fracture network is also adversely affected by the fluid imbibition but much less significantly. While sealed natural fractures untapped by fracturing treatment demonstrate opposite tendency through reopening by imbibition, which may coincide with the follow-up micro-seismicity recorded after treatment. It is found that natural fracturing spacing, fracturing design and shut-in time have significantly impacts on well productivity behaviors through imbibition. Natural fracture spacing determines the deliverability of fracture media. Larger fracture network increases the volume of imbibed water. Extended shut-in may be favorable for productivity depending on matrix capillarity and cementation of fracture filling materials.

Understanding imbibition effects on water saturation changes and permeability alterations provides significant insight to shale formation damage and reservoir management. Detailed fracture characterization, proper fracture design and managed shut-in can contribute to optimum post-frac well performance.

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Characterization of complex lateral heterogeneity using MWD, XRF and seismic inversion

Capturing lateral heterogeneity is challenging, particularly when only Measurement While Drilling (MWD) data are available and gamma ray (GR) character alone does not reflect the variability inherent in the zone of interest. Using Logging While Drilling (LWD) technologies is the preferred method of capturing and characterizing heterogeneity along the length of a lateral, but LWD technologies can be cost prohibitive. This paper presents two separate case studies where X-ray diffraction (XRF) was run on cuttings taken at regular intervals along the lateral length and used to correlate to core-calibrated regional geologic facies models at both the log and seismic scale. The results of these case studies demonstrate the viability of this technique to accurately predict lateral heterogeneity in a complex geologic system using relatively low cost measurements. The laterals presented in both case studies were located near key vertical cored wells where XRF analyses were run at 1’ resolution over the entire zone of interest. The full regional calibration dataset consisted of 10 cored vertical wells where this high vertical resolution XRF analysis was conducted.

LOPEZ, DAVID A., Geologic Consultant, Billings, MT

Petroleum geology of the Crow Indian Reservation, south-central Montana

The Crow Reservation is very under-explored area in the northern Powder River Basin of Montana. Producing reservoirs on the Reservation include the Cretaceous Shannon Sandstone, Pennsylvanian Tensleep Sandstone, and the Mississippian Madison Limestone. Of these, the Tensleep probably has the greatest potential for discovery of new oil accumulations. Recent detailed surface and subsurface research has led to a good understanding of the geometry and distribution of Tensleep Sandstone reservoirs. The Shannon Sandstone has potential in a limited area in the southern part of the Reservation. The Madison has widespread occurrence of porous reservoir rocks but requires significant structural closures in order to protect oil accumulations from groundwater flow. Potential also exists in Cretaceous Muddy Sandstone, Greybull Sandstone, and Pryor Conglomerate (Lakota equivalent). The Muddy and Greybull are well known channel sandstone reservoirs in the region and produce from combination structural-stratigraphic traps. Porosity in the Pryor Conglomerate is widespread and would require significant structural closures to trap oil. Potential also exists in Cretaceous Muddy Sandstone, Greybull Sandstone, and Pryor Conglomerate (Lakota equivalent). The Muddy and Greybull are well known channel sandstone reservoirs in the region and produce from combination structural-stratigraphic traps. Porosity in the Pryor Conglomerate is widespread and would require significant structural closures to trap oil.

MALESARDI, TERESA, Geologist, Denver, CO

Petroleum geology of the Niobrara Formation in Silo Field, WY

Silo Field, located in the northern section of the Denver Basin, is an interesting and unique area of Niobrara Formation oil production. Silo field is seated on a structural monocline on the eastern flank of the Denver Basin. The Niobrara Formation, composed by cyclic deposition of chalk rich benches and organic rich marls, has historically been found to act as both the source and trap majority of produced hydrocarbons. Reservoir properties of the chalk and marl units are very poor, but become economic with the presence of natural fractures. Alternatively, hindrances to production in this field exist as anomalous water production. This study explores the reservoir properties of the Niobrara Formation, the presence and predictability of natural fractures, and the potential root causes of excess water production in Niobrara wells. Although unconventional resource plays tend to offer many challenges, horizontal wells continue to be successful in Silo Field. This study strives to identify and understand the main driving forces in the Field to further enhance drilling and production success.

MATHESON, EDWARD, and TRACY FRANK,
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The influence of paleoceanography in controlling diagenetic pathways in the Phosphoria Rock Complex of the Bighorn Basin, Wyoming

The Permian Phosphoria Rock Complex (PRC) is a succession of bioelemental (phosphorite and chert), carbonate, evaporite, and siliciclastic rocks that stretches across parts of Idaho, Utah, Wyoming, and Montana. The PRC contains economic phosphate deposits and a prolific petroleum system with both source and reservoir rocks. It has received continued attention due to its economic significance and unique facies that suggest atypical paleoceanographic conditions. Oceanographic models have invoked upwelling, intermediate water masses, and temperature and salinity stratification, among other processes, in explaining the atypical oceanography. Despite continued debate, it is clear that the PRC accumulated in settings where oceanographic conditions were geographically and temporally variable. This study utilizes 35 stratigraphic sections and cores within the Bighorn Basin of north-central Wyoming to analyze the influence of the paleoceanographic conditions in determining diagenetic pathways and the modern expression of facies. In the Bighorn Basin the PRC consists predominantly of Park City Formation carbonates and Goose Egg Formation siltstones and evaporites. Depositional facies range from open-marine heterozoan carbonates to peritidal carbonates containing coated grains, fenestral fabric, microbial laminations, and teepee structures to supratidal and terrestrial red beds with carbonate and gypsum-anhydrite salina deposits. Overprinting the depositional facies are a diverse set of diagenetic processes and products. They include synsedimentary marine cementation; authigenic mineralization; synsedimentary and reflux dolomitization and displacive nodular evaporite growth; burial cementation and replacement by quartz, calcite, and dolomite; and telogenetic replacement of evaporites. In many cases diagenetic overprinting is pervasive with very little original material preserved. Both peritidal and open-marine reservoir facies have been exploited in plays with stratigraphic, structural, and diagenetic controls on trap locations. Thus, an important consideration is the diagenetic pathways that the rocks followed, and whether their modern composition is, at least indirectly, predestined by original oceanographic conditions. Oceanographic influence would have combined with burial history, structural activity, geographic variability, and other controls in determining the diagenetic modification of the PRC. Some of the oceanographic conditions that could affect diagenetic pathways include ocean chemistry, seafloor oxygenation, seawater temperature, and the influence of physical processes. These mechanisms control diagenetic pathways because they can affect skeletal mineralogy, matrix preservation (and its role in early cementation or porosity preservation), bioturbation and its influence on fluid flow, and authigenic mineralization (silicification, glauconitization, phosphatization, etc.) and its role in decreasing the diagenetic potential of allochems. The implications of paleoceanographic conditions influencing diagenetic pathways is that similar depositional facies deposited under differing oceanographic conditions could have variable modern expressions due to progression down different diagenetic pathways. As a result, the relationship between oceanographic, sedimentologic, and diagenetic characteristics is an important consideration with regards to the nature of the Phosphoria Rock Complex reservoir facies present within the Bighorn Basin.

MCDONALD, KATHLEEN, Cimarex Energy Company,
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Integrated Niobrara/Mancos maturity model for the Piceance Basin, Northwest Colorado, USA

Combining Niobrara/Mancos geochemical properties, production trends and geothermal gradient mapping in conjunction with the Piceance regional structure allows us to develop a predictive maturity model for continuing Niobrara development. This new model indicates the northern and southern and halves of Piceance Basin have different burial histories. Tertiary volcanic activity associated with the Colorado Mineral belt provides a late stage heating event that affected the southern portion of the Piceance Basin. The Douglas Creek Arch Left Lateral Shear Zone appears to be important in the division between the northern and southern portions of the basin. The model explains Niobrara dry gas production in the southern Piceance at shallower depths than the northern Piceance. While the in northern Piceance, this model indicates possible oil and condensate production in the north and west, and dry gas to the east.

MEEK, SCOTT R., and SAMUEL M. HUDSON,
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Quantitative reservoir characterization of the fluvio-deltaic Dry Hollow Member of the Frontier Formation, western Green River Basin, Wyoming

The Frontier Formation in the Green River Basin of southwestern Wyoming consists of Late Cretaceous (Cenomanian-Turonian) marine and non-marine sandstones, siltstones, mudstones and coals deposited on the western margin of the Cretaceous Interior Seaway. Tight gas reservoirs exist in fluvio-deltaic sandstones in the upper Frontier Formation (Dry Hollow Member) on the north-south trending Moxa Arch within the basin. These strata outcrop in hogback ridges of the Utah-Idaho-Wyoming Thrust Belt approximately 25 miles west of the Moxa Arch. Detailed, quantitative outcrop descriptions were constructed using emerging photogrammetric techniques along with field observations and measured sections at five key outcrop localities along the thrust belt. Understanding the architectural style of this low net-to-gross fluvial system allows for improved reservoir prediction in this and other comparable basins.

The architectural style of the Dry Hollow Member fluvial deposits varies vertically as the result of a relative shoreline transgression during Dry Hollow deposition. Grain size, reservoir thickness and connectivity of fluvial sandstones is generally greatest near the base of this member and decreases upward overall. While most of the sand in the system is not well-connected, amalgamated conglomerates and associated fine to coarse sandstones near the base of the section and much thinner, isolated sands near the top of the Dry Hollow occur in laterally extensive zones that can be identified over tens of miles. These significant lateral zones provide means to relate outcrop and subsurface stratigraphic architecture. Combined with available subsurface data, these techniques facilitate construction of fully-realized 3D static reservoir models for use as analogs in subsurface reservoir characterization.

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Updated regional and field-scale helium accumulation geochemistry, La Barge Platform, Wyoming

Economic (>0.5 mol. %) accumulations of helium at the La Barge Platform (La Barge) in western Wyoming are the result of radiogenically-produced helium from sedimentary crust that was mobilized by deep basinal ground water flow or possibly hydrocarbon migration, and concentrated by diffusion into stable traps. Helium production from La Barge occurs in Paleozoic natural gas reservoirs; the resource is the largest in the U.S., representing approximately 55% of current helium production in the country. Though La Barge is the largest producer of helium and a target for additional exploration, helium geochemistry at La Barge and in the surrounding region is not well understood.

From 2012-2016, gas and water samples were collected from six Mississippian Madison Limestone producing gas wells at La Barge, and from 17 regional gas-effusive surface springs within a 200-km radius of the field. Water and gas samples from all locations were analyzed for gas composition, major and trace element concentrations, and stable and noble gas isotopes.

Regional sampling for helium and other noble gas isotopes indicates three distinct regional helium source groups that approximately match the three major geologic provinces in the area. The first province comprises tectonically stable sedimentary strata surrounding and including La Barge; results here suggest helium concentrations are relatively high (0.5-1.0 mol. %) and have primarily crustal origins. However, the helium of this group is not purely crustal and appears to represent an unknown source component with R/RA ratios of 0.05 to 0.07. The second source group occurs west of La Barge in the Basin and Range province of southeastern Idaho. Here, there is more mantle-sourced helium with R/RA values of 0.15-2.2 with lower helium concentrations (0.0004-0.008 mol. %) than the first region. The last group, from the Yellowstone province to the north, is well documented in the literature as mantle-sourced helium, and was therefore only tangentially sampled for this study. Regionally, higher concentrations of helium occur in the sedimentary province including La Barge, which exhibits more of a crustal-sourced helium signature than the other sampled geologic provinces. High helium concentrations sampled at the springs near La Barge may suggest that additional, potentially economic accumulations are present.

Geochemical analyses of gas from La Barge field show trends in bulk composition with structural depth. Helium and carbon dioxide concentrations increase with structural depth while methane and hydrogen sulfide decrease with depth. These trends suggest a well-connected stable and stratified Madison Limestone reservoir, where the gas constituents have been able to concentrate by density through a permeable reservoir. Data from stable and noble gas isotope analyses do not show clear trends with depth. Instead, the data may provide preliminary evidence for two somewhat isotopically different pools of gas, one to the southwest on the steeper side of the structural crest of the platform, and another to the east on the more shallowly dipping side of the platform. Various proposed basement structures on the southwest margin of the La Barge Platform, related to its formation, may be conduits for migrating gases that cause the isotopic differences. However, confirmation that gases on opposite sides of the La Barge structure are in fact isotopically distinct is not possible given the current limited sample set.

