the ENERGY lab

E&P Focus

Summer 2012 Oil & Natural Gas Program Newsletter

NETL

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U.S. DEPARTMENT OF ENERGY

Seismic Evaluates Marcellus Shale for Flow-Back Water Sequestration

A research project, partially funded by NETL, was undertaken in Bradford County, Pennsylvania to illustrate the value of multicomponent seismic technology for evaluating the Marcellus Shale, the Utica Shale, and porous brine-filled rock units local to these shales. The study encompassed porous brine-filled rocks because such rocks can be used as reservoirs for sequestering flow-back waters produced during hydrofracing operations. At this test-site location, the Marcellus Shale was approximately 6,000 ft. The project was led by the Bureau of Economic Geology at The University of Texas at Austin. Additional participants included Austin Powder Company, Chesapeake Energy Corporation, Dawson Geophysical, Geokinetics, Geophysical Pursuit Inc., Halliburton, iSeis, Mitcham Industries, RARE Technology, Seismic Source, Sercel, United Service Alliance Inc., and the University of Pittsburgh.

Improved Resolution Provided by P-SV Data

The study shows the converted P-SV mode provides better spatial resolution of Marcellus Shale stratigraphy than does its companion P-P mode. The difference in resolution is significant, with P-P wavelengths being longer than P-SV wavelengths by 40-percent to as much as 50-percent. The improved resolution of P-SV data over P-P data can be documented by side-by-side displays of P-SV and P-P wiggle trace data over targeted depth intervals. Such a comparison across the Marcellus Shale interval is shown as Figure 1. In the notation used for this figure and in subsequent discussions, P-SV1 refers to the fast P-SV mode, and P-SV2 indicates the slow P-SV mode.

The Marcellus Shale is divided into two distinct units—the Upper Marcellus and the Lower Marcellus. The boundary between these two units is the

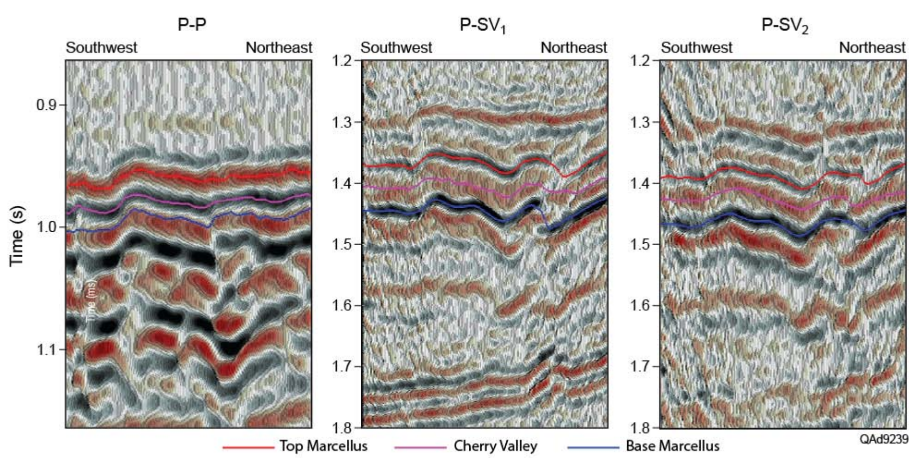

Figure 1. Profiles showing P-P, P-SV1, and P-SV2 images of the Marcellus interval.

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Commentary

The Office of Fossil Energy's research and development program is carried out, in part, across a number of Department of Energy (DOE) laboratories. Together, the 17 DOE laboratories comprise a preeminent federal research system, providing the nation with strategic scientific and technological capabilities. The laboratories:

- Execute long-term government scientific and technological missions, often with complex security, safety, project management, or other operational challenges;
- Develop unique, often multidisciplinary, scientific capabilities, to benefit the Nation's researchers and national strategic priorities, and;
- Develop and sustain critical scientific and technical capabilities to which the government requires assured access.

NETL is a cornerstone in this laboratory research and development effort. Just as important, however, is the large amount of research we carry out in the field. Our portfolio of projects includes field-based activities ranging from basic research to advanced field demonstration projects. Almost all of these projects are carried out in partnership with industry and, often, with academia.

