New PTTC Team Member to Chart the Future

Dr. William F. (Bill) Lawson has joined the PTTC headquarters team in February as the Strategic Manager to assist in moving PTTC forward in a more sustainable and effective direction. Dr. Lawson comes to PTTC with a broad background including 31 years at DOE’s National Energy Technology Laboratory and its precursors, the last 12 years of which he served in leadership roles in the oil and gas program area. He retired from DOE in January 2006 as the Director of DOE’s Strategic Center for Natural Gas and Oil. He was an adjunct professor for one year at the University of Oklahoma in the colleges of Business and Earth and Energy. He continues a part time position at the University of Tulsa as the Director of Technology Commercialization while he does some additional outside consulting.

Chris Hall, Chair of PTTC’s Board, declared “the PTTC has faced many challenges since it was first developed by a group of IPAA members in 1991; today is no different. One new challenge is the decision by AAPG to sever its formal ties with the PTTC. This necessitated the need to fill the senior management position. Bringing Bill Lawson on-board will better enable the PTTC to meet today’s challenges while continuing to provide valuable technological information to the oil and gas producing community.”

Dr. Lawson reports to PTTC’s Board of Directors and has been charged with four priority responsibilities:

- Develop and nurture non-federal sources of funding
- Review, revise and monitor HQ resources to further improve efficiency and productivity
- Strengthen team culture between HQ and the Regions
- Recover the industry/volunteer leading, staff executing culture of PTTC.

Lawson muses, “When I was at DOE, I respected the job PTTC did and believe it furthered both DOE’s goal of making industry aware of the program’s technology developments as well as more broadly supporting the independent producer community’s technology transfer needs. Now I’m honored to be a part of preserving and improving that effort.”

“I am impressed with the industry, focus and dedication of the HQ staff; but with all the challenges PTTC faces today, we simply need to develop a better working model,” Lawson notes. “PTTC’s regional programs are critical to PTTC’s success, but so is the HQ function. We have to pull together more to reduce overhead and increase effectiveness.”

Dr. Lawson can be contacted by email wlawson@pttc.org or phone 918-629-1056.
**News In General**

**Meeting Alerts**

<table>
<thead>
<tr>
<th>Date</th>
<th>Event</th>
<th>Location</th>
<th>Website</th>
</tr>
</thead>
<tbody>
<tr>
<td>4/18-20</td>
<td>6th Annual Developing Unconventional Gas Conference &amp; Exhibition</td>
<td>Fort Worth, TX</td>
<td><a href="http://www.dugconference.com">www.dugconference.com</a></td>
</tr>
<tr>
<td>6/12-14</td>
<td>Aapg/Gtw Resource Plays in Tight Unconventional Reservoirs: Multi-Disciplinary Technological Challenges and Solutions – Banff, Alberta, Canada</td>
<td></td>
<td><a href="http://www.aapg.org/gtw/CanadaResourcesBanff">www.aapg.org/gtw/CanadaResourcesBanff</a></td>
</tr>
<tr>
<td>6/20-23</td>
<td>SIPES 48th Annual Meeting - Jackson Hole, WY.</td>
<td></td>
<td><a href="http://www.sipes.org/meetings.htm">www.sipes.org/meetings.htm</a></td>
</tr>
<tr>
<td>8/2-4</td>
<td>U.S. Shale Plays - Fort Worth, TX.</td>
<td></td>
<td><a href="http://www.aapg.org/gtw/USShale/index.cfm">www.aapg.org/gtw/USShale/index.cfm</a></td>
</tr>
</tbody>
</table>

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The environmental emphasis for most field projects is on developing efficient, cost-effective methods to manage and treat water. Both service companies and field operators are involved in new technologies and strategies to treat and reuse water and to find ways to eliminate unnecessary chemical additives.

Ion Exchange Process for SAGD Water

Steam-Assisted Gravity Drainage (SAGD) uses brackish water to make up injection volume, but the water available contains silica and sulfate that can cause scaling if not diluted by large volumes of more expensive fresh water. Scaling also causes increased costs for equipment maintenance. Operators of SAGD in Alberta face a new challenge in that the Energy Resources Conservation Board has proposed restrictions on use of fresh and brackish water. A new ion exchange process, Sulf-IX, developed by BoiteQ Environmental Technology, Inc. of Vancouver, B.C. can remove silica and sulfate from brackish water and shale gas frac water. Sulf-IX is a two-stage ion exchange process that decreases sulfates to very low levels using chemical resins that remove calcium, magnesium and sulfate ions from solution. The resins can be regenerated and reused by processing with sulfuric acid and lime. Byproducts of the process are solid gypsum and clean water with no residual waste. Sulf-IX is capable of recovering 99% of the water treated compared to reverse osmosis processes that recover only 70%. BioteQ has processing plants in Canada, the U.S., Mexico, Australia and China, and the treatment is customized to the needs of the specific water to be treated.


Chesapeake’s Green Frac™ Technology

Chesapeake recognizes the need for improved environmentally-friendly technologies for hydraulic fracturing and started the Green Frac program in October 2009. The original work involved characterization of the types of additives used in hydraulic fracturing to determine their environmental impact on water quality. The GreenFrac™ procedure calls for elimination of any additive or chemical not critical to the completion process and suggests “greener” alternatives for all necessary components. In just over a year of operation GreenFrac™ has eliminated 25% of the additives that Chesapeake uses for hydro fracting shale gas plays.

