Identifying Critically Stressed Fractures Using Borehole Geomechanics: a Case Study in the Nikanassin

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The Nikanassin is a thick sandstone reservoir exhibiting 3-9% porosity with multiple large successions. The optimum production mechanism is believed to be a combination of primary porosity and natural fractures.

An application of Borehole Geomechanics was undertaken in an attempt to better understand the optimum production mechanism by identifying the critically stressed or hydraulically conductive fractures--those open to flow. The primary components of the Geomechanical model are: the Rock Model--defining the mechanical rock properties of the formation and the Stress Tensor--defining the interplay between the Vertical Stress Sv and the Minimum and Maximum horizontal far-field stresses. Once the Rock Model and Stress Tensor have been defined, the natural fractures as picked from the borehole image logs can be analyzed and the Critically Stressed fractures identified using the Mohr-Coulomb failure criteria.

This presentation will focus on the process used to build the rock model, define the stress tensor and identify the critically stressed fractures. The image log is used to constrain maximum and minimum stress values by analyzing the borehole breakout and it's relationship to the horizontal stress field, pore pressure, rock properties and wellbore trajectory. After the process of identifying the Critically Stressed fractures is defined, a detailed look at a Cadomin-Nikanassin well in NE BC (Canadian Foothills) is presented to validate the process. The example will focus on the geological and petrophysical analysis of the formation with production logs confirming the productive intervals and their relationship to the critically stressed fractures.

Technology in a Teapot: Overview of New Methods for Finding and Extracting Oil in from Old Stripper Field from Teapot Dome, Wyoming

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The U.S. Department of Energy operates the Teapot Dome Oilfield near Casper, Wyoming, as a technology testing and demonstration center. Also known as Naval Petroleum Reserve No. 3 (NPR-3), current oil production is about 300 BOPD from over 400 active wells. Primary producing reservoirs are the Shannon Sandstone, Steele and Niobrara Shales, Second Wall Creek Sandstone (Frontier), and the Tensleep Sandstone.

Numerous new technologies have been or are currently being tested and in some cases deployed in the field to improve production, extend the life of the field, or increase operational efficiency. This presentation will review some of those new technologies, drawn from the following list of domains and examples:

- Drilling: Rotary steerable systems, continuous sidewall coring, logging while tripping, bit vibration reduction, abrasive jet drilling.
- Production: Gas injection, surfactant soak or flooding, hydraulic pumps, Stirling generator, CO2 flood, flow assurance, downhole separators, leak detection.
- Exploration: Electro-magnetic, resistivity surveys, aeromagnetic, 4D seismic, fracture and geomechanics studies, petrographics, seismic curvature analysis.

● Renewable energy: Geothermal, wind, solar.

As one example of an innovative technology to reduce electrical power costs to operate the field, at NPR-3 40,000 barrels per day of hot water (190°F) are currently produced along with the oil from the Tensleep Formation, cooled in a series of ponds, then discharged into Little Teapot Creek. We are demonstrating, in partnership with a major geothermal company, a method for extracting that waste heat energy to power a hybrid Rankin Cycle generator. This has the potential to be applied in stripper oilfields in many areas of the U.S.

Assessment of the Mowry Shale and Niobrara Formation as Unconventional Hydrocarbon Systems, Powder River Basin, Montana and Wyoming

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A recent U.S. Geological Survey oil and gas assessment of the Powder River basin identified the Mowry Shale and Niobrara Formation as the primary hydrocarbon sources for Cretaceous conventional and unconventional reservoirs in the basin. The Mowry Shale has a 2-3 percent total organic content consisting of Type II and Type III kerogen. The Niobrara has an average of 3 percent TOC of Type II kerogen. Burial history modeling indicated that hydrocarbon generation for both formations started at about 0.60 percent Ro at a depth of about 8,000 ft. At maximum depths, Ro for the Mowry is about 1.2 to1.3 percent and about 0.80 percent for the Niobrara.

The Mowry and Niobrara continuous reservoirs were assessed using a cell based methodology that utilized production data. The size of each cell was based on geologic controls and potential drainage area of analog fields. Current and historical production data were used to determined the estimated ultimate recovery distribution for untested cells. Only production data from unconventional fractured shale reservoirs with vertical wells were used. The minimum, median, and maximum total recovery per cell for untested cells is 0.002, 0.25, and 0.35 MMBO, respectively, for the Mowry. For the Niobrara, the minimum, median, and maximum total recovery per cell for untested cells is 0.002, 0.028, and 0.5 MMBO.

Sweet spots were identified by lineaments and faults, which are believed to be areas of greater delivery potential than non-sweet spots; an upper limit of 8,000 ft was defined by over pressuring caused by hydrocarbon generation.

Mean estimate of technically recoverable undiscovered continuous resources for the Mowry is 198 MMBO, 198 BCF (billion cubic feet of gas), and 11.9 MMBNGL (million barrels of natural gas liquid), and for the Niobrara is 227 MMBO, 227 BCFG, and 13.6 MMBNGL.

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

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Geophysicists have attempted to squeeze as much useable information as possible from seismic data long before the discovery of bright spots. Today they display this information with 3D visualization software and 3D seismic is touted as the answer to all things…but what about the log data?

Most log data (even ancient log data) have 10-25 times better vertical resolution than today's seismic data however, many geoscientists treat log data much like it was treated in 1935. They obtain copies of the logs, display them in cross sections, correlate them, and map them. The use of mixed-vintage, incomplete, and/or poor quality log data however, can lead to serious problems in interpretation. Without accurate, normalized, high-resolution log data for every well in a study area, correlations, seismic ties and maps may be incorrect. As a result, 3D seismic interpretations based on these data may turn out to be amazingly colorful but inaccurate representations of what is actually happening in the subsurface.

Today the oil and gas industry is challenged with evaluating declining production in aging fields which could involve hundreds of wells with log data recorded from 1935 to last week. New plays often involve laminated, poor-quality, low permeability, fractured, or unconventional reservoirs. Using resistivity and SP inversion processing and neural network modeling run on their PCs, geologists and geophysicists can generate complete suites of accurate, high-resolution, edited, log, core, and production data for every well in a study area. Examples from California, the Mid-Continent, and Rocky Mountains will be shown.

Data Mining Well Completion Data for the Dakota Formation, San Juan Basin, New Mexico

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Data mining was used to analyze completion data for a tight gas data set to identify trends or interesting patterns between well completion/stimulation methods and gas production. The study data set was 370 non-commingled Dakota wells completed between 1994-2004. Predictive models were tested using 58 Dakota wells completed between 2004-2006. The project used data donated by IHS Energy. Data included geographical attributes Company Name, Completion Date, Location, and Depth to Dakota Top and non-geographical attributes Fracture Stages, Fracture Net Thickness, Fracture Gross Thickness, Fracture Fluid Type, Sand Lbs, Sand Type, Sand Size, and Sand Additive.

Differences between well successes by company were evaluated first. First year's gas (FYG) was selected as production indicator to compare wells with varying production time. A two-sample T-Test was performed with a null hypothesis that each company would match the average of all companies. Six of eight companies were statistically different from the null hypothesis. Attempts to cluster using location and production data by company resulted in no dominant trends. Completion/stimulation data was then mined to find the best parameters for predicting FYG. Hypothesis-generating approaches discovered interesting relationships and patterns in the data and each technique identified Fractured Fluid Gallons, Fractured Gross Thickness, Fractured Fluid Type, Sand Lbs, and Acid Gallons as key attributes.

Predictive models were built using regression trees and neural networks to predict FYG using these attributes. The best model used Fracture Net Thickness, Fracture Fluid Gallons, and Sand lbs and formed a nonlinear regression with 87 coefficients and correlation coefficients of 0.93 and 0.84 for training and testing data, respectively. The model accurately predicted FYG at 58 wells not included in the analysis.

The Wamsutter Tight Gas Reservoir - the Role of Stratigraphy and Sedimentology in a Tight Gas Field Study

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The Wamsutter tight gas field in the Eastern Green River Basin, Wyoming, has been in development since the mid 1970s with over 2500 wells drilled. The regional stratigraphic project was developed to provide a chronostratigraphic framework within which well and reservoir production histories could be better interpreted. Chronostratigraphic surfaces were mapped throughout the field using well log and seismic datasets keyed to a set of 21 regional cross-sections. Depositional environments were interpreted using well logs calibrated to multiple conventional cores. Combining the chronostratigraphic surfaces and the depositional environments facilitated the creation of gross depositional environment maps for key intervals. The relationships observed between the gas and water production in different depositional environments can then be related to time equivalent deposits. This extrapolation provides a basis for the optimization of density and location of future infill drilling opportunities and an improved understanding of the variability associated with reservoir deliverability and water potential.

Evaluating Reserves in Resource Plays: Strategies and Pitfalls

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Unconventional resources and reserves continue to increase in importance as a future source of gas production. Since resource plays tend to cover large areas of land, the magnitude of proved, probable and possible reserve bookings can be very large with a limited amount of data. SEC reserve definitions for proved undeveloped reserves require future locations to directly offset existing wells, be drilled in a reasonable period of time, be economic under existing economic conditions, and have reasonable certainty of recovering more reserves than estimated as of the date of the report. Even with these restrictive definitions, proved undeveloped reserves can be much greater than producing reserves in resource plays due to the leveraging effect of offset drilling locations. Probable and possible reserve levels can be much higher once step-out and infill locations are considered. In highly developed areas of resource plays where downspacing is occurring and well interference is expected, the OGIP estimates and overall recovery factors become of much greater importance. Therefore, emphasis must be placed in obtaining high quality data on existing wells. Reserve analysis requires an understanding of the different methodologies available, geologic trends, petrophysical parameters and

OGIP estimating, historical and future estimated well performance, depletion effects and analysis, sensitivity analysis to estimates, and reserve classification. Small errors in estimating reserves for existing wells can lead to large revisions of future locations in all reserve categories.

Covenant Field Blueqube Interpretation Results: Central Utah Hinge Line Exploration Strategy

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The Utah Hinge Line is an area with proven hydrocarbon potential. The discovery of the Covenant field by Wolverine in 2003 has generated much interest in the area. This discovery in Sevier County, Utah, is 146 miles South West of the nearest thrust belt production at Pineview in Summit County, Utah. Many structural targets exist between the Covenant field and the analogous production to the North. However, the area is structurally complicated and the cost of seismic data is high due to difficult terrain and permitting issues. The complexity of the area and sparse data coverage means that there are many unanswered geological questions. The Tertiary cover, the salt lenses in the Arapien and the volcanic cover all mean that structural interpretation of the thrust belt is challenging. Several counties are believed to have Navajo sandstone potential including Sevier, Sanpete, Millard, Wasatch, Juab and Utah. In order to explore effectively in the Hinge Line, detailed geological information is needed which either can be integrated with the existing 2D seismic data or used to target further geophysical data acquisition (2D or 3D seismic). Feasibility modeling of Covenant field suggested that there is sufficient density contrast in the stratigraphic column to identify structural closures at Navajo depth. To demonstrate the effectiveness of BlueQube technology as a blueprint for exploration in the Hinge Line a 150 sq mile survey was flown that incorporated the Covenant field discovery. The final results of the interpretation study clearly indicate that the technology would have highlighted the Covenant structure, plus with further 2D/3D modelling a structure map at Navajo depth can be generated that can be used for prospect evaluation. A robust workflow which includes all publicly available information elucidates additional structural highs that warrant further investigation.

Lidar: a Multidisciplinary Dataset for Integrated Solutions in Onshore E & P

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Increasing the chances for successful operations in sensitive areas begins with having a clear model to visualize the project site. Understanding the ground conditions is critical for making informed decisions and having well thought out strategic plans in place at the onset. Airborne LiDAR data provides that detailed elevation information and is valuable at multiple business stages within different disciplines including HS&E, seismic, facilities, pipeline, construction, regulatory analysts, etc.

LiDAR (Light, Detection & Ranging) is a proven technology that produces high precision, geo-referenced digital elevation models (DEM) with vertical accuracies <

30cm. Not only does Lidar capture detailed images on the vegetation and terrain, but unlike DEMs generated from aerial photography, lidar images the surface beneath the vegetative layer; thus revealing information on slopes, access, drainage, existing pad locations, geomorphology, etc that would otherwise go undetected with traditional photo. In addition, the lidar DEM can be put into a GIS database and a variety of map layers can be combined, including: survey, lease, permit, culture & utility data allowing for easier assessment of land issues, access, seismic points, existing/planned pipelines & roads, etc. all integrated into one complete digital dataset.

Incorporating lidar with existing data allows for the best overall view of ground conditions and leads to: 1) Minimizing environmental footprint; 2) Better cost estimating; 3) Less time spent scouting - field time is concentrated and efficient; 4) Pre-planning emergency response plans. Better decisions upfront lead to extremely valuable benefits downstream; Lidar - a legacy dataset for integrated solutions in onshore E&P.

Remaining Oil Resources of New Mexico: the Hubbert Curve Denied

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New Mexico has produced 5.5 billion bbls oil since production began in the 1920's. During 2006, 60 million bbls oil were produced. Available estimates of remaining resources indicate 1.4 billion bbls, 23 years at present rates of production; 60% of the estimated resource base is in proved reserves and the other 40% is in undiscovered resources.

The oil Reserve Life Index (the ratio of proved reserves to annual production) has been stable for the past two decades at approximately 10 years. The stability of this index indicates that new, previously unrecognized resources have been discovered and brought into production at a rate that replaced production. The volume of unproven oil resources has been, and continues to be, chronically underestimated.

Peak New Mexico oil production was attained in 1969 at 129 million bbls/year. From 1970 until 1982, an annual Hubbert-type decline of approximately 5% ensued. After 1982, oil production deviated positively from a Hubbert-type decline. Approximately twice the oil is currently produced than would have been predicted from application of a Hubbert curve in 1982. Positive deviation from a Hubbert-type decline has been caused mostly by waterflood of the Vacuum San Andres field during the 1980's, redevelopment of the Dagger Draw Upper Pennsylvanian field in the early to mid-1990's and discovery of the Brushy Canyon fields and trends in the late 1980's and early 1990's. These events brought into production major oil resources that had previously been either neglected or unrecognized.

The remaining New Mexico oil resource base is not mostly in known reserves in oil fields. Rather, the deviation from a Hubbert decline indicates it occurs as unrecognized sources that will only be found and produced through application of new and sophisticated exploration and development concepts and techniques and ultimately, drilling. Without exploration based on new concepts and application of sophisticated development techniques, new resources of oil will remain unrecognized and production will resume a Hubbert-type decline.

Monte Pallano Gas Field, Abruzzo Region, Italy Terrain Subsidence Monitoring Requirements

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Monte Pallano is located in the Region of Abruzzo, Italy, 220 kilometers due east of Rome. It is in the Central Apennine Range that resulted from compression of the Sardinia and Adriatic plates in the Oligocene. It is a fold belt with deformed sedimentary and volcanic units bisected by southwest-dipping thrusts. Extension in late Tertiary resulted in normal faulting.

AGIP drilled a discovery in 1966 followed by three successful wells and three dry holes. The reservoir is a fossiliferous, Upper Cretaceous limestone with porosity averaging 10% and permeability 10 md. The four wells initially flowed 2 to 6 MMcfd after acid cleanup.

At the time, a tragedy occurred in Northern Italy when a slide block fell into the Vajont reservoir. A pulse wave overflowed the dam and destroyed Longarone, a village of 2000 people. The gas field is partly located beneath a Lake held by a 57.50 meter earthen dam. AGIP elected not to produce the field in 1966 due to the Bomba dam proximity. The four wells were plugged and abandoned in 1992. Forest CMI S.p.A. was granted an exploration license containing the field in 2004. The permit required Forest to install monitoring sensors to measure subsidence resulting from gas withdrawal. Forest installed solar powered GPS stations capable of measuring movements to a one-millimeter scale. Upon fulfillment of this requirement, Forest obtained permission to drill two directional wells from a common pad in 2007. The wells re-established production with rates greater than 7 MMcfd. The field has 2500 acres within the closing contour, a GWC at -1112 subsea and a reservoir column of 110 meters. Reserves are placed at 56 Bcfg. Forest is designing a treatment facility and pipeline.

Arcgis Integrated Petroleum System Evaluation of the Greater Green River Basin

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Results from an integrated petroleum system study are displayed in ArcGIS map format. Data from a combination of a) source rock, b) oil, c) natural gas, and d) water analyses are integrated to assess each of the petroleum systems in the greater Green River Basin. The project concentrates on charge histories of the Phosphoria, Mowry, Mancos/Hilliard/Baxter, and Mesaverde systems, and focuses on the origin, thermal maturity, and quality of the oil and natural gas in the basin. The study incorporates source rock analyses of over 60 individual wells, detailed oil analyses of over 125 oil samples, and analyses of over 800 gas samples. Over 250 new gas samples were analyzed for stable carbon and deuterium isotope compositions.

Green River oil biomarkers define the source rock type (e.g. carbonate, distal shale, paralic shale) as well as age and maturity at expulsion. Stable carbon isotope compositions of the gases further refine source rock thermal maturities into the gas generative window. Together with source rock richness and present day measured maturity, the fluid and rock data are best integrated using a GIS platform. Each petroleum system can be mapped separately or together to optimize future exploration success.

Capillary Pressure Properties of Mesaverde Group Low-Permeability Sandstones in Six Basins, Western U.S

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Drainage and imbibition air-mercury capillary-pressure properties were measured for over 100 Mesaverde Group low-permeability sandstones from six basins in the Western U.S. For all samples pore-throat diameters associated with the threshold-entry pressure (Pe) decrease with decreasing permeability. Stressed (4,000 psi NCS) and unstressed curve pairs for high-permeability cores (k>1 mD) are nearly identical; however, with decreasing permeability the unstressed and stressed threshold-entry pressures diverge. For all sample pairs this difference is greatest at Pe and the curves converge with decreasing wetting phase saturation (Sw) down to 30-50%, where the stressed curve crosses the unstressed curve and thereafter exhibits 0-5% lower Sw with increasing capillary pressure.

The data imply that confining stress exerts principal influence on the largest pore throats and that pore throats accessed at non-wetting phase saturations below approximately 50% are not significantly affected by confining stress. This is consistent with these smaller pores comprising pore space within pore bodies or in regions of the rocks where stress is not concentrated.

Hysteresis analysis involving three drainage-imbibition cycles for each sample were performed on 32 samples and residual mercury saturation was measured for over 200 samples where initial mercury non-wetting phase saturation (Snwi) corresponds to conditions near “irreducible” wetting-phase saturation (Swirr). The relationship between Snwi and residual non-wetting (Snwr) saturations following imbibition is well characterized by a Land-type relationship: 1/Snwr*-1/Snwi* = C, where Snwr* = Snwr/(1-Swirr), Snwi* = Snwi/(1-Swirr), and C = 0.55 at Swirr = 0. Results indicate that residual non-wetting phase saturations (e.g., gas) are high following imbibition.

Gravity Fault Controlled Structural Traps, North-Central Montana

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Within the Bearpaw Mountains and hidden beneath the surrounding plains lies a world class example of gravity-induced faulting within Upper Cretaceous marine sedimentary rocks. Seismic exploration, mostly for shallow Upper Cretaceous biogenic gas reservoirs, has yielded high quality 2D and 3D datasets spanning a large area of North-Central Montana. Mapping utilizing this seismic data reveals a complex pattern of faulting hidden beneath a glacial veneer north of the Bearpaw Mountains and into

Canada. This fault pattern is very similar in geometry and origin to that mapped at the surface south of the Bearpaws.

Two principal decollements carry massive thrust sheets downdip off the flanks of the Laramide Bearpaw Uplift. The older, upper decollement is rooted in an organic-rich shale within the uppermost Colorado Group(1WS). Regional gentle NE structural dip on this thrust sheet is punctuated by regularly spaced fault-bounded horsts or "pop-up" structures that trap gas in the Eagle Sandstone. These "pop-up" structures were then carried piggyback by faulting associated with a lower decollement just above the Greenhorn (2WS). Several large thoroughgoing strike-slip faults offset earlier formed pop-ups with roughly 5000 feet right-lateral displacement.

Faults associated with both decollements trap biogenic gas in a variety of structural traps well imaged with 2D and 3D seismic. Most Eagle gas is trapped in comparatively small, fault-bounded horst blocks of 20-120 acres. Many one well fields have produced between 1 and 2 Bcfg from very high quality marine shoreface reservoirs. St. Joe Road field, discovered in 2001, covers 40 sq. mi. and has produced over 11 Bcfg from 74 wells in the Niobrara Sandstone. Analysis of gas-induced seismic anomalies serves to greatly reduce exploration risk.

