the ENERGY lab

# E&P Focus

Summer 2010 | Oil & Natural Gas Program Newsletter

NETL

## CONTENTS



## 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

# Challenges Facing Developers of the Marcellus Shale in the Appalachian Basin

Development of the Marcellus Shale play will result in 1000s to 10,000s of new wells over the next decade, a several-fold increase in regional natural gas production, and a wide range of regional economic benefits. NETL is helping to develop technology solutions that reduce risks, increase the efficiency of development, and inform state and Federal regulators. This article provides a brief overview of the status of the Marcellus Shale play, and outlines the technical challenges facing operators and the efforts of NETL in meeting those challenges.

## The Resource

The Marcellus Shale, a Devonian age, black, organic shale, underlies approximately 54,000 square miles (34,000,000 acres) of West Virginia, eastern Ohio, western and northern Pennsylvania, southern New York, and small portions of Maryland and Virginia (Figure 1). The Marcellus is found at depths of 3,500 to 8,500 ft, ranges in thickness from 50 to 200 ft and generally thickens from west to east.

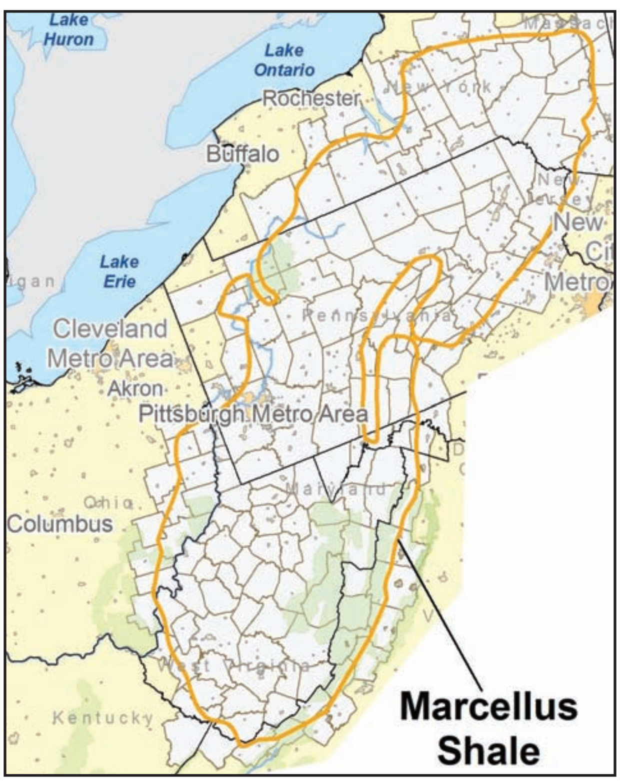



*Figure 1. Extent of Marcellus Shale (ALL Consulting, Modified from USGS and WVG&ES, November, 2009)*

Drilling to date has delineated two "sweet spots"; one is in southwestern Pennsylvania, where the gas exhibits high liquids content and the other is in northeastern Pennsylvania (Figure 2). The play extends to the southwestern portion of West Virginia where pressures and flow rates are lower from older wells drilled prior to the modern play. The geologically related Huron shale located in southeast Ohio, West Virginia and northeast Kentucky is being developed using some of the same methods.

**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**

# Commentary

The rapid growth of shale gas production in the U.S. is no longer news to most people. But, by any measure, the results are staggering. What began as a series of technical successes in the Barnett Shale in north east Texas has become, in less than a decade, a nationwide play that now accounts for more than 10 percent of total U.S. natural gas production. Equally important, in the five-year period from 2003 to 2008, the nation-wide shale gas play increased total proved U.S. gas reserves from 189 tcf to approximately 245 tcf, according to the Energy Information Administration. The beneficial impacts of the surge in shale gas production are important to the nation's energy mix going forward for several reasons. First, as the preferred bridge fuel to our greener energy future, natural gas is a clean option. Second, the increase in production has stabilized, and will continue to stabilize, natural gas prices at reasonable levels. Third, the increase in shale gas production may allow the country to become a net exporter of natural gas rather than a net importer, enhancing our energy security.

But the ramp up of shale gas production in the U.S. is not without issues. Near the top of the list is the treatment, disposal and/or reuse of frac flowback and produced water from shale gas operations. The issue is particularly relevant to development of the Marcellus Shale, especially in Pennsylvania, where the lack of suitable formations for injection of frac flowback and produced water from burgeoning shale gas development has brought the problem into sharp focus. This, combined with recent restrictions on the disposal of flowback and produced water in Pennsylvania's public water treatment plants, has dramatically increased the need for technologies to better clean flowback and produced water for disposal and expanded reuse in fracturing operations. NETL's Strategic Center for Natural Gas and Oil has been at the forefront of the issue, with 27 active shale gas research projects across all program areas. Of these, 14 projects specifically target the Marcellus shale. Project funding from DOE totals $18.5 million for these Marcellus projects, with an additional $8 million in cost share. Working with industry and academia, we fully expect these projects to provide solutions to some of the most vexing shale gas water problems. As always, your comments and feedback are welcome.

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

Estimates of the volume of ultimately recoverable natural gas for the Marcellus play have increased as more information has become public concerning the play's potential. The Potential Gas Committee's (PGC) latest assessment of the Nation's natural gas resource base (prepared as of December 2008 and released in June 2009) estimated the total technically recoverable natural gas resource in the Appalachian Basin region to be 227 trillion cubic feet (Tcf). While several other smaller shale plays were included in this total, the Marcellus is responsible for the majority of this estimate. While this estimate was considered to be the "most likely" number, the PGC range of values extends from 92 Tcf to 549 Tcf. In an August 2009 magazine article, Dr. Terry Engelder, an early proponent of the potential of the Marcellus at The Pennsylvania State University (PSU), suggested that the mean technically recoverable resource could be as high as 489 Tcf.

Until additional longer term production data is available for analysis, the range for estimated technically recoverable Marcellus natural gas will remain broad. The uncertainty is primarily a function of three questions: 1) how much of the known Marcellus acreage will be as productive as the current sweet spots, 2) what will be the longer term production decline behavior of Marcellus wells and thus the actual ultimate per well recovery, and 3) will new technologies be applied to favorably impact either of these factors?

## Current Activity

Between 2006 and May 2010, more than 2000 Marcellus wells were drilled. A recent report by PSU indicates that in Pennsylvania, where much of the development is centered, a total of 710 wells were drilled in 2009, of which 508 were horizontal. The report also identifies 625 Marcellus wells in Pennsylvania as "operating" during the last quarter of 2009, and estimates fourth quarter 2009 production at 550 million cubic feet per day (MMcfd) of natural gas and gas equivalent liquids. Because some operated wells may not be connected to sales lines or on full production, it is difficult to estimate an average rate per well at this early stage in play development. Between January and April 2010, another 821 Marcellus wells had been drilled in Pennsylvania alone.

