PTTC TECHNOLOGY CONNECTIONS
Appalachian Region
Timely, Informed Technology Decisions

Newsletter

Fall 2004 Vol. 5 No. 3

FROM THE DIRECTOR'S DESK

It has been a busy Fall, so busy that I have fallen short of my goal to publish four editions of this on-line newsletter this year. So, for the fifth straight year, here is number 3, the final edition of the year.

I have attended a lot of meetings this Fall, and at several of them I have gotten a lead on one or more workshops to bring to the basin. Over the winter, I will attempt to finalize arrangements for these, and announce them in the next issue.

It's time once again to get our Producer Advisory Group together to hold elections and go over plans for next year. Each PAG member is elected for 3 years, so this year we need to elect six members, some of whom may be existing members who will seek re-election. If you know of someone who has an interest in being a PAG member, please contact me.

As is our custom, we will not attempt to schedule workshops during winter months when weather conditions could potentially prevent a speaker or speakers from arriving for a scheduled event. However, we will begin anew in the Spring, and already have two Trenton-Black River core workshop/field trip combinations ready to go. One will be in Lexington, the other near Albany. I realize that Albany is a little out of the way, but

Taury Smith has some good cores to look at, and he has discovered a quarry north of the Mohawk River in which he has excavated en echelon dolomite bodies and associated fractures that make a good model for hydrothermal dolomite (HTD) reservoirs.

Taury and Fred Read also have agreed to teach a basic short course in carbonates in the Pittsburgh area, and the PAPG and Leo Schrider are working on a workshop concerning Upper Devonian sandstone plays.

So, have a good winter, and join us again in the Spring.

Doug Patchen
RLO Director

High Oil Prices: The Perfect Storm?

In the movie, "The Perfect Storm," a unique combination of meteorological events created the intense storm that took everyone by surprise and doomed our heroes and their small fishing boat. In the real world of today, another unique combination of supply and demand factors may have created the scenario that has led to oil prices that have topped $50 per barrel.

At least, that is the thesis outlined by Dr. Jamil F. Al Dandany, Director of Public Affairs for Aramco Services Company, a wholly owned subsidiary of Saudi Aramco, during his keynote address at the Opening Session of the Eastern Section AAPG meeting in Columbus. During his presentation, "Securing Oil Supplies in a Less-Than-Secure World," Dr. Al Dandany stressed that the current world situation was unique, and that no single supply or demand driver has led to higher oil prices. Instead, multiple supply and demand factors, acting in consort, have created the current world market conditions.

Among the demand factors cited, the love of people around the world, but Americans in particular, for SUVs is one key factor. Currently, more than half of the vehicles in the U.S. fleet are SUVs. The national average mileage for these vehicles is only 15 mpg, a key factor in the lowest mile/gallon average in the U.S. in 20 years.

But, SUVs alone would not have led to the current oil prices. World demand is rising, China is just beginning to come on-line as a major oil market, and the U.S. economy is demanding more oil and energy.

And, on the supply side, many factors have come together at the same time that demand is increasing. Disruptions in supplies due to politics, war, fear and the rise of speculators dealing in the futures market all have contributed to the high price. Dr. Al Dandany cited strikes in Venezuela, the war in Iraq and problems in Russia as chief among many supply disruptions that have come together at this specific time.

At the end of his presentation, Dr. Al Dandany was asked to elaborate on Saudi Arabia's ability to increase their production to meet the increased demand and offset some of the supply disruptions. He stated that Saudi Arabia currently estimates total oil resources at a trillion barrels, with 260 billion barrels of proved reserves and 740 billion barrels of unproven reserves. They currently produce 9.5 MMbbls/day, and could go to 11 MMbbls/day, if necessary, but no higher, given their current infrastructure. This daily production amounts to an annual production of 3.5 billion barrels. Current policy calls for replacement of reserves, not reserve addition, so as the 3.5 billion barrels per year of production are subtracted from proved reserves, a corresponding 3.5 billion barrels in unproven reserves are proven and added to the proven reserve column.

The keynote address by Dr. Al Dandany capped an opening session during which remarks were made by many key AAPG leaders, both national and regional, and honors and awards were bestowed on deserving section members. Larry Wickstrom, the meeting General Co-Chair, offered opening remarks, and was followed by his meeting Co-Chair, Steve Zody, the out-going ES President. Zody's remarks were followed by those from two of the three AAPG Division Presidents, Brian Cardott, President of the Energy Minerals Division (EMD) and Kenneth Vogel, President of the Division of Environmental Geology. Dr. Patrick J. F. Gratton, President of AAPG, then gave his Presidential address and introduced his Executive Committee and candidates for AAPG office. Unfortunately, only three of the six candidates were present: Tom Albrandt, President-elect; Douglas Patchen, Vice President; and John Hogg, Secretary.

Jeffrey C. Greenawalt, Chairman of the ES Honors & Awards Committee presided over the presentation of ES awards. Among those receiving professional services awards were: Dr. Stuart Dean and Dr. Byron Kulander, Outstanding Educators; Robert T. Ryder, Public Service; Hannes Leetaru, Distinguished Service; Dr. Aureal T. Cross, Honorary Membership; and Dr. Donald C. Haney, the John T. Galey Memorial Award, the highest honor bestowed by the Eastern Section.

Strong CBM Session at Eastern Section Meeting

Those geologists and engineers who have an interest in coal bed methane and were able to attend the recent Eastern Section meeting (Columbus, OH; October 3-6) were rewarded with a technical program that included 9 talks in an EMD-sponsored Coal Bed Methane session.

