An Exciting Time For Tech Transfer

Technology plays a key role in slowing domestic production decline. One way a producer can improve business economics is to stay current on what is working in other areas of the country. To serve that need, PTTC has focused on building its connections through expanding newsletter and e-mail distribution lists. The 13 regional and satellite offices continue to provide a diversified and responsive outreach program covering Drilling and Completion, Environmental Protection, Exploration, Operations and Production as well as Reservoir and Development issues. Within certain plays, such as the Hunton De-Watering play in Oklahoma and the Trenton Black River formation in Appalachia, technology progress is responsible for substantial production increase. The PTTC brings ideas to reduce costs and increase production to thousands of independent producers in the U.S.

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PTTC is a national not-for-profit information network formed in 1994 by oil and natural gas producers. Programs are funded by matching funds from the US Department of Energy (DOE) with funds from State Governments, Universities, State Geological Surveys and Industry. This program would not be possible without contributions from the DOE Office of Fossil Energy through the National Energy Technology Laboratory (NETL).

Phifer Assumes PTTC Leadership Reins

On March 22, Brook Phifer, President, NiCo Resources, LLC, Colorado, was elected Chairman of PTTC’s Board, succeeding James Bruning, Bruning Resources LLC. The family-owned NiCo Resources, LLC is an acquisition and production company with properties in the Rockies, Oklahoma, and west Texas. Prior to starting at NiCo, Phifer was Vice President of Production at Axem Resources in Denver. His initial industry training was with Exxon in Midland, Houston and Los Angeles. Brook is also active in SPE. He holds a B.S. in civil engineering from Stanford University.

Phifer first became involved with PTTC in 1994, serving on the Producer Advisory Group for the Rocky Mountain Region. Most recently as National Vice Chairman, he has lead PTTC’s Management and Budget Committee, a committee that provides month-to-month Board guidance to PTTC. As he continues his leadership responsibilities, PTTC felt it appropriate to pose a few questions.

What do you see as the biggest challenge, either internal or external to the industry, that U.S. independents must adapt to if they are to economically thrive in the next decade?

The biggest challenge is keeping up with change. The oil business’s political, economic and technologic environments keep changing faster and faster. During the 1970s and 1980s, natural gas could not be used as a boiler fuel. During the 1990s gas was the fuel of choice for power generation. Will that demand continue or be replaced by clean coal by 2010? No longer do we ask “could a horizontal well be better in this field?” Now we need to develop fields by asking “Why shouldn’t a horizontal well be utilized?” How do I evaluate my leases for the latest coal bed methane play? With the competitive nature of our business, an independent has to ask these questions and have the answers now.

Given that change, how can PTTC be a force assisting independents make the necessary adaptations?

PTTC will be a force for the independent producer, geologist and engineer by informing us of these technologic changes. The new technology questions and answers have to be provided in a low cost way, without taking much time, and in real time. PTTC can find the latest questions thousands of independents have by keeping in touch with them through our 10 regions. With PTTC’s association with numerous universities, the DOE, and our increasing connection with technology providers (service and equipment providers), service provider R&D dollars for the mature U.S. market can be focused where there is that critical market mass. Federal R&D dollars can be positioned to complement private sector investments.

Finally, the PTTC will continually be changing the way we deliver these newest technology solutions. I envision more webcasts of workshops like the ones developed by the West Coast Region at the University of Southern California. The

Cont. on page 2
archive of webcasts will be available on demand with indexes and search engines to locate answers to specific questions immediately. In the not too distant future, hopefully, we can provide live software training over the web. Then independents can get hands-on, live training without the time and dollar cost of leaving their (home) office.

Change is a process that involves action. Looking to this next year, what would you most like to see PTTC accomplish?

The PTTC will have to increase its focus on serving the full range of independents. Not only will regions provide workshops on the largest geologic and geophysics workstation solutions, but low cost basic workstations for the one man geology or engineering office. We shall have assisted the field operators and pumpers with understanding the latest production techniques, specifically for their regions. The PTTC’s transfer of technology needs to reach the large independent, small independents, field and office hands, within all 10 regions.

PTTC will promote the development of technologies appropriate for mature domestic oil and natural gas production. This includes encouraging continued federal investment in oil and natural gas research, development and demonstration currently implemented through the National Energy Technology Laboratory within the Department of Energy. Effective technology transfer is integral to this effort. When applied by independent producers, these technology solutions will lead to increased production and/or lower operating costs. Additional royalties and taxes are paid on this domestic production, enhancing true benefits to the consumer.

Brook welcomes input from any PTTC stakeholder about strategy and vision for PTTC to fully realize its mission of assisting U.S. independents. E-mail at nico@nicohorizon.com, or phone 303-730-7373.

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**Meeting Alerts**

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<td>SPE Gulf Coast: Reaching New Frontiers in Drilling</td>
<td>April 14, 2004</td>
<td>Houston, Texas</td>
<td><a href="http://www.spe.org/spe/sp/meeting/0,2460,1104_1535_2009830,00.html">www.spe.org/spe/sp/meeting/0,2460,1104_1535_2009830,00.html</a></td>
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<td>SPE/DOE Improved Oil Recovery Symposium Including Special Independents’ Day</td>
<td>April 17-21, 2004</td>
<td>Tulsa, Oklahoma</td>
<td><a href="http://www.ior2004.org">www.ior2004.org</a></td>
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<td>Offshore Technology Conference</td>
<td>May 3-6, 2004</td>
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<td>SEG Drilling &amp; Production Forum Increased Recovery Factors Through Reservoir Characterization</td>
<td>May 16-21, 2004</td>
<td>Galveston, Texas</td>
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Environmental Corner

Produced Water, A White Paper

On behalf of DOE's National Energy Technology Laboratory, Argonne National Lab recently issued a white paper or overview document covering key aspects of produced water. Basic information detailed in the report includes:

- Chemical and physical characteristics of produced water
- Where it is produced
- Potential impacts of produced water on the environment and on operations
- Volumes generated
- Federal and state regulatory requirements regarding discharge and injection
- Numerous options for managing produced water, including those that minimize the amount of produced water that is lifted to the surface, recycle or reuse produced water, and involve disposal
- Summary data on produced water management costs, which can be quite variable

The report is supported by more than 100 references, many new within the last three years. The report is available online at www.netl.doe.gov/scng/news/headlines/2004/pdf/whitepaper022304.pdf.

Unique SPCC Plan Service Offered

What began as a personal need for Spill Prevention, Control and Countermeasure (SPCC) plans for an operator has evolved into a unique, cost-effective service for other producers. As owner and operator of Columbia Production Company, a privately held Oklahoma-based independent in the early 1990s, David Yard, PE, found himself responsible for regulatory compliance, which included SPCC plans. He discovered that few were familiar with the regulations and consulting services were cost prohibitive to his company. Yard decided to learn what was required and has performed the service himself since 1991. Multiple training courses and SPCC plans later, plus lots of conversations with EPA, led to development of an "automated" approach for developing SPCC plans.