Facies and Mechanical Stratigraphy of the Middle Bakken, Mountrail County, North Dakota

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We recognize 5 facies within Middle Bakken cores from the Sanish and Parshall Fields of Mountrail County, North Dakota. Facies E is a thin basal unit sharply overlying the Lower Bakken shale. This facies is characterized by muddy, intraclastic-skeletal lime wackestone sometimes exhibiting a "patterned" texture, suggestive of (temporary) near hypersaline conditions. Facies D is a bioturbated, muddy, calcareous, poorly sorted, very fine grained sandstone/siltstone with common Helminthopsis burrow traces. This thickest Middle Bakken unit is interpreted as offshore deposition below storm wavebase. Both intergranular pores and open horizontal discontinuous microfractures are rare in this poor reservoir quality facies which shows some improvement upwards. Facies C is composed of parallel millimeter-laminated to low angle, hummocky cross-stratified, dominantly calcite-cemented, well-sorted very fine grained sandstone and siltstone interpreted as amalgamated storm deposits. Visible porosity is limited to rare intergranular, clay intercrystalline, and minor open discontinuous horizontal microfractures. When present, Facies B forms the Middle Bakken's "clean bench". Facies B varies from 0 to >20' with 2 sub-facies. Facies B2, a muddy calcareous sandy/silty "disturbed" facies, has common syn-sedimentary micro-faults, microfractures, and slumps representing soft-sediment deformation concurrent with inferred structural movement on Nesson Anticline. Facies B1 is the highest energy, coarsest grained unit in the Middle Bakken, represented by alternating units of cross-bedded bioclast-rich, very fine to fine-grained sandstone and sandy skeletal lime grainstone deposited in subtidal shoals and/or channels above storm wave-base. Pore types include rare to common intergranular and minor clay intercrystalline. Syntaxial calcite cement in crinoidal lime grainstone B1 occludes all

primary pores. Primary porosity retention and UV fluorescence improves in B1 with greater allochem diversity and/or quartz abundance. Facies A contains four sub-facies (bottom to top): 1) A-GR is a thin organic-rich mudstone forming a Gamma Ray log marker at base of A; 2) A2 is a thin-bedded dolomite mud/wackestone that is more dolomitic than B, C, or D; 3) A1 is a calcitic whole fossil dolo-to lime-wackestone serving as guide beds while drilling; and 4) A0 is patterned carbonate (pyritic dolomudstone with enterolithic-structure) immediately below the contact with the Upper Bakken Shale. Rare visible porosity in thin sections is limited to secondary pores and rare open discontinuous microfractures. Despite the paucity of visible porosity in core and thin sections, Facies A has weak yellow UV fluorescence emanating from micropores in grainy beds.

Facies successions and event stratification yield a mechanical stratigraphy thought to impact fracture height and spacing. Facies D is a single, massive mechanical unit; as such it has the greatest fracture spacing. Facies A, B, and C are composed of thin mechanical beds, with dolomitic, centimeter- to decimenter-bedded Facies A being the thinnest bedded and most fracture-prone. Linking core facies to MWD GR, drilling time, and mud gas enhances real-time tracking of horizontal wellbore trajectories. Facies A, B, and C remain the principal horizontal target due to greater porosity, fracture susceptibility and therefore permeability.

High Pressure Air Injection from the Cedar Creek Anticline

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Continental Resources, Inc. (CRI) has been in business for over 40 years. Harold Hamm began the business in 1967 and has continuously built it with application of high tech methods, including seismic, horizontal drilling, and hydraulic fracturing. The company went public on the NYSE in May of 2007, and has done well since the IPO. CRI is active in several key areas of exploration, including the Montana Bakken, North Dakota Bakken, Woodford Shale, Trenton-Black River and other emerging plays. The Cedar Hills field in southwestern North Dakota was brought on by the combination of horizontal drilling, and CRI immediately employed a unique application of High Pressure Air Injection (HPAI), which is a secondary/EOR method proven in the Buffalo field since 1982. This talk will highlight the history of HPAI within the Buffalo field and show how CRI has expanded the application to its Cedar Hills North Unit. The Red River B zone is a homogeneous, blanket of carbonate reservoir that has a unique blend of porosity, permeability and fluid saturation, which, combined with the depth and temperature, create a unique setting for and in-situ combustion project. This project is under increased density drilling to go to 160 acre well density. Its production is still increasing, and it is expected to peak at about 17,000 bbls oil per day in early 2009. The field is 45 % of CRI's reserve base, and a similar fraction of current production.

Evidence for a Variable Archie Porosity Exponent "M" and Impact from Saturation Calculations for Mesaverde Tight Gas Sandstones; Piceance, Uinta, Green River, Wind River, and Powder River Basins

Cluff, Robert M.[1]; Byrnes, Alan P.[2] (1) The Discovery Group, Inc, Denver, CO. (2) Kansas Geological Survey, Lawrence, KS.

We have measured formation resistivity factors (FRF =Ro/Rw) on a suite of over 300 Mesaverde core plugs at four brine salinities. The samples range from 0.2 to 23.4% porosity at 4000 psi NCS (phi_i); in situ permeability from 2 nD to 206 mD; and brine salinities of 20K, 40K, 80K and 200K ppm NaCl. The Archie porosity (cementation) exponent "m" was calculated from the measured FRF assuming a=1. Our prior unpublished work in the Washakie basin focused on sample sets with porosity > 6% and found only a weak correlation between m and porosity.

Present data show strong curvature where m decreases as a function of porosity below approximately 8% porosity. The relationship can be described by the dual porosity model or equally well by a family of logarithmic equations: m = a ln(phi_i) + b (m standard deviation = 0.13). The zero porosity intercept b increases with salinity from 1.25 (20K ppm) to 1.57 (200K ppm). The coefficient "a" decreases (0.23 to 0.16) with increasing salinity.

The impact of these relationships is that m decreases with decreasing porosity and salinity. At low porosity (<6%) m is significantly less than the nominal constant value of 1.85 commonly assumed for tight gas sandstones. Above 12% porosity, m is best characterized by a constant value of 1.9+0.05. Therefore there is more gas in these rocks at low porosities than a constant m model predicts, but there is little impact on saturation calculations at high porosity.

Ismay-Hovenweep Petroleum System, Blanding Basin, Utah

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Oil and gas in the Blanding sub-basin are produced mainly from upper Ismay (Desmoinesian) carbonate mounds. The mounds form linear, subparallel trends; are immediately underlain by thickened sections of Hovenweep Shale; are flanked by thick salina anhydrites; and are immediately overlain by thin upper Ismay sabkha deposits and marine carbonates of the basal Honaker Trail Formation. Correlative, but thinner, marine-shelf upper Ismay carbonates are underlain by thin Hovenweep Shale.

Based mainly on mapping of these thickness trends and on serial stratigraphic cross sections, we propose that the anomalously thick, productive upper Ismay carbonate mounds result from: 1) regional base-level changes, 2) differential subsidence during Hovenweep time due to salt movements, 3) loading of the salt by thickened upper Ismay carbonates and evaporites, and 4) differential compaction of the evaporites surrounding the carbonate-mound masses during latest Ismay and earliest Honaker Trail deposition. We propose an indirect linkage between basement tectonics, salt movements, sediment loading, and deposition of the mounds.

When mapped regionally, the dominant pore fluids in the Ismay and underlying Desert Creek zones follow trends consistent with the more-theoretical results of geochemical measurements and modeling, specifically kerogen typing and thermal maturity indicators. Basinward (northeast) of the Blanding sub-basin, Ismay and Desert

Creek hydrocarbons are dominantly natural gas with little mobile water. Shelfward (southwest) of the Blanding sub-basin, Ismay and Desert Creek pore fluids are oil with associated gas and abundant producible water. In the Blanding Basin itself, pore fluids are mainly oil and associated gas, with relatively little mobile formation water. Inferred source-rock maturity trends reflect mainly Laramide burial and inferred regional differences in kerogen types.

Stratigraphic Variability of Sandstone-Body Dimensions in the Williams Fork Formation: Outcrop Data from the Southwest Piceance Basin, Colorado

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This paper summarizes data on the size and architecture for 912 fluvial sandstone bodies or channel-form elements in the Upper Cretaceous Williams Fork Formation in Coal, Main, and Plateau Creek Canyons, near Palisade, Colorado. Methods used included high-resolution aerial LiDAR, digital orthophotos, outcrop photomosaics, and field mapping. In the study areas, the Williams Fork is approximately 1,800 ft thick and consists of two informal units. The lower one-third has a low net-to-gross ratio (40 to 70% mudrock) and was deposited in a coastal-plain setting. The remainder of the Williams Fork has a moderate to high net-to-gross ratio (25 to 45% mudrock) and was deposited in an alluvial-plain setting.

Individual sandstone bodies in the low net-to-gross interval were deposited primarily by meandering fluvial systems, and occur as three types: single-story channel fills (SSCF), multi-story channel fills (MSCF), and crevasse-splay deposits (CSD). In a 900-foot thick, 5.7-mile long transect of Coal Canyon, 158 SSCF, 321 MSCF, and 320 CS sandstone bodies were documented. The SSCF sandstone bodies range in thickness form 2.6 to 21.1 ft and in apparent width from 44 to 1,700 ft. The MSCF types are 4.5 to 32.5 ft thick and 38 to 2,791 ft wide, whereas the CS sandstone bodies are 0.5 to 9.1 ft thick and 40 to 1,661 ft wide. The moderate to high net-to-gross interval, which crops out in Main and Plateau Creek Canyons, is characterized by sheet-like sandstone bodies deposited by low-sinuosity to braided fluvial systems. These sheets, which consist of numerous amalgamated channel-form (ACF) components, can be traced up to five miles in an east-west direction and may be up to 200 ft thick. Measurement of 113 ACF components in a single sheet shows thickness to range from 8.7 to 54.3 ft and apparent width from 204 to 2,566 ft.

Realities of Shale Gas Resources: Yesterday, Today and Tomorrow

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Projections by the United States government indicate that annual U.S. gas demand could increase from the current 22 Tcf (trillion cubic feet) to 26 Tcf by the year 2030. This would occur during a period of declining Canadian gas imports and increasing U.S.

reliance on LNG imports, a commodity only available in a highly competitive market. The Rocky Mountain area is projected to have a major role in supplying future demand.

Shale gas production, which dates from 1821 in the United States, is now rapidly increasing, accounting for approximately 5% of annual production. The U. S. Energy Information Administration estimates that shale gas production will overtake coalbed methane production by 2025, and will grow from the current 1 Tcf to 2.3 Tcf annually by 2030.

Shale gas is also an increasingly large component of future, technically recoverable resources. Both of these trends are due to improvements in exploration, completion and production technologies, aided by wellhead price increases.

The latest Potential Gas Committee biennial assessment, (September, 2007), shows an overall increase of 18% (200 Tcf) for total U.S. gas resources. The bulk of this increase is for shale gas resources. This talk analyses shale gas future potential with an emphasis on Rocky Mountain plays and the economic realities of current and emerging U.S. Lower-48 plays.

The Use of Modern 3D Seismic for Interpretation of a Structural and Stratigraphic Framework in the Main Canyon Area of the Northern Uncompahgre Uplift, Uintah County, Utah

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Over 125 square miles of 3D seismic data were acquired and processed during 2005-2007 in the Main Canyon area of Uintah County, Utah. This higher resolution data has led to a more detailed interpretation of the structural and stratigraphic framework over the northern end of the Uncompahgre Uplift, with implications for the geologic evolution of the Uinta basin and the exploration for oil and gas in the region.

Through integrated interpretation of the 3D seismic volume (over 20+ seismic attributes) with well data, several modes of deformation were observed. Included in these observations are the confirmation of the Garmesa fault system, other deep rooted faults, left lateral basement movement and the identification of smaller thrust systems in the Cretaceous (Mesa Verde, Castlegate and Mancos-Niobrara) section. Various 3D azimuthal volumes have aided in fracture trend definition suggesting the presence of anisotropic stress fields. The new 3D seismic is also clarifying the understanding of the local stratigraphy by imaging lower Cretaceous Dakota channel systems and the relationship between the Paleozoic section and overlying unconformity.

The Carbon Sequestration Potential of Oil and Gas Fields in the Denver-Julesburg Basin of Colorado

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Carbon sequestration, or the storing of carbon dioxide (CO2) created by human activities, is an emerging technology of national and international importance due to its potential to significantly reduce greenhouse gas emissions. Geologic carbon sequestration involves the capture of CO2 generated from point sources such as coal-burning power plants and petroleum refineries, and its subsequent injection into subsurface geologic formations such as depleted oil and gas reservoirs, uneconomic coal seams, and deep saline aquifers.

GIS technology holds great potential for assessing options for geologic carbon sequestration by allowing the rapid screening of subsurface sequestration targets (sinks) and spatially relating CO2 sources and sinks. The Colorado Energy Research Institute at the Colorado School of Mines has created a geodatabase to assess the geologic sequestration options for specific CO2 sources in the Denver-Julesburg Basin of Colorado. Data parameters such as depth, distance from source, reservoir size, and production history were aggregated for 965 known oil and gas reservoirs, which were then screened for criteria necessary for CO2 injection and long-term storage. 64 oil reservoirs were identified as potentially amenable to CO2-enhanced oil recovery and 38 oil and gas reservoirs were identified as potential large volume sinks for CO2. The geodatabase was used to identify the most promising oil and gas fields for carbon sequestration from a specific CO2 source and narrow the focus of further assessment of the suitability of these reservoirs for long-term carbon storage. Future research will expand the assessment to Enhanced Methane Recovery potential and the results will be presented.

A Methodology for Assessing the Carbon Sequestration Potential of Deep Saline Aquifers Beneath from Industrial CO2 Source

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Geologic carbon sequestration involves the capture of carbon dioxide (CO2) generated from point sources such as coal-burning power plants and its subsequent injection into depleted oil and gas reservoirs, uneconomic coal seams, flood basalts, and deep saline aquifers. In order to impact the global climate, the volume of compressed carbon dioxide that will have to be injected each year is larger than the volume of oil produced from the ground in the same period. Therefore, sequestration in oil and gas reservoirs, whether depleted or producing, represents only a fraction of the storage capacity required over the next century. Deep saline aquifers contain the largest potential storage capacity with low estimations reaching over 1 trillion short tons in North America alone. But due to few existing well penetrations and only recent interest in these aquifers, there exist large uncertainties that make accurate modeling of CO2 injection into these aquifers difficult and often cost prohibitive with conventional reservoir simulation software. The Colorado Energy Research Institute at the Colorado School of Mines has developed a preliminary screening methodology utilizing established fluid property algorithms and databases, an analytical injection model, and GIS technology to assess the potential of deep saline aquifer horizons for carbon sequestration. Expected ranges of geologic conditions, reservoir parameters, and specific CO2 input requirements are entered into a Microsoft Excel spreadsheet to calculate best/worst case scenarios for plume size. GIS technology is then used to determine the number of expected oil and gas well intersections in a given aquifer. The methodology will be applied to the site of a proposed IGCC (carbon capture) power plant in the Denver-Julesburg Basin and the results of this assessment will be presented.

Experimental Quantification of "Good Log Characteristics" for Mesaverde Reservoirs of the Piceance Basin, Colorado: Toward a Reconnaissance Method for Evaluating Movable Water in Tight, Shaly Sandstones

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Petrophysical analysis of wireline data through thick intervals of shaly-sandstone is a critical aspect of geologic interpretation in tight-sand gas plays. Established practices commonly apply water-saturation calculations adjusted for local relationships with variables such as water resistivity, Archie exponents, matrix density and shale properties calibrated to core in developed areas. In exploration, it is helpful to have a reconnaissance technique to use in uncalibrated areas as a check on conclusions computed using the development standards.

An experimental log-evaluation method is described based on data from the Mesaverde Formation, comprising >2000' of alluvial shale and shaly-sandstone reservoirs, in the Piceance Basin, Colorado. The analysis uses two derived parameters: apparent water resistivity (RWA) and approach or cross-over of density and neutron porosities (DNXO). For both quantities, additional gas in the system increases the response whereas higher clay content decreases the response. Graphical modeling of various shaly-sandstone rock types shows that this method can successfully discriminate the effects of gas and clay without estimating the typical calculation variables previously listed.

Initially, the RWA and DNXO responses are calculated as a ratio to each curve's baseline which is specific to a subject well, so extensive curve normalization is not required. Next, log characteristics are quantified for gas saturation based on the highest coordinated responses of both parameters for an equivalent shaliness, defined by the gamma-ray curve. Finally, this pseudo-gas saturation is correlated with porosity in a water-risk calculation. Results from this technique of targeting a high chance for gas with low water-risk have been used to optimize completion intervals based on properties of the sandstone matrix or, in special cases, natural fractures.

Design Considerations for Successful Low Environmental Impact Natural Gas Compression Facilities in Sensitive Areas

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Minimizing environmental impacts related to natural gas compressor stations enables operators to serve the market while meeting permitting requirements in sensitive areas, as well as improving the image of the industry as a responsible steward of the environment and being a good neighbor to those who live nearby. Developing mitigation strategies during the early stages of project planning can help streamline the permitting process and helps reduce the total costs of mitigation efforts. Mitigation strategies may be developed to address air quality issues, noise, visual impacts, overall footprint, access issues, light pollution, impact on wetlands, watersheds, and wild lands, methane emission reduction, and others.

Examples of specific mitigation strategies utilized in recent projects are presented, including: highly sound-attenuated compressor buildings, low noise gas coolers, creative solutions that have minimized visual impacts, effective planning of small footprint sites, and low impact lighting design. Strategies for reducing methane emissions are also discussed.

Operating with a greater sensitivity to surface owner issues and to the overall stewardship of the environment will continue to be advantageous to the industry, especially in environmentally sensitive areas. Effective planning enables implementation of these mitigation strategies while minimizing costs.

A Tectonic Context for Basement Linears in Northeast Wyoming

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Wrench fault zones mapped where the Rocky Mountain province meets the Great Plains of North America indicate scaled lateral offsets in interior cratonic movement. In northeast Wyoming and surrounding areas the tectonic terrain is influenced by the intersection of two separate thousand mile long mega scale features. The westerly trending Nye-Bowler segment of a mega wrench fault zone connects the north ends of the Big Horn Mountains and the Black Hills. This linear shear also bounds the northern limit of the Powder River Basin between the two uplifts. The northerly trending Front Range fault system splits at the north end of the Laramie Range extending east and west into a linear system of basin-bounding faults. These faults form the southern margin of the Powder River Basin.

Surface mapped faults in this region are either vertical north-trending, or lateral east-west trending. Wrench elements in regional terrain north and west of the Powder River Basin have left-lateral orientations. East and south of the basin, wrench elements in the regional tectonic terrain usually have right-lateral orientations. Linear subsurface basement shear zone mapping from aeromagnetic data for the Powder River Basin shows that the synclinal axis occurs in an area where the right- and left-lateral styles intersect.

There is a strong correlation between linear basement shear zones and elongate oil and gas fields in the Powder River Basin. The wider flatter east side of the basin originally had stratal east dip and now has west dip. The steeper west side of the basin now dips more steeply to the east than it did during deposition of the Cretaceous strata. Surface tilting from lateral adjustments may influence deposition and migration similar to isostatic adjustments. These types of scaled tectonic movements influence the ongoing evolution of in-situ fracturing and faulting.

Calibrating Stable Carbon Isotopes of Reservoir Fluids As a Thermal Maturity Indicator

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Organic thermal maturity indicators are used to determine the maximum level of maturity for a given rock unit. Thermal indicators such as measured vitrinite reflectance, thermal alteration index (TAI), and the Rock-Eval ™ parameter Tmax measure the rock unit directly and indirectly and require core or cuttings for analysis. Stable carbon isotopic analysis of mud gas, production gas and headspace gases provides the opportunity to measure the maturity of reservoir fluids. Measuring the maturity of reservoir fluids in conventional and unconventional plays allows for a more complete interpretation of the petroleum system elements such as source maturity, migration of hydrocarbons, and charge history and timing. In the case of shale gas plays understanding the maturity of the fluids can be a proxy for the maturity of the shale itself if there is no migration of the gas out of the rock, into the rock, or the gas within the source rock is a risiduum. Mud Gas Isotope Analysis (MGIA) is a technique that allows sampling of the mud stream gases while drilling to measure δ13C isotopic concentrations of C1-5 components. δ13C ethane and δ13C propane are good thermal maturity indicators and can be derived from MGIA. These maturity parameters can be used qualitatively to understand relative maturity of the fluid/rock or, if calibrated to shale rocks, can be used as a robust quantitative thermal maturity parameter. Calibrations can be achieved using analogous systems from a global thermal maturity database or from basin and formation specific data. The objective of this talk is to provide information regarding limitations of global rock maturity data when calibrating basin and formation specific fluid maturity parameters. Also, the use of the gas maturity parameter in assessing conventional and unconventional hydrocarbon systems in the Rocky Mountains will be discussed.