The coal bed methane talks were organized around two themes: an analysis of current production and development and the potential for continued success; and a series of talks on current activity in five states in two eastern basins. Unfortunately, no activity report was presented for Virginia, by far the most successful and active state in the section.

J. Duda and C. Byrer (U.S. DOE) stated that natural gas from coal seams (1.6 Tcf) represented 9% of all lower-48 production in 2002, and CBM proved reserves represent more than 10% of all lower-48 proved reserves. However, the authors cautioned that although CBM production is expected to surpass 2 Tcf per year within the next two decades, led by the Rocky Mountain region, "multiple and some highly contentious issues exit" that may "limit or delay cost effective development" of these resources.

T. Moore (Illinois State Geological Survey) discussed a geological risk assessment of coal bed methane prospects in the Illinois basin. He emphasized that a CBM risk assessment scheme must be different than a scheme applied to a conventional prospect, and went on to outline a CBM prospect evaluation scheme.

C. Boyer (Schlumberger Data and Consulting Services) focused on the development of specialized analytical and simulation-based tools that help us to better understand this different reservoir. He emphasized the importance of understanding the past performance of a well or field, but pointed out that the high variability in production often dictates the use of statistical and probabilistic methods with higher-quality reservoir data to achieve a better understanding of reservoir performance.

J. Miller (Belden & Blake Corp) presented a case history of company operations in the northern Latrobe syncline in southwestern Pennsylvania, with an emphasis on structural and stratigraphic controls on production. He compared data on two fields that Belden & Blake has been developing since 1994, Blacklick and Derry. Both fields have similar coal thicknesses and gas contents, but EUR's in Blacklick field are 2 to 10 times greater than wells in Derry field. The difference may be related to the presence of a NW-trending cross strike discontinuity (CSD) in Blacklick field that has increased fracture and deliverability of gas from the coal beds.

D. Morse (Illinois State Geological Survey) and C. Eble (Kentucky Geological Survey) gave separate presentations on CBM potential in the Illinois basin. Morse took a "cradle to production" approach for starting coal-bed and coal-mine methane projects. Gas content and coal permeability data have been gathered on various coals, and although both are low relative to other basins, drilling activity has been accelerating. Optimal stimulation remains as a major hurdle to be overcome.

Eble took more of a reconnaissance approach, citing 15 years of geological analysis in western Kentucky that suggests the potential for coal bed gas to be produced from several coals, which he named. An analysis of 20 borehole records in two counties indicated an average of 17 feet of coal, increasing to 25 feet, in the prospect interval. An overburden map indicates a "considerable" amount of coal at depths of 500 feet or greater, and a larger amount under at least 200 feet of cover.

K. Lee Avary (WV Geological Survey) stated West Virginia is "starting to come of age in terms of coal bed methane drilling and production." She reviewed state rules and regulations related to coal bed methane operations in West Virginia, briefly cited the history of CBM in the state, and went on to provide current statistics on drilling and production and a discussion of the multilateral approach pioneered in West Virginia by CDX Gas. More than 375 CBM wells have been drilled in the state, with more than 25 Bcf of gas produced between 1992 and 2002.

T. Markowsi (Pennsylvania Geological Survey) stated that Pennsylvania has approximately 250 commercial CBM wells. Total production in 2002 was 1.7 Bcf. The largest project, operated by Belden & Blake, is in Blairsville field, Indiana County. Other projects include gob gas and vertical fracture wells.

E. Slucher (Ohio Geological Survey) said that a review of well records at the Ohio survey indicated that several small gas fields have been developed in coal reservoirs over the past 80 years, but at present only one coal-mine gas operation exists. He went on to mention that coal assessment studies and a CO_2 sequestration investigation indicate a significant potential to enhance coal bed methane production by injecting CO_2 into deep coal beds.

Call for Papers Issued for the 2005 Eastern Section Meeting

Katharine Lee Avary, General Chairperson for the 2005 Eastern Section meeting, which will be held at the Radisson Waterfront Hotel and Conference Center in Morgantown, WV, September 18-20, has issued a Call for Papers.

Authors are invited to submit new and original work for either oral or poster presentations. Abstracts are due April 1, 2005.

Papers are requested in 13 topical areas, although the Call for Papers specifically states that all papers of interest to the Eastern Section, the Division of Environmental Geosciences (DEG), Energy Minerals Division (EMD) and Division of Professional Affairs (DPA) will be considered.

General topics that have been proposed include: Exploration Workflow/GIS Data Integration into Exploration and Development Projects; Silurian Reservoirs; 3-D Seismic Acquisition Case Histories; and Reservoir Parameters and Log Interpretation for Mississippian and Devonian Reservoirs.

EMD topic areas include: Devonian Shales and Tight Gas Formations; Carbon Dioxide Sequestration; and Coal Bed Methane.

DEG topic areas include: Origin/Distribution of CO_2, Nitrogen and H_2S Production; Environmental Geology and Geochemistry; Environmental Technology; Ground Water Issues; Soil and Ground Water Remediation; and E&P Environmental Issues and Best Management Practices.

Trenton-Black River Regional Update

Interest in the Trenton-Black River play is expanding out of the traditional oil and gas province in the Appalachian basin to other eastern basins, as well. At least that is the opinion expressed by speakers in a special session on "Trenton-Black River Exploration and Development" convened at the recent AAPG Eastern Section meeting in Columbus. Nine speakers in the morning session attempted to push the play north and east into Ontario and Anticosti Island, and westward into the Illinois and Michigan basins.