MILKOV, ALEXEI V., Colorado School of Mines, Golden, CO, and GIUSEPPE ETIOPE, Istituto Nazionale di Geofisica e Vulcanologia, Rome, Italy

Geochemistry of shale gases from around the world: Commonalities and variations

We collected and investigated published chemical data on >1,300 samples of gases recovered from shales in >20 basins in Argentina, Canada, China, France, Poland, Saudi Arabia and the USA. Most shale gases are relatively dry (average dryness C1/(C1-C5) is 0.94) and contain nitrogen (average about 6%) and CO_2 (average about 2.5%). Methane has carbon isotopic composition $\delta^{13}C$ ranging from -70‰ to -24‰ and averaging around -42‰. Most shale gases have thermogenic origin, although gases from New Albany shale in the Illinois basin, Antrim shale in the Michigan basin, and Colorado shale in the Western Canada Sedimentary Basin have predominantly primary or secondary microbial origin. Isotopic reversal of the normal trend in carbon isotopic composition such that $\delta^{13}C$ of methane is larger than $\delta^{13}C$ of ethane is a common phenomenon observed in about 40% of studied samples. The vast majority of samples showing isotopic reversal have thermogenic origin and are very dry (ratio C1/(C1-C5) exceeding 0.97 and averaging 0.99) suggesting that isotopic reversal is common among thermogenic gases with very high maturity. However, isotopic reversal of the normal trend in hydrogen isotopic composition such that δD of methane is larger than δD of ethane is observed among both thermogenic and microbial shale gases.

MOORE, WILLIAM D., Consultant, Billings, MT

Petrophysics of the Greybull sandstone: Old log foundation for further exploration

This poster session considers some petrophysical characteristics of the Lower Cretaceous (Albian) Greybull formation along the Nye-Bowler lineament in south-central Montana. This session studies the petrophysical characteristics of producing wells within this field. This field, along with the nearby Golden Dome Field, produces higher gravity low-sulfur crude, unlike the other fields along the lineament, which produce low-gravity black oil from the Greybull. Since the oil from this field is a higher quality crude, the Greybull sand here is a higher quality objective and a better subject for further study. This session uses log, production and formation top data from the Montana Oil and Gas Commission to delineate the characteristics of a productive Greybull reservoir containing high-quality crude and furnish a guide to further exploration for other similar reservoirs. The logs used in this study range very old Electric Surveys (ES), Induction-Electric Surveys (IES) and Dual Induction surveys (DIL) from a variety of service companies. These surveys provide the majority of the log data within the field and provide useful data despite their age.

NAIR, KAJAL, SVEN EGENHOFF, and JOHN SINGLETON, Colorado State University, Ft. Collins, CO

Facies reconstruction of the Casper and Ingleside Formations: a mixed carbonate-siliciclastic system

The mixed carbonate-siliciclastic succession of the Pennsylvanian-Permian Ingleside and Casper Formations were deposited along the flanks of the Ancestral Front Range as a result of Late Paleozoic tectonism and eustatic sea level changes. Extending from central Colorado to southeastern Wyoming, the Ingleside and Casper Formations are composed of carbonate intervals representing relative sea level rises and siliciclastic intervals representing relative sea level falls.

Outcrop and drill core data from the Ingleside and Casper Formations were combined to measure fourteen stratigraphic sections. A north-south transect of the measured sections extends from Albany, Wyoming south to Boulder, Colorado. East-west transects extend within Albany, Wyoming and from Larimer, Colorado east to Welds, Colorado. General thickness of the formations increases towards the north and east. Stratigraphic intervals vary laterally from intervening carbonates and siliciclastics in the north to pure sandstones in the south. Deepening upwards carbonate facies transitioning from grainstones to mudstones represent a marine environment. Siliciclastic facies transitioning from shallow-marine massive sandstones to eolian cross-bedded sandstones represent an increasingly arid environment. Laterally continuous shale stringers lie adjacent to shelf carbonates and shoreface cross-bedded sandstones. Pure carbonate or siliciclastic units are rare, with siliciclastic grains observed in carbonate beds and carbonate components observed in siliciclastic beds. Mixing of the two sediment components indicates a constantly active carbonate factory. The model explaining carbonate-siliciclastic mixing in this system therefore differs from the common reciprocal sedimentation model which suggests the complete cutoff of carbonate production during lowstand periods.

The results of this study can be used to produce an idealized depositional model to facilitate field recognition of an environment that consists of an eolian dune field extending into a siliciclastic foreshore, a transitional shoreface, and an offshore carbonate ramp. This model will contain regressive siliciclastic facies and transgressive carbonate facies, with eolian sandstones representing maximum regressions and basinal shales representing maximum transgressions. Proximal eolian sandstones have been productive in the Casper Formation and would hold the maximum reservoir potential in such a system because of high intergranular porosities and permeability.

NESHEIM, TIMOTHY O., North Dakota Geological Survey, Bismarck, ND

Applying stratigraphy to the search for unconventional reservoir in the upper Tyler Formation (Lower Pennsylvanian), southern Williston Basin

The upper Tyler Formation comprises a prospective unconventional resource play that extends beyond the prolific Bakken-Three Forks play into largely undeveloped acreage along the southern Williston Basin. The upper Tyler is a mixed clastic-carbonate system composed of primarily very fine grained calcareous mudstone (limestone) interbedded with argillaceous-siliceous mudstone (shale) deposited within a brackish water lagoonal setting. The gross thickness of the upper Tyler section is typically around 50 ft. and holds conservative oil in place estimates of 3 to 5 million barrels of oil (MBO) per section (6-10 MBO/1280 acres). A couple relatively recent unconventional test wells targeted upper Tyler carbonate beds which yielded sustained oil production but at low flow rates with negligible produced formation water.

A preliminary reexamination of the upper Tyler's geology using sequence stratigraphy reveals five sequences

(S1-S5 in ascending stratigraphic order) that were identified and correlated across the study area of southwestern North Dakota using several dozen cores and several hundred wireline logs. Sequence boundaries are observed/interpreted as thin (<1 ft), discontinuous paleosols and/or caliche/calcrete crusts that formed during subaerial exposure when the Tyler seaway receded. Directly above and below the exposure surfaces/sequence boundaries are typically intervals of ripple-laminated fossil grainstone interlaminated with darkly colored organic-rich mudstone interpreted as intertidal deposits. These intertidal, interlaminated fossil grainstone-mudstone intervals can either fall within the transgressive systems tracts (TST) or highstand systems tracts (HST), and are further separated by very fine grained argillaceous-siliceous mudstone (shale) beds that constitute the maximum flooding surfaces of the upper Tyler sequences. Overall, upper Tyler sediments tend to be very fine grained across most of the study area and core plug porosity values of the carbonate beds are typically 1-8% with permeability values that often range from <0.01 to 10 millidarcies. However, the upper Tyler sediments overall coarsen moving eastward towards the Dickinson Field, and core plug porosity values within a the carbonate interval spanning the upper S1 (RST-high stand systems tract) and lower S2 (TST) sequences increase to upwards of 20% with 80-90% oil saturation within an area extending along the eastern Fryburg and southern Zenith oil fields. This more highly porous and oil saturated carbonate interval is typically 8-12 ft. thick (with additional prospective pay zones in close stratigraphic proximity), forms a curvilinear trend that parallels the S1-S2 paleo shoreline, and laterally separates interpreted very dark grey to black subtidal mudstone (west) from grey to red supratidal deposits (east). Future unconventional exploration of the upper Tyler along this higher porosity carbonate trend may ultimately lead to unlocking another resource play within the Williston Basin.

NESHEIM, TIMOTHY O., North Dakota Geological Survey, Bismarck, ND

Examination of the Red River Petroleum System

The Upper Ordovician Red River Formation contains a set of thermally mature petroleum source beds referred to as kukersites. The extent of these kukersites forms a north-south elongate trend that stretches from southern Saskatchewan, across western North Dakota, and likely also along eastern Montana and northwestern South Dakota. Kukersite thermal maturity ranges from immature with respect to oil generation along their northern margins of extent, to over mature within the central portions of the Williston Basin. Recent work has estimated that these source beds have generated approximate 64 billion barrels of oil equivalent beneath western North Dakota, and basin-wide Red River production totals only approximately 760 million barrels of oil equivalent (~75% oil), a small fraction of the hydrocarbon generation total.

The Red River D zone constitutes one of the primary reservoirs within the Red River Petroleum System and has been the target of recent conventional and unconventional exploratory and development drilling within the southern margins of the Williston Basin. The D zone consists primarily of burrow-mottled carbonate wacke-mudstone in which tight limestone (<2% ϕ) and porous dolomite (up to 25% ϕ) grade both laterally and vertically between one another. The discontinuous nature of the porous dolomite essentially forms localized stratigraphic traps that can now be more easily identified and targeted in the subsurface using modern 3-D seismic. Across western North Dakota, and possibly beyond, D zone reservoirs are locally charged by the interbedded, thermally mature kukersites, which are interbedded within the burrow-mottle carbonate mudstones. However, the localized hydrocarbon charge is in some cases partially to near completely lost through vertical migration along faults/fractures that breach the dense, low porosity limestone and kukersite beds that form hydrocarbon seals. Several other factors appear play roles in D zone hydrocarbon production as well, including: source bed (kukersite) thermal maturity as well as the API oil gravity and gas to oil ratio of producible hydrocarbons. Re-examination of these various factors that control Red River production, particularly in the D zone, numerous opportunities appear to be present for additional development in existing Red River Fields as well as continued exploration in prospective, undeveloped areas.

NORDENG, STEPHAN H., IAN E. NORDENG, JEREMIAH NEUBERT, and EMILY G. SUNDELL, University of North Dakota, Grand Forks, ND

Recognizing facies in the Red River Formation of North Dakota using a Convolutional Neural Network

Recent developments in machine vision technology suggests an alternative approach to the conventional way in which geologists evaluate "visual" aspects of sedimentary structures and texture. The reason for this new approach is the development of massively intricate algorithms known as Convolutional Neural Networks (CNN) or Deep Neural Networks. These algorithms use large arrays (650,000) of individual nodes or "neurons" within large arrays that act as banks of adjustable, nonlinear filters. These arrays are arranged into architectures that can be "trained" with labelled data, or in the case of this study, images. This process involves training the network with hundreds, or preferably thousands of images, each coded to an identified feature or texture. Once trained, validation of the network is provided by queries using images not included in the training set to evaluate the ability of the network to classify unknown images. Validation is obtained by comparing the classification provided by the trained network with one that is obtained independently.

The neural network employed in this study uses the Berkeley Vision and Learning Center's (BVLC) Caffe CNN architecture, which is a reference implementation of ImageNet, by Krizhevsky, Sutskever, and Hinton. Training and validation images are from core photos of the Red River Formation (Ordovician) available through the North Dakota Department of Mineral Resource's online inventory of core photography. The images were downloaded, cropped to cover roughly half of a slapped four inch core and resized to 256 X 256 pixels. Images with noticeable defects such as edges, fractures and plug holes were discarded. The images are divided into the following visible texture categories: 1) mosaic to enterolithic anhydrite, 2) finely laminated to thrombolytic dolostone/anhydrite and 3) Thallisinoides burrowed carbonates. The training set consists of 768 "anhydrite", 622 "laminated" and 652 "burrowed" images. The validation set contains 85 "anhydrite", 95 "laminated" and 858 "burrowed" images.

The network was trained using stochastic gradient descent with a batch size of 512 example images, momentum of 0.9, and weight decay of 0.0005. The learning rate was initialized to 0.01 and reduced by one-tenth every 5000 iterations. After 23,000 iterations the loss function (measure of inaccuracy) was reduced to less than 1X10-3 indicating that the CNN successfully "learned" the training set.

The trained network, when applied to the validation set, correctly predicted 93% of the classifications. All of the "laminated" images were correctly identified. Of the remaining "anhydrite" or "burrowed" images less than 3% were falsely classed as "laminated". 96% of "anhydrite" validation images were correctly classified as were 92% of the "burrowed" facies. Most of the errors that did occur involved "anhydrite" classed images being mistaken for "burrowed" (2%) or "burrowed" examples being classed as "anhydrite" (5%). Errors on the order of 1% to 3% were made in classing "anhydrite" or "burrowed" images as "laminated". These results suggest that a trained CNN will produce classifications that are highly consistent with those of the supervising geologist.