The field based projects fall into two general categories, characterization of resources and field demonstrations for proof of concept. In this issue of E&P Focus you will find a discussion of a resource characterization project describing multicomponent seismic evaluation of the potential to sequester flowback water in the Marcellus. This article is complemented by three discussions of field demonstration projects: electric power generation from produced water, pilot testing of a high salinity brine treatment, and advanced logging technology to increase the success of drilling a productive lateral in a mature field.

NETL's commitment to field operations is a vital part of the Office's program. It is here that we take the final steps toward commercialization of resources and technologies. This is nowhere better illustrated than in our field-based shale basin characterizations and technology development efforts in the late 70s and early 80s, research which President Obama has credited as being instrumental to the development of the nation's vast shale resources.

We hope you enjoy this issue of E&P Focus and as always, we welcome your comments.

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

Cherry Valley Limestone. To characterize the Marcellus interval, it is essential to interpret depth-equivalent P-P and P-SV horizons that correlate with the Top of Marcellus, Cherry Valley Limestone, and Basal Marcellus. Local VSP and well log data were used to define the depth-equivalent horizons shown on Figure 1.

The improved resolution of Marcellus geology provided by P-SV data compared to P-P data is striking when wavelength spectra are considered. P-P wavelengths (λP) are defined as $\lambda P = VP/f$, where f = frequency and VP is P-wave velocity. S wavelengths (λS) are defined as $\lambda S = VS/f$, where VS is S-wave velocity. Over any common frequency band shared by P and S data,

(1) $\lambda S = \lambda P\ (VS/VP)$.

Because the VP/VS velocity ratio within the Marcellus is approximately 1.6, this wavelength relationship simplifies to,

(2) $\lambda S = 0.62\lambda P$.

The hard rocks of the Appalachian Basin seem to allow higher-than-usual frequency components to survive in S-wave seismic data. As a result, the upgoing SV wavelengths of P-SV data are shorter than P-P wavelengths over a reasonably wide frequency.

Spectral analyses of depth-converted data volumes enforce this logic and also the wiggle-trace comparisons of P-P and P-SV1 spatial wavelengths shown on Figure 1. Wavelength spectra of depth-based P-P and P-SV data are displayed as Figure 2. These spectra show that at the study site, depth-converted P-P data (Figure 2a) are dominated by wavelengths of 100 ft to 800 ft; whereas, depth-converted P-SV1 data (Figure 2b) are dominated by wavelengths of 40 ft to 400 ft.

A second example of the increased stratigraphic resolution provided by P-SV data compared to P-P data occurs across sand-prone Devonian intervals that were evaluated as potential reservoirs for storing flow-back water from hydrofrac operations. Transgressive Devonian sandstones are often found in the stratigraphic interval immediately below the Tully Limestone. Because porous, brine-filled sandstones are good candidates for water-storage reservoirs, the interval between the interpreted tops of the Tully Limestone and Tichenor Limestone was analyzed to determine how P and S seismic data react to these particular sandstone targets.

Time windows chosen for analysis of the Tully-to-Tichenor interval in P-P, P-SV1, and P-SV2 image space are shown on Figures 3a, 3b, and 3c, respectively. The Tully Limestone is characterized by a strong reflection

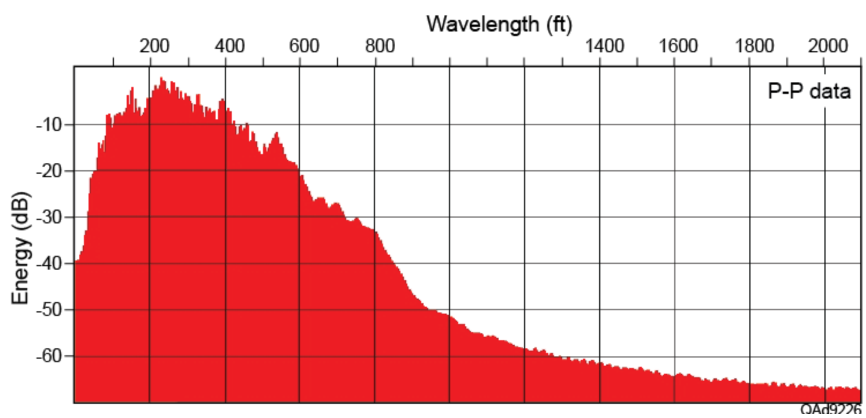


Figure 2a. Spatial-wavelength spectrum of depth-converted P-P data.