Maturity Determinations in the Vermillion Basin-Baxter Shale: Fluid Maturity Parameters Help Interpret Charge and Migration

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Mud gas isotope analysis (MGIA) has been conducted on three wells in Sweetwater County, Wyoming. The geologic province is known locally as the Vermillion Basin and is part of the greater Sand Wash/Washakie Basins. The Baxter Shale has been a target for some operators as an overpressured, unconventional, fractured shale play. Other deep targets in this area include the Frontier, Nugget and Dakota sandstones.

Organic thermal maturity indicators are used to determine the maximum level of maturity for a given rock unit. Thermal indicators such as measured vitrinite reflectance, thermal alteration index (TAI), and the Rock-Eval parameter Tmax measure the rock unit directly and indirectly and require core or cuttings for analysis. Stable carbon isotopic analyses of mud gas, production gas and headspace gases provide the opportunity to

measure the maturity of reservoir fluids. Measuring the maturity of reservoir fluids in conventional and unconventional plays allows for a more complete interpretation of the petroleum system elements such as source maturity, migration of hydrocarbons, and charge history and timing. Results from MGIA have delineated interesting distinctions among petroleum systems. In addition to discrete signatures among charged reservoirs, a clear demarcation of isotopic signature is seen at the top of overpressure. MGIA is a technique that allows sampling of the mud stream gases while drilling to measure δ13C isotopic concentrations of C1-5 components. δ13C ethane and δ13C propane are good thermal maturity indicators and can be derived from MGIA.

Applying a calibrated maturity scale to the fluids analyzed in the Vermillion Basin wells allows for a robust interpretation of charge history. The complex structural history of this area requires efficient and reliable methods for measuring maturity of the fluids in the reservoir. Integrating rock and fluid maturity and determining similarity or differences between rocks and fluids allows for meaningful interpretation of charge and migration.

Development of Produced Water Management and Treatment Strategies

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Produced water management and treatment has the potential to substantially enhance production and reduce the overall cost of developing unconventional petroleum resources, while minimizing adverse environmental impacts. In many locations, unconventional gas production is limited because adequate water management strategies have not been developed. Significant volumes of produced water are generated in the arid regions of the Western United States, where treated produced water may be put to beneficial use to augment fully-allocated conventional water supplies. There is a clear need and strong economic drivers to develop integrated approaches to improve treatment, handling, disposal, and beneficial use of produced water at a cost that does not impede development of the associated gas resources.

Through this planned research effort, we will develop an integrated guidance framework that will link the composition of produced waters to beneficial use applications and identify the most cost-efficient, environmentally sound, beneficial strategies for management and treatment of produced water from CBM and gas shale operations by taking into account the typical conditions of a field operation. This will be accomplished by cost-benefit analyses and life-cycle assessments considering technical and non-technical factors. The study will identify potential combinations of treatment processes, which minimize residual brines by considering well established, as well as emerging, desalination technologies. The work will also bring together producers with the water industry, regulatory agencies, tribal interests, landowners, agricultural stakeholders and environmental groups to identify solutions to the institutional impediments to beneficial use and to improve treatment, handling and re-use of produced water from unconventional gas operations. Offering solutions in these critical areas will help overcome current and future limitations in improving production of unconventional resources within high priority existing and emerging production areas.

The Use of Epifluorescence Techniques to Determine Potential Oil-Prone Areas in the Mississippian Leadville Limestone, Northern Paradox Basin, Utah

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Potential oil-prone areas for the Mississippian Leadville Limestone were identified in the northern Paradox Basin (Paradox fold and fault belt), Utah, based on hydrocarbon shows using low-cost epifluorescence techniques. The trapping mechanisms for Leadville producing fields are usually anticlines bounded by large, basement-involved normal faults. Epifluorescence microscopy is a technique used to provide information on diagenesis, pore types, and organic matter (including "live" hydrocarbons) within sedimentary rocks. It is a rapid, non-destructive procedure that uses a petrographic microscope equipped with reflected-light capabilities, a Hg-vapor light, and appropriate filtering.

Approximately 900 cutting samples were selected from 32 wells penetrating the Leadville Limestone (six gas, condensate, and oil wells, as well as 26 non-productive wells) throughout the region. These cuttings (generally four to ten samples per depth interval from each well) display intercrystalline porosity and occasional small vugs or molds. A qualitative visual rating (a range and average) based on epifluorescence evaluation was applied to the group of cuttings from each depth interval in each well. The highest average and highest maximum epiflourescence from each well were plotted and mapped.

As expected, productive wells (fields) are distinguished by generally higher epifluorescence ratings. However, a regional southeast-northwest trend of relatively high epifluorescence parallels the southwestern part of the Paradox fold and fault belt while the northeastern part shows a regional trend of low epifluorescence. This implies that hydrocarbon migration and dolomitization were associated with regional northwest-trending faults and fracture zones, which created potential oil-prone areas along the southwest trend.

Combined Electromagnetic Induction and Magnetic Susceptibility Surveys for the Detection of Near Surface Geochemical Anomalies

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As surface geochemical exploration for oil and gas gains greater acceptance in the exploration community, the number of methods that can detect alteration phenomena has also increased. Many geophysical methods have been applied to the detection of seepage anomalies with varying success. Electrical and magnetic techniques are at the forefront due to ease of use, rapid data acquisition, and immediate data interpretation. Several of the electrical and magnetic instruments available can be operated by a single user.

The literature states that most hydrocarbon accumulations are associated with magnetic anomalies. The chemical alteration of near-surface sediments by carbon dioxide and hydrogen sulfide produced by microbial degradation of hydrocarbons could account

for the observed electrical and magnetic anomalies over petroleum deposits. Magnetic Susceptibility (MS) anomalies associated with oil/gas fields are caused by secondary magnetite, low-temperature oxidation iron products such as maghemite, or the iron sulfide, pyrrhotite. Electromagnetic Induction (EM) surveys measure soil electrical conductivity of salts associated with near surface hydrocarbon alteration.

A combination of EM and MS has been used to identify hydrocarbon alteration in near surface sediments over oil fields. In general, the higher MS values lie within areas of lower conductivity. High conductivity readings occur as geochemical halos and appear at the edge of seepage anomalies.

Detecting Free Water Above Jonah Pay Using Pickett Plots and Core Analysis

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Defining the top of reservoir in the Jonah field has been an ongoing project since the beginning of development. In past years a considerable amount of money has been spent on fracing, testing, and squeezing perforations due to high production of free water. In addition to money being spent, many possible gas producing zones have been bypassed due to the fear of completing a zone which will produce high amounts of free water. As a result, recent studies have resulted in a top of reservoir correlation that has all but eliminated completing free water bearing zones, as well as targeting pay that would have been previously bypassed.

The Pickett Plot is a technique commonly used to quantify water saturation and identify water-bearing intervals. The crossplot is essentially a graphical representation of the ‘Archie’ equation. In unconventional reservoirs such as Jonah, the technique is not as straightforward due to a variety of factors including, but not limited to pore structure, grain sorting, and the presence of detrital and authigenic clays. However, strong graphical trends have been identified and utilized to differentiate zones bearing free water from zones at irreducible water saturations. Core analysis, specifically tritiated filtrate-corrected water saturations and previous completion results are used to verify trends seen during Pickett Plot analysis. Field-wide mapping of these trends has produced a stratigraphic top that serves as the upper boundary of the Jonah reservoir.

The Mowry-Muddy Hydrocarbon System of the Powder River Basin; a Developing Resource Play

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Recent successes in the Bakken Formation of the Williston Basin have generated renewed interest in oil-prone source rocks as potential producing intervals. While the Mowry is a comparable quality source rock to the Bakken Formation in the Williston Basin, the Bakken has retained much of it hydrocarbons in-situ due to the efficiency of seals adjacent to the source intervals. In contrast, the Mowry interval sourced millions of barrels of oil into the adjacent Muddy sandstones. It has yet to be determined how much insitu hydrocarbon remains within the Mowry as a possible exploration target. This is a world-class hydrocarbon system with over 549 MMBO and 1.978 TCFG produced to January 2008 in stratigraphically trapped accumulations adjacent to mature source rocks.

The Mowry-Muddy hydrocarbon system in the southeastern Powder River Basin is a continuous-phase oil accumulation sourced by the rich, dark siliceous marine shales of the Mowry Formation with adjacent continental and marine clastic reservoirs of the Muddy Formation. The Mowry Shale, like the Barnett Shale in the Fort Worth Basin, is a highly siliceous rich source rock and susceptible to fracturing creating good reservoir potential. This stratigraphic interval has potential to be a combination source-reservoir resource play. However, two marine sandstones within the Muddy, the Rozet and Springen Ranch Members, provide pathways for vertical hydrocarbon migration out of the Mowry reducing the exploration potential.

Pressure data as well as fluid distributions show a relationship between the Mowry source interval and the Muddy reservoirs. Production data and drill stem test data indicate an area of regional extent where mobile water is absent and only oil and associated gas are produced from either the Mowry or the Muddy Formations. Pressures across this area demonstrate both over-pressure and normal-pressure relative to hydrostatic gradient indicating isolation of highly pressured hydrocarbons from normally pressured saturated reservoirs. Structural as well as stratigraphic isolation occur locally and regionally.

Imapit™ Interactive Resource Map

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The iMapIT™ Interactive Resource Map (IRM) is a graphic Information System (GIS) based interactive resource application that provides users with the ability to query, view, and plot map objects in a spatial projection with overlays of topography and/or aerial imagery. The IRM is published in an ArcReader format which allows the user to interact with the map and layers of spatial data. The IRM allows the user to configure the display of multiple spatial data layers from many sources in the same view with the option to produce digital and hard copies of any map a user builds.

Optimal data visualization value is achieved by combining conditioned iMapIT™ spatial data layers from the public domain with proprietary data. The IRM is currently applied to energy development in the Rocky Mountain region and allows access to data for production and/or regulatory compliance reporting. Data can include: geology, hydrology, soils, and other environmental data; mineral lease and surface ownership boundaries; exploration and development infrastructure; local, state, and federal regulatory permit, monitoring, and compliance information; and other energy development related spatial data. Periodic monitoring of public domain spatial data sources allows updating of internally maintained databases. Proprietary data are updated as it is received.

The IRM is linked to an iMapIT™ Interactive Reporting Tools (IRT) application which allows on demand access to the spatial data used to create the maps so it can be viewed and charted or exported in a grid format for insertion into spreadsheet applications. The IRM spatial data is sourced from the same databases utilized by the IRT. IRM configurations currently used by oil and gas exploration and development companies are comprised of approximately 150 object-specific layers with 35 to 40 of these layers containing proprietary data sets.

The IRM is securely accessed through a Citrix Access Point and application servers are housed in a Tier 2 Data Center. ESRI GIS software ArcGIS Desktop 9.2 tools are utilized in conjunction with Arc SDE 9.2 and internally integrated with databases running on MS SQL 2005 platform.

Cased Hole Solutions: Predicting Open Hole Logs Using Artifical Neural Networks

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Neural Net predicted open hole triple combo logs (density, neutron, resistivity) have been used successfully in Jonah for reservoir characterization, net pay determination, frac staging, and OGIP calculations. Drilling and Hole conditioning problems in the area create poor open hole logging conditions, many times resulting in the inability to reach TD (12,000 + feet) with logging tools. In wells where an open hole logging suite is obtained, the borehole conditions adversely affect tool measurements because of borehole rugosity and tool sticking issues. These issues have been the motivation to move toward a cased hole logging program. The benefits have been lower costs, reduced risks, and improved vertical resolution and logging data accuracy.

The process and interpretation workflow involves training and application wells. A training well has both open hole logging data and cased hole logging data. An application well has only cased hole data. An artificial neural network (ANN) model is developed for the training well, across a specific stratigraphic interval or geographic area, using the relationship between the open hole triple combo data and the cased hole data. Pulsed neutron logs work especially well for this because of the strong correlation between sigma, inelastic and capture count rates to resistivity, bulk density, and porosity respectively. Once developed, the ANN model can be applied to application wells that have only cased hole data. The ANN model results are checked against offsetting wells and normalized (if necessary) to insure the most accurate porosity and resistivity data possible. After analysis for frac staging, these data can then be integrated with other wells in the field for net pay and OGIP calculations and reservoir characterization.

Basin Centered Gas Accumulations - Fact or Fiction?

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The concept of large, pervasively gas-saturated basin-centered hydrocarbon accumulations has been used as an exploration tool for several decades, particularly in many basins in the Rocky Mountain region. The recognition of regionally-extensive gas-charged areas dates back to a least the early 1950s, and the use of the basin-centered gas accumulation (BCGA) model gained wide acceptance in the 1970s and 1980s. This exploration model dictates that the deeper portions of certain basins contain gas-charged reservoir systems and produce essentially no mobile water. Under these conditions, many workers believed that any well drilled in a BCGA would encounter gas-saturated rock, and that commercial deliverability was a function of finding a "sweet-spot" within the accumulation that exhibited sufficient permeability for good deliverability. However, drilling experience has shown that mobile water does occur in areas thought to be BCGA areas. The recognition of this mobile water has recently led some workers to argue that the BCGA paradigm should now be rejected as an exploration model. In contrast to this argument, there is strong evidence that the BCGA model is still a viable exploration model. This viewpoint recognizes that regionally-extensive gas accumulations are more complicated than that envisioned using an over-simplified model. Despite these complications, the BCGA model can still be used as an exploration model with which to identify and exploit gas reservoirs in many hydrocarbon regions.

Use of 3D Seismic to Land Horizontal Wellbores in Thin Beds: Potash Solution Mining Near Moab Utah

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Intrepid Mining LLC acquired the "Potash" 3d survey in 2001 over its Cane Creek Potash Mine near Moab Utah. The 3d had duel objectives: 1) mapping of the Cane Creek Anticline to aid in solution mining of potash; and 2) mapping of the Cane Creek anticline for oil and gas potential.

Using the seismic character of the overlying clastic layer as a guide, Intrepid Mining LLC in 2002 drilled the first horizontal well solely for solution mining of potash (KCL)in the Intrepid 27H wellbore. This wellbore targeted "potash 9", a sylvinite (sylvite and halite) layer within evaporate cycle 9 of the Paradox Formation (this potash layer had not been previously mined in the Cane Creek Potash Mine).This wellbore was followed by a "fork" pattern of the 28H well that comprised 15,000 feet of lateral. In 2005 a second fork pattern was drilled with the 29H wellbore. These wellbores targeted the northeast flank of the Cane Creek Anticline which is not as structurally complex as the crest of the structure. The 27H and 28H well used a gamma ray tool (potassium has a highly radioactive signature) to stay in zone. Since the sylvinite layer is encased in halite, it was hard to tell whether the bore was drifting upwards or downwards out of zone. This was remedied in 29H well with an azimuthal gamma ray tool. Other problems encountered were: a slight sag in the seismic under the shallower mine cavern and the discontinuous nature of the potash zone. The seismic was accurate to plus or minus 20 feet.

The secondary objective of the Potash 3d survey was the evaluation of the oil and gas potential of the Cane Creek Anticline in and around the potash mine. In 1956 MODCO drilled a well adjacent to the future Cane Creek Potash Mine that produced oil from the Cane Creek member of the Paradox Formation. In addition, Texas Gas Sulfur encountered gas shows in the Cane Creek while drilling a delineation well for the future potash mine. Synthetic seismic modeling of the Cane Creek member shows amplitudes drops in the Cane Creek reflector where it develops porosity. Cane Creek amplitude loss was detected from the 3D survey under the potash mine . Exploratory drilling of the Cane Creek is pending.

Sequence Stratigraphy and Reservoir Architecture of the Lower Cretaceous J Sandstone, Wattenberg Field, Dj Basin, Colorado

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The Lower Cretaceous (Albian) J Sandstone has produced nearly 1.0 TCF of gas from Wattenberg Gas Field. PhiH, OGIP and EUR maps reveal broad, regional trends punctuated by an irregular distribution of "sweet spots" and "dead spots". Recent 32-acre infill drilling has encountered a wide range of bottom hole pressures that indicate small-scale compartmentalization. Results from a core-based, sequence stratigraphic study of the J Sandstone reveal a complex interplay among depositional and erosional processes, pedogenesis, diagenesis, and syndepositional and post-depositional faulting that helps explain both regional and small-scale compartmentalization.

The J Sandstone is divided into the Fort Collins and Horsetooth members. The older Fort Collins Member consists of several upward coarsening marine shoreface deposits comprising a progradational parasequence set. The Fort Collins Member is unconformably overlain by the Horsetooth Member and/or Mowry Shale. During the development of this unconformity, valleys were eroded into the Fort Collins Member and paleosols developed on interfluvial hillsides. The Horsetooth Member consists of fluvial-estuarine valley-fill and retrogradational barrier island deposits.

Most gas in the J Sandstone in Wattenberg Field is trapped within an erosional remnant of two parasequences of the Fort Collins Member bounded by "tite" Horsetooth valley-fill deposits on the west, south, and east. The northern trap appears to be related to an increase in porosity-occluding silica cement--a diagenetic boundary. Smaller sweet spots and dead spots reflect facies architecture on a shoreface clinoform scale as well as small-scale fault compartmentalization.

Shale Gas Potential of Fine-Grained Cretaceous Source Rocks, Raton Basin, South-Central Colorado and Northeastern New Mexico

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The Raton Basin is an asymmetrical Laramide basin west of the Sangre de Cristo Mountains in south-central Colorado and northeastern New Mexico. Since 1906, numerous exploration wells have been drilled within the basin. Except for coalbed methane and CO2 at Sheep Mountain gas field, the basin has yielded little oil and gas. Although numerous gas shows were reported from the Dakota Sandstone and overlying Cretaceous "shales", gas has only been produced from the small Garcia (Niobrara) and Wagon Mound (Dakota) structural fields.

In 2004, the gas potential of Cretaceous fine-grained source rocks was evaluated by EnCana Oil & Gas, USA. In ascending order, these "shales" include the Graneros, Greenhorn, Carlile, Niobrara and Pierre formations. To assess the rock type, kerogen type and quality, regional thermal history, samples from outcrops, cores and cuttings were analyzed for CaCO3, TOC, and Rock-Eval pyrolysis. Processed samples were examined optically to determine the degree of thermal alteration and vitrinite reflectance, and kerogen type.

The Graneros, Greenhorn, Niobrara and Pierre intervals have good organic enrichment. Residual TOC contents range from 1.5 to 2.5% for thermally mature sediments, and up to 5.0 % for adjacent immature / early mature Niobrara sediments. They all contain mixed Type II/III kerogens. However, the Niobrara contains intervals dominated by Type II oil-prone organic matter. The Greenhorn and Niobrara have the greatest hydrocarbon generative potential per unit rock and because of its thickness (>1500 feet thick), the Niobrara is the most potentially prolific source rock in the basin. The paleo-thermal gradient is steep and consistent with published data from coal studies, indicating high heat flow in the basin. These fine-grained source rocks pass into the dry gas thermal maturity window between approximately 4000 and 5000 feet TVDSS.

Recent Advances in the Analytical Methods Used for Shale Gas Reservoir Gas-in-Place Assessment

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Shale gas reservoirs are a commingling between conventional (compressed) and unconventional (adsorbed, i.e. CBM) gas reservoirs. Therefore, shale gas-in-place (GIP) evaluations require the use of analytical methods originally developed for each specific reservoir system. Unfortunately, many analytical techniques used to determine GIP and permeability for conventional and CBM reservoirs do not translate well when evaluating shale due to its complex lithology. Presented are the results of a rigorous study, conducted in an effort to improve existing shale analytical protocol to more accurately define the critical parameters necessary for shale GIP assessment.

The petrographic impact on the adsorbed phase gas storage capacity in shale was investigated to determine what, if any, gas adsorption vectors beyond available TOC exist. Research was also conducted to define the influence of liquid phase hydrocarbons on the adsorbed phase gas storage capacity (dissolution) in shale. The results provide insight into the mechanisms responsible for some of the unexplained phenomena observed when adsorption isotherm analysis is conducted on shale samples.

Improved sample handling methods were developed to maintain in-situ moisture conditions during processing and laboratory testing. Techniques were developed to allow the delineation of water saturations into its pore, irreducible, and bound water components. Procedures were developed to improve shale permeability and porosity measurements, using competent core under in-situ stress conditions. Furthermore, grain density measurements (required for porosity determinations) were conducted using select inert gas species with molecular diameters similar to methane to contrast and compare the results determined using the standard gas, helium, which can potentially overestimate available porosity.