ONWUMELU, CHIOMA, and STEPHAN H. NORDENG,
University of North Dakota, Grand Forks, ND

Oil generation rate prediction using Arrhenius Equation for Bakken Formation

Oil generation rate index is important in considering oil well performance. An oil generation rate index was estimated for two groups of wells in Bakken Formation in the North Dakota portion of the Williston Basin. Activation energies consistent with a fixed frequency factor (1x10-14/sec) and estimates of the current temperature within the Bakken Formation were used to calculate a reaction rate. The reaction rate was converted into a generation rate index by multiplying the reaction rate by the mass of crackable kerogen derived from Rock-Eval S2 analyses and bulk density logs. The Rock-Eval pyrolysis temperature of 435°C, production index of 0.1 and conversion fraction of 0.1~0.15 are believed to represent the threshold of intense hydrocarbon generation from mature rocks. The calculated reaction rate index appears consistent with this threshold.

PARKER, DOUGLAS M., Independent Geologist,
Highlands Ranch, CO

Volcanic ash fall the key to organic shales

Volcanic ash fall is the most important cause for the existence and preservation of organic rich shales. If this hypothesis is confirmed, the implications are many.

Formation of organic-rich shales correlates with high water column productivity rather than anoxia. Coastal upwelling occurs in about one percent of the world's oceans today. Upwelling concentrates sediments locally or regionally and does not adequately explain thin shale laminations extending across large percentages of particular sedimentary basins.

Cretaceous organic rich shales were induced by an undefined mechanism associated with massive volcanic events. Ash fall causes a phytoplankton bloom and, potentially, temporary sea floor anoxia. Ash fall has been concluded to cause the organic richness of many tight oil plays and at least one Triassic lacustrine shale.

Organic rich shales and coals possess many layers of bentonites and tonsteins. Hundreds of thin layers of volcanic ash have been documented in the Niobrara shale, all below electric log resolution. Sixty-five layers of volcanic ash have been documented in the Paleocene Big Dirty coal bed. The Eagle Ford contains abundant ash beds of varying thickness rich in planktonic foraminifera, indicating that high production may be triggered by nutrient flux associated with ash fall.

Extrapolating from the Smithsonian Global Volcanism database, 11,700 eruptions of VEI 6 or greater (Krakatoa) could have occurred worldwide during a 3 million year depositional period for the Eagle Ford shale.

Cores through productive shales should be analyzed for thin volcanic ash layers and their weathered remnants intermingled with other sediments.

PETERSON, KYLE J., and STEPHAN H. NORDENG,
University of North Dakota, Grand Forks, ND

Pore-size distributions from nuclear magnetic resonance and corresponding hydrocarbon saturations in the Devonian Three Forks Formation, Williston Basin, North Dakota

Pore-size distributions of four lithofacies from the Three Forks Formation were obtained using nuclear magnetic resonance (NMR). The upper Three Forks was divided into three lithofacies with the fourth coming from the uppermost section of the middle Three Forks. In ascending order the lithofacies studied were: 1) massive green to greenish-gray mudstone, 2) highly deformed, interlaminated pinkish-tan silty dolostone and green to greenish-gray mudstone, 3) thinly laminated pinkish-tan silty dolostone and 4) interlaminated green to greenish-gray mudstone and pinkish-tan silty dolostone.

Core samples (one sample per lithofacies) of various sizes and shapes were selected for six western North Dakota wells. Samples were prepared for NMR by saturating with 300,000 ppm NaCl brine solution under 100 psi of compressed air for a minimum of 60 days. Pore size distributions were obtained from NMR transverse relaxation (T2) analysis via Oxford Instruments GeoSpec2 core analyzer coupled with Green Imaging Technology software. Pore size distributions were calculated using T2 cutoff values to partition total porosity measurements into micropores (less than 0.5 microns), mesopores (0.5 to 5 microns), and macropores (greater than 5 microns). Although average core measured porosity and permeability values (5.5% to 7.5% and 0.02 mD to 0.09 mD respectively) remain relatively consistent in each lithofacies, average water saturations increase from 30% to 40% in the upper Three Forks to over 60% in the massive green mudstone of the middle Three Forks. NMR T2 data averaged within each lithofacies suggest that fluid saturations are related to pore size distributions. As mesopore and macropore percentages of total porosity increase, oil saturations increase. As micropore percentages of total porosity increase, water saturations increase.

PETTY, DAVID M., Geological Consultant, Katy, TX

Stratigraphic framework for basin-margin, sub-unconformity diagenesis below the Acadian unconformity in the southern Williston Basin

The Acadian discontinuity is represented by a late Devonian (Famennian) unconformity that lies on top of the Famennian Three Forks Formation in the central portion of the Williston basin and on truncated Devonian through Cambrian formations in basin-margin areas. Bakken-Pronghorn sediments were deposited in the basin-center and onlap the Acadian unconformity. A maximum flooding surface overlies the Bakken-Pronghorn system in the basin-center but this surface overlies the Acadian unconformity in basin-margin areas. The maximum flooding surface is overlain regionally by open-marine carbonate strata of the basal Lodgepole.

Sub-unconformity diagenesis was an important process in basin-margin areas around the southern Williston basin; however, the diagenetic analysis in this study focuses on a portion of the southwest Williston basin where good core data and numerous GR-neutron-density logs are present. Basin-margin, shallow-burial diagenesis beneath the Acadian unconformity formed a paleokarst characterized by evaporite dissolution and massive dolomitization. This diagenesis is illustrated in the Duperow and Birdbear formations, which consist of stratiform limestone, dolostone and anhydrite beds in the basin-center. These layered lithologies transition to massive dolostone in subcrop areas beneath the Acadian unconformity. A sub-unconformity paleo-dissolution front extends as much as 50 m below the unconformity and former anhydrite beds are now represented by solution-breccia beds within the dissolution area. Massive dolostone cuts across stratigraphic units and extends as much as 70 m below the Acadian unconformity.

While they overlapped in basin-margin areas, massive dolomitization was not related to the fresh-water processes that produced evaporite dissolution during paleokarst formation. Since the massive dolomitization front is sub-parallel to the unconformity over large areas and there is no massive dolostone in overlying basal Lodgepole beds, it is likely that dolomitization occurred after unconformity development and before Lodgepole deposition. This indicates that basin-margin dolomitization took place while Bakken-Pronghorn sediments were being deposited, 10-20 million years after deposition of the Birdbear and Duperow. Basin-margin massive dolomitization probably occurred during one or more evaporative events that caused regional dolomitization within carbonates of the Middle Bakken. The "massive" characteristics, defined by the absence of a stratiform geometry, relate to dolomitization that occurred after mineral stabilization and initial lithification within the Duperow and Birdbear.

PIERSON, RAYMOND M., Independent Petroleum Geological Consultant, Windsor, CO

The "ELLa GRA Process" - Concepts and methods for the prediction of reservoir hydrocarbon type using ratios of gas chromatography C1-C5 gases

The presentation will help provide greater understanding of the application of gas ratio analyses for the purposes of predicting the hydrocarbon type from which the gases were liberated during drilling. Using the various ratios described and contained in this presentation, it becomes possible to predict and interpret the hydrocarbon source types (not to be confused with the source rock). This is possible based on the premise that rock cuttings from any particular formation "produce" the gases, or the hydrocarbon vapors they contain, into the drilling mud. These same gases are detectable at the surface with the use of Gas Chromatography. It is reasonable to assume that the same formation, if completed, would produce gases of a similar composition. The use of ratios becomes a help in "fingerprinting" the source hydrocarbons. The presentation begins with an overview of basic concepts, then presents various analytical tools and techniques, discusses data applications and concludes with examples of how the ratios are integrated into and enhance reservoir description using the techniques presented.

REPPE, CALVIN C., KIC Oil and Gas Associates, LLC, Denver, CO

Exploration of resource plays in the Rocky Mountain Basins and the economic consequences

The Upper Cretaceous exploration resource plays in the Powder River Basin of Wyoming and the Denver-Julesburg Basin of Colorado, Nebraska, and Wyoming have numerous stacked plays. The Powder River Basin exploration resource plays include the Teapot Ss, Teckla Ss, Parkman Ss, Sussex Ss, Shannon Ss, Niobrara chalks and marls, Frontier-Turner Ss, and Mowry siliceous siltstones and sandstones. The Denver-Julesburg Basin exploration resource plays include the Niobrara chalks and marls, Fort Hayes Ls, Codell Ss, and Greenhorn Ls-Ss.

The exploration techniques utilized in the evaluation and reservoir characterization of each of these prospective producing horizons may include: 1) well log, core, DST, petrophysics, and sequence stratigraphic evaluations and interpretations; 2) borehole temperature modeling and GOR modeling; 3) source rock and rock mechanics evaluations which may include cores, drill cuttings, geochemistry, microscopy, conductivity, and proppant analysis; and 4) seismic interpretations and sequence stratigraphic and structural 3D reservoir modeling. These four techniques are then incorporated into an integrated reservoir characterization model and applied into the drilling, completion, and reservoir engineering. These techniques do not need to be costly, if already available geologic data is utilized and paired with a precisely modeled study.

These stacked exploration resource plays have the potential to significantly improve the economics of the plays. The TEAM approach will result in identifying and high grading sweet spots, infill locations, and PUD's for greater producibility. The rates of return (ROR), return on investment (ROI), and net present value (NPV) for the exploration resource play improves.

RICHMOND, DEAN R., Select Exploration Group LLC, Arcadia, OK, and NATHAN MURPHY, Judith River Dinosaur Institute, Billings, MT

Beach front property in central Montana: The upper Jurassic Morrison Formation in the northern portion of the foreland basin

The Upper Jurassic Morrison Formation covers much of the Western Interior of the United States. During the Oxfordian, the Sundance Sea retreated northward across Montana. The result was deposition of terrestrial Morrison sediments in the Jurassic-aged foreland basin. The formation as a whole has been studied extensively by paleontologists and geologists since the late 19th century. However, the formation in central Montana, with accompanying fauna and flora, remained unstudied. This is the area of interest for this project. Preliminary research shows that this northernmost region has characteristic distinctive from the southern regions of the formation. The J5 unconformity is not present in this area, indicating that deposition from marine to terrestrial was continuous. In recent years, two undescribed sauropod dinosaurs and the first known herd of stegosaurs have been excavated. The excavations are located in a very geologically complex region on the northeastern flank of the Big Snowy Mountains, at the convergence of the Rocky Mountains and the Great Plains. To date, this is the northernmost occurrence of Jurassic dinosaurian remains in North America. This project is a multifaceted approach to recreate the Morrison paleoenvironment. Geological investigation includes structure, stratigraphy, well log analysis, sedimentology, petrology, and geochemistry. Paleontological research consists of the osteological description of the dinosaurs, vertebrate taphonomy, and bone histology. Identification of various invertebrates (bivalves, gastropods, and ostracods) and their depositional environment is included in the study. The intent of the paleobotany study is to identify macroflora (petrified wood), and microflora (seeds and charophytes) and interpret the paleoclimate as evidenced by physical characteristics and growth patterns. Faunal and floral microfossils establish the biostratigraphic framework. The intent of this compilation is to understand the paleoenvironment, paleoecology, and paleoclimate of the previously unstudied Upper Jurassic Formation in central Montana.

RULONG-RASMUSSEN, KELLIE, Oasis Petroleum, Houston, TX

Reservoir characterization of Divide County, North Dakota

This study focuses on the first bench of the Three Forks Formation of the Bakken Petroleum System along the northern fringes of the Williston Basin, in Divide County, North Dakota. The aim of the study is to delineate the productive play fairway and its reservoir characteristics as found through wireline log analysis (structure, isopach, and petrophysical), utilization of prior geochemical analysis and publically available core analysis. Production results have similar volumes in the over-pressured basin center making the understanding of primary drivers essential. Regional structural mapping, petrophysical analysis and geochemical analysis aid in the delineation of three target areas.

Regional mapping of all publically available subsurface data within the study area in concert with regional strike and dip traverses of cross-sectional displays exhibits a group of structural trends with corresponding porosity trends in the 8.4% to 11.1% range. Reactivation of basement faults from the subduction of the Kula and Farallon plates during the Mesozoic and Cenozoic are the best explanation for their formation. Log and geochemical analysis show that the lower Bakken Shale Formation is not mature enough to contribute the bulk of hydrocarbon; therefore, the majority of hydrocarbons present migrated into the system from the basin center. The structure feature located in Divide County exhibits 283.8 MMBO of net reservoir barrels as calculated through cross-sectional areas. Two inferred migration pathways in the form of structural trends bound and developed porosity trends, which supply the study area with 179.2 MMBO of migrated light hydrocarbons.

