the ENERGY lab

E&P Focus

Summer 2009 Oil & Natural Gas Program Newsletter

CONTENTS

Appalachian Shale Gas 1
Commentary.....2
Optimized Re-Fracturing 7
Wastewater into Wine..... 10
Fayetteville GIS 14
Subsea Simulation Tool 17
Water Treatment with Gas Hydrates 21
E&P Snapshots 24
Upcoming Meetings and Presentations..... 26

CONTACTS

Roy Long

Technology Manager—Ultra-Deepwater, Strategic Center for Natural Gas & Oil

281-494-2520

roy.long@netl.doe.gov

Albert Yost

Technology Manager—Exploration & Production, Strategic Center for Natural Gas & Oil

304-285-4479

albert.yost@netl.doe.gov

U.S. DEPARTMENT OF ENERGY

Appalachian Shale Gas—Success in the Marcellus Brings Renewed Attention to NETL's Past and Present Gas Shale Programs

Introduction

Appalachian gas shales have seen unprecedented development in the last several years, as operators have found ways to produce large volumes of gas from the Marcellus and related Devonian Huron shale formations. Pioneering work by the Department of Energy's National Energy Technology Laboratory (NETL) from 1976-1992 has been instrumental in helping geoscientists and engineers understand and unlock this unconventional natural gas resource. Looking to the future, NETL has initiated a new, coordinated research effort to fill in the remaining knowledge gaps, including how to mitigate environmental impacts associated with rapid development of this emerging gas resource.

What is the Marcellus?

The Marcellus is an organic-rich, black shale of Devonian age that underlies much of western New York, Pennsylvania, West Virginia, and eastern Ohio, in an ancient foreland basin known as the Appalachian Basin (Figure 1). Like most gas shales, the Marcellus shale is both a source and a reservoir for natural gas – in fact it is known to be the source for much of the gas produced for many years from adjacent sandstone reservoirs, including the well-known Oriskany Sandstone. *This article is continued on page 3.*

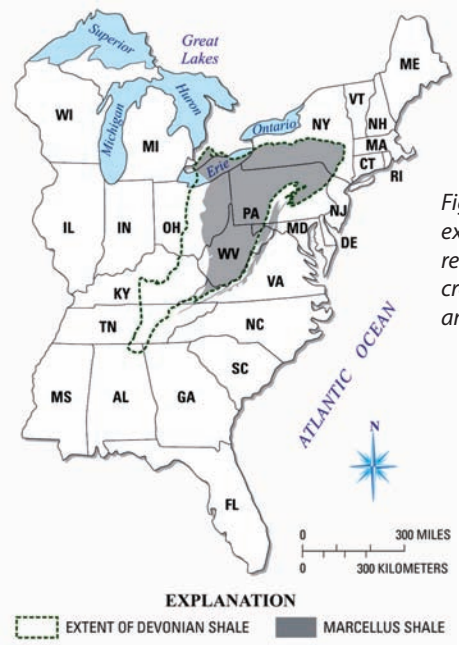


Figure 1. Map showing regional extent of Marcellus shale and related Devonian shales; map credit: U.S. Geological Survey and Dan Soeder.

National Energy Technology Laboratory

1450 Queen Avenue SW
Albany, OR 97321
541-967-5892

2175 University Avenue South
Suite 201
Fairbanks, AK 99709
907-452-2559

3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880
304-285-4764

626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940
412-386-4687

13131 Dairy Ashford, Suite 225
Sugar Land, TX 77478
281-494-2516

Visit the NETL website at:
www.netl.doe.gov

Customer Service:
1-800-553-7681

E&P Focus is published by the National Energy Technology Laboratory to promote the exchange of information among those involved in natural gas and oil operations, research, and development.

This newsletter is available online at http://www.netl.doe.gov/E&P Focus

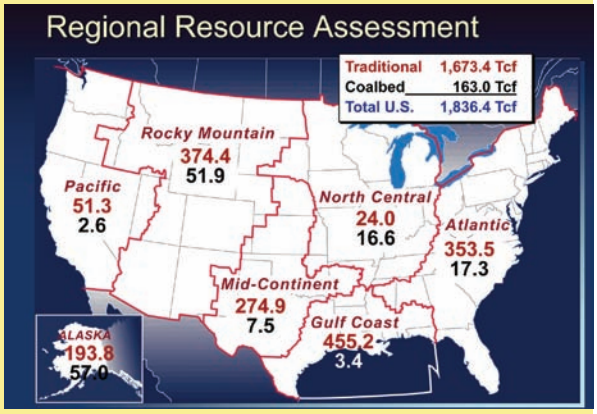
"Unprecedented Increase" in U.S. Natural Gas Resource Base

New numbers published by the Potential Gas Committee (link here) put the total U.S. natural gas resource base at 1836 trillion cubic feet (Tcf) – significantly higher than previous estimates. This increase is in large part due to reassessments of shale gas plays in the Appalachian, Mid-Continent, Gulf Coast, and Rocky Mountain areas (see map). Shale gas resources now total 616 Tcf or one-third of the total, technically-recoverable U.S. gas resource. These numbers are distinct from proven reserves, and represent the sum of *probable*, *possible,* and *speculative* (estimated for frontier plays) resources.

With these new estimates as a backdrop, the lead article in this issue of *E&P Focus* provides a fresh look at Appalachian gas shales and the role that NETL has played in helping to develop this resource, which was, until relatively recently, considered un-producible. NETL (and its predecessor organizations) recognized the potential of Devonian gas shales when it launched its Eastern Gas Shales Program in 1976. That collaboration of experts from government, industry, and academia resulted in a tremendous volume of core data, analyses, and innovations that, 30 years later, have helped guide the successful development of the Marcellus shale.

NETL is also proud of recent outreach efforts focusing on environmental issues associated with shale gas. NETL collaborated with the Groundwater Protection Council (GWPC) to develop an in-depth analysis of the water management and disposal issues related to shale gas stimulation and production (link here). We also worked with the GWPC to carry out a comprehensive review of regulations designed to protect water resources nationwide (link here).

Several articles in this issue of *E&P Focus* highlight the research being conducted through DOE's Oil & Natural Gas Program. Now more than ever, NETL is determined to develop the information and technologies needed to bring domestic gas resources to market, using sustainable, reliable, affordable, and environmentally sound approaches. Applications for R&D focused on gas shales are being considered for selection as you read this issue. The Department and its energy laboratory are also fully engaged in the current dialogue concerning hydraulic fracturing and its importance in producing domestic natural gas. We sincerely appreciate your continued interest and participation in working with us to achieve these goals.



Map credit: Potential Gas Committee.

John R. Duda
Director, NETL Strategic Center for Natural Gas and Oil

Appalachian Shale Gas Continued

Where the Marcellus is exposed, it exhibits a characteristic pattern of orthogonal, vertical fractures that divide the shale into one-meter slabs resembling sidewalk squares (Figure 2). At depth, the pervasive natural fracture system that cuts through the Marcellus shale is one of the potential keys to accessing its gas. Without the natural or created fractures from stimulation, the gas would remain tightly held in the shale's impermeable rock matrix. The natural and created fractures provide pathways for the gas to flow to a carefully positioned well bore and ultimately to a distribution pipeline, where it can be delivered to market.

Marcellus Challenges

One of the first-order challenges with the Marcellus is gaining an understanding of the natural fractures. This is critical to developing ways to intersect them with (typically) a horizontal well trajectory and stimulate the flow of natural gas through the fracture network and to the well bore. Rock quality issues and overpressure are also first order parameters to consider.

Back in the 1930's, industry became interested in the Marcellus shale, because it seemed to contain "pockets" of natural gas, most likely in areas where natural fractures were present. At that time, however, shale formations were considered too costly to drill and produce. It took new drilling and completion approaches -- specifically horizontal drilling and hydraulic fracture stimulation -- to bring gas shale plays to commercial production about 75 years later.

The Breakthrough

In 2005, Range Resources took slick-water hydraulic fracturing techniques that had proved successful in the Barnett shale of Texas, and applied them to the Marcellus shale in Pennsylvania. The result was the first contemporary successful Marcellus gas well, with initial gas production of about 400 thousand cubic feet per day. Bill Zagorski, Vice President – Geology for Range Resources, was recently recognized as the "Father of the Marcellus" for his and Range's technical team's role in bringing this highly effective well stimulation approach to the Marcellus and thereby initiating a new wave of Appalachian shale gas development. According to Zagorski, the reports and data generated by the DOE program were used substantially in the exploration and development strategies that would succeed in the Marcellus.

Figure 2. Photo of orthogonal fractures in Marcellus shale outcrop at Oatka Creek, New York; photo credit: Gary G. Lash.

Even in the current economic environment, the Marcellus remains a hot natural gas play, with over 25 companies developing Marcellus properties – or poised to develop these properties as soon as natural gas prices rebound. A recent well drilled by Atlas Energy Resources, LLC in southwestern Pennsylvania yielded initial gas production of over 10 million cubic feet per day. Atlas achieved this result by using a horizontal well bore to intersect multiple natural fractures, and stimulating production with a two-stage hydraulic fracturing technique. But the highest initial production rate from the Marcellus was achieved in the same area as the Marcellus discovery well. A horizontal well drilled in 2008, by Range Resources, topped all previous records with an initial natural gas production rate of over 24 million cubic feet per day. These successes prove that we now know how to produce large volumes of natural gas from tight shales. Atlas recently declared plans for twelve additional horizontal wells in 2009, and Range Resources plans to drill at least sixty horizontals in the Marcellus this year.

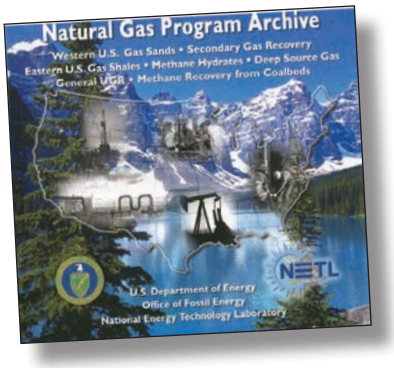
Impact of DOE's Eastern Gas Shales Program

Many geologists and engineers with experience in the Appalachian Basin argue that successful development of the Marcellus can be tied to gas shale research funded by the Department of Energy in the 1970's, 80's, and early 90's. In 1976, the Department of Energy launched a research effort known as the Eastern Gas Shales Program, with the purpose of advancing knowledge of Appalachian gas shale reservoirs and developing tools for unlocking its gas. The government collaborated with industry and academia to examine and quantify the shale gas resource, to study the natural fractures that are so critical to accessing the shale gas, and to test new well stimulation approaches for enhancing gas production from shale. The program included drilling and coring about 35 wells in Devonian shales of the Appalachian Basin.