Characterization of Syn-Depositional Faulting of a Composite Type B Halokinetic Sequence Along the La Popa Salt Weld, La Popa Basin, Nuevo Leon, Mexico

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Halokinetic sequences are growth strata associated with passive diapirs and are bounded at the top and base by local angular unconformities. The unconformities are caused by drape-folding of the strata adjacent to a diapir as it rises topographically and are used to interpret the history of salt movement in a basin. La Popa salt weld in the La Popa basin is a vertical salt-evacuation feature; the strata adjacent to the weld exhibit halokinetic sequences formed during the diapiric phase. Two types of halokinetic sequences (A & B) have been identified in the strata adjacent to the weld. Type A is characterized by a thin beam of strata over the diapir creating a tightly drape-folded package of sediment at the salt-sediment interface; whereas, Type B is characterized by a thick beam of strata over the diapir generating a broadly drape-folded package with an onlap wedge of younger sediments against the folded beam.

The definition and attributes of Type B halokinetic sequences are based on outcrops along the northeastern side of the weld where the Maastrichtian age Muerto Formation forms the onlap wedge onto the thick beam of Campanian age drape-folded Parras Shale. At this location there is a syn-depositional fault that cuts through the sequence. Documented slickensides on the fault surface indicate a normal fault sense of movement. Field mapping indicates faulting created a half-graben whose 3-D geometry is an elongate trough that parallels the trace of the weld. The hanging-wall strata is upper Parras Shale that is overlain by a growth stratal wedge of the Muerto Formation at the easternmost extent of the fault trace. This suggests that faulting was syn-depositional to the Muerto Formation and occurred late in the Type B halokinetic sequence formation as a response to extension associated with drape-folding of the thick beam of Parras Shale as diapirism progressed.

Building Better Fracture Models By Combining Structural Analysis and Bayesian Updating to Quantify the Relationship Between Multiple Fracture Causing Agents

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Gaining a better understanding of the impact that fractures have on reservoir hydraulic behavior often requires interpolating between areas of limited geologic control, such as wellbore or outcrop data. A common approach taken is to perform structural analysis on a properly constructed 3D model of the reservoir to generate attributes that relate to the deformation. Structural attributes can be generalized into classes: morphologic--relating to the present-day shape of the reservoir, kinematic--relating qualitatively to incremental or cumulative deformation, and mechanistic--relating quantitatively to incremental or cumulative stress or strain. It is common to discover that a combination of attributes best explains patterns of fracture occurrence; however, these attributes are usually calibrated to fracture intensity and used to infer the distribution between points of control one at a time. To provide the best possible model describing fracture occurrence, the multiple structural attributes should be combined simultaneously in a mathematically unbiased and consistent manner.

Bayesian Updating is a statistical theory relating conditional probabilities through multivariate correlations. In considering the prediction of a primary event A with two secondary events B and C, Bayesian Updating provides the conditional probability of A given events B and C. This is done by combining B and C into a likelihood that updates A. In this application A is fracture intensity and B and C are structural attributes.

To illustrate this technique we assessed the distribution of tectonically-produced fractures in the Frontier #1 Sandstone flanking Oil Mountain Anticline in central Wyoming. The intensity of folding-related fractures, which are easily separable from those that predate folding, were obtained by continuous scan-line measurement of fracture spacing along a 5 km outcrop extending from both flanks of the anticline and around the plunging nose. We compared fracture intensity against 13 morphologic and kinematic structural attributes and find that a measure “flexural-folding strain”, as a single attribute, best explains fracture intensity. Convolving that attribute with a properly filtered measure of curvature improves the correlation. We use the combined attribute to populate the entire anticline with tectonic fractures (as well as pre-tectonic fractures) and consider the result to be a viable analog describing fracture development in similar lithotectonic cases.

Tradeoffs in 3D Seismic Acquisition Between Shallow and Deep Objectives or Value of 3D High Density (Infill) Seismic Survey to Improve Economic Results of CBM Wells from Cow Creek Unit

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3D seismic data provides much needed lateral information in the inter-well space not possible through extrapolation of well information. However, the survey must be designed to provide the required coverage at the depth of interest. Seismic energy spreads away from its source in a spherical pattern or a cone spreading downward from the shot. Fold, or redundancy is developed by utilizing the overlap of these cones of energy produced by each shot and recorded into a 3D spread, or pattern of receivers on the surface Fold or redundancy is depth dependent as the cones of seismic energy spread out further as they go deeper. While shallow data may be easy to obtain and good quality, it is often cost prohibitive to increase the source and receiver sampling effort to the level required providing as little as 6 or 7 fold at shallow depth, 1000’ or less. In a survey designed for much deeper targets. One of the early bids for the Cow creek survey from PGS Onshore was designed to provide a nominal fold of 6-8 at a depth of approximately 1000’. The cost estimate for this survey was prohibitively high at a cost of over $1.8 million for acquisition alone. At that time the decision was made to pursue the deep data while preserving the option to come back at a later time to fill in the survey at a higher density. The higher density infill program would be designed to obtain better resolution of the deeper reservoirs and increase the possibility of obtaining some usable data at the shallow Mesa Verde level to improve the outcome of the shallow low risk CBM wells.

Concurrent to the planning and design of the 3D survey to image a deeper higher risk target, teh operator was planning 8 CBM wells in a 2 square mile area near the western edge of the survey. Would be possible to provide the higher density coverage in a 2.5 to 2 square mile area to image three Mesa Verde coals with thickness ranging from 5 feet to 25 feet and the intervening sandstone, siltstones? A plan was devised to infill the survey in a 1.75 square mile resulting in a nominal fold of 1 in most of the bin locations at a depth of 1000 feet. The approximate cost of this additional effort centered in section 12 T 12N R 92W would be between $50,000 and $60,000 based on the cost for additional, shotpoints and receivers outlined in the Western contract. The cost of each well contained within the survey area is $50,000 and the expected Value of a good well vs. poor well is summarized in the table below.

Cost $50,000/well

Well Value-High Producer Value Low-Producer

Well 32-12 $500,000 $200,000

Well 42-12 $500,000 $200,000

This paper will evaluate the value of the seismic information by estimating how the uncertainty the amount of gas to be produced by a given well would be affected by the information added by the higher density 3D survey shown in figure 1. The conditional probability that seismic could predict 'better locations' by addressing one of the key uncertainties, coal thickness, can be estimated forward modeling the seismic response of the expected ranges of coal thickness' and determining those which will be detectable by the higer density infill seismic. With the conditional probability that the 3D seismic data will be able to detect the coals estimated, Bayes Theorem of probability can be invoked to calculate the posterior probability that a thicker coal will be encountered in one location rather than another based on the observed response of the seismic data.

Seismic Petrophysics in Tight Gas Sands - a Piceance Basin, Mesa Verde Example

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Recent advances in seismic AVO analysis are applied to seismic data over the Rulison Gas Field in the Piceance Basin of Colorado. Pre-stack migrated gathers are analyzed for amplitude changes with offset and a cross-plot technique is used to evaluate reservoir properties of the low porosity Williams Fork Sands of the Mesa Verde. Seismic Lithology (LithSeisTM) is correlated to clay volume from open hole log analysis, AVO type is used to identify coal seams and porosity determined from seismic data is normalized to the open hole log porosity.

A reservoir summation sensitivity study compares the results of seismic analysis to log analysis. The reservoir summation results indicate that the reservoir volume (Porosity*Net Sand) from seismic analysis has a good fit to open hole results. The seismic summation results demonstrate that the AVO type cutoff eliminates the high porosity coal seams and that seismic porosity is sensitive to a 6 or 8% cutoff. The seismic reservoir summation run over the completed/hydraulically fractured, Williams Fork Sand interval also has a good correlation to production results and EUR estimates from the wells included in this study.

The result of pore pressure prediction from seismic frequency decay (QxTM) is also presented. In addition to drilling applications, pore pressure from seismic data adds to the potential understanding of the roll that faulting and natural fractures seem to have on the gas reservoir in the Rulison Field.

The Stone Cabin 3D Leads the Deep Exploration and Development of the West Tavaputs Plateau

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In 2002 Bill Barrett Corporation purchased 46,000 gross acres in the West Tavaputs Plateau area of the southern Uinta Basin. This purchase included three federal units and 11 wells producing 1.4 MMCFPD. In 2004 Bill Barrett Corporation acquired an 83 square mile 3D seismic survey to image the deep potential of the West Tavaputs Plateau area. Currently Bill Barrett Corporation produces over 100MMCFPD from Tertiary, Cretaceous, and Jurassic reservoirs.

At a cost of $8,000,000 the Stone Cabin 3D was acquired to define the deep structure and determine the exploration potential of formations below the Cretaceous Price River. In 2005 Bill Barrett Corporation drilled the #6-7D well to a total depth of 15,349 feet establishing the first Jurassic Navajo production in the Uinta Basin. Currently six deep wells contribute approximately 15% of the gross daily production.

The Stone Cabin 3D is a key component in the exploration and development of the deeper reservoirs at West Tavaputs Plateau. Bill Barrett Corporation is exploiting the existing Navajo reservoir with 3D seismic guided directional drilling. Exploration targets below the Navajo are being drilled in 2008. The company is also mapping shale gas potential within the Stone Cabin 3D. By acquiring and utilizing 3D seismic Bill Barrett Corporation has enhanced the knowledge of the shallow and deep producing formations providing the company with additional opportunities and reducing the risk in exploiting these reservoirs.

Fracture Modeling and Fault Zone Characteristics Applied to Reservoir Characterization of the Rulison Gas Field, Garfield County, Colorado

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Structural modeling is a potentially valuable reservoir characterization tool. A good structural model is grounded in geologic data but incorporates many aspects from other disciplines. This work presents a structural model that incorporates geologic well data, 3D seismic data, geomechanical analysis, and well production data to characterize the Cretaceous stratigraphic interval of the Rulison Field area in the Piceance Basin of northwestern Colorado. The structural evolution of the Rulison Field was derived from the interpretation of 3D seismic. Shale Gouge Ratios along the seismically mapped fault surfaces have been calculated based on available well data. Incorporation of geomechanical stresses allows the dilation tendency of faults and fractures within the field to be calculated and analyzed. The mapped faults and horizons were used to create an elastic dislocation model of the reservoir. This elastic dislocation model yields a 3-D fracture model, which predicts qualitative fracture densities and shear failure types from the known geomechanical properties of the reservoir interval.

Ultimately, this model highlights compartmentalization within key reservoir intervals in the Rulison Field. It also confirms that the fault zones are pathways for fluid migration through their dilation, and that predicted 3-D fractures can be correlated to areas of known fracture production. On a larger scale, the interpreted tectonic history of early Cretaceous extension followed by Laramide aged inversion is a new interpretation of the structural evolution of the Piceance Basin. Thus, the structural model could be used to better optimize drilling locations and therefore production from within Rulison Field.

Maturity and Organofacies Assessment of Bakken Shale: Implications for New Areas for Exploration and Production

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Williston Basin Bakken oil fields are unconventional stratigraphic traps that require horizontal drilling. The upper and lower members of the Bakken are excellent source beds and consist of highly organic rich black shales with TOC values averaging between 11 and 12%. The middle member is a clastic-carbonate unit with a preferred dolomitic facies. All three members contribute to the reservoir character with fracturing being the dominant porosity type. Fracturing is caused by overpressuring with contribution from lithostatic pressure, nonhydrocarbon and hydrocarbon generation from the black shales in mature areas, episodic basement uplift and wrench faulting, and Prairie Salt dissolution.

Generally, where productive, lineaments define dominantly northeast and northwest-trending fault systems and other structural features. Together with thickness variations, stratigraphic changes and overpressuring (up to 0.7 psi/ft.), Bakken reservoirs have been created. Two recent major oil discoveries, Elm Coulee and Parshall fields, have caused a renewal of the cyclic exploration effort of the Bakken.

These recent discoveries in the Williston Basin have occurred in areas where the Bakken Shale is immature to earliest oil window thermal maturity. Although controversial nearby indigenous oil is apparently being produced from the organic matter rather than migration into the system from more mature down-dip source areas. This assessment is based on geochemical characteristics of Parshall Field oil, which based on light hydrocarbon distributions is a low thermal maturity oil similar to the overlying Bakken Shale. Bakken Shale samples from Parshall Field area have geochemical characteristics suggesting potential production prior to renewed drilling and discoveries in this area.

Bulk open-system kinetic data measured on several Bakken Shale samples is used to evaluate relative rates of oil generation. While source rocks have been identified that generate hydrocarbons at lower thermal thresholds than classical onset of hydrocarbon generation windows, these are usually high sulfur Type II-S kerogens such as the Monterey Formation, rather than low sulfur, marine shales such as the Bakken. Our experience, however, is that all kinetic models currently in use, tend to under predict early hydrocarbon generation. A revised assessment of these results provides some insights as to why this may occur.

Investigation of available Bakken Shale and middle member rock data suggest variations in organofacies that are now being evaluated and compared. There is considerable variation in their properties and these may play a role in variations in the timing of hydrocarbon generation across the basin. Fracturing results from a variety of factors, but our investigation focuses on generation-induced fractures. This could result from either nonhydrocarbon or hydrocarbon generation. Likewise, bulk kinetic data suggests a range of temperatures for the onset of generation apparently controlled by organofacies differences in Bakken Shale with one organofacies generating at lower temperatures than the predominant organofacies found in the Bakken. Thus, apart from other geological activity, both hydrocarbon and nonhydrocarbon gases generated at low thermal maturities may provide means for creating fractures or secondary porosity for early oil accommodations.

A key issue that arises from this investigation is the possibility of identifying additional Bakken and shale-oil plays in other basins that have been described as too low thermal maturity for indigenous hydrocarbon generation.

An Overview of Hydraulic Fracture Mapping in the Jonah Field and Its Implications for Field Development and Completions

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The lenticular sands of the Lance formation in the Jonah Field in South-West Wyoming require a special completion strategy for the best economic development. The Jonah field is a large, structurally complicated wedge shaped fault trap in the Green River Basin. Production is primarily from an over-pressured stacked sequence of 20 to 50 fluvial channel sands in the Lance Formation.

The main reservoir issues in Jonah are low permeability and small pay sections across a large gross interval. Hydraulic fracturing is required to sustain commercial production in these low permeability reservoirs and wells in the Lance are stimulated in multiple fracture stages. Each fracture stage may target three to six sand bodies with eight to twelve stages per well.

With about 13 Tcf of OGIP over an area of about 23,000 acres, the operator embarked on an aggressive strategy to determine the best infill drilling and completion strategy by directly measuring fracture growth on hundreds of fracture treatments in various pilot areas in the field. Direct fracture mapping technologies such as microseismic and tilt mapping played a major part in the decision-making process to determine well placement, infill drilling, staging and fracture treatment design.

This paper provides a management level summary, will provide an overview of the Jonah Field and present details of the following general findings from fracture mapping:

- Main fracture azimuth is generally N 45° W. The well pattern was adjusted to accommodate this;
- Multi-directional complex fracture growth;
- Fracture half-lengths are 600 to 800 ft for normal fracture treatments, but effective half-length are significantly smaller;
- Fracture height growth is mainly driven by the effectiveness of shale barriers;
- Unexpected faults have been encountered and showed a significant impact on fracture growth behavior.

Fracture and Small Fault Networks in Basement-Involved, Fault-Related Folds Above Oblique-Slip Faults: Insights from Physical Models

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Networks of fractures and small faults play an important role in determining reservoir produceability and trap viability in basement-involved, fault-related folds. Because many basement-involved, fault-related folds originate by reactivation and/or inversion of pre-existing normal faults, their formation often involves a component of oblique-slip on the underlying basement fault. Under oblique-slip conditions, fold-related fracture and small fault networks may have significantly different characteristics than in folds formed above pure dip-slip faults. This study uses scaled physical models to investigate how varying degrees of oblique slip affect fracture network properties in basement-involved, fault-related fold. The models consist of a single homogenous clay layer overlying a rigid basement with a single master reverse-fault. We systematically vary the degree of obliquity in each model and use close-range photogrammetry to quantify and examine the patterns of strain that develop in each model.

In our models shear strains are accommodated on the limb of the fold, while extension occurs at the top of the fold, and shortening occurs at the bottom of the fold. Our results show that with increasing obliquity there is an increase in extension in the upper region of the fold, and hence an increased likelihood of opening mode fracturing. Because shear strains are localized on the fold limb, it is important for any structural analysis of natural structures attempting to interpret oblique slip that the analysis is performed at the appropriate vertical position on the fold. Higher shear strains can lead to increased faulting in the limb of fold that can compartmentalize and act as a barrier to fluid flow. In summary, the results of our experiments suggest that increased oblique slip leads to increased secondary porosity via fracturing in the upper fold region, while at the same time permeability is decreased in the fold limb, decreasing reservoir quality while at the same time increasing sealing potential.

Triangle Zones in Front of Basement-Cored Uplifts in the Rocky Mountain Region

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Frontal triangle zones, formed by a frontal thrust, a back thrust, linked by a basal detachment are common features at the front of thrust belts around the world. Recent field mapping, seismic and well data have shown that they are also present in some areas at the front of Laramide age basement-involved faults in the Rocky Mountain Foreland. These areas include at least the eastern margin of the Beartooth Mountains, the eastern Absaroka Front, the western flank of Casper Arch, the southern Owl Creek Mountains, the southern Gros Ventre Mountains, the southern margin of the Granite Mountains, and the east flank of Front Range Uplift. These structures are identified by divergence of reflections in seismic data, abrupt decreasing dip and parallel thrust faults that dip in

opposite directions, and often have unexpected and complicated fault displacement relationships. The triangle zones for which we have the best data and that form in the basement-cored structures develop early in the structural history of the uplift and basin. They form by wedging of deformed strata into the basin stratigraphy on a low angle thrust that soles beneath the mountain front. This wedging delaminates and elevates the undeformed strata above the wedge. The structure is in places then cut off by the main bounding fault between the uplift and the basin. Dipping strata above the wedge yield hydrocarbons from combination stratigraphic-structural traps, but to date, the deformed wedge in the core of the triangle zones is underexplored.

Relationship of Faults, Fractures, and Critical Stress to Mesaverde Reservoir Performance, North La Barge Field, Sublette County, Wyoming

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The North La Barge Shallow Unit (NLBSU), located on the northern extension of the Moxa Arch, , produces oil from the Mesaverde formation at depths of 2000 ft (610 m). Three-dimensional seismic data, borehole images, and cores were used to identify fault and fracture controls on reservoir performance.

The NLBSU is dissected by several subtle strike-slip faults. One such fault compartmentalizes the field. Detailed sedimentologic mapping demonstrate that this sealing fault has a complex history of reactivation.

The NLBSU exhibits four types of production behavior including fracture-dominated, matrix-dominated, fracture/matrix combination, and significantly reduced production near faults. The fracture-dominated production behavior is centralized in a structurally complex, highly stress-controlled region, which includes a horsetail splay termination of a strike-slip fault. This faulted region results in critically stressed natural fracture production.

Faulting and fault-related fracturing play a complex role in controlling production histories at the NLBSU. In addition to critically stressed natural fracture production, several producing wells that were drilled in fault damage zones exhibit significantly reduced production performance. The presence of fault damage zones takes precedence over the occurrence of natural fractures in terms of reservoir enhancement and results in poor production performance. Knowledge of these types of production controls can aid in reservoir management throughout the life of a field

Comparison of Natural Fractures Based Upon Image Logs- Shale Gas Plays of the Western US

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Image-based logs are historically used to identify natural fractures in the tight gas plays of the western US. As the shale gas plays are developed, these image based logs are increasingly used to diagnose the presence, type and origin of natural fractures within the shale.

This poster will display released examples of shale based natural fractures that are present in various basins throughout the Western US, including a comparison to the routine question: How does this compare to the Barnett Shale? The discussions will include the type of fractures present, open and healed as well as their petrophysical characterization including fracture aperture, fracture permeability, fracture porosity, and reservoir fracture spacing.

The building of a reservoir scale Discrete Fracture Network (DFN) will be diagrammatically presented using the reservoir fracture spacing's from individual wells as the building block for matrix to fracture connectivity.

Shear-Wave Splitting Analysis for Natural Fracture Zone Identification, Rulison Field, Piceance Basin, Colorado

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Shear-wave seismic acquired at Rulison Field, Piceance Basin, Colorado by the Reservoir Characterization Project in 2003 exhibits evidence of natural fractures from shear-wave (S-wave) splitting analysis. Rulison Field is a thick unconventional natural gas reservoir producing from the fluvial tight gas sandstones of the Late Cretaceous Williams Fork Formation. Natural Fractures are known to vary throughout the reservoir and to greatly increase the permeability of the tight reservoir rock (Lorenz, 2003). S-wave splitting analysis can be used to predict these changes in fracture density. Since the reservoir interval is thick (~2500ft), S-wave splitting calculations were done using an unconventional approach on 3-D seismic volumes through the reservoir interval as opposed to the traditional horizon-based approach. This process resulted in S-wave splitting volumes that correlate to existing well data. These volumes show lateral and vertical changes in fracture intensity and some of the discontinuous fractured fluvial sandstone bodies. These volumes can ultimately be used to optimize well locations and drilling efficiency.

