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TECHNOLOGY DEVELOPMENTS IN NATURAL GAS EXPLORATION, PRODUCTION AND PROCESSING

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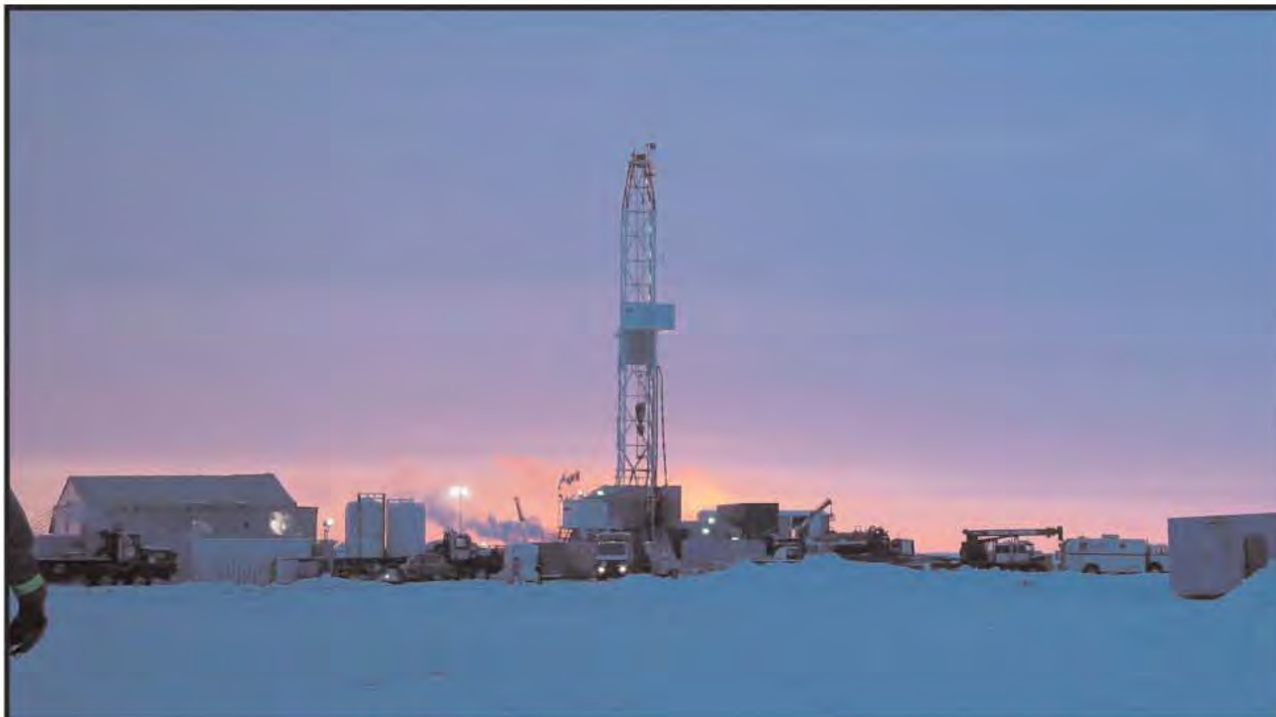

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Early Investments in Hydraulic Fracture Mapping Pays Off

Two of the articles in this issue of *GasTIPS* focus on hydraulic fracture mapping, a technology that has grown rapidly during the past two decades. Today, hundreds of fracture mapping jobs are performed each year and the number of companies offering various types of fracture mapping services has also grown. Perhaps no one is better suited to describe the connections between early Department of Energy (DOE) research and development investments and the current success of this technology than Norm Warpinski, one of this issue's authors. We talked with Norm about the DOE's role.

"Remember, there are two ways to map hydraulic fractures, microseismic monitoring and tiltmeter monitoring. Each has its strengths and weaknesses. The first systematic application of microseismic fracture mapping was geothermal research – the Hot Dry Rock Project carried out by Los Alamos National Labs with funding from the DOE in the 1970s. This work helped to establish the basic science behind the technology," he said.

The Los Alamos work continued for a number of years, and somewhat later, the DOE also funded Sandia National Labs to build and deploy receivers for fracture mapping. Warpinski joined Sandia in 1977 and was involved in that early work.

"In the 1980s, the Sandia system was used in a few industry tests, but the most success derived from those tools was in the DOE Multiwell experiment (M-Site) in the southern Piceance Basin, where four of five major fracture experiments were successfully monitored," he said.

By the end of the 1980s, Warpinski said it became clear that single receivers in multiple monitor wells would not be adequate for microseismic monitoring applications in oil and gas operations where multiple wells are not usually available. The DOE funded a joint Sandia and Oyo Instruments project that resulted in a multi-level receiver system that could be run on a fiber-optic wireline. This effort laid the groundwork for several generations of multi-level receiver systems with superior capability in sampling rate and the number of receivers that could be fielded. These advances helped make single monitoring well fracture mapping possible.

The DOE also funded early research related to tiltmeters, the second fracture mapping approach.

"There was some early work using surface tiltmeters supported by the DOE in the 1970s and scattered tiltmeter tests in the 1980s, but surface tiltmeters became a commercial technology when Chris Wright formed Pinnacle Technologies in 1992. Downhole tiltmeter mapping arrived in the late-1990s after their application was validated at M-Site and Pinnacle developed the first downhole wireline tiltmeter system," Warpinski said. "Chris was also involved in much of the early fracture diagnostic research at M-Site as an engineer with one of the subcontractors, Resources Engineering Systems."

During the 1990s, Gas Research Institute (now Gas Technology Institute) joined with the DOE in funding research on hydraulic fracture mapping at M-Site, and eventually partnered with Pinnacle Technologies to help commercialize the microseismic technology.

"Chris and Pinnacle made it a business, but M-Site experimental work helped to pave the way for all of the fracture mapping that is being done today," Warpinski said.

After the M-Site work, industry microseismic activity picked up with a couple of drill cuttings injection tests, one of which had surface and downhole tiltmeter fracture mapping funded by the DOE. In about 2000, a second generation of highly reliable multi-level receiver systems spurred the wider application of microseismic monitoring. Pinnacle began using these receivers in 2001 and developed a business that quickly grew to several hundred mapped fractures per year. One sign of the health of this technology is the fact that by 2005, several competitors had entered the field.

Warpinski's article in this issue of *GasTIPS* focuses on the ways microseismic monitoring and tiltmeter monitoring can be combined to achieve even greater clarity in understanding the complexity of hydraulic fractures.

"The growth in unconventional gas development here in the U.S. and around the world will continue to drive enhancements in the application of this technology," he said. "But it is important to recognize the DOE's very significant historical role in its development. It took over two decades to make fracture mapping workable for normal oil and gas activities, and the DOE's long-term support was critical."

We hope you find this issue of *GasTIPS* informative.

The Editors

Tight Gas Reservoir Characterization Projects to Provide Wealth of Online Data for Producers

By Thomas H. Mroz,
National Energy Technology Laboratory, Strategic Center for Natural Gas and Oil

The Department of Energy's National Energy Technology Laboratory is funding a number of projects to develop reservoir characterization databases for tight gas formations in the Appalachian Basin and in several Rocky Mountain basins.

The projects were selected based on broad industry interest in unconventional gas resources in the Appalachian and Rocky Mountain basin regions in general, and in the Mesaverde and Dakota formations of the western basins in particular. Tight gas sands represent 72% (342 Tcf) of the projected unconventional resource for the United States. Mesaverde Group sandstones represent a principal gas productive unit in western U.S. basins like the Washakie, Uinta, Piceance, Upper Greater Green River and Wind River.

The parallel efforts are focused on acquisition of detailed data that can be used to better define reservoirs, identify thinner pays and reduce drilling and completion costs in these unconventional reservoirs. The data being collected includes core samples and analyses, well logs, and geochemical and geophysical data. As the studies are completed during the next year or two, both final reports and databases will be made available on the National Energy Technology Laboratory (NETL) Web site *(www.doe.netl.gov/technology/html)* for public access.

The petroleum industry utilizes geographic information system (GIS) software to manage well data for spatial analysis. Several service companies offer packages with interfaces to allow use of spatial data as input for mapping, cross sections and development of input for reservoir models. The data made available under these projects will have all the attributes needed to allow its use in most petroleum industry software packages.

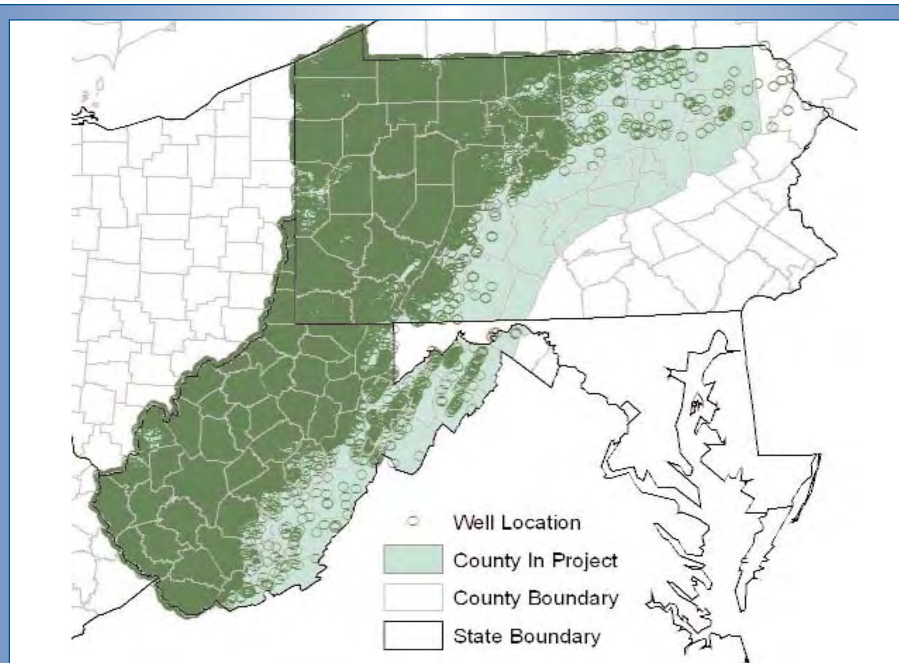

Figure 1. Distribution of wells included in the project area.

These projects will have positive impacts on production within each of the targeted basins. The significant increase in availability of critical information that producers can choose to utilize in their own work processes will allow them to make better decisions on placement of infill wells. In addition, improvement in producers' ability to identify and quantify bypassed pay zones in existing wells should increase the rate of development and improve the efficiency of recovering natural gas from these low-permeability formations.

Appalachian Basin project

The first project, titled *Critical Information for Development of Tight Gas Reservoirs in the Appalachian Basin,* is a dual effort by the West Virginia Geological and Economic Survey and the Pennsylvania Geologic Survey. The effort will collect and digitize information and data on gas reservoirs with the greatest remaining reserves within these two states and make the data available to the public through an interactive geospatial model on the Internet. Specifically targeted are the siltstone and sandstone intervals in the Mississippian, Upper Devonian and Silurian sequences that industry has identified as having high potential for future development.

Information will be collected for the Lower Mississippian/Upper Devonian Berea/Murrysville plays and the Upper Devonian Venango, Bradford and Elk plays in West Virginia and Pennsylvania as well as the Lower Silurian "Clinton"/Medina play in Pennsylvania. Geophysical logs for wells that have penetrated the selected plays will be scanned along with any available core slabs (Figure 1). Researchers will also digitize tight intervals within representative logs for each play, take digital photographs of available thin-sections and core slabs, and convert relevant maps and cross sections from the *Atlas of Major Appalachian Gas Plays* and selected state survey publications to digital form. The Atlas was prepared under the supervision of the Appalachian Oil and Natural Gas Research Consortium with funding provided by the Department of Energy (DOE) and published in 1996.

After collecting the data, the researchers will develop an Internet-based geospatial data delivery model designed for public access by American Petroleum Institute number, location, or any of the attributes in the dataset, and populate the model with the collected data, organized by tight gas play. The online GIS will include application tools to create maps, cross sections and digital picture graphic displays using the well log and other data. Users will be able to select a detailed area of the basin, identify wells, and make a cross section with stratigraphic picks displayed and links to reservoir analytical data and core pictures where available in the section.

The system will be integrated with the Petroleum Technology Transfer Council (PTTC) Appalachian region Web site, with links to the online model from the Web sites of all of the state geological surveys in the region. Availability of data and information through the Web site will be advertised via professional society and industry publications.