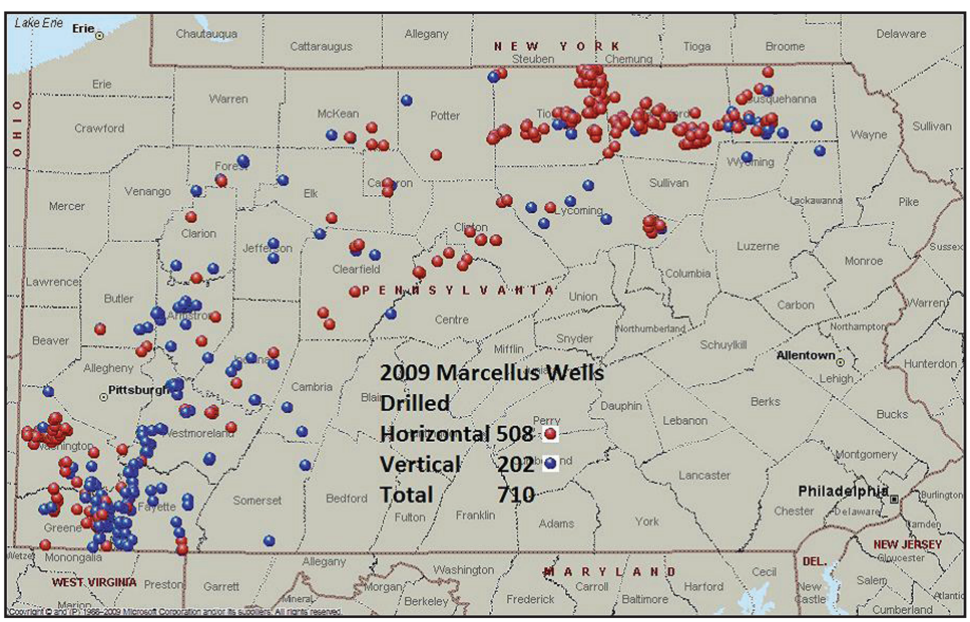



*Figure 2. Wells Drilled in Pennsylvania during 2009 Indicate "Sweet Spots" in Marcellus Play (Considine, 2010)*

Marcellus wells have also been drilled in West Virginia as part of the modern play. In 2007 and 2008 there were 756 Marcellus drilling permits issued in WV, dropping to 415 in 2009 and 96 to date in 2010. A total of 394 Marcellus wells were completed in West Virginia in 2007 and 2008, and another 106 in 2009.

Marcellus development in New York is on hold pending regulatory action. New York's Department of Environmental Conservation (DEC) has developed a draft Supplemental Generic Environmental Impact Statement (dSGEIS) for the horizontal drilling and high-volume hydraulic fracturing needed to develop the Marcellus. The public comment period for this document has closed and the Department is currently evaluating the comments received before taking action.

In April 2010 the DEC also announced new regulations for watersheds sourcing the New York City and Syracuse water supplies that will effectively prevent drilling in those areas. The New York City watershed, covering more than 60 square miles, makes up only about 8 percent of the Marcellus play region in New York. The watershed that serves the city of Syracuse is even smaller, so the impact of this action is not large in terms of limiting development. There are only 58 pending drilling permit applications in New York's portion of the Marcellus play area, and none are in the watersheds in question.

## Drilling and completion operations

The approach for developing the play has evolved. Currently, typical operations involve the construction of a well pad (Figures 3, 4, 5) from which several wells are drilled in succession. Early in the play, operators are more likely to drill 2-3 wells per pad because well spacing has not been established yet by performance. Most operators drill enough wells to establish production, with plans to come back and drill infill wells at some future time, if warranted. Where production is established, operators may drill 6 – 10 wells per pad. At depth, each wellbore is directed horizontally for a lateral length of up to 6,000 feet within the shale zone. The horizontal laterals may be drilled in parallel patterns or in whatever pattern suits the acreage (Figure 6). Vertical sections of the well are generally drilled using air. The curved and horizontal lateral portions of the wellbore are then drilled with a different rig that uses drilling mud rather than air as the drilling fluid. It takes roughly 20 days to drill each well bore.

Once drilled, the horizontal lateral wellbore is hydraulically fractured in a series of fracture treatment stages, starting at the bottom (or "toe") of the horizontal lateral and moving uphole (toward the "heel"). In Pennsylvania during 2008, horizontal laterals were typically in the range of 2,000 ft and stimulated with 8 to 10 fracturing stages. In 2009 numerous operators had moved to 3,000 ft horizontal laterals stimulated with 12 to 14 stages, and a few operators had explored the productivity of 6,000 ft laterals with up to 25 stages.

Each treatment stage typically involves approximately about 10,000 bbl of water (420,000 gal) and about 400,000 lb of sand (200 tons). Typically, about 40% of the fresh makeup water comes from public water supplies while 60% comes from surface water (rivers). The average total volume of fluid injected per well has been about 2.8 million gal, but between 10 and 20% of that is now being supplied from flowback water from previous fracture treatments. Producers are reporting 15 to 40% initial flow-back of fracturing fluid. Service companies now offer fracturing fluid formulations that enable the reuse of flowback water that has high salinity.

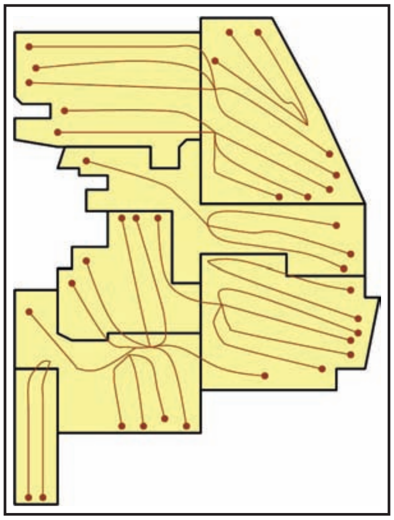


*Figure 6: Well plat showing horizontal lateral trajectories from multiple well pads*

*Figure 3: Marcellus well pad with adjacent water impoundment. Photo courtesy of www.marcellus-shale.us*

*Figure 4: Six-well pad during fracturing. Photo courtesy of www.marcellus-shale.us*

*Figure 5: Wellheads post drilling and pre-stimulation. Photo courtesy of www.marcellus-shale.us*

Depending on the local terrain, a lined central impoundment serving numerous pads may be constructed with water piped through temporary surface lines (Figure 7), or a lined pit may be constructed for a single pad. It can require 3 to 4 hours to pump a single fracture treatment stage, and thus 60 to 100 hours of total pumping time for a single well. Two lateral wellbores may be simultaneously fractured with the crew alternating perforating the casing in one lateral while pumping a stage in the adjacent lateral. Hydraulically fracturing six or more wells on a pad may require a few weeks on location.

After a well is fractured a coiled tubing unit is generally brought in to drill out the plugs between stages and a company that specializes in flow back services to set up the equipment required to flow back the wells (produce back the water pumped into the formation during the fracturing process). Each well is individually flowed back, with typical well "blowdown" and gauging of productivity taking about a week. After blowdown, each well is shut in until sales line and separation facilities are installed. This can be six to nine months after the stimulation.

A range of well productivity is being reported, as would be expected given the range in well designs and apparent variability in regional productivity. For example, EQT has reported that the 30-day average initial production rate for the company's seven Marcellus wells completed so far in 2010, averaged 7.0 MMcfe (million cubic feet of gas and gas equivalent oil) per day; ranging between 2.7 MMcfe and 15.8 MMcfe per day.

### Projected development

Currently, a projected development scenario has been developed by PSU that projects drilling and production within the Pennsylvania portion of the play to 2020. This forecast estimates that the number of wells drilled in Pennsylvania in 2010 will total 1,743 (versus 710 in 2009) and that Pennsylvania Marcellus production in 2010 will average 1000 MMcfed. Further, these totals are projected to rise steadily to 3,587 wells per year and 13,500 MMcfed by 2020.

