



Appalachian Region

Timely, Informed Technology Decisions

Newsletter

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FROM THE DIRECTOR’S DESK

The end of an era? Well, we haven’t been around long enough to warrant a reference to an era, but for 12 years PTTC has tried to bring a variety of proven and new technology and information to producers in the Appalachian basin. Unfortunately, we are faced with the reality that at midnight on September 30, DOE will discontinue all funding for this effort.

But, perhaps it is not all bad news. Like the Phoenix, a new PTTC will rise from the ashes of the current PTTC, hopefully as soon as April 1, 2007. For 12 years DOE and state governments in most of the producing states have provided the funds to continue the PTTC program in 10 domestic regions. And, to be sure, industry has played a key financial support role, usually - and very importantly - by providing speakers at no or low-cost for workshops,

and volunteers to serve on Regional Producer Advisory Groups (PAGs) and the national Board of Directors (BOD).

Now, however, industry will be asked to step up even further and assume the dominant financial role to support the new PTTC. The BOD is working feverishly on a restructuring and marketing plan to present to industry later this fall. When you are approached - even now before you are approached - please take a few moments to think about what PTTC has meant to you and others in your company. If you conclude that PTTC has had value and would be missed if it disappeared completely, then I hope that you would be receptive to the plans that will be presented to you.

Meanwhile, even as we await our ultimate fate, we continue to do what we can with the limited funds we have remaining during an official 6-month, no-cost extension period that will end March 31, 2007. With more than a little help from industry, we worked hard over the summer to develop eight workshops to be hosted in the late-July to early-October time frame. As I write this, we still have four of these left to host, including two in September and two in October, associated with the Eastern Section AAPG meeting in Buffalo. These workshops offer a wide diversity of topics, and all of them are important for our producing community, beginning with the September 20th offering, **“Acquisitions and Divestiture Market in the U.S.”** This is another important workshop that you will not want to miss, and one on which PAG member Dave Wozniak has worked long and hard to develop for you.

Earlier in the year we began a series of workshops on safety, and we will conclude that series with a September 27th offering on **“Oilfield Explosives Safety”** that will be presented by Craig Beveridge of Owen Oil Tools. This course has been very well received in other PTTC regions this year.

In Buffalo, we have made arrangements for Richard Green, President of AAPG’s Division of

Professional Affairs, to present a one-day, very low-cost version of what is typically a three-day, much higher-cost AAPG short course on **“Reservoir Engineering for Geologists.”** This is an excellent opportunity for geologists in the eastern basins to be exposed to an overview of this course without having to travel to Houston or other points west to do so. This workshop precedes the Eastern Section meeting, and because it is co-hosted by AAPG, you must register directly with AAPG. However, you do not have to be an AAPG member to register for the course.

Following the ES-AAPG meeting, PTTC will offer what might be our final workshop for 2006, a short course on **“Structurally Controlled Hydrothermally Altered Carbonate Reservoirs.”** This course will be taught by the well-known Graham Davies and our own expert, Langhorn “Taury” Smith, who will double as the Technical Program Chairman for the ES-AAPG meeting.

Douglas G. Patchen
RLO Director

Coming Soon: AAPG and SPE Eastern Meetings

Dr. Robert Jacobi has released the preliminary program for the 2006 Eastern Section AAPG meeting, to be held October 7-11 in Buffalo, NY. The general theme for the meeting is “New Concepts for Old Basins,” a reference to the need to apply new ideas and technologies to our mature hydrocarbon producing basins in the east.

The meeting organizers promise to offer an exciting balance between technical and social components. In addition to concurrent technical sessions and poster sessions on Monday and Tuesday, the meeting also will feature pre-meeting field trips hosted by the New York State Geological

Society, pre- and post-meeting workshops, a core blast on Sunday through Tuesday, and a special display of William Smith’s “map that changed the world.” on Sunday evening. Social events include an Octoberfest Icebreaker Reception on Sunday following the Opening Session and Awards Ceremony, and a buffet reception following the close of the technical sessions on Monday. Both events will be in the exhibit area with access to the core blast.

The technical sessions will emphasize black shales, carbonates and structural evolution of the eastern basins. Specific sessions include: New Approaches to Carbonate Reservoirs of Eastern

America; Structural Evolution of Eastern North America and Impact on Reservoir Distribution, Performance and Exploration Techniques; Hydrothermal Dolomitization Models and Case Studies, Trenton/Black River Reservoirs; Geological Carbon Sequestration in the Eastern U.S.; Geology and Gas Geochemistry of the Trenton/Black River Play; and New Models for Exploration and Development of Sandstone Reservoirs, Eastern North America.