Dr. Robert Jacobi (University of Buffalo) discussed the relationship of fault systems and reservoir development in the Trenton-Black River play in New York, and suggested that the play can be extended to the west and to the east. Trenton-Black River fields are characterized on seismic lines by narrow grabens with increased offset up section. The faults that control the grabens involve Precambrian basement. The question is, "Do similar faults exist in areas outside the central New York play area?" In western New York, seismic data indicate basement-deep faults in the Trenton-Black River section that were extensional, and thus open, during early Taconic time. In eastern New York, similar Trenton-Black River grabens can be interpreted from seismic data.

Terry Carter (Ontario Ministry of Natural Resources) assessed the Trenton-Black River hydrothermal dolomite (HTD) reservoirs in Ontario, which currently are producing nearly a million barrels of oil a year, even after 100 years of production. Geologically, the reservoirs are similar to the giant Albion-Scipio field; dolomitized and fractured limestones adjacent to vertical faults are defined on seismic by a structural depression over the dolomitized zone and vertical displacement in the basement surface under the reservoirs. Currently, the initial and remaining resource potential of these reservoirs is being assessed.

Claude Morin (Hydro-Quebec Petrole et Gaz) addressed this question: "Could Anticosti Island be the next Albion-Scipio?" Eight exploratory wells were drilled to poorly defined targets during the 1960's and 1970's, with another five new wells drilled between 1996 and 2001. These later wells confirmed the hydrocarbon potential of the Anticosti basin, and that hydrothermal dolomites in the Trenton-Black River section represent one of the potential targets in this basin. This exploration concept was established by a well drilled in 1999 that encountered 70 meters of fracture porosity in the Trenton. Other "sags" on the top of the Trenton have been identified on seismic, often associated with a low acoustic impedance, zones of conductivity and class- III AVO anomalies.

Other speakers shifted the focus westward in to the Illinois basin, beginning with K. Strunk (Wabash Resources & Consulting) who examined the development of the classic Indiana-Trenton field through a series of maps. Strunk made the point that one of the keys to future Trenton-Black River development is a better understanding of what happened 100 years ago, and that one way to do this is to examine development and exploration patterns as depicted in a series of historic and modern maps. By examining the maps, the development pattern, geology, relative reservoir quality and production can be determined. This increased understanding of a complex reservoir will aid future exploration.

B. Keith (Indiana Geological Survey) compared two distinct dolomitization trends in the Trenton Limestone in Indiana. The northern trend, that covers one-third of the state, is part of the Lima-Indiana hydrocarbon province. A smaller trend in southwestern Indiana is less than half as large, in terms of geographic area. Two types of dolomite have been described in the productive (100 million barrels) northern trend: a thin but extensive, non-porous ferroan dolomite that caps the unit; and an underlying, nonferroan dolomite that is more porous, but varies in thickness and stratigraphic extent. In contrast, dolomite in the as yet non-productive southwestern trend is finely crystalline and quite permeable, and was formed in laterally discontinuous lenses at different stratigraphic levels.

L. Wickstrom (Ohio Geological Survey) had a two-fold message: he suggested that the large Lima-Indiana field in northwestern Ohio may still contain additional reservoirs, and that the Trenton-Black River reservoirs in the field provide an analogue for deep exploration elsewhere in the eastern mid-continent.

H. Leetaru and J. Grube (Illinois State Geological Survey) attempted to encourage deeper exploration in the Illinois basin in two separate presentations. Leetaru pointed out that although the Trenton has produced 13.5 million barrels of oil in Illinois, it is under explored and has a high potential for new reserves. Mississippi Valley-Type (MVT) ore deposits in the Trenton along the northwest and southwest flanks of the Illinois basin suggest to Leetaru that Albion-Scipio style traps may be present deeper in the basin. He further suggested the use of trend surface analysis for structural mapping, taking into account structural displacement between shallower and deeper units when locating deeper wells, and using geologic models based on MVT deposits along the basin's flanks.

Grube repeated that the Trenton-Black River section in the Illinois basin is an incompletely understood and developed target, pointing out that only 7.5% of the oil produced in Illinois has come from Lower Paleozoic reservoirs. He compared the small Illinois fields that were drilled on structural highs with prolific reservoirs in other eastern basins that were developed on structural lows associated with fractures. He pointed out that the geological characteristics of the Trenton-Black River play in the Appalachian and Michigan basins do exist in the Illinois basin, including a hydrothermal footprint along faults and fractures.

W. Harrison (Western Michigan University) offered a summary of Trenton-Black River reservoirs and production history in the Michigan basin. He emphasized that current thinking is that faults and fractures control field locations and reservoir quality. However, he also pointed out the difference in original facies and their control on later dolomitization and thus, on reservoir quality.

Coal Bed Methane Exploration Model Presented

Andrew Scott, a highly-experienced, internationally-known coal bed methane expert was recruited to share an exploration model that has evolved over many years of practical experience in a variety of coal bed methane plays and basins. This very successful, well-received, "traveling expert-style" of focused technology workshop was presented to make coal bed methane stakeholders in the Appalachian basin aware of a proven exploration technique that has been used in western basins.