By looking at the requirements for each specific shale Chesapeake was able to show that clay swelling was not an issue in the Barnett shale. KCl could be eliminated, the volume of surfactant could be reduced and no cross-linked gels are needed to hydro frac the Barnett. Other regional shale plays have their own characteristics. For the Barnett 1,000 bbl of water per MMcf produced gas is recovered, but only 10-15% of the recovered water is reused because of the high total dissolved solids content. Plays such as the Marcellus, Haynesville and Fayetteville have lower volumes of recovered water. In the Marcellus nearly 100% of the recovered water can be reused, which significantly reduces truck traffic and associated environmental costs. The key to GreenFrac™ technology is to characterize each shale gas play for the best environmental options for hydro fracting.

While the public has expressed a great deal of concern about hydro fracting chemicals, the truth is that these additives are all common, everyday household products found in laundry detergents, cleaning products and even in food and beverages. Concentrations of the chemicals used for hydro fracting are similar to the pH adjusting agents and chlorine used in swimming pools. GreenFrac™ is focused on identifying alternative additives for hydro fracting that are more environmentally friendly and providing guidelines to vendors on safe handling and use of all additives during hydro fracting processes for shale gas recovery.


New Oxidant-fused Surfactant-Enhanced Oil Recovery (OF-SEOR™) Technology for IOR from VeruTEK

For years VeruTEK has applied patent-pending, oxidant-fused co-solvent and surfactant technology to mobilize and achieve near-complete recovery of coal tar and other extremely viscous hydrocarbons from shallow sand and high clay content lithologies. VeruTEK is now working with independent producers to apply this same technology platform to improve oil recovery in stripper fields. The company recently completed Phase I testing and is interested in working with additional producers for Phase II.

Sophistication of the multi-action formulation allows activity to be delayed up to several hours until treatment can be positioned in target areas of the formation. This gives operators flexibility to treat specific decline issues in the manner and location most impactful to restoring their production—near-wellbore, in virgin areas around the frac, or across the formation area as an offset injection and water flood augmentation.

The multi-stage treatment solution removes blockages, creates zones of increased effective porosity within the formation and drops oil viscosity and interfacial tension (IFT). This is key to the technology’s ability to so effectively mobilize viscous materials and to achieve high removal efficiencies even at low temperatures and in high clay content formations. Once positioned within the formation and the activation begins, CO₂ is produced, providing a temporary and localized upsurge in energy and significantly propagating the aggressive surfactant/co-solvent across a larger surface area of the formation.

The active ingredients are readily dispersible in water and penetrate water interfaces. The green, non-toxic components also satisfy the strictest of environmental requirements. The treatment process is simple to implement, does not require special equipment and is relatively non-interruptive to existing production.

The technology platform is flexible, so formulations can be customized to specific oil and reservoir characteristics for optimal performance under a range of conditions.

For further information visit VeruTEK’s website (www.verutek.com), contact Jeff Ayers at jayers@verutek.com or call 860-242-9800 x317.
Chena Hot Springs—Resort and Geothermal Energy Research

Chena Hot Springs Resort in Alaska dates to the 1905 discovery of hot springs where crippled prospectors went to recover from their aches and pains. The resort continues to attract year-round visitors, thanks to innovative uses of geothermal energy. The resort used geothermal energy to develop and maintain an ice palace full of ice sculptures and fantasy, and the latest addition is a Geothermal Renewable Energy Tour offered daily to show the public that there is more to the resort than fun. The Geothermal Energy tour exposes thousands of people each year to the potential of geothermal energy, including power generation, year-round greenhouses in a frozen climate and new methods to save energy. Since 2005 Chena Hot Springs has hosted an Annual Renewable Energy Fair in August. Google’s philanthropic arm, www.google.org, a proponent of renewable energy sources conducts the annual event. The program works to develop electricity from renewable energy sources that could become cheaper than electricity developed from other sources such as coal.

Chena has also partnered with U.S. DOE, the University of Alaska, Southern Methodist University and several industrial partners in a geothermal exploration project designed to locate and characterize geothermal resources. Phase I of the project conducted (2006-2008) drilled wells under the Chena geothermal complex to determine the maximum temperatures and to assess the potential for geothermal projects in other areas of Alaska. The predicted temperatures of 250 °F would increase the current highest measured downhole temperature at Chena by over 70 °F, which would make a tremendous difference to the quantity and longevity of power generation. Results from Phase I show the 250 °F temperature isotherm is very likely located at depths that are economic to drill. Chena is representative of numerous other hot springs spread across the central portion of Alaska. The photo shows the Chena Hot Springs geothermal area from the DOE Phase I report.

Another innovative project that Chena Hot Springs built with help from United Technologies Corp. and DOE was the Chena geothermal power plant that came online in July 2006. The plant is the lowest temperature geothermal resource used for commercial power in the world. The cost of power production in this remote location is significantly reduced by the use of geothermal energy.


Map of geothermal resource potential in the U.S. from AAPG Explorer, November 2010.
Hydraulic fracturing and seismic interpretations are two of the most significant developments for the oil and gas industry. Hydraulic fracturing has advanced from simple mechanical means to complex technologies that have opened up shale plays that were previously regarded as seals rather than reservoirs. Advanced seismic technologies provide a means to pinpoint sweet spots and to stimulate production.

History of Hydraulic Fracturing

SPE’s new Legends of Hydraulic Fracturing CD ROM was based on a 2006 symposium honoring nine industry pioneers critical to the development of hydraulic fracturing technologies. Over 150 papers in the CD cover all aspects of the history of hydraulic fracturing made possible by pioneers in the industry; Claude Cooke Jr., Francis Dollarhide, Jacques Elber, C. Robert Fast, Robert Hannah, Larry Harrington, Thomas Perkins, Mike Prats and H. K. van Poollen.