All data included in the full-scale analysis of this capstone is public in origin. The limitations of that data source restrict the ability to pinpoint definitively the exact geologic mechanisms that drive improved performance within the study area; however, numerous key trends and characteristics support this hypothesis. Additional data beyond the public realm is necessary to understand the burial and tectonic history of the area, structural limitation, causation of porosity and lower Bakken Shale hydrocarbon contribution. Specifically, 2D/3D seismic data would be required to achieve a greater understanding of this analysis.

SAPARDINA, DESSY WIDYASTI, and PIRET PLINK-BJÖRKLUND, Colorado School of Mines, Golden, CO

Contrasting facies in slope and basin-floor deposits that correspond to rising and flat shelf edge trajectories, Lewis Shale, Washakie Basin, Wyoming

The Upper Cretaceous Lewis Shale shelf margin of the Washakie basin, Wyoming, is a distinctive system, as this margin has a high sediment supply compared to many other systems, and thus produced basin-floor fans during relative sea-level lowstands as well as highstands. This study focuses on comparing and contrasting the slope and basin-floor deposition during lowstands and highstand, with the aim to understand the differences of depositional dynamics in rising vs falling relative sea-level conditions in such sediment-supply dominated systems.

Sixteen sedimentary facies are identified using detailed core descriptions based on lithology, sedimentary structures, and biogenic features. The falling stage and lowstand systems are recognized as shelf-margin clinothems with falling or flat shelf-edge trajectory, and the highstand systems as shelf-margin clinothems with rising shelf-edge trajectory.

This study shows that there is no distinct difference in the distribution of facies in lowstand vs highstand fans. Thus, other criteria have to be used to contrast the slope and basin-floor fan deposits. Facies proportions, occurrence of linked debrites, bed thickness, grain size, organic matter content, sandstone sorting, and sandstone sedimentary structures are shown to differ, and these differences are interpreted to be mainly controlled by the river-mouth position in relation the shelf edge and by the availability of accommodation on the shelf. During falling or low relative sea level (flat shelf-edge trajectory), a river mouth feeds directly into slope and basin, as the self is exposed, resulting in thicker and coarser slope and basin-floor deposits, more abundant organic content on the basin floor, poor to moderate sandstone sorting, and a higher proportion of structureless and graded sandstone. The latter is related to high deposition rates. In contrast, during relative rise of sea level (rising shelf-edge trajectory), a larger proportion of sediment accumulated on the shelf, resulting in thinner and finer beds on the slope and basin floor, low organic matter content, moderate to good sandstone sorting, and more laminated sandstone facies. The latter reflects lower deposition rates, compared to the lowstand systems. The improved sorting is assigned to transient reworking of sediment on the shelf by basinal processes.

SCHAMEL, STEVEN, GeoX Consulting Inc., Salt Lake City, UT

Sunnyside oil sand reservoirs at Bruin Point, southwest Uinta Basin - a core photo poster

The south flank of the Uinta Basin in northeast Utah is the high Tavaputs Plateau, which dips gently northward towards the basin center and is deeply dissected by the Green River and its tributaries. Where not removed by canyon incision, bitumen-impregnated sandstones in the middle Green River Formation (lower Eocene) occur along nearly the full length of the plateau. The bituminous sandstones encompass an area greater than 600 square miles and hold an estimated 11.6 to 14.0 billion barrels (BBO) of crude oil, but the net thickness of the bituminous sandstone and the OOIP rarely exceed 70 feet and 80 thousand barrels per acre (MBO/ac), respectively. However, in an exceptional 4.5 square mile area centered on Bruin Point (elev. 10,120 ft) on the southwest basin rim, the net thickness of bituminous sandstone and OOIP are measured in hundreds of feet and MBO/ac, respectively. The estimated OOIP in just this small area is 1.16 BBO. Bruin Point is an erosional remnant of a structural-stratigraphic trap formed by the superposition of a monoclinal flexure on a thick stack of deltaic-littoral sandstones. In the 1970s-1980s, this unique area was extensively evaluated to characterize the reservoirs and delineate the oil resource. Over 120 test wells with cores were drilled and analyzed. As many as 32 stacked bituminous sandstone bodies were encountered, 17 of which hold nearly all of the oil. The sandstones were deposited in constantly shifting deltaic lobes and along inter-delta shorelines. They are encased in marsh and floodplain mudstone and littoral calcareous mudstone and bioclastites. The sandstones are poorly-sorted, fine-grained feldspathic arenites up to 115 ft thick in distributary channels, but less than 10 ft thick in beach deposits. Average porosity and permeability are 23% and 570 md, respectively, but values vary widely between, and even within, depositional settings. The bitumen at Bruin Point is heavy (8.6 degrees API) and highly viscous (10 million cp). Just 25 miles to the north, these same deltaic sandstones are the reservoirs in the greater Monument Butte conventional oil fields. Although many operators have attempted to exploit this site for liquid hydrocarbons using both in situ steam flood and mining with solvent extraction, so far only small-scale mining of the bituminous sands for road construction has been commercially successful. This poster presents four cores, several approaching 1,000 ft in length, that graphically display the distribution of oil resource as related to stratigraphic heterogeneity and location within the deposit.

SCHULTZ, CLAYTON, SM Energy, Houston, TX, MICHAEL H. HOFMANN, and MARC HENDRIX, University of Montana, Missoula, MT

Diagenesis of the Sappington Formation, SW Montana: Insight into reservoir heterogeneity in the time-equivalent Bakken Formation

The middle member of the Late Devonian-Early Mississippian Bakken Formation has been the focus of petroleum exploration and development in the Williston Basin over the last decade. Yet, the relationship between diagenesis, reservoir architecture, depositional facies, and reservoir quality has remained undocumented. Previous studies have relied on information gleaned from core and well log data, which is insufficient to provide a comprehensive understanding of the depositional and diagenetic history.

This study focuses on the time-equivalent Sappington Formation, exposed across SW and central Montana and lithostratigraphically continuous with the Bakken. The excellent outcrops of the Sappington Formation in the Bridger Range, north of Bozeman, Montana, provide an opportunity to observe and quantify the influence that facies variability and stratigraphic architectures have on diagenesis.

Diagenesis in the Sappington Formation is characterized by a complex paragenetic sequence that started shortly after deposition. Early dissolution of detrital feldspar created abundant secondary porosity at shallow burial depths. Subsequently, syntaxial overgrowths and illite linings formed on the surfaces of detrital quartz grains. Increased burial resulted in the precipitation of magnesian dolomite rhombs with ferroan rims, and ferroan dolomite rhombs. Later-stage pyrite and calcite cements commonly replace dolomite. Dissolution of dolomite during maturation of organic matter in the overlying and underlying shale promoted late stage dolomite dissolution and secondary porosity development.

The distribution of cements in the Sappington can be linked to the primary depositional fabric, reservoir architectures, and influence from faults. Dolomite and calcite cements are most abundant in the coarsest-grained depositional facies where they occlude porosity. Conversely, well-developed illite linings are most abundant in the finer-grained facies where they inhibit abundant dolomite cementation. Clinoformal sedimentary architectural elements served to compartmentalize diagenetic fluids, resulting in large variations in dolomite cementation across clinoformal bounding surfaces. Large faults served as upward-migrating fluid conduits resulted in porosity-occluding dolomite cementation on the down-dropped side of the fault.

The facies and post-depositional history between the Sappington Formation and the Bakken Formation is strikingly similar. Understanding the distribution of cements and pores within a depositional and structural framework is essential to identify and predict the best target intervals to optimize horizontal well spacing and completion design in the Bakken Formation. Integrating findings from this study to existing facies models and structural frameworks in the Bakken Formation will assist in predicting reservoir heterogeneity away from well control and enhance development strategies.

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Using outcrop of the Three Forks Formation in western Montana as an analog to the subsurface Three Forks reservoir of the Bakken Petroleum system

Outcropping lithologies of the Logan Gulch Member of the Late Devonian Three Forks Formation in Western Montana can be used as an analog to study the equivalent reservoir lithologies of the Three Forks Formation in the Williston Basin Bakken Petroleum System. The western Montana Three Forks Formation is subdivided into two Members: The lower supratidal-to-intertidal Logan Gulch Member, and the overlying marine Trident Member. Only the Logan Gulch Member lithologies are equivalent to the Williston Basin Three Forks Formation lithologies. Unlike in the Williston Basin where the Three Forks Formation exists wholly in the subsurface, the reservoir-equivalent lithologies in Western Montana are spectacularly exposed.

Our method was to first locate and describe outcrops of the Three Forks Formation that contain good expressions of correlative reservoir intervals in order to create a workable analog to the Three Forks Formation reservoir. Based on sedimentological and stratigraphic analysis of nine outcrops across western Montana, the Logan Gulch Member was found to contain a heterolithic intertidal facies composed of interbbeded dolostone and dolomitic shale that bears a striking sedimentological similarity to the Williston Basin Three Forks reservoir facies. Due to complex basin geometry, the thickest deposits of the intertidal facies occur updip on the margin of the Beartooth Shelf. Elements of this facies are interfingered with supratidal deposits that include massive beds of anhydrite collapse breccia. These supratidal deposits are the depositional equivalent to the anhydrite beds of the lower Three Forks Formation in the Williston Basin and the thick evaporites in the subsurface Potlatch Formation of northwestern Montana

The Logan Gulch Member is composed of a transgressive systems tract that comprises a partial stratigraphic sequence. This partial sequence is bounded by two regionally recognized sequence boundaries. The overlying Sappington Formation progressively truncates the Logan Gulch Member in outcrops to the east. The thickest expressions of the intertidal facies most comparable to the “Apple-Tan” Three Forks reservoir are found in the easternmost outcrops. Detailed study of these outcrops will provide better understanding of lateral lithofacies relationships within Three Forks reservoir lithologies in the subsurface.

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Strategies for effective petroleum systems analysis: Tertiary lacustrine systems of the Greater Rocky Mountains

Tertiary lacustrine depositional systems developed in a variety of structural settings within the Greater Rocky Mountain region: compressional, transtensional, and extensional basins. While sharing certain traits, each of these basins formed within a unique geographic and stratigraphic setting. These individual settings have a profound influence on the resulting lacustrine system (water budget vs. sedimentation rate vs. accommodation) and invoke a unique set of petroleum system elements and processes. Elements include source rock (quality and quantity), reservoir, seal, and overburden material, while the processes consist of trap formation, and hydrocarbon generation / migration / accumulation. Taken individually, each component yields a partial understanding of the petroleum system, but each needs to be interpreted in a collective manner. A work flow protocol that identifies both critical variables and geologic input is advocated. The successful exploration program will seek to understand the petroleum system as a whole by relating the source rock data, including kerogen kinetics with accurate thermal maturity analysis, to the geographic and stratigraphic framework. This study will compare and contrast petroleum system elements and processes of Tertiary lacustrine systems in the Greater Rocky Mountain region to demonstrate the benefits of comprehensive and detailed petroleum systems analysis.

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Codell Sandstone, DJ Basin, what sets Brennsee/Fairway Field apart from Wattenberg Field: core characteristics in a tight oil and gas play

The Codell Sandstone has been producing gas and oil in the Colorado/Wyoming DJ Basin since 1979. Due to relatively good porosity but low permeability Codell production has historically been restricted to the Wattenberg Field where thermal maturity of the Codell is in the gas window. Recent advances in horizontal drilling and multi-stage fracture stimulations have extended the play outside of Wattenberg Field into the northern DJ Basin. Stabilized production rates up to 1300 BOPD are associated with recently completed horizontal Codell wells at Brennsee/Fairway Field. The Brennsee/Fairway Field in Laramie County, Wyoming is distinct from Wattenberg Field and has maturity in the oil window with gas-oil ratios <1000 scf/bbl and wells producing 40-50% water cuts. Wattenberg Field has been pushed from the gas window into a high oil gravity window with gas-oil ratios >1000scf/bbl and little to no water production. The Codell Sandstone was deposited on the eastern side of the Western Interior Seaway by storm events during Late Cretaceous time. The Codell at Brennsee/Fairway Field is a very-fine to fine-grained very poorly sorted sand that produces oil from two facies: bioturbated sandstone and hummocky sandstone. The Codell in Wattenberg is very-fine grained and better sorted than at Brennsee/Fairway Field and produces primarily from bioturbated sandstone. Porosity ranges from 6 to 16% for both areas but perm is lower in Wattenberg. MICP data shows that pore throat size decreases from north to south from Brennsee/Fairway down to Wattenberg. The Codell is a low-resistivity pay zone in both Fields that produces gas/oil from zones with less than 10 ohm-m resistivity. Clay content is approximately 20% with abundant microporosity in feldspars as imaged with epifluorescent microscopy. Codell thins from north to south due to erosional truncation beneath an angular unconformity at the base of the Fort Hayes Limestone Member of the Niobrara Formation. Gross thickness ranges from <5 to 40 feet. Two Codell cores will provide an example of the two depositional facies and rock characteristics of the Brennsee/Fairway and Wattenberg Fields. The Child VO #30-9 core in Laramie County recovered 26 feet of Codell Sandstone, including 22 feet of bioturbated facies and 4 feet of hummocky facies. The Rock Oil Ronald #1 core recovered 12 feet of Codell Sandstone, all bioturbated facies. Both Codell cores lie in productive areas, the Child core is in the heart of the Brennsee Oil Field and the Ronald core is on the edge of the Wattenberg gas/oil window near Wells Ranch area of development.