This projection will require that a total of nearly 31,000 Marcellus wells be drilled in the Pennsylvania portion of the play alone over the next decade. An assumption of 2.8 Bcf estimated ultimate recovery (EUR) per

*Figure 7: Temporary water lines laid along road right-of-way. Photo courtesy of www.marcellus-shale.us*

well was used, along with a fairly conservative decline rate based on the lower performing examples of well performance that have been publicly divulged. This projection would result in about 87 Tcf of recoverable gas being developed over the next decade in Pennsylvania alone.

## Technical Challenges

The dramatic increase in activity and production is sharpening the focus on a number of issues facing Marcellus shale gas developers, listed below.

***Water management*** – The large volumes of water that must be injected to stimulate Marcellus wells must be supplied from surface or subsurface sources. When this water returns to the surface it typically contains high concentrations of dissolved solids and smaller amounts of fracturing chemicals. The water must be disposed of in deep disposal wells or treated for surface disposal, or reused. Currently, about 60% is being reused to stimulate subsequent wells, and 40% is being either shipped to disposal wells in Ohio or West Virginia (there are very few subsurface locations in Pennsylvania where deepwell injection is possible), or treated to remove contaminants and then either reused or disposed of via surface disposal. Finding ways to ensure that the supply, handling and fate of this water is managed in a safe and environmentally benign manner over the long term is an issue that producers, state regulators and citizens groups are actively involved in debating and studying.

***Pipeline infrastructure*** – The Marcellus play region has existing large-scale pipeline and storage infrastructure that provides access to demand centers in the Northeast. These include major interstate pipelines that extend northward from the Gulf Coast and large diameter pipelines running West-East that receive gas from local production and from the long-haul pipelines. As development of the Marcellus proceeds, analysts expect to see numerous projects involving gathering and supply laterals built to the existing pipelines. If obstacles to building the necessary processing, gathering, and pipeline infrastructure arise, growth in Marcellus production will be delayed.

***Environment, Safety and Health*** – Unconventional natural gas plays such as the Marcellus require a large number of wells to convert the significant resource into reserves. The intensity of this development, particularly in rural areas that have not seen such levels of activity before, will increase the potential for environmental impacts if special care is not taken. These impacts can be to the water (uncontrolled releases of well fluids at the surface or subsurface), to the ecosystem (plants and animals affected by spills or changes to the landscape), or to the air (emissions from increased truck traffic, rig power generation, or gas production and processing emissions). There are also visual (rigs on the horizon and land cleared for pads and pipeline construction) and audio (noise from drilling, trucking and compression facilities) impacts (Figure 8). Regulatory reaction to these potential impacts must be carried out in a manner that addresses the concerns of citizens while encouraging responsible development.

***E&P operations (reducing risk and improving efficiency)*** – In an unconventional gas play such as the Marcellus, success or failure for an operator is not defined by a single dry hole, but by learning how to drill, complete, and operate wells in a manner such that the average reserves/flow rate exceed a commercial threshold (the "manufacturing" model). Accordingly, operators that reduce unit costs and improve unit performance over time will be successful. Critical to this process is the ability to develop and test new ideas, gather and analyze data, learn from mistakes and successes, and adapt or extend existing technology to new applications. In the case of the Marcellus, perhaps the most important element of the overall E&P operation is the fracturing process. The development of new techniques and the adaptation of existing techniques to optimize production are progressing on independent fronts and are dependent on the technical and financial resources of each individual operator. Efforts to develop industry-wide best practices and share lessons learned could advance the overall efficiency of the play's development.

Regulatory framework – State agencies and local bodies in New York, Pennsylvania, and West Virginia are modifying existing regulatory processes and, in some cases regulations, to manage the rapid increase in drilling activity and to address perceived threats to citizens or the environment. Reactions have spanned the spectrum, from moratoria on leasing to adding staff to more effectively process drilling permits. Not only state regulatory bodies but also quasi-federal agencies such as the Susquehanna River Basin Commission and Delaware River Basin Commission are taking action on issues where they feel they have a part to play. Congressional efforts to shift the regulation of hydraulic fracturing from the states to the Environmental Protection Agency have been re-activated by the Marcellus play development. If regulations are

*Figure 8: Drilling site near Washington, PA with sound barriers in place. Photo courtesy of www.marcellus-shale.us*

not designed and applied through a process that is based on a scientific assessment of costs and benefits, the considerable potential positive impacts of Marcellus development could be delayed or lost. Other sources of competitively priced natural gas would replace Marcellus production.

## NETL Shale Gas Research

NETL is currently managing a number of R&D efforts that bear directly on natural gas production from shales. These projects are focused on four areas: Water treatment and management, resource characterization, E&P technology, and environmental issues. Some of these projects are part of NETL's traditional R&D program, and some are being administered by the Research Partnership to Secure Energy for America (RPSEA) consortium under the Energy Policy Act of 2005 Section 999 R&D Program. About half a dozen of these projects deal specifically with Marcellus shale, but all of them have elements that relate to the Marcellus challenges listed above.

***Water treatment and management*** – NETL has 15 projects focused on produced water and fracture flowback water treatment and management challenges. These projects involve a total DOE investment of $12.1 million.

***Resource characterization*** – NETL has 4 projects focused on shale resource characterization. These projects involve a total DOE investment of $8.4 million. In addition, The Office of Research and Development at NETL is undertaking an in-house research project focused on the Marcellus shale reservoir.

***E&P technology*** – NETL has 13 projects focused on E&P technology development. Eight of these are focused on production optimization, and five are focused on fracturing technology. The total DOE investment is $12.1 million.

***Environmental issues*** – NETL has 11 projects focused on environmental impact mitigation technologies and regulatory streamlining. The total DOE investment is $15.7 million.

Together, these 43 projects amount to $48.4 million in public R&D over about four or five years (most projects began in 2009 or 2010 and will end in 2011 or 2012). The large majority of projects are with universities (24), many of which are partnering with technology providers or producers to carry out their research. When research performer cost share is included (average of 32%), the total amount of funding for these 43 projects is $70.7 million.

## Summary

Although the exact pace and extent of development of the Marcellus play has yet to be fully defined, it is clear that the play will result in many new wells and a several-fold increase in regional natural gas production. This development will involve some risks. There is a role for the Federal government in helping to develop technology solutions that reduce risks and increase the efficiency of development, and that inform state and Federal regulators. DOE-NETL is already actively involved in technology R&D focused primarily on water treatment and management, E&P technology development, and environmental issues. DOE can continue working with other agencies, states, industry partners, and research organizations to help fill gaps in the shale development technology portfolio.

# Cost Effective Recovery of Low-TDS Frac Flowback Water for Re-use

Two significant challenges facing developers of shale gas plays are: (1) availability of water for drilling and hydrofracturing, and (2) disposal of the resultant waste water produced by the hydrofracture process (frac flowback water). The large volumes of water required for multiple, slickwater fracturing stages can become a limiting factor in the development process. It has been estimated that in some cases 100 barrels of water are used per million cubic feet of produced gas. Effective technologies to reclaim a portion of the fracturing flow back water for reuse are needed.