AAPG, PTTC and NYSERDA will sponsor workshops before and after the meeting. Richard Green, President of AAPG's Division of Professional Affairs will arrive early to teach a one-day workshop (Saturday) on "Reservoir Engineering for Geologists." PTTC will co-host that workshop and host a post-meeting workshop to be taught by Graham Davies on "Structurally Controlled Hydrothermally Altered Carbonate Reservoirs," and NYSERDA will host half-day workshops on "Tectonic Evolution of the Faulted Northern Appalachian Basin and its Influence on the Development of Clastic, Hydrothermal and Fractured Reservoirs" taught by Dr. Jacobi and Gerald Smith, and "Geochemical Evaluation of

Unconventional Shale Gas Plays and Prospects," taught by Dan Jarvie.

The Eastern Regional meeting of the Society of Petroleum Engineers will meet from October 11th through the 13th at the Canton Marriott McKinley Grand Hotel in Canton, OH, just a short drive from Buffalo. Technical sessions on Thursday will include "Unconventional Gas Resources;" "Safety/EOR/IOR;" "Drilling & Completions;" and "Economic Evaluations/Reserves Analysis." Friday sessions will include "Case Histories/Mature-Field Revitalization" and "Stimulation/Production Enhancement." In addition, an Echometer Seminar will be held from 8:30 to 4:30 on Wednesday.

Social highlights include a Golf Outing at the Wilkshire Golf Course, located 15 minutes from the hotel; the Welcoming Reception in the Grand Ballroom on Wednesday; the Keynote Luncheon on Thursday featuring Gene Smith, Director of Athletics at The Ohio State University; and an evening reception at the Pro Football Hall of Fame on Thursday. Go to the SPE website for more details.

PTTC Hosts Introduction to ArcGIS (ver. 9.1) Software Workshop

The Kentucky Geological Survey (KGS) hosted a late-July, 2-day PTTC workshop on ArcGIS in the computer training facility at the W.T. Young Library at the University of Kentucky. Course instructors were Matt Crawford, an ESRI-certified instructor, and Brandon Nuttall of KGS. PTTC thanks these instructors and Dave Harris, who organized the workshop, and John Hickman, also of KGS, who provided additional assistance.

This focused technology workshop was held to provide training in geographic information system (GIS) software. ArcGIS is a leading GIS software application produced by ESRI that is not designed specifically for the oil and gas industry, but is commonly used with various types of oil and gas spatial data. In addition, ESRI supports oil and gas industry customers with a petroleum users

group (<http://www.esri.com/industries/petroleum/index.htm>).

Spatial data have always been a fundamental basis of the oil and gas industry. Computer-based digital mapping is now commonplace and widely used in the industry. There are specialized computer mapping packages tailored to oil and gas data, but these are expensive, costing in the tens of thousands of dollars. More generic geographic information system software (GIS) is much less expensive, and is capable of sophisticated mapping and analysis of oil and gas data. This workshop was an introductory class in the use of ArcGIS, a leading GIS program marketed by ESRI. This class was the 2-day official training class as written by ESRI, and utilized their training manuals. Because the standard class does not involve any oil and gas data, KGS added oil and gas content on the second day with lecture and

exercises using real data from the database at the Kentucky Geological Survey.

The class was sold out, with a total registration of 24 participants. Class size was limited to the number of computers available in the classroom, with each registrant having their own computer for use in the hands-on exercises.

The workshop lectures and exercises provided an introduction to ArcGIS 9.1. The agenda followed the standard ESRI outline and manuals, and included the following: *ArcGIS overview*: Capabilities and applications, Interacting with the interface, and Basic display; *Spatial data concepts*: Representing spatial data and descriptive information; *ArcGIS data model*: Geodatabases, Shapefiles, Coverages, Feature types, and Attributes; *GIS software*: Components, Functions, and Applications; *Spatial coordinate systems and map projections*: Georeferencing data, What map projections are, and How ArcMap works with map

projections; *Querying data*: Selecting and identifying features, and Creating reports and graphs; *Map displays*: Creating, Symbolizing, Scaling, and Adding map elements.

Two ESRI manuals were provided to each participant: “*Introduction to ArcGIS I, course lectures*,” and “*ESRI Educational Services*.” These included a lecture manual with copies of all the Powerpoint slides, and an exercise manual with a data CD-ROM. Participants also were provided with a registration list, class agenda, and list of GIS data resources in Kentucky. In addition, Brandon Nuttall provided a handout and CD-ROM for his material (Integrating GPS and GIS with Examples Drawn from the Petroleum Industry).

- David Harris

Kentucky Geological Survey

Designing and Forecasting Waterfloods Workshop Well Received

Rod Hall of GrailQuest Corp. led a well-attended workshop at the Ohio Geological Survey on the purpose and operation of ReservoirGrail, a computer program for calculating and mapping original oil in place, and for predicting oil and water production from wells during water injection in a field. Beginning with a structure map, elevation of the oil/water contact if appropriate, a map of net pay or permeability, well locations, and per-well or per-lease production data, the program computes the original quantity of hydrocarbon in place across the field, and the hydrocarbon remaining.