In this automated approach, basic data are gathered in a site visit and from the operator. Information is efficiently processed through software that develops a tailored, thorough SPCC plan. Plans provide maximum protection for the operator, exceeding requirements laid out in the generic API form. Plans are regularly reviewed by EPA Region 6 for conformance with the ever-changing interpretations of the law. Yard formed SPCC Plans, LLC (SPCC Plans) in 2002 as an offshoot of Columbia Engineering, a consulting firm he formed in 1986. Because of efficiencies built into the process and Yard's commitment to the domestic producing industry, plans for onshore facilities cost only $150 per facility.

SPCC Plans initial focus is in Oklahoma, but services are offered for facilities in other states. Services are not offered for offshore facilities. SPCC Plans currently processes 200-250 plans per month with a 2-3 week turnaround time. Capabilities exist to handle more, but price and turnaround time may increase as the August 2004 deadline for updating and implementing SPCC plans approaches. For further information, contact SPCC Plans at E-mail spccs@attglobal.net, or by phone at 405-373-3452.

Editor’s note: PTTC well recognizes there are numerous firms offering SPCC plan services, but because of the low cost of SPCC Plans’ approach, felt obligated to inform producers of its existence. Importantly, producers are urged to take action now on their SPCC obligations, thereby avoiding the anticipated August rush.

Reliability of Natural Gas Infrastructure

DOE maintains an active RD&D program targeting the U.S.'s natural gas infrastructure. Reliability of that infrastructure presents both cost and safety issues. To establish baselines guiding technology development, DOE's National Energy Technology Laboratory has, in conjunction with other researchers, developed Technology Status Assessments. Two recent assessments, of 25 performed (www.netl.doe.gov/scng/trans-dist/ndgeltech-status.html) since 2001, focus on natural gas leak detection.

- Active Remote Detection of Natural Gas Pipeline Leaks, Eastman Kodak Company (Dec 2003)
- Technology Status Assessment on Natural Gas Leak Detection in Pipelines, En'Urga Inc. (Nov 2003)

In that vein, a recent DOE Tech Line (www.fe.doe.gov/news/techlines/0303/0303_leakdetection.html) reported successful testing of a mobile natural gas leak detector. Physical Sciences Inc. reported that its prototype detector detected natural gas leaks from 30 feet away at speeds approaching 20 miles per hour. Further testing in an operating distribution pipeline is planned.

Diesel Fuel Eliminated in CBM Hydraulic Fracs

Following extended study of CBM hydraulic fracturing issues, EPA and industry has reached a Memorandum of Agreement (MOA) addressing the use of diesel fuel in these frac treatments. During December 2003, the three service companies that pump the vast majority of hydraulic fracturing treatments, Halliburton Energy Services, Inc., Schlumberger Technology Corporation and BJ Services Company, signed a MOA in which the service companies “agree to eliminate diesel fuel in hydraulic fracturing fluids injected into coalbed methane production wells in underground sources of drinking water...” DOE assisted EPA in its study of the impacts with a white paper prepared by the National Energy Technology Laboratory included in the report.

The MOA is available on EPA’s website at the following address: www.epa.gov/safewater/uic/pdfs/moa_uic_hyd-fract.pdf.

Improve Gas Recovery, Reducing Methane Emissions

EPA’s Natural Gas STAR Program, a voluntary program working with industry to reduce methane emissions, coordinates an annual workshop for producers to learn how to apply technologies that profitably reduce methane emissions. This year’s workshop, to be held June 17 in New Orleans, is co-sponsored by Murphy Exploration and Production, Gulf Coast Environmental Affairs Group and the American Petroleum Institute. Topics to be covered include:

- Murphy's Experience in Reducing Methane Emissions: Technologies/practices implemented; reductions and cost savings, data collection and management, gaining company support
- Collection of best operating practices for reducing emissions
- Company—reported opportunities, lessons learned, cost effectiveness
- Installing plunger lift in gas wells
- Methane emission reductions from reciprocating compressors
- Emerging technologies, such as ejector vapor recovery units, optical image leak detection

See EPA’s website www.epa.gov/gasstar/workshops/neworleanswksp.html for further information.
Tight Gas Sands, Intensive Resource Development
Is A Key Concept

Intensive Resource Development (IRD) is the integrated application of a series of complementary resource assessment, reservoir characterization and field development technologies. IRD is particularly applicable to low-permeability reservoirs with thick but discontinuous pay zones.

IRD can encompass:

- Natural fracture identification technologies to detect high-productivity sections
- Well logging technologies that reliable distinguish between gas and water
- Multi-zone completion technologies
- Well testing technologies to establish drainage volumes, communication and anisotropies

Begun in the 1980s, techniques have evolved with major research investments by the Department of Energy, Gas Technology Institute and others and from operators drilling wells and applying the lessons learned. Three field/basin examples illustrate different aspects of IRD.

Southern Piceance Basin, Colorado. The Williams Fork (Mesaverde) Formation in the Rulison Field is thick, containing up to 135 Bcf per section but sands are very lenticular and discontinuous. Drainage area is very limited. These thick but discontinuous sections led operators early on to think of wells as vertical rather than areal reservoirs. Pressure data showed minimal depletion/communication through successive waves of down spacing, from 80s to 40s to 20s and now down to 10 acres in selected areas. In the initial 10 wells drilled on 10-acre spacing, pressure testing detected partial depletion in only six of 98 individually tested sand bodies. Reserves for the initial 10-acre wells are about 2 Bcf per well, in the range of earlier wells developed on larger spacing.

Northwestern Greater Green River Basin, Wyoming. The Lance Formation is the major producing horizon in the Jonah and Pinedale fields. A unique geologic setting involving the local uplift of the over-pressured Lance section and a series of lateral sealing faults has resulted in large volumes of gas in place, from 250 to 300 Bcf per section. Development there reveals a history of successive improvements in the completion/stimulation approach. Before 1992, stimulation treatments used relatively small amounts of proppant (80,000 to 200,000 lb) and cross-linked water-based gel or carbon dioxide foam. Production was noncommercial. Between 1992 and 1995, treatments grew larger, average of 550,000 lb, and used nitrogen foam. Initial production was much higher, but rapid declines occurred. Beginning in 1994, a new approach using water-based fluids with borate cross linkers and a modified perforation technique designed for flexible treatment of multiple intervals began to be used. Flow rates were still good, but declines are much shallower leading to higher reserves. Reserves have increased from 1 to 2 Bcf per well in the early 1990s to 5 to 10 Bcf per well currently. Development has begun on 40-acre spacing, and it may go even lower.