While the Section 29 tax credits were also a factor in the number of shale wells drilled after 1976, the Eastern Gas Shales Program helped expand the limits of gas shale production into new areas of West Virginia and improved understanding of reservoir production mechanisms. A look back at the data and innovations generated by the program makes it clear that in many ways the Eastern Gas Shales Program was simply ahead of its time. Dr. Terry Engelder, a Penn State University geology professor and leading expert on the Marcellus shale, states "it is one of the great examples of value-added work led by the Department of Energy -- it just took 25 years before its value became clear."

The program resulted in the collection of 25,000 feet of core, much of it oriented core from Devonian shales. The core provides the ground truth for understanding the geological and geophysical properties of gas shales that are in some cases at depths of over 8000 feet. The core data are still utilized routinely by companies planning wells in correlative shale units. Dr. Lee Avary, of the West Virginia Geological and Economic Survey, says she is constantly referring energy professionals to the core data and reports generated by the Eastern Gas Shales Program.

The Eastern Gas Shales Program also included the first test of nitrogen foam fracs for stimulating gas shale wells; the first application of directional drilling to intersect natural fractures in a shale reservoir; and early testing of micro-seismic monitoring for mapping hydraulically-induced fractures. Collectively, these successes laid the foundation for recent advances in gas shale development in the Marcellus and similar Devonian shales of the Appalachian Basin.



Archived data and reports from the Eastern Gas Shales Program are available on DVD and can be ordered by contacting the NETL Library, at 304-285-4184 or visiting http://www.netl.doe.gov/publications/cdordering.html.

Selected references on Devonian Shales of the Appalachian basin can be found at http://www.wvgs.wvnet.edu/www/datastat/devshales.htm.

For further information, readers are directed to summaries of individual R&D projects available on the NETL website (http://www.netl.doe.gov/technologies/oil-gas/EPAct2005/Research_Program/ORD_TOC.html).

For more information on the current NETL Appalachian Gas Shale Program, contact Tom Mroz at Thomas.mroz@netl.doe.gov.

NETL's Current Efforts

In response to the recent interest in the Marcellus and other Appalachian gas shale formations, NETL has ramped up a coordinated effort to address remaining issues associated with this unconventional gas resource.

NETL is conducting resource assessment studies of the Marcellus shale, to develop a more accurate estimate of its resource potential. Experts have estimated that the Marcellus contains 200-500 trillion cubic feet of gas in-place, but how much of that is technically recoverable? According to Tom Mroz, of NETL, the new assessment will provide estimates of gas-in-place as well as technically-recoverable gas volumes. This 2-year study is being carried out by West Virginia University, Pennsylvania State University, and NETL and will focus on the West Virginia and Pennsylvania portions of the Appalachian Basin. Assessment results will be available in the spring of 2010. The resource assessment work is being funded under the Complementary Research portion of the R&D program established by Title IX, Subtitle J, Section 999 of the U.S. Energy Policy Act of 2005.

Also as part of the Complementary Program, NETL is building a gas shale research facility in Morgantown to carry out pore-scale characterization of samples collected from the Marcellus and related tight shale formations. The goal is to provide more detailed imagery of shale microstructure than was previously possible, in order to advance our understanding of where and how the gas is trapped in these ultra-low permeability rocks. The lab will include high-resolution microscopes for viewing mineralogy and textural details of the shale matrix, pores, and fracture surfaces; a fluid inclusion stage for analyzing trapped hydrocarbons; and a source rock analyzer for identifying organic carbon types and measuring their thermal maturation (Figure 3).

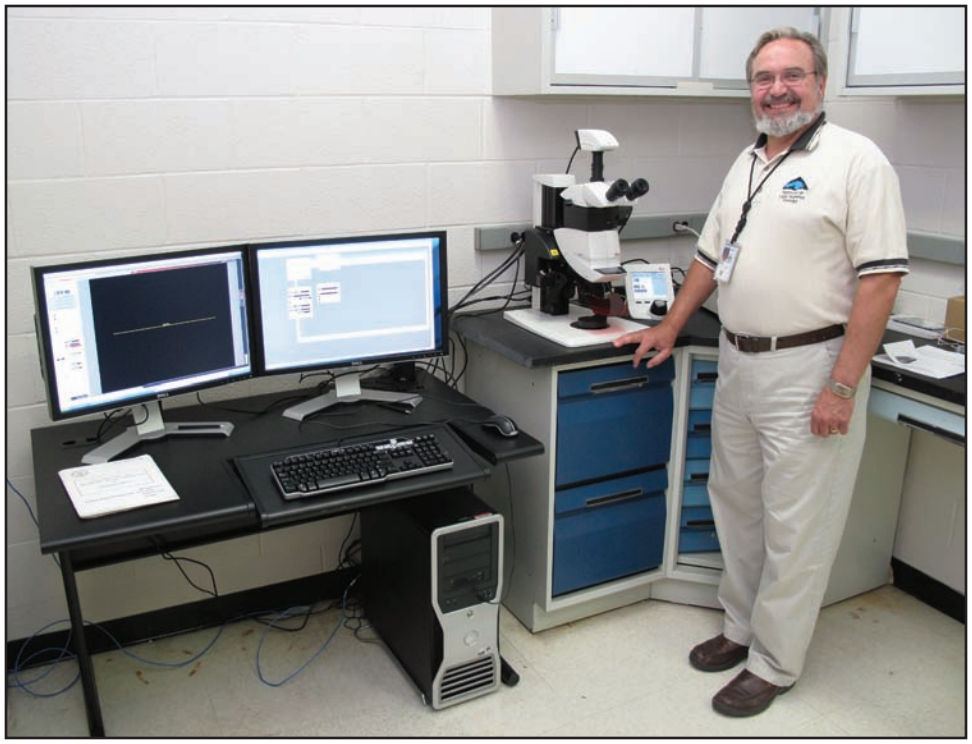
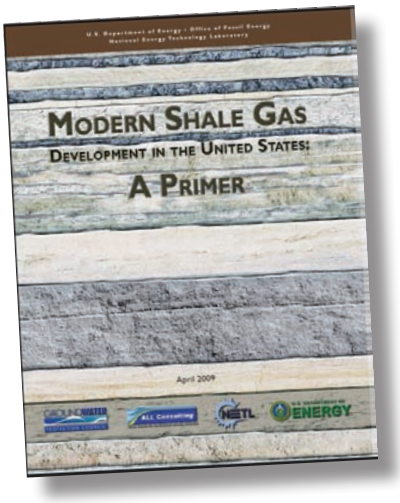


Figure 3. NETL's Tom Mroz utilizing the Gas Shale Research Facility.



A discussion of environmental issues associated with shale gas development can be found in "Modern Shale Gas Development in the United States: A Primer," at http://www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf

Using appropriated funds, NETL has also initiated a number of projects to address environmental issues associated with shale gas development through its extramural R&D program. NETL collaborated with the Groundwater Protection Council to carry out a comprehensive study of the impact of utilizing large volumes of fresh water to carry out the massive hydraulic fracturing jobs needed to stimulate shale gas wells. Typically, 2-4 million gallons of water are needed per well, so that in some basins water supply and water resources may be significantly impacted. In addition, responsible management of the produced water – a mix of returned fracture fluid and formation water – has become increasingly important and contentious. NETL recently issued (now closed) a solicitation for new projects to address water resource and management issues related to massive hydraulic fracturing activities in shale gas development areas. The objective is to address constraints to development of domestic natural gas shale resources.

Finally, the Research Partnership to Secure Energy for America (RPSEA) consortium, which administers select elements of the Section 999 Program for the Department, has awarded several new projects to address specific water use and management issues related to shale gas operations. A new project led by the Gas Technology Institute aims to develop strategies to reduce demands for freshwater and reduce the environmental impact of brine disposal from natural gas development in the Barnett and Appalachian gas shales. A project led by GE Global Research and STW Resources will develop a strategy to treat frac flowback fluids, through a process that removes salts and metals from the fluid and results in reusable water and salt product that meets road salt specifications.

Looking Forward

In 1976, when NETL initiated its Appalachian gas shale research program, many in industry were skeptical that gas from these shales could ever be produced in significant quantities. Today, with over 25 companies actively drilling Marcellus wells in Pennsylvania and West Virginia, results of the original NETL program are utilized routinely by geologists and engineers looking to drill and produce gas from this challenging reservoir. Directional wells and hydraulic fracturing were technologies that were foreign to the Appalachian Basin before their introduction and demonstration under the NETL program, and now they have been commercially adopted and tailored to the specific challenges of the Marcellus. These technologies have facilitated economic drilling and production of gas that was previously viewed as un-producible.

New research efforts by NETL and its partners promise to help industry continue to unlock the secrets of this complex resource – from the standpoint of reservoir quality, completion strategies, and mitigating environmental impacts of production operations.

Beating the Decline Curve through Optimized Re-Fracturing

In the challenging price environment that the natural gas industry has been facing since late 2008, re-fracturing of unconventional natural gas wells can provide a low-cost alternative to re-drilling poorly performing wells or adding infill wells. However, selecting which wells to re-fracture and when and how to re-fracture them in a manner that optimizes performance, is difficult.

Selecting wells for re-fracturing is typically based on heuristic rules-of-thumb and statistical databases and does not incorporate recognition of any stress reorientation due to the original fracture treatment and subsequent production, or the placement of proppant during the initial stimulation.

A research project currently under way aims to develop an approach to well selection that takes these factors into account and thereby optimizes re-fracturing decision-making. By choosing wells that will benefit most from the procedure, and accurately timing a re-fracturing operation, a producer can potentially beat the decline curve and reduce the need to drill additional wells to maintain production.

Part of a Portfolio of R&D Projects

A team at the University of Texas at Austin is performing this research, as part of a portfolio of projects administered by the Research Partnership to Secure Energy for America (RPSEA) under an R&D program launched by the Energy Policy Act of 2005, [See the Spring 2009 issue of E&P Focus for a description of this program, or visit the RPSEA Web site (http://www.rpsea.org/) or NETL web site (http://www.netl.doe.gov/technologies/oil-gas/EPAct2005/Index.html) for more information.] Other team members working on this project are Noble Energy, BJ Services, Pinnacle Technologies, and Anadarko Petroleum Corporation.

The research plan will generate three primary products: a methodology for re-fracture well candidate selection; recommendations and tools for determining the optimal timing of re-fracture treatments; and re-fracture treatment designs that utilize novel fluids, proppants, and injection strategies. The researchers theorize that stress re-orientation is one of the key factors determining the success of a re-fracture treatment, so the team plans to explore thoroughly the role of stress reorientation during this investigation.