San Juan Basin project

The Petroleum Recovery Research Center (PRRC) at New Mexico Institute of Mining and Technology is carrying out a second project, titled *Petrophysical Analysis and GIS for San Juan Basin Tight Gas Reservoirs*. The PRRC has considerable experience in performing similar studies for the DOE.

The primary goal of this project is to increase the availability and ease of access to critical data on the Mesaverde and Dakota tight gas reservoirs of the San Juan Basin (Figure 2). Secondarily, the researchers hope to improve industry understanding of the variability of formation waters within the basin through spatial analysis of water chemistry data. The project will collect, integrate, and standardize a variety of petrophysical and well data concerning the Mesaverde and Dakota reservoirs, with particular emphasis on data available in the areas designated as tight gas for the purposes of the Federal Energy Regulatory Commission.

A relational GIS will be created to archive this data. The information will be analyzed to fine-tune regional well log interpretations, improve pay zone recognition from old logs or cased-hole logs, determine permeability ratios, and also to analyze water chemistries and compatibilities within the study area. Data will be extracted from existing databases as well as paper records, then cleaned and integrated into a single GIS database. A user interface will provide tools to make the data and results of the study accessible and useful. The final deliverable for this project will be a Web-based GIS providing data, maps and user tools that will be accessible to the public.

Figure 2. A map of Dakota and Mesaverde core analysis wells included in the project.

Mesaverde reservoir study

A third project, titled *Analysis of Critical Permeability, Capillary and Electrical Properties of Mesaverde Tight Gas Reservoirs,* will be undertaken by The University of Kansas, the Kansas Geological Survey and The Discovery Group Inc. of Denver.

The main goal of this project is to improve the understanding of the minimum gas saturation necessary for gas flow, a characteristic fundamental to defining the tight gas sandstone resource and particularly critical in the quantification of economically marginal gas reserves. The objective is to reveal the nature of critical gas saturation, capillary pressure and electrical properties of tight gas sandstones of the Mesaverde Group, how these vary with basic properties such as porosity, permeability and lithofacies, and the impact of these relationships on drainage patterns in tight natural gas reservoirs. Detailed and accurate moveable gas-in-place resource assessment is most critical in marginal gas plays, and there is need for quantitative tools for definition of limits on gas producibility because of technology and rock physics as well as for defining water saturation.

Published rock property data and at least 300 rock samples and digital wireline logs from four or five wells will be collected from Mesaverde Group intervals representing the range of lithofacies present in each of the five major tight gas sandstone basins: Washakie, Uinta, Piceance, Upper Greater Green River and Wind River. Basic properties, including routine and *in-situ* porosity, permeability and grain density of the rock samples, will be measured and, based on these measurements, a subset of 150 samples will be selected to represent the range of porosity, permeability, and lithofacies in the wells and basins. The objective of this sampling process is to create a population of core samples that represents the complete range of properties the Mesaverde Group exhibits.

Advanced measurements to be performed on the selected samples include: drainage-critical gas saturation; routine and *in-situ* mercury intrusion capillary pressure analysis; cementation and saturation exponents and cation exchange capacity (via multi-salinity method); geologic property characterization (core description and thin-section microscopy, including diagenetic and point-count analysis); and standard wireline log analysis.

The compilation of published data and that measured in the study will be input to a Web-based relational database. Public access to the data will allow producers to construct individualized rock catalog format reports based on user-defined search and comparison criteria. The data will also be made available as a complete database if people are interested in loading the data into their own systems.

In addition, core and wireline log calculated properties will be compared and algorithms developed for improved calculation of reservoir properties from log responses. The scale dependence of critical gas saturation will be evaluated through bedform-scale reservoir simulation models that represent the basic bedform architectures present in Mesaverde sandstones. Simulations will be used to parametrically analyze how critical gas saturation and relative permeability scale with size and bedding architecture.

By providing a database of advanced properties that will improve resource evaluation tools for gas exploration programs, this project should have a significant impact on quantitative resource assessment of Mesaverde and other western tight gas sandstones.

Tight gas reservoir modeling

A fourth project, a more generic tight gas sand reservoir study, has been funded through the Historically Black Colleges and Universities Program under the DOE's educational support for college students program. This project is titled *Production of Natural Gas and Fluid Flow in Tight Sand Reservoirs* and is being led by Florida International University.

The study will investigate the influence of microscopic flow parameters on gas production in tight, low permeability sandstone reservoirs by altering input parameters in several reservoir models and running sensitivity analysis on ranges of tight gas formation characteristics. The research seeks to identify relationships between macroscopic reservoir parameters easily identified and measured by commercial operators and the microscopic flow dynamics that significantly affect well performance. If successful, these relationships can be used by operators to make cost-saving and/or production-enhancing decisions during completion of tight sandstone reservoirs. Preliminary modeling results indicate water chemistry is a significant factor in determination of gas and water saturations, and small changes in brine saturation can have a large impact on gas-in-place estimates.

Technology transfer plans

The results of similar projects in the past have been transferred through the presentation of papers at technical meetings and active participation in regional workshops. Unfortunately, because of the planned reduction in funding for the NETL's natural gas and oil research areas, which fund the PTTC, such technology transfer outlets, like workshops on how producers can utilize the GIS and its data, will not be available.

The principal investigators for these projects are:

- *Appalachian Basin Project*—Douglas Patchen at WVGES, (304) 594-2331; and John Harper at the Pennsylvania Geological Survey in Pittsburgh, (412) 442-4230.
- *San Juan Basin Project*—Martha Cather at New Mexico Tech's PRRC, (505) 835-5685.
- *Mesaverde Reservoir Study*—Alan Byrnes at Kansas Geological Survey, Kansas University. (785) 864-5317.
- *Tight Gas Reservoir Modeling*—Maria Bravo at Florida International University, (305) 348-4238.

Past NETL Research Related to Unconventional Resources Online

The NETL's Strategic Center for Natural Gas and Oil Web site is an archive of past research where new or newly reorganized companies can access final reports on a number of plays. These past projects include methane from coal, fractured Devonian shale, oil shale, tight gas sands, drilling-stimulation-completion technology applications to all reservoir types and deep gas.

The DOE-funded research projects have been a mainstay of the technology that the majority of the operators in the continental U.S. have relied during the past 30 years to develop new plays. Tools developed through laboratory experimental studies and field demonstrations, and projects designed to integrate the efforts by service companies, petroleum companies of all sizes, academia, state and other government agencies and national laboratories, have played a part. Many projects were accomplished with industry cooperative funding and the sharing of data that would otherwise not be available for evaluation and interpretation.

The current projects outlined above follow the same pattern of collaborative research but will employ the latest GIS tools to allow easy access to the data and facilitate the creation of maps and cross sections for online evaluation. It is anticipated this online resource will contribute to the continued success of the industry in exploring for and producing natural gas in U.S. sedimentary basins in the United States. ✧

New Technology Supports Increased E&P Success in Coalbed Natural Gas

By John M. Pope, Ph.D.,
WellDog Inc.

Extraction of natural gas from coal seams continues to be challenged by complex exploration and production issues, many of which originate from the unconventional and heterogeneous reservoir behavior typical of coalbed natural gas.

While conventional oilfield tools and analysis methods are used with varying success to describe unconventional and heterogeneous reservoirs, few technologies have been developed specifically to address the key issues involved in coalbed natural gas exploration and production (E&P) – namely, which seams contain the most gas and how much water must be removed to produce it.

Successful production of natural gas from coal requires producers to depressurize a reservoir via water production to allow gas to desorb from the coal. Specifically, the reservoir pressure must be reduced below the effective partial pressure of methane in the reservoir (the "critical desorption pressure") to allow two-phase flow of gas and water from the coals so methane can flow directly from its adsorbed state in the coal to the gas phase and into the wellbore.

Because coal seams are relatively continuous and highly permeable, it is common for production-related pressure perturbations in one wellbore to affect the reservoir surrounding another reservoir. Therefore, assessment of reservoir producibility and economics must consider the overall field. Conventional wisdom in the industry holds that even uneconomic wells contribute to overall field depressurization, and thus to production of gas.

This analysis, however, is based on a tenuous assumption: that the key reservoir properties of gas content, critical desorption pressure and total reservoir pressure are fairly consistent across typical fields, and that "sweet spots" effectively do not exist independent of other parts of typical fields. This assumption has been necessary because of a lack of data regarding reservoir heterogeneity for coalbeds. This lack of data is generally because of the high cost and long lead times required for gas desorption from cores, and accuracy problems inherent to other methods such as mudlogging and gas desorption from cuttings. Because of these constraints, a typical coalbed operator may collect core samples from only one seam in one well per township, while subsequently drilling between 100 and 250 wells on each township – sometimes completing them in as many as three seams for each well. As a result, the operator must make decisions regarding up to 1,000 possible completions based on the results of just one test.

As in most unconventional gas projects, increasing E&P success for coalbed natural gas requires new technology that can provide reservoir data faster, more accurately and for a lower cost. The WellDog Critical Gas Content reservoir analysis service has been developed in response to this need.

This technology takes advantage of the fundamental geophysics of coalbeds – most importantly, that the effective partial pressure of methane in the unperturbed reservoir is equivalent throughout the local coal and surrounding water. This partial pressure of methane can thus be measured in one location, such as the wellbore fluid, and be determined for the local reservoir accessed by that wellbore. In the coal, this partial pressure can be related to the gas content of the coal via an adsorption isotherm, which measures gas storage capacity of methane by coal as a function of the methane's partial pressure. Key to this analysis, though, is the ability and knowledge required to ensure the wellbore fluid accurately represents the far-acting reservoir.

Determining the partial pressure of methane in the wellbore fluid can be done by a number of

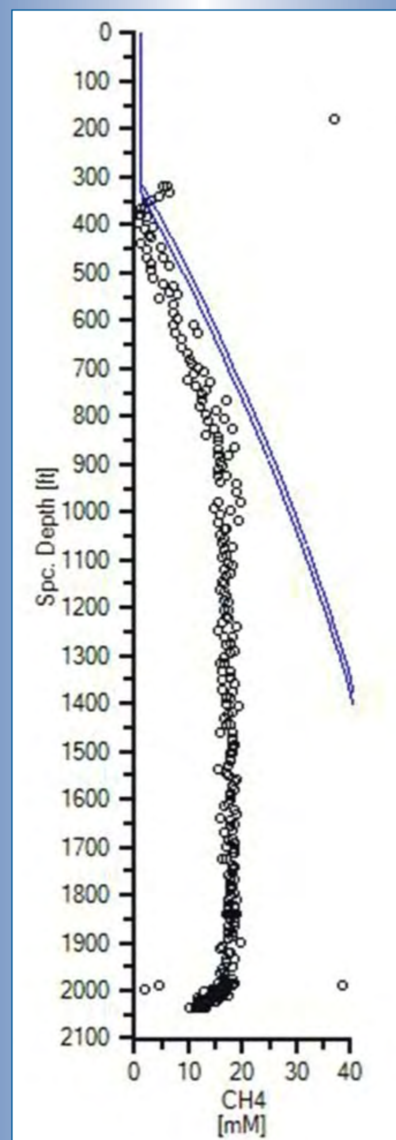

Figure 1. A typical plot of methane solution gas concentration vs. depth was measured in a Powder River basin wellbore. (All figures courtesy of Well Dog)

