



Appalachian Region

Timely, Informed Technology Decisions

Newsletter

Spring-Summer 2006

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FROM THE DIRECTOR’S DESK

It has been awhile - too long - since our last newsletter went on-line, and I apologize for the “lost issues.” We had a very busy winter and spring, and suddenly it was summer before I realized that I had missed an issue. Maybe two. So, here is our annual winter-spring issue, which we now present as a Spring-Summer edition.

The year began with our annual January PAG meeting, which was preceded by a thrilling victory for WVU over a fine Georgetown team that made it to the NCAA tournament. The next day PAG Chairman Rick Goings announced that we had

elected six members to 3-year terms, including two new member and four veterans. I would like to thank **Royal Watts** and **Charlie Burd** for their years of loyal service, and welcome new members **Jeremy Jacobs** and **Mark Leidecker** to the team. In addition, **Bill Goodwin**, **Bernie Miller**, **Leo Schrider** and **Roger Willis** re-enlisted for three more years.

PAG members also discussed various workshop options for 2006, some of which were holdovers from 2005, and others of which were new topics being considered for the first time. During

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this discussion, PAG members volunteered to be “Champions” for workshops dealing with certification of reserves, well control, re-entry and re-stimulation, stimulation imaging and effectiveness, mapping, reserves and economics software, and well safety. In addition, the PAG approved efforts to organize workshops on public oil and gas databases and websites, including data delivery systems, and a workshop on various shale plays.

Our 2006 workshop season kicked off with three workshops in May, beginning on the 16th with a workshop organized by PAG member **Steve Nance**, called “**Well Control 101.**” Safety was a point of emphasis for our PAG members, as subsequent workshops demonstrate quite clearly. One week later, **Matt Vavro** and SOOGA hosted a workshop in Marietta on “**Drilling and Completion Safety,**” and we have arranged for a workshop on “**Oilfield Explosives Safety**” to be held in September.

The third May workshop was held in the Lodge at Salt Fork State Park near Cambridge, Ohio on “**Drilling and Completion Technology Updates.**” PAG member **Greg Mason** teamed with **Dale Jennings** to identify and recruit speakers and make all arrangements for this workshop.

As the months continue to fly by, please check this PTTC website often for updates on additional workshops for 2006, including “**Introduction to ArcGIS Software**” July 27-28 in Lexington, KY; “**Natural Gas Engineering and Reserve Evaluation**” on August 15 in Morgantown; “**Designing and Forecasting Waterfloods using ReservoirGrail**” August 29th in Columbus; “**Stimulation Effectiveness and Imaging,**” September 13th in Pittsburgh; “**Acquisition & Divestiture Market in the U.S.,**” September 20th in Pittsburgh; and “**Oilfield Explosives Safety,**” September 27th in Morgantown.

Also, remember that two regional meetings of professional societies will be held in October. The **Eastern Section of the American Association of Petroleum Geologists** will hold their annual technical meeting in Buffalo, NY on October 7-11.

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The New York State Geological Association (NYSGA) is the local host for the meeting, and will offer field trips on the 7th and 8th. PTTC has arranged with national AAPG headquarters for a low-cost version of Richard Green’s workshop on “**Reservoir Engineering for Geologists**” on the 7th, and is negotiating for a workshop on “**Hydrothermal Dolomite Reservoirs**” to be held on the 11th.

The workshop on the 11th, unfortunately, overlaps with the first day of the **Eastern Regional meeting of the Society of Petroleum Engineers**. SPE will hold their annual technical meeting from the 11th through the 13th in Canton, OH, just a short drive from Buffalo, so do your best to support both of these fine technical meetings.

We have a lot of workshops planned, and would like to continue to bring more low-cost workshops to you through the DOE-funded PTTC program. Unfortunately, **all funding for oil and gas research programs in DOE currently is in peril**. The Administration did not recommend that any funds be provided for oil and gas research in DOE’s budget for FY2007, and the House Committee on Energy and Water essentially went along, eliminating all gas funding and recommending only a small amount dedicated to two specific projects in the oil program. Because PTTC is funded under the oil and gas programs, at this time we have to recognize the reality of the situation, which is that unless the Senate acts soon to restore oil and gas program funds to DOE, then in all likelihood our program will not continue, at least in its current form, after September 30th this year. So, if you believe that PTTC and other DOE funded oil and gas research programs have benefitted the basin in the past and should be continued, feel free to contact your Senators to let them know. Mail does not reach federal offices in DC for months, so consider delivering your letters by e-mail and fax, or just stopping by the Senators’ local office in your state, if it is convenient to do so.