The biggest obstacle to coal bed methane development in the Appalachian basin is who owns the natural gas in the coal beds: the coal owner, the mineral owner or the surface owner, even if the coal and/or mineral rights have been severed. Other obstacles are more technical, and include public data that indicate low permeability and low gas content, and water production and disposal problems. Consequently, many, if not most, coal bed methane projects that have been drilled and developed in the Appalachian basin are in areas where coal and mineral owners have agreed to develop the resource together, often in areas of active mining. Thus, "opportunity" has been the key factor in determining the location of these coal bed methane projects, not an initial scientific evaluation of geologic and engineering parameters that are key factors in an integrated exploration model.

In western coal bed methane producing basins, the hydrologic dynamics of a basin and how they affect coal bed methane production have been well established. However, this approach has been overlooked in the Appalachian basin. Therefore, the first objective of this workshop, to describe a hydrogeologic approach to comparing and evaluating the coal bed methane potential of basins, was a new consideration for many attendees.

Other objectives of the workshop were to: learn how to delineate sweet spots in a basin and avoid areas with relatively lower coal bed methane potential; develop a working understanding of the synergistic interplay among six key hydrogeologic factors that affect coal bed methane production (the exploration model); discuss factors affecting gas content distribution in coal beds and how gas and water chemistry data are used to develop exploration concepts; and how to explore for coal bed methane with little or no data. This final purpose, to demonstrate how very limited and often diverse data for different areas can be evaluated in terms of their relative importance, enabling the geologist or engineer to rank areas for their coal bed methane potential, was the subject of the final exercise.

Following a brief introduction to unconventional gas resources in general and coal bed methane in particular, the workshop instructor introduced attendees to his coal bed exploration model. This model contains six key elements: depositional systems and coal distribution; tectonic and structural setting; coal rank and gas generation; gas content; permeability; and hydrodynamics.

The orientation and fabric of the depositional system is more important than the type of system. Explorationists need an appreciation for the big picture of the depositional fabric, how coals are distributed in it, and how water moves from recharge areas through the fabric. It is relatively easy to move water through a fabric that is parallel to the direction of recharge, but very difficult to move water across a depositional fabric.

Burial history is important in determining the type and timing of gas generation. As the coal is buried to deeper, hotter depths, thermogenic gas is produced. As the coal is uplifted, biogenic gas is produced as fresh water containing bacteria recharges the system. Coal rank also increases as burial depth increases, and cleat development increases as coals lose water and shrink. If hydrogen is present, methane can be generated at lower coal ranks, but if not, methane generation begins at medium ranks, around 0.8 on the vitrinite reflectance scale. At higher ranks, the coals are overcooked and contain no gas, so coal maturation data from the outcrop that can be extrapolated into deeper parts of the basin are key parameters.

Gas content of a given coal bed is affected by how much was generated and by coal properties and reservoir conditions. For these reasons, gas content data from different coals in the same well may show a wide range in values. Therefore, explorationists need a lot of gas content data to determine how much gas is in the coals in question over the entire play area. Gas content in a coal is not fixed; it can change when equilibrium conditions in the reservoir change. It is possible to have high gas content in low-rank coals, but this is indicative of gas migration from another, higher-rank source.

Permeability is very important, but only if you have gas in the coal to begin with. Coal rank and gas generation increase with depth, but permeability decreases with depth. All the permeability in a coal bed is in the cleat system; none is in the matrix, so cleat spacing and width are important. The orientation of present day *in situ* stress also is important. If the *in situ* stress is parallel to the face cleats, permeability is increased. But, if the *in situ* stress is perpendicular to the face cleats, forcing the cleats to close, permeability is reduced. The presence of saline water in deep coals can be indicative of low permeability.

Fluid flow through a coal bed is very important and is affected by a variety of factors. Under optimum conditions, coal would be brought to the surface by a structural high adjacent to a highland area with high precipitation, creating a recharge area for the basin. Permeability barriers in the basin would create hydrodynamic traps. Unfortunately, this is not a common occurrence. Under-used tools in this area include potentiometric maps that show the direction of water movement, and chlorinity maps that indicate flow direction from areas where formation waters have been diluted by fresh water near the recharge area, to saline water deeper in the basin. Low gas contents can indicate areas of flushing by water flow, and high gas contents can indicate the presence of hydrodynamic traps. If water is moving downward, toward a barrier, the explorationist should drill on the updip side of the barrier. If water is moving upward from deeper in the basin toward the barrier, one should drill on the downdip side of the barrier. Therefore, one must determine the flow direction.

Mr. Scott went through the introduction to the exploration model in about 45 minutes. The rest of the day was devoted to revisiting each of the six key elements of the model in more detail, followed by an hour-long exercise at the end of the workshop.

The 53 registrants were divided into 7 teams for the final exercise, which was to plot a wide variety of data, some important, some less so, for 8 basins in the same geographic area on a map, and use the regional depositional framework, cleat orientations, current *in situ* stress direction, and very sparse data on coal thickness, vitrinite reflectance from outcrop samples, and well data to rank the coal basins one through eight in terms of their coal bed methane potential.

All eight groups ranked the worst basin as their bottom one or two, but none of the eight groups was able to pick the top basin, as determined by Mr. Scott. In fact, only two of the groups ranked the best basin in their top three, and two other groups ranked it as number four out of the eight basins. This exercise certainly gave workshop participants a better appreciation for the experience required to make the best interpretations from little or poor data. Surface vitrinite reflectance data, the orientation of present day *in situ* stress, cleat directions, coal thickness and the presence or absence of an adjacent highland to create a recharge zone appeared to be the main criteria in ranking the basins, but not all these data were present for all basins.