Hydraulic fracturing was introduced by Stanolind Oil and Halliburton in 1949 in two commercial fracturing treatments in Stephens County, OK and Archer County, TX. Since that time 2.5 million fracture treatments have been conducted worldwide. Over 60% of wells in the U.S. in 2010 used hydraulic fracturing stimulation. Fracturing oil wells goes back to the 1860s when nitroglycerin was used to fracture shallow wells in the northern Appalachian Basin. Shooting a well with liquid or solid nitro was dangerous, but it served to breakup the formation and initiate flow capacity and model fracture lengths. The fluid used in early frac jobs was a gelled crude or gelled kerosene. They were low cost and low viscosity so there was less friction allowing treating at low pressure. The first crosslinked gels were patented by ARCO in 1962. Innovations including foams, clay stabilizing agents and alcohols and other acid and brines mixtures followed in the 1960s-70s. By the early 1970s metal based crosslinking agents were in use to improve viscosity for use in higher temperature wells. Recent innovations allow control of when and where in the wellbore the gelling agents and crosslinker fluids are permitted to interact. Proppants have gone through similar innovation processes from river sand to manufactured beads of glass, plastic, aluminum pellets, nut pellets, steel shot to resin-coated sands and zirconium. Computer capabilities have added greatly to the ability to simulate and plan the correct materials and mixing rates for hydraulic fracturing. Pioneer H. K van Poollen used electrolytic models to study flow capacity and model fracture lengths.

The history of hydraulic fracturing has come a long way in 60 years. Many fields would not exist today and the shale gas plays could not have occurred without hydraulic fracturing technologies.


Customizing Shale Wells

Shale gas operators quickly learned that there is a steep learning curve for each shale gas play. Wells drilled very close together and in the same manner with similar logs can have significantly different production characteristics. Nathan Meehan, executive advisor for Baker Hughes, notes that “some operators go for a factory approach” based on little science and the need to drill to prove leases. However, shale plays have proved to be very heterogeneous and fast optimization rarely occurs. The rush to produce has caused many operators to skip the important reservoir characterization steps necessary to understand the reservoir. Low or no porosity and permeability shale reservoirs require understanding of how the gas can flow from very small pore spaces. Understanding the microfracturing in shales is a customized operation. Scott Stockton, vice president of Vector Seismic Data Processing in Denver notes that in the Bakken a volumetric increase of nearly 170% results as the kerogen cooks out of the shale. This energy stored in the volumetric change tends to fracture the rock along bedding planes. Meehan comments that microseismicity of the natural fractures is the key to understanding the Bakken shale play. Microseismic movement creates slippage that “generates a lot of ability to drain some incredibly tight rock.” These geomechanical issues are critical to understanding how to hydraulic frac shale wells and it takes more than one well to evolve an optimal plan for each play.

Excerpted from “Shale Wells Tend to be Custom Jobs,” AAPG Explorer, December 2010, p. 18, 20 and 41.

Seismic—Simultaneous Source Shaking

Over the past three decades seismic contractors have tried numerous times to use vibration to improve seismic data acquisition. For simultaneous source shaking the time required for data acquisition across a prospect is reduced by the number of source stations where the vibrators shake simultaneously. Wavefields traveling from the source complicates the data, but simultaneous vibrations reduce the complexity. High Frequency Vibroseis System (HFVS) is the technology that can acquire data from multiple vibration sources simultaneously. HFVS was developed by Mobil and is now offered through seismic contractors. HFVS was developed to reduce the cost of 3D seismic data acquisition and the results indicate that simultaneous shaking may in fact be cost effective. Seismic contracts have to pay a royalty to use the technology, but this small add-on fee may be well worth the cost to improve data acquisitions and data processing.

**Tech Transfer Track**

**The price of natural gas is a critical issue for unconventional producers. Several well known investment counselors have recently addressed new models and scenarios for how operators can react to low natural gas prices both in the near-term and to make long-term investment plans.**

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**Hybrid Model for Unconventional Resources**

As an investment model for unconventional resources, the newest concept is the hybrid model addressing natural gas, gas liquids, light oil or all three from shales and tight sand reservoirs. The model emphasizes the fact that the cost of producing liquids is low compared to the higher Btu value for liquids versus natural gas. This model rates investment in gas liquids and associated gas as preferable to investment in shale gas alone. The hybrid model is cyclic, and if or when natural gas prices climb from their present low, the model will reverse itself and favor investment in natural gas over liquids.

Twenty top natural gas producers are evaluating the hybrid model for their investments. Chesapeake has announced increasing its market share in liquids from 10% to 25% by 2015. EOG Resources is moving into liquids at a faster rate, transitioning from natural gas in 2007 to dominantly oil and gas liquids by the end of 2011. EOG is considered a pioneer in developing the 4 year old hybrid model.

Other companies using the hybrid model include Petrohawk Energy, ConocoPhillips and ExxonMobil. Petrohawk’s involvement with the Eagle Ford Shale play that contains shale gas, gas condensate and oil makes the hybrid model a natural choice.

Small to mid-sized companies geared to discovery and proof of concept in the U.S. will experience a more rapid return on investment from the hybrid model in the near term than majors. Initial use of the hybrid model has focused on Texas basins, starting with the Barnett Shale and then the Eagle Ford Shale, but is being adopted for new areas including the Granite Wash in Oklahoma. Shale plays that have recently discovered gas liquids associated with natural gas include Bienville Parish, LA in the Haynesville Shale, the Horn River Basin in British Columbia, the Bone Spring trend in the Delaware Basin of Texas and New Mexico and the Collingwood/Utica Shale in the Michigan Basin. These plays are all unconventional shale gas or tight gas sands.

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**Megatrends in Energy Investment**

As hydrocarbons become more and more expensive to find and produce, investors are looking at long-term opportunities. New technologies for specific and highly specialized aspects of energy exploration and development have the edge on investment. Every company would like to be the new Google that has changed the world of advertising from a small start in 2000 to worldwide dominance of information and business development. In the area of oil and gas exploration, drilling and production, six major trends are predicted to transform the energy sector in the next decade.