Eastern Wind River Basin, Wyoming. The largest Fort Union/Lance Formation natural gas field in the Wind River Basin is Waltman/Cave Gulch, on the northeast flank of the basin. Discovered in 1959, the Cave Gulch Unit produced only modest amounts of gas, less than 5 Bcf and only a few MMcfd until Barrett Resources began applying IRD techniques in 1994. The Bureau of Land Management estimates the Fort Union and Lance formations in this area contain an average 885 ft of net pay within a 4,000-ft gross interval, holding from 450 to 680 Bcf per section. With IRD, wells are completed in as much of the vertical sand interval as possible, averaging between four and five stimulation stages per well with about 200,000 lb of sand per stage on average. Production rates and reserves are much higher, averaging about 9 Bcf per well versus 5 Bcf per well in earlier shallower Fort Union only completions.


New ChevronTexaco Center of Research Excellence at CSM

In late 2003, the Colorado School of Mines (CSM) and ChevronTexaco announced plans to establish a new Center of Research Excellence (Center). The center will develop advanced technologies to improve interpretation of subsurface geology through computer modeling. ChevronTexaco will provide R&D funding to establish the Center of Research Excellence, which will draw upon expertise and resources within the CSM Department of Geology and Geological Engineering. The center will focus on developing integrated technologies.

ChevronTexaco employees will directly participate in the program and the company will provide real-world geological data from oil and gas fields from around the world. ChevronTexaco also plans to provide additional research investments as expanded programs develop with CSM. The center’s co-executive directors will be John Hebberger, research manager at ChevronTexaco Exploration and Production Technology Company, and Chuck Kluth, distinguished scientist at CSM.

Prior research centers or partnerships formed by ChevronTexaco and academia include the University of Tulsa (production fluid flow, December 2001) and the University of Southern California (interactive smart oilfield technologies, August 2003). PTTC takes pride in that two of its regional programs (Rocky Mountain and West Coast Regions) emanate from universities selected for Centers.


GeoScience World, Comprehensive Online Earth Science Resource

Six leading earth science societies and one institute are launching GeoScienceWorld (GSW), a comprehensive electronic research resource. GSW will deliver online the aggre-
Custom-Designed Bits Improve Drilling Performance

Two case studies, one a hardrock slimhole horizontal in New Mexico and a second North Texas vertical well, demonstrate how custom-designed bits can lower costs and improve drilling performance. In the slimhole horizontal example, high bit failures were being experienced in a section that was 70-90% chert. After several failures, RBI-Gearhart examined dull bits and failure modes. The gage-row area reflected insert breakage as the primary failure mode with the inner-row, flat-crested wear being a secondary mode. The solution involved a simple modification that changed the insert carbide grade and increased the insert count. New custom-designed bits were on bottom within six days. Rates of penetration in the chert were doubled, lowering the average cost per foot nearly 60%.

In North Texas, an operator wanted to improve drilling efficiency of a formation consisting of shale with chert stringers. Reviewing drilling histories of earlier wells in the area, RBI-Gearhart determined that three different bit types were required—one for the top, middle and bottom sections. Data were summarized for 14 wells drilled with the same rig using off-the-shelf bit designs. An initial test well using that rig and off-the-shelf bit designs duplicated results from the 14 well sample. On the second well, a custom-designed bit for the upper section lowered costs per foot in that section by 20%. In the third well, a custom-designed bit for the middle section lowered costs per foot in that section by 37%. These formation-specific bits and a third slightly modified bit for the bottom section were used in the fourth and final well. Average cost per foot, compared to the original 14 wells, was lowered by 28%. The overall custom design project took 45 days, but benefits will be realized in many wells yet to be drilled.


California Effort Reducing Operating Costs

Global Energy Partners, LLC (GEP), with $1.7 million of funding support through the California Public Utilities Commission (CPUC), has been working for the last 18 months with small independent producers in an energy efficiency program for small independents in Southern California. PTTC’s West Coast Region has been supporting with technology transfer. Both were involved in an earlier study that identified the energy saving opportunities and led to the CPUC funding.

The program provides incentives such as free energy consumption audits for qualified wells, training and incentives totaling up to 50% of the installation cost of qualified energy efficiency measures. Program funds have been committed and field visits are underway to gather data confirming the savings achieved. In a nutshell, the program worked. Following the systematic analysis procedure offered by GEP, the results thus far have indicated that the operators are able to recoup their limited investments in just a few months and can enjoy substantial savings in their operating cost. Power consumption has/will be influenced on more than 200 wells. Achieved power savings in kW and kWh exceeded planning expectations by 21% and 39% respectively.

The program uses a systems approach to diagnose problems and savings possible with different solutions. Energy efficiency measures employed have included pump-off controllers, variable frequency drives, load balancing on rod pumps, proper sizing of water injection pumps, variable frequency prime movers, optimization of fluid cooling systems and premium efficiency motors. GEP has developed a template that enables producers to quickly determine potential impacts.

Results are being shared in a May 27th PTTC workshop in Los Angeles (see calendar, p. 15). This workshop will also be webcast so producers across the country can hear the case studies and gain insights first hand.

Information about this project is available online at www.cutopex.com, or contact Mark Reedy at GEP, E-mail mreedy@gepllc.com or phone 925-284-3780.

New Depth Record for U.S.

In the Gulf of Mexico, Chevron Texaco and Schlumberger Oilfield Services achieved a new U.S. depth record, reaching 31,824 ft true vertical depth in the Tonga 1, Green Canyon Block 727. New records were set for pressure (26,138 psi) and measurement-while-drilling (MWD) and logging-while-drilling (LWD) depths. Schlumberger delivered continuous real-time surveys, allowing the well trajectory to be kept on target throughout the entire logging/drilling process. Drilling was conducted from Transocean’s Discoverer Deep Seas drillship.

Editors Note: In the trivia question in its Feb 25 E-mail Tech Alert, PTTC noted that the Bertha Rogers #1, Oklahoma, had the U.S. depth record. That was true until the Tonga 1, as an informed reader pointed out. PTTC apologizes for that prior error.

Excerpted from World Oil column, Drilling Advances, February 2004, p. 17.

Deepwater/Deep Shelf Technology Needs Assessment

Gulf Research, a subsidiary of Gulf Publishing, recently released its “2003 Deepwater/Deep Shelf Technology Needs Assessment” study. More than 200 individuals in exploration, drilling, completions and production job functions were interviewed. Results reveal how industry prioritizes over 60 major technical needs in the deepwater environment.

Interested subscribers should contact Lanie Finlayson, E-mail lanie.finlayson@gulfresearch.com.
Hart’s 2003 Meritorious Engineering Awards

Hart’s E&P recently announced winners of the “2003 Meritorious Awards for Engineering Innovation.” The award program recognizes new products and technologies that offer innovation in concept, design and application. Winning entries represent techniques and technologies that are most likely to solve costly problems and improve exploration, drilling production efficiency and profitability. Twenty one experts representing a broad industry spectrum reviewed industry nominations to select the winners. The 14 winning products or technologies address diverse problems.