Potential Shale Gas Resources in Utah

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Shale gas reservoirs in Utah have tremendous untapped potential. These include the Mississippian Manning Canyon Shale, Pennsylvanian Hermosa Group (primarily the Paradox Formation), and Cretaceous Mancos Shale (Prairie Canyon, lower Blue Gate, and Tununk Members) of north-central, southeastern, and northeastern Utah, respectively. Shale beds within these formations are widespread, thick, buried deep enough to generate dry gas, and contain sufficient organic material and fractures to hold significant recoverable gas reserves.

The Manning Canyon Shale is mainly claystone with interbeds of limestone, sandstone, siltstone, and mudstone, and has a maximum thickness of 2000 ft. Total organic carbon (TOC) varies from 1% to greater than 8% with type III (?) kerogen. In

north-central Utah, the Manning Canyon was deeply buried by sediments in the Pennsylvanian-Permian-aged Oquirrh basin and is therefore likely very thermally mature.

Cyclic shale units in the Paradox Formation consist of thinly interbedded, black, organic-rich marine shale; dolomitic siltstone; dolomite; and anhydrite. They generally range in thickness between 25 and 50 ft. These units contain TOC as high as 15% with type III and mixed type II-III kerogen, are naturally fractured (usually on the crest of anticlinal closures), and are typically often overpressured.

The Mancos Shale consists of interbedded claystone, siltstone, and very fine grained sandstone. The thickness of potential shale-gas members of the Mancos ranges up to 1500 ft. In the Uinta Basin, vitrinite reflectance at the top of the Mancos ranges from 0.65% to 1.50%; TOC is 1% to 2% with type II to mixed type II-III kerogen.

The 3D Path to Successful Decisions in O&G Expenditures

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A forward-looking tool, 3D seismic is becoming an accepted and valuable tool for controlling upstream O&G expenditures, including decisions about land and operations. As the price of oil escalates so do costs of services, acreage, personnel, and government regulations. The use of 3D seismic gives managers the ability to evaluate, plan, and change expenditures based on successful interpretation of 3D data.

Four decision paths to plan expenditures are presented. They are: 1) Risk Evaluation of Exploration Plays; 2) Evaluation of Acreage Holdings; 3) Evaluate and Optimize Production; 4) Minimize Surface Damage; and Unintended Opportunities
Six examples follow that use one or more of four ways that 3D can limit, control, and/or optimize expenses.

Timing, Mechanisms and Modes of Cenozoic Fracturing and Deformation in the Southern Raton Basin, Northern New Mexico

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The Raton Basin is a highly asymmetric Laramide basin that lies immediately east of the Sangre de Cristo Mountains of south-central Colorado and northern New Mexico. The Raton Basin is unique amongst Laramide basins as late Cenozoic erosion hasn’t removed the majority of its syn-, and post-orogenic strata. Synorogenic strata were subsequently intruded in the Oligocene by mafic dikes which trend approximately perpendicular to the basin axis. The onset of Rio Grande Rifting and associated intrusive and extrusive igneous activity in the early Miocene and their continuation through the Neogene provide a detailed record of the tectonic stress regimes in northern New Mexico for over 60 Ma.

New and previously published kinematic data collected from across the basin are used in an attempt to constrain the orientations of Laramide stress and strain in the southern Raton Basin and adjacent Sangre de Cristo Mountains. We will present new balanced structural cross sections constrained by recently published geologic mapping and

proprietary seismic and well data and discuss the implications of 2D modeling on the styles and modes of Laramide deformation. New and published surface fracture data, natural and induced fracture data from proprietary CBM well logs and earthquake focal mechanism data are utilized to constrain the modern stress regime within the lithosphere. We will then discuss the implications of these and other stress data and introduce hypotheses for both the mechanism and timing of jointing in the southern Raton Basin.

Seismic Characterization of Fractured Tight Gas Reservoirs, Piceance Basin, Colorado

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The Piceance Basin, located in northwest Colorado, contains one of the largest gas accumulations in the U.S. This northwest trending asymmetrical, Laramide-age basin is composed of low porosity (1%-10%) and microdarcy-scale matrix permeability (1-60μD) sands and shales in the Upper Cretaceous Mesaverde Group. A west to northwest trending regional maximum horizontal compressive stress exists and aligned fractures have developed at depth. Since open fractures could have profound effect on the hydraulic behavior of this tight gas reservoir, the ability to reliably predict fracture anomalies is critical for reservoir characterization. Although numerous seismic studies of fractured rock exist, we extend previous work by investigating northern Piceance where the productive interval is thick (3000-5000 ft) and complicated by an additional 5000-8000 ft of overburden.

In this study we analyzed well logs, laboratory core measurements, numerical models, borehole seismic and surface seismic measurements to understand the relationship between reservoir fractures and surface seismic detection methods in the north Piceance basin. FMI and sonic logs were examined to observe the correlation between lithology, fractures and velocity anisotropy. An extensive borehole seismic program was collected to calibrate between downhole well measurements and surface detection methods. Several multi-component 2D surface seismic lines were acquired at different azimuths to measure fracture anomaly detection capabilities. Preliminary results suggest that fractures occur in sand intervals and seismic anisotropy has a positive correlation to fracture occurrence.

Origin of Gas in the Mamm Creek Field, Piceance Basin, Colorado

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The Mamm Creek field, one of the largest gas fields in the Piceance Basin, Colorado, produces mostly gas (estimated reserves more than one trillion cubic feet) and some liquids from sandstones of the Williams Fork Formation of the Upper Cretaceous

Mesaverde Group. The source of the gas is widely regarded to be coal beds (including the Cameo coal zone) within the lower part of the formation. Recently acquired gas compositional and isotopic data, integrated with other geologic information from the field, provide new insights into the sources of the gas, the timing of gas generation, migration pathways, and reservoir compartmentalization. Specifically, these data indicate that the field has more than one major source of gas. The western portion of the field appears to contain gases derived predominantly from the intraformational coals; however, isotopically lighter and wetter gases in the northeastern part of the field point to a marine shale source, possibly the underlying Upper Cretaceous Mancos Shale. Comparison of Mamm Creek gas geochemistry data with the results of a kinetic isotope fractionation model for gas generation from the Cameo coal and a thermal history model for the Piceance Basin indicates that gas generation occurred from approximately 45-10 Ma. Additionally, spatial variations in gas geochemistry throughout the field clearly indicate the presence of multiple reservoir compartments. This demonstrates the utility of gas geochemistry for providing further insight into the reservoir geology when geophysical data are unavailable.

Application of Rhenium-Osmium Geochronology to Phosphoria Oils, Wyoming

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The Permian Phosphoria Formation (eastern Idaho / western Wyoming) is estimated to have generated petroleum between the Late Triassic and Early Cretaceous. In this study, we applied the rhenium-osmium (Re-Os) geochronometer to oils considered to be derived from the Phosphoria Formation to constrain the timing of petroleum generation. Results show that the majority of the Phosphoria oils yield a Permo-Triassic age (255±73 Ma), but with considerable scatter about the regression (mean square weighted deviate, MSWD = 696). For isotopic data to yield a linear array, all samples must have formed at the same time and possess the same initial $^{187}Os/^{188}Os$ composition. The scatter may reflect different periods of oil generation or variations in the initial $^{187}Os/^{188}Os$ composition of the source rock. A subset of oils with similar initial $^{187}Os/^{188}Os$ values (0.37 to 0.54) yield a Middle Triassic Re-Os age (244±20 Ma). This older age may reflect early oil generation from Type II-S kerogen, or may record the timing of bitumen generation, which precedes oil generation. In contrast, Re-Os data for samples of Phosphoria oils from Torchlight field, Big Horn Basin, yield a Miocene age (9.30 ± 0.67 Ma, MSWD = 0.65). This young age supports studies that suggest that Phosphoria oil may be locally derived at younger times in parts of the basin. Alternatively, the young Re-Os age may reflect the timing of alteration by thermochemical sulfate reduction, which has been proposed to affect the Torchlight and nearby fields. Although these preliminary results are promising, research is continuing to fully understand the Re-Os isotope systematics of petroleum generation.

Fracture Characteristics in Core from Tensleep Reservoirs Across Wyoming

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Cores from 25 wells across Wyoming show that fractures are common in the anticlinal reservoirs of the Tensleep Formation, and that most of them are vertical extension fractures. The most intense fracturing is typically found along crests of the folds. Where orientation data are available, most of the fractures trend approximately normal and parallel to the hinge of the anticlines, although oblique fracture orientations have also been reported. Shear fractures are present in the more tightly folded anticlines. Tests on fractured plugs from core usually show that the fractures have less permeability than the associated matrix, and these test results are commonly used to erroneously suggest that fractures have little effect or may even degrade system permeability. This is because typically only the tightest fractures are tested since they are the only ones that will keep their integrity during plugging. Fracture populations typically include a range of sizes, and it is the more open fractures, those that don't remain intact during plugging and that get discarded, that control permeability. In fact, well tests suggest that fracture-enhanced permeability is present in most of the fields studied. Tensleep fractures are variously mineralized with anhydrite, quartz, calcite, dolomite bitumen, yet most fractures are not completely occluded, retaining up to 80% of the original aperture as remnant porosity. In contrast, although the tight dolomites between the Tensleep sandstone reservoirs commonly act as seals for pressure compartments even though they tend to be highly fractured, probably because the fractures in this facies are short and poorly interconnected.

Late-Mississippian Paleokarst Features and Related Porosity Creation and Destruction in the Aspen, Colorado Area

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Open space porosity within paleokarst features in the Mississippian Leadville Formation occurs in the Aspen, Colorado area. Three episodes of solutional porosity generation and one episode of porosity destruction are recognized. The first two porosity enhancement stages are paleokarst related. Porosity destruction accompanied burial and infilling of the paleokarst by overlying sediments. During burial, solutional modification of the paleokarst features by basinal brines occurred.

The first paleokarst episode occurred after deposition of the basal Red Cliff, its subsequent dolomitization, and subaerial exposure. Solutional features developed on and within the Red Cliff including a rubble breccia at the upper contact. Following deposition of the overlying Castle Butte Limestone member, the Leadville Formation was again subaerially exposed. This second paleokarst episode resulted in more extensive paleokarst development including caves, sinkholes, solutionally enlarged joints and a rubble breccia along the upper Castle Butte surface. During this paleokarst episode, caves developed in the earlier paleokarst breccia zone between the Red Cliff and Castle Butte members. Locally significant erosion is also shown by thickness variations of the Leadville Formation. In one case, the formation is removed along with an additional 30 meters of underlying sediments, allowing Pennsylvanian age shales to be deposited on Ordovician age sediments.

Following the paleokarst formation, the area was submerged and the Leadville Formation overlain by interbedded Pennsylvanian black shales and carbonates. The openings of many of the paleokarst features were filled by black carbonaceous shale. During burial, the remaining porosity in the paleokarst features helped channel basinal brines that locally enlarged paleokarst features producing caves and cave roof brecciation.

Region-Based Basin Modeling: Correlating Depositional Environment to Connected Pore Volume, Powder River Basin (Prb), Wyoming and Montana

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Accurate geologic-based rock property distribution remains elusive, particularly for basin-scale models. Current methods to determine connected pore volume in a sedimentary basin are based on overly simplistic stratigraphic architecture resulting in high geologic uncertainty. This study uses the relationship between environment of deposition (EOD)and connected pore volume to increase model accuracy by documenting standardized parameters across five reservoir classes (RC) with known inputs. The degree to which connected pore volume varies between RCs depends on which geologic controls are most influential.

Region-based modeling of the PRB, 7,000 km2 and over four km deep, employs 28,000 wells correlated basin wide with over 50 standardized stratigraphic surfaces. Sedimentation regions, each corresponding to an EOD, are defined by mapped thickness distributions tied to well-log shape and lithology cutoffs and then calibrated to paleogeographic and depositional system maps. A subset of 3,500 digital well log suites and petrophysics from 1,400 cored wells and outcrop studies provide rock property data for the model.

We compare 5 RCs and evaluate 17 standardized parameters in 5 categories (tectonics, facies, sedimentary bodies, paleogeographic region and stratigraphy) that governed sedimentation patterns. Stratigraphic signals in RC1-5, in order of decreasing depth, record the transition from more climate control to that of tectonics associated with foreland development. Climatic variations under Greenhouse conditions produced RC1, a long-lived Mississippian carbonate platform system (<500 m-thick; 12 m.y.) composed of laterally expansive vertically connected karst-bounded sequences. Secondary porosity follows depositional patterns and results in large areas of connected porosity. Brecciation provides zones of high permeability and preferred-facies fracture zones. Instead, under Icehouse conditions RC2 (<250 m-thick; 28 m.y.) shows more layering and interfingering of eolian erg, coastal dune, shelf and sabkha clastics with bands of basin-wide dolomitized clastics that record marine reworking of coastal dunes upon rapid transgression. This complex arrangement of environments produces potentially high, but more isolated connected pore volumes.

Alternatively, foreland development through the Cretaceous resulted in increasing subsidence rates, the onset of which recorded by thin (<50 m-thick) valley fill sandstones of RC3 during 2 m.y of latest Albian time. Gentle subsidence to the west and long-term transgression resulted in progressive onlap within a dendritic erosional surface and

development of bay head deltas and tidal inlets during still stands. Subsequently, the deltaic wedge of RC4, half the 600 m-thick overlying RC5, records more erosion and bypass along forced regression surfaces in the more channelized delta front region (Cenomanian-Turonian), as evidenced by forced-regression erosion and basinal turbidites. The mature rapidly subsiding foreland of the Campanian influenced rapid accumulation of RC5 (half the 8 m.y. RC4) composed of shoreface sands and offshore bars encased in shelf mud. Minimal erosion along forced regression unconformities and thick mudstones separate three clastic wedges.

Preliminary results suggest that carbonate systems become much more heterogeneous under Icehouse conditions suggesting greater connected pore volume lies in Greenhouse carbonate platform systems. Furthermore, in the upper 3 RCs, foreland evolution phases were most influential, producing connected porosity restricted to valley fills, concentrated by significant erosion that gave way to significant subsidence. These patterns are fundamental to predicting connected pore volume from log data for depositional systems filling cratonic sedimentary basins

A Lower Smackover Unconventional Resource Play in Louisiana

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The Upper Jurassic Smackover Formation is a well documented conventional oil and gas play in the Gulf Coast. Oil and gas production occurs in the high energy carbonate deposits of pelletal and oolitic grainstones in the upper Smackover section which rims the Gulf Coast basin from Texas to the Florida panhandle. Hydrocarbons in these reservoirs are sourced from the underlying, organic rich, laminated lime mudstones of the lower Smackover. The lower Smackover source rocks extend to the south, down dip from the upper Smackover producing fairway. Apparent fracture production from the down dip lower Smackover section suggests it has remaining potential as an unconventional resource play, which may be exploited with horizontal drilling technology.

New Facility Offers Public Access to Rocky Mountain Core and Data

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In collaboration with Omni Laboratories based in Houston, TX, the Rocky Mountain Oilfield Testing Center (RMOTC) is establishing a public core repository in Casper, WY. Being the hub of the northern Rocky Mountains petroleum industry, Casper is an ideal location for such a facility. All core is available for public viewing and in most cases, testing. There are currently about 1000 ft of core readily available to the public. Another roughly 2000 ft of core are archived in on-site shipping containers, also available to the public. All producing zones at Naval Petroleum Reserve Three (NPR-3, Teapot Dome Field), Natrona Co., WY are represented by core at the repository. Upper Cretaceous rocks include the Shannon Sandstone Member, Niobrara Shale Formation, and Frontier Formation (including the First, Second, and Third Wall Creek Sandstone Members). Lower Cretaceous rocks include the Muddy Sandstone Member, Dakota Sandstone (Fall

River) member, and Lakota Conglomerate Member. Pennsylvanian/Permian rocks include the Tensleep Formation. Core can be viewed in a new layout facility at Omni. Both natural light and UV light are available in the viewing room. Core photography is available in natural and UV light. Thin sections and core plugs can be sampled from core with RMOTC's permission. Conventional core analysis is available on site. Whole core can be slabbed if required, again with permission from RMOTC. Well history files will be available for each well represented by core in the public area. A working area allows a comfortable environment to examine well file documents. Other NPR-3 cores will be placed in the repository as they become available from future drilling projects.

A Practical Use of Shale Petrophysics for Stimulation Design Optimization

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The most common fallacy in the quest for the optimum stimulation treatment in shale plays across the country is to treat them all just like the Barnett Shale. There is no doubt that the Barnett Shale play in the Ft. Worth Basin is the “grand daddy” of shale plays and everyone wants their shale play to be “just like the Barnett Shale”. The reality of shale plays are very much the same as in tight sand plays, each reservoir is different and the stimulation and completion method should be determined on its individual petrophysical attributes. Where does one begin the journey of selecting the completion style for an emerging shale play? It begins in the laboratory.

Actual measurements of absorption-desorption isotherms are also a critical piece of the puzzle. With this type of data available, significant correlations can be drawn by integrating the wireline log data as a tool to estimate the geochemical analysis. Thus the wireline logs could be a very useful tool in extending the reservoir understanding and productivity potential away from the wellbore where actual lab data are measured. A recent review of a shale laboratory database representing principal shale lithotypes from each of the major shale plays has revealed some statistically significant correlations between mineralogy, Kerogen type, and shale lithotype to mechanical properties, sorbed gas and permeability. Mineralogy and fluid sensitivity testing also show significant correlations to regained permeability testing results. These results have been implemented in a Petrophysical model driven by wireline logs that are common in the industry. The results of the Petrophysical model are used to classify the shale by lithofacies and emulate the lab measurement results for the first step in resource in-place determination and a stimulation treatment development and design.

The Successful Application of a Compartmental Completion Technique Used to Isolate Multiple Hydraulic Fracture Treatments in Horizontal Bakken Shale Wells in North Dakota

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When it comes to completing the Bakken shale in North Dakota, the options are a real confusing buffet of choices. But which method is really working? To achieve optimum recovery, the Bakken formation needs to be drilled horizontally and hydraulically fracture stimulated. If the wellbore is drilled in the orientation to achieve a longitudinal fracture treatment, only one fracture treatment is needed and the issue of frac stage isolation is not an issue. If the stress orientation is unknown or the wellbore is drilled in the orientation for transverse oriented hydraulic fracture direction, then frac stage isolation is an important decision. In the past few years, numerous methods have been tried to achieve good frac stage isolation in the Bakken. A brief review of completion success in the Bakken identifies one method that has the highest degree of success when completing transverse-oriented hydraulic fractures. The best wells have an uncemented liner and a compartmental completion technique. These compartments can be tailored to cover specific areas of the borehole so you put the treatment near the best shows. The frac compartments are created with the use of swellable external casing packers and ball-actuated stimulation sleeves. In one pumping event, multiple frac stages are pumped, separated by opening individual stimulation sleeves selectively from the toe to the heel. The completion of two wells are discussed that show positive proof of this concept from a completion and production perspective.

Is That Frac Job Really Breaking New Rock?

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With all that horse power sitting on location shaking the ground while pumping a frac job it is really hard to imagine what the fracturing treatment is doing down hole. Is it breaking into new rock in a linear elastic mode or is it just opening pre existing planes of weakness in the reservoir? Let's consider the implications of both scenarios.

If the rock is failing down pre existing planes of weakness in the rock, the frac job will tend to stay in the weakened zone without growing through weak shale barriers. This could explain why most of the frac models show poor containment in tight sands yet tracer logs show good frac containment. How about Microseismic surveys during frac treatments? They tend to see a rather large stimulated reservoir volume and shorter lengths than is modeled. If the fracture treatment is breaking new rock the created fracture will tend to be more like what is modeled in current frac simulation models.

So how do you tell if you are opening a pre-existing weakness in the rock or breaking new rock? A novel concept to do this is to integrate the geomechanically determined stress state of the rock with hydraulic fracture diagnostics. By comparing the estimates of minimum horizontal stress from both disciplines one can determine which type of fracturing one is doing. This leads to an improved post stimulation diagnostic analysis and trouble job analysis.

Growing and Indispenable: the Contributions of Rocky Mountain Unconventional Gas Resources and Production to U.S. Gas Reserves and Production

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Production and reserve additions from unconventional gas resources have been growing and indispensable components of U.S. gas production and reserve additions. This paper first examines the contribution of each unconventional component - tight sandstones, coalbed methane, deepwater, shale gas, tight carbonates, and ultradeep gas - to U.S. gas production and reserve additions from 1990 to 2006. During this period, the share of unconventional gas production in total U.S. gas production grew from one-sixth to one-half. The particular emphasis of the paper will be on the specific contributions of unconventional Rocky Mountain gas to national production and reserve additions. These contributions have come predominantly from tight sandstones and coalbed methane. The presentation will conclude with a forecast of Rocky Mountain unconventional production and reserve additions to 2020. From 2010 to 2020, the Rocky Mountain region should be the most important region for U.S. gas production.