Fracture Re-Orientation

Production from a hydraulically fractured well via the initial fracture causes a local reduction in the pore pressure in an expanding elliptical region around the induced fracture. The pore pressure depletion changes the stress distribution in the reservoir. Numerical simulations have shown that the total stress parallel to the initial fracture reduces faster than the orthogonal stress as a function of time. If the induced stress changes are large enough, the direction or azimuth of the minimum horizontal effective stress becomes the maximum within an elliptical region around the initial fracture (Figure 1). Under these conditions, a second fracture will propagate orthogonal to the initial fracture (i.e., orthogonal to the current local minimum principal stress), until it reaches the limit of this stress reversal region, whereupon it will revert to the direction of the initial fracture.

The research conducted to date has determined that a hydraulic fracture will propagate toward a nearby injection well and away from a nearby production well. Also, the areal extent and timing of the stress reversal depend on fluid properties, stress contrast, drawdown, reservoir thickness, and mechanical properties of the bounding layers.

In situations where well performance indicates a need for infill drilling to capture remaining natural gas, rather than drilling more wells a more economical option could be to consider re-fracturing the wells to take advantage of the re-orientation of the fractures.

Research Plan

The project includes a number of elements. First, the research team will compile data on fracture treatments carried out in two unconventional formations, the Codell formation (in the Wattenburg Field of Colorado) and the Barnett shale (in the Fort Worth Basin of Texas). Much of this data will come from databases provided by the producing company partners on the team. The researchers will use these data to develop further a stress reorientation model that accurately represents the post-stimulation change in reservoir stress regime that occurs in tight sands and fractured shales.

Next, the research team will develop a method for candidate well selection and treatment timing based on the model and field data analysis. Guidelines for this selection process will be one of the deliverables for the project.

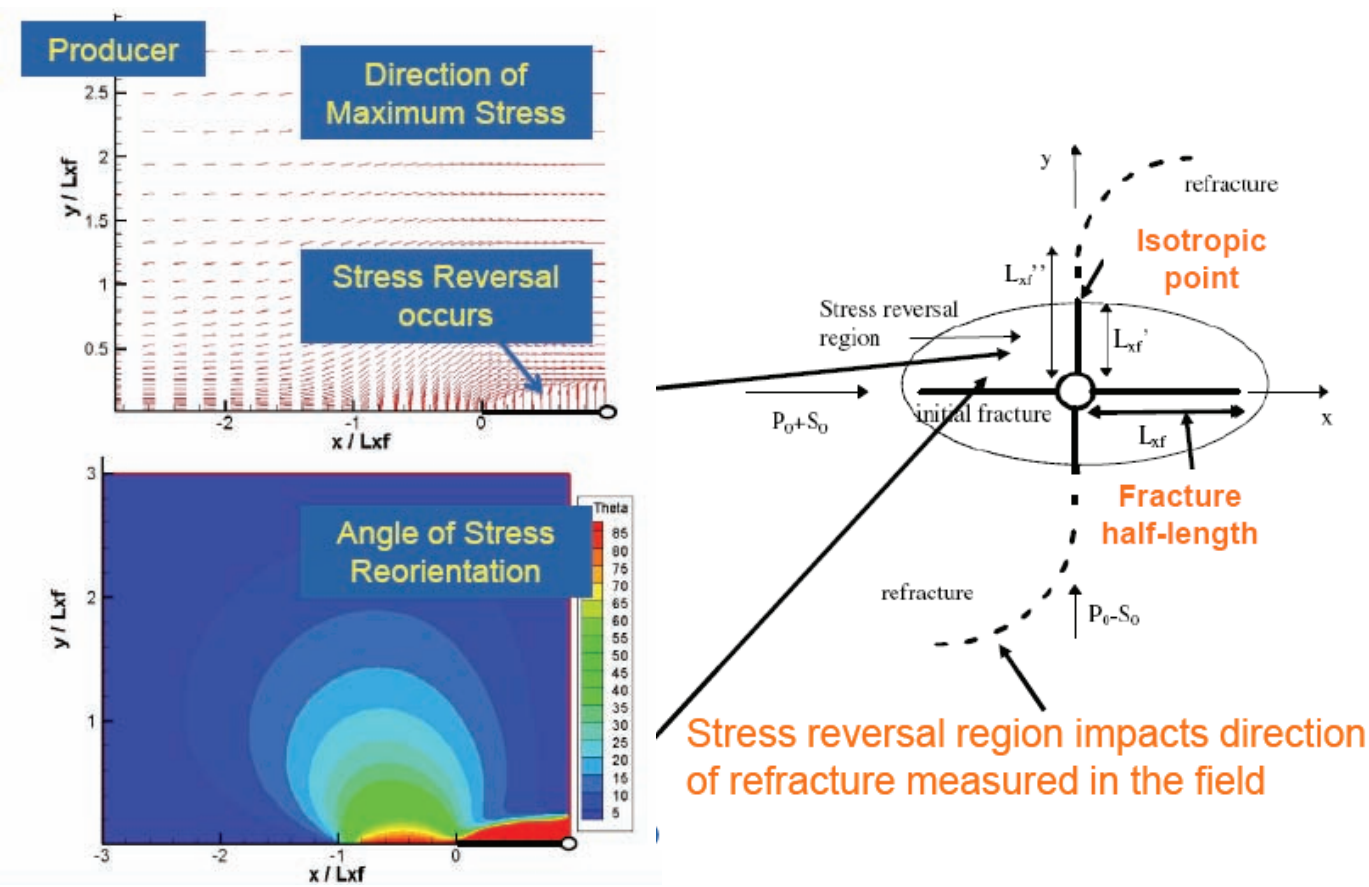


Figure 1. Model output showing the direction of maximum stress and the degree of stress reorientation near a producing fractured well (left), and a schematic depiction of the direction of a new fracture based on the altered stress regime (right).

The team will also develop designs for re-fracturing treatments in the Codell and Barnett based on model simulation runs that incorporate new fluids and proppants. Designs will be developed for both vertical and horizontal wells.

Another task will involve an investigation of proppant placement in re-fracturing treatments (in both vertical and horizontal wells), and the development of novel proppant placement strategies for re-fracturing operations.

With all of the analytical work completed, the research team will implement its recommended practices and designs in a series of re-fracturing treatments in selected Codell and Barnett wells. Following post-frac testing and evaluation, the team will deliver a final report on the results of the entire project as well as a workshop to explain how to apply the approach.

Tight Gas and Shale Wells to be Studied

About 90 percent of the refrac treatments that have occurred over the last ten years in the Codell Formation of the Wattenburg Field in Colorado are considered economically successful. Tight gas wells there were initially drilled on 40 acre spacing, but production analysis has indicated the effective drainage area to be just 10-20 acres. In addition, the drainage pattern was observed to be elliptical in shape and confined to the reservoir volume near the propped fractures.

This project will model and quantify the role that stress re-orientation plays on re-fracturing productivity improvement. Statistical methods, such as principal component analysis (PCA), will aid the researchers in determining the increase in production rate following a re-frac event as well as in reducing data redundancy and highlighting important correlations.

A unique and powerful element of this research will be the calibration of the modeling through extensive analysis of field data from both the Codell formation in Colorado and the Barnett shale in Texas. The producing company partners in this project will provide these data.

Work Begun with Wattenburg Data

Work on the three-year project commenced in August 2008. Currently, re-frac treatment data from the Wattenburg field in Colorado's Denver Basin is undergoing statistical analysis to identify trends, and re-frac treatment designs are being reviewed. Stress reorientation due to poroelastic effects has been calculated for vertical and horizontal wells, and key parameters and conditions controlling re-orientation have been identified. An additional accomplishment has been the first computation of the optimal timing of a re-frac treatment in the Wattenburg Field.

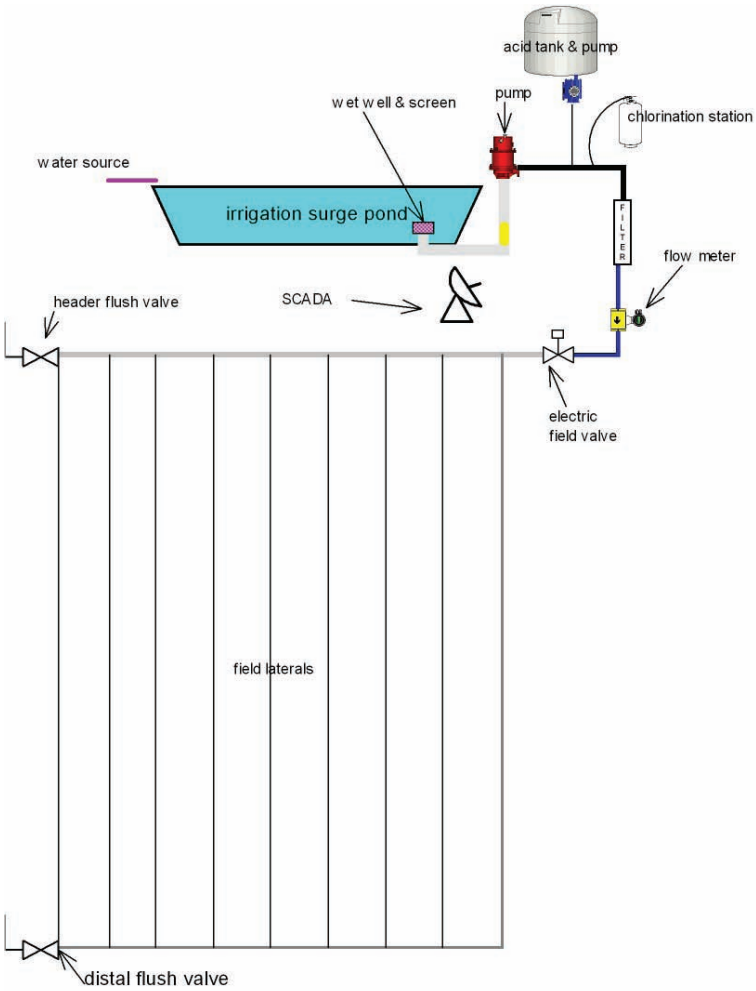
For additional information related to this project contact Kent Perry at RPSEA (kent.perry@gastechnology.org or 847-768-0961), or Virginia Weyland with NETL (Virginia.Weyland@netl.doe.gov or 281-494-2517).