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Sequence stratigraphy of the Bakken and Three Forks Formations, Williston Basin, USA

The Williston Basin Bakken petroleum system is a giant continuous accumulation. The petroleum system consists of source beds in the upper and lower Bakken shales and reservoirs in the middle, and upper Three Forks, Pronghorn member of the Bakken and the middle Bakken. The Petroleum System is characterized by low-porosity and permeability reservoirs, organic-rich source rocks, and regional hydrocarbon charge. USGS (2013) mean technologically recoverable resource estimates for the Bakken Petroleum System is 7.375 billion barrels oil, 6.7 TCF gas, and 527 million barrels of natural gas liquids.

The Three Forks is a silty dolostone throughout much of its stratigraphic interval. The Three Forks ranges in thickness from less than 25 ft to over 250 ft in the mapped area. Thickness patterns are controlled by paleostructural features such as the Poplar Dome, Nesson, Antelope, Cedar Creek, and Bottineau anticlines. Thinning and/or truncation occurs over the crest of the highs and thickening of strata occurs on the flanks of the highs. The Three Forks can be subdivided into three units (up to six by some authors). Most of the development activity in the Three Forks targets the upper Three Forks.

The Three Forks consists of at least five system tracts: a lowstand system tract consisting of the lower continental to supratidal sediments (overlies marine Birdbear carbonates and evaporites); overlain by a transgressive system tract of subtidal dolostone; overlain by a highstand systems tract of the middle Three Forks consisting mainly of peritidal sediments; in turn overlain by a transgressive system tract representing subtidal dolostones; which in turn is overlain by highstand systems tract of the upper Three Forks consisting of peritidal dolostones. A major unconformity separates the Three Forks from the Bakken Formations probably representing tectonic movement from the Acadian/Antler orogenies. The unconformity is complex in that it probably represents both a lowstand surface of erosion and a transgressive surface of erosion.

The Bakken Formation regionally in the Williston Basin consists of four members: upper and lower organic-rich black shale; a middle member (silty dolostone or limestone to sandstone lithology); a basal member (dolostone, limestone, and siltstone) recently named the Pronghorn. The Bakken Formation ranges in thickness from a wedge edge to over 140 ft with the thickest area in the Bakken located in northwest North Dakota, east of the Nesson anticline.

The Bakken in the U.S. Williston Basin consists of five system tracts: the Pronghorn member represents a lowstand to transgressive system tract (proximal and distal members); a lower transgressive system tract consisting of the Lower Bakken Shale; a highstand systems tract consisting of the lower Middle Member; a falling stage to lowstand systems tract consisting of the oolitic, bioclastic, sandy Middle Member; overlain by a transgressive system tract consisting of the upper Middle Bakken and the Upper Bakken Shale. The Upper Bakken Shale is overlain sharply by the Lodgepole Formation which represents a highstand systems tract.

Sharp downlap surfaces are noted at the base of the middle Bakken and the base of the Lodgepole. The downlap surfaces represent the transition from transgressive system tracts to highstand system tracts. Maximum flooding surfaces are found in the middle and upper portions of the upper and lower Bakken shales.

Relative sea level changes occur in the Bakken and Three Forks intervals related to both tectonics and glaciation. These changes result in the numerous system tracts identified in this study.

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Keys to Niobrara and Codell production, east Pony/Redtail area, Denver Basin, Colorado

The Niobrara Formation and Codell Sandstone are important producers in the East Pony and Redtail areas of the Denver Basin. These formations are currently being developed with horizontal drilling and multi-stage hydraulic fracturing. Many geological and technological factors influence production in this area. Principal source beds are the Sharon Springs member of the Pierre Shale, Niobrara marls, Carlile Formation shales, and Greenhorn Formation organic-rich marl/shale intervals. Source bed maturity is an important control on production. Elevated maturity values as compared to surrounding areas appears to be related to continuation of the Wattenberg Field geothermal anomaly. Maturity is recognized by source rock and petrophysical analyses. Other important keys to production include matrix and fracture porosity and permeability, reservoir facies, mechanical stratigraphy, and drilling and completion technologies.

The Niobrara is approximately 300 ft thick and consists of Smoky Hill and Fort Hays members. Vertical depths to the Niobrara are approximately 5600 to 5950 ft for the area. The Smoky Hill is approximately 280 ft thick and can be divided into five chalks units (in descending order: A, B1, B2, C, and D). Porosities as measured on density logs for the chalk interval ranges from 12 to 16%. The most important source rocks in the Smoky Hill member are found in the A marl, and C marl units. TOC contents range from 3-5.5 wt. %. The C marl unit has anomalously high resistivity as compared to other areas in the Denver Basin.

The Codell is 7-10 ft thick in the area. It is also targeted with horizontal drilling. The overlying Fort Hays member of the Niobrara and Codell are thought to be a common-source-of-supply. Oil-in-place for the area is estimated to be 40-70 MMBOE per section. Operators are planning for 16 wells per drilling and spacing units (640 to 9660-acre). Recoverable oil per well at a 10% recovery factor is 370 MBOE. Initial production has been up to 860 BOEPD for B chalk completions.

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Quantifying the impact of flow back methods on horizontal wells, DJ Basin, Colorado

Eight years into the horizontal development of the Niobrara oil play in the DJ Basin operators still struggle to understand and explain well performance. Small operators with limited acreage positions do not have the luxury of the trial and error approach operators with large contiguous positions can take. Determining best practices now commonly includes some form of multivariate statistical analysis. Completion parameters, geologic variables, well spacing/orientation, seismic derivatives, and reservoir parameters are common inputs to these models. However, even the most robust model can still fail to explain well performance.

A geoscientist's role in the development of unconventional reservoirs is evolving. In addition to needing to be geosteerers, understanding geomechanics, seismic data, completions and reservoir engineering, geoscientists now need to understand how a well was produced to explain its performance.

In the DJ Basin, it is demonstrable that operators with acreage positions in established fringe areas can outperform offset operators with better quality acreage positions. A key driver to a well's performance is how the well was flowed back, this is especially important in low GOR areas. This paper will focus on quantifying the impact of flow back methods on well performance which can only be done after the aforementioned variables are understood and modeled with a multivariate approach.

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Sandstone composition variation in regressive to transgressive cycles in the Telegraph Creek and Eagle formations in south-central Montana

The Upper Cretaceous Telegraph Creek and Eagle formations in south-central Montana contain a series of regressive to transgressive cycles deposited on the western margin of the Cretaceous Interior Seaway. This study focuses on sandstone mineralogy/provenance and sandstone clay composition. Four cycles have been identified and mapped regionally using outcrop and subsurface data. Each cycle left behind an upward-coarsening shoreface and/or deltaic sandstone body, capped by either a transgressive sand, an erosional top or maximum flooding surface. Each successive cycle stepped further basinward creating a larger progradational wedge. The lowest cycle studied, the Telegraph Creek Formation, contains a single regressive sandstone topped by a transgressive ravinement surface and pebble lag. Petrographic composition modes average Qt/F/L 54/25/21 and clay content is primarily Fe chlorite and berthierine. The Eagle Formation is composed of three cycles. The basal cycle is a detached low-stand delta capped by a ravinement surface, which is overlain by transgressive “green” marine sands. The regressive delta sandstones average Qt/F/L 59/17/24 and clays present are dominantly Fe chlorite and berthierine. The “green” sands are Qt/F/L 68/11/21 and the clays primarily smectite, Fe chlorite and glauconite. The middle cycle is a highstand normal regressive delta and a sharp-based forced regressive shoreface that are incised into. This is indicative of base-level fall and the incision surface represents a sequence boundary. The delta sandstones are Qt/F/L 66/17/17 and clays dominantly Fe chlorite and berthierine. The shoreface Qt/F/L is 68/17/15 and clays are primarily kaolinite and Fe chlorite. This is transgressed by a tidally-influenced valley-fill, shoreface, and marine “green” sand. The valley fill is Qt/F/L 73/14/13 with clays primarily kaolinite and Fe chlorite in the lower part. Smectite and glauconite become abundant in the upper part. The shoreface is Qt/F/L 68/15/17 with clays primarily smectite, Fe chlorite, and glauconite. The "green" sand is Qt/F/L 70/10/20 and clays are primarily smectite and glauconite. The top cycle is normal regressive shoreface and delta deposits capped by a transgressive ravinement surface with a black chert-pebble lag, representing the Claggett transgression. The delta deposits are Qt/F/L 72/13/15 and the shoreface is Qt/F/L 81/8/11. Clays in this cycle are dominantly Fe chlorite and berthierine. Petrographic data indicate that all cycles are sourced from a recycled orogen setting with a trend of increasing quartz content up-section. Potassium to plagioclase feldspar ratios are ~1 to 1 in the Telegraph Creek, basal Eagle cycle, and the incised valley fill/transgressive shoreface part of the middle Eagle cycle; otherwise the ratios are ~2 to 1. The lower ratios are coincident with the presence of bentonite beds, indicating active volcanism. The dominate clays in regressive sandstones represent a verdine facies (Fe chlorite ~35% and berthierine ~25%) indicating deposition in a shallow warm-water nearshore setting with substantial fresh water input. Transgressive clays are dominated by smectite (~25%), Fe chlorite (~20%), and glauconite (~15%), similar to a glaucony facies suggesting a dominance of marine shelf processes. The preponderance of kaolinite (~30%) in forced regression shoreface and valley fill sediments is thought to be the result of delta plain incision.

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3D reservoir characterization and integrated completion optimization for understanding horizontal well spacing and frac staging of the Niobrara Fm., DJ Basin

Detailed subsurface characterization for developing unconventional oil and gas assets is a critical component in understanding where and how to drill horizontal wells, pinpoint subsurface targets, identify reservoir sweet spots, optimize well spacing in a DSU, determine resource-in-place [STOOIP] and engineer completion designs. A new methodology is developed employing statistical rock physics techniques in order to address these complex unconventional challenges. This procedure integrates petrophysics, rock typing, 3D seismic attributes and geostatistics to build the reservoir model, and most importantly, directly incorporates the model results into frac designs. This methodology is employed on the Cretaceous Niobrara fm. in the DJ Basin where horizontal pad drilling has been in practice for a number of years with much experimentation in terms of well spacing, stage spacing and job size. As a result of the industry downturn, operators are now more focused on increasing recovery factors in a DSU while maintaining individual well economics; i.e. ROCE. This new process goes right to those concerns which will allow operators to make more informed decisions going forward.

Applied statistical rock physics approach for reservoir characterization integrates fundamental petrophysical concepts of effective porosity, hydrocarbon saturation and geomechanics with statistical and non-statistical pattern recognition, 3D seismic elastic properties and geostatistics. The petrophysics allows for the linkage between reservoir properties with seismic responses and to extend the data for training purposes in a supervised neural network or an unsupervised classification scheme. Geostatistic simulations add spatial correlation and small-scale variability along with uncertainty analysis in the model. This approach, along with the engineered completion designs, is proving to help in high-grading and ranking Niobrara horizontal well pads, managing production expectations and identifying the critical factors for increasing bbls/CFLAT in any given area of the basin.