- Si-Flex Accelerator by Input/Output
- VectorSeis System Four VR by Input/Output
- GeoTap Formation Testing Service by Halliburton, Sperry-Sun
- Score 100 Coring by Corpro Systems, Ltd.
- Expandable Drill Bit “Xpandabit” by Weatherford International Inc.
- Accolade Drilling Fluid System by Halliburton Energy Services Inc.
- Trapped Pressure Compensator by Nam/Halliburton
- Digital Hydraulics by Well Dynamics
- C-TECH “Precision Strength” Syntactic Foam by Cuming Corp.
- Fiber Optic In-Well Seismic System by Weatherford Completion Systems
- BJ Python Composite Bridge Plug by BJ Services Co.
- GoFlo by Subsea 7/Halliburton
- RamPump by Weatherford Artificial Lift
- Deepwater Sulfate Removal by Marathon Oil Co.


Well Service Rigs Entering Information Age

Key Energy Services unveiled it KeyView™ rig instrumentation package last fall. Rigs are first being deployed in the Permian Basin, followed by California with other regions to follow. The initial deployment will cover about 25% of their fleet, ultimately working towards 100% coverage. The system monitors equipment, rig operations and activity. Computer systems capture vital information from sensors and encoders strategically placed on the rig. Captured data are transmitted from remote locations to a central database where they are available through a secure website.

Real time notification of safety incidences, such as toxic levels of gases around the well site, allows for quick response that can resolve incidences before they escalate. The system measures torque on rod makeup, which properly done can eliminate many failures. Operational information, such as oil pressure, running time, and various fluid levels, can be collected. Examination of historical data can reveal bottlenecks, either human or equipment, which can be addressed.

Setup is relatively simple and the system is fairly easy to learn. Training helps operators know how to record exceptions so the system can be leveraged to identify ways of improving efficiency.


An LNG Focus at Offshore Technology Conference

With the natural gas supply situation, Liquified Natural Gas (LNG) is receiving increased attention, from producers whose prices for natural gas may have a ceiling influenced by what it really costs to bring LNG to the U.S. and especially for those planning to be involved in LNG importing. Offshore terminals will be part of the picture, and the 2004 Offshore Technology Conference in Houston, May 3-6, recognizes that and has developed three LNG-related sessions.

- General Session, Tue., May 4, 2-4:30 pm: Liquefied Natural Gas—Understanding the Value Chain. Participants will discuss upstream operations; LNG processing; transportation, regasification and distribution. They will also address market forces and regional supply and demand requirements.
- Tech Session, Mon., May 3, 9-30 am to noon: LNG and CNG Facilities and Handling
- Tech Session, Mon., May 3, 2 to 4:30 pm: Designing for LNG Terminals


SEG Visa Invitation Process

Nowadays, attendees from foreign countries attending a conference in the U.S. may need months to obtain a visa. Recognizing this need, the Society of Exploration Geophysicists (SEG) has developed a process through their website (www.seg.org) to generate an official invitation letter. SEG recognized the need since 27% of annual meeting attendees historically have come from outside the U.S. This year, SEG’s annual meeting is from Oct. 10-15 in Denver, Colorado.

New Option for Production Logging in Deviated/Horizontal Wells

Early production logging tools for deviated/horizontal wells simply strung together tools used in vertical wells. Considering how multiple phases flow in deviated/horizontal sections, there were technical limitations and tools were long. For example, Schlumberger’s early Flagship Platform tool was about 100 ft long, which was an operational drawback. Additionally, because tools were long, sensors might be in different flow regimes, which presented interpretation problems.

The result of years of research, Schlumberger’s new FloScan Imager for production logging in deviated/horizontal wells has at its heart miniaturized spinners and optical and electrical probes. The simplicity of electrical probes is attractive—in water they work, in oil they don’t. When used in conjunction with optical probes to look at the difference in gas and liquid holdup, one gets a true three-phase holdup measurement. And that is achieved at the same depth by deploying the sensors on an arm across the wellbore once the tools are deployed. Importantly, the tool is only 30 ft long.

The tool has a typical production logging tool diameter of 1-11/16 in and can log holes from 2 7/8-in to almost 11 in open hole. It is rated for conditions of 15,000 psi and 150 degrees C. On test in international applications, the tool is slated for commercialization during spring 2004.

Unconventional Energy in the Southern Midcontinent
by Dylan Powell, houstonwriter.com on PTTC’s behalf

"Nothing great was ever achieved without enthusiasm," noted Ralph Waldo Emerson. With enthusiasm as the measure, numerous speakers involved in unconventional energy and 345 energetic participants at the recent Unconventional Energy Resources in the Southern Midcontinent conference portend further significant growth for unconventional energy from shale, coalbed methane and tight gas sands. Insights from hundreds of millions of dollars of project experience were revealed, which accelerated progress in the remaining learning curve. The event was organized by the Oklahoma Geological Survey, with special compliments to Brian Cardott, and co-sponsored by the U.S. Department of Energy’s National Energy Technology Laboratory and PTTC’s South Midcontinent Region.

Unconventional Energy for an Unconventional Future

A recent National Petroleum Council study points out that increasing natural-gas-supply diversity is a serious national issue. Our current energy landscape forewarns a strong dependence on increasing unconventional gas production in the lower 48 and Canada. As David Fleischaker, Oklahoma Secretary of Energy and the conference’s lunch speaker, points out, "Non-conventional fuels will play an important role in the short- to mid-term—serving as an essential bridge until the time that we increase imports by building a pipeline to the North Slope and increasing our Liquified Natural Gas imports."

The Newark East Barnett Shale field, the largest active gas field in Texas, now produces more than 220 Bcf of natural gas per year. Unconventional energy resources in Oklahoma include Hunton de-watering and coalbed methane (CBM) activity in the Arkoma and Cherokee basins. According to Cardott, CBM activity in Oklahoma’s Arkoma Basin produced about 70 Bcf of gas cumulatively through mid-2003. About two-thirds of this production is from vertical wells, but horizontal production is rapidly overtaking that from vertical. Cherokee Basin CBM cumulative production is about 45 Bcf, all from vertical wells. CBM wells in southeast Kansas are now producing about 10 Bcf per year, and activity is strong. Arkansas CBM production is just now taking off.

Barnett Shale Ignites Imagination

As Jeff Hall, Manager of Exploration and Exploitation with Devon Energy, pointed out during his presentation, the Barnett Shale is still one of the most exciting discoveries around. With its first completion in 1981, the Barnett isn’t a secret. Estimated resources are as high as 140 Bcf per square mile across its 54,000 square miles. Though about 2,500 wells have been drilled in this field, there is a lot of action forthcoming. Devon, who operates about 60 percent of the wells in the field, estimates that recovery from conventional vertical wells will be 10 to 12 percent, with an additional 5 to 10 percent from re-fracs and additional production enhancements. That leaves 80 percent of gas-in-place for innovative thinkers who can successfully leverage new technology!