Turning Wastewater into Wine: Subsurface Drip Irrigation Offers Option for Beneficial Use of Produced Water

NETL has teamed up with the U.S. Geological Survey (USGS) and BeneTerra, LLC to implement and monitor an experiment on a 200-acre subsurface drip irrigation (SDI) site in the Powder River Basin near Arvada, Wyoming, an area where coalbed methane (CBM) wells are producing large volumes of water. NETL became involved in the research project after the Wyoming Department of Environmental Quality (DEQ) requested that the laboratory perform research on management of CBM produced water in the basin. In this demonstration project, NETL is providing hydrogeochemical and geophysical monitoring and analysis that will help to determine if CBM produced water can be used as a source of irrigation water without damaging the soil or hydrologic system. The research team installed the system in October 2008 and has already acquired nine months of data. The research will answer three major questions:

- ***Will the land be as productive after SDI with CBM produced water as it was before?*** *Has the soil been affected, in what way, and are any changes reversible?*
- ***What is the effect of SDI on native groundwater?*** *Is high total dissolved solids (TDS) native groundwater displaced into the Powder River?*
- ***What is the ultimate fate of the CBM produced water?*** *What percentage is taken up by evapotranspiration? Is there an impact on the chemistry of underlying Class I aquifers? Does the applied CBM produced water reach the Powder River?*

Figure 1. Schematic diagram of the SDI system.



How SDI Works

BeneTerra, an agricultural company, developed SDI technology as an approach for putting water produced from CBM wells to a beneficial use. Other methods for managing the water that provide little or no benefit include impoundments, land application, direct surface discharge, and reinjection. In the SDI approach, the produced water is filtered, treated, and then pumped into a buried network of perforated polyethylene tubes known as laterals (Figure 1). These laterals incorporate emitters spaced about 6 to 10 inches apart in an agricultural field at a depth of 18 to 48 inches, the base of the plant root zone (Figure 2). Water is released at a rate of between 0.75 and 1.5 gallons per minute (gpm) on a year-round basis.

SDI could provide a variety of benefits for both energy producers and agricultural producers, including year-round water management, decreased environmental risk associated with infiltration impoundments, increased production of livestock forage, improved relationships with landowners, preservation of native soil surface conditions, and enhanced wildlife habitat. When managed appropriately, the produced water may be applied to a site at a rate of 90 barrels per acre-day using SDI.

Why Not Use Surface Irrigation?

The reason for designing a system to deliver irrigation water to the subsurface rather than conventional spray irrigation is to avoid the formation of a hardpan surface, a routine problem with traditional surface irrigation methods when irrigation water is high in sodium. Hardpan is a very dense layer of soil that is essentially impervious to water, restricts air movement, and interferes with the rooting of plants. It forms readily when clay particles in the soil encounter sodium ions in produced water. SDI circumvents this problem by introducing the water below the root base (Figs. 3 and 4).

A factor called the sodium adsorption ratio (SAR) is an important aspect of this issue. SAR is a quantitative means of characterizing a water's suitability for irrigation; it measures the relative concentration of sodium to calcium plus magnesium and can be calculated by the equation, $SAR = Na/\sqrt{(Ca + Mg)/2}$, where the ion concentrations are expressed in milliequivalents per liter (mEq/L). In general, the higher the SAR, the less suitable a water is for

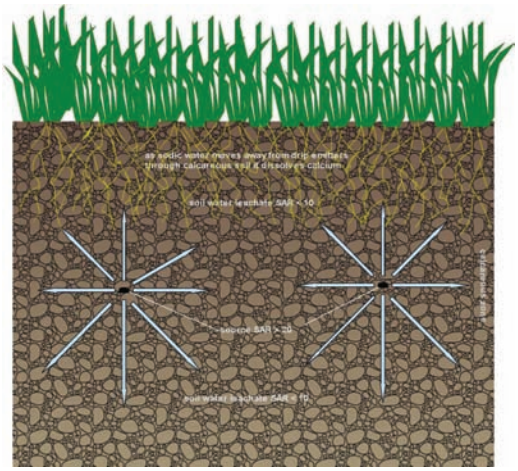


Figure 2. Location of SDI emitters at base of root zone.

Figure 3. Laying down laterals on coils.

Figure 4. Close-up view of laterals and SDI system in trench.

irrigation. While the CBM produced water has a high sodium content and SAR, it is thought that native calcium and magnesium ions in the soil at the depth of the SDI laterals will counteract the effects of the sodium. As the sodic water dissolves and transports (or leaches) these ions, it will lower the SAR while driving the salts deeper into the ground. This decreases the need for chemical surface soil amendments associated with surface irrigation using the same water. At the same time, vigorous root penetration of crops such as alfalfa will help preserve vertical infiltration pathways.

NETL's Research Program

NETL's data collection program consists of semiannual sampling of six lysimeters and 15 wells installed specifically for monitoring. A lysimeter is an instrument that penetrates the ground only a few feet, where it collects water from the pore spaces of soils. This data can be used to quantify evapotranspiration, the combined process of direct water evaporation from the ground and indirect water uptake and release to the atmosphere via growing plants. Other data collection includes semiannual electromagnetic (EM) and resistivity surveys, and continuous hydrologic monitoring of water table elevation, groundwater conductivity, and temperature at six monitoring wells approximately 25 feet deep. Well and lysimeter sampling will allow for NETL to determine the effect of SDI on vadose and phreatic zone chemistry, and the EM and resistivity surveys permit tracking of the movement of the wetting front (Figure 5).

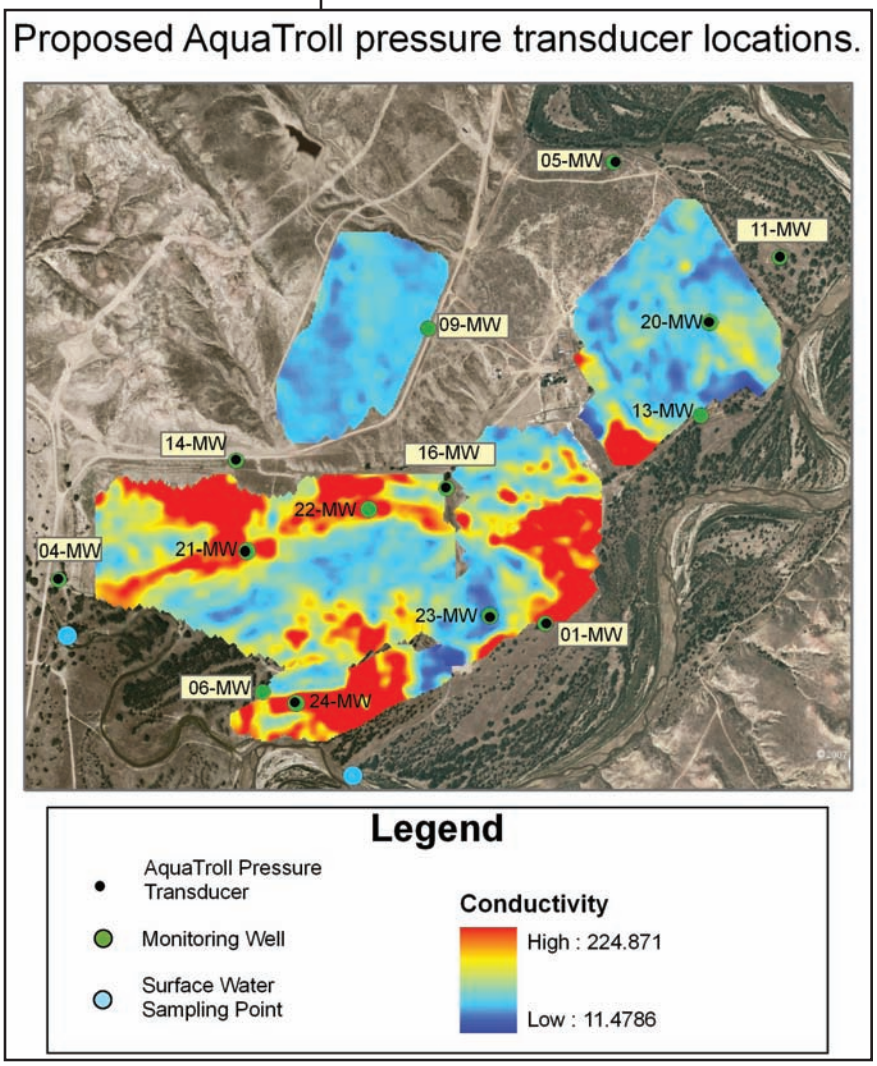


Figure 5. EM generated map showing a range of ground conductivity.

Field work began with a background ground geophysical survey performed in June 2007 and was followed by a helicopter EM survey in July 2008. Two more ground geophysical surveys were later conducted in October 2008 and March 2009. In addition to the EM survey, a multi-parameter weather station was installed in March. The next EM survey is slated to take place in July 2009.

Since the summer of 2007, groundwater quality sampling has taken place on a quarterly basis and will continue to be undertaken by the USGS on at least 15 wells. Samples are being analyzed by NETL at its Pittsburgh lab facility. During the first summer, over 45 soil cores were collected to characterize existing soil conditions (Figure 6).

Continuous hydrologic monitoring of groundwater levels has occurred since fall 2007. Meanwhile, the USGS is conducting slug testing to measure hydraulic conductivity by adding or subtracting a known volume of water to a well and then quickly taking measurements of the water level to determine how fast the water level recovers. NETL expects to continue monitoring and analysis of the SDI system over a five-year period, ending in 2014.

BeneTerra and NETL will present the study's results at relevant conferences and will also publish in peer reviewed journals. Furthermore, the research team is communicating all results to the Wyoming DEQ regularly, where the insights generated can aid in establishing policies related to permitting SDI systems.

The SDI research project is an example of the complementary research being performed at NETL as part of the program established by Title IX, Subtitle J, Section 999, of the Energy Policy Act of 2005. This fundamental research is designed to support the development of unconventional gas and other petroleum resources. For more information contact the Project Manager, Rick Hammack (Richard.Hammack @netl.doe.gov).

Figure 6. Soil sample collection.

Using GIS to "Green" the Fayetteville Shale Play

The growing need for energy in the U.S. often competes with the desire to keep environmentally sensitive areas off-limits to drilling. It is likely that operators will drill thousands of wells in Arkansas' Fayetteville shale play over the next few years, where E&P companies have leased more than 2 million acres. In preparing for this natural gas rush, the University of Arkansas (UA) and Argonne National Laboratory (ANL) have collaborated on a project funded under DOE's Oil and Natural Gas Program to protect environmentally sensitive areas in the Fayetteville shale play area while development of this important domestic gas resource moves forward. UA has developed a web-based software application that became available in June 2009. It utilizes a Geographic Information Systems (GIS)-based risk-management tool to identify sensitive areas and allow operators to devise alternatives for lease layouts (Figure 1).