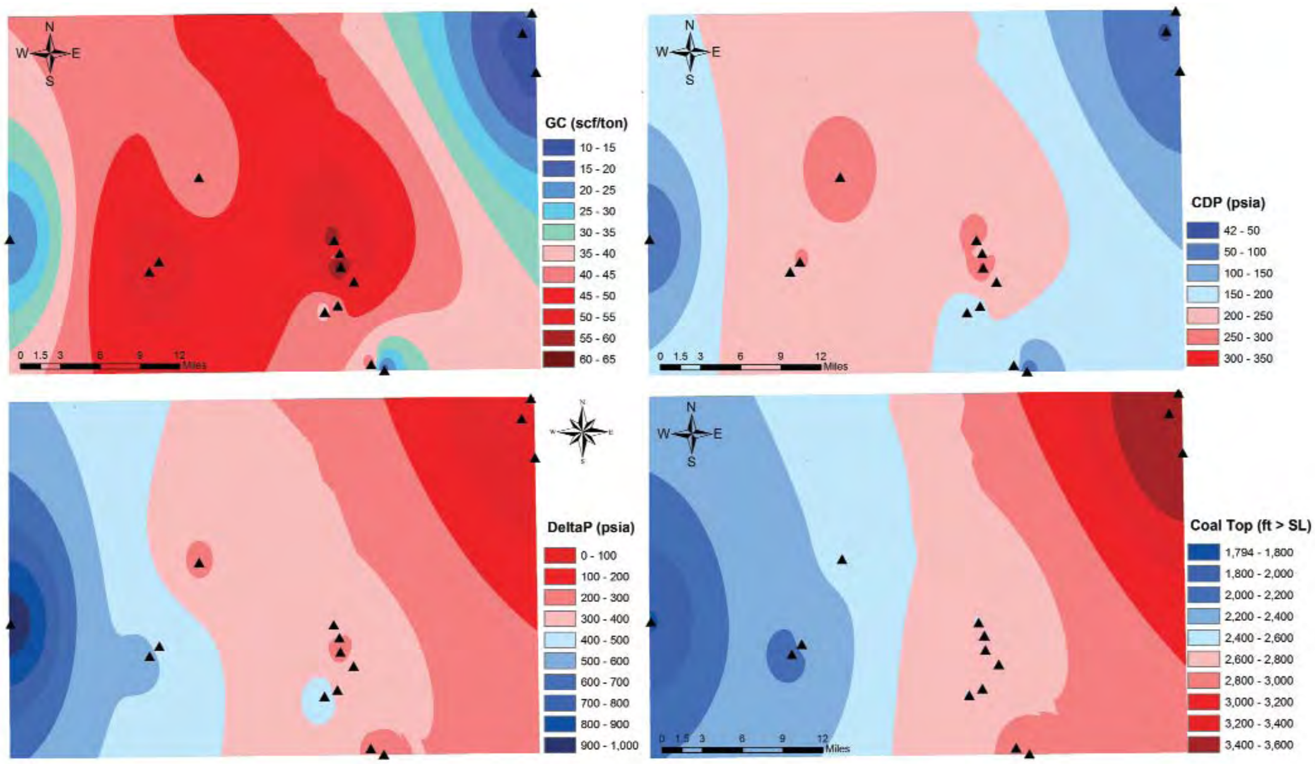

Figure 2. A series of isopleths illustrates how coal structure, critical desorption pressure, gas content and initial gas saturation in the coal vary across a 7 by 5 township area.

standard bubble-point analysis techniques such as headspace analysis of bottomhole samples or water/gas ratio measurements. However, after surveying partial pressure throughout hundreds of wellbores, we have found the effective partial pressure of the fluid in a wellbore can be affected by a number of regularly occurring conditions, including perturbation by production from the surrounding coal, presence of residual solids from the drilling or completion process and contribution of fluids from other completion zones.

Thus, a single measurement of partial pressure at one depth in a wellbore cannot be certain to represent the local reservoir. Only by performing continuous measurements, in depth and/or time, and comparing the results with the well completion and production history can definitive results be obtained.

For example, Figure 1 shows a typical plot of methane solution gas concentration vs. depth measured in a Powder River Basin wellbore. The completion history of this wellbore included perforation at 2,000 feet below surface (fbs), high-rate water stimulation and blow down to the coal seam prior to the test. Below that depth, the wellbore contained fresh water. Above 2,000 fbs, the wellbore contained fluids drawn in from the target coal seam.

The results of this completion are evident in the plot – below 2,000 fbs, the solution gas levels decreased as the reservoir fluids mixed with fresh water. Above about 900 fbs, the solution gas levels began to decrease as methane gas evolved from the water. Thus, the pressure at 900 fbs approximates the bubble point but is not equivalent to it since the temperature, pressure and possibly ionic strength at 900 fbs were all different from those quantities in the reservoir at 2,000 fbs.

Most importantly, the solution gas levels in fluid at depths between 900 fbs and 2,000 fbs are constant. This constancy indicates the coal seam surrounding the wellbore contains fluids that have fairly uniform solution gas levels, as would be expected for an unperturbed reservoir. Taken together, these data provide a high level of confidence that the solution gas level of the fluid between 2,000 fbs and 900 fbs represents the local reservoir.

By applying a solubility law, it is possible to convert the methane concentration measured in that fluid to an effective partial pressure of methane, for example, methane partial pressure that would be required under reservoir conditions to solubilize the measured concentration of methane. This partial pressure of methane in the wellbore fluid is thus equivalent to that of the reservoir, since the fluid originated from the reservoir and was unchanged in composition during its journey into the wellbore. The methane partial pressure in the reservoir is related to two key reservoir characteristics: it is equivalent to the pressure at which methane will desorb directly from the coal (and the pressure below which the well begins to produce gas); and it

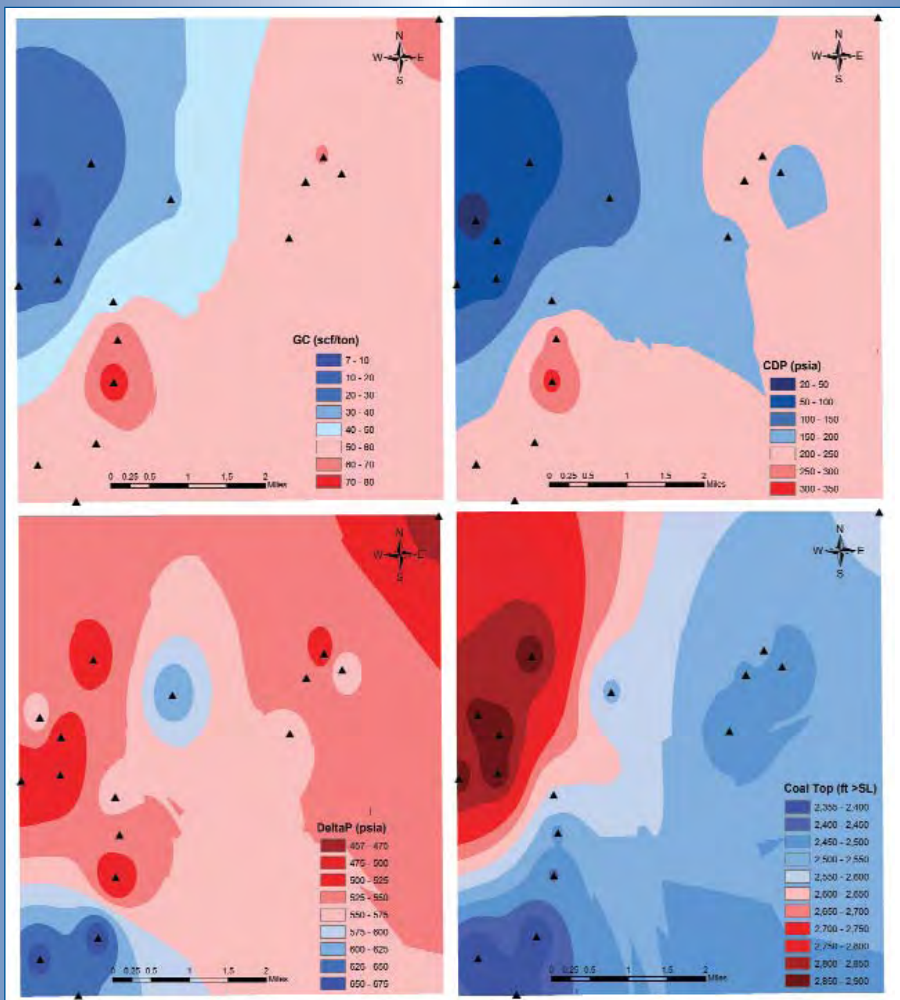

Figure 3. A series of isopleths was generated from data collected in 20 wells distributed across a field measuring about 2.5 miles by 2.5 miles (4 m by 4 m).

is directly related to the gas content of the coal by a relationship described by a measured methane gas adsorption isotherm for that particular coal.

In this manner, by careful analysis of well completion and production history and by direct measurement of trace levels of solution gas, it is possible to directly and quickly determine critical desorption pressure and gas content of a coal seam. These analyses have returned consistently accurate data in hundreds of laboratory and field tests, The Critical Gas Content method provides an unprecedented fast, low-cost tool for scoping reservoir heterogeneity. This tool has been employed during the past year by a number of operators in basins across North America. For example, Figure 2 shows a series of isopleths (generated using the inverse distance weighted interpolation method on data collected in fifteen wells over about 10 days) illustrating how coal structure, critical desorption pressure, gas content and initial gas saturation in the coal vary across a 7 by 5 township area.

In this field, the coal dips from the northeast to the west. Conventional wisdom suggests the gas content would be greater in the deeper portion of the seam where the reservoir pressure is greater. However, the results of testing showed the highest methane partial pressure, and thus critical desorption pressure and gas content, in the middle of the field. While the producibility, such as the amount of pressure drawdown required to produce gas from the coal, was most favorable in the northeast, little or no gas was present in that part of the field. Also, the producibility and gas content were poor in the deepest part of the field on the west side. Unexpectedly, most of the gas was located in the center of the field, which was also a region with reasonable producibility. Another unexpected result was that the gas content varied widely across this field – from less than 15 scf/ton in the northeast to more than 60 scf/ton in the center of the field. This level of gas content heterogeneity is consistent with results observed in other fields, as well.

To examine reservoir heterogeneity over a smaller field, higher density data sets were also collected. For example, Figure 3 shows a similar series of isopleths generated from data collected in 20 wells distributed across a field measuring about 2½ miles by 2½ miles. Data collection and analysis required about 2 weeks.

In this case, the coal showed a general dip from northwest to southeast, with distinctive small structures present in the southwest and east. A river flowing from the southwest to northeast intersected this field. In general, on the northwest side of that river, gas content and critical desorption pressure were low, while on the southeast side of the river, both were generally high. Producibility varied widely, appearing to depend more on individual structures than on general field trends. This field included an excellent production target (gas content greater than 60 scf/ton) near the southwest and good production targets (gas contents ranging between 40 scf/ton and 60 scf/ton) throughout its eastern half. While producibility was good in the northwest, economic quantities of gas were not present in that area and it is unlikely, given the field structure, that producing wells in that area would significantly impact reservoir pressures in the rest of the field.

Scenarios such as these emphasize the significant benefits that can be obtained by gathering more complete and accurate reservoir data. Conventional oilfield tools fall short when confronted by the complex geology and geophysics inherent to coalbed natural gas reservoirs. Data from the Critical Gas Content service can immediately and substantially mitigate risk and water production costs for coalbed E&P. ✧

Application of Microseismic Imaging to Improve Shallow Hydraulic Fractures

By Roger B. Willis,
Universal Well Services Inc.;
L. Paugh, *Great Lakes Energy Partners LLC;*
and L. Griffin,
Pinnacle Technologies

The Stripper Well Consortium, a group with a mission to foster and transfer technologies that can help improve production from the nation's many stripper wells, funded in part a project that combined a series of technical disciplines in an effort to improve stimulation effectiveness in shallow Devonian age reservoirs in western Pennsylvania.

Project partners were the operator, Great Lakes Energy Partners, Universal Well Services Inc. and Pinnacle Technologies, a provider of imaging technologies and interpretations of subsurface fracture geometries (Figure 1).

Thousands of wells are hydraulically fractured in the Appalachian Basin each year with little clear understanding of what the resulting fracture actually looks like. A number of variables exist in the subsurface including natural fractures, permeability variations, *in-situ* stresses and faults that can influence the ultimate dimensions and orientation of the created fracture. It is necessary the stimulation design team understands the impacts these features can have on the path a hydraulic fracture takes in the subsurface. The created fracture and its conductivity ultimately dictate a well's productivity and drainage area.

The majority of Appalachian Basin reservoirs require some type of stimulation to be economically viable. Thousands of wells have been drilled and completed utilizing a variety of stimulation techniques. The reservoir and created fracture are, by their nature, difficult to see and assess with any real certainty. It is therefore necessary to make assumptions about how the geology of the reservoir will respond to the style of stimulation to optimize the recovery of hydrocarbons. Throughout the years, some principal assumptions have been accepted that influence the hydraulic fracture design for the majority of treatments. Some of these assumptions were controversial at first but have gained general acceptance. Other design factors are the result of "local" conclusions based on the results of treatments that have been refined through years of modification.

Traditional methods of predicting fracture growth include computer modeling, treatment pressure analysis, radioactive tracers and well testing. Comparing the inferred geometry for a series of wells with the direct far-field fracture mapping results can help determine whether the inferred techniques have merit in the determination of true fracture geometry. Microseismic imaging, a technique that images the created fracture by monitoring seismic or micro-earthquake "events" during the treatment from an array of sensors in an offset wellbore, has gained acceptance as a reliable method of determining created fracture geometry during the past 5 years. The images can also be utilized to calibrate other simpler and lower cost techniques if they prove applicable.