The user can view a map of remaining oil within the field to determine the best places to site injection wells. From critical parameters such as water injection rate and characteristics of any new producing wells, the program predicts the flow of water and oil and displays quantity of oil at each stage of the water injection. Well-by-well performance is calculated as well as total production from the field. The user can try any

number of what-if scenarios in trying to maximize production.

This is an art as much as a science. The instructor brought a sample dataset that participants used to try to optimize production. One pair of attendees was able to beat the instructor’s best efforts in regard to maximizing oil production.

The program ran very quickly relative to the size of the problem. The instructor explained that the software does not attempt to calculate the movement of fluids through the reservoir as done by a flow simulator. Data input requirements are minimal; that combined with the speed of the program means that the user can get answers to a range of scenarios within minutes or hours, depending on the number of “what-if” situations run.

The workshop was definitely hands-on, with each attendee running the software. Some attendees

with laptop computers were given a copy of the software with a two-day license so they could demonstrate the software to people back at the office.

- Michael Ed. Hohn
West Virginia Geological Survey

Ordovician Shale and Carbonate Potential Discussed During IOGA-NY Meeting

During the technical session at the IOGA-NY summer meeting held at the Peek 'n Peak Resort, Jim Morabito presented a talk on the Paleozoic black shale potential of the Northern Appalachians, specifically in Quebec and New York, and asked if there is a hint that this could be the next Barnett Shale. His study focused on the shale potential in an area of Quebec, but the method and results can be applied to New York and other areas as well.

The research resulted in the identification of 8 potential plays in the Ordovician Lorraine and Utica shales along the Taconic Front, where areas with deformed shales are down to the east from undeformed shale areas. Large areas have been identified with both source beds and reservoirs, but drill data are limited.

Potential biogenic and thermogenic plays have been identified. The biogenic play would be analogous to the subcrop Antrim Shale and New Albany Shale plays; the thermogenic play would be similar to the Barnett Shale play. Per well gas estimates range from 0.25 Bcf/well in the shallow (700-2500 ft) biogenic play to 1.2 to 2.75 Bcf/well in the deeper (3000-6000 ft) thermogenic play area.

A possible evaluation plan would be to select an area based on target depth, subcrop below glacial deposits, stress regimes, and pipelines; use aeromagnetic and gravity surveys to locate structures; and obtain low-altitude airborne multi-

spectral data with soil geochemistry to identify highly fractured areas with micro leakage.

Also during the IOGA-NY meeting, Don Clark presented a talk on a re-evaluation of the natural gas potential of the Beekmantown Group carbonates of eastern New York. He began with an overview of carbonates that are correlative with the Beekmantown of New York, including the Ellenberger in west Texas, the Arbuckle in Oklahoma, the Beekmantown in eastern Ohio, and the Ordovician carbonates in Quebec. In each of these cases, karst development enhanced porosity and reservoir development, and a pre-existing fracture network was very important. Therefore, Clark suggested that companies look for karst areas in the Beekmantown of eastern New York.

The typical karst-enhanced Ellenberger of west Texas consists of an upper roof cave with high (20%) porosity, a middle cave fill with low porosity and a lower cave collapse zone with 15% porosity. The Arbuckle also includes zones of karst, sinkholes and cave deposits. Cores of the Beekmantown in New York show evidence of breccia, some of which is similar to cave collapse zone deposits. Clark suggested that faults create topographic highs, similar to the situation in eastern Ohio, and fracture zones parallel the faults. Both of these lead to karst development. Remnants of the paleohighs could exist as erosional hills, with black shale adjacent to the carbonate remnants on the down dropped side across the fault zone.

Kevin Smith Receives PTTC Award

Former Appalachian Region PAG (Producer Advisory Group) Chairman Kevin Smith (Oxford Oil Company) attended the recent PTTC workshop in Pittsburgh on “Maximizing the Effectiveness of Hydraulic Fractures,” which provided us with the opportunity to surprise him with a long-overdue award, the Past Chairman’s Award. The award was

presented to Kevin in recognition of his energetic and self sacrificing leadership of the Appalachian Producer Advisory Group, 2000-2001. Thank you, Kevin Smith, and thank you, Oxford Oil for taking on this important leadership role in the history of the PTTC in this basin.

Another big Winner: Maximizing the Effectiveness of Hydraulic Fracture Workshop

PAG member Roger Willis has had a vision of a special workshop on hydraulic fracturing for at least the past year. Finally, after months of discussion, planning and recruiting the very best speakers to create the necessary information flow that he desired, his vision became reality on September 13. On that day, PTTC hosted a workshop in Pittsburgh on “Maximizing the Effectiveness of Hydraulic Fractures, from Devonian Sandstones to the Barnett Shale.”