Many attendees said that this was the best workshop that we had offered and asked if we could bring Andrew Scott back for his full, two-day workshop. One geology manager who attended, stated that "no one can beat what you do, especially for the money." He went on to say, that his company would continue to support the PTTC program by sending younger staff members to all of our workshops.

Fractured Reservoir Workshop Returns

Dr. Ron Nelson, a well-known and recognized expert in the field of fractured reservoirs, returned to the Appalachian basin to present a one-day version, designed specifically for PTTC, of his workshop on exploration and evaluation of fractured reservoirs. The workshop was held in conjunction with the Eastern Section meeting of the American Association of Petroleum Geologists, October 6 in Columbus, OH.

The object of the workshop was to offer a one-day sampler of the kinds of natural fracture systems; fracture morphology; calculating fracture porosity and permeability; how fracture/matrix interaction affects book reserves; mechanical predictions, i.e., where on a structure one will expect to find more fractures; fracture reservoir classifications; and reservoir heterogeneity, resulting in wells being winners and dogs.

In addition to the workshop notebook, Dr. Nelson directed attendees to two websites: www.dh.com, where one can search on "Ron Nelson" to find 450 slides in Pdf and Power Point; and www.brokenN.com, where Dr. Nelson offers other helpful hints based on his long experience throughout the world.

The workshop began with an explanation of a generalized fracture reservoir work flow diagram, and the steps in creating a static conceptual model in a fractured reservoir. One of the initial cautions offered to participants was to avoid "fracture denial." Too many times, geologists and engineers deny the presence of fractures in their reservoirs, for a variety of reasons, but mainly because they are hard to model. But, the giant carbonate reservoirs in the middle East are all fractured. Eventually, these will undergo EOR, and when water is injected, where will it go?

Sometimes we assume that all reservoir heterogeneity is due to stratigraphy or facies changes. Often it is too late when we realize the control of fractures on heterogeneity. We also tend to underestimate the drainage area of a well, and the elliptical nature of the drainage area around wells in fractured reservoirs. This results in offsetting good wells too closely with wells that are not as good.

Some geologists think that fractures are random, or fail to see them at all. In truth, fractures are highly ordered, and one can read a lot from them, once one knows how. Fracture orientations faithfully record the state of stress at the time of their formation.

Natural fractures can be classified as tectonic, regional, contractional and surface-related and induced. Tectonic fractures can be either fault-related or fold-related. Fractures related to faults increase in number closer to the fault, are more concentrated on the hanging walls, and have a predictable dip, if you know the dip on the fault. The key is, how broad is the zone of more intense deformation near the fault? In a play like the Trenton-Black River, faults and associated fractures provide permeability and porosity and serve as pathways for the movement of diagenetic fluids and hydrocarbons. What is not always known is the extent of the fractured zone around each fault.

"Not all positions along a fault are created equal." Dr. Nelson cautioned that if you space your wells equally along a fault, you are doomed to failure. Some Trenton-Black River faults have reversed their direction over time. Deeper formations associated with fault inversion, i.e., the Beekmantown-Knox below the Trenton-Black River, may contain more fractures, and higher porosity.

It is important to distinguish between the "process zone" and the "damage zone" bordering a fault. The process zone is a zone of intense deformation, several 100's of feet wide. The damage zone is the result of intense deformation related to fault slip, and is usually only a few 10's of feet wide. The goal is to get close to it, but not too close. Pre-slip fracturing forms the process zone; the fault propagates through it at a later stage of deformation, but not necessarily in the center of the zone.

Fault surfaces are neither straight nor smooth. The topography of a fault surface can be mapped using 3D seismic. Knowing the location of bends in a fault can allow you to predict the location of intense fracture zones. Open fractures are expected on the outside of a bend in a fault; fractures on the inside of a bend are expected to be under compression and thus, more closed. Even in cross section, faults exhibit "outside" and "inside" corners, with the same effect - extension and more open fractures on the outside and compression and more closed fractures on the inside.

How do you calculate fault zone pore zone volume and oil reserves? Dr. Nelson went though several examples, changing some of the parameters to demonstrate the effect on the final oil volume.

Following lunch, Dr. Nelson began his discussion of fold-related fractures, beginning with where extension and shear fractures are fold on a fold, and the orientation of type I and II fractures on the fold. Fault-related fractures are relatively restricted, measured in 100's of feet, whereas fold-related fractures are the most productive. Everywhere we have folds we have very pervasive fractures at various scales, from thin section scale to those observed on satellite photos.

This analogy was presented: a fractured reservoir is the rush hour going to work. Assume that all roads, of any size, are fractures. When you leave your house you may begin with a narrow alley or street, which leads to a wider access road which takes you to the expressway. Each different road is wider, each one allows you to go faster. Therefore, it is necessary to consider the little fractures as well as the larger fractures. Like getting from your house to the freeway, the little fractures lead to larger fractures; all contribute to well performance.

Dr. Nelson then moved on to regional fractures, those fractures that are developed over large areas with little change in orientation, no evidence of offset along the plane, and are perpendicular to bedding. Examples are the well-developed fracture sets in the Devonian shales in the Appalachian and Michigan basins and fractures, commonly called cleats, in coal beds. Some of these fractures extend through all of the beds, whereas some are restricted to certain beds. Numerous examples of shales and sandstones were shown, including the non-systematic "fanning out" of fracture orientation tangential to the mountain front in New York and Pennsylvania.