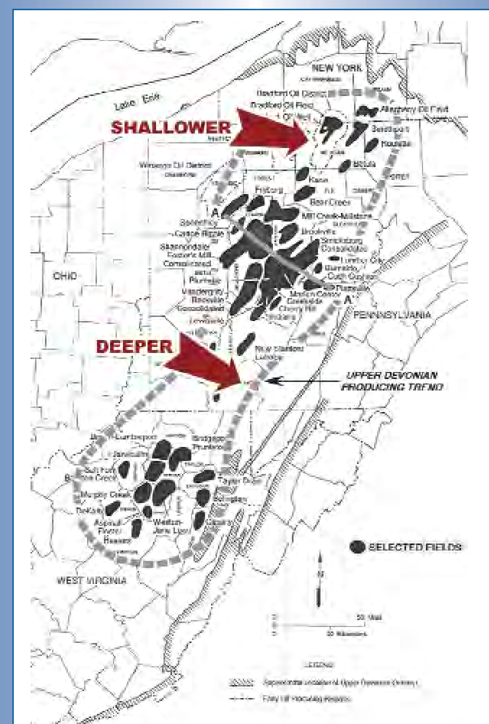

Figure 1. Upper Devonian Sand Fields

These measured created fracture geometry results need to then be related to production from the stimulated intervals to determine the fracture's effectiveness. Where the results in production improvement are obvious and seem to apply for a formation over a large area, the stimulation style will usually be accepted and quickly applied over a large region. This can be seen in the shallow reservoirs of the Bradford group where operators are steadily increasing the number of fracture stages, which directly correlates to increased production. The highly competitive nature of regional leasing and the difficulty in obtaining good treatment data and production information makes correlating job type and profits a daunting task. A good first step is to better understand the created fracture geometry for a particular fracturing style in a given reservoir.

It would be helpful for the design team if there were some easy way to determine the actual geometry of the created fracture. Until relatively recently, there was not much reliable data about what the created fracture actually looked like. Direct far-field fracture monitoring techniques (passive microseismic and downhole tilt) hold the promise to definitively measure the created

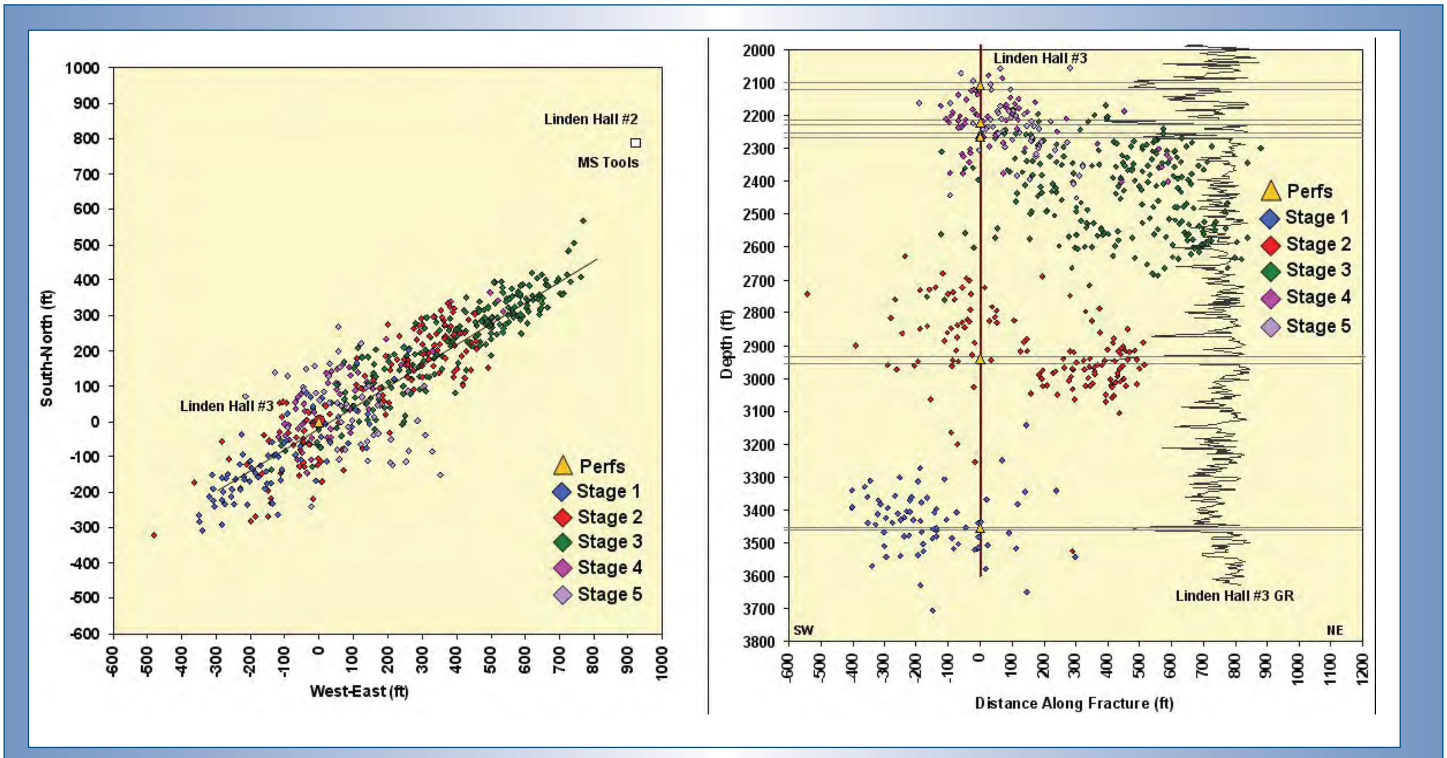

Figure 2. Microseismic Overview

fracture. While commercial, these are relatively expensive and require an optimum situation where the tools to image the fracture are placed in an offset wellbore at a distance close enough to detect the signal from the created fracture. It is anticipated that refinements of these techniques will allow imaging from the treatment wellbore itself in the near future at a lower cost. A number of different techniques have been developed and refined in hopes of better understanding fracture geometry without having to dig down and see it with our eyes.

Passive microseismic imaging of hydraulic fracture treatments, while widely utilized in other parts of North America, has not seen general application in the Appalachian Basin. The microseismic mapping process detects and plots in three dimensional space microseisms, which are micro-earthquakes induced by the changes in stress and pressure associated with hydraulic fracturing. These micro-earthquakes are slippages that occur along pre-existing planes of weakness, such as natural fractures, which emit seismic energy that can be detected at nearby seismic receivers. If an array of tri-axial receivers is situated at depth near the hydraulic fracture, compressional (primary or p) and shear (secondary or s) waves can be detected and locations of the events can be calculated. These microseisms are small, and sensitive receiver systems are required to obtain accurate results. The location of any individual microseism is deduced from arrival times at the receiver of the p and s waves (providing distance and elevation data) and from particle motion of the p-wave (providing azimuth from the receiver array to the event). To use the particle motion information, it is also necessary to orient the receivers, which is typically performed by monitoring perforating, string shots or other seismic sources in the treatment well or some other nearby well (Figure 2).

This microseismic data can be assembled to portray the geometry of the fracture in a format useful to the design team. It can reveal many facets of the fracture, including its azimuth, height and symmetry. Of particular importance is its ability to define the complex nature of fracture growth as it intersects natural fractures, differing stress zones, and more in the subsurface. It has often been discovered that multiple fractures are being created where it was thought single fractures existed. This has been proven to be invaluable in helping maximize the production rates and total recovery in a variety of fields, including the Barnett Shale.

The Microseismic Fracture Imaging of the Great Lakes Energy Partners Linden Hall prospect in the Hunker field has added a large piece to the puzzle of how hydraulic fractures grow in some reservoirs of the Appalachian Basin.

The most common stimulation style for the deeper reservoirs of the Upper Devonian is referred to as "ball and baffle." The well is cased, cemented and perforated using jet perforators. The unique component is the use of multiple, sequentially smaller, restrictions called baffles, placed in the casing as it is being run. This technique allows for the isolation of zones during the treatment by dropping progressively larger "frac balls," which land on the strategically placed baffles.

In shallower Devonian Sand reservoirs, it is necessary to complete every discrete reservoir with a stage to maximize recovery. In deeper settings, the design team needs to determine the geometry of the fracture and relate it to the geology of the reservoir rocks. In this case, it is vital to determine

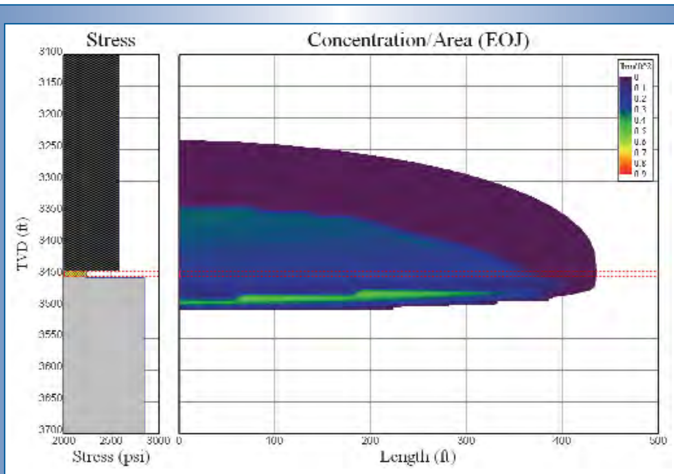

Figure 3. Uncalibrated Fracture Model

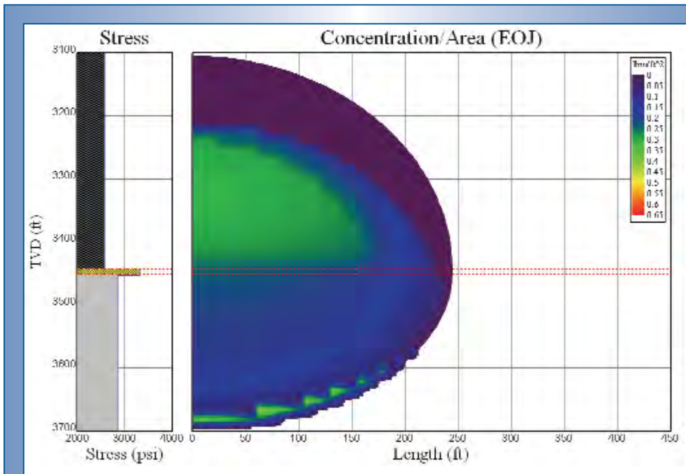

Figure 4. Calibrated Fracture Model

the height of the fracture. This is necessary for several reasons. First, the fracture could be growing vertically through several target zones from a single stage. In this case, it is necessary to decide whether one stage can serve to stimulate several zones in a more cost-effective manner than pumping multiple stages. A vertical fracture can penetrate the many vertical permeability barriers and communicate with multiple discrete reservoirs. For this reason, it is important the design team has a clear understanding of what the geometry of each stage will connect.

The microseismic image of the created fractures in the Linden Hall project allow us to compare and calibrate some of the simpler techniques commonly utilized because of their lower cost and availability. It will take a more in-depth analysis to properly analyze the results but preliminary comparisons point to some correlations:

- uncalibrated computer models gave a more contained fracture aspect ratio than was actually created;
- calibrated computer models more closely resemble the created geometry as illustrated by microseismic mapping;
- vertical penetration of fractures into sand bodies, both above and below, was greater than previously thought;
- initial pressure analysis of the treatment showed a close understanding of the contributing variables is necessary to give the technique any validity; and
- tracer studies would not have predicted actual fracture geometry in the far field as fracture growth would have been to far away for the receiver to detect the radioactive material (Figures 3 and 4).

The imaging of Upper Devonian Sand horizons in the Linden Hall project points out the need to evaluate if the overlap of fractures from discretely fractured zones has a negative or positive impact on well performance. It will be necessary to determine whether the hydraulic fractures actually intersect or exist in parallel but unconnected geometries. The implications of either scenario are not trivial as they pose many questions for the design team. Some of the possible implications include:

- the fractures do communicate with each other, and it is not necessary to perform as many stages to drain sand bodies that can be stimulated in one stage;
- the fractures do not communicate. They are parallel and non-connected. In this case, it is unlikely this is an efficient and cost-effective method of draining the adjacent reservoirs. One stage might be sufficient to effectively drain the targets in this case;
- sand placement might be less than optimal based on design goals for fracture conductivity;
- the fractures do communicate but have a positive impact on production as they serve to better distribute the sand pack and assure fracture conductivity for each zone in a suitable range;
- stress shadowing, a term used to describe the effect an existing fracture can impose on a nearby propagating fracture, might have a positive influence on containing the propagating hydraulic fracture; and
- stress shadowing may also be responsible for causing asymmetrical fracture growth.