The amount of contaminants (primarily salts) in the flowback water varies from play to play, within plays, and over time for an individual well, from the initial fracture flowback period through sustained production. NETL has initiated a research project designed to develop a membrane-based flowback water treatment process that specifically targets the low-Total Dissolved Solids (TDS) portion of the flowback water produced during hydrofracturing operations (Figure 1). Partnering with GE Global Research to carry out the research, NETL aims to enable the cost-effective production of clean water suitable for re-use in successive hydrofracturing operations. The project, which began in October 2009, will conclude in March 2011. This effort is being carried out in concert with a complementary project focused on the high-TDS portion of the flowback water stream.

## Background

Between two and four million gallons of water are introduced into a shale gas well during typical drilling and hydrofracturing operations. Trucked-in fresh water constitutes a large part of this volume, and this approach entails high transportation costs. Other water sources utilized to a lesser

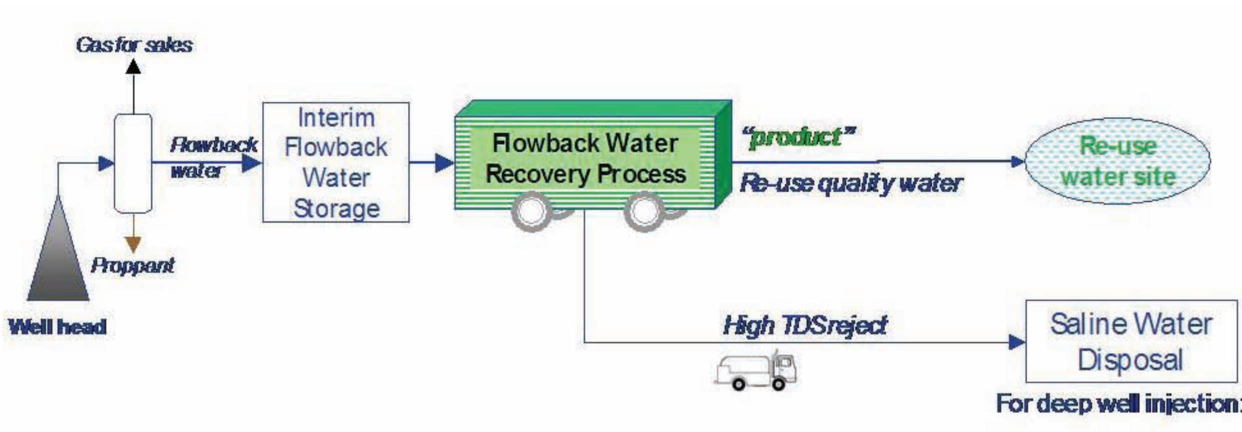



*Figure 1. Schematic illustrating partition of low-TDS water for recycle*

extent are local freshwater sources (lakes, rivers, water wells, etc.). In areas where the water availability is limited (the Barnett Shale play) or where withdrawal from scenic streams might impact the ecosystem (the Marcellus Shale and other plays), natural gas related water consumption has met with public opposition.

Upon completion of the drilling and fracturing processes, between 15% and 80% of the water used returns back up the bore hole as frac flowback water and produced water. This water contains a significant mineral content, as well as frac chemicals, and requires that proper disposal protocols be followed. Most flowback water is transported to deep disposal wells and injected. However, in some plays there are few geographically convenient deep-well injection sites. For example, many operators in Pennsylvania truck flowback water to Ohio for disposal at a cost of up to $10/bbl plus transportation cost. Development of a cost-effective process for treating produced and/or flowback water, making it suitable for re-use, would be of great benefit to the industry from both an economic and environmental perspective.

## Project structure and objectives

The project has four key elements. First, a preliminary design study addressing recovery process alternatives, based on field flowback water analysis and gas well operation requirements, will be conducted to quantify the benefits of treating the low-TDS portion. Second, a suite of high-flux membranes will be evaluated for use in low-TDS water treatment processes. Third, effective pretreatment processes for removal of suspended and dissolved contaminants capable of adversely affecting membrane performance and longevity will be developed. The final element of the research study is a techno-economic feasibility assessment of a mobile rig configuration for delivering the treatment capability to a wellsite. This evaluation will be based on bench-scale experimental data derived from field water samples and performance modeling.

Successful completion of this project should provide the technical and economic foundation for the commercial reclamation/reuse of nearly all of the low-TDS shale-gas flowback water that is generated. This should be at a cost that is competitive with the costs associated with the current practice of trucking wastewater to deep-well injection sites. The project has the potential to reduce the overall costs and environmental impact of shale gas production by significantly reducing fresh-water consumption, waste-water disposal, and water-transportation related traffic on roads (Figure 2).

## Accomplishments to date

The research team has completed a number of tasks on this project. First, the team reviewed information published in open literature, discussed this information with hydraulic fracture treatment operators, and visited frac flowback and underground injection disposal sites to get a better understanding of the current operation logistics and more importantly, the specifications required for water to be eligible for re-use.

A parametric value assessment tool has been developed to evaluate the economic merits of any Flowback Water Recovery Process (FWRP) relative to conventional disposal. While there appears to be no clear consensus on specifications for frac re-use water, based on best available information, a TDS spec of <20,000 ppm, and a cost target for a FWRP mobile rig treating flowback water of <$2/Bbl to treat up to 35,000 ppm TDS flowback, were selected.

Most operators currently insist on using very low-TDS source water to avoid scaling issues in the downhole piping. Some well operators have reported success in using water with up to 26,000 ppm chlorides in the Marcellus shale. Some experts feel that water salinity equivalent to seawater (ca. 35,000 ppm TDS) may be usable for hydrofracturing, while some speculate as high as 120,000 ppm chlorides may be tolerated. Moreover, the methods used for hydrofracturing are being continuously updated as the industry tries to maximize gas recovery while minimizing energy and, especially, fresh water usage. For example, current research on new slicking agents (friction reducers) may allow the use of higher salinity in the feed water. This will allow for greater re-use of the flowback water with minimal treatment either with or without blending with fresh water. Until the frac industry has resolved their requirements, there will be uncertainty regarding the specifications for the treated water and discharge water. This affects the determination of how much of the flowback water would be treatable, the choice of technology options applicable, and the overall system cost.

Information on frac flowback attributes (flow rate vs. time and corresponding water analysis) is not readily available, as frac operators tend to keep their data proprietary and confidential. Nevertheless, relevant information on the flowback and produced waters in the Marcellus, Haynesville, Barnett, Fayetteville, and Woodford shales was acquired, albeit under non-disclosure agreements.

Flowback water is not a uniform "raw material" from a process development perspective. The physical and chemical properties of flowback water vary considerably depending on the geographic location of the shale play, the geological formation, and the chemicals introduced during the drilling and fracturing operations. Moreover, flowback volume and water properties vary throughout the lifetime of the well. The components in the flowback water of interest in this project are particulates (>5 µm), suspended solids (< 5µm, colloids), free oil, dissolved organics, volatile organics, hardness ions (Ca, Mg, Ba, Sr, sulfates,


*Figure 2. Large numbers of water trucks on Pennsylvania roads have raised concerns related to road degradation, safety and potential spills. Photo courtesy of www.marcellus-shale.us*

carbonates), Fe, silica, and bacteria that may affect the product quality and/ or the desalination membrane performance.

Based on surveys of the TDS content of flowback waters from the different shale plays, the team's present view on the extent of applicability of the low-TDS recovery approach is as follows:

In the Fayetteville and Woodford plays, almost 100% applicability, since the flowback water has generally < 40,000 ppm TDS.