The question was raised: how many of these regional fractures are related to "unroofing?" Out west, when you move away from a canyon surface, these fractures maintain the same orientation. It seems that we have different mind sets in different parts of the country. For example, in the Appalachian basin, there is a mind set that says you cannot drill horizontal wells in these rocks. To this Dr. Nelson replied, "Get yourself a new driller."

Contractional fractures are fractures of varying origin, either tensile or extension, associated with a bulk volume reduction throughout the rock. Dessication, syneresis, thermal gradients and mineral phase changes are processes that can generate contractional fractures. "Chicken-wire" polygonal fractures in the Devonian shales are an example. However, Dr. Nelson cautioned not to confuse these fractures with those seen in old cores. Old cores commonly have polygonal fractures on the outside that formed as the cores dried.

Chicken-wire fractures can significantly increase permeability and production.

Following the afternoon break, Dr. Nelson discussed surface-related fractures and fracture morphology types, including open fractures, deformed fractures, mineral-filled fractures and vuggy fractures in carbonates.

Dr. Nelson confided that of all the workshops he teaches, he gets the most feedback from PTTC workshops. He believes that PTTC workshops are attended by geologists and engineers who are interested in "getting stuff done."

Unconventional Natural Gas and Global Energy: Just a Matter of Time?

It's just a matter of time before the historical trend in increased H/C ratios brings us to the point where natural gas replaces oil as the World's preferred fossil fuel of choice. That was the opinion stated by Dr. Scott Tinker, Director of the Texas Bureau of Economic Geology and of PTTC's Texas Region, during a luncheon address at AAPG's Gulf Coast Section in San Antonio, TX. Furthermore, Dr. Tinker stated that unconventional gas would play a big role in meeting the increased global demand in the future, and that the development of a larger LNG infrastructure is necessary to make natural gas a global commodity.

Dr. Tinker began his remarks with a discussion of the shift in H/C ratios over time. The world has shifted from solids (wood and coal) to liquids (oil) and is about to shift to gas (natural gas, followed by hydrogen). During this predictable progression, the H/C ratio has changed from 0.1 (wood) to 1 (coal) to 2 (oil) and soon will be 4 (methane), before the world shifts to non-fossil hydrogen as the primary energy source.

However, the shift away from fossil fuels is not imminent. “The world is dependent on fossils fuels everywhere. We are a long way from leaving a fossil fuels economy,” stated Dr. Tinker.

Until the late 1940's, U.S. domestic supply and demand curves for oil were essentially identical. However, since that time, demand has exceed domestic supply. To satisfy the U.S. market, we simply began to import oil. Because the cost was competitive, there was no economic driver to increase domestic supply. However, in terms of global oil supply, when demand catches up with supply, increasing imports will no longer be an option. At that point in time, we need a cost-effective alternative fuel, and natural gas will be that fuel.

In terms of global natural gas, supply continues to increase and probably is decades away from a slowing trend, according to Dr. Tinker. However, in terms of the U.S. market, natural gas is at the same point today that oil was in the 1950's and early 1960's when we began importing oil and increasing those imports annually. Right now we are importing natural gas, through pipelines, from our neighbors to the north and south. Relatively soon, natural gas will be transported globally, as LNG, resulting in a supply-demand future that will reflect the past three decades of oil imports to meet demand.

But, Dr. Tinker cautioned, LNG is only a supplement, not a solution. In the U.S.,
The development of unconventional sources of natural gas is the key to the future gas market. According to Dr. Tinker, our “unconventional gas industry is on the rise, really just starting.” He predicts that we will develop an unconventional natural gas economy that will mirror the “old” natural gas economy. Tight formation gas, coal bed methane and gas from shales all will be important. In terms of U.S. basins, the Rockies hold the majority of the unconventional gas resource base, but the Appalachian basin will be a player.

Actually, we could be entering the natural gas economy right now. This is a fuel that is good for the environment, the economy and national security. Unconventional gas and LNG will be critical players, and research and technology will be very important. The federal government has a role to play, by investing in research and technology.

We also have a critical role to play, an educational role. It is up to us to educate the public and the policy makers, and to support increased government investment in research and technology.

Exploration Model, Potential New Play, Devonian Shales Addressed

Speakers at the recent meeting of the Ontario Petroleum Institute (OPI) and Independent Oil and Gas Association of New York (IOGA-NY) addressed a variety of clastic reservoirs and potential plays. Lynne Davies and Marianne Molgat (Talisman) presented a model for exploration and development of Whirlpool and Grimsby (Lower Silurian) sandstone reservoirs, using a case study of the East Lake field as an example. David Copley suggested that the Theresa Sandstone (Cambrian) could be the next big play in New York. And, Jim Morabito (Consultant) summarized Devonian shale activity and unconventional gas opportunity in New York.

Lower Silurian clastic reservoirs are productive throughout a vast area from the Ontario Peninsula to western West Virginia. Historical production is estimated at 11 Tcf, of which 125 Bcf has come from the Ontario Peninsula. The principle reservoirs in the play are the Whirlpool, Grimsby and Thorold, which are called Medina and Clinton, or just Clinton, in different parts of the Appalachian basin.

In East Lake field, Ontario Peninsula, the basal Whirlpool is interpreted by the speakers as braided fluvial sandstones and shales associated with tidal flats and channels, whereas the upper part is a marine sandstone. The lower Grimsby is subtidal channel sandstones, and the upper part, tidal channels and mud flats. Each facies has a distinctive signature on well logs. These sandstone reservoirs have a wide range in porosity and permeability. Porosity ranges from 2 to 20%, averaging 7%, and permeability ranges from 0.5 to 250 md. Post-stimulation open flows average 1.5 MMcf/d, but cumulative recoveries range from 0.03 to 3 Bcf. Operators need 0.1 Bcf (100 MMcf) to break even.