After the wells in the study area were "cleaned up," production logs were run in an effort to correlate the fracture geometry with the contribution each zone gave to the total. Some of the early results indicate the fractures did not connect even though the microseismic images indicated some degree of overlap in nearby horizons. This could be because of fractures that did not intersect but instead ran parallel to each other in the subsurface. More evaluation will be necessary to refine the interpretation of how the created fracture geometry relates to the production and the ultimate impact on the wells economic performance.

The interaction of the hydraulic fracture with the geology present in the target is the design team's fundamental concern. The engineering and geological participants of the team must spend time discovering the critical aspects of the controlling factors in effective reservoir drainage. All members of the team should strive to define the factors that contribute to the design for each particular discipline and horizon. ✧

Imaging Ultra-deep Geologic Structures using Wave Equation Migration and Illumination

By A. M. Popovici, S. Crawley, C. Lupascu, Y. Li and Y. Zhang
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In a project sponsored by the U.S. Department of Energy's National Energy Technology Laboratory, geophysicists from 3DGeo and the Bureau of Economic Geology, University of Texas at Austin test novel ideas on synthetic and real datasets for imaging ultra-deep complex geologic structures using wave-equation depth migration, wave-equation velocity model building and wave-equation illumination.

The work performed under the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) project developed and tested a novel, next-generation technology, designed to enhance seismic resolution and imaging of ultra-deep complex geologic structures by using wave-equation depth migration; wave-equation velocity model building technology for deeper data penetration and recovery, steeper dip and ultra-deep structure imaging, and accurate velocity estimation for imaging and pore pressure prediction; and accurate illumination and amplitude processing for extending the amplitude-variation-with-offset (AVO) prediction window. Ultra-deep wave-equation imaging provides greater resolution and accuracy than what can be accomplished with standard imaging technology. The advanced imaging methodology may improve the success rate and cost effectiveness for new deep-field discoveries. It also has applications in increasing recovery efficiency for the development of existing fields.

Utilizing 3-D wave-equation migration for seismic imaging is a new approach that has shown promise imaging the complex deep Gulf of Mexico structures. Previously, only Kirchhoff methods could be used to generate common-reflection point gathers in offset domain and iteratively improve the velocity model used for imaging. Recent research has established a new approach to generate angle-domain common image gathers directly from 3-D wave-equation methods. The angle-gathers can be used to update the initial velocity model, and they form the basis for a novel method of 3-D migration velocity analysis. This technology can be used for oil and gas exploration in deep complex structures more than 15,000ft where conventional single travel time arrival Kirchhoff imaging (Figure 1 left) fails to provide an accurate structural image, while wave-equation imaging (Figure

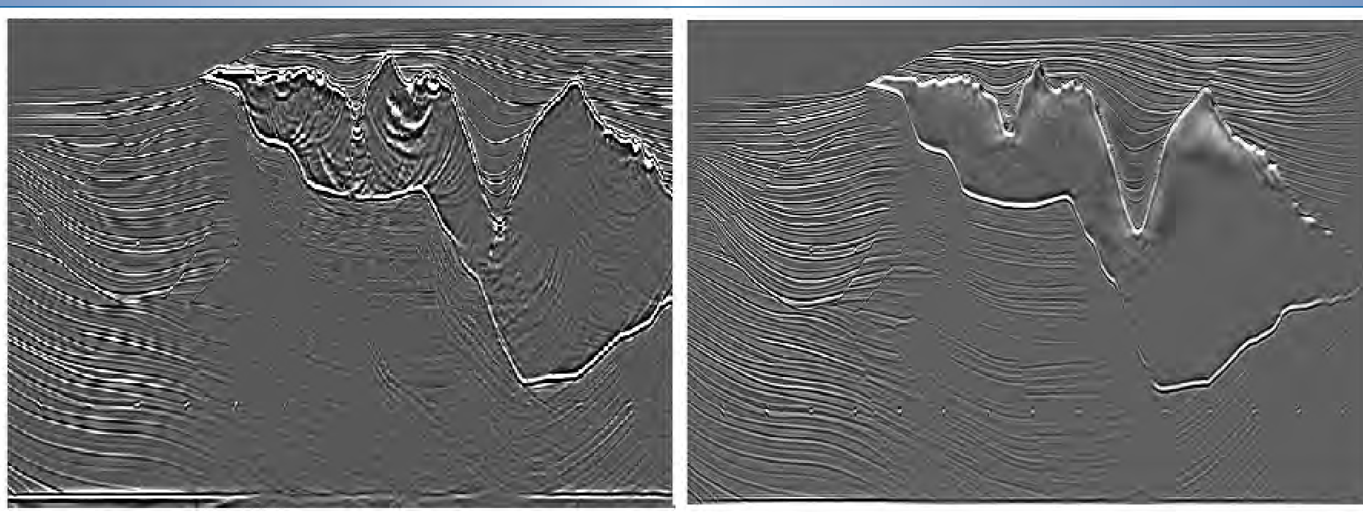

Figure 1. A comparison of standard Kirchhoff depth migration vs. wave-equation depth migration. The sediments under the salt body are not imaged correctly by Kirchhoff migration because of multi-pathing (left). Wave-equation depth migration focuses accurately the multiple arrivals under the salt (right).

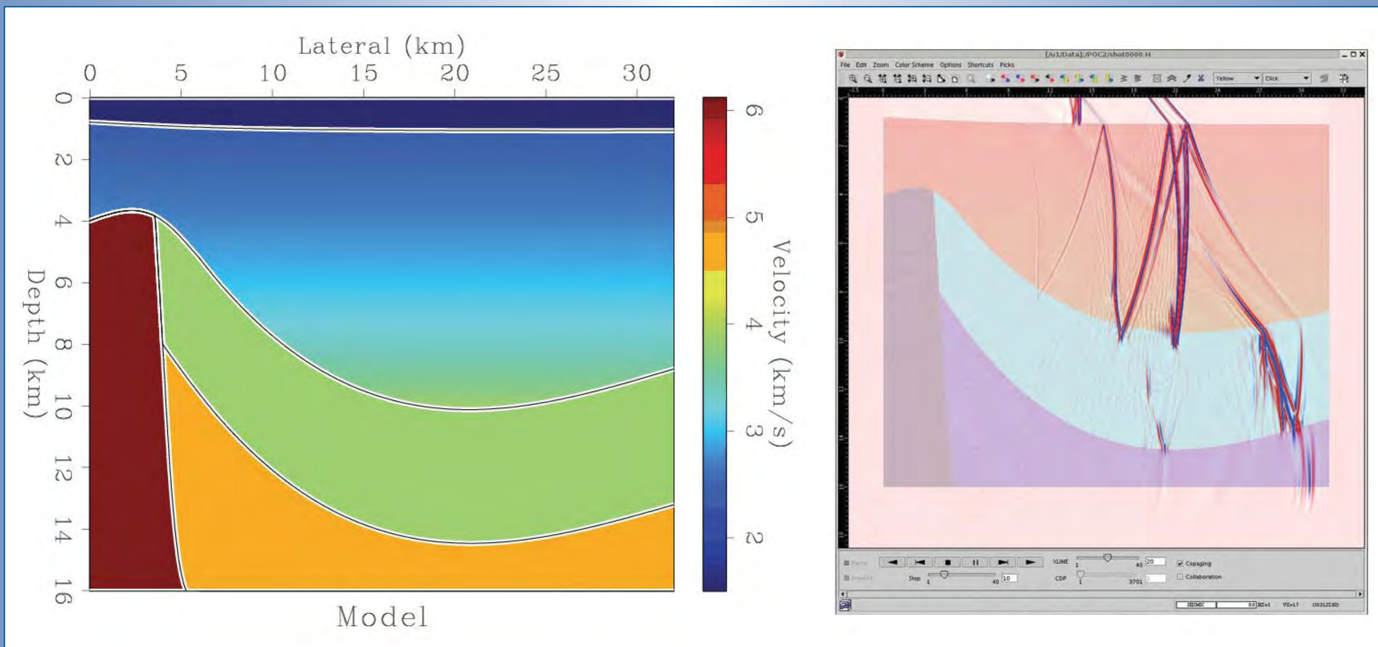

Figure 2. A velocity model and example of wavefront snapshot finite differences modeling for generating true amplitude wave equation imaging.

1 right) provides much higher structural resolution and amplitude fidelity. This in turn allows the geophysicist to obtain higher resolution petrophysical information, linking the accurate seismic amplitude to reservoir properties like porosity, sand/shale content, water/oil saturation, Vp/Vs ratio and more. 3DGeo has been one of the pioneers in researching common image angle gathers technology and holds the patent (US6546339) for using the moveout of the angle gathers for computing the velocity update. The current work focused on wave-equation ultra-deep illumination and accurate amplitudes in conjunction with wave-equation imaging and velocity model building.

Because of a major gas shortage forecast for the United States, oil and gas companies are increasing domestic exploration in an effort to find large gas reserves. One of the key areas of focus is the Gulf of Mexico shelf, where reserves in the 250-Bcf-range are being discovered at depths exceeding 15,000ft. Another key area, the Gulf Coast onshore, is now emerging as the next frontier to extend these plays. The onshore plays are expected to yield discoveries in the 1-Tcf-range at depths between 20,000ft and 30,000ft and possibly 40,000ft. These plays are now referred to as ultra-deep. Ultra-deep plays present a significant opportunity for oil companies to add oil and gas reserves. The opportunity for seismic companies is also significant because legacy data sets, whether proprietary or multi-client, fall short technically of what is required to open these new trends.

The U.S. Department of the Interior, Minerals Management Service OCS Report MMS 2001-036, assessed that the amount of undiscovered, conventionally recoverable resources in the deep Gulf of Mexico is an average of 37 billion bbl of oil (high estimate of 45 billion bbl of oil), and 193 (high estimate of 207 Tcf) Tcf of natural gas. At a conservative average price of $40/bbl and $8/Mcf of gas, that is a value of $1.48 trillion for the oil reserves and $1.54 trillion (respectively) for natural gas reserves. The importance of obtaining accurate images in these areas was highlighted by Kenneth J. Bayne, deepwater development manager at Unocal (now Chevron): "In the Southern Green Canyon area, where fields such as **Mad Dog**, **Holstein** and **Atlantis** lie, the geology is less understood because some of the reservoirs are subsalt and, thus, have lower-quality seismic."

The lower quality seismic refers to standard prestack depth imaging technology. During the past 3 to 4 years, the exploration industry has realized the importance of using wave-equation migration methods in parallel with Kirchhoff in the deep-water areas of the Gulf of Mexico, and 3DGeo has been part of the effort of using and demonstrating this technology.

Theoretical and practical approach

The objective of the research effort was to examine the feasibility of imaging ultra-deep structures onshore and offshore, by using wave-equation migration, angle-gathers velocity model building, and wave-equation illumination and amplitude compensation. The effort consisted of answering critical technical questions that determine the feasibility of the proposed methodology, testing the theory on synthetic data and finally applying the technology for imaging ultra-deep real data. This research addressed a number of questions, including: the handling of true amplitudes in the downward continuation and imaging algorithm and the preservation of the amplitude with offset or amplitude with angle information required for AVO studies; the effect of several imaging conditions on amplitudes; non-elastic attenuation and approaches for recovering the amplitude and frequency; and the effect of aperture and illumination on imaging steep dips and on discriminating the velocities in the ultra-deep structures. All these effects were incorporated in the final imaging step of a real data set acquired specifically to address ultra-deep imaging issues, with large offsets (12,500m) and long recording time (20 seconds).

True-amplitude imaging is necessary when the amplitudes of the seismic image are used as input for estimating the petrophysical properties of the reservoir rocks. Seismic imaging of deep targets requires particular attention to amplitude preservation. Seismic signals are attenuated and scattered during propagation to deep targets. Compensating for the signal loss and an irregular illumination of exploration targets at depth becomes a necessity for obtaining a reliable structural image and obtaining an image with meaningful amplitudes. In structurally complex media, the single-arrival assumption and the classical asymptotic theory of Kirchhoff integrals become inadequate. Wave-equation imaging is identified as a preferable alternative to the Kirchhoff method because of its ability to handle multiple arrivals, large velocity variations and limited bandwidth wave-propagation effects. However, the theory of amplitude preservation in wave-equation imaging is less understood, and practical implementations still lack reliable tools of amplitude compensation. There are four parts of the amplitude compensation problem in wave-equation imaging:

Preserving true wave amplitudes at the downward wave-propagation**—**True amplitudes are not automatically preserved by wave-equation methods, because the one-way equation, which serves as the basis for most of them, does not preserve the correct two-way equation amplitudes. Amplitude preservation at this step is especially important for imaging steeply dipping reflectors such as salt flanks and faults.