Doug Patchen

RLO Director

Now Available: Detailed Surface Structural Geology Maps of the Burning Springs Anticline, Northwestern West Virginia

Philip L. Martin, retired Petroleum Geologist and Photogeologic Specialist, has announced the release of four additional 7.5' quadrangle surface structural geology maps located along the surface axis of the Burning Springs anticline. In his announcement, Martin notes that the Burning Springs anticline, the site of the first commercial development of oil in West Virginia (1859-60) and the site of the first pre-Cambrian basement exploratory well in the Appalachian basin (1955), extends north-south for more than 30 miles in northwestern West Virginia, through four 7.5' quadrangles and parts of four counties. From south to north these quadrangles are Burning Springs, Girta, Petroleum and Willow Island. Martin has mapped the surface structure in all of these quadrangles using the same photogeologic methods he applied to the fifty six quadrangles in Pennsylvania offered in previous announcements.

Although unlikely to approach the fervor of the early 1980's Devonian shale drilling boom on and east of the Burning Springs anticline, current high oil and gas prices and the advent of slant and horizontal drilling could revive interest in this fractured reservoir play. The maps offered by this

announcement should provide some insight into major faulting and ancillary fracture patterns associated with Upper, and possibly Middle, Devonian rocks in the anticline and flank areas. Structure in older rocks is complicated by detachment and thrust faulting with possible wedging, as well as normal and strike-slip faulting in Ordovician, Cambrian and basement rocks.

Structure on the maps is displayed at a fifty-foot contour interval using a prominent bench-forming sandstone near the top of the Pennsylvanian Conemaugh Formation as a datum. Much elevation control on the maps is interval-converted to this datum from six or eight other sandstones above and below the datum. All of these sandstone benches and hogbacks were readily stereo-traced on aerial photos by this experienced observer. The outcrop traces were then transferred from the photos onto 7.5' topographic maps. Elevations on, or converted to, the datum could then be established wherever an outcrop trace crossed a topographic contour. Contouring these data then produced the structural interpretation as presented on the final maps.

The Barnett Shale: a Useful Analog for the Appalachian Basin Devonian Shale Play?

BJ Services USA attempted to answer the above question with a series of three talks presented during a technical session that marked the beginning of the IOGA-WV winter meeting. Randy LaFollette led off with a presentation on "Lessons learned from the Barnett Shale applicable to the continuing development of the Devonian shale." He was followed by Dan Kendrick, who discussed a "Novel stimulation approach to fracturing the Devonian shale in the Big Sandy field of eastern

Kentucky," and Brian Beall's talk on "High quality foam fracturing with new pre-mixed fracturing slurry."

LaFollette, Manager of Applied GeoScience for BJ Services, described the geology and geography of the Barnett Shale play in the Fort Worth basin, and made these two key points: the Barnett Shale is a non-uniform reservoir, and in this play, operational practices matter!

More than 75,000 wells have been drilled in the Fort Worth basin, but only 4800 of these have tested or currently produce from the Barnett Shale in an irregular-shaped, generally north-south trend originally developed by Mitchell Energy. The Ellenberger Limestone underlies the Barnett Shale throughout the play trend, and because the Ellenberger is always wet, operators must avoid fracturing into it when they stimulate Barnett Shale wells. Fortunately, in part of the play, the Viola Limestone is present at the base of the Barnett Shale, providing a fracture barrier between the shale reservoir and the wet Ellenberger Limestone. In much of this same geographic area, a younger limestone, the Forrestburg Limestone, splits the Barnett Shale into an upper and a lower unit, and forms a fracture barrier between the two shale tongues. The Marble Limestone caps the Barnett Shale in the play area, and provides an upper fracture barrier for operators who stimulate Barnett Shale wells. An isopach map of the Barnett-Forrestburg combined interval indicates that the units thin to the west and southwest, and increase in thickness to more than 1000 feet to the northeast. Estimates of gas in place change as the gross interval thickness changes.

Maps of the first 6-month cumulative production from Barnett Shale wells indicate a fairly well-defined core area of the best vertical wells. This core area of best producing wells is in the southern part of the area where the Viola Limestone is present, near the southern pinchout. More detailed maps of cumulative production, even in the core area, indicate that there actually are two highly productive areas, separated by a linear, less-productive area in which a fault has been interpreted. Thus, the reservoir quality changes even over the best productive area.

Oil as well as gas is produced in the Barnett Shale play, and generally in an inverse relationship. The best gas areas are the poorest oil areas, and the poorer gas areas are the better oil areas. Water also is a problem, with the better gas areas containing less water. These production sweet spots appear to be controlled by several factors, including: natural fractures; fracture barriers, like the Viola

Limestone; faults; Ellenberger karsting; Barnett Shale oiliness; and the water to gas ratio.

Approximately 800 of the 4800 wells that have tested the Barnett Shale in the play area were drilled horizontally. Sweet spots encountered by these horizontal wells occur in the same geographic area as the sweet spots encountered by the vertical wells, and also in places outside the vertical well sweet spot area, typically to the south. Because this area to the south is near or even beyond the edge of the Viola Limestone, which provides a fracture barrier between the Barnett Shale and wet Ellenberger Limestone, operators must take care to avoid fracturing into Ellenberger water, and this is easier to do with horizontal wells.