Directly importing our reservoir models into the frac model has allowed for laterally varying properties across the length of the horizontal and more accurate calculations of permeability, stress and frac height. Most importantly, the production predictions obtained from the frac model are in much greater agreement with actual production in the area lending confidence to the quality of the reservoir-driven frac designs.

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From mantle to mountain top – A restorable east-west transect across Colorado following Interstate 70

In the spirit of past Colorado structural syntheses by Hayden, Grose and Tweto, the aim of this project is to build a restorable transect following Interstate 70 east to west across the state. The section incorporates disparate data sets including potential field, seismic, well, thermochronology, and outcrop data, much of which has become available since a section like this was last published, to illustrate Colorado's structural evolution. Restoring Laramide geometries involved using a projected top Cretaceous horizon as the upper bounding surface and a mid-crustal interface as the basal decollement/lower bounding surface. Refraction seismic combined with magnetotellurics provide evidence for the undulating mid-crustal interface at subsea depths between 12 and 29 km. In areas stripped to basement, missing stratal and structural cover geometries were projected into the section aided by low-temperature thermochronology and by analog to structures seen along strike. Ancestral Rocky Mountain structures were treated as early elements of the Laramide fault arrays, a premise supported by their reactivation during the Laramide. To permit restoration, the crooked section following Interstate 70 was projected into a straight profile oriented parallel to N65E, which approximates the Laramide transport direction. Recent wells and reflection seismic showing fault-bend folds, multiple bedding-parallel detachments, and stacked triangle zones guide the structural style and allow greater translation to be interpreted within the Laramide thrust systems. These data also show greater depths within some of the hinterland relative to the foreland basins suggesting underthrusting may have been an important structural process. Preliminary versions of the restoration show approximately 67 km of translation or 26% shortening across the uplifts between the Denver and Piceance basins. This synthesis indicates an early Laramide phase of differential subsidence starting at ~78 Ma and coincident with the arrival of magmatism related to encroaching flat-slab subduction beneath central Colorado. This was followed by a late Laramide phase of differential uplift starting at ~68 Ma and continuing episodically to at least 56 Ma. Onset of the early Laramide phase was marked by abrupt realignment of isopach trends with stratigraphic thicks developing in the Piceance and Denver basins separated by a thin across what are now South Park and the Sawatch Range. Onset of differential uplift during the late Laramide is indicated variously by the appearance of basement clasts in the Arapahoe Conglomerate at ~67 Ma, thrust deformation before, during and after intrusion of sills at ~63 Ma, fault gouge dated between ~68 and ~56 Ma, possible inflections in the apatite fission track elevation/age gradients at ~67 Ma, and deformation after the Laramie Fm. (~69 Ma) and before the South Park Fm. (~67Ma). The post-Laramide was marked by denudation and development of the Rocky Mountain Erosional Surface starting at ~45 Ma with localized increased heat flow and reburial of this surface beneath extensive volcanics to ~30 Ma. Differential extension overprinting the earlier contractional orogen began at ~28 Ma with the development of the Rio Grande Rift and other Tertiary basins and continues today. Finally, recent passive-source seismic shows low-density mantle and crust underly high elevations, active denudation and epeirogenic uplift centered on Colorado since ~10 Ma.

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Determining oil migration using Rare Earth Elements and cyclicity in the Pennsylvanian southern Tyler petroleum system, Williston Basin, North Dakota

Cyclicity of the Pennsylvanian Tyler Formation is evident in the rapid lithology changes in core samples and in the sequence boundaries and parasequences that are identified in geophysical logs. In addition, changes in paleoenvironments are indicated by the distribution of Rare Earth Elements (REE) derived from sediment and oil samples, and in the two kerogen types exhibited in the sediments of the Tyler Formation.

Extreme lithology changes observed in the cores range from terrestrial to deep oceanic sediments, indicate fluctuation in Tyler Formation depositional settings in Billings and Stark counties, North Dakota. Four cycles divided by three sequence boundaries were identified on well logs, as were ten third order parasequence cycles. The sequence boundaries can be identified and traced throughout the available geophysical logs in the gamma ray, resistivity, density and porosity.

The Tyler Formation represents both source and reservoir for the accumulated oil, and is independent of other reservoirs and source rocks in the Williston Basin. REE provide an excellent tool for fingerprinting different paleoenvironments. The sediment rocks collected from the Tyler core samples depicted paleoenvironments from anoxic-euxinic with abundant organic material, to suboxic-anoxic with moderate total organic carbon (TOC) and moderate clay, to oxic with high clay content and very low TOC, to a very basic, high pH, oxic environment with high salinity. The REE distribution on ternary diagrams of the oils indicated two distinctly different paleoenvironments; a normal oceanic oxic water with basic pH and relatively high salinity, and a suboxic to oxic environment with moderate organic matter and terrigenous influence (more acidic).

REE signatures of the Tyler oils compared with oil stained reservoir rocks demonstrate that the paleoenvironment of oil formation and sediment diagenesis are distinctly different from the paleoenvironment of the host rock.

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Cliff mapping of surface outcrops in the Powder River Basin using unmanned aerial systems

As an abundant petroleum producer since the late 1800s, the Powder River Basin continues to be a location of great interest for the oil and gas business. Continual advances in technology allow for enhancements in exploration and production. Formed during the Laramide Orogeny, it is a structural basin with abundant stratigraphic components. During the Cretaceous, the Powder River Basin was filled by the Western Interior Seaway which deposited numerous sandstone-shale sequences corresponding to numerous transgressions and regressions. The unit of interest for this study is the Campanian Shannon Member of the Cody Shale. The Shannon Member is laterally extensive in the Powder River Basin; it is thicker in the west and thins to the east. In the western portion of the basin the Shannon Member has several surface exposures that reach heights of up to 36 meters. These outcrops are steep cliffs of friable sandstone that pose safety risks for detailed mapping in close proximity. Unmanned Aerial Systems, commonly referred to as drones, can allow for detailed imaging of the outcrops without the risk to an individual. This detailed imaging will be high enough in quality to identify facies changes and sedimentary structures. Using a drone to survey these outcrops will produce a map equal to or higher in quality than existing maps. Cliff mapping of the Shannon outcrops in Natrona County, Wyoming near Edgerton, WY, will be performed with a rotor copter during the summer of 2017. After collection of the high resolution imagery, the images will be imported into Agisoft Photoscan which will allow for the creation of a detailed three dimensional map of the outcrops. This can then be compared to existing maps including the United States Geological Survey map MF-2095 by Margaret Ellis.

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Paleozoic source rocks and thermal history of the Denver Basin, Western Mid-Continent region USA

Recent drilling in Denver Basin has resulted in several new fields that produce from certain Paleozoic reservoirs. The Denver Basin is an asymmetric foreland basin with a north-south configuration that is up against the ancestral and present day Rocky Mountains. The Transcontinental Arch crosses through the center of the basin, south of the arch is the Pennsylvanian depo center for Denver Basin. They contain several thin highly organic carbonaceous mudstones within the Morrow to Marmaton formations. Pennsylvanian strata on and to the north of the Transcontinental Arch in the Denver Basin, production is from Permian reservoirs and almost all of the thin Pennsylvanian source rocks have disappeared. Prior to 2012 the source identity of petroleum found in the prolific Mississippian and Morrowan reservoirs had not been identified. Many authors assumed oil migrated from the deep Anadarko Basin into the Denver Basin. The Las Animas Arch, a northeast trending positive structural feature on the southeastern part of the Denver Basin make this unlikely. This feature was present during deposition of Paleozoic sediment and a barrier during times of expulsion and migration from the Anadarko Basin. The petroleum in accumulations west of the Las Animas Arch contain petroleum in reservoirs based on geochemistry that are not derived locally. The Cherokee and Marmaton formation reservoirs contain oil that is derived from marine carbonaceous shales and limestones present in the Cherokee strata. The Atokan rocks have generated oil which are lacustrine or terrestrial in nature. Recent drilling has identified Ordovician source rocks in Elbert County, Colorado close to the basin center that are not find elsewhere in the basin to date. The Pennsylvanian basin center, located on the southern end of the basin, has been thought by some researchers to be the area of petroleum maturation and expulsion but there is no evidence for this. Many of the Pennsylvanian carbonaceous shales in this area are less organic, contain more coarsely clastic material and there is a lack of oil shows or accumulations in this area. Discussed here will be the recent data that is available that suggests that oils in Paleozoic reservoirs were thermally altered and expelled from Morrowan, Atoka and Cherokee carbonaceous mudstones in the area of the present day basin center.

TEDESCO, STEVEN A., Running Foxes Petroleum Inc., Englewood, CO

Surface geochemical and aeromagnetics surveys integrated with subsurface geology and seismic data to find conventional reservoirs in the Mid-Continent United States

Prior to shooting seismic but after areas have been defined by subsurface well data or no data for petroleum exploration, aeromagnetics and surface geochemistry provide a way to high grade exploration and target definition. Defining basement features and faulting by aeromagnetics allows the identification in a general sense of the areas favorable to formation of structural closures and potentially stratigraphic traps. This is followed by surface geochemistry to define further where the accumulation(s) may actually be present. The surface geochemical methods specifically used were micro-magnetics, iodine and soil gas. The concept of surface geochemistry as a petroleum exploration tool is based on the concept of vertical migration of hydrocarbons from the reservoir to the near surface. Petroleum migrates from an accumulation along micro-pores, micro-fractures and micro-unconformities. The petroleum compounds react with atmosphere and soil substrate to create various compounds. The light hydrocarbons tend to escape to the atmosphere or be trapped temporarily as inclusions within carbonate minerals. The heavier hydrocarbons are generally broken down by plant and bacterial action. The presence or absence of surface geochemical anomalies over a specific target area allows the explorationist to either proceed forward to define a prospect further with other methods or abandon it. Surface geochemistry and aeromagnetics has proven to be an excellent screening tool for potential target areas. Presented here will be surface geochemical and aeromagnetic surveys integrated with seismic and subsurface data from the Denver, Michigan, Forest City and Williston basins in the central part of the USA.

TIMM, KIRA, and STEPHEN A. SONNENBERG, Colorado School of Mines, Golden, CO

Increased organic content in the presence of floccules: a case study of the Sharon Springs Member of the Pierre Shale, Cañon City Basin, south-central Colorado

Primary production within the Cañon City Basin, south-central Colorado, targets the fractured Upper Cretaceous Pierre Shale, which is sourced by the underlying Sharon Springs. The Sharon Springs Member of the Pierre Shale contains some of the most organic-rich sediments deposited in the Western Interior Cretaceous Seaway. Typically, organic carbon ranges from 2 to 11 weight percent while maturity of the source rock varies from immature to over-mature across the basin. Previous researchers variously ascribe the origin of the organic matter to fecal pellets, phytoclasts and amorphous material. Rock-eval pyrolysis indicates that the kerogen present is of Type II marine origin, however this does not explain the disproportionately high percentage of organic matter.

Facies analysis of the Bull 42-4 core, containing the Sharon Springs within the Cañon City Embayment, reveal the presence of sediment gravity flow deposits in the lowest facies of the Sharon Springs. When examined in petrographic thin-section, opaque spheroids represent the previously described fecal pellets or phytoclasts. FESEM analysis of these spheroids show an amalgamation of fine clay particles with an absence of casing surrounding the spheroids, indicating that they are not fecal pellets. Analysis of a bentonite bed, which has characteristics of a sediment gravity flow deposit, also contain diagenetically altered clay-aggregate spheroids. In stratigraphically higher facies, which show laminated fabric, the clay aggregates are elongated along the lamination, indicating a calmer environment of deposition with subsequent compaction.

Detailed XRF analysis of the core indicates that deposition occurred within dysoxic, anoxic or euxinic conditions.

Settling of clay particles is often aided by flocculation. In the presence of organic matter, the organic material will adsorb to the surface of the clay particles during flocculation. In flume studies performed by Shieber (2011), clay floccules formed in a current were shown to roll and compact into spheroids, similar to those seen in the sediment gravity flow deposits. However, those formed in quiet water settled as uncompacted aggregates. As seen in the Bull core, uncompacted aggregates align with foliation during burial. Bulk XRD analysis illustrates that the entirety of the Sharon Springs, despite variations in facies and depositional environment, is a silica-rich argillaceous mudstone. Detrital matter in the form of quartz and plagioclase were brought into the system along with clay and likely some or all of the organic matter. Enhanced organic concentrations result from adsorption of organic matter to clay floccules with subsequent deposition in dysoxic to euxinic conditions.