Removing overburden propagation effects**—**The overburden propagation effects should be removed to recover the true reflectivity at each image point. True reflectivity is recovered based on the reflection angle.

Compensating for irregular target illumination resulting from incomplete seismic acquisition geometries**—**This step is crucial for imaging under salt bodies and in other difficult areas of deep exploration. Wave-equation methods (unlike ray-tracing methods) offer the additional benefit that the illumination can be studied for individual frequency bandwidths.

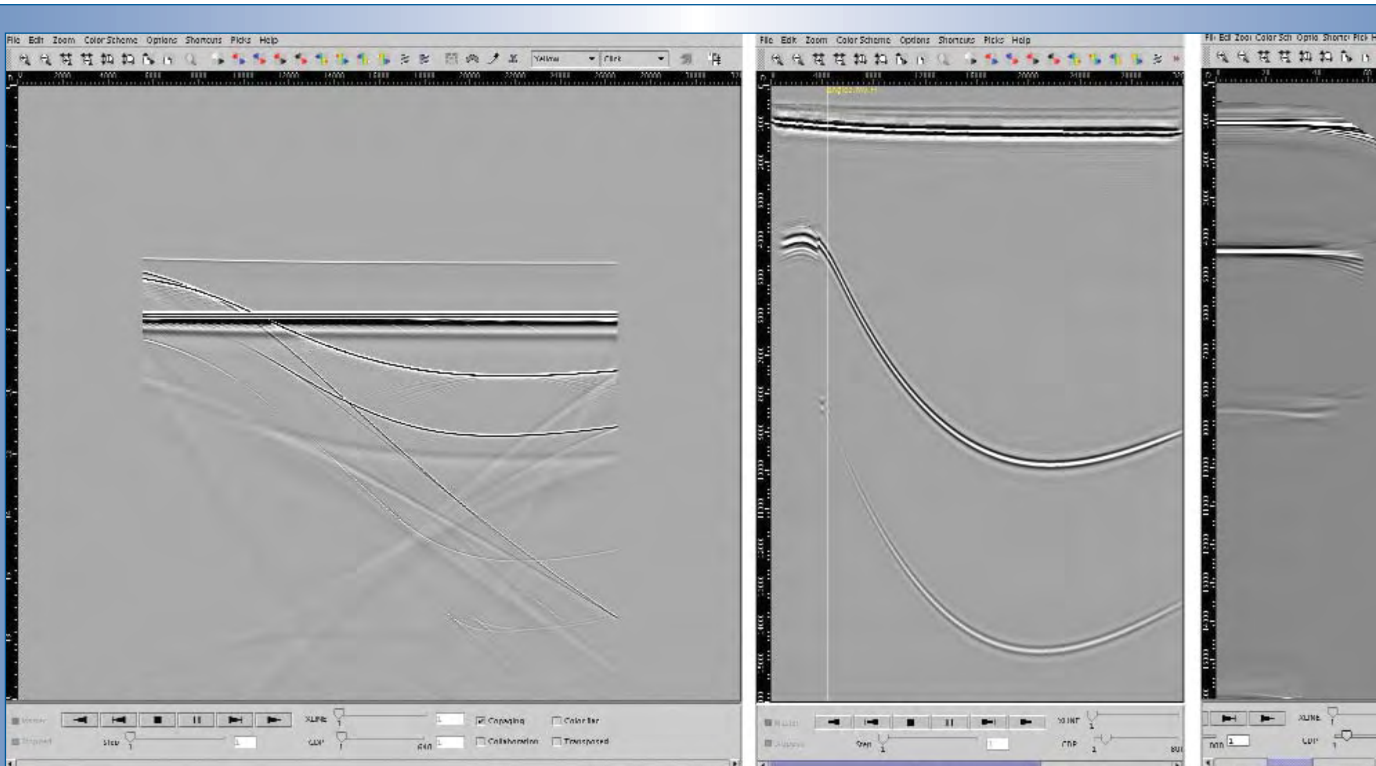

Figure 3. A constant offset section from the synthetic dataset (left). One of the many depth migration images testing the amplitude and imaging condition (middle). Angle gather output at the CDP location market with a vertical line in middle image (right).

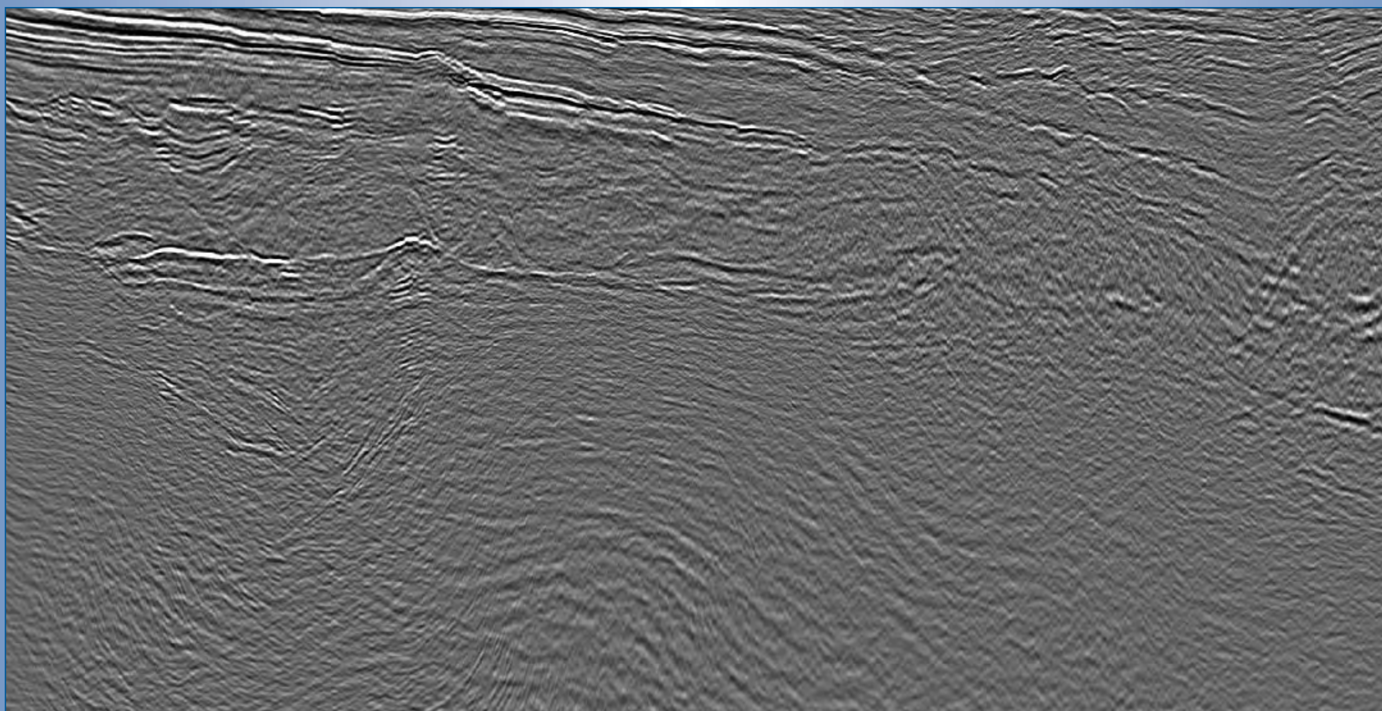

Figure 4: This standard processing sequence uses Kirchhoff depth migration for final imaging, between about a 5,000-m and 18,000-m depth. (Data courtesy of PGS)

Compensating for non-elastic attenuation losses that degrade amplitude and resolution of seismic images at large depths**—**The velocity model in Figure 2 is the benchmark model for testing true amplitude wave equation imaging. It contains a shallow, gently dipping interface, as well as curved and steeply dipping interfaces. On the right side of the model, the velocity variation is mostly depth dependent, while on the left side there is a strong velocity variation similar to the sharp velocity variation when a salt body is present. This benchmark tests gently dipping interfaces, curved interfaces and steeply dipping interfaces in the presence of depth variable velocity as well as rapidly varying velocity.

Figure 3 shows a constant offset section (out of 640 sections) through the synthetic model and the corresponding wave-equation depth migration image performed using the true amplitude terms. Many amplitude tests were performed on the model to calibrate the amplitude weights in the migrated image and the variation of amplitude with angle.

Real data examples

The vast majority of seismic data in the Gulf of Mexico and onshore Texas has been recorded with relatively short offsets (seldom exceeding 16,000ft) and with insufficient record lengths (6 to 8 seconds), for imaging shallower structures onshore and offshore. To address the need for acquisition of seismic data appropriate for ultra-deep imaging PGS has acquired a proof of concept line, using large offsets, 1,000 channels live (split-spread) onshore, and 500 channels live offshore (simulated split-spread) with 250 fold, a record length of 20 seconds, and maximum offsets of 41,200ft in the upper Texas coast using dynamite and Airgun sources. This is an appropriate dataset for testing ultra-deep technology, since it has a long record length and large offsets. The length of the record allows us to image deep structures and steep dips, while the large offsets offer good data redundancy and ability to better discriminate the velocity of the deeper structures. This is an ideal dataset for this project and comes with several challenges. The shot gathers show packets of coherent energy at large times, indicating there is structural information in the deep data, but at the same time, the stacked data shows well defined structures to 7 or 8 seconds, after which the image becomes incoherent. One of the challenges is to bring out this deeper information and image the geological structures deeper than 7 or 8 seconds.

The stacking velocity was used for an initial run of pre-stack time migration (PSTM). The PSTM velocity was updated for an improved pre-stack time migration run. The updated velocity was converted to interval velocity and served as a starting model for a wave-equation depth migration run. The depth velocity model was updated through successive iterations of migration and velocity update using normal ray and tomographic updates. We have performed several tests on improving the coherency of deep and ultra-deep events. The first set of tests established optimum functions for boosting lower

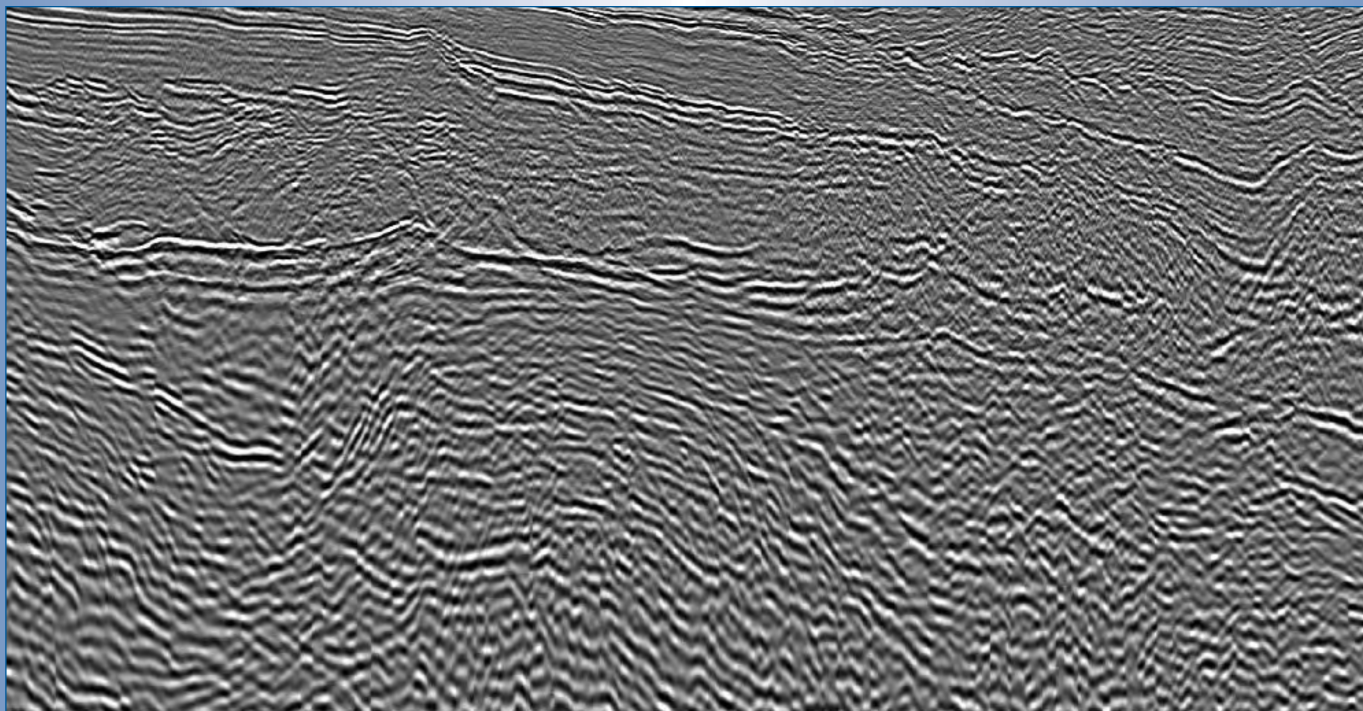

Figure 5. This wave-equation depth migration uses ultra-deep events boosting technology between about a 5,000-m and 18,000-m depth. (Data courtesy of PGS)

frequencies in the downward continuation part of the migration, and the second set analyzed post-migration processing for flattening non-hyperbolic (parabolic for angle-gathers) move-out. We also ran several data regularization tests to optimize the azimuth moveout parameters. Figures 4 and 5 show the improvements of the wave-equation depth migration using ultra-deep event boosting technology compared with the existing standard Kirchhoff technology. Some of the techniques used to boost the deeper events can also be applied to the standard Kirchhoff, though some of the applications in frequency domain may be limited to wave-equation methods operating in frequency domain. The figures show a small area of the PGS proof of concept line between 5,000m and 18,000m. The deeper structures show better continuity in the wave-equation case, better resolution and allow the interpreter to define and contour structures at depth previously hard to image with standard technology.