When production is compared to the azimuth and length of horizontal well legs, two best-well trends are apparent, roughly 180 degrees apart, but the best wells are not always the longest wells. Natural fractures typically trend northwest-southeast in a narrow fairway. Induced fractures typically occur in a broad northeast-southwest fairway, about 90 degrees to the natural fracture trend. The better horizontal wells are approximately parallel to the natural fracture trend, and the induced fracture orientation is perpendicular to the well bore and to the natural fracture trend in these wells. Operators have found that drilling the horizontal wells slightly uphill from the heel to the toe allows liquid to flow from the toe to the heel from where they can be removed.

Operators have tried a variety of fracturing fluids, including slick water; water-based gels and cross-linked gels; gelled oil; surfactant gels; and energized fluid and foams. They also have tested a variety of proppants, including ultra-light weight proppant (ULWP); sand and RP sand; ISP and RC ISP; and bauxite. The key appears to be to match proppant crush resistance to closure stress. Particle size also is important, as smaller particles can be carried further along a fracture and can enter a smaller diameter induced crack in the reservoir rock.

All of the horizontal wells that currently are being drilled are being fractured. Some operators

have experimented with drilling their horizontal wells in two, perpendicular directions, and the results are clear: the better wells are those that are drilled parallel to the natural fracture system, not perpendicular to the natural fracture set. Induced fractures in these wells can then encounter other natural fractures parallel to the well bore.

Dan Kendrick stated at the outset that some of the characteristics of the Barnett Shale are similar to those of the Devonian shales in the Appalachian basin. The rest of his talk, however, was focused on designing effective frac jobs in the Devonian shale of eastern Kentucky, beginning with a description of the shales encountered and what drives effective frac length when they are fractured.

The Devonian shale section in eastern Kentucky is dominated by black to black-gray shales that have been intensely fractured, yet matrix permeability is low to very low. The main fracture set trends northeast-southwest, with a minor set perpendicular to the main set. Therefore, a well-designed frac job can connect both of these natural fracture sets to the well bore. The goal then is to design a job that will carry a higher percentage of proppant to the end of the fracture, and slow the flow down enough that it can carry the proppant “around the corner” from one fracture set into the intersecting, perpendicular set. Nitrogen fracs have

been popular and somewhat effective, according to Kendrick, in some areas. The same can be said for conventional proppant which is carried by a nitrogen foam, although cleanup is a problem and logistics are a challenge, just to get all the equipment to some of the locations. The conventional job in Big Sandy field is designed in two stages, the Lower Huron in one stage, the Upper Huron, Cleveland Shale and Berea in the second stage, and the volume of the job appears to be the key.

BJ Services has pumped 31 jobs to date using Lite Prop 125, which features low proppant concentrations, lower frac fluid requirements, effective frac half lengths and more volume than the conventional treatments that have been used in the area. Results to date have been encouraging, especially when comparing first six month production between offset wells. Frac cost is reduced, a smaller footprint is required, dozer time is reduced, and overall frac to in-line cycle time is reduced. Kendrick concluded that proppant-laden stimulations are economic in this area, that Lite Prop 125 results compare favorably with conventional frac jobs, and cost also is comparable between the two technologies, especially when you take into consideration every cost involved, and the money that is saved in other areas, such as reduced dozer time and water handling.

New Microhole Coiled Tubing Trend in Drilling Shale Wells

Clay Terry (Halliburton Energy Services) presented a discussion of “Coiled Tubing Drilling - Microholes” to attendees at the IOGA-WV technical meeting in Charleston, WV. According to Terry, coiled tubing represents a new trend in drilling shale wells, and microhole coiled tubing drilling offers several advantages that should be considered. This drilling technology reduces well cost by reducing hole size, and with that, reduced mobilization and site preparation costs, demobilization costs, and pipe handling time and cost, while increasing safety, decreasing environmental impact, improving well bore transmissivity and reservoir deliverability.

Halliburton, with their project partners, Advanced Drilling Technologies and Rosewood Resources, tested the microhole coiled tubing drilling technology in the Niobara gas play of northeast Colorado and northwest Kansas. The rig they used was capable of drilling to a depth of 5000 ft, more than adequate for the 2500 ft maximum depths of these wells. The rig employs a zero discharge mud system and can drill to total depth, run casing and cement the casing in the hole.

The Niobara Formation is characterized by high porosity but low permeability, and produces biogenic gas from under pressured reservoirs that

require stimulation to be productive. This is an old play, discovered in 1912, that really did not see much activity until a surge in drilling occurred during the 1980s. Production in 1994 was 10 Bcf, but increased to 20 Bcf in 2004.