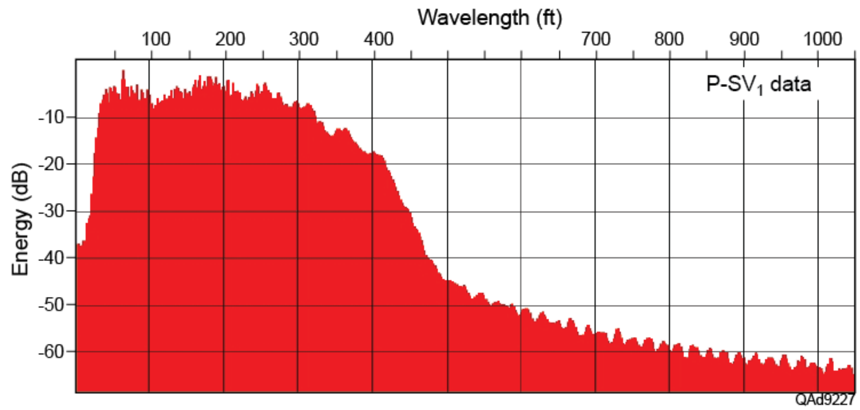


Figure 2b Spatial-wavelength spectrum of depth-converted P-SV1 data.

peak (black) immediately followed by a high-amplitude wavelet trough (red) in all three data volumes and is easily mapped across the image area. In contrast, the Tichenor Limestone appears as a modest-amplitude reflection in the P-P data volume, and has an even lower amplitude response in both the P-SV1 (Figure 3b) and P-SV2 (Figure 3c) data volumes. Visual inspection of these side-by-side data windows again leads to the conclusion that P-SV data provide better resolution of stratigraphy across the study area than do P-P data. An important implication is that this same advantage of S-wave seismic data over P-wave data may occur across other shale-gas prospects.

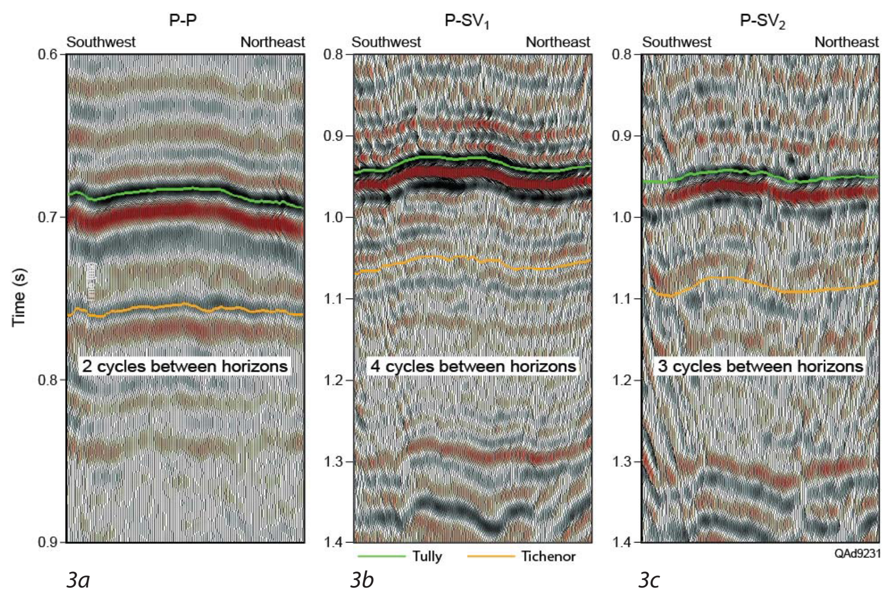
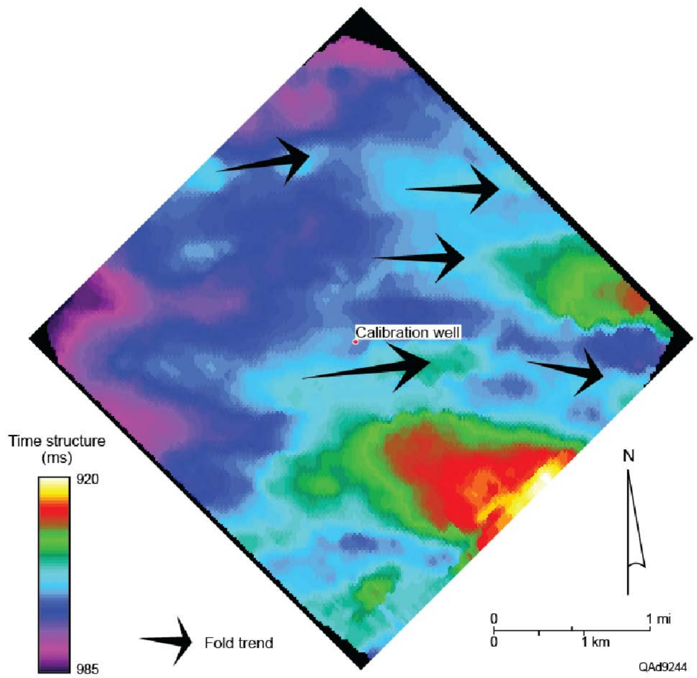