In the Barnett, by selectively directing the flowback from the first 5 days, ~30 to 40% of the flowback may qualify as low-TDS. However, recovery may not be considered at all since disposal via underground injection is readily and cheaply available.

In the Marcellus, only a small fraction (<10%) of the flowback water may be amenable to low-TDS recovery. However, 20–40% of the flowback may be amenable at certain locations with appropriate water management protocols to isolate the first 3~5 days of flowback water.

In addition, frac flowback samples were obtained from wells in the Woodford shale in Oklahoma, and also from a Midwestern shale play, to be used in evaluating the membrane options. Conceptual process alternatives have been developed and evaluated based on best available information and knowledge with similar wastewater treatment experience for technical, cost, and equipment mobility performance.

### Remaining Tasks

The final deliverable of the project will be a report that defines a mobile, membrane-based, cost-effective process to treat low-TDS (<35,000 ppm TDS) frac flowback water for re-use in hydrofracture operations, that employs a low-cost, high-flux membrane with a modest salt rejection level, that will meet frac water requirements in the range of 3,000 to10,000 ppm TDS. Additionally, the report will define appropriate pretreatment methods for the frac flowback water to ensure the commercial viability of the membrane process. Performance, cost and mobility factors for the process will be determined as well.

The team will evaluate pretreatment and membrane processes in bench-scale experiments, assessing the capability for removal of known flowback water contaminants. Experiments will be conducted using the selected pretreatment methods and a range of membrane processes to treat simulated and actual field frac flowback water. This will provide the data for developing system and cost models for commercial feasibility determination.

A method will be developed to distinguish the cut-off point between low- and high-TDS flowback water generated by commercial shale-gas drilling operations. A cost analysis, considering the commercial feasibility of a mobile rig configuration and how such a configuration influences the overall low-TDS flowback water recovery process, will be conducted.

For additional information on the current status of this project contact Sinisha (Jay) Jikich (Sinisha.Jikich@NETL.DOE.GOV, 304-285-4320).

# Marcellus Water Management Project to Test Use for Mine Drainage Water

A team of researchers from the University of Pittsburgh and Carnegie Mellon University, funded by NETL, is developing a novel approach for re-use of fracturing flowback water in the Marcellus Shale play. Begun last October, and scheduled to run through September 2012, the project will examine acid mine drainage (AMD) water as a possible supplement to flowback water, and develop new viscosity modifiers that are stable at the high salinities observed in some Marcellus flowback water.

The project is in response to growing concerns over flowback water management in the Marcellus shale, particularly in Pennsylvania where drilling has expanded dramatically in the last year. A total of at least 710 Marcellus wells were drilled in the state in 2009 and a further 821 shale wells were drilled in the first four months of 2010 alone. Combined with the practice of larger and larger hydraulic fracturing jobs, this activity level has led to an exponential expansion in the amount of fracturing flowback water in Pennsylvania. At one point, more than one thousand tank trucks a day were estimated to the leave the state with loads of treated fracturing flowback and produced water headed for disposal in injection wells, primarily in the state of Ohio.

A technically and economically feasible approach for the reuse of flowback water could reduce the amount of freshwater needed for Marcellus Shale development, minimize disposal liability and costs, and find a practical use for an existing wastewater product from past mining activity in the Appalachian Basin.

## Background

Hydraulic fracturing has enabled the economical recovery of natural gas from the Marcellus shale. The fracturing fluids used in development of the Marcellus consist almost entirely of fresh water withdrawn from local sources, amended with chemical additives. A single well hydrofracture in the Marcellus may require up to 5 million gallons or more of fracturing fluid, of which between 15% and 40% may be returned to the surface as “flowback” or “produced” water that must then be disposed of or reused. In addition to chemical additives, flowback water from Marcellus hydrofracturing typically contains high levels of total dissolved solids (TDS), ranging from 70,000 to 250,000 mg/L, hydrocarbons, and heavy metals. The presence of these constituents precludes untreated reuse, reinjection, or direct discharge onto land or into receiving streams. Also, the flowback water is not amenable to reinjection due to high concentrations of scale forming constituents.

Disposal by dilution into Publically Owned Treatment Works (POTW), one option for handling Marcellus flowback water in Pennsylvania, is not sustainable either, as transportation costs are extremely high, and POTWs are limited as to how much water they can accept and treat (Figure 1). For example, in response to high total dissolved solids (TDS) levels measured in the Monongahela River in the fall of 2008, the PA Department of Environmental Protection ordered a restriction on the amount of oil and gas produced water (including flowback) disposal to POTWs in the basin. This restriction effectively halted gas drilling operations in some locations in western PA and has limited disposal options for expanding shale gas production.

AMD refers to the outflow of acidic water from (usually abandoned) coal mines. It is the main pollutant of surface water in the mid-Atlantic region.

AMD is caused when water flows over or through sulfur-bearing materials, forming solutions of net acidity. The acidity of coal-mine drainage is caused primarily by the oxidation of the mineral pyrite ($FeS_2$), which is found in coal, coal overburden, and mine waste piles.

Typically, mine water contaminated with pyrite reaches the surface through abandoned mine shafts or other underground openings. When it reaches the surface, AMD develops an orange or yellowish-orange color when oxygen reacts with the dissolved iron (Figure 2). The high acidity results in loss of aquatic life and restricts stream use for recreation, public drinking water and industrial water supplies.

## Objectives of this project

The work will be conducted in two phases. During Phase I, the location, quantity, and quality of flowback and AMD waters will be evaluated, and their chemical interactions will be examined in order to identify optimal treatment processes. Potential locations for experiments involving flowback water and AMD water (three locations for flowback water and three locations for AMD water) during Year 2 of the project will also be identified. Samples of water from these locations will be obtained for a detailed characterization of water chemistry and subsequent treatability studies for treatment of flowback water and preparation of hydrofracturing water.

During Phase II, a field demonstration of the treatment process identified in Phase I will occur, and key technical and cost parameters for field demonstration of a hydrofracturing operation using the mixture of flowback and AMD waters will be assessed. Novel friction reducing polymers that can be used with the highly saline flowback water will also be developed.

The research team will work with the Appalachian Shale Water Conservation and Management Committee, the Pennsylvania Department of Environmental Protection,

*Figure 1. McKeesport Treatment Plant near Pittsburgh, has accepted shale fracture flowback water*