Biogenic Gas Resource Potential of the Upper Cretaceous Pierre Shale in the Denver-Julesburg (Dj) Basin

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The Upper Cretaceous Pierre Shale Formation is the thickest sedimentary rock interval in the Denver-Julesburg (DJ) Basin. Oil and natural gas are produced from the Terry and Hygiene Sandstone Members of the Pierre Shale Formation, and oil is also produced from several naturally fractured areas in the Pierre Shale. The natural gas in the sandstones is chemically wet, i.e., has a high, 16-25 mole percent content of C_{2-5} hydrocarbons, which is a distinctive, thermogenic gas-origin geochemical signature. Previous geochemical analyses of source-rock potential and C_{15+} hydrocarbon compositions of oils indicated that the organic matter in the surrounding Pierre Shale is too thermally immature to be the hydrocarbon source-rock. Carbon and hydrogen isotope analyses reveal, however, that the methane in the Terry and Hygiene sandstones actually has a mixed biogenic-thermogenic origin isotope signature. Geologic analog comparisons suggest that the source for the biogenic methane in the Terry and Hygiene sandstones was breakdown by anaerobic bacteria of thermally immature organic matter in the surrounding Pierre Shale or underlying Niobrara chalk beds. In the eastern Denver-Julesburg Basin, biogenic methane is produced from thermally immature, fractured Niobrara chalk beds. In the northern Great Plains, southeastern Alberta, and southwestern Saskatchewan, biogenic methane is produced from thin sandstones and siltstones encased in thick Cretaceous shale sequences. The presence of biogenic methane in these Pierre Shale sandstones indicates that others areas in the Denver-Julesburg Basin where the Pierre Shale contains thin, interbedded sandstones and siltstones or is naturally fractured may have potential for significant future biogenic gas resource discoveries.

Contingent Resources: Definitions and Real World Examples

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Hydrocarbon deposits progress through a variety of categories on their way to being classified as proved reserves. There are three broad categories currently recognized by the industry; prospective resources, contingent resources, and finally reserves.

The subject of this talk is contingent resources, which are considered discovered, technically recoverable volumes which are not currently economic.

Formal definitions will be presented, followed by examples in North Williston Basin unconventional oil, the Wyoming Baxter shale, and early San Juan Basin coal bed methane

Contingent resource evaluation is especially amenable to probabilistic analysis techniques.

Multiple Origins of Thin-Bedded Deepwater Slope Sandstones: El Rosario Formation (Upper Cretaceous - Paleocene) Baja California, Mexico

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One dilemma in sedimentology is that multiple depositional processes produce similar features while one formative process generates multiple patterns. Comparison of (1) depositional energy trends from grain size and primary structures, (2) placement within a stratigraphic hierarchy, (3) ichnofacies type, and (4) sedimentary body type and associated architectural changes are used to assess the causal mechanism. Variations of these attributes reflect flow initiation processes (flood vs. failure), depositional processes (flow stripping, overspilling or bottom current reworking), and preservation (thin-beds bounded by erosional channels).

El Rosario outcrops expose five different thin-bedded sandstone types (TBS): (1) Hyperpycnite successions (4-15m thick) are interbedded with slope mudstone deposits that together form tabular (85m thick; >1km wide) successions, with sandstone channels and scours common at the base and mass transport deposits present at the top. (2) Wedge-shaped TBS flank and confine multistory channelbelts up to 90m thick that thin and pinch out within 500m of interdigitated but stacked conglomerate channels. (3) TBS separating channel bodies form 25m-thick and 230m-wide preserved remnants. Unidirectional current ripple laminations are most common in upward-thicking successions within these channellized regions. (4) TBS successions (9m thick; 120m wide) also cap upward-fining channelbelt cycles; their stratigraphic position suggests waning energy conditions within these cycles. Similarly, (5) contourites comprise <3m wide sandstone lenses amalgamated laterally to form (4m thick; >1km wide) tabular bedsets. Structureless sandstones capped by highly bioturbated mudstone are common. Paleocurrent indicators change from unidirectional offshore during hyperpycnal flow to slope parallel flow during waning energy conditions of this mudstone-rich cycle.

Risk Management and the Economic Redemption of Seismic Data in the Sacramento Basin, California

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In 2007, Venoco drilled 127 wells in the Sacramento Basin, California, and is on track to drill another 120 wells in 2008. The primary reservoir in over 90% of the wells is the Cretaceous Forbes, a 3000' thick section of interbedded marine shales and turbidite clastics. Quality 3D seismic data is critical to refining the architecture of and successful drilling locations in the incised channel sequences, fault traps, and shingled turbidite packages. Effective seismic data analysis also delineates amplitude pitfalls to avoid such as bentonites, basalts, and superpressure zones.

Venoco currently owns over 1500 square miles of 3D seismic and over 20,000 line miles of 2D seismic in the Sacramento Basin, California. Another six 3D surveys are planned for 2008 through 2009, at a cost of $40,000 to $100,000 per square mile. All seismic expenditures compete with drilling dollars and are sold to engineering management in equivalent terms of capital exposure, risked reserve adds, enhanced chance of success, PV10, and salvage value. Economic scenarios on new play entry are run as a part of strategic planning and include seismic, acreage, dry holes and successful wells. Competitor analyses also provide plenty of case studies on amount of reserves likely to be found in a geographic province and reserves that must be found to achieve acceptable economic metrics.

Lewis Shale Petroleum System, Eastern Greater Green River Basin, Wyoming and Colorado

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Sandstones within the Lewis Shale have produced approximately 892 billion cubic feet of gas and 8.7 million barrels of condensate. Recent assessments of undiscovered gas indicate that resources range from 9.7 to 13.7 trillion cubic feet of gas, with significant potential for additional reserve development in the next 30 years. Data from published studies and investigations conducted by Colorado School of Mines Lewis Shale Consortium students are integrated utilizing a petroleum-system approach, with emphasis on stratigraphic framework and characterization of reservoir and source rocks. The stratigraphic framework was established from analyses of marker horizons in over 1,000 wells and outcrop localities. Isopach map anomalies indicate syndepositional tectonics played a major role in influencing sediment dispersal patterns and impacted distribution of both reservoir and source rocks. Reservoir characterization focused on Hay Reservoir field because of the availability of modern logs and abundant core data. Production variations in the field may be explained by a new model that suggests early charging preserved reservoir quality in paleostructurally high positions, which differ from the present-day structural configuration. The model is applicable to future field development and exploration programs. The Asquith Marker condensed zone contains the highest concentration of total organic carbon in the lower part of the Lewis Shale. Core-calibrated gamma-ray logs are used to develop a regional Asquith Marker average TOC map. Thermal maturity of the Asquith Marker is estimated from vitrinite reflectance analyses of carbonaceous shales in the Lewis Shale and coals in associated intervals. The average TOC and thermal maturity maps suggest that the Asquith Marker interval contains sufficient organic matter at appropriate levels of thermal maturity to have generated petroleum.

Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Bakken Formation, Williston Basin, Montana and North Dakota, 2008

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Advances in drilling technology combined with new concepts and models in exploration for oil from fractured shale in the Upper Devonian-Lower Mississippian Bakken Formation, Williston basin, resulted in improved recoveries and new discoveries in areas such as Parshall field, Montrail County, North Dakota. These factors have led to renewed exploration and increased the geographic area of potential success for commercial Bakken production.

The U.S. Geological Survey (USGS) is assessing undiscovered oil and gas potential of the Bakken Formation in the Williston basin, which includes parts of Montana and North Dakota. The assessment, based on geologic elements of a total petroleum system (TPS), is for the Bakken-Lodgepole TPS, where oil sourced from upper and lower shale members of the Bakken Formation is reservoired in a primary continuous-type reservoir and two conventional reservoirs. A composite continuous fractured Bakken reservoir is defined as the entire Bakken Formation including, where present, the “Sanish Sand” of the underlying Three Forks Formation. Conventional reservoirs include Waulsortian carbonate mounds of the overlying Lodgepole Formation and sandstone units of the middle member of the Bakken Formation where Bakken oils have migrated beyond the Bakken “oil window”.

Five continuous-type assessment units (AU) and one conventional AU are defined by the USGS for the Bakken Formation within the Bakken-Lodgepole TPS. The five continuous AUs are: 1) Elm Coulee-Billings Nose AU, 2) Central Basin-Poplar Dome AU, 3) Nesson-Little Knife Structural AU, 4) Eastern Expulsion Threshold AU, and 5) Northwest Expulsion Threshold AU. A conventional Middle Member Sandstone AU was also assessed.

Reservoir Characterization of the Bakken Formation, Elm Coulee Field, Williston Basin, Montana

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Elm Coulee Field is one of the 20 largest oil fields in the United States and the highest producing onshore field found in the lower 48 states in the past 56 years. US Geological Survey estimates the resource for the Bakken formation to be 413 billion barrels (mean estimate). The Elm Coulee field, discovered in 2000, produced 15 mm bbl of oil through 2005 and is yielding nearly 50,000 BOPD. This production is about half Montana’s crude oil production.

The Bakken Formation consists of three members: upper, middle, and lower. The field produces from the middle dolomite member and is sourced from the upper and lower organic rich shale members. The three members onlap and pinch out towards the

south-southwest in the field area. The thickness of middle Bakken ranges from 8 to 20 feet, with average porosity of 8 - 10% and average permeability of 0.05 md. The vertical depth of the middle Bakken ranges from 8,500' - 10,500'.

Horizontal drilling and fracturing stimulation of the horizontal legs are the main technologies in the Elm Coulee Field development. Currently there are approximately 350 horizontal development wells that have been drilled in the field.

An integrated reservoir characterization study by performing petrophysical analyses, petrography, and subsurface geological mapping, is being conducted in the Elm Coulee Field. Creating correlations between petrophysical properties and lithofacies is an essential product for future Elm Coulee development. The main deliverables will be a paleoenvironmental setting interpretation, reservoir connectivity, and reservoir quality determination, which lead to the creation of geologic models that will be applicable for the field in specific, Williston Basin in general, and also as an analog for other tight dolomite and shale reservoirs.

Integrating Outcrop and Subsurface Data to Define Regional and Reservoir-Scale Patterns in the Lewis Shale and Fox Hills Sandstone of the Great Divide and Washakie Basins, Wyoming

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The Cretaceous Lewis Shale and Fox Hills Sandstone of the Great Divide and Washakie Basins, Wyoming are a significant gas resource in the Rocky Mountains. Regional studies in the Lewis Shale have revealed southward facing clinoforms that resulted from the progradation of a linked shelf-slope-basin system. Outcrops along the eastern margins of the basins were integrated into a regional cross section in order to resolve how facies and stratigraphic architecture changes in four physiographically distinct areas: (1) shelf edge, (2) slope, (3) proximal base-of-slope, and (4) medial base-of-slope. These outcrops provide a unique opportunity to resolve regional and reservoir-scale patterns in this complex system.

Shelf-edge strata are >50% sandstone and are composed of channels, river-mouth bars, mudstone sheets, and large sandstone slumps. Slumps appear to be related to seafloor instability at the shelf edge. These deposits are interpreted to record a mechanism for generating sediment gravity flows that transmitted sandstone to the slope and base of slope positions. Slope strata are only ~15-20% sandstone and are composed of mudstone that is locally truncated by submarine channels that display architectural and facies asymmetry. This asymmetry is interpreted to reflect channel sinuosity. A large proportion of the mudstone in slope strata is interpreted to be levee strata. Proximal base-of-slope strata are ~50% sandstone and are composed of sandy submarine-fan strata consisting of slumps, amalgamated submarine channels, and turbidite lobes. Medial base-of-slope strata are >80% sandstone and are composed entirely of turbidite lobes. This area is the sandiest part of the depositional system.

The patterns described can be used to help interpret borehole image and core data for Lewis Shale and Fox Hills Sandstone reservoirs.

Pennsylvanian Petroleum System of the Deep Paradox Basin Fold and Fault Belt, Colorado and Utah

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A revived exploration frontier in the Paradox Basin is the deep Fold and Fault Belt adjacent to the Uncompahgre Uplift, an area characterized by extremely thick evaporites deposited during the Pennsylvanian, and complexly deformed by deposition of thick siliciclastics from Late Pennsylvanian to Early Triassic. Plays include a Permian-Pennsylvanian marginal siliciclastics gas play, a fractured interbed (shale) gas play, and the many structural and stratigraphic features related to halokinesis which remain essentially unexplored. Play analysis benefits from a renewed look at the associated Pennsylvanian Petroleum System. This study expands on previous work, focusing primarily on the thermal maturity and timing of generation and expulsion using high-resolution data and forward kinetic modeling tools. Onset of hydrocarbon generation for the organic-rich source rocks is highly variable, starting earlier (Late Pennsylvanian) closest to the Uncompahgre Uplift and migrating progressively westward during the Permian and Triassic. Hydrocarbon expulsion began during the Early Permian and continued as late as the Early Cretaceous. On the shelf outside of the deep Fold and Fault Belt, late generation and expulsion occurred during the Late Cretaceous to Miocene. For all source rocks, onset of hydrocarbon generation corresponds with a calculated thermal maturity of 0.46%Roc, and the maximum rate of hydrocarbon generation corresponds with a calculated thermal maturity of 0.8%Roc. The influence of thick Pennsylvanian to Triassic siliciclastic deposition and contemporaneous salt movement on the thermal history and burial history is important and helps explain the temporal variability of the Pennsylvanian Petroleum System. Salt movement played the most important role, albeit indirectly, in early source rock generation and expulsion in the deep Fold and Fault Belt. Salt withdrawal related to thick siliciclastic wedges shed from the ancestral Uncompahgre Uplift resulted in rapid burial and thermal maturation of source rocks. Uplift of the Colorado Plateau removed as much as 9,000 feet of overburden since the Late Miocene and modeling indicates that this uplift and subsequent erosion was sufficient to stop generation and expulsion in the deep Paradox Fold and Fault Belt and surrounding shelf and basin margins.

Series of Posters and Video Features from NCAR in Boulder

Raynolds, Bob [1] (1) Denver Museum of Nature & Science, Denver, CO.

The staff and researchers at University Corporation for Atmospheric Research and the National Center for Atmospheric Research in Boulder have prepared a variety of outreach display materials that are used to illustrate and visualize climate change issues for the public. We are arranging to have a variety of these made available for this Poster Session. The goal is to have the research results from the National Labs made available to our audience in a visually enticing and user-friendly format.

Climate Change through Geologic Time

Raynolds, Bob [1] (1) Denver Museum, Denver, CO.

The Earth's climate has always changed and it continues to change. This set of graphs presents data obtained from a variety of climate proxies to illustrate climate changes over geologic time. Older data sets are derived from sedimentary rocks, younger data sets from ice cores, tree rings and finally, instrumental data. The data sets are presented as a sequential series of curves blown up by factors of ten; thus we can examine patterns over 100's of million years, over 10's of millions of years and so forth down to a decadal level. While we cannot use the past to predict the future, we can use the past to place the present in context. As geologists we hold the rear-view mirror depicting Earth's changing conditions. This marvelous perspective allows us to comment cogently on our current circumstance.

Unconventional Gas Resources to Reserves - a Predictive Approach

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Estimating potential hydrocarbon recoveries from greenfield (but resource-rich) unconventional gas plays remains a challenge. While analogs are routinely employed for this purpose, there is no shortage of examples of how new tight sand, coalbed methane and organic shale plays have defied historical experience.

An analytic approach is presented to account for whatever limited geologic and reservoir information might be available for a new resource play, and based upon sound engineering principles, make predictions of potential gas recoveries, their variability, and identify areas of uncertainty. In summary, the methodology involves selecting the potential ranges (and distributions where appropriate) of reservoir parameters across a particular acreage position, such as depth and pressure, formation thickness, porosity, fluid saturations, permeability, relative permeability, etc. Ranges in geostatistical variogram parameters are also often established.

Where no data exists, analogs and experience must still be employed. Single-well probabilistic reservoir simulation forecasting is then performed using Monte Carlo and/or experimental design methods to establish a distribution of potential well recoveries, which are in turn used for field development economic analysis. Factors having the greatest impact on well recoveries and economics can be identified via statistical analysis of the results, thus focusing field data collection efforts on topics with the greatest potential for uncertainty reduction. Each step in the methodology, and its value, will be presented as examples from a series of case studies.

Probabilistic Analysis of Fault Seal Capacity in Compressional Settings: Risking Prospects and Fields in Exploration and Production

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Fault seal capacity is well-studied in extensional terrains, but publications concerning compressional terrains are scarce. We present selected analyses from compressional settings here.

Analysis of fault seal capacity and its impact on potential hydrocarbon columns is affected significantly by uncertainties of reservoir geometry, fault position, orientation and throw as well as stratigraphic changes and uncertainties along and across faults. A new technique for stochastic analysis provides probability of leakage, ranked leak points and ranges of potential hydrocarbon columns. In production settings, compartmentalization effects of faults are also modeled with statistical distributions.

Basic data inputs are a key 3d surface intersection with a fault, fault parameters for orientation and displacement profile with estimated uncertainty ranges. For the stratigraphic sequence of interest, the reservoir-seal stratigraphy and Vshale from nearby wells or regional estimates is also input, with variations along and across the fault as well as ranges of uncertainty on thickness. A workflow interface allows rapid input of parameters. The calculations are in full 3d.

Results to date indicate a good match between predicted hydrocarbon-water contacts and observed contacts. Examples from a variety of settings show the applicability and effectiveness of the technique in compressional settings. As the results of the analysis are probability of seal and distributions of fluid contacts, they aid understanding of risk on prospects and field development.

Measuring the Currently Unmeasured in a Resource Play: Model of Rulison Nuclear Re-Entry Well Shows Higher Than Expected Gas-in-Place

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A reexamination of produced-gas volumes from the 1971 Rulison Nuclear test suggests that currently accepted Williams Fork Formation resource calculations are substantially pessimistic.

The authors constructed a 3-D dynamic flow model to test if Project Rulison site gas could migrate to future wells drilled within 1000 feet of the Project Rulison site. The model was constructed with currently accepted rock parameters and tested against known well performance. The results of the model fit well within the range of the current performance of area wells. However, a comparison of the results of the model with the results of the nuclear well production indicate that substantial volumes of gas are not being accounted in the Williams Fork through current production or modeling methods. This gas could be present in shales and coals or chemically bound to organic matter that are “beneath the cut-off” used in gas-in-place calculations.

Six wells had been drilled and completed in the model area including the Rulison nuclear emplacement well and the Rulison reentry well. To ensure a “real-world” stratigraphic match, the model was divided into six zones from top of the Williams Fork Formation to the top of Iles Formation. Each zone was assigned a dominant sand-body type based on field studies published by Cumella and Cole. Sandstone facies were assigned based on gamma-ray and density porosity cutoffs of 70 API and 6% porosity.

The model was populated with sand bodies based on the three typical dimensions from Cole and Cumella. To ensure an acceptable match of the model to reality, sand histograms of each zone was examined and matched to actual-drilled wells.

Model rock-properties were calibrated from core data and from the Department of Energy Multi-Well Experiment wells to the north of the study area. Natural fracture permeability in the west-east direction was simulated by multiplying permeability in the north-south direction times 25. Hydraulic fracturing of wells was simulated by using a west-east permeability multiplier of 20 for 250 feet away from wells. A simulated cavity and fracture chimney, created by the Rulison nuclear detonation, was added to the model (measuring 100 ft x 100 ft x 350 ft, permeability = 1 md, porosity = 37%) and a zone of enhanced fractures (permeability of model times 5) measuring 2.8 times the radii of the chimney. These parameters were necessary to match the volume of gas produced by the nuclear re-entry well during testing in 1971.

The Rulison nuclear well produced substantially more gas from approximately one-third of the Williams Fork section, far more than any of the surrounding wells have produced from full Williams Fork completions over a similar producing period. The simulation model suggests the nuclear well liberated substantially more gas per volume of rock than was contained within the modeled rock volume. To explain the large amount of liberated gas produced at nuclear detonation site several theories have been proposed: extensive, very well connected fracture system that penetrates sandbody discontinuity related to clay drape and siltstone interbeds, extreme reduction in bound water saturation due to vaporization during nuclear detonation, pulverization of the chimney rock allowing full liberation of all gas-in-place.

The model results coupled with the nuclear well performance suggests that current gas-in-place resource estimates could be much lower than actual. The challenge will be to capture this resource.