GIS Software Allows Users to Evaluate Options

The software will foster communication between regulators and producers and will expedite the permitting process. Producers will be able to quickly evaluate the environmental impact of proposed infrastructure at a specific

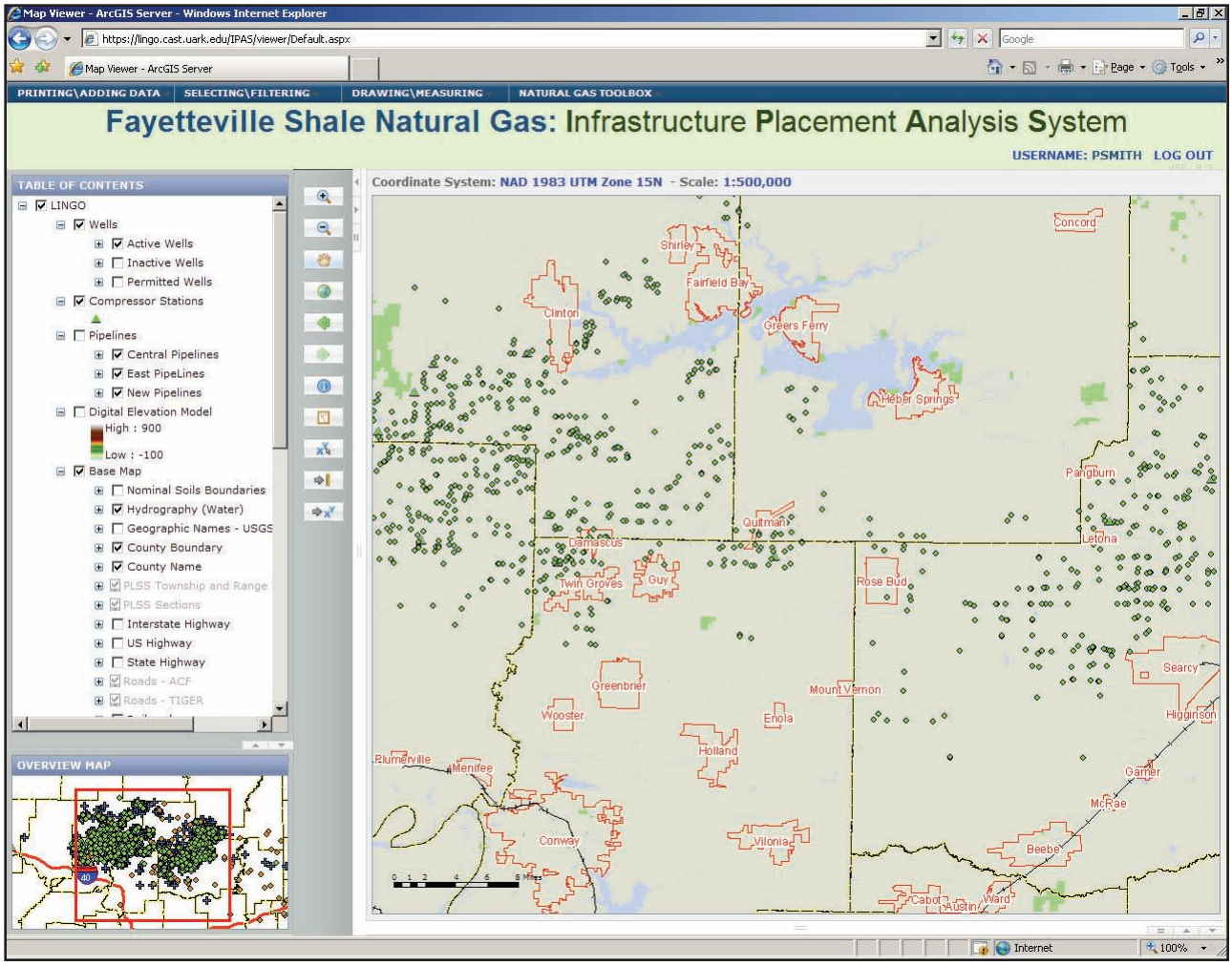


Figure 1. Screen shot of software application main screen.

location, and regulators will be able to respond to permit requests by performing their own geospatial analyses (Figure 2). Navigation of the site is structured to mimic the life cycle of a natural gas lease. The GIS-based tool will allow for determination of the following measures, among others: 1) Proximity to threatened and endangered species habitats, 2) Delineation of potential run-off areas based on local terrain, soil type, and land cover, 3) Proximity to bodies of water and pathways to and from water bodies throughout the hydrologic system, 4) Required stream crossings, and 5) Infiltration potential.

Auxiliary Educational Site Provides More Information

In addition to the GIS tool intended for regulators and producers, the researchers developed an educational website for the broader public (http://lingo.cast.uark.edu/LINGOPUBLIC/). The site contains information on state and federal regulations and a description of the play's geology, geographic extent, and economic importance. From gaining access to the land to delivering gas to the marketplace, the steps involved in developing the shale are detailed. For each of these steps, the measures industry is taking to minimize environmental impact are illustrated. An interactive map that indicates drilling locations, permitting information, well status, compressor stations, and monthly production output, can be displayed in aerial or road view and in 2D or 3D.

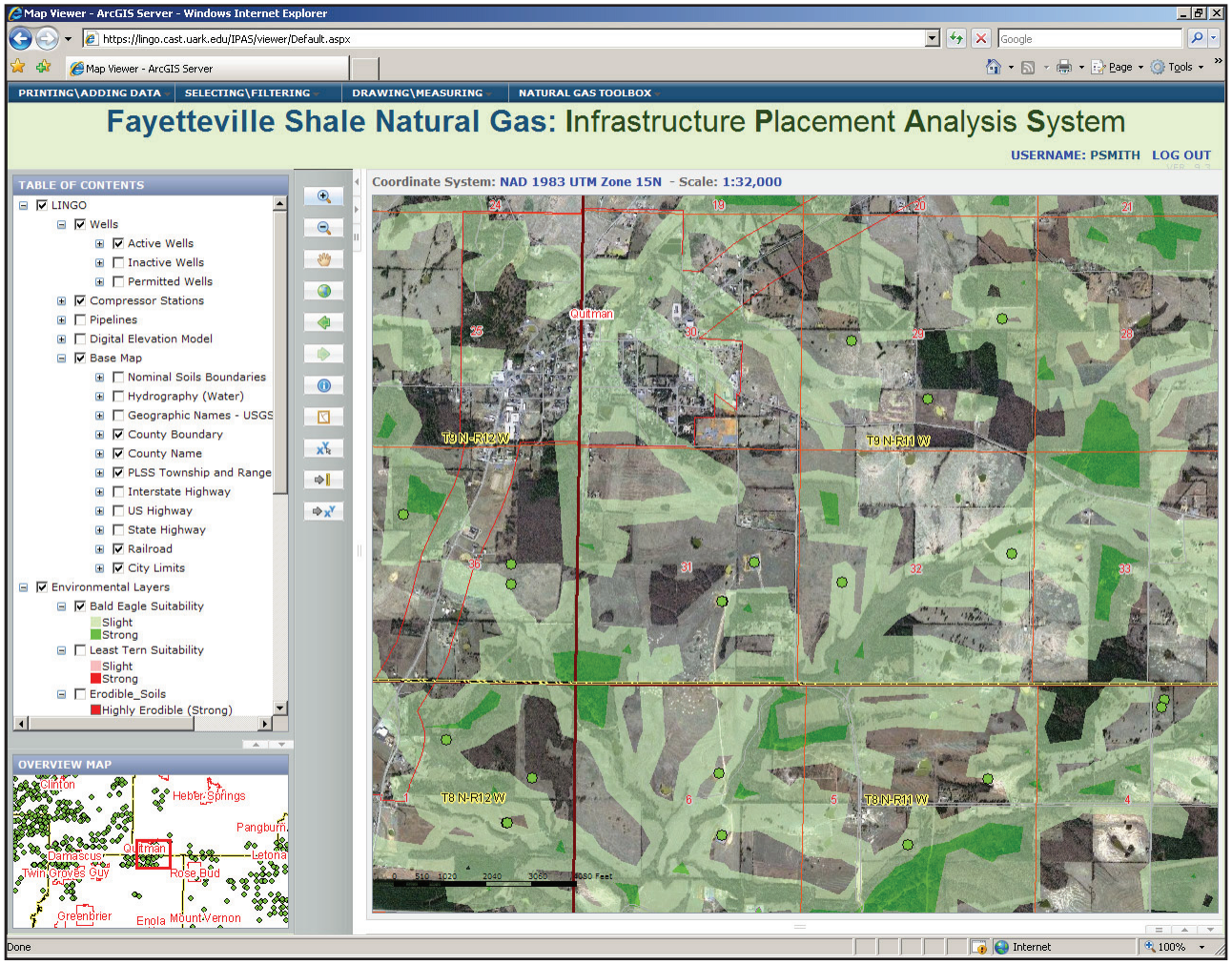


Figure 2. Screen shot of GIS display.

Tool Will Save Time and Money

Both large and small independent E&P companies will benefit from the use of this research tool, saving both time and money when complying with regulatory requirements. Since operators can use the tool as part of the planning process in locating leases, it can help minimize unnecessary field time. For example, the intersection of proposed development features (e.g., roads, drilling pads, water locations, and transmission lines) with environmental data (e.g., soil type or animal populations), can be mapped with the software, identifying potential impacts. Depending on the magnitude of the potential impact, operators may choose to shift proposed projects to alternative locations.

The decision support tool is conservatively estimated to reduce the time required to locate infrastructure for well development by one day for 20 percent of well sites because of decreased on-site survey requirements and improved lines of communication between producers and regulators. Clearly, the GIS-based tool has applications beyond the Fayetteville shale play, which, if widely implemented, will magnify its benefits many times.

This new software application, in conjunction with other DOE-sponsored technology development efforts being carried out under the research program established by Title IX, Subtitle J, Section 999 of the Energy Policy Act of 2005, will help to ensure that clean-burning natural gas continues to play a vital role in meeting U.S. energy needs.

Users can access the tool at http://lingo.cast.uark.edu/IPAS/. Users must fill out a form with some basic information before obtaining an access code.

For more information regarding this research project, contact Jesse Garcia, NETL Project Manager at jesse.garcia@netl.doe.gov or 918-699-2036, or UA Prof. Greg Thoma at gthoma@uark.edu or 479-575-4951.

New Simulation Tool to Encourage Subsea Processing in Deepwater Environment

Engineers funded by the Department of Energy are creating a new simulation tool to help accelerate the application of advanced subsea processing technologies in the Gulf of Mexico. This simulator will allow equipment developers and deepwater producers to better understand and apply the advantages of subsea processing.

This project is one of a portfolio of subsea research projects selected by the Research Partnership to Secure Energy for America (RPSEA) under an R&D program launched by the Energy Policy Act of 2005. See the Spring 2009 issue of E&P Focus for a description of this program, or visit the RPSEA Web site (http://www.rpsea.org/) or NETL web site (http://www.netl.doe.gov/technologies/oil-gas/EPAct2005/Index.html) for more information.