Figure 3. Profiles comparing Tully (green horizon) to Tichenor (orange horizon) intervals in (a) P-P, (b) P-SV1, and (c) P-SV2 image space.

Marcellus Structural Interpretation

Both P-P and P-SV data show the Marcellus has a strong structural-fold fabric trending East-to-West. These linear folds were mapped and correlated in both P-P and P-SV data volumes to understand local effects of tectonic stress on the Marcellus. Understanding stress fields is useful for determining where natural fractures should be localized and for predicting how embedded fractures may behave when reactivated during hydraulic fracture treatments, or when pore pressure is altered because of fluid injections.



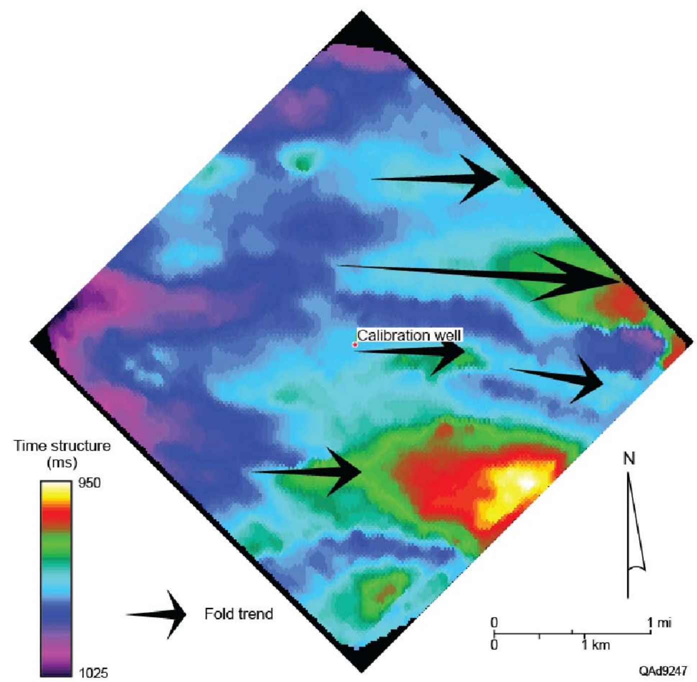
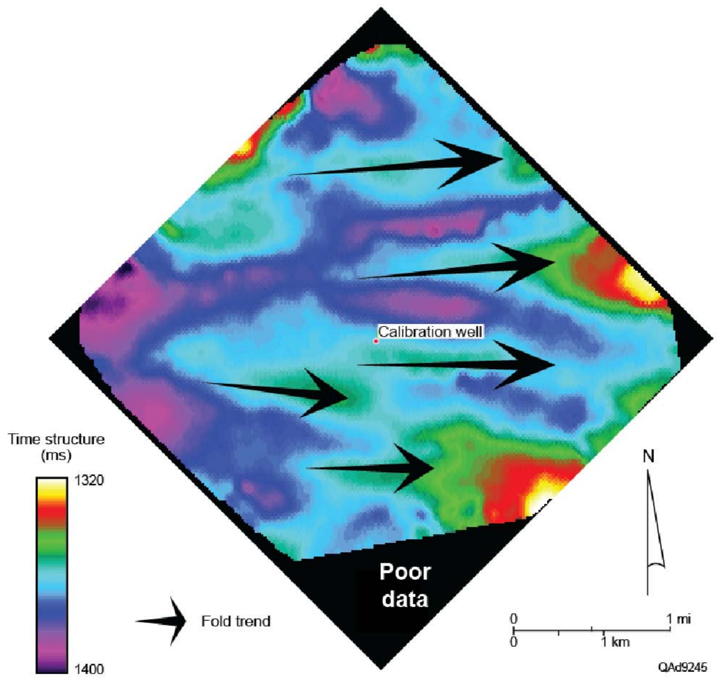