Conclusions

We present a U.S. DOE NETL project designed to enhance seismic resolution and imaging of ultra-deep complex geologic structures by using: wave-equation depth migration; wave-equation velocity model building technology for deeper data penetration and recovery, steeper dip and ultra-deep structure imaging and accurate velocity estimation for imaging and pore pressure prediction; and accurate illumination and amplitude processing for extending the AVO prediction window. We addressed the theory of the handling true amplitudes in the downward continuation and imaging algorithm and the preservation of the amplitude with offset or amplitude with angle information required for AVO studies, the effect of several imaging conditions on amplitudes, non-elastic attenuation and approaches for recovering the amplitude and frequency as well as the effect of aperture and illumination on imaging steep dips and on discriminating the velocities in the ultra-deep structures. The results on real data show that ultra-deep wave-equation imaging provides greater resolution and accuracy than what can be accomplished with standard imaging technology. The advanced imaging methodology may improve the success rate and cost effectiveness for new deep-field discoveries and also has applications in increasing recovery efficiency for the development of existing fields. ✧

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Hydraulic Fracture Mapping With Hybrid Microseismic/ Tiltmeter Arrays

By Norm Warpinski,
Pinnacle Technologies

A project to develop a new method for fracture mapping combines the best features of two of the most widely used current mapping technologies – downhole tiltmeters and microseismic monitoring. The new "hybrid" array provides an improved capability for monitoring and interpreting fracture growth.

Hydraulic fracturing is employed in almost all U.S. onshore natural gas wells to improve the deliverability of the well and economics of the development.

The application of hydraulic fracturing is particularly important in unconventional gas reservoirs, where economics may be marginal even with a successful stimulation. In such reservoirs, the application of new technology to characterize, access, stimulate and produce the reservoir is critical for optimization of the stimulation treatments and field development. Many of these resources can be characterized as "technology plays," where economic development would be impossible without some of the advanced technology employed.

One of these new technologies is hydraulic fracture mapping, which is frequently used to provide information about the growth and geometric features of the fracture. This type of mapping is a subset of fracture diagnostics, which encompasses all technologies used to derive information about the fracture and its effectiveness. Fracture diagnostics include logging and tracers to provide near wellbore information, pressure analyses and pressure-history matching with a model, and well testing and production analyses among others. Fracture mapping could be defined as the process of determining fracture geometry through direct measurements of geophysical properties influenced or altered by the fracturing process.

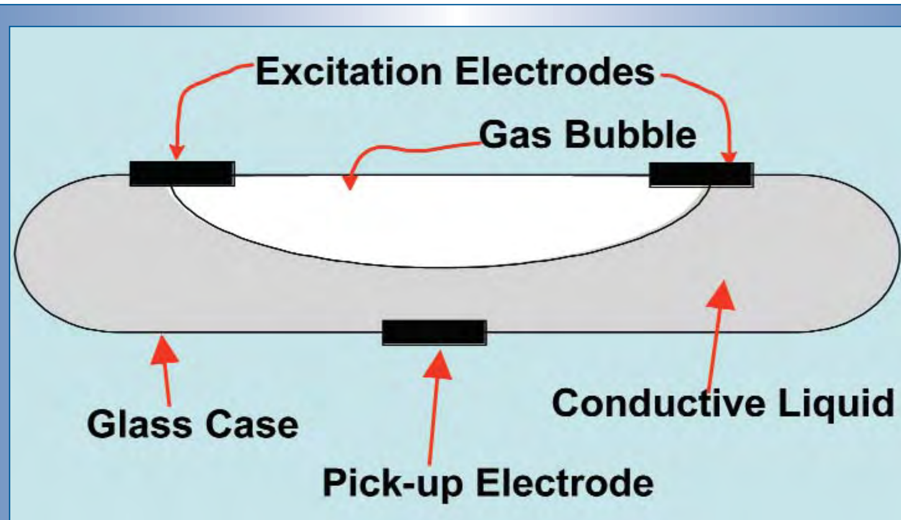

Figure 1. A schematic of a tilt sensor is shown above.

Fracture mapping technologies

There are only three proven types of fracture diagnostics that can measure far-field fracture geometries: surface tiltmeter mapping, downhole tiltmeter mapping and microseismic mapping. To explain these technologies, it is necessary to describe the sensors used to make the measurements.

Sensors

Tiltmeters are sensitive devices that measure the slightest deformation of the ground, much like a carpenter level. However, the tiltmeters used in hydraulic fracture mapping are designed for higher sensitivities and can measure tilts as small as 1 nanoradian. Figure 1 shows a schematic of a tiltmeter sensor, which uses a conductive fluid and suitably placed electrodes to achieve the required precision. Arrays of tiltmeters are used to measure the deformation around a fracture induced by the opening of the fracture. This deformation is measured and then inverted for the size and shape of the fracture that created the deformation.

Microseismic mapping is performed with an array of tri-axial seismic receivers, which detect small earthquakes induced by the changes in stress and pore pressure caused by the fracturing process. The geophones or accelerometers in these receivers need to be sensitive and also have higher frequency capabilities than typical VSP receivers, as the microseisms are generally small, high-frequency events. The receiver array detects the microseisms, and P (compressional) and S (shear) arrivals are determined during processing. By appropriate ray tracing, the distance and elevation to the microseism can be determined. The particle motion of the P and S waves (the reason why tri-axial receivers are required) provides the information on the direction to the microseismic source. Since these microseisms are generated in

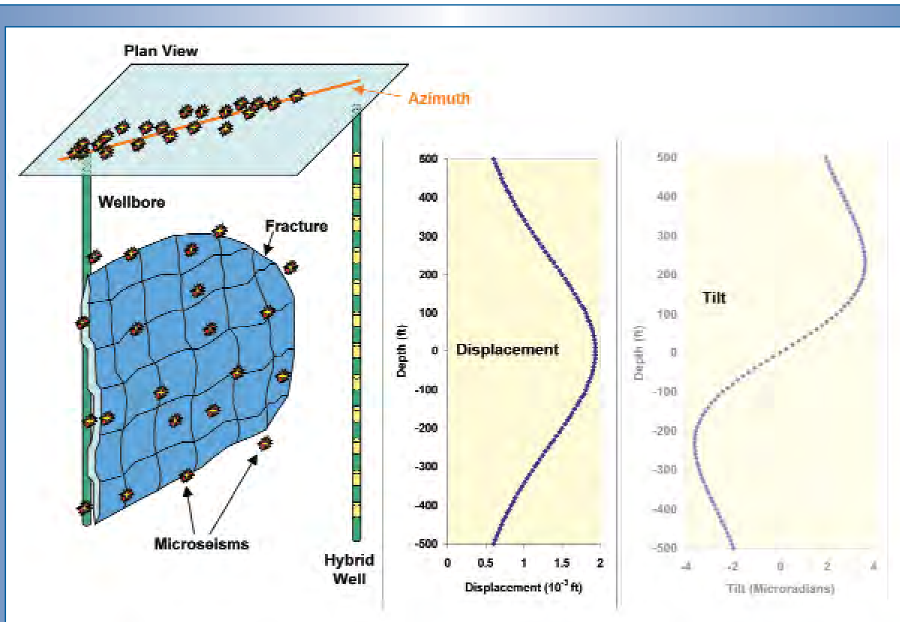

Figure 2. An example of tilt and microseismic measurements.

a zone surrounding the fracture, the overall shape and size of the fracture can be evaluated from the spatial distribution of the microseisms.

Mapping technologies

Surface tiltmeter mapping is a significant reconnaissance tool for mapping fracture azimuths and dip (especially valuable for evaluating horizontal vs. vertical fractures), but being far away from the fracture (at the surface), geometric parameters such as height or length can only be obtained for shallow fractures. Surface tiltmeters are often used in conjunction with downhole tiltmeters and microseismic mapping, but they are not integral to the hybrid system.

If an array of these tiltmeters are placed downhole across from the fracture, more information about the height, width and fracture center can be obtained. In many circumstances, fracture length can also be determined from downhole tiltmeters, along with dip and possibly azimuth. Figure 2 shows an example of the deformation that occurs alongside a vertical fracture and the subsequent tilt that would be measured in an offset well. The shape of the tilt field provides information on height, dip and center while the amplitude of the tilts also helps specify width and length.

Microseismic mapping is also performed with downhole arrays, but it relies on detecting microearthquakes caused by the deformation measured with the tiltmeters and by leakoff of fracturing fluid. Because hundreds of these earthquakes may be created, there is potential for obtaining detailed structural information about the fracture that would otherwise be impossible to obtain. Figure 2 also shows an example of the typical microseismic activity that might be observed in such a fracture.

Hybrid microseismic/tiltmeter array

In most fracture mapping situations, there is at most one monitor well close enough to be useful for microseismic or downhole tiltmeter mapping. In such cases, it is necessary to choose one of these two technologies based upon the type of information required. However, there is no guarantee *a priori* that the selected technology will actually yield better results. For example, tiltmeters are insensitive to seismic noise, as induced by nearby drilling or fracturing equipment on the same pad, while microseismic receivers may be "deafened" by the noise to the point that few or no microseisms can be detected. On the other hand, microseisms gain an advantage as the monitoring distance increases because resolution from the tilt measurements decreases with distance. There are numerous similar advantages and disadvantages of these two technologies that interplay under various circumstances, leading an observer to the conclusion that it would be optimal to have both technologies in a single array in the monitoring well. This is the rationale behind the hybrid array concept.

A project to develop hybrid arrays has been ongoing for more than 2 years. The first part of this project is developing the necessary hardware and equipment for fielding these two arrays on the same wireline and sending both sets of data to the surface simultaneously. Fortunately, the microseismic arrays are fielded on fiber-optic wirelines that also have six electrical conductors for power and other uses. The optical fiber is necessary for the high-density telemetry requirements of a microseismic array, such as 12 levels x 3 channels x 4,000 samples/sec x 4 byte data x 8 bits = 4,608,000 bits/sec, run with even a minimum number of tools. Use of 15 or 20 receivers would increase this accordingly. However, because the data telemetry is handled easily by the fiber alone, there are free conductors that can be used independently for the tiltmeter data, which is run multiplexed (only two conductors needed). While a combined telemetry system is the ultimate solution, this separate-system approach was envisioned to be one that could prove up the hybrid system in the shortest time.

Given this separate-system approach, the primary hardware needs were crossovers between tools and a method to pass the microseismic telemetry and power lines through the tiltmeters. This was accomplished by constructing a new tiltmeter housing with space for additional lines and new end caps and connectors to mate with the microseismic receivers. Other issues included getting appropriate power downhole to all tools and ensuring all telemetry remained functional. Surface equipment remained the same for each set of tools.

Joint inversion of hybrid data

The result of a hybrid-array monitoring test would be a tiltmeter map and a microseismic map, each of which would show its own perspective of the fracture geometry. In many cases, these two maps will not agree because of: some inability of one or the other to clearly "see" the fracture; some degree of complexity that cannot be easily reconciled by the tiltmeter model; non-seismic intervals that do not produce microseisms yet still have deformation; or any number of plausible causes. In these cases, the best result will likely be one that provides a best-fit solution for both data sets. Since the tiltmeter results require an inversion (fitting the data to a model) to produce the fracture parameters, a sensible approach is to tie the microseismic data to that same model and determine how well the event locations match the model, that is, jointly inverting the data.