About 60 companies currently work the play. Its strong activity stems from evolving Barnett stimulation knowledge, including re-fracing and horizontal drilling. Progressive Barnett Shale developers, armed with frac mapping and tiltmeter technology, noticed that as their wells produced for a few years, the rock stress environment changed. When it was re-fractured, orientation of the new fractures was different from the original fractures.

Because the Mississippian-age Barnett is so tight, and its drainage area so limited, even a minor re-orientation of frac fractures essentially opened up a new reservoir to production. It is similar to getting a whole new well at times. Currently, most well workovers involve re-fracing the Lower Barnett with better frac technology and adding Upper Barnett perforations. About two-thirds of the production increase and reserves observed in re-fracture treatment completions come from the Lower Barnett. Although the first series of re-fracs have proven profitable, none of the wells are mature enough to test the potential of additional rounds of re-fracing.

When one considers shale, one typically thinks of natural fracturing delivering increased recovery. Not in the Barnett, where fractures are not as important as thermal maturity. Given the optimum thermal maturity, the Barnett Shale becomes a stimulation technology play. "Technology is going to extend the play beyond its core area," noted Devon’s Hall. The play also has surface access challenges, with the subdivision and strip-mall laden Dallas-Fort Worth suburbs sprawling just above the action.

Stimulation considerations led to the current trend of horizontal wells. In the heart of the play, Ordovician tight limestone provides barriers to keep the large frac treatments in...
the Barnett. Moving westward, this lower frac barrier disappears. Moving southward, both its upper and lower frac barriers disappear. Horizontal wells where frac barriers are absent are said to stand the best chance of staying in zone. And they are being oriented according to prevailing stress orientations that run southwest to northeast.

Over time, will re-fracing the Upper Barnett create similar reorientations as experienced in the Lower Barnett? For either, would a second re-frac after an extended production period create yet another frac orientation that would give production an economic boost? Stay tuned. "When I went to school at Oklahoma State University and took geology," noted conference presenter Kent Bowker with Star of Texas Energy Services, "we did not discuss this rock as a reservoir rock. We have to re-educate ourselves and try to understand how we can take what we learn from the Barnett and apply it to other basins."

**Woodford Shale: Decades of Potential**

If it took 15 to 20 years to realize significant value from the Barnett Shale, our goal with the Woodford Shale is to half the Barnett’s learning curve—even if the Woodford doesn’t become as significant a reservoir as the Barnett has. The prime area for this Upper Devonian/Lower Mississippian shale’s gas potential lies just a couple hundred miles north of the Barnett Shale, but it is considered to be where the Barnett Shale was 15 to 20 years ago and gas wells have not yet proliferated. Current Woodford Shale production stands at 24 Woodford-only gas leases and 48 Woodford-only oil leases (oil and associated gas). Cumulative production may be minimal, but the resource potential is large.

Many questions remain about how to turn Woodford Shale gas-resource potential into production. As in the Barnett, will thermal maturity combined with stimulation technology be the keys to economic production? Or will it be natural fracturing? Or will it be something else entirely? Coalbed-methane researchers have developed a six-element producibility model. Will that model or a modification thereof help operators unlock the secret to shale gas reservoirs such as the Woodford?

**Midcontinent Coalbed Methane**


Cherokee Basin production, which with a few exceptions comes from vertical wells, is now about 11 Bcf per year in northeast Oklahoma and 10 Bcf per year in southeast Kansas. In the Oklahoma side of the Arkoma Basin, production from horizontal-well completions has now exceeded that from vertical wells-around 12 Bcf per year versus 8 Bcf per year from vertical wells. CBM activity in Arkansas is embryonic, limited almost exclusively to horizontal wells in the Lower Hartshorne coal.

When it comes to Midcontinent CBM, what we know depends on where we are. In Kansas, there is a strong focus on CBM resource definition, including looking further north into the Forest City Basin. The Kansas Geological Survey has developed isopach maps for different coals and is developing depositional interpretations that will turn them into treasure maps. Understanding gas content is still critical in Kansas. Limited sampling indicates that it can be quite variable. Contrary to logic, some of the shallower coals can have higher gas content!

"The Western Interior Coal Region is vast, located in six states and 87,000 square miles," commented Simon Testa, who summarized some of his results gathered by TICORA Geosciences, Inc. for a three-year study on frontier basin resource and production potential sponsored by the Gas Technology Institute. "Our sample density was low. But you’ll be amazed at some of the regression that we’ve found across the general region." An interpretative framework is developing to explain observed gas content trends for the study, which is schedule to be completed in August.

And then there’s Arkansas. Because of its nascence, resource definition is paramount to its Arkoma Basin activity. According to Bill Prior with the Arkansas Geological Survey’s Coalbed Methane Project page at ogs.ou.edu/coal.htm, aside from general information about Oklahoma's coal resources, such as maps and stratigraphy, you can get links to coal rank and production data, details about activity in the Arkoma Basin and northeast Oklahoma shelf, and even a CBM completion histogram. The links section will get you to all major Oklahoma CBM data from national, government and academic sources. And don't forget the coal database, where you can search for CBM completions by county, bed, operator and other useful categories.

**Kansas**

Interested in the Western Interior Coal Region? A visit to the Kansas Geological Survey’s Coalbed Methane Project page at www.ks.usgs.gov/CM/index.html is a must. Links to Kansas and regional sites, plus nationwide and USGS endeavors alone make the site worth a look. But its real beauty is Kansas-specific reports, presentations and other information available for download. From stratigraphy reports to isopach maps to chemical analysis—there is a lot of good material. Some great PowerPoint presentations are there for the taking, too. Check back this fall to see the final results of the GTI study on which Simon Testa presented at the Oklahoma show!

**Arkansas**

With Arkansas unconventional gas production still short in the tooth, CBM public data resources are more limited than in other states. But it is a highly developed region conventionally, and the Arkansas Geological Commission offers a nice, comprehensive resource for Arkansas geology at www.state.ar.us/age/age.htm, which includes extensive research on stratigraphy, mineral resource estimates and maps, as well as links to a number of useful other resources. Also, the site offers an impressive list of maps and publications available for purchase.
Arkoma CBM Development: Horizontal or Vertical?

The Hartshorne coal in Oklahoma’s Arkoma Basin has been brought to profitable fruition both horizontally and vertically. And fans of both will find assurance. Horizontal completions will reach a higher peak rate sooner; but their initial decline is steeper. At the four-year point, horizontal wells will produce about two and a half times as much as a vertical well. Comparative ultimate recoveries are yet to be determined, but cost data shared by speakers indicated horizontal wells will cost from between two and a half to four times higher than their vertical counterparts. The perspective from which one approaches the problem influences the answer regarding injection falloff-testing to measure permeability. A vendor can do this, but the costs can add up. So Wendell built his own injection falloff-testing rig for roughly the cost of a single service job. It did not have leather seats and a sunroof, but it got him there; and it was a capital expenditure.