This variability in performance "creates a problem with predictability" according to the authors. To aid in locating good wells versus poor performers, they have incorporated the locations of strike-slip faults as mapped on the underlying Queenston Shale into an exploration model. Fault trends and fold axes with NW-SE trends parallel production trends. On seismic, these faults produce small grabens at the level of the Whirlpool and Grimsby, and good wells have been drilled and completed in the grabens. Their conclusion is that secondary porosity is associated with the NW-SE faults and that surface fracture patterns reflect basement fault patterns and faults/fractures in these deeper subsurface reservoirs.

David Copley reviewed deeper drilling to the Theresa Formation in western New York, in an area of abundant Medina wells. In this area, the Galway (Theresa) Formation consists of sandstone and dolomite, 800-1000 feet thick, separated from the Black River Limestone by the sandy Little Falls Dolomite. An 80-foot sandy zone is present at the top of the Theresa.

Copley's subsurface correlations and mapping demonstrate that the Little Falls Dolomite thins from southwest to northeast where it subcrops below the Knox Unconformity. This unconformity also cut down into the 80-foot sandy section in the Theresa. Gas shows have been reported in the Black River and Little Falls in Northwoods field, Wyoming County.

Conventional subsurface mapping and seismic mapping show a nosing on the Packer Shell in Northwoods field, accompanied by a thinning of the interval between the Packer Shell and the Onondaga Limestone. 3D seismic data over the field indicate that the Onondaga is flat, but the Trenton and Theresa roll across the feature; time structure maps of the Trenton and Theresa show closure over the nose.

Production through 2002 from two wells is 329 MMcf, "not stellar, but enough to get us interested in developing the play," according to Copely. He concludes that the Theresa is a viable drilling objective, with two successful wells and two more in the planning stages. Closure is the key, so seismic, aeromagnetics and subsurface mapping are key components in an exploration plan. However, he states that the reservoir is easily imaged and mapped, and more drilling will occur.

Jim Morabito discussed how drilling history, analogs and economics were incorporated into a model for Devonian shale exploration and development, as seen through the eyes of an asset manager charged with drilling 100's of wells, evaluating big blocks of acreage and managing a large investment fund.

He began by discussing an Antrim Shale analog on the north edge of the Michigan basin, where the shale has to be de-watered prior to producing gas. In that area, seismic data are essential to avoid channels below glacial deposits that have cut out the shale target. He then discussed the New York situation, including maps of fields and shows, total thickness, drilling depth and total organic carbon content, before summarizing common practices in drilling and completion. This included the assumption that the shales would be wet, so a rat hole was drilled.

Morabito concluded by showing examples of reserve estimates and his recommended criteria for selecting areas in which to drill. These criteria included, among other factors, drilling depth, subcrop below glacial drift, an evaluation of lineaments and close proximity to a pipeline.

And Still More Trenton-Black River Talks

Petroleum Geologists and Engineers in the Appalachian basin just can't seem to get enough information on the Trenton-Black River play, hydrothermal dolomites, exploration methods, etc. During the recent combined meeting of OPI and IOGA-NY, six speakers addressed various topics that were applicable to the play.

Bruce Hart (McGill University) is conducting research on seismic imaging of diagenesis to develop a tool for studying the presence and extent of dolomitization in a host limestone formation. His premise is that diagenesis creates porosity which can be imaged with seismic data, so if we reverse the process, seismic techniques will allow us to determine porosity, some of which will be primary, and some of which will be secondary, i.e., due to diagenesis.

Several examples were presented, one of which was from the Trenton-Black River productive trend in the Finger Lakes area of New York. The problem was distinguishing between prospective and non-prospective structures, so inversion techniques were used to image porosity zones just below the top of the Black River at various structural elevations in separate fault blocks.

David Harris (Kentucky Geological Survey) discussed Trenton-Black River analogs for fault-controlled Ordovician dolomites in Kentucky. He stated that dolomites developed in Trenton-Black River outcrops in Kentucky may be analogous to subsurface reservoirs in New York. With assistance from two students, Dr. Harris is studying the petrography and geochemistry of samples from the outcrop and a core taken near the outcrop, and is using seismic to determine the extent of dolomitiztion in the subsurface away from the outcrop.

Preliminary results were presented. However, the core has just been cut, so it will be next Spring before the study is complete. At that time, a PTTC-sponsored workshop will be organized and hosted, combining the core research with a field trip.

A second PTTC-sponsored core workshop and field trip will result from a similar study in eastern New York. Taury Smith (New York Museum Institute) discussed the origin, distribution and reservoir characteristics of hydrothermal dolomites in Lower Paleozoic carbonates in New York. Again, Dr. Smith is conducting a detail study of an outcrop analog of Trenton-Black River reservoirs to better understand the structural complexity of these reservoirs and the links between the reservoirs and faults and fractures.

The outcrop of interest is in the Mohawk Valley approximately 100 miles northeast of the play area. Among the more interesting observations made to date is that all of the dolomite observed in outcrop is north of the river; to the south, it is all limestone. Several en echelon dolomite bodies were observed on the floor of a quarry north of the Mohawk River, and their trend parallels the river. These bodies were excavated and cleaned, and a 3D ground-penetrating radar survey was shot over the quarry. Once this was done, it was discovered that two of the bodies were actually connected. These dolomite bodies do not extend laterally to boundary faults that have been mapped, and the dolomite bodies do not follow fractures. Instead, the dolomite cuts across the fractures.