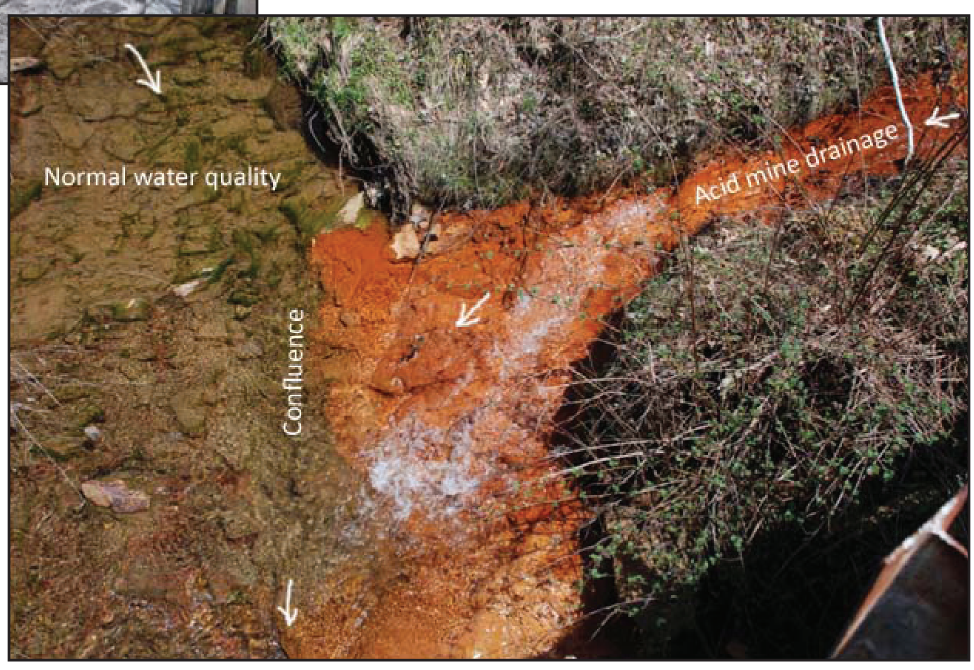



*Figure 2. Confluence of AMD with normal water (photo courtesy of Joel Bosch)*

and members of a Project Advisory Committee (PAC) to identify and compile the list of locations where the drilling and hydrofracturing has already been done or is planned in the near future. The PAC includes representatives from CONSOL Energy, Hedin Environmental, Veolia Water Solutions and Technologies, Universal Well Services, Inc., PA Brine Treatment Inc., Pennsylvania Department of Environmental Protection, and NETL.

The research team will also produce a report discussing the status of produced water technology "Status of Produced Water Technology Treatment and Disposal in Pennsylvania."

### Accomplishments to date

Thus far in Phase 1, flowback water locations and AMD sites have been catalogued. An ArcGis database has been created for this data that also includes information about water quality and quantity, when available. For AMD sites, the database gives access to water flow rate and important chemical constituent concentrations. Flowback water and AMD sites can be compared for both location and chemical compatibility.

In addition, a significant number of water samples have been collected from both AMD and drilling sites in the Pittsburgh area. A complete set of analyses has been carried out, allowing the researchers to determine chemical composition variations with location and time. Based on their chemistry, the collected AMD samples appear compatible for mixing with flowback water and reuse as fracturing fluid.

The high TDS in Marcellus flowback water is an important factor in understanding how flowback water might be treated for re-use. Researchers have reviewed different models for calculating activity coefficients depending on the solution's ionic strength. Two software packages have been tested using a recipe simulating a collected flowback water sample with the addition of sodium sulfate and sodium bicarbonate. Experiments to decide which model is more reliable are ongoing. However, the calculations show high removal of barium with sulfate addition, as well as partial removal of strontium. The addition of bicarbonate improves strontium removal and allows calcium to precipitate.

### Expected Impact

By providing a technically and economically feasible approach for the reuse of flowback water, this project will effectively reduce the amount of freshwater needed for Marcellus Shale development and minimize the disposal liability and costs associated with new well drilling. The use of locally available AMD as make-up water will also reduce the amount of freshwater use as well as the transportation costs associated with bringing make-up water to the project site.

For further information on the status of this project contact Dr. Radisav Vidic, University of Pittsburgh (vidic@pitt.edu or 412 6241307) or Chandra Nautiyal, NETL (chandra.nautiyal@netl.doe.gov or 281 494 24880).

# A Decision-making Support Tool for Marcellus Play Water Management

NETL is developing a modeling system that will help operators and regulators to plan operations related to lifecycle water management during Marcellus Shale gas development in New York, Pennsylvania, and West Virginia; including water supply, transport, storage, use, recycling, and disposal. This modeling system will be a useful tool for planning, managing, forecasting, permit tracking, and compliance monitoring. The tool will assist regulators and operators in devising water management schemes and improve the efficiency of decision-making throughout the entire industrial water lifecycle. The system will permit the analysis of environmental impacts, allow users to identify the most efficient operations, assist in regulatory tracking and compliance, and facilitate planning for future water usage.

Scheduled for completion and launch in early 2012, the model is being developed by NETL and the New York State Energy Research and Development Authority (NYSERDA) under an agreement with ALL Consulting, of Tulsa, OK. Other partners include the Susquehanna River Basin Commission and the Delaware River Basin Commission. ALL Consulting will continue to provide user support after the model is made public.

## Regional approach important

The Appalachian Basin's Marcellus Shale holds a tremendous volume of natural gas. Due to its vast geographic extent (~54,000 square miles), the number of wells required to tap the resource (thousands), its potential to provide energy for decades, its ability to generate state revenues and local economic opportunities, and the perception that its development could result in environmental impacts to water supplies, the activities of producers involved in development of the Marcellus Play have been closely scrutinized by both regulators and citizens.

Concerns have been raised about the volume of water required for hydraulic fracturing of wells and the potential for contamination of ground water and surface water as a result of drilling, hydraulic fracturing, water transport, and water disposal. Operators incur significant costs in acquiring, transporting, treating, hauling, and disposing of water and face a lack of treatment and disposal options, including a limited number of underground injection wells and qualified treatment facilities. As alternatives, operators are recycling fracturing flowback waters and transporting water via temporary pipelines, rather than hauling by truck. These alternatives can raise new questions. All parties involved—regulators, producers, landowners, and local citizens—need to have access to tools for simplifying the complexities of the issues surrounding water use in the development of this valuable and important energy resource.

As ground water and surface water cross geographic and political boundaries, a regional approach that incorporates the complexities brought on by diverse regulatory environments, hydrology, geography, and geology is much more likely to be successful. The productive area of the Marcellus Shale underlies at least three, and possibly four or more, river basins (Figure 1), and at least three states. Any water management decision-making support system must work within a regional context. This project follows that path in dealing with water issues related to Marcellus Shale development.

## Phase I research currently underway

The R&D team is currently in Phase I of its research; the data collection and initial design phase. During this phase, the team is collecting datasets, documents, maps, and photographic images pertinent to the target area. ALL Consulting has already performed initial literature searches and will be conducting site visits this fall to characterize the water resource issues and water management needs in the project area.