The complete assemblage can be transported to the well site on three vehicles: a tractor-trailer carrying the rig, a second trailer with the dog house, and a third trailer with the mud tanks. All of this can fit on a 70' by 50' well site that does not require mud pits, so surface disturbance is kept to a minimum. Rig up time typically is one hour, with another hour to pick up the bottom hole assemblage, and three hours to drill to 1200 feet, the normal depth of wells in the Niobara. After circulating for 10 minutes, logs are run in approximately two

hours, with another three and a half hours required to case and cement. One final hour is required to rig down and depart. Drilling rates are in the 250 to 350 ft/hr range, but have been shown to increase over time, from well to well, as the four to five rig hands, all that are required to operate this rig, gained experience.

This technology has gained a wider acceptance in Canada than it has in the United States. In the US, operators considering this technology have expressed concerns with production problems associated with water handling, their ability to complete wells, and their ability to plug and abandon slim holes. Experience to date has resolved some of their concerns.

More Barnett Shale: A Re-occurring Topic for Presentations in the Basin

The Barnett Shale continues to hold the attention of the industry across the nation, even among those who confess that they have never been involved in the play. In spite of this lack of activity among them, the Barnett play intrigues them to the point that they continue to turn out to listen to local and regional experts expound on the play.

Joe Frantz, Schlumberger Pittsburgh, is one of these local experts, a person who has worked not only the Barnett Shale play, but numerous other plays across the U.S. as well, such as the Floyd Shale, Woodford Shale, Carney Shale and Fayetteville Shale in the Gulf Coast region and mid-continent, and the Antrim, New Albany and Huron closer to home in the Michigan, Illinois and Appalachian basins. At the March combined meeting of the Pittsburgh Chapter of the Society of Petroleum Engineers and the Pittsburgh Association of Petroleum Geologists, he presented a talk on **“Evaluating Barnett Shale Production Using an Integrated Approach.”** The main purpose of the talk was to present the results of using a shale-specific, finite-difference reservoir simulation model to history match and forecast production from the Barnett Shale reservoirs in the play. The

model was applied to both vertical and horizontal well data, and was used to determine gas in place, recovery factor, optimal well spacing, drainage area and shape, optimal fracture half-length and conductivity, infill evaluations, horizontal well modeling and optimal number of stimulation treatments, analysis of microseismic data and compression evaluations. The main objective is to develop a technique to better evaluate a shale reservoir. Their approach was to integrate a variety of data and ultimately provide a predictive tool that will drive well location and development strategy and optimize stimulation success.

In 2000, there were approximately 750 vertical wells and only 4 horizontal wells in the play. But, by 2004 the play had exploded, with more than 3400 vertical wells and approximately 300 horizontal wells that pushed the play to the south and west. Cumulative daily production from these wells was about 3 Bcf. The main pay zone is in the Lower Barnett Shale, which is separated from the Upper Barnett Shale by the Forestburg Limestone. Where the Viola Limestone is present below the lower shale zone it creates a fracture barrier; where the Viola is absent to the south,

induced fractures can extend into underlying, water-saturated zones which should be avoided when completing these wells. In the early 1990s, operators tried cross-link gel fracs, then went to foam fracs, and now are using water fracs. The water fracs appear to be better, allowing more fluid to be pumped and multiple vertical fractures to be produced. An oil leg is present updip, with the highest Btu gas downdip.

In plots of production versus time, data for more than 200 horizontal wells initially plot on top of data from more than 2700 vertical wells. After two years on line, a slight divergence in the data sets appears, and after five years, the divergence between production values for horizontal and vertical wells is greater. Everywhere in the play the horizontal wells are better than vertical wells,

usually by a 3 to 1 or 4 to 1 ratio. The average increase for the entire data set is 3.8 to one, horizontal to vertical. The typical wells now cost approximately \$750,000 for a vertical well and \$1.5 to \$2.0 million for a horizontal well with a 3500 foot reach. The typical horizontal well is drilled perpendicular to the maximum stress direction to optimize the ability to induce a fracture and prop it open.

The integrated evaluation approach presented in this talk combines all data from cores, calibrated logs, natural fracture evaluation, pre-fracture well tests, reservoir evaluation, and completion and stimulation design to create a model. The final model is calibrated once wells go on line and actual production data are available.

Drilling and Completion Technology Update Workshop Held at Salt Fork Lodge

Microhole and coiled tubing drilling, as well as other applications and new methods to stimulate, image, log and complete wells in old reservoirs, were the subjects of presentations made at a joint PTTC-Ohio Geological Society workshop held May 31st at the Salt Fork State Park Lodge near Cambridge, Ohio.