The top of the dolomite bodies is heavily brecciated. Porosity is present in vugs, fractures and in the breccia. Bitumen coatings are common. It is being suggested that the dolomite bodies were produced by tectonics and hydrothermal fluid flow from depth.

Future work leading up to the PTTC workshop will include more cleaning of the bedrock exposed in the quarry, plus detailed mapping and cutting a core to the top of the Little Falls Dolomite below the Black River.

Marianne Molgat (Talisman) presented a case study of Trenton-Black River reservoirs in the Rochester Pools on the southwestern side of the Ontario Peninsula. Two NW-SE productive trends have been developed, in which the EUR is 2.7 MMbbls. Of this amount, 2.5 MMbbls have been produced to date. Reservoirs are secondary, late diagenetic dolomite developed in the Trenton and Black River carbonates. Some facies control of dolomitization is apparent, as the bioclastic Sherman Falls Member of the Trenton is more pervasively dolomitized than other members. Exploration currently is confined to the area south of the limit of bioclastic development in these carbonates.

Production has not been evenly distributed between the two pool trends. The north pool or trend has produced 700 Mbbls, whereas the south pool or trend has produced 1.6 MMbbls. The question is, or was, “Why?”

The answer seems to be that dolomitization in the north pool is restricted to the Sherman Falls Member of the Trenton Limestone and most of the underlying Black River Formation. However, in the south pool, nearly all of the Trenton and Black River have been dolomitized.

A seismic program that was shot in 2002 provided much better results than an older survey shot in 1991. After en echelon strike-slip faults were identified and mapped, the first horizontal well was drilled.

Three types of wells have been drilled. Vertical wells are confined to the Sherman Falls; horizontal wells also are drilled to the Sherman Falls; and dual wells are drilled to the entire Trenton-Black River section. Horizontal wells are the preferred choice, because they offer the best opportunity to encounter dolomitized zones.

Terry Carter (Ontario Ministry of Natural Resources) and his co-author, Sean McFarland (Golder Associates) presented an analysis of Trenton-Black River reservoirs in the Ontario Peninsula after 100 years of production. They are conducting a three-part study to collect data; calculate/estimate reserves; and estimate the remaining but as yet undiscovered resources. No price assumptions were used while estimating resources, but the authors did assume that the resources would be technically recoverable with existing technology.

Previous studies have used a volumetric method to estimate resources. This study used a truncated discovery process method, which is a statistical approach based on pool size and discovery date (often called a pool size distribution method). The model was run, geology was then added, and the model was run a second time. This method assumes a log-normal distribution of pool size discovered over time.

In a 1981 survey, 1.4 MMbbls and 16 Bcf were estimated as remaining but undiscovered resources. The current study estimates these resources at 39 MMbbls of oil and 247 Bcf of gas. Reserve estimates from a 2002 study were 22.5 MMbbls of oil and 41 Bcf of gas. The authors concluded that most of the oil has been discovered and produced, with only 42% remaining to be found, whereas most of the gas, 83%, remains to be discovered.

Ian Colquhoun (Veteran Resources) and Peter Johnson (Union Gas) appeared in costume (hard hats, drill rig apparel) to present a highly-animated presentation, complete with sound effects, of the Dover 7-5-VE Trenton-Black River hydrothermal dolomite reservoir. The field was discovered in 1983 and development continued until 1992, resulting in several productive trends being recognized. Oil and solution gas are produced from the Black River in a long, linear NE-SW trend. But, in the overlying Trenton, the productive trend is more E-W, and separated into two distinct reservoirs on opposite sides of the Black River oil trend. The western Trenton pool produces only from the Sherman Falls Member, whereas in the eastern pool, separate intervals in the Sherman Falls and deeper in the Black River have been developed.

This same observation has been made in the NE-SW Black River oil trend. In the southwestern end, production has been established in two Black River members, whereas in the northeastern end, some production has been established in the Trenton as well as in the Black River. When the authors overlaid a net porosity isopach map on a Trenton time slice map from 3D data, they observed a correlation between porosity and isolated structure lows as interpreted from 3D. They also interpreted distinct reservoirs in the Trenton and Black River when they overlaid fault traces on the pool maps.

A SW-NE seismic line was shot through the productive trend. The Trenton and Black River were observed to drop down along 6 or 7 interpreted faults, which begin in the basement. The basement surface was covered by a Cambrian sandstone unit. In fact, all significant Ordovician production occurs in wells above this Cambrian sandstone.

The authors summarized the development of hydrocarbon reservoirs is three stages. In Stage 1, dolomitization from the Coboconk Member of the Black River to the bioclastic Sherman Falls Member of the Trenton occurred when warm fluids moved into the Cambrian sandstones and then up fault and fracture zones to the carbonate units. In Stage 2, hydrocarbons were emplaced, oil in the Black River, gas in the Trenton. Cementation at the end of Stage 2 sealed the reservoir. In Stage 3, an evolution of fluids and structure occurred. As faults and fractures lower in the feature were activated, oil migrated into younger, solution-enhanced reservoirs on the flanks of the feature in the Sherman Falls Member, well above the Black River oil reservoir.

In conclusion, the authors stated, “the rocks speak volumes.”