Rockies 3D; Business Drivers and the Multiple Benefits of the Full 3D Seismic and Associated Data-Sets

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Much of the land in the Rockies inter-mountain petroleum basins is remote and controlled by the Bureau of Land Management (BLM). The decision to acquire regional-scale (+20 square miles) 3D seismic in the area is not an easy one as the financial commitment is high and the permitting and acquisition process is usually complex. In addition there can be severe topography, and critical wildlife habitat as well as historic cultural sites which all need to be incorporated into the survey design and future development plans. Due to this the permitting and pre-planning process can be complex and take several months to several years in the extreme case. However, once the business decision to acquire 3D has been made the benefits are multiple, and not limited to seismic data and associated drilling/development alone. Some of the full data-set benefits include:

1) High resolution aerial photography and/or Lidar. These pre-acquisition images are not only beneficial from the planning standpoint but also provide detail on surface topography, critical vegetation, land reclamation, water resources, existing roads, well locations and associated facilities.

2) Regional archeological surveys.

3) From the drilling standpoint, once the data has been processed and interpreted 3D seismic can reduce risk through the identification of shallow gas hazards, over-pressured zones and faulted/fractures intervals.

4) From the geologic and prospecting standpoint 3D seismic provides high resolution detail of subsurface structure and stratigraphy which can supply a significant reduction in pre-drill exploration/development risking.

5) From a reserve booking standpoint the structural and stratigraphic detail imaged by 3D seismic can greatly aid in assigning un-drilled well locations into the PUD, Probable and Possible categories.

Integrated Burial and Thermal Reconstruction of the Bakken Shale in the Canadian and Us Williston Basin

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Accurate basin reconstruction and burial/thermal history analysis is an important step in determining the petroleum potential of a sedimentary basin; and in delineating the lowest risk segments of a play fairway such as the Bakken play in the Williston basin. In this presentation we summarize a workflow to derive an accurate, geologically reasonable thermal reconstruction of the Bakken across the basin, stretching from northern USA to southern Canada.

Historically, the maturity of the Bakken source rocks has been estimated and mapped in a number of ways:

(1) Electrical resistivity, tied loosely to present day temperatures (Meissner's work of the late 70's)

(2) Geochemical investigations using pyrolysis data (Webster's and Price's work of the early-mid 80's)

(3) Two-dimensional sectional thermal modeling (Burruss et. al., 1984)

Although it has long been recognized that the Alberta foreland has been significantly uplifted and eroded, none of these studies based in the US sector of the Williston basin have addressed the problem.

We approached the thermal history of the Bakken by constructing a map-based model combined with a suite of 1-D burial history temperature models to illustrate the thermal and structural evolution through time. A representative spread of wells were chosen in North Dakota, Montana, and Saskatchewan, selecting those with both present day temperature control, and Bakken core data on which thermal stress indicator (TSI) data can be derived. (We thank North Dakota Geological Survey and the Saskatchewan Mineral Resources Board for access to samples and data.) As pointed out by Price, vitrinite reflectance data is very poor in the Bakken, so we used biomarker-derived thermal stress indicators (hopanes, steranes and aromatic steranes) with known kinetic parameters to estimate paleo-thermal stress - and hence the amount of eroded section.

The Tertiary burial history of the basin was revisited and re-evaluated using coal compaction models from various coal-producing horizons in Cretaceous and early Paleocene stratigraphy.

Two conclusions are immediately evident from the modeling:

(1) There are significant lateral variations in present day (and paleo-) heat flow across the basin, which are best explained by variations in the radiogenic heat contribution, in turn reflecting the composition of the underlying Pre-Cambrian crust.

(2) As in the Alberta foreland, significant post-Paleocene/Eocene deposition was followed by rebound and erosion (most likely taking place during the Oligocene). This observation is supported by the rank of lignites in the surface-mined Paleocene deposits.

For a combination of these two reasons, present-day depth is a very poor indicator of (paleo-) thermal stress in the Williston basin.

The next phase of this project will combine the thermal history with kinetic models of generation/expulsion within the Upper and Lower Bakken Shale units, to predict regions of most favorable charge, fetch and focus in the Bakken fairway.

Analysis of Production Logs and Calculated Reservoir Properties to Gain a Better Understanding of True Reservoir Quality in from Effort to Eliminate Non-Productive Zones and Enhance Completion Efficiencies in Future Field Development

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As Oil & Gas assets become more mature Operators look to increase completion efficiencies in order to continue field development. Operators have many options when it comes to analysis tools that can be deployed to determine the quality of the reservoir or effectiveness of their completion methods. The most common and widely used tools are Calculated Formation Properties that have been derived from Open Hole Logs through the use of Log Models and Production Logs taken at different time intervals in the early life of the well. Many Operators would like to be able to look at the properties of a reservoir from an open hole log and be able to definitively determine if that sand is going to be economically productive or not. This seems like a simple thing to accomplish, but in reality it is very difficult to be able to definitively determine whether a zone is going to be economical to complete or not. This is even more evident in the tight sands that are common to the Rocky Mountain Region of the United States.

This paper will present one approach used to help determine reservoir quality parameters from the evaluation of production logs coupled with reservoir properties that are derived from Log model interpretations of open hole logs. This analysis can then determine reservoir property cut-offs to be used to differentiate completion designs among different reservoir intervals or eliminate non-productive zones altogether from the completion. In turn, this would allow the Operator to increase their completion efficiency by targeting the most productive zones with improved completion designs and also help reduce costs by eliminating non-productive zones.

Analysis of Completion Design, Log Parameters, and Production Results to Gain a Better Understanding of Effective Production Enhancement Methods in the Piceance Basin

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To economically develop many fields in the Rocky Mountain region of North America operators use a "Factory Mode" approach. This mode emphasizes fast and continuous fracturing operations, with little to no pre- and post-job engineering design and analysis. The Piceance Basin of North Western Colorado is such a place. The operators in this basin have tried many different completions methods and designs to improve production, but many times do not have time to perform a rigorous analysis of the data to fully evaluate the benefits of completion changes. Adding to the complexity of a rigorous analysis is the lenticular, non-continuous, nature of the sands that make up the mesaverde reservoir. The sands in one well do not correlate well, even among direct offset wells. This, along with other issues, prevents using simple production comparisons for evaluating the effectiveness of changes to designs. This has caused many misconceptions about what works and what doesn't work in Piceance Basin completions.

This paper will present a more rigorous engineering evaluation to help answer questions about what is working in the Piceance Basin. The focus of the paper will be an analysis of completions used in the Mamm Creek Field of the Piceance Basin. This analysis makes use of log model parameters, completion designs, and production results to help answer the question "How can I make a better well?"

Utah Bituminous Sandstone Deposits: the Good, the Bad and the Ugly

Schamel, Steven [1] (1) GeoX Consulting Inc, Salt Lake City, UT.

Utah has the largest unexploited bituminous sandstone resources in the contiguous United States, an estimated 15-20 BBO. Virtually all previous investigations of the deposits have evaluated their suitability for surface mining and bitumen extraction. While the studies have highlighted the serious drawbacks of this recovery strategy, they point to the potential viability of targeted in-situ recovery methods. Factors that are encouraging for successful in-situ recovery are: a) substantial portions of deposits with grades in excess of 125 MBO/acre, b) bituminous-saturated sandstone units 60 to 150 ft thick, c) good porosities and acceptable permeabilities, and d) easily upgraded reservoired oils. The oil-water contact is unknown in several large deposits, which opens the possibility for larger resources than previously predicted and more easily exploited "water-wet" reservoirs at depth. Unfavorable factors include: a) high degree of reservoir heterogeneity, b) unusually high viscosities at reservoir temperatures, and c) overall low oil grades, generally less than 75 MBO/acre. Nearly all of the deposits are on public lands, most of which have high ecologic, recreational and scenic values that will preclude or seriously limit commercial-scale strip mining operations. The future for development of this valuable heavy and extra-heavy oil resource lies in the application of innovative in-situ recovery methods having minimal surface impacts.

Shale Gas Potential of the Paradox Basin, Colorado and Utah

Schamel, Steven [1] (1) GeoX Consulting Inc, Salt Lake City, UT.

Black “shale” intervals within the Hermosa Group (Pennsylvanian), particularly those within the 7,000+ feet thick Paradox Formation, have a high potential for future shale gas production. The synorogenic Hermosa Group was deposited as a series of orbital-forced transgressive-regressive cycles dominated by restricted-basin carbonates and anhydrite. Typically in the Paradox Formation the base of each cycle is a 10 to 150 feet thick transgressive dark gray laminated organic carbon-rich dolomitic mudstone or shaly dolomite. This interval grades upward into intercalated anhydrite, dolostone and limestone, with minor black shale, overlain by a thick halite interval deposited during the lowstand, arid-icehouse portion of the glacio-eustatic cycle. The TOC of the black “shale” averages 2% to 4%, and commonly exceeds 10%. Kerogen is dominantly amorphous (algal) with minor terrestrial organic matter. Limited Ro values show the Paradox Formation to be in the gas-generative window in the northwest, north and eastern parts of the basin, and in the oil-generative window in the south and southwest. Logs in the northeast half of the basin record mud gas in the black “shale” up to thousands of gas units. Currently, oil with associated gas is produced from the black “shale” intervals in the south-central part of the basin, and gas with minor condensate is produced from a few wells in the northeast part of the basin. Several factors favor the development of shale gas in the northeast half of the Paradox Basin: the high organic carbon content, the elevated level of thermal maturity, the known presence of gas in the “shale”, and a net “shale” thickness greater than 350 feet. The evaporite beds enclosing the “shales” are important both as a barrier to natural hydraulic fracturing during hydrocarbon generation and as an exceptionally effective seal to retain the hydrocarbons and maintain an overpressure to keep the fractures open. The black ”shales” of the Paradox Basin constitute a potentially large natural gas resource waiting to be evaluated and exploited.

Modern 3D Interpretation of a Mature, Structurally-Complex Oil Field, Los Angeles Basin, California

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The Whittier field is one of many aging Los Angeles Basin fields. The reservoir section consists of deep-water turbidites both channelized and amalgamated fans. The field was developed over 100 years starting with cable-tool, then rotary vertical drilling (no logs), then with rotary directionally drilling (logged using modern wireline tools). The wireline data combined with limited data from older wells provides the control set for our complete 3D model study.

The structural geometry is very difficult to interpret from logs alone because of vertical and overturned beds. Log signatures vary wildly with the wide range of penetration angles relative to bedding. Lateral variations in stratigraphy further complicate interpretation. Because of these difficulties, historical development has been based on a strategy of offsetting successful wells along strike.

Our study integrates log data, surface mapping, surface and subsurface dip data and hydrocarbon indicators into a 3D volume interpretation environment. Well correlation using bedding-parallel foreshortened views enables accurate true stratigraphic thickness correlations. Translation of surfaces conforming to dip control and perpendicular to layering (pseudo-concentric construction using a neural-network dip prediction algorithm) aids construction of the faulted, near vertical and overturned footwall structures. Horizons modeled in 3D were used to construct layered stratigraphic grids. Geostatistical and probabilistic modeling of rock-type consistent with paleodepositional trends were performed on these stratigraphic grids.

The resulting integrated 3D model reveals that the trapping of hydrocarbons in both the hanging wall and the footwall, is controlled by both stratigraphy and fault truncation. New drilling has been successful by targeting specific elements of the structure and stratigraphy.

The Profitable Use of 3d Seismic in Hydrocarbon Discovery and Development

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3D seismic has been successfully used to better identify undiscovered and under-developed hydrocarbon reserves than its 2D seismic predecessor; however, application of the technology without the application of fundamental business logic can lead to lessened or even negative profitability. By using tradition business analysis techniques such as product lifecycle understanding, niche exploitation, barrier-to-entry concepts, and an understanding of the product commoditization process, profitability from 3D seismic can be enhanced and strategic advantages developed and maintained.

3D seismic has found application all along the time line of hydrocarbon discovery, development drilling, and secondary and tertiary recovery programs. At each stage of field evaluation, 3D seismic methods, ranging from research ideas through commoditized technologies exist reflecting traditional product lifecycle analysis. As with any generic product, companies must first identify a potentially profitable niche to enter from, evaluate the niche in terms of their company’s risk tolerance, and understand the strength of barriers-to-entry necessary in order to both maximize the time to commoditization for the product and to identify the transition from product development to process improvement. In terms of value being defined as revenue divided by expenses, a company must identify when to switch from spending numerator focused research dollars in order to make the product Better, to making denominator focused efficiency improvements along the Faster Cheaper guidelines.

Examples of successful and unsuccessful projects, ranging from research to well established 3D seismic methods, will be used to highlight the business analysis methods available for evaluating potential 3D seismic projects.

Structural Controls from Detachment Folds Associated with Foreland Arches: Beaver Creek Anticline, Wyoming

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Of the smaller, second-order anticlines adjacent to Rocky Mountain basement arches, detachment folds basinward of fault-propagation folds bounding the arches are mostly covered by synorogenic strata and are thus the least well known. These anticlines host important hydrocarbon reserves and provide prospects for undiscovered fields. This study documents the geometry and kinematics of the Beaver Creek Anticline (BCA) which is located basinward of a complex series of northwest-trending thrust faults and folds defining the Beaver Creek reentrant on the western edge of the Bighorn basement arch. Possible origins for this detachment fold system include syn-Laramide detachment rooted in mountain front faulting, syn-Laramide gravity sliding during folding of the mountain front, and post-Laramide gravity sliding down and away from the mountain front folds.

To test these hypotheses, 450 minor faults and 1,050 shear bands were analyzed from 34 stations in the Leavitt Reservoir Quadrangle and surrounding area. Both datasets record mostly strike-slip and thrust movements. Initial kinematic analyses indicate N45°E horizontal compression and shortening along the BCA within Mesozoic strata and N65°E compression and shortening within Paleozoic strata in the mountain front.

The presence of indurated fault planes and slickenlines indicate that if the BCA formed due to gravity sliding, the sliding was not a near-surface mass movement but occurred slowly under significant overburden. The variation in shortening directions suggests that different stratigraphic levels may have been moving in different directions due to 3D space constraints within the Beaver Creek reentrant. Independent movement at various levels in the strata suggests that local kinematics may not parallel regional deformation, resulting in discordant orientations for fracture systems at different stratigraphic levels.

Utilization of Magnetic Resonance Bin Distribution to Determine Specific Permeability

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The Granite Wash formation in Oklahoma is an arkosic detrital material resting on older Precambrian rocks. It can range in age from Precambrian to Middle Pennsylvanian. Formed by erosion of uplifted segments, it is generally granitic in nature, it may also include large areas of reworked carbonate. This wash presents a very difficult log interpretation problem since reservoir consistency varies greatly from well to well. Magnetic Resonance Image Logs were added to the logging program toe establish additional parameters that could be used for reservoir description.

The standard Coates permeability equation and variations were applied to estimate permeability with little correlation to production. As the grain size, the cementing material of the rocks and the lithology vary so greatly from well to well, the Coates relationship does not remain constant, and this technique proved to be inconclusive.

An observation was made that T2 bin distribution data tended to mirror production rates. Attempts were made to establish an algorithm that would directly establish permeability for this formation using the measured T2 data.

This case study details this method of using T2 bin information for estimating permeability and includes several Granite Wash wells. The Bin data was correlated to flow rates measured 30 days after fracture treatment. A permeability was then calculated directly from this established flow rate and modeled to the observed NMR bin data. Sufficient data was utilized to establish a generalized algorithm for permeability within this formation.

Subsequent logging and comparison of projected versus actual permeability as established by cores and production data has proven the value and accuracy of this technique. We anticipate that this same iterative technique may be applied with positive effect to many other reservoirs.

Sandstone-Body Connectivity in a Meandering-Fluvial System: from Example from the Williams Fork Formation, Piceance Basin, Colorado

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This study explores the static connectivity of fluvial deposits of the lower Williams Fork Formation (Late Cretaceous) of the Mesaverde Group in western Colorado (U.S.A.). The lower Williams Fork Formation is a relatively low net-to-gross ratio (< 50%) succession of approximately 700 feet of fluvial channel-fill sandstone bodies, crevasse splays, floodplain mudstones, and subordinate coal interpreted to have been deposited in a highly sinuous meandering river system in a coastal-plain setting. These deposits, as exposed within Coal Canyon, serve as an excellent reservoir analog; the strata dip gently eastward into the Piceance Basin where they produce natural gas. Static connectivity of these high-sinuosity meandering-fluvial sandstones is most sensitive to sandstone-body width; therefore width statistics are a critical input parameter to constrain 3-D numerical models of these reservoirs. For the lower Williams Fork Formation, the shape and orientation of the sandstone bodies have a less pronounced effect on static connectivity.

Three-dimensional architectural-element models constrained to outcrop-derived sandstone-body dimensional statistics show that connectivity is controlled largely by sandstone percent (net-to-gross ratio). Connectivity analyses reveal an S-curve relationship between net-to-gross ratio and connectivity at 160-acre well spacing. As well density increases, the S-curve relationship diminishes and connectivity increases linearly with increasing net-to-gross ratio. At dense well spacings, there are enough wells to intersect a high proportion of sandstones, regardless of sand content. Even at 10% net-to-gross, 10-acre spacing connectivity is typically above 60% and can be as high as 85%. Infill drilling scenarios increasingly intersect a higher percentage of crevasse splays.

Meissner Keys to the Bakken Petroleum System, Williston Basin

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The Devonian-Mississippian Bakken Petroleum System of the Williston Basin has been the focus of several cycles of exploration activity since the 1950s. The current development of the middle member of the Bakken with horizontal drilling has resulted in the most significant cycle to date.

Meissner keys about the Bakken Petroleum System include: abnormal pressure created by hydrocarbon generation; high resistivity Bakken shales associated with maturity; and minimum temperature associated with mature source rocks (165oF).

The Bakken Petroleum System consists of organic rich shale members of the Bakken (upper and lower shales) and genetically related oil reservoirs (middle Bakken member, lower Lodgepole, and upper Three Forks). The middle member of the Bakken is the most significant reservoir in the Bakken Petroleum System and has lithologies ranging from carbonates to sandstones to siltstones.

Several large areas are currently being developed in the middle member of the Bakken. The giant Elm Coulee field of Richland County Montana has been horizontally drilled since 2001. The field has produced in excess of 41 million barrels of oil and 24 BCF gas from over 400 horizontal wells and has an estimated ultimate recovery of over 200 million barrels. In North Dakota the Robinson Lake and Parshall field areas are currently being developed. Further drilling will determine if this area has similar potential to the Elm Coulee area.

An understanding of Meissner keys, Bakken tectonics, stratigraphy and diagenesis may lead to the discovery of new resource play areas in the Bakken.

Transforming Rockies Gas Resources to Supplies: Implications of Gas Production Performance Factors

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Rocky Mountain region gas production increased by 4.9 Bcfd from January 1997 through May 2007 and development plans signal that production could increase by another 2.7 Bcfd by 2015. This positive outlook is bolstered by pending completion of the Rockies Express pipeline which will boost export volumes while also reducing the Cheyenne Hub price basis differential. Analysis of vintaged gas production for 25 key Rockies gas plays, though, reveals trends that merit concern. The increase in Rockies gas production since 1997 was accomplished by doubling the number of active gas wells to some 55,000 producers by mid-2007. Much of this increase resulted from reduced well spacing--from 80 acres to 20 and even 10 acres in the most productive plays. Of concern is the observation that average peak well production decreased by 52% to 464 Mcfd and average reserves per new well decreased by 44% to 264 Mcfd over this same period. These numbers represent the composite of all types and depths of gas wells in the region. Nevertheless, these parameters deteriorated in essentially all of the plays that were analyzed. This was not a concern in 2005 when high gas prices generated substantial incremental well head margins for most Rockies gas plays. But with subsequent 49% increase in a Capital Cost Index and the outlook for moderate gas prices, Rockies operators cannot be complacent. Operators must continue to apply new technologies to improve recoveries, reduce expenditures, develop new plays and improve deliverability across the supply chain while minimizing environmental impacts. This presentation summarizes cost and gas productivity parameters that must be considered to sustain the conversion of Rockies unconventional gas resources to reserves.

The Wyoming Transect: What, Where, How, and Why

Stone, Donald S.[1] (1) Independent, Littleton, CO.

The Wyoming Transect is a detailed structural cross section across the state of Wyoming, originally drawn at a scale of 1: 24,000 (1in = 2000 ft). It begins at the South Dakota-Wyoming border and extends southwest some 400 miles to the Idaho border, traversing the northern Black Hills, Powder River, Big Horn, Wind River, and Green River basins and the intervening mountain ranges, ending in the Wyoming thrust belt. An extensive data base was used in construction, including published geologic and commercial photogeological mapping, data from 150 deep wells, and considerable proprietary seismic data through critical parts of the basins and across the thrusted mountain fronts. The Transect provides a foundation for analyzing structural relationships on both a regional and local scale.