Biological research into the use of algae as a source of energy is in its infancy. Since hydrocarbons are based on plant materials from past eons, algae became a direct link to advancement in DNA sequencing. Synthetic Genomics using alga is the next generation biofuel.

Nanotechnology is devoted to understanding the transformation of physical matter at the atomic scale. Advances in computer microchip technology have made nanotechnology possible. Potential uses of nanotechnology include nanofabrication of drilling fluids to reduce drag or stimulation fluids for use in hydro fracking.

The petroleum industry is highly dependent on measurements from wireline logs to advanced seismic. The new trend may be hyperspectral technology that uses a digital fingerprint of the Earth across hundreds of channels in portions of the electromagnetic spectrum.

Data management of huge volumes of data is a challenge for technology. Because this involves integration of many types of data from multiple sources, development will call for networking from geological, engineering and software companies.

Cloud computing of data from the global oil and gas industry will require more sharing of information with multiple interests and companies to successfully compete in the future.

The final frontier may be new methods to bring together the problem with problem solvers from multiple organizations and different continents. Integration of talented individuals and local markets with new technologies world-wide will hold the key to the future.

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**Price Scenarios for Unconventional Resources**

As gas prices in the U.S. have decreased at the wellhead over the past two years, gas producers have shifted from conventional to unconventional resource development. Recently companies have responded by diverting capital investment from gas to oil projects to capture the higher oil recovery prices. Within companies this includes moving rigs to liquid-prone areas in shale gas and tight sand plays. As the rig count goes down and production decreases, demand for gas will increase and balance the market. In the past two years natural gas companies have used several tactical methods to remain financially stable; debt rollover, new equity issuance, asset lease and sales, and more recently improving margins by shifting from a gas capex to an oil capex. Gas is still critical as a transition fuel and for transportation needs, and world-wide unconventional gas is being explored for as a means to overcome dwindling conventional gas resources.

Price regulation of utility companies ensures they recovery of capital investment costs, but this regulation in conjunction with upstream price deregulation has impacted global energy prices and the U.S. wellhead price for gas. An increase in gas price would stimulate more investment in unconventional gas resources. However, new capital investment is low for natural gas. Gas price shock could occur if large sub-economic portions of shale gas plays become shut-in. A predicted 10-20% of current production would be shut-in before a gas shock scenario took effect. One result would be a return to LNG consumption and increased price for LNG. However, such a price shock would be short-lived as the price hike would encourage new investment resulting in lower prices. A smooth recovery of the natural gas price would be much better for the industry than the volatility of the price shock scenario.

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**Excerpted from “Megatrend Technologies Poised to Transform Oil & Gas Industry,” The American Oil & Gas Reporter, January 2011, p. 100-109.**

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**Excerpted from “New Investment Models Have Operators Targeting Tight Oil and Hybrid Unconventional Reservoirs,” The American Oil & Gas Reporter, December 2010, p. 44-52.**
**Unconventional Resources abound in the Arctic and in shale gas reservoirs across the United States. Recovery of heavy oil in the Arctic presents an extra challenge due to permafrost conditions and transportation issues. The public regards shale gas development as a recent effort, but DOE has funded research projects with unconventional resources including shale gas, tight sands and coalbed methane for decades.**

**DOE Highlights - Arctic Technology Conference**

The first Arctic Technology Conference, an Offshore Technology event organized by the American Association of Petroleum Geologists was held February 7-9 in Houston, Texas. The DOE sponsored session on Physical Environments on Feb. 7 had four speakers covering environmental research and heavy oil characterization. The first presentation by K. Kamaran and Randy Seright on the effect of residual oil saturation on recovery efficiency during polymer flooding described laboratory experiments conducted at New Mexico Tech PRRC using viscous oil samples. Use of polymers to reduce oil saturation holds the potential for significant recovery of heavy oil from Alaskan reservoirs.

Two presentations described the North Slope Decision Support System by Kelly Brumbelow (TX A&M) and Leslie Gowdich (PBS&J). The North Slope Decision Support System is designed as a integrated database that provides data and technical capacities to model water resources management for the North Slope. One of the North Slope Decision Support Systems tasks was to determine the optimal location of ice roads considering a number of factors including; distance, topography, water availability, sensitive environmental or cultural areas, wildlife and vegetation and long term sustainability of the route. The second paper discussed the information gathering processes, database functionality, stakeholder input and GIS data on the North Slope lakes survey task.

The final presentation in the DOE session by Sveta Stuefer (Univ. of Alaska, Fairbanks) dealt with snow management as a means of augmenting fresh water supply from North Slope lakes. The North Slope is a frozen desert with very low annual precipitation mostly occurring as snow. Water from the lakes is withdrawn in the fall to build ice roads to transport oilfield equipment for drilling and production season. Comparisons from the control and snow fenced lake indicated that the snow fence provided an additional 32 days of melting snow water supply to the fenced lake in 2010.

On Feb. 8th a DOE funded project in the Resources; Circum-Arctic Geoscience of Petroleum Basins session, Cathy Hanks (Univ. of Alaska Fairbanks) presented results on research on light oil from a shallow, frozen reservoir in the Umiat Oil Field in Northern Alaska. The project has characterized this unique permafrost reservoir and discussed technologies for producing the oil.

**Notes from DOE Session co-chair, PTTC’s Viola Schatzinger**

DOE also co-sponsored a technical session entitled “Exploration Drilling Onshore: Gas Hydrates,” focused on research towards Gas Hydrate production in the Arctic.