The outstanding group of speakers included Jim Beck, President of Tiger Eye Resources LLC and former President of Seneca Resources; Norm Warpinski, Chief Technology Officer for Pinnacle Technologies and formerly with the Sandia National Laboratory; Mike Mayerhofer, Applied Diagnostic Engineering Manager at Pinnacle Technologies and formerly with Union Pacific in Ft. Worth; Glen Penny, President of Flotek Industries and CESI Chemical and founder of StimLab; Becky Stansfield, Well Test Engineer with Eastern Reservoir Services and formerly with Marathon Oil Company; Mark Miller, Manager of Technical Services with Universal Well Services, and formerly the co-founder and President of Eastern Reservoir Services; Roger Willis, Senior Vice President of Universal Well Services, PTTC Producer Advisory Group member and technical activist with Independent Oil & Gas Associations in New York and Pennsylvania; and Ray Walker, Vice President of Completion Technology for Range

Resources, who formerly worked for Halliburton and Union Pacific Resources before founding Stroud Oil Properties.

Jim Beck led off the workshop with his presentation entitled “**To Frac or Not to Frac: That is Not the Only Question.**” His initial point was, there are many questions to answer before you ask yourself whether or not to fracture a well, including why fracturing is necessary in the Appalachian basin. In this basin, the reservoirs are old (Silurian to Pennsylvanian), and hard, mainly tight sandstones, shales and carbonates. Typical well locations are small, and wells are completed open hole, fracturing from 8 to 10 sandstones from the top down. In other instances, casing may be run prior to fracturing. Horizontal fractures are expected at depths less than 2500 ft; vertical fractures are expected at greater depths.

Factors to consider include commodity pricing, economics, well bore conditions, reservoir character, type of frac job, fracture orientation and legal issues. According to Beck, fracturing really was not economic in this area in the early 1990s when prices were less than \$3/Mcf - and may not be economic at prices less than \$4.00 now - so his company drilled mostly stratigraphic tests while waiting for prices to rise. After 2000, drilling ramped up as prices rose and it became economic to fracture wells, which is necessary in this basin.

Appalachian basin wells typically experience a high initial decline in the first 6 to 12 months. Therefore, his company strategy was to drill wells in the summer and have them ready to go on line during high price points in the annual pricing cycle, typically the winter months. Plotting price per month for several years enabled them to predict the historical peak price months and plan fracturing programs accordingly.

Should we drill horizontal or vertical wells in this basin? For multiple-zone plays, he suggested that vertical wells should be drilled. However, for shales like the Marcellus or Rhinestreet, perhaps horizontal wells would be the better choice. Other questions to be asked and answered in advance are to drill with air or mud? Cased or open hole? Size of the well location? Where is the well location? Access to the well site? And, what is the optimum hole size?

He included in his presentation a discussion of his experience in the Barnett Shale play, where vertical wells are deep (10,000 ft) and horizontal wells have long laterals (2400 ft) with 16 degree/100 ft build rates. High volumes of water and sand are required to frac these wells, so well locations are much bigger than the typical Appalachian basin well. The character of the well bore affects the frac job, so an understanding of the various lithologies encountered is essential. Log analyses also enable operators to find water zones and determine mechanical properties, which in turn will affect how fractures are propagated.

Factors that have an impact on the type of frac treatment include the size of the frac, type of carrying fluid, the type of proppant, direction of the frac (horizontal or vertical), and effective frac length. Fracture orientation will impact the drainage area, well spacing and well orientation. Participants were advised to test everything! What works elsewhere may not work here. New formations may require many tests to determine the best frac type. Cores should be taken to find out exactly what you are dealing with. Experience in a basin counts; there usually is a good reason why things are done in a certain way, but keep yourself open to new ideas and test accordingly.

So, the bottom line is it's not just "To frac or not to frac" anymore. Participants were challenged to be able to answer these questions by the end of the day: How to? What type? When during the year? Which zones? What well spacing?

Norm Warpinski followed with his presentation on the "**Geologic and Rock Mechanic Controls on Fracturing.**" He briefly summarized the history of hydraulic fracturing research from the 1940s to the 1970s, and the mineback and core-through experiments of the 1970s and early 1980s. These experiments led to the conclusions that fractures are more complex than had been envisioned; that geologic controls are critical; stress and modulus are controlling rock mass properties; and we usually lack knowledge of the critical properties before fracturing a well.

Geology and fracture complexity are important. As a general rule, the more complicated the reservoir, the more complicated the fracture created. Natural fractures induce additional complexity. Induced fractures zig-zag away from a well, intersect natural fractures, and separate into two parallel fractures, or into an echelon strands, often as the fracture orientation turns. Multiple fractures can originate at the perforations, but then may come and go along the frac length and height.