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A Simplistic workflow to estimate how much of OOIP is producible

The process of calculating original oil in place (OOIP) for unconventional oil plays is an important component in assessing a resource and tier-ranking acreage positions. Not all the oil in place is producible, however. An estimate of what percentage of the oil in place is producible, and how that percentage varies over a play, is also a useful parameter in the assessment process. For example, lower maturity, high TOC acreage where the oil in place is consists of higher amounts of immobile bitumen may yield large OOIP numbers but the fraction of that OOIP that is producible may be significantly diminished.

Obtaining an accurate measurement of how much of the oil in an unconventional reservoir is producible is a difficult proposition, but obtaining an estimate that admittedly has error bars can be a useful tool. A simplistic approach to obtaining such an estimate involves comparing produced oil to oil extracted from core via some simple geochemical analyses. Three independent methodologies were applied to arrive at an estimate of the amount of producible oil in core: extract GC, bulk composition SARA analysis, and modified programmed pyrolysis. We will discuss one workflow to estimate producible vs. non-producible oil for several reservoirs.

TUTTLE, TREVOR R., and SAMUEL M. HUDSON, Brigham Young University, Provo, UT

Fine-scale spatial distribution of organofacies in the Mowry Shale, Wind River Basin, Lander, Wyoming

The Cretaceous Mowry Shale is an organic rich, siliceous marine shale, and as such is a major source rock in the Western United States. Because the amount of organic material in a rock is linked to its oil and gas generative capability, several studies have outlined the lateral variability of total organic carbon (TOC) on a basin scale, covering large areas with limited sample sets. Little is known about fine-scale lateral variations of TOC on a scale of several miles, however. Over 300 samples from the same 10-cm stratigraphic interval of the Mowry Shale have been collected at regular 10 meter intervals over three outcrops near Lander, Wyoming. Pyrolysis analysis and clay mineralogical characterization of samples shows meaningful fine-scale variations and spatial trends. Average TOC of all samples is 1.65% with a standard deviation of 0.229 and a range of 1.57%, and samples are characterized as either Type III or mixed Type II/III source facies. Based on a 3D spatial model built in Petrel, TOC decreases basinward (southeast) in the study area despite a documented larger regional increasing basinward trend. Additionally, kerogen types become slightly more gas prone in a basinward direction. This suggests important localized trends, often important on a production scale, in both the Mowry shale and other fine-grained systems can be quite different than larger, generalized basinward trends.

VAN DELINDER. STEVEN W., and THOMAS A. HEWETT, Ballard Petroleum Holdings, LLC, Billings, MT

Stacking geometry of the Parkman Sandstone and its controls on production: A case study of the Porcupine to K-Bar area of the Powder River Basin

The Parkman Sandstone may prove to be the single largest unconventional sandstone oil reservoir play in the Powder River Basin; however, it has been plagued with variables that have impeded its development. Issues that have confounded operators include pay identification, water cut prediction and trap configuration. Five Parkman cores in the study area were analyzed and described at a very high resolution level. These descriptions were subsequently incorporated into subsurface open hole log characteristics to determine recognizable pattern signatures for facies and depositional interpretation. Through this, a model was developed consisting of a highstand systems tract bound at the top by a significant wave ravinement surface. This is overlain by a diachronous transgressive systems tract that onlaps and backsteps west-northwest in the study area. Four 3D seismic data sets covering a large portion of the study area were merged and re-processed with simultaneous inversion techniques to extract rock property volumes. After inversion, the data set revealed confirmation of the depositional model stacking pattern that otherwise cannot be seen in the traditional P-wave data. The two systems tracts have distinctly different internal stacking patterns which control sand body geometry. This appears to have a significant influence on productivity.

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Great Salt Lake microbial carbonates: Geology Vs. Biology

Great Salt Lake in northern Utah contains a wide variety of microbial carbonate structures, but several questions still exist about their formation and morphology. All currently submerged microbialites in the South Arm of the lake are covered with a green-brown "living" microbial mat. However, several unique morphologic characteristics exist depending on the microbialite's location relative to wave energy, proximity to the shoreline and bedrock outcrops, as well as other factors. For example, larger, taller, and more well-cemented microbial domes tend to occur in higher-energy environments (e.g., north side of Lady Finger Point, Antelope Island), whereas smaller, low-profile, poorly cemented superficial domes are common in sheltered areas (e.g., Bridger Bay, Antelope Island). Petrographic analysis reveals that microbialites in high-energy environments contain a higher ratio of carbonate grains to microbial clots than structures in low-energy environments. In locales far from bedrock outcrops (e.g., Bridger Bay), the microbialites are composed mostly of clots and carbonate rip-ups, ooids, and pellets, whereas structures near steep bedrock cliffs contain significantly more lithic fragments (e.g., Buffalo Point, Antelope Island). In some locations, the microbialites form mushroom-shaped structures, whereas in other areas they develop as long, linear ridges. As research progressed, one significant question remained unanswered: is the morphology of the microbialites only related to geologic/environmental conditions, or do different microbial communities play a role in the variety of microbialite shapes and sizes? To answer this question, microbiologists from Montana State University analyzed the microbial community compositions of the microbialites surveyed in this study using next-generation DNA sequencing techniques. Bottom line, the microbial community across all sampled sites in the South Arm of Great Salt Lake are not significantly different, indicating that geology/environmental variation is the primary driver of microbialite morphology. This new observation has significant implications regarding our understanding of microbialite formation and the interpretation of ancient analogs in the rock record, including microbial reservoir facies.

VANG, KORBIE, ZACHARY GRIGGS, KOURTNEY GRISHAM, STEVEN BORN, MICHAEL LACOURSE, and WILLIAM LITTLE, Brigham Young University-Idaho, Rexburg, ID

Strategic placement of Alfalfa to achieve up-floodplain gradient channel migration

Previous studies conducted at BYU-Idaho have successfully created meandering patterns on a 1.22 x 2.27-m stream table by adjusting bank cohesion through the use of alfalfa; well-sorted sand, and kaolinite clay. Well-sorted sand and kaolinite clay alone in a homogenous mixture resulted in a meandering stream that had wide, shallow channels and low sinuosity. Adding alfalfa seeds as a uniform blanket to mimic natural vegetation generated a meandering pattern with narrow, deep channels, higher sinuosity, and regularly spaces, angular meander bends. Our objective was to take this process another step and create a meandering channel that more closely resembled a natural pattern, in which bends became more chaotic and portions of the channel migrated up-gradient. To do this, we added heterogeneity to the floodplain by separating the sand and clay into individual beds, with sand on the bottom overlain by a thinner layer of kaolinite. This was done to encourage undercutting, bank collapse, and channel armoring to more closely simulate natural stream erosional processes. We hypothesized this would cause differential erosion rates along the channel as removal of the underlying sand would cause collapse of overlaying clay, initiating a meander bend. Once a meander pattern was established, alfalfa was added strategically to increase cut bank cohesion, prevent point bar incision, control channel expansion, and armor banks. This differed from earlier experiments in which alfalfa was distributed evenly across the entire floodplain.

To date, experiments on small-scale stream tables have been unable to simulate a natural meandering pattern that is both chaotic and cuts up-gradient. Our objective to accomplish this is by controlling sites of deposition and erosion through strategic placement of kaolinite and alfalfa.

VINEYARD, MICHAEL S., and LARRY SMITH, Montana Tech, Butte, MT

Sequence stratigraphic correlation of the Bow Island Formation using surface outcrop and subsurface data, Liberty and Hill Counties, Montana

The Lower Cretaceous Bow Island Formation, a shallow gas producer across a wide area in north-central Montana, has received little sequence stratigraphic work. Whereas its correlative stratigraphic units, the Viking Formation of Alberta and the Muddy Formation of southeast Montana and Wyoming, have been extensively exploited for oil and gas and are, unsurprisingly, well studied. Although a few studies have described the stratigraphy and sedimentology of the Bow Island, none have directly tied stratigraphic sub units of the formation from the surface to the subsurface. A 260-foot stratigraphic section of the Bow Island was measured at section 15, T36N, R5E Liberty County, Montana. This area located on Dafoe Ranch exhibits a well exposed stratigraphic section. In this study, formation boundaries and stratigraphic subunits recognized in the measured section were correlated to well logs to describe and interpret changes in stratigraphy and sediment distribution throughout a 35-township area in north central Montana.

Well logs from exploratory and producing wells provide the opportunity to tie the surface lithologies to the subsurface. Correlation of 814 wells located near East Butte and the surrounding area into Liberty and Hill counties are used to map surfaces recognized in outcrop in the subsurface. Formation and informal subunit tops were correlated across the area: the top of the Bow Island, middle Bow Island, lower Bow Island, and top of the Skull

Creek Shale (base of the Bow Island). Four structure contour maps, three isopach maps and two models are made to illustrate the Bow Island Formation. The Bow Island is comprised of five sandstone units and four mudstone units, where sandstones coarsen upwards and are capped by mudstones marking a sequence boundary. Sequences coarsen-upward from offshore marine mud through prodelta or offshore transition sandy muds, to delta mouth bars and uppershorface trough-cross stratified sands and foreshore seaward inclined laminae. A previously recognized bed of chert-pebble lag gravel, at the boundary between middle Bow Island and the Shell Creek Shale marks a position of erosion and an Early Cretaceous eustatic drop in sea-level, interpreted as 2nd order sequence. Four 3rd to 5th order sequence boundaries within the measured section and well logs are recognized by flooding surfaces separating coarsening upward parasequences.

The PANalytical TerraSpec Halo Mineral Identifier was used to describe the minerals within samples obtained from the exposed beds of the sediments in the Bow Island Formation to determine the cause for decreased production in wells throughout the Bow Island. Illites and micas are the predominant minerals throughout the column. A combination of processes (particle plugging, clay swelling, change in pH) lead to decreased permeability if reservoir rocks are exposed to water during drilling or by production from another zone.

WALKER, JEROME, Consultant, Reno, NV, and DON E. FRENCH, Ciannis Exploration, Billings, MT

Prolific megabreccia reservoirs in Railroad Valley, Nye County, Nevada: key to future discoveries

The term megabreccia conjures a variety of mental images. Landis (1945) described units containing large, randomly oriented blocks. Longwell (1951) applied the term to gravity-slide deposits. Cook (1984) described megabreccias in carbonate slope and basin settings. We use the term for thick, generally homogeneous units, usually with extensively fractured and sometimes cavernous texture. In the Basin-Range, these units are encased by syntectonic Miocene-Pliocene valley-fill deposits and were emplaced under the influence of gravity as landslides. A Neogene landslide deposit beneath Railroad Valley was first encountered at the Shell Oil No. 1 Eagle Springs Unit, discovery well for Nevada's first oil field. Valley fill was drilled to about 3,265 feet, where cuttings abruptly changed to Paleozoic dolomite and limestone. After drilling 215 feet, the cuttings returned to sand, silt, and clay typical of valley fill. This was interpreted as a Paleozoic block that resulted from a massive rock fall or slide from the adjacent Grant Range (Peterson, 1994.) Subsequent exploration established production from megabreccias at four fields in Railroad Valley. A production test at the Balcron No. 23-17A Bacon Flat well demonstrated the highly permeable nature of a megabreccia reservoir, flowing at a rate greater than 13,000 barrels of oil per day. The Mapco No. 3 and 4 Grant Canyon wells flowed steadily for six years at combined rates up to 8,000 barrels of oil per day. Wells in Kate Spring and Ghost Ranch fields flowed over 1,700 barrels of fluid per day. The exploration experience in Railroad Valley shows that well cuttings and most wireline logs can be used to distinguish deposits of megabreccia from sand, silt, and clay typical of valley fill. Small-scale rock texture can be identified with whole core and image logs. However, interpretation of megabreccia texture at the reservoir scale requires data from a larger volume, such as seismic, production performance, or correlation of adjacent wells. This requires the correct stratigraphic interpretation, which can be difficult where the base of a megabreccia is not completely penetrated or directly overlies bedrock. In addition to the fields, a number of wildcat wells in Railroad Valley have also encountered Neogene landslides. Some of these have been misinterpreted as reaching total depth in bedrock. The well control defines an area of approximately 30 square miles that is prospective for the discovery of megabreccia reservoirs. Furthermore, the model for megabreccia reservoirs as landslide deposits can be applied throughout the Basin-Range physiographic province.