- Methane Gas Production from a Mount Elbert Core Sample: Experimental Observations and Numerical Simulations — T. J. Kneafsey
- Impact of Exchange Kinetics on the Injectivity of Liquid CO2 into Arctic Hydrates — M. D. White, S. Silpangarmiet
- Evaluation of the Hydrate Deposit at the PBU L-106 Site, North Slope, Alaska, for a Long-Term Test of Gas Production — G. J. Moridis, M. T. Reagan, M. Kovalsky, K. Boyle, K. Zhang
- Simulation of Arctic Gas Hydrate Dissociation in Response to Climate Change — M. T. Reagan, G. J. Moridis, S. M. Elliott, M. Maltrud

**Shale Gas Technology is Producing Results for America**

A U.S. Dept. of Energy press release on Feb. 2, 2011 addressed the $92 million investment in shale gas research funded by DOE since the 1970s. The four decades of research has stimulated development of domestic natural gas from shales across the U.S. Currently natural gas from shale plays produces over eight billion cubic feet per day, representing 14% of the natural gas produced in the U.S. DOE’s Energy Information Administration (EIA) predicts that shale gas will represent 45% of all natural gas production by 2015. In the 1970s DOE research focused on Devonian shales and low permeability tight sands in the Appalachian Basin and the Rocky Mountain regions. DOE funds have fostered development of technologies to improve coalbed methane recovery, increase unconventional gas resource use and provide environmentally sound operating practices. Highlights of the DOE research include: 1) collection and characterization of over 25,000 ft. of core and well log data from 35 shale wells in West Virginia, Ohio and Kentucky, 2) the first air-drilled horizontal shale well in the Appalachian Basin in 1986, 3) roadmapping hydraulic fracturing technologies, and 4) encouraging development of new plays and technologies based on reservoir characterization. The DOE program has provided new jobs and increased state and federal tax revenue through higher production of domestic natural gas.

**Shale Gas—NETL’s Newest Release**

In March 2011, the National Energy Technology Laboratory released a publication aimed at developing unconventional resources. SHALE Gas: applying Technology to Solve America’s Energy Challenges is an eight page brochure highlighting shale gas plays, regional development and issues to be addressed. The brochure can be downloaded from NETL’s website www.netl.doe.gov/publications/brochures/Shale_Gas_March_2011.pdf.
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Haynesville Operators

Focus on Liquids

Operators in the Haynesville shale play are increasingly turning to the liquid-rich areas of the play following the success of multiple asset plays like the Eagle Ford, Wolfberry and Niobrara. Oil prices above $80 per barrel and natural gas prices below $4 per MMBtu have dictated the change in focus. Petrohawk, Chesapeake Energy and Encana have all announced plans to develop the liquid-rich area of the Haynesville in 2011. Haynesville Shale gas wells are still top unconventional gas performers, so investment in shale gas will continue. Most of the leasing in the Haynesville occurred in 2008 when the price of gas reached $10 MMBtu. The Haynesville extends from Louisiana into Texas with the deeper Bossier trend mainly in Texas. Advances in drilling efficiency, reduced drilling time and hydraulic fracture design have improved the economics of shale gas production for the Haynesville. In 2010 operators continued to lease acreage and drill new wells, but many are talking of scaling back and holding production on gas. Red River, Sabine and Beinville parishes in Louisiana experienced increased leasing in late 2010, related to volumes of gas liquids. The interest in liquid-rich assets is expected to promote new joint ventures in the Haynesville in 2011.


LNG Opportunities

in the Gulf Coast

Liquefied Natural Gas technology is opening new market opportunities for both conventional and unconventional gas in the Gulf Coast. LNG offers a way to maximize the value of produced gas even when the wellhead price for gas is low. LNG and CNG for transportation have created a market due to the interest in more environmentally friendly fuels. The Gulf Coast offers an area were gas production and lower-cost LNG fleet transportation cost can be utilized. Fleet use of LNG or CNG for the U.S. Postal Service, United Parcel Service, Federal Express, utility companies and vehicles for ship and rail yards is potentially a large market. Other large corporations that may find LNG cost-effective are large grocery and retail chains, fuel transportation suppliers, mass transit commuters such as city buses, taxis and off-road vehicles used in mining and agricultural operations.


Unconventional—

Eagle Ford Shale

As a shale play the Eagle Ford is proving to be unconventional in several ways. The combination of shale gas, oil and associated liquids makes it a both a challenge to manage and economic. Depths across the Eagle Ford from 2,500 ft. to over 15,000 ft. at the eastern edge provide maturation windows of crude oil, dry gas and wet gas. The gas condensate window contains 1,200 Btu with yields up to 500 barrels per million cubic feet. The organic-rich shale has higher porosity and permeability than other shale plays, due to its carbonate content, which makes it more brittle and naturally fractured. Thickness reaches up to 350 ft. in some areas with a great variability in rock properties across the play. Advanced seismic technology is critical to exploration and development strategies to optimize the complex Eagle Ford Shale.

The Upper Cretaceous Eagle Ford rapidly transitions from a downdip gas play to an updip wet gas and oil play. The variation in depth across the Eagle Ford testifies to the effect of tectonics and eustatic sea level changes on sedimentation and stratigraphy. The Eagle Ford zone with the highest total organic carbon (4-7%) and highest porosity (7-15%) directly overlies the Buda Limestone. This zone is somewhat less well defined where the section grades into the Austin Chalk. Seismic interpretations of this stratigraphic variation rely on impedance values to map the target zone. Understanding the zones of higher porosity and permeability, based on impedance values, dipole sonic measurements and formation microimaging is critical to placing horizontal boreholes in the Eagle Ford.