Stress is the most important factor in determining how high a fracture can grow, and it is possible to do a quick calculation to estimate if the frac height in your model is realistic or not. Modulus, layering effects, tip effects and pressure gradient also are additional factors, although modulus is not as critical as stress. An induced fracture will propagate upward across an interface with a high modulus rock, but will not propagate downward into a higher stress regime. Fractures will stop at a weak interface. This is particularly important at shallow depths, or in over-pressured zones where frictional forces are lower.

Tiltmeter data support microseismic data, in some cases indicating that frac height is not as high as originally assumed, and suggesting that geologic

layering, such as composite shale and massive sandstones, may be the cause.

Young's modulus is one of the two key parameters to determine - stress is the other - but it is hard to obtain. It can be measured statistically in a lab on core plugs - horizontal core plugs are a necessity - or dynamically from rock velocities. It is not a simple value, and depends on loading vs. unloading, saturation, strain rate, confining stress and axial stress. The problem is how to get a good number for your analysis, and the answer is from logs or tomograms.

Poisson's ratio has a small effect in most models, but it does affect stress calculations, so it is important. In situ stress measurements are the cause of more problems in fracturing than any other type of measurement. Measurements include microfrac, step-rate tests, shut-in test, and log-calculated stress. The only reliable stress measurements are from closure tests, microfracs and other direct measurements; stress from a dipole sonic log is little better than a guess.

Leakoff is a problem in naturally fractured reservoirs, especially in a formation with a network fracture pattern, like the Barnett Shale. Natural fractures probably are the greatest source of complexity in hydraulic fractures, and leakoff is dependent on conditions of the natural fracture. Plots of permeability vs. pore pressure can measure permeability response due to natural fractures. Microseismic studies in the Barnett Shale play indicate a complex, long, wide fracture pattern.

Tip effects can't be measured directly in the field or in the lab, but are inferred from pressure behavior. However, the much-reduced frac height growth that has been observed in mapping tests negates the need for tip effects in many cases. Although hard to measure, tip effects are easy to include in models.

Perforations can cause problems, such as crushed, compacted, onion-skin zones. Perforations should not be ignored, because their effect on fracture initiation and overall performance can be significant.

In conclusion, Warpinski emphasized that fractures are much more complex than our conceptual models, and complex reservoirs induce complex fractures; getting useful data for fracture design requires more than logs, with stress and modulus measurements the key; and leakoff is important, and needs to be determined with field tests, such as pressure history matching and analysis and mapping.

Mike Mayerhofer discussed "**Fracture Modeling and Design Issues**," beginning with the relative importance of fracture conductivity and fracture length, and then moving on to differences in design for low-permeability vs. high-permeability formations. The primary goal in fracturing a low-permeability formation is to create a long fracture, whereas for a high-permeability formation, conductivity is very critical, so one must design the job accordingly. He also presented an economic optimization methodology, wherein a plot of cumulative gas vs. time for different fracture half lengths is used to predict the response to fracture length, and then a plot of fracture half lengths vs. treatment costs is used to find the maximum economic length that should not be exceeded. The optimal fracture half length can be found on a plot of NPV vs. fracture half length as the point where the curve rolls over.

Different fracture models, both 2-D and the time intensive, 3-D models that are run today also were discussed, along with the evolution of fracture design and analysis. Early designs did not incorporate feedback from real data, but measured net pressure was generally higher than model net pressure. This observation led to modeling with net pressure feedback in which a net pressure history match could be obtained. Allowing real-time data to guide the models gives a better chance that the inferred geometry could be correct, but pressure matching inferred geometry does not always fit the measured geometry. Thus, the model provides an answer, but not always a unique one, and there is still a need for a calibrated frac model and a measure of net pressure.

Therefore, the next step in the evolution of frac design and analysis was modeling with net pressure and geometry feedback. In this model, the physical mechanisms were changed to match both measured net pressure and directly observed fracture geometry, resulting in a predictive tool that is linked to actual growth behavior. However, although models have been improved dramatically, there still is room for improvement; they still do not accurately predict fracture growth. A new approach is to combine modeling and measuring, with the ultimate goal of developing a fully integrated fracture, reservoir and production model.

Direct diagnostics are not predictive, so they need to be combined with a fracture growth model to achieve a calibrated model that will more realistically predict how fractures will physically grow for alternative designs. Several examples were presented, including case studies in the Cotton Valley Sandstone and the Barnett Shale that employed microseismic technology, and then examples in shallow coal bed methane and tight gas plays.