Dwight Rychel (PTTC, Tulsa) began the workshop with an overview of the development of coiled tubing drilling technology, the growth in the number of units now in operation, current applications and potential other uses, the key players in the technology, and the advantages offered by the technology. In his abstract, Rychel noted that the use of coiled tubing became common in the 1970s, but was primarily for well clean-out operations. Subsequent improvements in tubing, rigs and downhole equipment led to increase use of coiled tubing. Drilling began in the late 1970s, but was not economic until the 1990s. Although the technology has spread world wide, in North America three distinct areas of operation, each with different technologies, have emerged: Alaska, Alberta and shallow drilling and reentry for horizontal laterals in the lower 48. Canada is the

leading edge of grass roots drilling with specific equipment, resulting in a boom that has seen a growth in this technology from approximately 1000 wells in 2003 to more than 5000 wells in 2005. Currently, R&D programs are developing smaller diameter tools to drill smaller holes.

Kent Perry (Institute of Gas Technology, Chicago) followed with a discussion of microhole coiled tubing drilling that reviewed the results of field tests conducted on 25 project wells in the Niobrara gas play in Nebraska and Colorado. The objective of the project was to determine rig performance under actual drilling conditions. The rig in question has been operating for approximately one year drilling wells for Rosewood Resources, Inc. Rig performance (i.e., Rate Of Penetration) has improved to the point that now a 3100 foot well can be drilled in a single day, and the next morning the rig is set up on a new location. The cost of drilling these wells has been reduced by 30% relative to rotary drilling, and well performance has improved, mainly because faster drilling reduces formation exposure to drilling fluids, and thus, formation damage is reduced. The speaker estimates that as many as 452,625 shallow (<5000

ft) Appalachian basin wells could be drilled with this technology, with a cumulative resource base of 47.75 Tcf. At present there are no rigs in the basin, but a license has been issued to one company.

John Purcell (Integrated Production Services, Houston) discussed coiled tubing re-entry for tight gas in a 10-well program in the Texas panhandle in the Fall of 2005. Challenges that had to be overcome included locating adequate surface equipment, rig-up time and mobilization problems. The objective of the project was to drill single laterals from existing vertical wells using proven North Slope technology, but using equipment available in the local geographic area. In the words of the speaker, the first well "was a disaster," wells 2 and 3 experienced casing problems, and wells 4 through 10 resulted in only 3 successful well completions. However, those three wells paid for the entire 10-well program. The speaker concluded that now they know how to drill these wells, so a new team is being formed for a second project.

Don McClatchie's (BJ Services) presentation was on expanding the envelope of coiled tubing drilling. He focused on three main areas where the technology is being applied and expanded: horizontal wells in Alaska; horizontal wells in Canada; and shallow grassroots vertical coal bed methane wells in Alberta. In all three areas, he discussed what is being done, and then shifted to a discussion of what else could perhaps be done in other areas in the future. In the lower 48, for example, he envisions applications in storage wells, deep fractured reservoirs, deepening of existing wells, precision emplacement of well bores and hybrid well construction to accelerate drilling and address the rig shortage problem.

Virginia Weyland (NETL, Tulsa) discussed microhole technology with a focus on future E&P. She began with a strong opening statement: we can directly link 25% of domestic gas production to DOE research results, and we can directly link 13% of domestic oil production to successful DOE research projects. Current awards for microhole projects began with a road mapping exercise in 2004, then a solicitation process in 2005 that resulted in the first 10 awards, which were followed

by 6 more. She briefly discussed most of these projects, and some future projects, and pointed out that PTTC has been tracking industry activity using microhole technology. A CD on microhole technology was provided to each workshop participant.

Steve Sadoskas (Pinnacle Technologies) led off the afternoon session with an overview of hydraulic fracture mapping and applications, specifically a discussion of the technology and application of tilt mapping and microseismic mapping for hydraulic fracture diagnostics. There are three ways to look at shales: using indirect methods, in the office; using direct, near-wellbore measures; and using direct far-field measurements. The goal of the research is to be able to determine not only fracture direction and dip, but lateral and vertical dimensions in cross section as well. Tiltmeter and microseismic mapping can be used to determine the length, height and azimuth of fracture growth over time. An example of extremely long and complicated fracture growth in Barnett Shale waterfracs was presented, wherein fracture network length was correlated to treatment volume and cumulative production was correlated to fairway width.

Jim Fontaine (Universal Well Services) followed with an application of Pinnacle's technology in the Appalachian basin. His company became interested in this approach because in this basin it is well known that the performance of thousands of wells does not meet expectations, and we do not have an easy method to measure the geometry of a fracture to determine where it grows and what it looks like. His goal, therefore, was to develop an optimum completion strategy that would increase production, effectively drain the area, calibrate frac models and identify by-passed zones. Examples were presented from a 3-well multi-frac program on the Linden Hall lease in Pennsylvania. Up to six sandstones (Upper Fifth, Lower Fifth, Upper Bayard, Lower Bayard, Speechley, First Bradford) in the Upper Devonian section are productive in the area, and are usually stimulated using a ball and baffle staging system. On average, all stages mapped grew along a NE-SW azimuth. However, in cross section, fracture growth was

more complex. For example, if fractures from the first stage grew preferentially to the southwest, stage two fractures grew to the northeast due to a change in stress direction following the initial fracture growth. Also, fractures were not confined to the individual sandstones in which they were initiated. Instead, they grew both upward and downward, such that the fourth and fifth stages appear to overlap each other. One conclusion reached was that the upper three zones could be perforated and stimulated in one stage rather than in three stages. The speaker concluded with a suggestion that perhaps we should look at the Devonian sandstone plays as thick shale plays with interbedded sandstone fingers and stimulate them accordingly.