In this presentation I will review the elements of the “basement-involved thrust-generated fold” model that is incorporated in Transect construction and briefly discuss the geology of the oil and gas fields and thrusted mountain uplifts along the line of section.

The 15 individual segments of the original colored Transect have been digitally scanned and saved on two DVDs, copies of which are packaged together with a pre-folded, colored hard copy of the full-length Transect at a scale of 1: 96,000 (1in = 8000 ft). Also on the DVDs is a description of the method of construction and the data base (including a well list), a topographic strip map along the bottom of each Segment showing the exact line of section, and relevant well locations, a Stratigraphic Legend, and a list of References for each Segment. Transect sales are handled by the Rocky Mountain Association of Geologists and all net proceeds are funding the newly established Stone/Hollberg Graduate Scholarship in Structural Geology, to be administered by the RMAG Foundation

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proprietary seismic data through critical parts of the basins and across the thrusted mountain fronts. The Transect provides a foundation for analyzing structural relationships on both a regional and local scale.

The poster includes photos of the analog clay model studies of the kinematic development of “basement-involved thrust-generated folds” that characterize the Paleozoic oil fields crossed by the Wyoming Transect and some of the seismic profiles that served as part of the critical data base.

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K-Ar Dating of Authigenic Illites: Integrating Diagenetic History of the Mesa Verde Group, Piceance Basin, NW Colorado

Stroker, Trevor [1]; Harris, Nicholas B.[1] (1) Colorado School of Mines, Golden, CO.

Tight gas sands represent a significant portion of the U.S. domestic petroleum reserves. The ability to date diagenetic reactions that significantly influence reservoir quality will enhance our ability to characterize and produce these fields. Information from this study will help provide a chronology for reservoir alteration and hydrocarbon charge for several fields in the Williams Fork Formation, Piceance Basin. Correlation of secondary mineral alterations with tectonic events such as burial and uplift will provide a better understanding of the factors controlling diagenesis during these times.

Core samples from fields located in the central basin area will be examined for clay minerals, in particular for the presence of fibrous illite. This process includes freeze-thaw disaggregation to preserve the size and character of the clays followed by XRD and SEM to classify clay composition and habit; fibrous illite will be separated using centrifuge and reprocessed for K-Ar dating.

Illite dating will provide fixed reference points for the digenetic history of the Piceance Basin, which until now has been limited to relative order. Though diagenetic clays form only a small percent of the sandstone, they have a disproportionately large impact on reservoir properties because of their high surface-to-volume ratio. It has been found in other basin-centered gas systems that fibrous illite typically precipitates from brine. As gas replaces this brine, growth is halted, recording the time of significant gas saturation. Mapping the history of latest growth should provide a chronologic depiction of gas charge through the reservoir. Integrating gas charge with the burial and uplift history may add support to the proposed diagenetic fracturing of sandstones due to increased pore pressure associated with gas charge.

Effect of Layered Heterogeneity from Fracture Initiation and Containment in Tight Gas Shales

Suarez-Rivera, Roberto [1] (1) TerraTek, Salt Lake City, UT.

Hydraulic fracturing is the methodology for completing nano-darcy matrix-permeability tight gas shales. Commercial success in producing these reservoirs depends to a large extent on successful hydraulic fractures. There is growing evidence that initiating hydraulic fractures from horizontal wellbores is often difficult, and requires abnormally high treating pressures. We postulate that the unusual combination of high stiffness, and high elastic anisotropy results in near-wellbore stress concentrations not observed in homogeneous, isotropic rocks.

In this paper we consider the dependence of wellbore pressure for fracture initiation on material anisotropy, in-situ stress, and lateral well orientation. Results show that the presence of strong elastic anisotropy facilitates the development of longitudinal hydraulic fractures and makes the initiation of hydraulic transverse fractures more difficult. The higher the elastic anisotropy, the stronger this effect is. There are combinations of anisotropy in Young's modulus and Poisson's ratio that reduce the overall effect. The collection of results provides a framework for understanding these phenomena and for anticipating potential problems based on measured values of shale elastic properties.

Results from this study also show that the origin of high treatment pressures is rock type dependent, and provides a methodology for selecting alternative lithologies for landing the horizontal wellbore, for minimizing these problems.

Due Diligence in Sensitive Areas: How to Facilitate Project Authorization and Minimize Litigation Risks

Sumner, Brett A.[1] (1) Fulbright & Jaworski L.L.P., Denver, CO.

The often politically charged atmosphere in which oil and gas companies must operate in the Rocky Mountains and other onshore regions in the United States often results in agencies delaying authorization for exploration and development projects, particularly those that fall within sensitive areas. These costly delays are compounded by legal challenges, or even just threats of legal challenges, brought by environmental organizations and anti-industry groups.

In order to avoid or significantly reduce these delays, technical specialists within the industry, such as geologists, geophysical seismic specialists, petroleum engineers, and landmen, must play a proactive role in performing due diligence for projects in sensitive areas. Just as a company must understand the underlying geology of a prospect, the company must also understand the regulatory and legal landscapes of the overlying surface. Specifically, these specialists must work closely with staff of state and/or federal agencies to resolve concerns and build the agency administrative record that will support the agency's decision to authorize a project. In addition, this proactive involvement, when combined with legal counseling, can substantially facilitate faster project authorization and also minimize a company's litigation risk with respect to reducing the chances that a court may halt a project pending resolution of any legal challenge filed, or even issue an adverse ruling against the project.

This presentation will provide a brief overview of the legal and regulatory landscapes that a company must understand when seeking to perform an exploration or development project in sensitive areas. Strategies will be discussed that companies and technical specialists can employ with applicable state or federal agencies to build a legally sufficient administrative record that will (1) facilitate efficient project approval, (2) support authorization for the project, and (3) minimize litigation risk in the event a legal challenge is filed against the project.

Distribution, Amount, and Maturity of Coal Resources in the Sego Coalfield, Grand County, Utah

Tabet, David E.[1]; Quick, Jeffrey C.[1]; Hucka, Brigitte [1] (1) Utah Geological Survey, Salt Lake City, UT.

Coal resources of the Sego coalfield occur in the Upper Cretaceous Neslen Formation of the Mesaverde Group in the southeastern Uinta Basin of Grand County, Utah. The Neslen consists of a 200- to 520-foot-thick series of paludal to alluvial plain sandstone, mudstone, siltstone, and high-volatile bituminous coal beds. Data from 95 drill holes and 106 outcrop measurements were used to characterize the distribution and amount of resources for seven coal zones in the study area. During Neslen deposition, rapid cycling of sea level did not allow for prolonged subsidence and development of large amounts of accommodation space to provide for the deposition of thick, widespread coals. The resulting coals are therefore patchy in areal extent and generally less than four feet thick. Locally individual beds reach 10 feet thick, generally in the northeastern part of the study area. The total net coal in all the mapped Neslen coal beds has a maximum measured cumulative thickness of 28 feet. The in-ground coal resource in beds greater that 6 feet thick is in excess of 350 million tons.

Trace Gas in Archived Tight Shale Cores As a Tool for Maturation Assessment

Tobey, Mark H.[1]; Schmude, David E.[2]; Newhart, Richard E.[2] (1) Independent Petroleum Geochemist, Castle Rock, CO. (2) EnCana Oil & Gas (USA), Inc., Denver, CO.

Thermal maturity evaluation of gas shale prospect areas is an essential element of exploration risk assessment. Source rock shales need to be sufficiently mature to yield significant quantities of gas, and in many cases the presence of hydrocarbon liquids can lead to deleterious production issues. Two conventional means of determining the thermal maturity of sediments include optical kerogen analysis (kerogen isolate and whole rock vitrinite and solid hydrocarbon reflectance) and pyrolytic analysis (Rock-Eval). The quality of reflectance data often is dependent upon the skill and experience of the organic petrographer, and in dry gas maturity sediments, Rock-Eval based maturation data can be unreliable due to the lack of residual generative potential. Moreover, regional heat flow differences and burial history differences complicate maturation assessments. Thus it is not uncommon that conflicts exist among published reports of maturation, and

between published and independently obtained maturation data. One objective means of assessing the relative maturity of tight gas shales when other maturation data are inconsistent is through isotopic examination of trace gas trapped within core. Trace gases extracted from archived core samples as old as 35 years were used to successfully validate regional thermal maturation assessments and establish a hierarchy of relative maturities. The application of this technique, and the interpretative complexities of these data, are reviewed.

Non-Exclusive 3D Geophysical Data Projects in the Western US

Trevino, Rick [1]; Bertness, Mike [1] (1) Land Data Library (USA), CGGVeritas, Houston, TX.

What business considerations do Geophysical Companies evaluate to determine which 3D projects may be successful candidates to add to their geophysical data libraries? How do Data Library businesses provide more data for less money?

Capture and Beneficial Use of Fugitive Production Tank Vapors

Trost, Paul B.[1]; Varani, Fred T.[1] (1) MV LLC, Goldon, CO.

Production tanks typically can be a source of hydrocarbon vapors emitting into the atmosphere. In fact the Colorado Dept. of Health (Reg. 7) has recently adopted regulations limiting such emissions from production tanks. Depending on temperature, color of production tank, orientation to the sun, and gravity of the contain liquids, coupled with normal separator operations, the amount of vapors may vary from minimal to in excess of 4 mcfd. Typically these vapors have a very high BTU content. Capture and beneficial usage of these vapors (as opposed to flaring) is both economically and environmentally rewarding.

MV LLC has a patent pending tank vapor capture system that will insure no air/oxygen leakage into the production tank occurs when gauging and/or emptying the tank plus a constant reservoir-type storage system.

Beneficial uses include: 1) recompression of the gas for pipeline injection or re-injection into the well bore, 2) use of gas for oil water separator, or heater treater and/or as an energy source for Ajax-type engines (as opposed to propane purchase), or 3) on site produced water evaporation (thereby cutting water disposal costs). The system can operate without electrical service to the tank battery.

Payback for the system is site specific, however for a condensate production tank payback is projected at 2.5 years.

Seismic Operations in Sensitive Areas

Wagaman, Mark [1]; FitzMaurice, Michael [2] (1) CGGVeritas, Denver, CO. (2) Bill Barrett Corporation, Denver, CO.

Conducting a successful seismic geophysical project to meet economic, technical, scheduling and regulatory goals is often a challenging and complex endeavor. When the seismic project happens to be located in a sensitive area, the challenges and complexities multiply. By reviewing legacy seismic projects that have been successful in sensitive areas, a set of “best practices” that contributed to the outcome can be can assembled for consideration on future projects.

Large tracts of land under Federal, State and Tribal control exist throughout the Rocky Mountain region and these in turn specify the sensitive areas with cultural, wildlife, vegetative or other natural occurring concerns. On privately owned land, sensitive areas can include lands used for agriculture, livestock, industrial (including oilfield) and municipal purposes. Operating in these sensitive areas can involve restricted operational areas, shorter operational timeframes but longer project duration timeframes, increased costs, technical concessions and objections from concerned groups. Any or all of these issues can compromise the goals of the project.

There are a variety of tools and techniques available that can help smooth through the difficult processes required when working in sensitive areas. Some of the techniques include the use of heliportable drilling, heliportable equipment deployment, remote sensing, block archeology, on-site monitors and contracting environmental companies. Even more critical is remaining perseverant and maintaining communication through the awareness, planning, compromise and operational phases of the program.

Lithofacies and Petrophysical Properties of Mesaverde Tight-Gas Sandstones in Western U.S. Basins

Webb, John C.[1]; Byrnes, Alan P.[2]; Cluff, Robert M.[1]; Krygowski, Dan A.[1]; Whittaker, Stefani D.[1] (1) The Discovery Group, Inc., Denver, CO. (2) Chesapeake Energy, Oklahoma City, OK.

The relationship between core and log petrophysical properties and lithofacies are examined in Mesaverde Group tight gas sandstones from forty cores in the Washakie, Uinta, Piceance, Greater Green River, Wind River, and Powder River basins. Fine-grained intervals of the Mesaverde Group include mudstones and silty shales; burrowed, lenticular and wavy-bedded very shaly sandstones; and wavy-bedded to ripple cross-laminated shaly sandstones. Sandstone intervals include ripple cross-laminated and cross-bedded, very fine to fine-grained sandstones, low-angle cross-laminated to planar laminated sandstones, and massive sandstones. Lithofacies were deposited in nonmarine, paludal, marginal marine and marine environments. For all lithofacies undifferentiated in the cores sampled, grain density averages 2.654+0.033 g/cc (error of 1 std dev) with grain density distributions differing slightly among basins. Core porosity ranges from 0-25%, averaging 7.2% (n=2200). In situ Klinkenberg permeability ranges from 0.0000001-200 millidarcies, averaging 0.002 millidarcies. Characteristic of most sandstones, permeability at any given porosity increases with increasing grain size and increasing sorting though this relationship is further influenced by the nature of cementation. Cements include chlorite, ML-IS and illitic clays, quartz, calcite and ferroan calcite. Capillary threshold entry pressure and pore characteristric length are well correlated with permeability. Archie cementation exponent, m, can be modeled with a dual porosity

matrix-fracture model with m approaching one as porosity approaches zero. Critical gas saturation is generally less than 5% but increases with increasing bedform complexity. Integration of wireline log analysis and core petrophyscial relationships provides guidelines and equations for predicting reservoir properties. The Mesaverde Project website is (http://www.kgs.ku.edu/mesaverde).

Fracture Diagenesis and Its Effects from Reservoir Permeability in Tensleep Sandstones, Wyoming

Yin, Peigui [1] (1) EORI, University of Wyoming, Laramie, WY.

Fractures in reservoir sandstones have been characterized intensively on intensity, aperture, orientation, and connectivity, but there is a gap between these characterizations and fracture permeability. This gap is fracture diagenesis, which determines whether a fracture serves as permeability conduit or barrier. Fracture diagenesis, counting all chemical, physical, and biogenetic changes after fracture generation, includes cementation, granulation, dissolution, and replacement within fractures and their associated belts in the matrix sandstones.

Five types of natural fractures were observed in Wyoming Tensleep sandstones: gouge-filled, gouge and mineral-filled, mineral-filled, partially-open, and open fractures. The filled fractures are pervasive in most of the highly-permeable Tensleep sandstones, whereas open, partially open and mineral-filled fractures are usually observed in tight Tensleep sandstones. Most the original fracture cements are anhydrite, which probably resulted from re-distribution of anhydrite in the deep marine carbonate-evaporate sections. Granulation of the fracture-filling minerals indicates multi-episodes of fracture reactivation. Dissolution of the anhydrite cement has contributed some partially-open or open fractures in the Tensleep sandstones. Calcite replacement of anhydrite is commonly observed in the outcrops and shallow depths. The filled fractures and their related cemented zones display much lower permeabilities than those of the associated permeable sandstone matrix, and act as baffles or barriers in the subsurface flow regime. Whether the fractures are filled or open, the permeability directionality in the Tensleep sandstones is always parallel to the fracture orientation.

Fracture Development within Partially-Decoupled Basement-Involved Folds

Zahm, Chris [1] (1) Bureau of Economic Geology, The University of Texas at Austin, Austin, TX.

Resurgence in hydrocarbon exploration in the U.S. Rocky Mountains has broadened from traditional structural traps to more subtle secondary structures and compartmentalized reservoirs blocks. Furthermore, the presence of structural heterogeneities (e.g., reservoir-scale faults and fractures) has been shown to have a profound effect on hydrocarbon production in existing field by creating permeability anisotropy within reservoirs. Prediction of the occurrence, geometry and intensity of structural heterogeneities is difficult, but is further complicated in areas like the U.S.

Rocky Mountains where significant rock strength contrasts create heterogeneous deformation mechanisms and vary the expected structural geometries.

In this study I propose mixed modes of deformation for basement-involved folds which are strongly dictated by the mechanical properties of the strata being deformed. The heterogeneous deformation styles have profound implications for the creation of fault-bound reservoir compartments in rocks associated with folding or overlying weaker strata which develop secondary faults and fractures. I will compare fault and fracture development of the basement-coupled Tensleep sandstone at Alcova Reservoir Anticline with partially-decoupled, Mesozoic strata exposed at Thermopolis Anticline. Results of this study will highlight potential areas of high deformation that may occur along the crest and forelimb Mesozoic strata within folds that may be prospective for limited hydrocarbon exploitation.

A Case History of Exploration and Development of Natural Gas Resources in from Environmentally Sensitive Area - West Tavaputs Plateau, Utah

Zavadil, Duane [1] (1) Bill Barrett Corporation, Denver, CO.

Bill Barrett Corporation has prevailed in taking a natural gas development project from rank geologic prospect to field that will soon yield nearly a quarter of all the gas produced in Utah. This success was achieved even though the area is host to, among other issues, a high density of nationally significant cultural resources, sage grouse habitat, critical habitat for big game, and wilderness study areas. The process was time consuming but ultimately successful through persistence, a thorough understanding of the issues, application of innovative mitigation strategies and legal support. The process required preparation of several Environmental Assessments and an Environmental Impact Statement. Several legal challenges were rebuffed. Community support has proven vital to the success of the project.

Integrated Petrophysical Study of the Fractured Tuff in Junggar Basin

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Tuff is a of kind of igneous rock, which can be divided into some types such as tuff, deposition tuff, tuffaceous sandstone, tuffaceous glutenite, tuffaceous breccia based on the size fraction and the mineral component. In recent years oil and gas has been found in tuff reservoir of the carboniferous in Junggar Basin of Xinjiang Province in China. Tuff reservoir has common characteristics of low porosity, low permeability and fractured. Fluid identification and fluid evaluation are always difficult because of complex logging response. Especially electrical resistivity logging is hard to reflect the pore fluid property change. Tuff is a complex lithology, and the pore configuration are often consists of pore and fracture. The integrated petrophysical study is conducted in the paper to investigate the pore fluid characteristic of the tuff for formation evaluation. 42 samples have been measured with the different method including density, X ray energy spectrum, SEM, magnetic susceptibility, porosity, permeability, acoustic velocity, NMR and so on. The experiment results show that the relationship between the density and porosity is negative line correlation, whereas the compressional velocity and porosity is approximate line correlation, the cause of low porosity and low permeability is weak in matrix pore and fracture is main percolation channel, and the paramagnetic effect of matrix on T2 is to reduce the NMR signal amplitude. And the results also imply that the combination of acoustic velocity and T2 can help direct fluid identification and fluid evaluation.

Experiment Study of Mud Filtrate Salinity Effect from NMR T2 Data in Tight Clay Sandstone

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Nuclear Magnetic Resonance (NMR) logging is an effective tool for formation evaluation, which is often used to estimate permeability, porosity, pore size distributaries, wettability, free fluid and bound volumes and so on. The limitation of NMR logging is shallow depth of investigation (DOI). Invasion of the drilling mud filtrate is representative for displacement of the original pore fluid as well as the development of a mud-cake on the borehole wall. For lower permeability tight rocks, invasion may be deeper due to the slow build up of mud cake. The mud invasion often has a strong effect on NMR logging response, but this is poorly understood. In the paper two groups of tight clay sand core samples, where one is low porosity / low permeability and the other is relative high porosity and low permeability, are used to investigate the mud filtrate salinity effect on NMR data in low field NMR measurement at lab. The transverse relaxation time (T2) measurements using CPMG sequence have been conducted with different interecho times (TE) in the different salinity to simulate downhole NMR tools. The analysis of experiment results, combined with the measurement of X-ray, SEM, magnetic susceptibility, porosity and permeability, show that the mud invasion effect on T2 data mainly depend on clay mineral type and porosity.

Using 3D Seismic to Forecast Development from the Pinedale Anticline, Wyoming

Zinke, Sally [1]; Shearer, Sarah E.[1] (1) Ultra Petroleum, Lakewood, CO.

Pinedale Field, in the Greater Green River Basin of western Wyoming, has emerged as a giant natural gas field producing from tight gas sands of the Lance formation. By coupling the use of geophysical, geological and drilling assessment tools, Ultra Petroleum has successfully increased the productivity and reserves on the Pinedale Anticline from negligible volumes in 1999 to an estimated 27 Tcfe of recoverable gas.

3D seismic attribute analysis calibrated with production and EUR results is used by Ultra as a powerful tool for projection of potential productivity and economics on step-out wells. These efforts have driven successful field expansion results.

Additional economic decisions based on 3D seismic input include aquifer mapping for water disposal wells, down-spacing efforts, and assessment of deeper pool potential. Seismic aids in financial evaluations related to daily drilling operations including directional design, detection of pressure boundaries, identification and avoidance of drilling hazards, and fault identification and management.