Early Examples of GOM Subsea Processing

Shell's Perdido facility, installed last August about 200 miles south of Houston, Texas in Alaminos Canyon Block 857, set a new record as the deepest spar in the world in over 8,000 ft (2,438 m) of water. The facility will handle 130,000 barrels of oil equivalent (BOE) per day from 34 wells, 12 of which will be remote subsea wells from the Great White, Silvertip, and Tobago projects. A 77-mile oil line and a 107-mile gas pipeline are expected to start flowing about 2010.

What makes this project a bit different from the long list of other deepwater engineering marvels constructed by Shell and others is that it represents the first application in the Gulf of Mexico of *full-scale* subsea separation and boosting. Separating the produced fluids at the seafloor *and* boosting their pressure will remove about 2,000 pounds per square inch (psi) of backpressure from the wells, which will in turn lead to significant improvement in recovery. A unique caisson that extends about 300 feet into the seabed will act as the separator, and an electric submersible pump will lift the separated oil and water to the surface. This approach will extend well life and reduce the risk of hydrate plugging in the system by separating the gas and water.

Perdido is not the first use of subsea pumps in the Gulf of Mexico. The first commercial application of subsea boosting technology in the Gulf was for wells at the King field at Mississippi Canyon, operated by BP. In late 2007, two existing subsea wells were retrofitted with a subsea booster pump to optimize oil recovery.

Advanced Subsea Processing Technologies Are Coming

Subsea processing technologies that are currently being implemented in deepwater developments around the world include partial separation with pumping (like Perdido), multiphase pumps (like King) and subsea separation (like Troll, offshore Norway). Technologies currently in development for future applications include combinations of separators, scrubbers, and pumps that allow complete separation of the production stream at the seabed (Figures 1 and 2). The most advanced systems under development may someday include multistage separation and fluid treatment and the pumping of export quality oil and gas, all on the seafloor.

However, companies are understandably cautious about plunging ahead with subsea processing systems. There are significant costs associated with moving the fluid processing function to the seafloor. Accessing

NETL PARTNERS WITH RPSEA CONSORTIUM

An innovative new research program launched by the Energy Policy Act of 2005 ("EPAct") Title IX, Subtitle J, Section 999 is moving rapidly forward with a portfolio of new research projects. This DOE program is being administered in part by the Research Partnership to Secure Energy for America (RPSEA), a consortium of more than 130 companies, universities and research organizations. Each year, RPSEA solicits proposals for research with input from two Federal Advisory Committees made up of experts from industry, academia and non-governmental organizations. Funding of about $32 MM per year is provided from offshore Federal lease royalties, rents, and bonuses and is directed towards research targeting three areas: (1) ultra-deepwater resources; (2) unconventional natural gas and other petroleum resources; and (3) the technology challenges of small producers.

the equipment for maintenance and making alterations as operating conditions change over the life of the field become much more challenging tasks when compared with surface processing systems.

However, the potential benefits in terms of increased production rates and extended field life can make otherwise marginal fields economically viable. This will make a big difference in the fraction of deepwater resource recovered.

Simulator Will Enhance Acceptance of Subsea Processing

Despite assertions by equipment suppliers that compact subsea processing systems are ready to deploy, operating engineers remain less certain of that readiness and have particular concerns about separator performance under harsh conditions. The objective of a new research project being carried out by General Electric's (GE) Global Research and VetcoGray business units, is to develop a physics-based subsea processing simulator that can be used by equipment suppliers and facility engineers to make reliable predictions of sub-sea separator performance over a specified range of operating conditions.

The GE research team will base the simulator's development on robust analytical models for compact separation devices operating in a subsea multi-phase flow environment. They will first compile a library of analytical models of separator components, then develop an integrated processing simulator, and finally, perform laboratory testing to validate the simulator and its component analytical models.

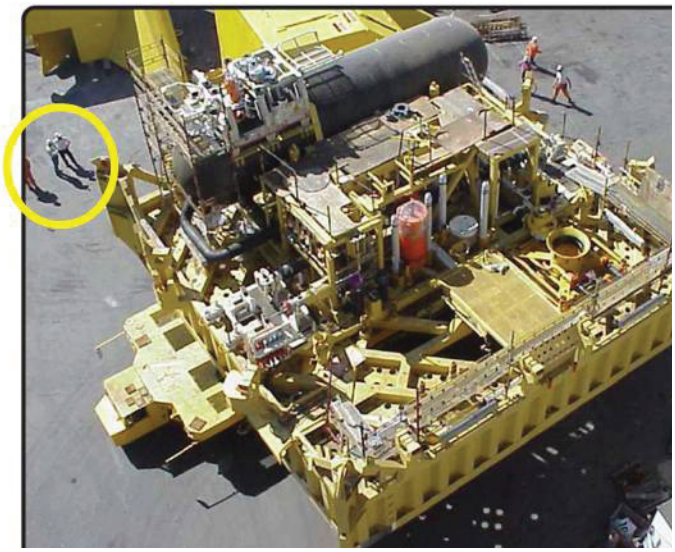


Figure 1. Photo of VetcoGray subsea processing module for Troll C during installation (left) and in yard prior to deployment (on right – see figures for scale).

The individual component models will be structured to allow more complexity to be added, as needed. The simulator framework will utilize four object levels:

- separator component models (such as inlets, cyclones, demisters, weirs, volumes),
- separators that are constructed of groupings of the components,
- subsea processing systems that are composed of one or more separators, along with any valves, pipes, fittings, autonomous control systems, and pumps, and
- solver wrappers that exercise subsea processing system numerical models through various design variations and multi-phase flow cases and perform statistical analyses to characterize system performance, support robust design development, and calculate probabilities of system failure.

The research team will carry out the laboratory testing at GE VetcoGray's multi-phase flow test facility to validate the component analytical models and overall simulator performance. The lab tests will simulate both steady state and dynamic flow conditions. A key element will be development of a conceptual scheme for up-scaling the lab-scale test results to a full-scale subsea operation.

Deliverables for this $1.2 MM project will include an alpha version of the Subsea Processing Simulator, including the simulator code and supporting documentation on its theoretical basis and recommended methodologies, and reports on the laboratory testing. The GE project team will analyze and report on the laboratory testing results and provide a recommendation on future work needed to improve the analytical models and the Subsea Processing Simulator.

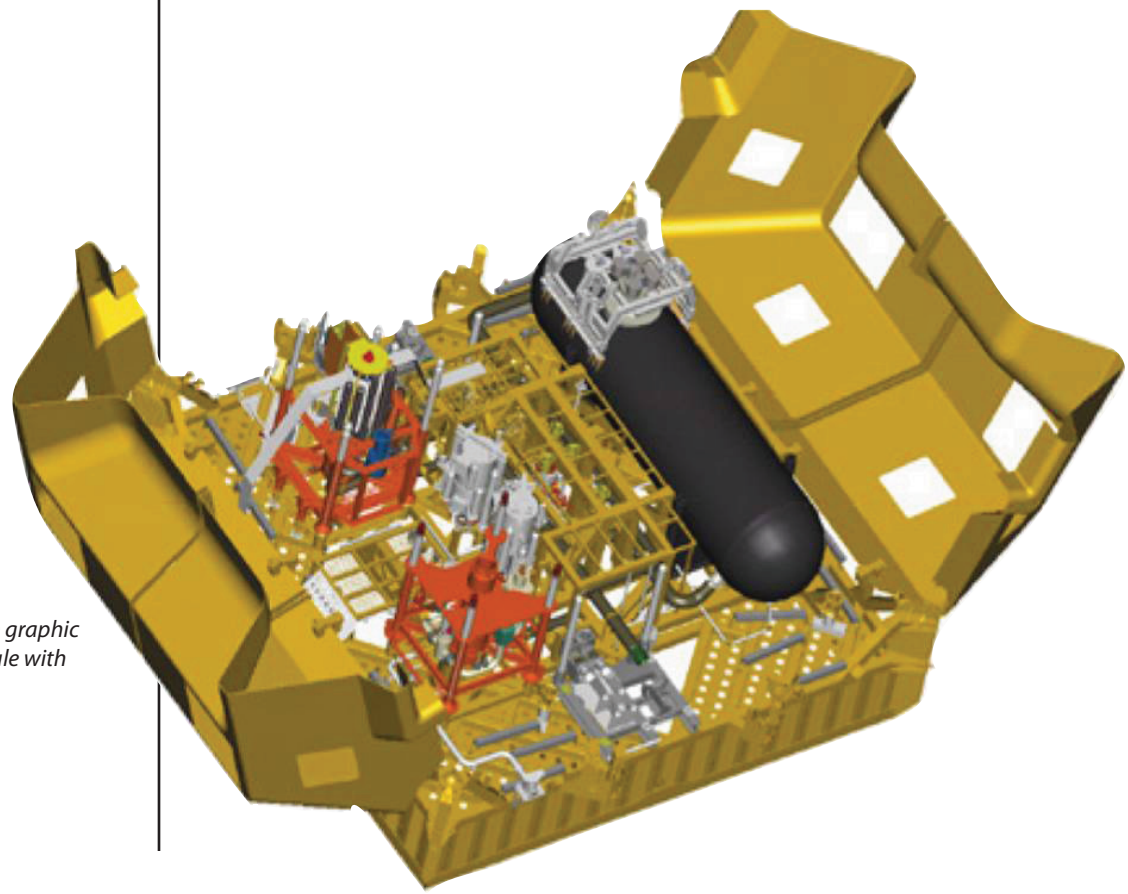


Figure 2. Computer design graphic depicting the Troll C module with protective cover opened.

Progress to Date

The kick-off meeting for this project was held on February 19 in Houston, so there have been only about four months of work completed in what will be a 1½ year project.

The bottom-up alpha version of the horizontal 3-phase separator component is currently being coded in MATLAB. This version will help the researchers understand the unit model creation, the flow of information across units, and how to solve for the entire system. This exercise is playing a vital role in setting the structure and design of the C++/NPSS-based, full-up simulator that is being developed in parallel from the top down.

The research team has developed a preprocessor and postprocessor to implement statistical analyses within the MATLAB "sandbox." This feature will allow the user to set up a set of run cases for simulation that can consist of a combination of inputs and design/operation parameters. The simulator core will then execute all the cases with all results available for post processing. The postprocessor will allow analysis of the result data sets, including performance metrics, probabilities, success/failure metrics, and operability envelopes.

The simulator will be able to interface with an existing process simulator (HYSYS) and the unit model interfaces will be standardized to allow users to incorporate their own proprietary characterizations into the model library.