Holly McDaniel (Halliburton) gave a brief overview of Haliburton's shale log that provides a tool to identify and quantify the potential of unconventional reservoirs. The technology integrates raw log data with core analyses to locate organic shale zones and provide values for gas content, total organic carbon, thermal maturity, kerogen types, shale mineralogy, brittleness, Young's modulus, Poisson's ratio, fracture barriers, and shale reservoir type. Actually, the method can be applied with or without core data. If digital files are available for four key logs, a shale log analysis can be run using generic core data from other cores in the region.

Former PAG Chairman Kevin Smith (Oxford Oil Company) revealed Oxford's strategy to revitalize old fields, using as examples four Clinton sandstone wells in Noble County, Ohio that were identified as performing below economic limits. These four wells are located between two existing Berea Sandstone fields, so Oxford studied the Berea through Gordon interval to identify potential plug-back candidates. However, a search through their log library revealed very little in the way of data on the reservoir properties and characteristics of these sandstones. Therefore, Oxford turned to the south, where they had established production in these units in Crooked Tree field, and used those wells as models for a

completion strategy in the four Clinton wells slated for recompletion. In each case, the lower portion of the hole was plugged and abandoned according to state law, and the recoverable 4.5" casing was pulled, inspected and rerun. The wells were completed in two stages, first the lower Gordon-Thirty foot interval, and then the upper Berea-Gantz interval in stage two. After stimulation and cleanup, the first well produced 5.4 MMcf in the first four months on line. An economic analysis of the project concluded that 240 MMcf of new reserves had been added for the four wells. Following this successful, recompletion, Oxford has begun to use this same strategy in other wells slated for abandonment.

Martin Miller (Alliance Petroleum Corp) continued the theme of successful Upper Devonian multiple zone completions in Southeast Ohio. Step one was to examine all available logs and use the data to upgrade maps of all Upper Devonian sandstones and to identify faults that were present through the entire interval of interest. The observation had been made that high reservoir pressure was associated with these faults, so wells were spaced 1200-1500 feet apart to avoid steep declines. In older Berea wells, a pressure decline had been noticed in the Upper Devonian sandstones as the overlying Berea Sandstone was produced. New wells were drilled on air to total depth and a full suite of logs, including sonic and temperature, were run to identify reservoirs and gas shows. Four sandstones were completed in three stages; the "best" sandstone always was isolated, whereas two of the "poorest" sandstones were completed in one stage. The operator attempted to keep the number of perforations to 20 or less per interval, and injection rates to 20 bbl/min to stay in the zone of interest. Typically, 600 bbl/stage was pumped, but up to 900 bbl were pumped in the best zone, or in a two-sandstone stage completion. Production ranged from 7-10 Mcf/d, leading to the conclusion that good sandstone was not enough; faults and fractures are necessary to make good wells. Therefore, a seismic program was initiated to pick deep faults with a NE-SW azimuth that extend upward through these shallow zones of interest.

“Well Control 101” Kicks off Safety Workshops

A recurring workshop theme has emerged for PTTC workshops this year - safety around the wellhead. The initial offering - **Well Control 101** - preceded by one week a workshop on **Well Safety** that was held in Marietta, Ohio, and by three months a workshop on **oil field explosives safety** planned for Columbus, Ohio on August 29th.

Wild Well Control, Inc. cooperated with PTTC to teach “Well Control 101” on May 16th at the Holiday Inn, Washington, PA. The workshop was based on the assumption that four factors typically contribute to the escalation of well control events: the drilling program, rig equipment, rig personnel and corporate preparedness.

The workshop began with an introduction to well control, after which the instructor, Bill Mahler, proceeded to discuss management of well control risks and responses to well control incidents.

At the very outset of the workshop, Mahler warned that “a blowout today can very easily bankrupt a small company,” and that small incidents by a company fortunate enough to never have had a blowout still can lead to big problems. In today’s business environment, more wells are being drilled by more rigs requiring more crews, and these rigs and crews are being asked to drill deeper and deeper. Also, rigs - and even crews - are being moved to the U.S. from other countries, such as China. Consequently, insurance rates are increasing due to the limited pool of experienced workers and the increase in the number of start-up companies. These smaller companies - often with a larger risk profile - are drilling deeper and faster, often in unconventional oil and gas plays, and frequently

employ the use of consultants. In addition to rig utilization being at maximum capacity and crew experience being low, high rig personnel turnover, drug test failures, language barriers, unproven technology and deeper drilling to reservoirs with higher pressures are key factors to be considered.