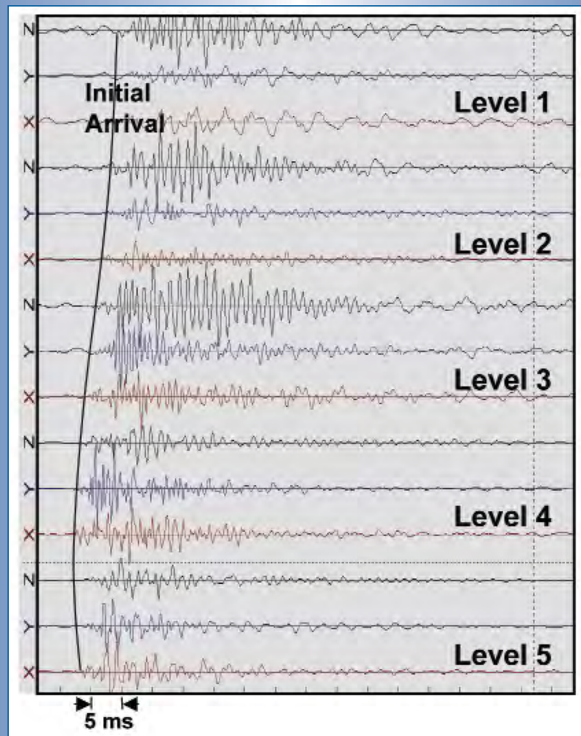

Figure 3. An example of microseismic data from hybrid-array test.

As noted above, inversion of the tiltmeter data is straightforward. A model of the process is selected (or several models together, as would occur with multiple fractures), a forward model calculation is made with some initial conditions, the observed data is compared with the forward model calculation, and a decision is made on how to change the model to better fit the data. This process is repeated until the model adequately fits the data.

The uncertain part is how to adequately factor in the microseismic data. The ultimate approach would be to construct a structural model of fracture deformation and leakoff, calculate the stress perturbations and pore pressure changes around the fracture, determine the normal and shear stress on existing failure planes (fracture and faults), calculate where slippage is likely to occur and then use the slippage zone as an envelope that must contain the microseisms. Unfortunately, this approach is complicated and requires data about the reservoir that is seldom available (all three stresses, pore pressure, fracture sets, faults, coefficient of friction, poroelastic parameters, permeabilities of the matrix and fractures, etc.) and guessing these parameters would not be a good way to improve mapping results.

There are simpler approaches, which are not structural, but still require the microseismic data to adequately fit the model. One such approach is distributional, that is, the microseismic events must be distributed in some reasonable way about the model fracture. When they do not distribute adequately about the model, the model is in error and must be changed, similar to the way the tiltmeter inversion changes the model to match the tilt data. The primary questions here are: how to handle the distribution and what parameters to invert.

In the simplest sense, the microseismic distribution about its own center of mass is compared with the distribution about the fracture model. If the model and microseism co-align, then the model is "correct;" if not, the model is changed. An initial approach is to find the standard deviations of the events about its vertical center as an estimate of the fracture height (times a multiplying parameter), the standard deviation of the events horizontally about projected well location as an estimated fracture length (also with a multiplying parameter) and a similar distribution about its edge-on width. Also available from the distributional analysis is an azimuth, the center of the fracture, and the fracture dip.

It was recognized that this approach could also allow for inversion of the velocities of the formation. Assuming the picked arrival times of the P and S waves are correct and the polarization is accurate, (for example, the data are good; the interpretation is the issue), the formation velocities are then the remaining parameters that can result in movement of microseismic locations. Yet formation velocities are not always precisely known in many situations. An inversion that not only finds the best model geometry, but also finds optimized velocities that provide an overall best fit of the total data set, is clearly a desirable result. Such is the approach taken in the joint inversion investigated here.

Treatment-well hybrid array

In addition to the offset-well approach given above, it is clear that a hybrid array run in the treatment well offers the potential for considerable information about the fracture if no nearby monitoring wells are available. Treatment well microseismic arrays are typically run with rigid interconnects and a gyro tool to orient the string. Adding tiltmeters to this string adds the potential for additional new information and corroborating information. For example, if the tiltmeters – bi-axial devices that will provide a direction of the deformation if the sensors are oriented – are now oriented, then the orientation of the tilt defines the fracture azimuth, which can be compared with the azimuth derived from the locus of microseismic data. Treatment-well tiltmeters are primarily a height-measurement system, which can be compared with the microseismic height.

Initial prototype field test

Two protype hybrid arrays were tested in wells to work out final details and evaluate problems last year and early this year, but the first fielding of an array in a fracture-monitoring test was conducted in May in a coalbed methane field in Colorado. This test had five microseismic receivers and three tiltmeters run together on a fiber-optic wireline. Several minifracs and calibration injections (no proppant) were monitored with the tools in various positions relative to the perforated interval.

Figure 3 shows an example of the type of microseismic event detected after shut in (there is generally too much noise to hear events during pumping). This example shows an arrival on five levels of an event that is about horizontal with level 4 at a distance of a little more than 100ft.

Figure 4 shows an example of the tilt data (right side) from one of the calibration tests and a graph of the tilt changes vs. depth during the shut-in period. An examination of the changes in these measurements (center) suggests the fracture bottom was somewhere in the vicinity of the lower tiltmeter (about 3,110ft) giving a large tilt response, and the fracture center was near 3,080ft with not much change in the tilt. The fracture top could not be clearly identified with only the three available tiltmeters. The left side shows a histogram of the observed microseismic heights, which agrees fairly well with the limited tiltmeter data.

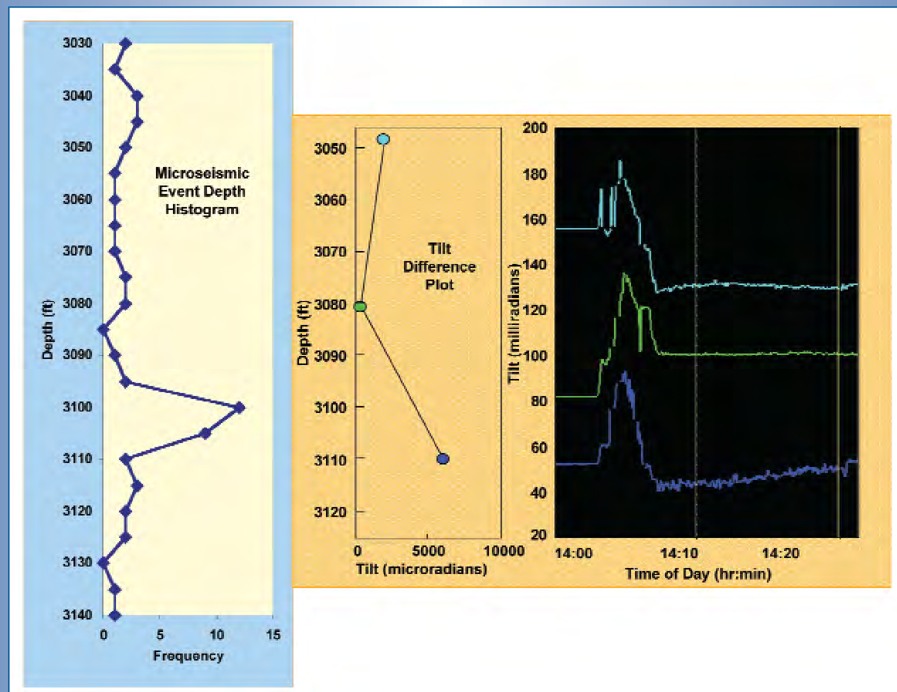

Figure 4. An example of tiltmeter data from hybrid array test, compared with microseismic events.

Conclusions

The hybrid tiltmeter project has been used to develop combined tiltmeter/microseismic mapping arrays that can be used for obtaining the most precise fracture mapping measurements possible. These arrays have been tested in the field and shown that both data sets can be obtained simultaneously in the same well.

A method for jointly inverting the two data sets has also been developed. In addition to a microseismic map and a tiltmeter map, the joint inversion provides an estimate of fracture dimensions that is a combination of the two. ✧

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DOE-FUNDED TECHNOLOGIES WIN R&D 100 AWARDS

Three technologies developed with support from the Department of Energy's National Energy Technology Laboratory (DOE NETL) have earned prestigious research and development (R&D) 100 Awards from *R&D Magazine*. The R&D 100 Awards are presented annually to the 100 most technologically significant products introduced into the marketplace during the past year. The new technologies, which received funding from the Energy Department's Office of Fossil Energy and Office of Energy Efficiency and Renewable Energy, include tools to improve drilling and mining operations and a robotic system to inspect live natural gas pipelines. For more information, visit *www.netl.doe.gov/publications/press/2006/06058-2006_R%26D_100_Awards.htm*

DOE-FUNDED TECHNOLOGY IMPROVES DIRECTIONAL DRILLING EFFICIENCY, SAFETY

A new Department of Energy-funded technology has demonstrated the capability to dramatically reduce costs and improve safety and efficiency in drilling America's oil and natural gas wells. The new technology overcomes the shortcomings of steerable motor/measurement-while-drilling systems used in directional drilling by automating the rocking motion during sliding. The new, patented tool controls torque from the surface with a combination of robotics and innovative software that integrates surface and downhole data to automate the rocking motion during sliding. The system works over a wide range of pipe-rotation equipment and no equipment is added downhole. In three field demonstrations, the technology increased revolutions per minute, reduced drilling time and almost eliminated stalling, thus extending motor and drillbit life. The field tests also showed that the system increased revolutions per minute by 60% to 200% for estimated savings of 11% to 23% of total well costs. For more information, visit *www.netl.doe.gov/publications/press/2006/tn_robotics.html*

DOE-FUNDED TECHNOLOGY TO UPGRADE LOW-QUALITY NATURAL GAS COMMERCIALIZED

A new Department of Energy-funded technology to upgrade low-quality natural gas – a resource that accounts for almost one-third of America's known gas reserves – has been successfully commercialized. The new technology targets cleanup of natural gas with a high nitrogen content in which a membrane separation process is used to separate the nitrogen from natural gas. Successful field demonstration led to a marketing and sales partnership, which has sold six commercial nitrogen rejection natural gas membrane separation units totaling almost $2.6 million. For more information, visit *www.netl.doe.gov/publications/press/2006/tn_membrane.html*

DOE SELECTS PROJECTS METHANE HYDRATE RESOURCES

The U.S. Department of Energy has announced the selection of six cost-shared research and development projects that seek to unlock a significant potential source of hydrocarbon energy: methane hydrate. Methane hydrate is an ice-like solid that results from the trapping of methane molecules within a lattice-like cage of water molecules. In the United States, where methane hydrate occurs beneath the permafrost of Alaska's Arctic north and below the seabed offshore, the volume of this resource is staggering. The U.S. Geological Survey estimates the nation's methane hydrate deposits could hold as much as 200,000 Tcf of natural gas. This compares with a non-hydrate U.S. natural gas resource of 25,000 Tcf of which only 1,400 Tcf is deemed recoverable with current technology. If just 1% of the hydrate resource in America were commercially developed, it would more than double the nation's proved gas reserves. For more information, visit *www.netl.doe.gov/publications/press/2006/06047-Methane_Hydrate_Project _Awards.html*

DOE PROJECT INJECTS 700 TONS OF CARBON DIOXIDE INTO TEXAS SANDSTONE FORMATION

When a U.S. Department of Energy (DOE)–funded project recently pumped 700 metric tons of the greenhouse gas carbon dioxide (CO_2) a mile underground as a follow-up to a 2004 effort, it initiated a series of tests to determine the feasibility of storing the CO_2 in brine formations, a major step forward in the DOE's carbon sequestration program. The Frio Brine project is designed to determine how the CO_2 moves through brine-filled highly porous sandstone representative of formations found worldwide. By closely monitoring the CO_2 flow with technologically advanced instruments during the next year, the researchers will add to their knowledge of whether these formations can effectively store CO_2 during long periods of time, thereby significantly reducing the amount of the gas released to the atmosphere. This yearlong monitoring project will provide new information to better assess and monitor larger-scale, longer-duration injections of CO_2, an important step forward in understanding the sequestration process. For more information, visit *www.fossil.energy.gov/news/techlines/2006/06057-Frio_CO2_Injection.html* ✧

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