Artificial lift is generally required to keep water lifted off CBM wells. While conventional rod pumps are common, there are disadvantages: volume limitations; fines; maintenance costs, etc. Brian Weatherl of Source Rock Energy Partners discussed two increasingly popular alternatives. These include soap injection through capillary strings using gas-powered pumps and a simplified gas lift. Soap injection is cheaper than using rod pumps and lifts similar capacity. And it is maintenance-friendly. Using a simplified gas lift, setting a wellhead compressor and injecting gas back down the annulus, also has an economic advantage.

Great Things to be Achieved Unconventionally

The abundance of expertise in Oklahoma City created the kind of enthusiasm that multiplies. "I certainly enjoyed the presentations I saw that dealt with the Hartshorne coal and horizontal drilling. They were done well and I enjoyed being informed on horizontal drilling in the Arkoma Basin," notes conference attendee Ed Butler, who is in charge of engineering and planning for CDX Gas LLC. Butler agrees that this technology will be important over the long haul. John Dewey of Vintage Petroleum added: "I thought the conference was very good; it was informative, the papers were well done and the turn out was very good."

"I was very impressed with the technical presentations and the technical knowledge presented," noted Robert Gibson, one of three Questar Exploration and Production attendees at the conference. He continues: "Anybody that came could take something away—either an awestruck type of perspective of how much tight gas sands, coalbed methane and shale gas has contributed to increasing overall gas supply in the United States or, at a more microscopic level, a good understanding of the maturation process for these types of reserves. We’ve been producing these things since the turn of the last century. It’s becoming more and more a part of our domestic overall U.S. gas supply and its projected to increase even more over time."

For further information, contact Lance Cole at lcole@pttc.org. ✤
ConocoPhillips, Total E&P USA, partners include ChevronTexaco, in the deepwater Gulf of Mexico. JIP industry characterize naturally occurring gas hydrates effort involving industry, DOE and academia is one of the most technologically advanced be the recently renovated Fugro Explorer. It board scientific staff. The drilling vessel will organizing and leading the plan and ship - The Scripps Institute of Oceanography is selected sites. pretation of the geologic framework of the maps of gas hydrate indicators and an inter- researchers selected the drilling sites based on correlation and instrumentation. The researches selected the drilling sites based on maps of gas hydrate indicators and an interpretation of the geologic framework of the selected sites. The Scripps Institute of Oceanography is organizing and leading the plan and shipboard scientific staff. The drilling vessel will be the recently renovated Fugro Explorer. It is one of the most technologically advanced geotechnical drilling vessels now available and is capable of operating in water depths up to 10,000 ft. The effort is part of a 4-year collaborative effort involving industry, DOE and academia to develop technology and collect data to characterize naturally occurring gas hydrates in the deepwater Gulf of Mexico. JIP industry partners include ChevronTexaco, ConocoPhillips, Total E&P USA, Schlumberger, Halliburton Energy Services, the Minerals Management Service (Gulf of Mexico Region), the Japan National Oil Corporation, and India’s Reliance Industries. Academic collaborators include the Georgia Institute of Technology, the Scripps Institute of Oceanography, and Texas A&M University through the Joint Oceanographic Institute. Contact Gary Sames, DOE NETL E-mail SAMES@netl.doe.gov or phone 412-386-5067 for more information. DOE Receives Licensing Achievement Award DOE recently received the Licensing Achievement Award from the Licensing Executives Society U.S.A. and Canada (LES). The Licensing Achievement Award is the highest honor bestowed by LES, to recognize leading organizations that promote intellectual property commercialization through licensing. Prior recipients of the award are Stanford University, Pfizer, and IBM Corporation. Recognized for its outstanding technology developments with commercial potential, DOE operates a database of more than 1,500 patented inventions available for license. In presenting the award, LES acknowledged a recent DOE project, The Licensing Decision. This is a practical guide to licensing and technology commercialization designed for individuals and small businesses supported by the Department’s Inventions & Innovations Program. The Licensing Executives Society (U.S.A. & Canada), Inc. is a professional society comprised of over 5,500 members who are involved in the transfer, use, development, manufacture and marketing of intellectual property, including professionals in the field of law, academics, science government and the private sector. The full press release may be viewed online at www.usa-canada.les.org /press/archives/ doe.asp. Targeting ‘Sweet Spots’ in Fractured Reservoirs Geospectrum Inc., DOE’s National Energy Technology Laboratory, Burlington Resources Inc. and Huntington Energy L.L.C. worked together to select, drill and complete the Canyon Largo Unit #452 in the San Juan Basin, targeting fractured Lower Dakota sandstones. Geospectrum selected the well location using an innovative new methodology that combines seismic attribute analysis (including a special gas sensitive AVO attribute), petrophysical analysis, and production data analysis to target potential fracture sweet spots. All parties agreed to drill Geospectrum’s recommended site and Huntington Energy was brought in as a farm-out partner to handle the actual drilling and completion of the well. The well was drilled, logged and cased to a depth of 7590 feet on December 12-21, 2003. Two Lower Dakota sandstones were perforated, the Burro Canyon (7518-7524 feet) and the Encinal (7420-7455 feet), and both intervals had gas shows. Because of potential water problems in the Burro Canyon reservoir, the decision was made to produce from the shallower Encinal unit. The Encinal was isolated and fracture stimulated on January 14th, and it produced gas at an initial rate of 4 MMCFGPD. Production continues at 1.4 MMCFGPD at 175 psi, which appears to be one of the better wells in the Unit and a very good well for this part of the basin. Three additional wells have been permitted. The demonstrated methodology has application in many tight gas basins. For more information, contact DOE’s Frances Toro, E-mail TORO@netl.doe.gov or phone 304-285-4107 and/or GeoSpectrum’s Principal Investigator, Dr. James J. Reeves, E-mail jreeves@ geospectrum.com or phone 432-686-8626 Ext. 101. Reminder—Proposal Due Dates Proposal due dates are imminent for three DOE programs. If not already working on a proposal to compete for this federal funding, there is still time for the energetic. Take a look and see if there are opportunities for you. Advanced Diagnostics and Imaging (www.netl.doe.gov/business/solicit/index.html)— April 12 Focused Research in Federal Lands Access and Produced Water Management in Oil and Gas Exploration and Production (www.netl. doe.gov/business/solicit/index.html)—April 19 Stripper Well Consortium (www.energy.psu.edu/swc/)—April 27 (must be a member to submit a proposal).
DOE Announces Two More “Smart Drilling” Awards

DOE recently announced two new awards in its program to develop “smart drilling” technologies. Last fall, DOE had announced two other awards within this program (www.fe.doe.gov/news/techlines/03/tl_smartdrilling_2projects.html). Focus of the program is to advance performance when drilling for deep natural gas. “Smart drilling” options can increase productivity, improve drilling safety, and lower costs when drilling for these hard-to-reach deep gas supplies.