Expected Benefits Are Significant

This project will produce a simulator that industry can use to predict with confidence the performance of subsea processing systems and components prior to their deployment. This will allow for quicker and more widespread deployment of subsea processing systems, particularly in deepwater environments. This tool will allow manufacturers to optimize their system designs and more accurately demonstrate the benefits to operators. It will also allow operators to optimize their subsea processing system operating practices, which will minimize production risks.

Subsea processing systems have the potential to bring deep and ultra-deep oil and gas production to market faster while extending the life of existing fields, particularly in harsh environments. In addition, subsea separation and pumping can cut topside facility costs and allow for development of marginal fields using existing infrastructure. Over the long term, acceptance and deployment of subsea processing systems should bring more domestic oil and gas production to market, while extending field life and making marginal fields economically viable.

For more information on this project, contact Roy Long at 281-494-2520 or roy.long@netl.doe.gov.

Produced Water Treatment Using Gas Hydrate Formation at the Wellhead

BC Technologies, Ltd, LLC of Laramie, Wyoming, Oak Ridge National Laboratory (ORNL) in Tennessee and the National Energy Technology Laboratory have been working together to develop a new, lower-cost technique for treating water produced from coalbed natural gas (CBM) wells at the wellhead, that employs gas hydrate formation as an element of the process.

The goal is to develop a technology that will reduce environmental compliance and disposal costs, and simultaneously provide water for beneficial use in arid regions of the United States. Treating produced water at the wellhead to a quality suitable for beneficial use eliminates significant environmental issues related to CBM development. In particular, reduction in handling requirements substantially reduces fugitive dust emission by reducing trucking and/or the need for construction of water handling pipelines.

Hydrates are solid crystalline compounds in which a lattice of hydrogen-bonded water molecules traps molecules of gases such as methane. The formation of hydrate from produced water excludes solids, dissolved salts, and other impurities. This results in residual concentrated brine after the hydrate forms. If one separates the hydrate from the brine and then dissociates it, gas and purified water result. The purified water can be discharged or reused for a variety of beneficial purposes and the smaller volume of concentrated brine can be disposed of using conventional strategies.

The process involves forming stable hydrates at relatively low temperatures (32-50 °F) and reasonably high pressures (1450-1890 psi) at the wellhead. The hydrates are separated from the concentrated brine and washed before being dissociated by pressure reduction to recover purified water and gas.

The objectives of this project are to determine the effectiveness of hydrate formation for treatment of produced water at the wellhead through proof-of-concept laboratory experiments, to design a prototype-scale injector and test it in the laboratory under realistic wellhead conditions, and to demonstrate the technology under field conditions. The research team has built and tested a prototype, and will implement a field demonstration phase beginning in September 2009.

Initial Experiments

Phase 1 of the project was comprised of proof-of-concept experiments that began in October 2005 at ORNL. The research team conducted laboratory-scale experiments using synthetic brines and a variety of gas compositions. Hydrates were successfully formed using ethane, propane, and a mixture of 95 percent methane and 5 percent propane. Initial laboratory tests showed that the process was capable of reducing the salt level in the synthetic produced water from 35,000 ppm to 2,000 ppm.

The laboratory and bench-scale testing conducted at ORNL over the first two years utilized equipment specifically developed to create hydrates for natural gas hydrate research. ORNL optimized the performance of their continuous-jet hydrate reactor (CJHR), performed scale-up testing and initial prototype design, and provided the CJHR to BC Technologies for prototype development.

PWMIS

The volume of produced water related to oil and gas production in the U.S. is estimated to be in excess of 20 billion barrels per year, enough to fill Utah's Great Salt Lake in just six years. The Produced Water Management Information System is an online resource for technical and regulatory information for managing produced water, including current practices, state and federal regulations, and guidelines for optimal management practices. Developed by Argonne National Laboratory for NETL, the system is accessible on the NETL website and currently receives about 6000 hits per month.

Data Gathering

The research team reviewed Wyoming Oil and Gas Conservation Commission (WOGCC) databases to acquire well data on permitted CBM wells in the Greater Green River Basin (GGRB). BC Technologies personnel developed and maintained an Access database for managing these data. Tracking well data in this fashion provides the research team with a way to easily view well permitting activity, operators, well locations, well depths, producing formations, production activity, and (limited) water quality data for currently producing CBM wells in the basin. This database will continue to be updated periodically and will be used to select suitable wells for field demonstrations.

Prototype Development

Phase 2, development of the prototype system, entailed scaling up the laboratory-scale injector and technology to handle a typical volume of water produced from a coalbed methane well (25 to 50 bbl/day). BC Technologies implemented the ORNL design and constructed a prototype at its facility in Laramie, Wyoming during the third year of the project.

BC Technologies personnel tested the prototype in bench-scale experiments during 2007 at their Laramie, Wyoming facility. The primary issues addressed were how to operate the CJHR in a continuous or semi-batch mode and the design of the heat transfer systems required for hydrate formation and the separation of natural gas, purified water, and concentrated brine during hydrate dissociation.

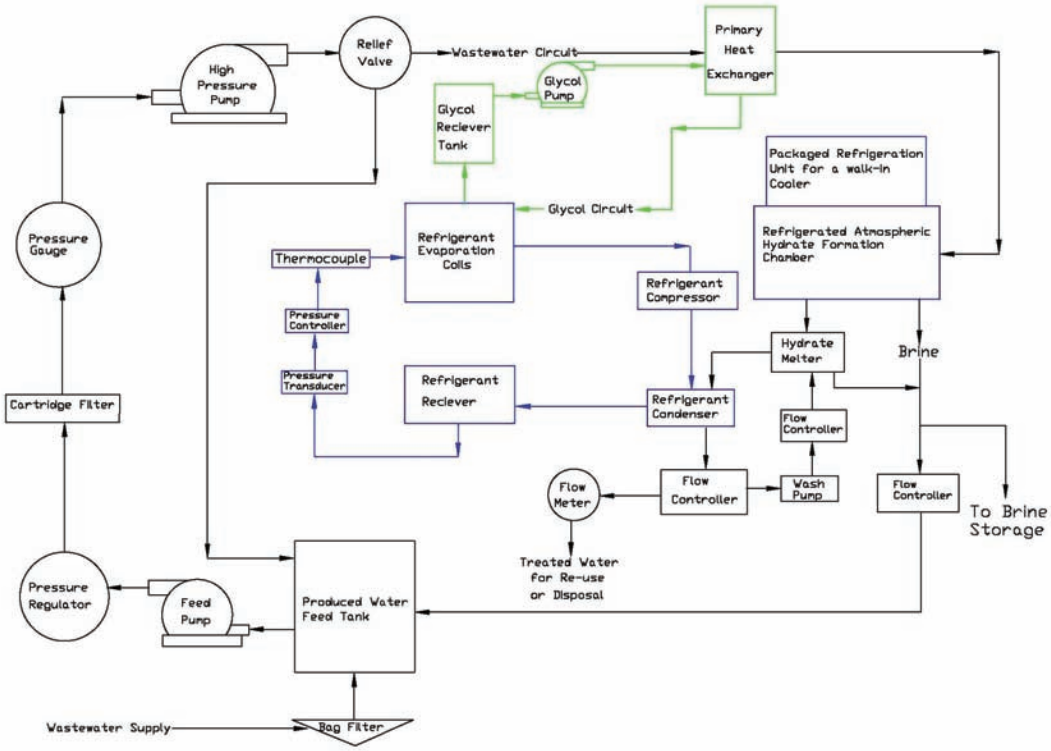


Figure 1. Schematic process flow diagram of water treatment system utilizing hydrate formation.

The original ORNL design was modified to enable formation of hydrates that could be discharged into low-pressure vessels where dissociation could be controlled by adjusting the temperature in an initial dissociation chamber. Brine and natural gas from the hydrate dissociation is separated and collected in the first chamber, and the remaining hydrate can then be transferred to a final dissociation chamber where it is rapidly dissociated using warm water and the remaining natural gas is collected.

The system utilizes three heat exchange systems. A standard refrigerant compressor is used to cool a glycol/water solution that in turn is used to cool the feed water, and a third heat exchange system utilizes a standard refrigerant compressor to control gas temperature in the hydrate collection chamber, which operates at atmospheric pressure (Figure 1).

Testing of the bench-scale system began in 2008. After a lengthy shakedown and modification period, the researchers achieved production of carbon dioxide hydrate in the atmospheric chamber (Figure 2). BC Technologies reported that the system successfully lowered produced water total dissolved solids (TDS) levels from >10,000 to < 1,000.

Figure 2. Hydrate created inside hydrate formation chamber of lab-scale system.

Field Testing

Preliminary results from the bench-scale tests conducted in Laramie indicate that the prototype can successfully form gas hydrates. The BC Technologies research team is currently making refinements to improve the unit's efficiency and increase its chances for success in the field. While BC Technologies has successfully operated the prototype, they are presently working to establish the level of consistent performance needed to move forward to the planned field tests. BC Technologies has identified a location in the GGRB for the field test, which will take place during the second half of 2009.

Potential Benefits

The project team anticipates that the successful development and demonstration of this water treatment technology could help increase commercial CBM production in the GGRB, through a significant reduction in water management costs. In southwestern Wyoming, costs for transporting produced water by truck from the well site to a centralized disposal facility were reported as high as $7/bbl in 2009. Over the past decade, 33 locations in the GGRB have been explored for CBM development. In July 2009, there are only 7 CBM fields reporting production. Over 2/3 of the fields are no longer being produced, largely because of economics associated with produced water disposal in this basin. Cost effective, environmentally acceptable produced water management that includes treatment at the wellhead to levels suitable for beneficial use, discharge or infiltration could help to advance each of these projects, providing much needed, clean, domestic energy to our Nation.

For more information on this project, check the project summary available on the NETL website (http://www.netl.doe.gov/technologies/oil-gas/Petroleum/projects/Environmental/Produced_Water/15551.htm), or contact Sandra McSurdy, NETL Project Manager (sandra.mcsurdy@netl.doe.gov or 412-386-4533), or John Boysen, BC Technology primary investigator (bctechnologies@qwest.net or 307-742-5651).

Two Tight Sandstone Web Sites Launched

Two projects supported by NETL have created public web sites that allow quick access to information on tight gas sandstone plays. The first project, led by New Mexico Institute of Technology, developed a database of well logs, core data, and gas production results for Dakota sandstone wells in the San Juan basin of New Mexico, and is available at http://octane.nmt.edu/SanjuanAjax/. The second project, led by West Virginia University and the West Virginia Geological and Economic Survey, with contributions from the Pennsylvania Geological Survey, compiled well-specific and regional data on five tight gas plays in the central Appalachian basin. These data, which include digital well logs, core data, production data, and reports, are available through an interactive GIS-based system at http://www.wvgs.wvnet.edu/atg/ProjectInfo.aspx.