A calibrated fracture model can then be used as input for a production model to observe the effect of fracturing. Participants were warned that production analysis can be very non-unique, but can become more unique if well interference data are used. Examples were presented in which long, narrow, “cigar-shaped” fracture patterns were developed. Wells drilled on trend interfered with the initial well, so once the fracture length and azimuth were determined, a different drilling pattern was developed. Eventually, the optimum well spacing and drill pattern were determined.

The speaker concluded that effective fracture lengths can be very long, as evidenced by well interference data, and in low-permeability formations, these long fractures will create slim, cigar-like drainage areas, which have a significant effect on well placement and spacing. Wells should be placed far apart in the direction of fracturing to avoid interference. However, because the drainage area is quite narrow, the area drained could be quite small. Using large fluid volumes in a frac program could result in better well performance.

Glen Penny discussed “**Hydraulic Fracturing Fluid Design for Shales,**” during which he presented examples from the Barnett Shale play in Texas and the Rhinestreet and Dunkirk shales in the Appalachian basin. He emphasized the difference in mineralogy among the various shales, especially in clay mineral content, as well as the amount of silt-sized quartz and feldspar and carbonate grains. There is a difference in the total amount of clay minerals as a percentage of the total makeup of the shales, and there is a difference in the type of clays that are present in the different formations.

An example was presented of designing a typical vertical fracture treatment in the Barnett Shale, where the goal was to create narrow, multiple fractures. The speaker went through the list of additives used in shale frac programs, including polymers and friction reducers, breakers, biocides, clay stabilizers, iron control agents, surfactants and proppants. Participants were cautioned to check their water for impurities and identify the hardness, iron level and pH of the water to be used.

Clays in shale and other formations can be a significant problem, especially in the Appalachian basin, where clay stabilizers become important. Whereas the main clay mineral in the Barnett Shale is illite, a formation like the Rhinestreet Shale contains illite, smectite, chlorite and kaolinite. Illite holds a high amount of water and can create a water block. Kaolinite is a clay that crumbles and migrates through permeable pathways. Smectite, also called bentonite, is a swelling clay and must be stabilized to avoid a reduction in permeability. Chlorite contains a large amount of ferrous iron, which is not a problem as long as fluids on the formation maintain a low pH. If the pH rises, iron can precipitate as a very fine orange colored residue and begin to migrate, restricting the flow of gas to the wellbore.

Surfactants, foamers and the new microemulsion fluid system also were discussed, with an example from the Rhinestreet Shale, prior to discussing a field study of completion fluids that were used to enhance production from the Barnett Shale (SPE paper 100434). A typical Barnett Shale

well returns less than 25% of the injected fluid, so the trapped fluid has a detrimental effect on relative permeability, effective flow area and effective frac length, and ultimately well performance. A treatment was designed in which the only variable was the use of a conventional surfactant in 12 wells and the microemulsion in another 12 wells. After 6 months, the 12 wells in which the microemulsion had been used produced 47% more gas than the 12 wells in which the conventional surfactant had been used. Because more of the injected fluid came back, more gas could be produced.

Mark Miller and Becky Stansfield combined for two presentations on “**Application of Well Testing for Stimulation Design and Evaluation**” and “**Production Logging Theory and Applications.**” Well testing was defined as the science of measuring and interpreting the relationship between flow rate and bottomhole pressure in a well. Well tests are commonly run to determine the nature of productivity problems in a well and to determine the future performance of the well. Well tests provide more information than cores because they penetrate further into the formation and yield more accurate measures of the reservoir than cores. This information includes permeability, skin damage, fracture length and conductivity, reservoir pressure, oil and gas reserve estimates, fluid level and a description of the reservoir, including faults and boundaries, natural fractures and interbedded lithologies.

The benefits, uses and common types of well tests were reviewed, and examples of typical tests were presented. Buildup test procedures and interpretation were emphasized, leading up to a discussion of how well tests are used to develop a stimulation program. Well tests assist in stimulation design by helping to determine various reservoir properties, such as permeability and pressure, and to quantify skin factor.

Well tests should be run long enough to get past well bore storage effects, and they should be run long enough to reach pseudo-flow conditions. Flow rate must result in drawdown pressures of 10% to 30%. Well tests also should be run about 4 times longer than the duration of well bore storage.

Well tests also can be used in post-frac evaluation to determine effective frac length - a measure of how the well is actually responding - and conductivity.

Production logging is a “specialized downhole data acquisition service used to locate and measure oil, water and natural gas production from a well.” Production logging also can be used as an injection logging tool to determine the best zone or zones for injection. This tool determines the percent of the total flow both in and out of each zone in wells with co-mingled production. Thus, it can identify thief zones, and locate entry points of fluids and leaks in tubing and casing. Workshop attendees were cautioned to obtain good information on a well prior to running production logs.