Figure 4. (a) Upper Marcellus Shale P-P time structure. (b) Lower Marcellus Shale P-P time structure. The arrows depict orientations of fold hinges.



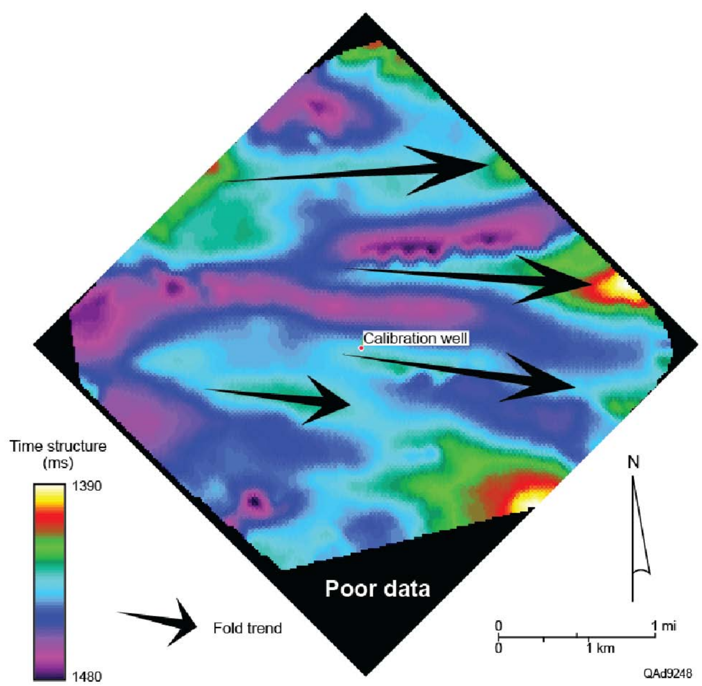
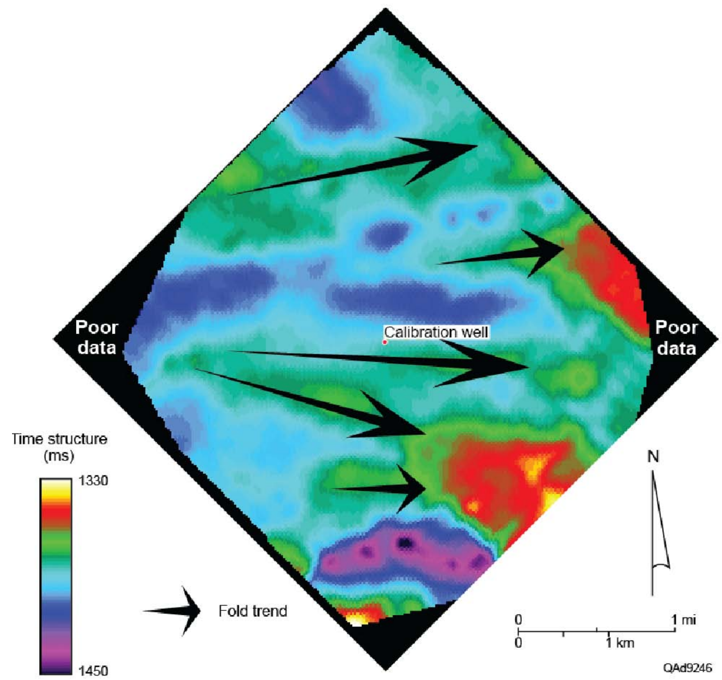


Figure 5. (a) Upper Marcellus Shale P-SV1 time structure. (b) Lower Marcellus Shale P-SV1 time structure. The arrows depict orientations of fold hinges.