Matador Resources believes that modern seismic techniques are more valuable than traditional log interpretations. They are using full-azimuth, long offset 3-D seismic data for high-resolution subsurface characterization of the Eagle Ford. Full-azimuth data provides better reservoir quality interpretation and identification of faults and other drilling hazards. Full-azimuth seismic processing provides information on velocity and amplitude differences that change with azimuth to give a more complete image of the Eagle Ford. Another technology Matador uses is elastic inversion that converts near and far offset seismic data into prediction of attributes of rock properties and rock strength, including density and fracturing. The combination of advanced seismic data and interpretation techniques is helping Matador identify the sweet spots and plan their drilling program in the Eagle Ford Shale.


A list of scheduled PTTC regional workshops can be found on page 15, or for the most current workshop information, go to www.pttc.org.
Scientific Evaluation of Marcellus Groundwater Needed

Most of the recent claims of groundwater contamination resulting from drilling and hydraulic fracting in the Marcellus in Pennsylvania have been made without the benefit of any scientific knowledge. Groups of families in Susquehanna and Washington counties have brought lawsuits against companies operating in the counties alleging contamination of drinking water by barium, manganese, strontium, iron, arsenic and benzene, naphthalene and methane gases. The media and environmental groups have made much of these claims, while ignoring reports by state and federal agencies that have actually tested the waters. The Pennsylvania Department of Environmental Protection (DEP) has “found no instance where fracting has contaminated groundwater.” DEP’s John Hanger says that gas migration into water wells is rare, but not new or unique to Marcellus drilling.

Speculation on possible water contamination by hydraulic fracting has resulted in an moratorium in New York and generated a hail of unfavorable publicity in Pennsylvania. Operators in Pennsylvania are taking additional precautions against any potential leaks and addressing new ways to manage waste water from drilling operations. Since 2008 DEP has doubled the number of oil and gas inspectors to ensure adequate protection of the state’s water resources. New stricter regulations by the Pennsylvania Environmental Quality Board went into effect in December 2010 with changes in permitting discharge of treated wastewater to surface waters. The new rules will allow discharge of wastewater from natural gas operations only if they have been treated in a centralized wastewater treatment (CWT) facility that meets standards. Municipal water treatment facilities will not be allowed to accept oil and gas wastewater unless previously treated at a CWT facility.

Marcellus operators as all shale gas operators in the country are regulated by the Environmental Protection Agency under the 2005 Clean Water Act. A review of hydraulic fracting in currently underway based on scientifically collected data. The EPA study will assess both costs and benefits of hydraulic fracting to provide a sound scientific basis for decision making. Scientific information should serve as the basis for any legal decisions in trials brought to court by citizen’s groups. Pennsylvania law on scientific data is based on a 1923 decision that states “judges should be guided by scientists when assessing the reliability of a scientific method.”

Litigants should not be allowed to recover damages based on the sole fact that Marcellus operations occur on or near their property. Reliable scientific evidence should be the basis of any court decisions on groundwater contamination from Marcellus shale operations.

Granite Wash Tight Gas Play

Horizontal drilling and hydraulic fracturing technologies developed for shale gas plays are now being adapted for tight gas plays in other depositional environments. The Granite Wash is a tight sandstone that has been known for decades, but new technologies are opening up new opportunities and increasing natural gas production. Granite Wash covers an area of western Oklahoma and the Texas Panhandle 160 miles long and 30 miles wide. The first horizontal well in the Granite Wash was drilled in July 2010 by LINN Energy, LLC of Houston. Initial 24-hour production tests reported 27 million cubic of gas and 3,190 barrels of gas condensate that were processed to 3,530 barrels of natural gas liquids. The early results brought in operators from the region with Apache Corp, ONEOK of Tulsa and Chesapeake Energy all announcing plans for drilling and development of the Granite Wash play by the end of 2011. Previous wells in the Granite Wash (over 2,600) had all been vertical and most were drilled while targeting more productive deeper zones in Atoka or Morrow formations. Arden Walker, CEO of LINN Energy said that the Granite Wash is a 3,000 ft. thick zone with numerous target horizons and the company plans to drill 35 wells in 2011. Horizontal wells are planned to average 4,300-4,500 ft. in length using 10-14 stages for hydraulic frac completions.

Tight gas sands are very different from gas shales, but some of the drilling and completion strategies are similar. The biggest similarity is that these are both low-permeability unconventional plays. Reservoir quality and porosity are generally better in tight gas sands than in gas shales. The presence of gas condensate as well as gas makes the economics of the Granite Wash a good investment.

Geologically the Granite Wash is complex and poorly defined, representing several tight sandstone units or formations shed off the Wichita-Amarillo Uplift by alluvial fans and erosion. The closer to the uplift drilling occurs, more conglomerates and coarse gravels are encountered, hence the name Granite Wash.

Excerpted from “Granite Wash a Wild Mix of Geology,” AAPG Explorer, February 2011, p. 8, 10 & 12.
Shale plays continue to be the big producers in the Rocky Mountain region. The Bakken and Niobrara are hot topics and both present interesting management challenges with infrastructure and water use. Unconventional resource plays in Colorado, Utah and Wyoming will be highlighted at the RPSEA Unconventional Gas Conference, open to the public.

How We look at Geology Has Changed

The emergence of new shale plays across the U.S. has led to a shift in thinking about geology for many independent operators. Just what constitutes a reservoir has been redefined through technology. The combination of horizontal drilling and advanced hydraulic fracturing have been revolutionary processes. In the Rocky Mountain region the biggest play is the Bakken in North Dakota, but the Niobrara also has the potential to become a big play. The new buzzword, hybrid (see page 6) is the means for independents to leverage gas and liquid-rich shale plays and maximize production. A panel of executives from leading independent companies active in shale plays in the Rocky Mountains included Aubrey McClendon, Chesapeake Energy Corp.; Jeff Hume, Continental Resources; and Ralph A. Hill, Williams Company were interviewed.