Memory production logging involves sensors such as gamma ray, CCL, pressure, temperature dielectric and fullbore spinner run on a slickline with the logging data being stored in the tool as logging progresses. These data are downloaded after the tool reaches the surface. Logging should begin below the lowest set of perfs, and should be run several times, both up and down, across the zones, at different speeds. However, during any one pass, speed should be maintained, and changed only prior to the next pass. While the well is flowing, the tool should be stopped at various depths above, below and in the perforated interval.

Various examples of production logs were shown, including application in problem wells. For problem wells, a diagnostic procedure was designed, beginning with running a memory production log followed by the interpretation of the logs, and leading to a determination of the required remedial action. Other examples that were shown included how to apply this tool in conjunction with a stimulation program. Pre- and post-frac tests were run and interpreted, and zones that responded to the treatment, zones that actually were producing, and thief zones were identified.

Production logs do have limitations. The spinner needs to be in a flowstream with a minimum velocity of about 50 ft/minute. Higher flow rates, smaller diameter casing, lower pressure (in gas wells) and faster logging speed (down) or slower logging speeds (up) assist spinner response. The speaker concluded that memory production logs can provide a simple and cost effective way to determine where gas, water and oil production actually is coming from in a well with multiple producing zones. Also, in some cases, these logs can be used to identify downhole production problems, and they can be used in both production and injection wells.

Roger Willis presented a **Microseismic Fracture Mapping Case Study** of an Upper Devonian sandstone play in Fayette County, Pennsylvania. Multiple sandstone zones commonly are completed in the play, but historically producers have wondered which ones actually were fractured. Although thousands of wells have been fractured in this basin, well performance does not always meet expectations and we only think that we know how and where a frac actually grows, according to the speaker. In fact, there has been no easy way to get a direct measure of fracture geometry, or to determine where a fracture grows and what it looks like. For these reasons, using new technology for imaging fractures makes a lot of sense.

Imaging the actual fractured area can increase production, allow us to have a better understanding of the size and shape of the drainage area, save money by controlling stimulation cost, help calibrate fracture models, identify areas with bypassed reserves, and determine the geometry of fractures at different depths, such as horizontal fracs at shallow depths versus inclined and vertical fractures at greater depths.

The case study involved four wells on the Linden Hall lease, three of which were fractured while the other served as a monitoring well. A monitoring well must be within the imaging range, and must be a “quiet” well while tools are being put in place. Four or five stages were fractured in each of the three production wells to stimulate sandstones from the 1st Bradford at the bottom up

through the upper Fifth at the top. A video was run during the presentation, in which the growth of fractures in each stage could be seen sequentially. In some cases, the frac stayed in the intended zone fairly well, but in the upper stages, the induced frac grew out of zone, so at least one stage was not cost effective.

The results of the frac imaging survey were compared to maps of sandstone thickness and results of production logging in the three wells. In some cases, a fracture grew out of the sandstone body; in others, the frac grew into an area of thick sandstone. Production logs indicated that in all three wells fracturing the Speechley was not cost efficient, nor was fracturing the lower Fifth in one well. These zones failed to produce even 5% of the total gas flow in all cases. The upper Fifth and upper Bayard were the main producing zones in all three wells, and the 1st Bradford was a tertiary contributor in two of the wells.

Norm Warpinski's second presentation focused on the three types of **Hydraulic Fracture Mapping**: surface tiltmeter mapping, downhole tiltmeter mapping and microseismic mapping. The tiltmeters are extremely sensitive and capable of detecting even minute changes in the orientation of bedding after fracturing. Surface tiltmeters can provide data on fracture azimuth, dip and possible depth. Downhole tiltmeters can provide information on fracture height, width and possibly length. Microseismic mapping can determine fracture height, length, azimuth and internal structure.

Surface maps and cross section displays of microseismic data often reveal that the induced fracture stays in a very narrow zone. However, application of this technology in the Barnett Shale play indicates a distinct fracture network is created in the fracturing process. Microseismic can be applied in vertical and horizontal wells.

The speaker emphasized that one of the three mapping technologies should be chosen to fit your specific needs. Hydraulic fracture mapping that employs microseismic and tiltmeter technology can provide information that cannot be obtained

elsewhere. Under optimum conditions, the entire fracture geometry and development can be determined. The best technology choice for you depends on your needs, well availability in which to install the technology, and other conditions, such as noise, depth and temperature.

Ray Walker was the workshop closer, and presented a comprehensive overview titled **“Getting Started in an Unconventional Play: What are the Questions...and How do I find the Answers?”** Examples were provided from his company’s experience in coal bed methane, shale and tight oil and gas plays in the Appalachian basin, Gulf Coast and Southwest.

Workshop attendees were cautioned that they must understand the resource triangle for natural gas, and that all natural resources are distributed log normal in nature; pure deposits are rare and small; as quantity decreases, the size of the deposit increases; and to produce low-quality deposits, either increased product pricing or better technology is required.