General Electric Global Research, Niskayuna, N.Y., will conduct a two-phase project to develop a revolutionary solid-state gamma ray detector for extended downhole gas and oil exploration in harsh environments. Projected benefits are: able to operate in temperatures as high as 200 degrees C, and at a 40 percent increase in operating depth over current technology; and it will have a higher immunity to shock and vibration, leading to a longer life downhole. Total funding = $1.51 million.

Pinnacle Technologies, Inc., San Francisco, Calif., will develop and test an advanced "hydraulic fracture mapping system." The new system will incorporate seismic sensors and tiltmeters, which detect and measure small changes in the earth’s surface. In addition to the new tool, Pinnacle will develop and test improved instrumentation to increase viewing distance and accuracy. These advancements will improve the quality of hydraulic fracture mapping results, reduce limits on the use of fracture mapping, and make the process more cost effective. Total funding = $1.51 million

More information is available in DOE’s techline www.netl.doe.gov/publications/TechNews/m_smart_drilling.html. "x

Low Volume, Submersible Diaphragm Pump Offered By Smith Lift

Smith Lift, LLC, a subsidiary of Smith International, Inc., has introduced a new submersible pump line, commercializing a pumping system developed by Pumping Solutions, Inc. with some funding support from DOE’s Stripper Well Consortium (see prior Network News article, 2nd Qtr 2003, www.pttc.org/tech_sum/ts_v92_11.htm). The pump is similar to conventional submersible centrifugal pumps, but uses a patented true positive displacement, diaphragm pumping unit to improve efficiency, handle solids and pump mixtures of gasses and liquids. The current pump design is 3 ¾ inches in diameter, 10 feet long and weighs less than 150 pounds. Versions of the pump are designed to produce 50 to 400 barrels of fluid per day from depths of up to 6000 feet.

The Smith Lift™ electrical submersible pump has been used to move a wide variety of fluids, from heavy oil to fresh water, under a wide variety of fluid conditions, including up to 2 percent sand/coal fines, gassy fluids, and high H2S/CO2. This new pump is constructed of stainless steel and is installed similarly to a conventional submersible centrifugal pump. The operator can accomplish chemical treatments, such as acidizing and paraffin solvents, with the pump in place. The pump typically consumes about one-third of the power required to drive a conventional rod or centrifugal pump, and due to the ability to pump off, more fluid production is typically achieved, especially in high gas situations.

For more information, please contact Smith Lift at 505-239-4655.<Void>

Alaskan Gas Hydrate Well, No Hydrate But Wealth of Information

Hot Ice No. 1, the first dedicated gas hydrate well in Alaska (see Network News, 1st Qtr 2003, www.pttc.org/news/1qtr2003/v9n1p11.htm#4), did not encounter methane hydrate as expected, but it did prove out several technologies and produce information that should contribute to future commercial production. The Hot Ice No. 1 well was drilled as part of a two-year cost-shared partnership between the U.S. Department of Energy’s Office of Fossil Energy, Anadarko Petroleum Corp., Maurer Technology Inc. and Noble Engineering and Development.

Although spudded in spring 2003, Hot Ice No. 1, located just south of the Kuparuk River field, was not completed until early 2004 because 2003 drilling operations had to be terminated because of warming weather. On February 7, 2004, the well reached its planned total depth of 2,300 feet, about 300 feet below the zone where temperature and pressure conditions would theoretically per-
Cromwell Play In Southeastern Oklahoma

Late 2003 in Norman, Oklahoma City, Tulsa, OK. Co-sponsored by PTTC’s South Midcontinent Region; Oklahoma Geological Survey; Oklahoma City Geological Society and Tulsa Geological Society

PROBLEM ADDRESSED

The Cromwell play was originally an oil play starting in the early 1900s. Recently it has become a major gas play with less potential from oil development. The large Cromwell fields located in the Arkoma Basin of Oklahoma and extending into the Arbuckle fields located in the Arkoma Basin of Southeastern Oklahoma.

BOTTOM LINE

A key to understanding the Cromwell is the updated stratigraphic interpretation and nomenclature presented in the workshop. Correlation of the subsurface Cromwell sandstone to surface rocks defined as Morrow has aided construction of regional cross sections that assist in delineating the Cromwell play. This study of the Cromwell is the final workshop in a series analyzing the widespread Morrowan reservoirs in Oklahoma.

PTTC has been fortunate in that many individuals have stayed engaged with PTTC for several years. Their dedication deserves special recognition for long-term service and unselfish participation. PTTC posed two questions to each of them to tap into the insights they have gained from their long-term experience in domestic oil and natural gas production. These gentlemen include:

- David Boneau
  Southwest Region PAG Chairman
- Mike Gatens
  SPE Representative
- Jay Haskell
  Service Company Representative
- Brian Sims, Vice Chairman
  Eastern Gulf PAG Chairman

What is the biggest technology-related challenge facing U.S. independents?

**Boneau:** The drilling targets in the U.S. are small and hard to find. We need (a) a very much cheaper drilling method and/or (b) very much better seismic or some substitute that can see thin zones and can see hydrocarbons.

**Gatens:** Access to advanced technologies and skilled personnel to employ them. As reservoirs get tougher to find and/or produce in our mature domestic basins, such as unconventional gas (CBM, tight sands, ...), top technical personnel are essential. We need to ensure continued training of our domestic talent, at universities and through on-the-job experience and courses. PTTC has a role to play here.

**Haskell:** Cost-effective water management from gas wells loading with water to declining oil wells with increasing water production. Water management will be the key to extending the economic life of many mature U.S. wells. There has been limited R&D addressing this and more research and new technology will be required to make a difference.

**Sims:** A major concern is data availability/ preservation, especially considering today's acquisition and consolidation trend. Data can help get discovery wells drilled, or keep unnecessary wells from being drilled. Other key needs are for technologies to identify smaller reservoir targets and faster drilling techniques to lower development costs. The more wells we can drill, the more oil and gas we can find.

Knowing PTTC’s mission, its evolution and what it is now, what would you most like to see PTTC do to increase its impact? Impact is defined as independents running with technology-related information they receive through PTTC, making decisions and taking action that increases production and recovery?

**Boneau:** I continue to believe that PTTC needs smart people who actually go to the office of independents and work directly with them on the best technology for independent’s needs. I realize this is extremely difficult and very costly.

**Gatens:** PTTC should continue and expand upon its various outreach programs, including workshops, one-on-one operator meetings, and collaborative efforts with groups like AAPG, DOE, SEG, SPE and others. Stay in touch with domestic independents to focus on delivering the technologies they want and need now.

**Haskell:** PTTC has done an excellent job of disseminating best practices through workshops. The workshops could be expanded in scope to obtain solutions to field- or operator-specific problems in conjunction with relevant technology providers. These would be results-oriented workshops with the objective to deliver more hydrocarbon or reduced operating expense in order to extend field life.