Historically exploration for petroleum has looked at where natural gas and oil leaked from shale to become trapped in conventional plays. According to McClendon, shales as source rocks are a lot more abundant than conventional plays, one of the results is a long term stable natural gas price. For Chesapeake shales have transformed business and cut the cost of finding gas in half.

Continental Resources began to focus on oil in 1989 and the Bakken Shale is a natural choice for them. Hume says that Continental expects to triple in size in the next five years. Although Williams Co. is primarily focused on natural gas they have invested in the oil-rich Bakken and Hill says they have an edge with shale plays because of their experience in low-impact environmental development. The Bakken is a significant shale play in that it contains oil rather than gas and liquid-rich plays such as the Bakken, Eagle Ford and Niobrara will be critical to economics according to McClendon. Hume notes that since 2005, crude oil production in North Dakota has jumped 400%. He says that experience in the Bakken will be valuable for the Niobrara, which has recently experienced a lot of leasing activity. Commodity prices and regulatory framework and infrastructure requirements have also been critical in development of the Bakken according to Hill.

All the executives cited the benefits of improved horizontal drilling and hydraulic fracturing as the key to success in shale plays. Continental Resources cites downhole telemetry as a critical technology that has allowed drilling longer intervals with increased stability and penetration rates. More efficient multistage completion techniques were borrowed from the Barnett, but modified for the Bakken. Hume discussed the practices in the Bakken where up to 40 hydro frac stages in 9,500 ft. laterals are common. Completions in the Bakken are run on a 24-hour schedule, using top drive drilling rigs to optimize drilling speeds and control penetration rates. Hume said the drilling costs in the Bakken vary from $2 to $4 million so there is pressure to optimize drilling and completion efficiencies.

For the future of shale plays, Hill believes there are more plays to find and that the industry needs to view “seals” as reservoirs in exploration models.


Bakken Highlights

For the latest information on how the Bakken unconventional resource play has impacted oil recovery, NETL has dedicated the entire Winter 2011 issue of the E&P Focus newsletter to articles on the Bakken. www.netl.doe.gov/technologies/oil-gas/publications/newsletters/epfocus/EPNews2011Winter.pdf.

Water Reuse for the Denver-Julesburg Basin

As both conventional and unconventional plays in the Denver-Julesburg Basin continue to grow, the need for water becomes a critical issue in the water-stressed Front Range. A recently proposed water treatment plan is using waste streams from the Greater Wattenberg oil and gas field to manage water resources. The Wattenberg is a tight oil and gas field with over 20,000 wells in a largely agricultural area near large urban centers. All these factors contribute to concerns over water supply. The novel treatment plan would allow for reuse of waste stream water and reduce the need for operators to draw on municipal and state water supplies.

Conquest Water Services operates the waste water treatment facilities for Wattenberg field. Waste streams include all variety of oil and gas field wastes including produced water, flowback water from slick water stimulation, flow back water from acid stimulation and tank bottoms. The new treatment is designed to reduce the risk of mechanical fouling of filtration membranes by use of chemical processes. Control of salts to reduce clay swelling and pore throat plugging was a major criteria for the process. Undisclosed chemical treatments avoid the high cost of desalination while removing harmful constituents for the waste water. The chemical treatment process removes salts, surfactants and starches (which promote bacterial growth) and other stimulation substances. The waste stream treatment works through a coagulation and flocculation process that reduces the waste stream to less than 1% of the intake volume. As a byproduct of the water treatment process a dried filter cake that supports plant growth can be sold or disposed of in landfills. The Conquest treatment facility has the capacity to treat 5,000 to 6,500 barrels of fluid per day. Water can be sent to deep well disposal or back to industry for reuse. The process lengthens the life of existing disposal wells by reducing the volume of fluid pumped into them. The process developed for waste streams in the Wattenberg field can be modified to other basins.


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Growing interest in exploration and development of Arctic Resources was evident at the 1st Arctic Technology Conference held in early February in Houston (see page 7), attended by over 3,000 people. PTTC contributed an effort to promote understanding of Alaskan geology in a workshop in Anchorage in January. How this exploration can be achieved is a growing concern that will be address by the Joint SPE/AAPG Western Regional meeting in May.

PTTC’s Alaskan Workshop

Exploring Alaska’s Geology and Regulatory Landscape held on January 20, 2011 in Anchorage featured speakers Robert B. Blodgett, PhD, David Hite PhD and Wayne Wooster. All three have extensive experience with Alaska geology and regulatory processes. Robert Blodgett, an geologic consultant presented a photo history of oil exploration in Alaska from 1898 to the present. Exploration started in southern Alaska with discovery of numerous natural oil and gas seeps. But it was the discovery of Prudhoe Bay on the North Slope in 1967 that brought Alaskan oil to the attention of the nation.

Petroleum Consultant, David Hite gave three presentations. The introductory presentation was an overview of Alaskan Petroleum Geology that included technical definitions and information for the many non-geologists in the audience. The two main presentations were on the Cook Inlet and the North Slope with a final summary of other potential petroleum basins in Alaska.

Wayne Wooster, ASRC Energy Services, Regulatory & Technical Services discussed the very complex permitting process in Alaska. Features which add to the complexity are the varied topography, the myriad of federal, state, Native and private land ownership and management organizations, the remoteness and environmental concerns.


Can We Develop The Arctic?