Well control “incidents” can lead to “events” which in turn can lead to blowouts. These “incidents” increase as the rig count increases, and at this time number one for every 1000 wells drilled. Thus, if we expect to drill 50,000 plus wells in the U.S. this year, we can project approximately 50 incidents or blowouts (uncontrolled flow from the well). The ultimate result will be an increase in the risk profile for the oil and gas industry. In parts of the U.S. today, insurance costs equal drilling costs for deep wells.

One of the first, perhaps even the first objective of a safety plan is to increase the crew’s awareness of basic well control principles. You need to teach them what to look for as they do their jobs so when they experience something out of the ordinary they can “call time out” and “check it out.” Historically, more than 80% of major well events have had 7 to 11 incidents leading up to them. In addition, safety drills should be designed, held and repeated until they become second nature to all members of the crew. This in itself will improve emergency response time. Companies also should prepare a first response action list and an ICS, or Incident Command System, with established lines of command. For best results, workshop participants were advised to keep it simple and flexible.

“Log Scan” Project Kicks Off; TBR Project Nearing Completion

The Appalachian Oil and Natural Gas Research Consortium (AONGRC) has been awarded a 3-year contract to improve the

availability and delivery of critical information for tight gas resource development in the Appalachian basin. Dubbed “Log Scan” by the two principal

research team members, the Geological Surveys in West Virginia and Pennsylvania, the project was designed to simplify and accelerate the data collection process for independent producers interested in developing tight gas reservoirs in the basin. The first objective is to advance the understanding of selected tight gas accumulations in the Appalachian basin by collecting a wide variety of data and information currently dispersed in public records, file drawers, core facilities and publications. The second objective is to make this information more readily available through an on-line, interactive geospatial delivery model designed for public access on the Internet.

Data collection will be concentrated on five gas plays of regional significance: the Berea play and three Upper Devonian sandstone plays (Venango, Bradford and Elk) in Pennsylvania and West Virginia, and the "Clinton"/Medina play in Pennsylvania. The first objective will be met by scanning geophysical logs for wells that penetrated the selected plays; scanning available core slabs; digitizing tight pay intervals within representative logs for each play; taking digital photographs of thin sections and core slabs; and converting the relevant maps and cross sections from "The Atlas of Major Appalachian Gas Plays" and other survey

publications to digital form. The second objective will be met by defining attribute data to be included for public access; developing an Internet-based delivery model that can be accessed by any of the attributes in the dataset; populating the model with datasets gathered to satisfy the first objective; and organizing the information by gas play.

Although these five gas plays collectively have produced more than 30 Tcf over many decades, remaining resources have been estimated to be in the 20-25 Tcf range. Drilling activity in these plays remains at high levels, and operators have expressed the need for more and better data in a more accessible form. Being able to access log, core and production data for wells in these plays will assist operators in making decisions regarding new locations, recompletion programs, developing resources behind pipe, and optimizing infill drilling locations.

Meanwhile, the AONGRC is preparing a final report on the Trenton-Black River Playbook project. The report should be available on the DOE-NETL website in the Fall. Several summaries of various aspects of the research are expected to be presented at the Buffalo ES-AAPG meeting.

IOGCC Passes Resolution in Support of PTTC

The Interstate Oil and Gas Compact Commission's Resolution Committee, meeting in Billings, Montana on May 22nd, submitted for consideration a resolution in support of PTTC's appropriation effort. Specifically, the committee wrote language that "IOGCC supports the efforts of the PTTC Executive Committee to obtain a Federal appropriation to sustain and enhance PTTC programs and activities, and that Commission acting through its member states and professional staff will undertake appropriate actions to assist in the procurement of funding for the PTTC." The membership passed the resolution during their final business meeting on the 23rd, and passed a motion to have Executive Director Christine Hansen write

an appropriate letter in support of reinstating funding for DOE's oil and gas programs at the FY2006 level.

Also during the meeting, Alaska Governor Frank Murkowski, former IOGCC Chairman, presented an "Update on the Alaska Natural Gas Pipeline" and provided meeting participants with a one-page fact sheet. His conclusion was that "This Alaska gas pipeline is about our future. It will provide jobs, energy and economic security now and for generations to come. This project moves the most gas, at the lowest cost for the highest revenue for Alaska."

Nick Tew, State Geologist of Alabama, organized a new State Geologists Forum with the intent that it will become a regular event at all IOGCC meetings in the future. Representatives of six state geological surveys (Utah, South Dakota, Alaska, Montana, West Virginia, Alabama) gave

presentations on a variety of topics during the initial forum. The West Virginia paper emphasized the cooperation among five state surveys in the Appalachian basin that led to the successful completion of the Trenton-Black River playbook project.