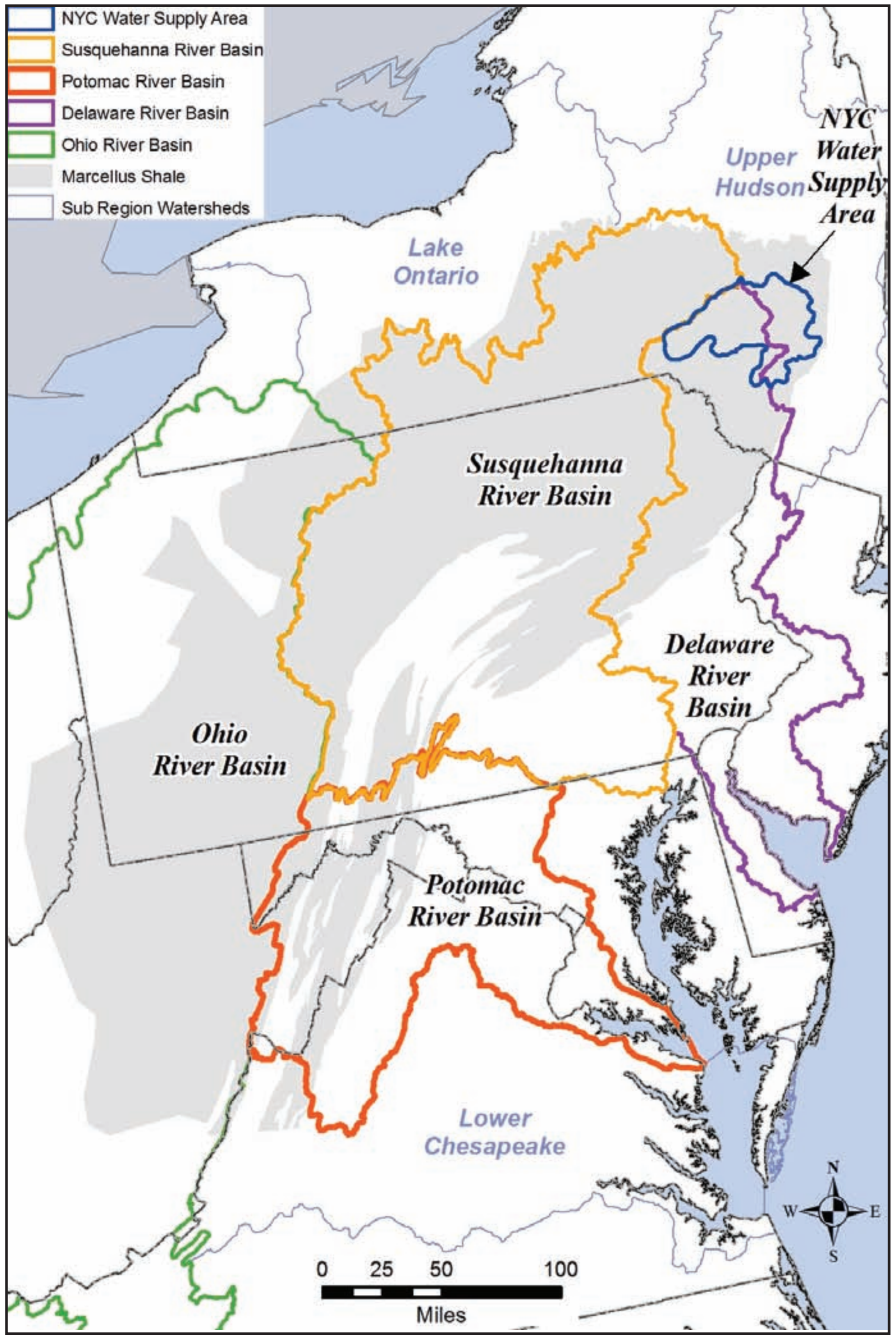
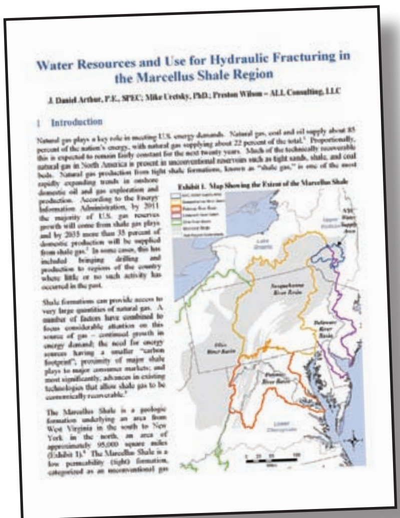



*Figure 1: Marcellus Shale Basin within watersheds in target area. Source: ALL Consulting*


Water Resources and Use for Hydraulic Fracturing in the Marcellus Shale Region

J. Daniel Arthur, P.E., SPEC; Mike Uretsky, PhD.; Preston Wilson – ALL Consulting, LLC

1 Introduction



A paper summarizing the water resources and regulatory structure surrounding the Marcellus play has been published and can be downloaded from the NETL website.

The R&D team has observed that the water lifecycle for shale gas wells proceeds through several phases: 1) source withdrawal, 2) transport and storage, 3) drilling and fracturing, 4) treatment, 5) reuse-recycle, and 6) disposal. These phases will be modules in the modeling system created in Phase II of the project and tested and deployed in Phase III. Since there are multiple water issues that need to be addressed simultaneously and numerous regulations to follow, oftentimes in several states, operators and regulators stand to benefit from this comprehensive modeling system that will allow them to plan an entire lifecycle for the water holistically rather than treating the decision-making as a step-by-step process. Further, users will be able to analyze the pros and cons of different scenarios by using the system to answer “what if” questions. Providing the ability to visualize the entire lifecycle will minimize costs through more efficient regulation and planning, and will offer better protection for the environment as regulators will be able to analyze impacts and determine the appropriate protection methods over the entire area.

## The final impact

Environmental issues, especially those dealing with water, occupy a significant amount of time and resources for both operators and regulators involved in Marcellus Shale development. Management of water resources, therefore, will greatly influence the pace of development. The public, operators, and regulators will all benefit from the increased ease of decision-making and planning for water management options offered by a comprehensive modeling system. This “one-stop-shop” will allow for the optimization of safe and cost-effective water handling—from withdrawal to disposal—by allowing operators to compare various means to handle water, by facilitating permit applications, reporting, and compliance management, and also by incorporating all of the regulatory requirements of the different states and regulatory bodies involved in the process.

## More information

A detailed project website (http://www.all-llc.com/projects/shale_water_lifecycle/) was created in December 2009 and a paper entitled “Water Resources and Use for Hydraulic Fracturing in the Marcellus Shale Region” (available on the NETL web site here) was published in March. The paper addresses three overlapping topics, each with a bearing on water sourcing within the three primary states: (1) a description of the major water resources associated with the Marcellus Shale areas of New York, Pennsylvania and West Virginia; (2) a description of the regulatory structure in New York, Pennsylvania and West Virginia, as well as the two major river basin commissions in the area: the Susquehanna River Basin Commission and the Delaware River Basin Commission; and (3) a description of the metrics used by each of these organizations to regulate water use.

For more information on the status of this project, contact Skip Pratt (Skip.Pratt@netl.doe.gov or 304-285-4396).




*GOAL PetroPump tools designed to improve production from stripper oil (left) and gas (right) wells were developed by SWC*

## DOE Extends Support for Stripper Well Consortium

The Stripper Well Consortium (SWC)—a program that has successfully provided and transferred technological advances to small, independent oil and gas operators over the past nine years—has been extended to 2015 by the U.S. Department of Energy (DOE).

An industry-driven consortium initiated in 2000, SWC's goal is to keep "stripper wells" productive in an environmentally safe manner, maximizing the recovery of domestic hydrocarbon resources. More than 396,000 stripper oil wells account for about 10 percent of U.S. lower-48 production, and more than 322,000 stripper natural gas wells account for about 9 percent of the natural gas produced in the lower 48 states.

The consortium is administered by The Pennsylvania State University on behalf of DOE. The National Energy Technology Laboratory (NETL) and the New York State Energy Research and Development Authority provide base funding and technical guidance to the program.

Nearly 100 projects have been funded since the initiation of the consortium, which consists of small domestic oil and natural gas producers, as well as service and supply companies, trade associations, industry consultants, technology entrepreneurs, and academia. The successful development and commercialization of products developed by a number of these projects provided the incentive for DOE to continue program funding.