Gas shales are perhaps the most complex reservoirs. Production in shales can be from the shale matrix, fractures and through desorption. Shale reservoirs are usually analyzed as a layered (interbedded; varying lithologies) system. Currently, there are nearly 20 active shale plays in the U.S., including the New Albany, Antrim and Devonian shales in the northeast, and the Barnett Shale plays in the Fort Worth and west Texas basins.

In getting started, it is very important to always manage your expectations. “The Barnett doesn’t always work in the Barnett all the time” Walker noted, adding that we could quote him on that. His point was that technology cannot be transferred with confidence from one part of the Barnett play to another, much less from another shale play to the Barnett play.

You should approach an unconventional play by asking two very important questions. First, will it make gas? And second, can we frac it? If you can’t frac it, you won’t make gas. Next, you

need to have staying power: how many wells are you willing to drill to adequately test the play? The speaker noted that two thirds of all Barnett Shale wells produce less than the average per well volume for the play, and that 10% of the wells really make the money in the play.

Once you have answered the two important questions, and have determined that you do have staying power, you can then develop a systematic approach that begins with designing a pilot program to get the answers you need; utilizes technology and applies diagnostics; designs both vertical, and then horizontal, wells; and ends with development planning and value assessment.

During the pilot test, you must stay the course, once committed. How many wells will you need to drill to answer the two questions: will it produce, and can we frac it? Therefore, you must do the research: learn the geology, study the literature and study all offset information. Then, develop a work plan that fits the play. The Barnett is a statistical play and requires a statistical approach. Conventional engineering methods do not work well in the Barnett play, nor do they work well in other unconventional plays. Complex reservoir models have to be applied in most cases.

Lots of information is needed, and when you obtain it, pay attention to it, keeping in mind that if you can’t frac it, it won’t be commercial. It is important to identify fractures, fracture types and stress regimes, and to identify and quantify stress anisotropy. Low stress anisotropy exposes more formation surface area, resulting in better wells than wells in high stress anisotropy areas, where long fractures develop.

The proper completion and fracture design is needed to optimize production. “You need to tweak a lot of knobs to get a model to represent what is downhole” warned Walker. Shales in particular involve very complex rock mechanics. Walker asked, are we creating planar fractures which interconnect conjugate fracture system? Or, is the rock failing in multiple planes and multiple directions (spider web)? An understanding of the present day stress direction and the natural fracture

system will play an important role in your development planning.

Even in the Barnett play, it took a long time to get even some of the answers. The speaker went through the complicated history of well completion techniques attempted during the past 24 years, beginning with CO₂ foam fracs, then gel and N₂ fracs, x-link gel fracs and finally water fracs in the late 1990s. At that point in time, re-fracs using water frac methods began to be employed, often very successfully. A 1 Bcf well that was re-fraced often produced another Bcf.

Horizontal wells became more common in recent years and continue to be drilled today. Again, a variety of techniques were tried, beginning with single, then multiple stage completions, both in un-cemented horizontal wells, followed by multi-stage completions in cemented wells. Longer laterals and more stages have resulted in better initial potentials.

Completion diagnostics include micro-seismic mapping; radioactive tracers; the new chemical frac tracers; production logging; net pressure mapping and 3D fracture simulator modeling; zonal isolation; and BHP analysis and injection/falloff testing. The speaker concluded this portion of his Barnett example with a list of today's "typical" Barnett completion, and then went on to describe microseismic imaging examples, radioactive tracers and chemical frac tracers.

Operators in the Barnett Shale play still face several critical issues, including rig availability,

water usage, water disposal, frac equipment availability and scheduling, sand availability, drilling in urban environments, and surface/lease configuration issues. These are in addition to issues with reservoir modeling, reserve estimation, optimum well spacing, horizontal well targets, fracture initiation, long-term conductivity, optimum perforation design, re-fracturing and maximizing NPV.

What is new in the Barnett Shale play? There is an increase in well density, with 500 ft offsets now being drilled. Dual, opposing laterals also are being drilled. Finer mesh (100) is being used, often exclusively in frac jobs. Multi-well, simultaneous frac operations are being conducted, under the theory that if you get the fracs out there, they will curve and intersect, creating a better induced fracture network. This appears to be working. Another approach is to drill 20-30 degree directional wells through the target zone. These can be used to initiate horizontal wells at a later point in time.

In conclusion, Walker once more cautioned workshop attendees that they must manage their expectations throughout the process and use a methodical engineering approach, while recognizing that conventional engineering approaches will not work. You need to determine early what the questions should be, but not assume that you have the answers. Instead, study the data and take advantage of diagnostics and technology. Understand that one well or even a few wells will not provide the answers. And finally, don't assume that Barnett Shale play technology will work in your new play.