Exploration Trends in PA and the Appalachian Basin

During the recent meeting of the Independent Oil & Gas Association of Pennsylvania in Pittsburgh, Bill Hayward and Ramsey Barrett presented summaries of shallow and deep plays in Pennsylvania and adjacent portions of the basin. Hayward began by providing statistics on permits to drill shallow wells that indicate the trend toward shallow drilling is still strong, even increasing. In 2005, more than 6000 permits were issued to drill shallow targets; through the first quarter of 2006, more than 1750 permits have been issued, which projects to approximately 7000 for the year. However, although more than 3650 wells were actually drilled in 2005, only 132 were drilled during the first quarter this year.

Most of these permits were issued to drill in the shallow gas belt in western Pennsylvania, a northeast-southwest trending area that extends from the New York to the West Virginia border immediately southeast of the shallow oil trend. Targets of interest in the shallow belt include the Mississippian Big Lime, Big Injun and Berea/Murrysville plays, and the Upper Devonian Venango, Bradford and Elk plays, each with multiple pay sandstones. Hayward described narrow production trends in the Bradford play as the “meat and potatoes” of the shallow gas drilling trend.

In summary, Hayward believes that shallow oil wells will continue to be drilled in northern and north central Pennsylvania; Big Injun wells will be drilled in southwestern Pennsylvania; Venango play drilling will focus on 100 Foot sandstone wells associated with structure, Gordon sandstone wells in one-well wide trends to the southwest and distal 5th and Bayard sandstone plays; Bradford play wells

will include distal Speechley and Balltown sandstone wells in southern Pennsylvania, Bradford wells in central, north central and eastern areas, and Kane sandstone wells in central and north central portions of the shallow drilling trend; and Elk play wells will target distal sandstones to the east and siltstones and sandstones in the south, north central and eastern areas of the trend. He predicted three new trends will emerge: in southwestern Pennsylvania, operators will move off structure and drill deeper; other companies will look for gas in the oil belt; and drilling will continue to move east to find other Council Runs. Finally, he mentioned that the Ohio Shale and Rhinestreet Shale will continue to be targets, with the Ohio Shale wells in a slightly shallower trend than the adjacent Rhinestreet Shale trend to the southeast.

Ramsey Barrett confined his remarks to the deeper targets of interest, specifically the Clinton/Medina, Oriskany, Tuscarora/Bald Eagle, Trenton-Black River, and plays that may develop along the Allegheny Front. He referred to the Oriskany as the classic deep play developed from the 1920s through the 1950s in a wide productive trend. The Tuscarora/Bald Eagle play is confined to two very small but highly productive areas to the east in which the Grugan, Devil’s Elbow and Runnville fields have been discovered. Two wells in the Grugan field have produced in excess of 10 Bcf. Barrett suggested that some 3-D seismic would help develop these two, very narrow trends.

He predicts that the Tuscarora/Bald Eagle play will be developed in a Rome trough/anticlinal subplay and an Allegheny Front subplay. His suggested exploration concept is to high grade areas based on geology, 3-D seismic, pipeline availability

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and the presence of the Oriskany as a fallback pay, and the deeper Trenton/Black River as a “fantasy” play deeper in the section.

Another exploration strategy suggested was to look closely at the intersection of the Rome trough trend with cross strike discontinuities (CSDs). He also suggested that the intersection of the CSDs with anticlines mapped within the Rome trough are worthy of detailed mapping and investigation. Reversal on these Rome trough faults

Odds and Ends

AAPG has announced the results of the 2006 election for national officers. Petition candidate Willard R. Green of Dallas, Texas came out on top in the race for President-Elect, John C. Dolson, currently of Moscow, Russia was elected as Vice President; and Randi S. Martinsen, University of Wyoming in Laramie was elected as Treasurer. We congratulate the new officers and wish them well during their terms. We also would like to acknowledge the commitment in time and finances put forth by G. Warfield “Skip” Hobbs, who held all

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folded the section above, so that Oriskany folds overlies a faulted Tuscarora/Bald Eagle section.

In summary, Barrett said that the Tuscarora/Bald Eagle play is still immature, but is “on the cusp” at this time. He suggested that Oriskany plays should be combined with Tuscarora potential along the Allegheny front, and that it always “well be nice to have the Trenton/Black River at depth.” The primary exploration strategy in the future will be to concentrate on areas that are “3-D seismic friendly.”

of the Eastern Section AAPG Executive Committee offices in the mid 1980s, in his unsuccessful bid for the President-Elect office. Skip became the fourth member of the Eastern Section of AAPG to “run” an unsuccessful, but I’m sure highly rewarding, campaign for national office in the last four years. The Eastern Section does not turn out the membership for these elections, a trend that we must reverse if we are to convince other Eastern Section members to commit to candidacy in the future.