WANG, HAIHONG, RONALD KENNY, and ARIKUMA TSUYOSHI, CGG GeoConsulting, Houston, TX, JEFF ZAWILA, SAMUEL FLUCKIGER, R. GIBSON, and PRESTON KERR, SM Energy, Denver, CO, MICHAEL H. HOFMANN, AIM GeoAnalytics, Missoula, MT

The approach, the benefit, the value of closing the gap between geology, geophysics and engineering - A case study in the Powder River Basin, Wyoming

Two complementary but expensive technologies - hydraulic fracking and horizontal drilling have led to a huge upswing in oil production. The only drawback is that oil prices must remain high enough to justify the costs of extraction. In the Rocky Mountains, there has been a marked drop in rig counts due to the decline in oil prices since 2015. Overall efficiency can be improved if wellbores target rock packages with favorable reservoir and geomechanical properties. A predictable subsurface model utilizing geology, geophysics, and engineering, allows for more effective well placement and low completion cost.

This paper presents an integrated method of building a subsurface model to predict reservoir properties using core, well and seismic data of the tight Wall Creek/Shannon sandstones in the Powder River Basin, Wyoming.

Traditional geomodeling methods construct a detailed model at well resolution, where the main issue is the predictability away from the wells. Yet the ability of prediction and risk management are paramount for an effective well placement. Currently, 3D seismic has dawned a veritable new era of geoscience, and yet seismic data is still generally used for structural interpretation, amplitude attribute analysis, and deterministic inversion. None of these results could exceed the limitation of seismic resolution, which is far removed from well resolution. A seismically constrained subsurface model, is a combination of traditional geomodeling and seismic inversion. It allows for quantitative integration of all data types from different scales of measurement in an unbiased manner, at a scale that approaches that of well logs.

This study includes a total of 18 distinct core facies, identified by mineralogic, petrographic, physical and biogenic sedimentary features observed in core. The initial core facies were subsequently upscaled and tied to 9 unique log facies. These resulting log facies were then upscaled to seismic facies via a rock physics model, bridging the scale gap between core, log, and 3D seismic data.

A simultaneous, geostatistical seismic inversion was conducted on a 3D seismic volume. One of the primary benefits of seismic data is the lateral resolution away from the wells. Rock physics plays an indispensable role here, as it forms the link between seismic elastic parameters and reservoir /geomechanical properties of the rock. Interpreting the change of seismic signatures of rock types, porosity and fluid is achievable via rock physics. Rock physics has been embedded in the modeling and inversion processes of the geostatistical inversion, which makes the result more robust and predictable. A series of highly detailed lithofacies and elastic rock property models were created.

The final stage involves a cross-validation and refinement of geologic understanding. A geological stratigraphic interpretation was used to validate the 3D geostatistical model, which highlights details beyond the wells, as long as it honors the geological interpretation. Geological interpretation can be refined based on the subsurface model.

The subsurface model accurately characterizes 3D reservoir heterogeneity, helps an advanced geological understanding, provides Phi-H maps, and measures uncertainty. A subsequent reservoir model can be used to identify sweet spots. It has been demonstrated that the subsurface model correlates with gas show and fracking pressure, thereby mitigating inherent risks in drilling and enhancing well economics.

WANG, JIANQIAO, and PIRET PLINK-BJÖRKLUND, Colorado School of Mines, Golden, CO

Variable discharge signatures in a large fluvial fan: paleomorphodynamics reconstruction and stratigraphic prediction of Sunnyside Delta Interval, Green River Formation (Eocene), the southwest Uinta Basin, Utah

This study investigates variable discharge signatures in the well exposed cliff face outcrop along the Nine Mile Canyon Road in Southwestern Utah. Whether fluctuating flow results in sediment deposition and preservation in fluvial systems has remained debated. Experiment studies and a few field examples in publications have shown that under high aggradation rate/deposition rate, unique bedforms can be formed and preserved in ancient records. It has also been proposed that rivers with extreme variable discharges promote the deposition of fluctuating flow sedimentary structures. The goal for this study is to document characteristics of variable discharge signatures present not only in bedform scale, but also in barform scale. Detailed quantitative field studies on the fluvial channel facies, geometries and architecture are conducted and whether or not they are influenced by Froude supercritical flow under high deposition rate. This work adds a significant contribution the current facies model of seasonal rivers. The results show that a total of six types of channel fills were identified. The first three types are characterized of high amounts of Froude supercritical flow and high deposition rate sedimentary structures, which show great lateral variability in outcrop, whereas cross stratifications or laminations are significantly lacking. Type 4, 5, and 6 has relatively lower proportion of Froude supercritical flow and high deposition rate sedimentary structures. In barform scale, slipface cross strata are not seen as much as low angle downstream accretions, highly amalgamated channel fills, and systematic upstream migrating bedforms. Incorporating channel fill amalgamation ratio, mud proportion, and the associate facies, the six channel fill types are also analyzed in the context of their lateral and stratigraphic position in a fluvial fan system, ranging from the axial to lateral/distal part of the fan, and to the fan toe.

WASHBURN, ALEX, and SAM HUDSON, Brigham Young University, Provo, UT

Constraining timing of South Caspian Basin isolation and source rock deposition using Re-Os geochronology on black shales of the Maikop Series, Eastern Azerbaijan

The Oligocene-Miocene Maikop Series of Azerbaijan records a critical change in the regional paleogeography relating to the evolution of the Paratethys Sea. The deposition of discreet, organic-rich intervals of claystone within the Maikop Series directly relate to increased restriction and periodic isolation of the Paratethys Sea and its basins from open marine waters. Constraining the time of basin restriction would allow scientists to attribute basin restriction to the continued tectonic movement of the Arabian Plate to the northeast, or to the fall of sea level during the Messinian Salinity Crisis. The Maikop Series is also a key petroleum source rock interval for basins of the Paratethys Sea. Increasing the resolution of Maikop stratigraphy, specifically in relation to the preservation of organic matter, will aid in the development of predictive subsurface models. Timing constraints on the Maikop are notoriously difficult because it is primarily composed of clay-rich rocks that are largely devoid of diagnostic microfauna. While recent chemostratigraphic divisions of this 3 km thick package have been proposed and are effective in a rough division of the Maikop into individual members, new advances in Re-Os geochronology on black shales offer the hope of a more quantitative division of this strata. This study seeks to employ Re-Os geochronology on the discreet, organic-rich intervals of black shale in the Maikop Series of the Kura Depression in Eastern Azerbaijan with the hope of resolving the paleogeographic conditions of the Paratethys Sea and the effects on the preservation of organic matter in the Maikop Series.

WAVREK, DAVID A., and MARIA N. SLACK, Petroleum Systems International Inc., Salt Lake City, UT, and DANIEL D. SCHELLING, Structural Geology International LLC, Salt Lake City, UT

Organic facies in Petroleum Systems Analysis: A neglected component with profound implication to conventional and unconventional play economics

Volumes have been written that describe source rock distribution within a sequence stratigraphic framework. These studies have identified key controls on organic richness and source quality as an interplay of primary productivity (terrestrial vs. aquatic), preservation, and sedimentation rate in lacustrine / swamp, marginal marine, and marine (clastic and carbonate) systems. While full blown sequence stratigraphic studies are relatively rare (data availability, cost, etc.), experienced personnel can extract key variables from existing geologic / geochemical studies to integrate into the petroleum system analysis. Some of the most important examples include the position of effective source rock to migration conduits, organic facies assignment for the generated oils, and understanding the molecular methods of thermal stress. Practical application of these seemingly academic themes include expulsion efficiency, top seal integrity, preferential expulsion direction, hydrocarbon retention, in-situ vs. migrated hydrocarbons, quantification of migration vectors (distance and direction), and differential thermal stress (separation of imprint imposed by kerogen kinetics vs. expulsion). Practical examples are used to illustrate the concepts from Greater Rocky Mountain petroleum systems.

WEDDLE, PAUL, RACHEL GRANDE, and ELLEN WILCOX, Liberty Resources II, LLC, Denver, CO, BARBARA PICKUP, and ERIC MARSHALL, Fracture ID, Inc., Denver, CO

Detecting depletion in the Middle Bakken using Drillbit Geomechanics

The results of these two case studies demonstrates the viability of utilizing XRF from cuttings from an economic standpoint as well as being a technically valid means of capturing heterogeneity in complex geologic environments. While the case studies presented here are specific to the Williston Basin, the same methodology can be applied to other resources plays.

WEN, RENJUN, Geomodeling Technology Corp., Calgary, AB, Canada

Multi-seismic attributes analysis workflows and a case study in a shale gas play

A key question to be addressed in applying seismic attribute analysis to the exploration and exploitation of shale and tight sand plays is whether the analysis can help explain the large variability of production among horizontal wells in the same play. It is "common" in these plays to observe an 80-20% phenomenon in well's production, whereas about 80% of the production is contributed by 20% of the wells. Advancement in well completion and horizontal drilling technologies are major factors for the success of shale and tight-sand plays. Due to very low permeability and porosity of the reservoir rock, these plays would not be economical at all without fracking. While acknowledging that proper completion and drilling can determine the success of one well, a large variation of productivity can still be observed among horizontal wells that share similar drilling and completion parameters. It is therefore reasonable to attribute the variation of well productivity to the spatial variation of reservoir properties, which is controlled by the local geological setting. The challenge therefore faced by seismic geophysicists is how to map these reservoir properties before drilling.

This talk will present two lines of thought in developing seismic attribute analysis workflows to map high productivity areas (sweet-spots) in shale and tight-sand reservoirs. The first line of thought is a prospecting workflow that is based on model-based attributes. The second line of thought is a forensic workflow that is based on "data-based" analytics. A case study of applying these two workflows in a shale gas play will illustrate the strength and weakness in each workflow.

In the prospecting attribute analysis workflow, we rely on seismic attributes that have clear physical meanings, which can be linked to rock properties through physical models. There are a variety of rock properties that are regarded as influential to the productivity of shale and tight-sand plays, such as total carbon content, in-situ porosity and permeability, content of brittle minerals, in-situ fracture density and orientation, local stress field, etc. In the forensic attribute analysis workflow, we use a more "data-driven" approach. We do not assume any direct link between any seismic attribute and rock properties or production potential. Instead, we rely on historic production data in the reservoir to reveal if there is any relationship between production data and seismic attributes. The analysis of such a type of relationship must also consider the influence of drilling and completion parameters.

Combining both types of seismic attribute analysis workflows discussed above is a more pragmatic approach in practice. Using these workflows together can help in reducing the uncertainty of mapping "sweet-spot" and increase well productivity.

WHEELING, SENCER L., and RICHARD LeFEVER, University of North Dakota, Grand Forks, ND

Kukersites of the Williston Basin Red River Formation in North Dakota

The Red River Formation is a stratigraphic unit located in the central part of North America; being recognized as a formal unit in North Dakota, Manitoba and Saskatchewan, portions in South Dakota, and unit equivalents in Montana and Wyoming. According to the Oil and Gas Division of the North Dakota Industrial Commission Department of Mineral Resources, the Red River Formation is North Dakota's third largest hydrocarbon producing unit, trailing only the Bakken Formation (first) and the Madison Group (second). The Red River Formation produces hydrocarbons in many fields, but there was uncertainty as to the origin of the oil and gas found in the formation. Winnipeg shales were originally proposed to be the source of oil in the Red River Formation, but the Red River was later interpreted to be self-sourced. These source beds are called kukersites. Kukersites are kerogenous, lime mudrock composed predominantly of the Ordovician microfossil Gloeocapsomorpha prisca alginate, which is the dominant component of many Ordovician-aged organic rich hydrocarbon source rocks and oil shales around the world. Previous studies have stated kukersite beds were not deposited uniformly across the basin, but can be laterally continuous over distances of tens of kilometers. They are common in the southern and western parts of the Williston Basin where there is an abundance of Red River oil fields, but they are also common in the northern part of the basin where relatively few fields have been found. Kukersites are best developed in the upper part of the "C" burrowed member (Upper Yeoman Formation).

This study’s purpose was to thoroughly examine kukersite bed distribution in North Dakota. Previous works have expressed the regional distribution of kukersite source beds remains poorly documented. Because past studies have shown kukersite beds to be the source of hydrocarbons for the Red River Formation, but no one has made a strong effort to regionally map out the source beds, especially within North Dakota borders; this study examined 161 cores (16119 total feet (4913 meters)) across 23 counties in North Dakota and created a regional distribution map of the kukersite source beds.