NETL to Collaborate with Chinese Academy of Sciences

NETL is forging a collaboration with the Chinese Academy of Sciences (CAS), China's most prestigious scientific organization, to work together on developing low-carbon energy technologies. NETL Director, Carl Bauer, met with CAS officials on May 12, to sign two Memoranda of Understanding (MOUs) setting forth the terms of the collaboration. The first is a tri-party agreement among NETL, CAS, and the Pacific Northwest National Laboratory and will focus on carbon capture and storage, coal gasification, and conversion of synthesis gas to commercial products. The second MOU, between NETL and CAS, is centered on multi-phase and multi-scale modeling of carbon capture and storage, gasification, and combustion processes.

SeismicPULSER™ Developed for Borehole Imaging

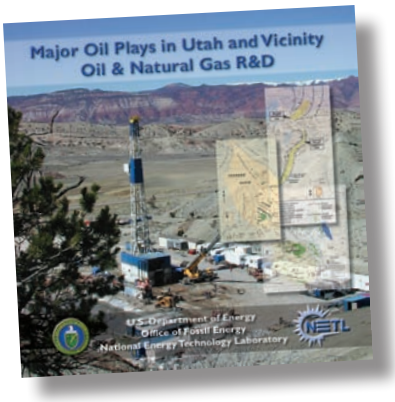
Technology International, Inc. of Kingwood, Texas has developed the SeismicPULSER™, a down-hole seismic tool that can provide real-time reservoir imaging roughly 600 feet ahead of the drill bit, potentially to depths of 30,000 feet or more. Attached at the drill bit, the tool emits low-frequency pulses that can be used to guide the drillstring. Technology International, Inc. is currently working to commercialize the patent-pending system. Learn more about the project here (http://www.netl.doe.gov/technologies/oil-gas/NaturalGas/Projects_n/EP/AdvDiagnostics/AD_42242SeismicWD.html).

Shale Gas Primer Provides Objective View

NETL announces the release of "Modern Shale Gas Development in the United States: A Primer." The Primer provides regulators, policy makers, and the public with a balanced, comprehensive view of the historical development, current practices, and environmental challenges associated with deep shale gas development. The publication describes the importance of shale gas in meeting the future energy needs of the United States, as well as issues related to water management in shale gas fields. This effort was championed by the Ground Water Protection Council through a cooperative agreement with NETL. To download the complete report, go to http://www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf.

M-I SWACO to Invest in Process for Treating Produced Water

M-I SWACO, a Houston-based supplier of drilling fluid systems, has agreed to invest $4 million to further develop and license a process for treating produced water using advanced mobile membrane filtration and desalination. Texas A&M developed the process with financial support from NETL during 2003 to 2007. By reusing the produced water, M-I SWACO and Texas A&M are hoping to reduce costs and lower the impact of oil and gas operations in environmentally sensitive environments. Read more here (http://engineering.tamu.edu/news/index.php/2009/01/08/texas-am-and-oil-field-service-giant-m-i-swaco-form-research-partnership-for-wastewater-treatment/).



Utah Geological Survey Completes Portfolio of Oil Plays in Utah, Colorado, and Wyoming

A new portfolio developed by the Utah Geological Survey, with funding from NETL, provides detailed information on oil plays located in Utah, Colorado, and Wyoming. The portfolio is available as a CD entitled "Major Oil Plays of Utah and Vicinity." It contains maps, geologic data, land-use data, and best development practices for 10 oil plays and 13 sub-plays, including the Paradox basin, Uinta basin, Utah thrust belt, and the recently discovered Covenant field. NETL expects that this information will help operators increase recoverable oil from existing fields, prevent premature abandonment of small fields, identify the best drilling and recovery techniques for a specific play or sub-play, and possibly spur new oil discoveries. The CD is available through the NETL library, at 304 285-4184, or via http://www.netl.doe.gov/publications/cdordering.html. The Utah Geological Survey plans to release the portfolio in Bulletin format in early 2010.

Upcoming Meetings and Presentations

Below is a listing of some of the meetings and presentations on NETL-sponsored oil and natural gas projects that will be taking place over the next three months. Please visit the Reference Shelf for more information on these activities.
http://www.netl.doe.gov/technologies/oil-gas/ReferenceShelf/

August 5–6, 2009: PTTC Workshop on Openhole Logging. Day long workshop held in Long Beach and Bakersfield, CA on successive days. Contact PTTC West Coast at (661) 635-0557 or Email (pttcwestcoast@cccogp.org) for more information.

August 11, 2009: A paper on "A Hybrid Treatment Process for High TDS Oil-Field Produced Water" will be presented at the 2009 New Mexico Water Research Symposium, at Macey Center, New Mexico Institute of Mining and Technology, Socorro, New Mexico. This paper discusses initial results from NETL project DE-NT0005227, Membrane Technology for Produced Water at Lea County, New Mexico. View project information.
http://www.netl.doe.gov/technologies/oil-gas/Petroleum/projects/Environmental/Produced_Water/05227_MembraneTech.html

August 19, 2009: PTTC Workshop on How to Start/Fix/Manage a Small Waterflood – Houston, TX. Contact: 512-232-1527.

September 8-10, 2009: RPSEA Ultra-Deepwater TAC Quarterly Meeting, Bellaire, Texas (on each of the three days focus will be on Floating Facilities, Subsea Facilities, Flow Assurance).

RPSEA's Ultra-Deepwater Technical Advisory Committees (TAC) each focus on a particular ultra-deepwater technology area. The role of the TACs, with representation from subject matter experts who study and apply ultra-deepwater technologies in real field situations, is to identify current technology gaps and define the specific R&D efforts needed to address these gaps. The UDW TACs are open to the public. Please visit RPSEA's website, www.rpsea.org, for more information.

September 9-11, 2009: A paper entitled "Focusing of Ultrasonic Waves in Cylindrical Shells Using Time-Reversal" will be presented at the 7th International Workshop on Structural Health Monitoring – 2009, at Stanford University in Stanford, California. The paper is related to NETL- project DE-NT0004654, Instrumented Pipeline Initiative. View project information.
http://www.netl.doe.gov/technologies/oil-gas/NaturalGas/Projects_n/TDS/TD/04654_PipelineInitiative.html

September 13-16, 2009: The Groundwater Protection Council (GWPC) presents "Water/Energy Sustainability Symposium – Water and Energy Policy in the 21st Century" at their Annual Forum, to be held at the Hilton Salt Lake City Center, in Salt Lake City, September 13-16. Representatives from state and Federal agencies will meet with leaders from industry, research organizations, and environmental groups to examine the complex relationship between energy development and water resources. The symposium is sponsored by GWPC and NETL. View Symposium details. http://www.gwpc.org/meetings/forum/forum.htm

September 15-16, 2009: Federal Advisory Committee Meeting for the Unconventional Resources and Small Producer Challenges elements of the EPAct 2005 Title IX, Subtitle J, Section 999 R&D program, in San Antonio, TX. See DOE website for more information.

September 16-17, 2009: Federal Advisory Committee Meeting for the Ultra-Deepwater element of the EPAct 2005 Title IX, Subtitle J, Section 999 R&D program, in San Antonio, TX. See DOE website for more information.

September 16, 2009: RPSEA Ultra-Deepwater Drilling & Completion TAC Quarterly Meeting, Houston, TX.

September 17, 2009: RPSEA Ultra-Deepwater Systems Engineering TAC Quarterly Meeting, Houston, TX.

September 22, 2009: RPSEA Ultra-Deepwater Reservoir Engineering and GeoscienceTAC Quarterly Meetings, The Woodlands, TX.

September 22, 2009: PTTC Workshop on Water/Gas Shutoff and Conformance Control – Knowing What To Do/Where – Lafayette, LA. Contact: 225-578-4538.

September 24, 2009: PTTC Workshop on Water/Gas Shutoff and Conformance Control – Knowing What To Do/Where – Midland, TX. Contact: 512-232-1527.

September 24-25, 2009: A paper on "Environmentally Friendly Oil and Gas Operations for the Eagle Ford Shale" will be given at the Exploration and Production Technology Summit 2009, at The Woodlands Waterway Marriott Hotel and Convention Center, Houston, Texas. The paper is related to project DE-FC22-05NT42658, "Field Testing of Environmentally Friendly Drilling System." View abstract and other project information. http://www.netl.doe.gov/technologies/oil-gas/Petroleum/projects/Environmental/Federal_Lands/42658.htm

September 30-October 2, 2009: Two papers will be presented at the 3PArctic Conference in Moscow, Russia, September 30-October 2, 2009. The first paper will be on "The Petroleum Geology of the Umiat Oil Field, North Slope, Alaska" and the second on "Production Methods for a Light Oil in a Frozen Reservoir: Umiat Field, National Petroleum Reserve, Alaska." The papers are an outcome of NETL project DE-FC26-08NT0005641. View project information. http://www.netl.doe.gov/technologies/oil-gas/Petroleum/projects/Arctic_Energy/5641_FrozenReservoirs.html

October 15, 2009: PTTC Workshop on Water/Gas Shutoff and Conformance Control – Knowing What To Do/Where – Casper, WY. Contact: 303-273-3107.

October 20–21, 2009: PTTC Workshop on Property Taxes. Day long workshop held in Long Beach and Bakersfield, CA on successive days. Contact PTTC West Coast at (661) 635-0557 or Email (pttcwestcoast@cccogp.org) for more information.

October 26-30, 2009: A talk on "Time Reversal Focusing for Pipeline Structural Health Monitoring" will be given at the 158th Meeting of the Acoustical Society of America, to be held in San Antonio, Texas, October 26-30, 2009. The talk is related to NETL project DE-NT0004654, Instrumented Pipeline Initiative. View project information. http://www.netl.doe.gov/technologies/oil-gas/NaturalGas/Projects_n/TDS/TD/04654_PipelineInitiative.html

October 27, 2009: PTTC Workshop on Fundamentals of Waterflood Design – Wichita, KS. Contact: 785-864-7396.

October 28, 2009: PTTC Workshop on Waterflood Systems and Operations – Wichita, KS. Contact: 785-864-7396.

October 29-30, 2009: PTTC Short Course on Fundamentals of Waterflooding: Day 1 – Design and Implementation; Day 2 – Operations and Management – Wichita, KS. Contact: 785-864-7396.

November 3-5, 2009: The 16th Annual IPEC Petroleum and Biofuels Environmental Conference, Renaissance Houston Hotel, Houston, TX. The Integrated Petroleum Environmental Consortium (IPEC) is a joint effort of four major research universities: The University of Tulsa, The University of Oklahoma, Oklahoma State University, and The University of Arkansas. See website for more information.