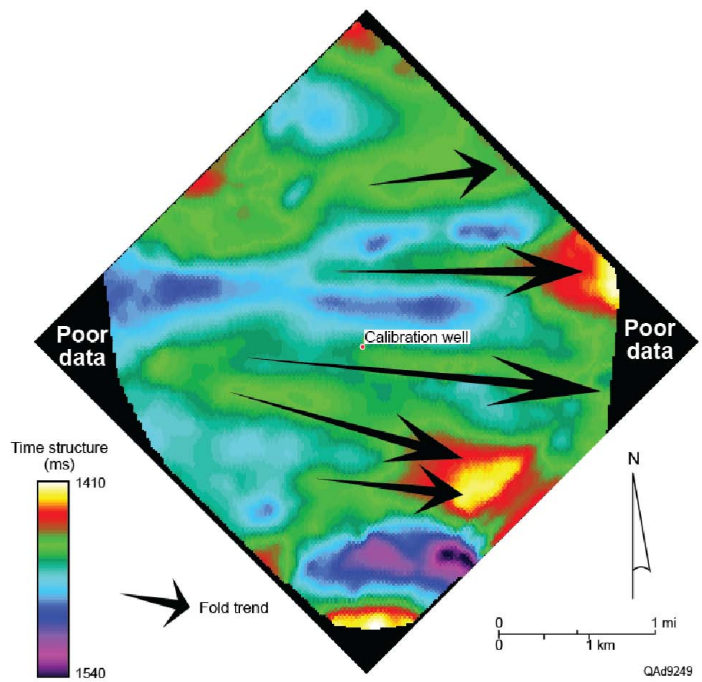


Figure 6. (a) Upper Marcellus Shale P-SV2 time structure. (b) Lower Marcellus Shale P-SV2 time structure. The arrows depict orientations of fold hinges.

Similar fold patterns occur in both the Upper and Lower Marcellus units, but, at the study site, folds within the Lower Marcellus have larger vertical relief than do their equivalents in the Upper Marcellus. These differences in fold height imply stresses acting on the Lower Marcellus may have been greater than stresses that generated folds in the Upper Marcellus. Folds are evident on P-P data (Figure 4) but are more pronounced in P-SV1 data (Figure 5) and P-SV2 data (Figure 6).

If it is assumed that stresses at this site are compressional in nature, maximum horizontal stress would be perpendicular to the fold trends exhibited on Figures 4 – 6 (which would be approximately a north-south orientation of maximum stress). Minimum horizontal stress would be parallel to fold axes, which would orient minimum stress approximately east-west. If the Marcellus folding is caused by strike-slip mechanisms or by salt tectonics related to salt-prone units below the Marcellus, other stress orientations have to be considered.

Conclusions

The 3C3D seismic data used in this study provided the most dramatic contrast between P-wave and S-wave imaging of geologic targets that the research team at the Bureau of Economic Geology has observed in the 12 years its laboratory has been engaged in developing multicomponent seismic technology. The impressive aspect of these data is that both the P-SV1 (fast-S) mode and P-SV2 (slow-S) mode provided better spatial resolution of key geologic targets than did P-P (compressional) data. The latter data (P-P) are the principal seismic data used to evaluate shale-gas prospects. The increase in P-SV1 resolution over P-P resolution was particularly significant, with P-SV1 wavelengths being approximately 40-percent shorter than P-P wavelengths.

All three data volumes (P-P, P-SV1, and P-SV2) showed linear folds existed in the Marcellus Shale. These fold trends were not observed in the stiff rocks above and below the Marcellus. The consistent fold orientations across seismic image space imply Marcellus fracture properties may be reasonably consistent across the small area spanned by the seismic data that were analyzed.

Acknowledgments

The seismic data used in this study are owned by Geokinetics and Geophysical Pursuit Inc. These multi-client data are available for leasing by anyone who wishes to do an independent analysis of these multicomponent data.

For additional information about this project contact Chandra Nautiyal at NETL (chandra.nautiyal@netl.doe.gov or 281-494-2488) or Dr. Bob A. Hardage at The University of Texas at Austin (bob.hardage@beg.utexas.edu or 512-471-0300).