Growing concerns over environmental regulations have slowed exploration and development in the American portion of the Arctic. The U.S. Fish and Wildlife Service has designated over 448,000 sq. km of onshore barrier islands as critical habitat for polar bears. Royal Dutch Shell plans to continue exploration of the Beaufort and Chukchi seas off Alaska and drill in the Beaufort Sea in 2011 in a manner that will mitigate any potential impact on polar bears and other marine life. Planning for environmental protection and being careful about drilling in Arctic regions is necessary from Alaska to Canada, Greenland and northern Europe and Russia. Extensive environmental studies are called for in specific areas and for specific animal and plant habitats. Currently seven international companies are planning seismic exploration off Greenland with plans to be drilling in 10-15 years. Safety planning must focus on a worst case scenario of an oil spill occurring at the end of the drilling season when containment poses extra hazards. Development of oil and gas resources in the Arctic will be a slow and careful process.

Excerpted from “Growing Arctic Concerns,” Oil & Gas Journal, Dec. 6, 2010, 42.

SPE Western Regional/ AAPG Pacific meeting

May 7-11, 2011 the SPE Western Regional Meeting will be held in conjunction with the Pacific Section AAPG meeting in Anchorage, AK. The conference is titled Arctic to the Cordillera: Unlocking the Potential The conference and associated PTTC workshops will focus on technologies and issues affecting oil and gas fields in the Western North American. Technical sessions will host a variety of topics including:

• Geology and hydrocarbon potential of the North Slope, Beaufort and Chukchi Seas
• Cook Inlet oil and gas fields
• Recent advances in exploration and development
• Case studies and best practices
• Environmental geology and geohazards
• Alternative energy - progressive future

To register or for further information go to www.spe.org/events/wrm/2011 or http://psaapg.org/convention.aspx.

PTTC West Coast Region is sponsoring seven workshops following the conference on May 12-13.

• Multiphase Metering (Parviz Medizadeh, Production Technology, Inc.)
• Introduction to Well Logging (Todd Sidoti, Schlumberger)
• Thermal Recovery (Anthony Kovscek, Louis Castanier, Stanford University)
• Drilling & Completions for the PE Exam (Bing Wines, Winrock Engineering Inc.)
• Unconventional Shale Resources: Drilling, Evaluation, Fracturing & Completions Methodology & Approaches (Halliburton)
• OCS Regulatory Review (BOEMRE)
• Production & Reservoir Engineering for the PE Exam (Bing Wines, Winrock Engineering Inc.).

For more information or to register for these workshops, got to PTTC’s website calendar, www.pttc.org/national_calendar.htm or call 661-635-0559.

Early 1900s exploration crew cooking over a natural gas seep. Photo courtesy of Robert Blodgett.
Upcoming Events

PTTC’s affordable regional workshops connect independent oil and gas producers with information about various upstream solutions. For further information, please call the direct contact listed below. Check PTTC’s online calendar (www.pttc.org/national_calendar.htm) frequently as changes do occur.

April 2011

4/11-15 Rocky Mountain: Complex Well, Core Competency 2011 (Bob Knoll) -- Golden, CO. Contact: 303-273-3107
4/19-20 Rocky Mountain: Fracture Analysis (Michael Fahy, consultant) -- Golden, CO. Contact: 303-273-3107
4/25 Midcontinent: Enhanced Oil Recovery by Chemical Flooding -- Tulsa, OK. Contact: 918-631-2979
4/26 West Coast: Facilities Engineering -- Bakersfield, CA. Contact: 661-635-0559

May 2011

5/3 West Coast: Facilities Engineering -- Long Beach, CA. Contact: 661-635-0559
5/5 Eastern: Core Workshop @ Western Michigan University -- Kalamazoo, MI. Contact: 269-387-8633
5/10-11 Rocky Mountain: Completion & Stimulation(s) of Horizontal Wells in Tight and Unconventional Gas Reservoirs (Larry Britt, Tulsa University) -- Golden, CO. Contact: 303-273-3107
5/12-13 West Coast workshops @ SPE Western Regional Meeting -- Anchorage, AK. Contact: 661-635-0559

June 2011

6/2 Rocky Mountain: Petra Basics (Jewel Wellborn of Hydrocarbon Exploration and Development) -- Golden, CO. Contact: 303-273-3107
6/7 Midcontinent: Multistage Hydraulic Fracturing in Unconventional Reservoirs (Jennifer Miskimins, CSM) -- Wichita, KS. Contact: 785-864-1759
6/8 Midcontinent: Horizontal Drilling in Kansas (the Hot Play) -- Wichita, KS. Contact: 785-864-1759
6/8-10 Rocky Mountain: Tight Gas Sands, Geology, Petrophysics and Core -- Golden and Lakewood, CO. Contact: 303-273-3107
6/21 Rocky Mountain: Completions and Stimulations for Geologists (Jennifer Miskimins, Colorado School of Mines) -- Golden, CO.
6/25 Rocky Mountain: Petrophysical Evaluation of Unconventional Reservoirs (RMS AAPG) -- Cheyenne, WY. Contact: 303-273-3107

Fossil Energy Today

In January 2011, the U.S. Department of Energy launched a new, free digital newsletter to be published quarterly by the Office of Fossil Energy. Fossil Energy Today will provide updates on activities, progress and new developments sponsored by Fossil Energy. The January issue highlights research on high speed imaging, methane hydrates, coal-fired projects, risk assessment and introduces the Carbon Sequestration Atlas and developments at the Rocky Mountain Oilfield Testing Center (RMOTC). One section announced 10 awards in Tools for Unconventional Oil and Gas Resources. To subscribe, please send a blank e-mail with the word “subscribe” in the subject line to: EnergyToday@hq.doe.gov.


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To learn more about our green technology and how it effectively applies to EOR and in-place oil clean-up visit our website at: www.verutek.com or call 860-242-9800