**Sims:** PTTC has not only increased the effectiveness of the exploration dollar but also of the technology transfer dollar. People who are not normally exposed to technology transfer have benefited from the information that is available through PTTC’s workshops, website, and personal contact with staff and volunteers. Put simply, to increase impact, PTTC must reach out and expand the audience it serves.

PTTC values insights of its long-term stakeholders too. If you have insights you’d like to offer on the above questions, we welcome your comments at E-mail hq@pttc.org.
1st Quarter 2004 Case Studies
Petroleum Technology Digest

Internet Data Rooms Save Dollars,
Increase Marketing Efficiency

Bottom Line: Once a decision is made to
divest an oil and gas asset, timing is of
the essence to take advantage of opportunistic
market conditions or realize cash flow
quickly. The marketing objective is to get
relevant data to qualified prospects quick-
ly and efficiently. Lehman Brothers
employed Petris Technology, Inc.'s
Internet Data Room (IDR) software to
present data online for a 500-well Gulf of
Mexico/Louisiana divestiture. This
approach saved Lehman, the marketer,
and the seller more than 100 hr of time.
Savings in normal paper, copying and dis-
tribution costs incurred with a physical
data room offset the IDR costs.

Competition was enhanced, because each
prospective purchaser had an opportunity
to begin evaluating the package without
leaving his office. Each prospective pur-
chaser who reviewed the package saved
thousands of dollars and many hours by
being able to review it more efficiently.
IDR access history provided real-time
feedback to the marketer and its client
about the interest levels of prospective
purchasers.

Horizontal Waterflooding Increases
Injectivity and Accelerates Recovery

Bottom Line: Grand Resources is apply-
ing horizontal waterflooding in northeast
Oklahoma's Bartlesville Sandstone to
realize much higher injectivity, improved
sweep and accelerated recovery. The
combined effect should improve present
value (PV10) over five-fold, compared to
conventional vertical waterflooding.
Grand has successfully drilled an injec-
tion and two production wells using
short-radius drilling techniques. Real-time
learning and innovation proved effective
in controlling costs. Initial injection,
which is just now beginning, confirms
higher injectivity. More time, but not may
months, is needed to realize the oil pro-
duction response that simulation predicts.

Progressing Cavity Pumps, Insights
From 14 Years in a Southern
Oklahoma Waterflood

Bottom Line: Oak Resources, Inc. (Oak)
began employing progressing cavity
pumps (PCP) in the West Hewitt Penn
Sand Unit, a waterflood in southern
Oklahoma, in September 1988. Unit wells
produce 200 bfpd to 1,400 bfpd from
about 2100 ft. Initial PCP installation
costs were found to be 25% below those
of beam-pump units and electrical sub-
mersible pumps (ESPs). Electrical power
savings are 5% below beam-pumped units
and 35% below ESPs, for comparable
production rates. Through an evolution of
PCP configurations and designs, up to
a seven-year stator life is now expected,
with only minor repairs. Adjustable rates
at the surface, low capital costs, low
repair costs and high electrical efficiency
make PCPs attractive in this type applica-
tion.

Petroleum Technology Digest is a joint project of Gulf Publishing (World Oil) and PTTC. See case studies online at www.pttc.org/case_studies/case_studies.htm. Contact kcole@pttc.org.
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I hope to see you there!

Bruce Smith, 2004 GCPE Chairman
Denbury Resources, Inc.

Presented by Louisiana Independent Oil and Gas Association
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PTTC's low-cost regional workshops connect independent oil and gas producers with information about various upstream solutions. For information on the following events, that are sponsored or co-sponsored by PTTC, call the direct contact listed below or 1-888-THE-PTTC. Information also is available at www.pttc.org. Please note that some topics, dates, and locations listed are subject to change.

**April 2004**

4/1  Southwest: *Produced Water Management and Issues* - Farmington, NM. Contact: 505-835-5685
4/5  Central Gulf: *Drilling and Completion Technologies for Deep Shelf Gas* - New Orleans, LA. Contact: 225-578-4538
4/6  Rocky Mountain: *SMT Kingdom Suite, EarthPAK* - Golden, CO. Contact: 303-273-3107
4/7  Rocky Mountain: *SMT Kingdom Suite, VuPAK* - Golden, CO. Contact: 303-273-3107
4/14 South Midcontinent Lunch and Learn: *Why Shut The Well In, Already Got The Data* (Arkansas O&G Commission, SPE Ft. Smith) - Ft. Smith, AR. Contact: 405-325-3031
4/20 North & South Midcontinent: *Independents' Day @ SPE DOE IOR Symposium* (Marginal Well Commission, SPE) - Tulsa, OK. Contact: 918-241-5801

**May 2004**

5/2  Rocky Mountain: *Oil SPCC Plan Development for Oil Producers* (Horizontal Well and Petroleum Conference) - Minot, ND. Contact: 303-273-3107
5/3-7 Eastern Gulf: *International Coalbed Methane Symposium* (other sponsors) - Tuscaloosa, AL. Contact: 205-348-4319
5/19 South Midcontinent Lunch and Learn: *Optimized Gas Well Completions and Operations* (Arkansas O&G Commission, SPE Ft. Smith) - Ft. Smith, AR. Contact: 405-325-3031
5/27 West Coast: *Case Studies of Power Consumption Reduction in California Oilfields* - Los Angeles, CA. Contact: 213-740-8076
5/27 Appalachian: *Horizontal Drilling, A Technology Update for the Appalachian Basin* (Ohio O&G Association, Ohio Geological Society) - Cambridge, OH. Contact: 330-264-4454
5/27 Rocky Mountain: *Hydraulic Fracturing-Measurement, Characterization and Analysis* (SPE Casper) - Casper, WY. Contact: 303-273-3107

**June 2004**

6/13-18 Rocky Mountain: *Futures in Energy Student Training & Internship* - Golden, CO. Contact: 303-273-3107
6/15 Appalachian: *Introduction to GeoPlus PETRA* (Kentucky Geological Survey) - Lexington, KY. Contact: 304-293-2867 ext 5446
6/21-25 West Coast: *COMET Student Training & Internship* (USC) - Los Angeles, CA. Contact: 213-740-8076

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**Futures in Energy**
PTTC’s Rocky Mountain Region
June 13-18, 2004
Colorado School of Mines, Golden, CO
www.mines.edu/Research/PTTC/People/Futures/
Sandra Mark: Phone 303-273-3107

**COMET**
PTTC’s West Coast Region
June 21-25, 2004
Univ. of So. California, Los Angeles, CA
Iraj Ershaghi: Phone 213-740-0321
## PTTC's National Board of Directors

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<td>SEG</td>
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<td>ConocoPhillips</td>
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<td>ChevronTexaco</td>
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<td>Service Companies</td>
<td>Jay Haskell</td>
<td>Schlumberger Oilfield Services</td>
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<td>Regional Lead Orgs.</td>
<td>David Morse</td>
<td>Illinois Geological Survey</td>
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<tr>
<td>Executive Director</td>
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