*Development drilling in North Dakota's Bakken Shale oil play*

## Bakken and Three Forks-Sanish Study Extended

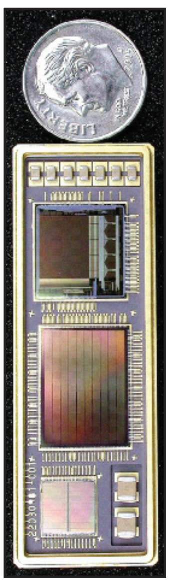
DOE-NETL has teamed with the University of North Dakota Energy and Environmental Research Center (UNDEERC) to extend a study of the factors affecting oil production from the Bakken and Three Forks-Sanish formations within the Williston Basin.

In October 2009, North Dakota became the fourth largest oil producing state, exceeded only by Texas, Alaska, and California. At the end of 2009, North Dakota was producing 242,000 barrels of oil per day (bopd), and estimates for 2011 range from 300 to 400 thousand bopd, driven by the success of the Bakken and Three Forks-Sanish formation plays.

During the first phase of the research project, UNDEERC evaluated and compared key Bakken play geologic, geochemical, geomechanical, and engineering attributes in two North Dakota counties, Mountrail and Dunn. Comparison of these key attributes provided several preliminary insights to improve productivity and guide exploration and production of new sub plays.

During Phase Two, UNDEERC plans to study oil production mechanisms within the Bakken and Three Forks-Sanish formations. UNDEERC plans to develop a geographic information system web-based Bakken decision support system to enable investigation of various engineering and geologic parameters to improve oil production. Additionally, geomechanical studies will be conducted on middle Bakken cores to better understand fracturing mechanisms. The results will provide insight regarding the development and application of effective well completion and stimulation strategies. Fluid and rock interrelationships, especially between pore pressure and natural fracturing, will be evaluated for their correlation to oil production.

UNDEERC efforts will be coordinated with other NETL Bakken research projects at the Colorado School of Mines and the University of North Dakota Department of Geology and Geological Engineering.



*Internal view of high temperature electronic component developed by NETL and Honeywell for deep drilling applications*

## Reprogrammable High Temperature Processor Introduced

NETL, working with Honeywell International, Inc., has developed a Reconfigurable Processor for Data Acquisition (RPDA)—a reprogrammable, multi-functional device that can operate at temperatures up to 250 degrees C (482 degrees F). The system is housed in a rugged package suitable for deep down-hole oil and natural gas logging and measurement-while-drilling (MWD) operations, and permanent wellbore installation applications.

Potential recoverable natural gas and oil resources from deep (>15,000 feet) and ultra-deep (>25,000 feet) formations are significant. Resource studies conducted by the Potential Gas Committee, the U.S. Geological Survey, and the Mineral Management Service (MMS) estimate technically recoverable resources for onshore deep natural gas between 114 and 132 trillion cubic feet (Tcf), and offshore, shallow-water deep natural gas is estimated to be as much as 55 Tcf. A 2000 MMS assessment of deepwater and ultra-deepwater hydrocarbons indicated that more than 50 billion recoverable barrels of oil equivalent (BOE) remains to be discovered; and their 2006 report identified a gap of 9 billion BOE between proven reserves and the discovered resource base.

Yet despite the vast resource, only a small percentage of wells are drilled to 15,000 feet or deeper, due primarily to the high costs involved. The problems encountered in deep drilling are largely the result of escalating temperatures and pressures that seriously challenge the capabilities of down-hole equipment, particularly electronic components. The RPDA is designed to help meet this challenge.

At the heart of the RPDA lie highly reliable, co-fired ceramic Multi-Chip Modules (MCM's) that can perform reliably at high temperatures. The MCM is similar to an electronic circuit board implanted in a single solid piece of ceramic material. The package is tailored to down-hole applications in terms of physical dimensions, wide operating temperature ranges, and the ability to withstand high shock and vibration environments.

The RPDA addresses a unique, previously unfilled need for flexible, reprogrammable digital electronics that can operate in extreme down-hole oil and natural gas drilling, exploration, and production environments.

Honeywell plans to offer these components commercially to the oil and natural gas industry as well as to other industries that require data acquisition tools for extreme temperature applications.

## $26.5 Million Directed to Section 999 Research Projects

The Research Partnership to Secure Energy for America (RPSEA) recently announced the award of 26 projects in the 2009 R&D portfolio. This is the third portfolio of projects, following selections in 2007 and 2008. Many of the 2007 projects will be completing their research this year.

The projects will undertake research in the fields of ultra-deep water, unconventional gas resources and technology to address the challenges facing the nation's small producers. Funding for the projects is provided through the Department of Energy's "Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research and Development Program" established pursuant to the Energy Policy Act of 2005.

This program—funded from lease bonuses and royalties paid by industry to produce oil and gas on federal lands—is designed to maximize the value of natural gas and petroleum resources in the United States by reducing the cost and enhancing the efficiency of exploration and production. RPSEA is an industry consortium that administers the program. The following are just a few of the projects awarded under the 2009 program (with project performers in parentheses):

Autonomous Inspection of Subsea Facilities (Lockheed Martin Corporation)

Development of Carbon Nanotube Composite Cables for Ultra-Deepwater Oil and Gas Fields (Los Alamos National Laboratory)

Deepwater Subsea Test Tree and Intervention Riser System (DTC International, Inc.)

Prediction of Fault Reactivation in Hydraulic Fracturing of Horizontal Wells in Shale Gas Reservoirs (West Virginia University)

Cretaceous Mancos Shale Uinta Basin, Utah: Resource Potential and Best Practices for an Emerging Shale Gas Play (Utah Geological Survey)

A Geomechanical Model for Gas Shales Based on the Integration of Stress Measurements and Petrophysical Data from the Greater Marcellus Gas System (Pennsylvania State University)

Treatment and Beneficial Reuse of Produced Waters Using a Novel Pervaporation-Based Irrigation Technology (University of Wyoming)

Green Oil™ CO2-Enhanced Oil Recovery for America's Small Oil Producers (Pioneer Astronautics)

Characterization of Potential Sites for Near Miscible CO2 Applications to Improve Oil Recovery in Arbuckle Reservoirs (University of Kansas)

## Upcoming Meetings and Presentations

PTTC North Mid-Continent Region Technology Fair, **September 7 – 8**, Great Bend, Kansas. www.torp.ku.edu

Shale Energy: Eagle Ford Conference, **September 15**, Norris Conference Center, Houston, Texas. www.GulfPub.com/ShaleEnergyConference

PTTC Workshop on Water Issues (and Solutions) Associated with Hydraulic Fracturing (preceding Ground Water Protection Council Symposia, **September 27**, Pittsburgh, PA. http://www.pttc.org

PTTC Rocky Mountain Symposium: Overcoming Geologic Challenges with Advanced Drilling and Completions Techniques, **September 30**, Denver, CO. http://www.pttc.org

Developing Unconventional Gas, Eagle Ford Conference and Exhibition, **October 5 – 6**, Henry B. Gonzalez Convention Center, San Antonio, Texas, www.dugeagleford.com

Permian Basin International Oil Show, **October 19 – 21**, Odessa, Texas. www.pbioilshow.org

E&P Techology Summit (World Trade Group), **October 21 – 22**, JW Marriot Hotel, Houston, TX. http://www.exproevent.com

2nd Annual Developing Unconventional Gas East – Marcellus Conference and Exhibition, **November 3 – 4**, The David L. Lawrence Convention Center, Pittsburgh, Pennsylvania, www.dugeast.com

AAPG/SPE/SEG/SPWLA Hedberg Research Conference, “Critical Assessment of Shale Resource Plays,” **December 5 – 10**, Austin, Texas, www.aapg.org