Generating Clean, Green Electricity from Produced Water

There are 823,000 oil and gas wells in the U.S. that co-produce hot water with oil and gas. This equates to approximately 25 billion barrels annually of water, the heat from which could be used as fuel to produce up to 3 GW of clean electrical power. Not only will generating power from the produced water from these wells add much needed electrical generation, the life of many of these wells will be extended, allowing for additional oil and gas production. A recent, NETL funded project conducted field demonstrations to determine the potential of generating electricity from hot produced water. Participants included Gulf Coast Green Energy (GCGE), ElectraTherm, Denbury Resources, The Southern Methodist University (SMU) Geothermal Lab, the Texas A&M Petroleum Engineering Department, and Dixie Electric Coop.

The primary goal of the project was to prove the feasibility of interfacing the ElectraTherm Green Machine waste H2P generator with a producing oil or gas well. The project had several subsidiary goals. Chief among these were:

1. Demonstrate the ability to produce electricity from the waste heat in the produced water,
2. Demonstrate that producing electricity from produced water does not interfere with the normal operations of an oil/gas well,
3. Address the needs of small oil and gas producers to increase the profitability of producing oil and gas wells by adding additional income during production,
4. Determine the economic viability of generating electricity from the heat from produced water,
5. Determine if the kWh output would have practical applications, and,
6. Determine any environmental impact from generating fuel-free, emission-free electricity from heat from the produced water.

It was important to use an actual field trial to determine the unknowns that were acknowledged to exist, but which could not be identified in lab and bench scale runs. A field trial was also needed to identify the areas for corrective action that could be incorporated in newly designed equipment and produced water projects. The site chosen was a producing oil well, Denbury's Summerland #2, near Laurel, Mississippi. The well, in production for five years, has a high water cut and high produced water temperature. It produces 100 bopd and 4000 bwpd from a depth of 9,500 feet with an electric submersible pump (ESP). The temperature of the produced water exiting the "knockout tank" at 120 GPM is 204°F. The site has an ambient temperature range of 60-105°F.

Choosing the Right Technology

Organic Rankine Cycle (ORC) generators create pressure by boiling various refrigerants/chemical working fluids into a high pressure gas. The gas then expands in a one way system and turns an expander or high speed turbine, which, in turn, drives a generator that generates electricity. Historically, ORCs incorporating turbo-expanders or turbines have not been commercially viable in sizes less than 1MW. However, one technology uses a patented, robust, low-cost twin screw expander which requires much less water volume than the larger ORC's . The ElectraTherm Green Machine is capable of generating between 30 kWh and 65 kWh with hot water flows of 200 GPM and less. Because most oil and gas wells produce less than 200 GPM of hot water, the ElectraTherm Green Machine waste H2P generator was selected for this demonstration. While the technology is relatively new, a prototype suitable for oil and gas applications has been tested and demonstrated in a boiler room application beginning in May of 2008 at Southern Methodist University. Another reason the Green Machine was selected for this project is size and portability. It is skid mounted and can be moved with a small forklift, making it easy and quick to install. It has a minimal footprint of 300 square feet.

In use, produced water from the well enters a heat exchanger where the hot water excites (pressurizes) the working fluid, which is an EPA-approved, non- hazardous, non-toxic and non-flammable fluid, driving the twin-screw expander (the power block) to create electricity. The twin-screw expander is unique in its configuration, lubrication and specifications, but is based on reliable, proven compressor technology that has been around for more than 20 years. The twin-screw expander has a rotational speed of 4,300-4,800 RPM, 1/10th that of most turbo expanders. The robust screw allows the admittance of wet vapor through the expander, thereby allowing access to lower temperature resources. A patented process and lubrication scheme simplifies and/or eliminates lubrication reservoirs, oil coolers, pumps, lines and filters, creating a simple, efficient system with fewer parasitic loads.

After the working fluid expands across the twin-screw expander (spinning a generator) the low pressure vapor must be condensed to a liquid to begin the cycle again. The condenser for the ORC for this demonstration was air cooled, eliminating the extensive amount of fresh water usage and maintenance expenses associated with operating a cooling tower. The Green Machine's control system is fully automated, allowing remote control, remote monitoring, and off-site diagnostics and trending.

The Green Machine and air-cooled condenser were tested and mounted on a drop-deck flatbed trailer at the factory and trucked to the site. The truck with the equipment mounted on the trailer arrived on-site and nine hours later a test run was completed (Figure 2). A hot water bypass valve was installed by GCGE and Denbury field personnel, which allowed the produced water to by-pass the Green Machine during times that the Green Machine was down. Denbury laid and connected the pipe from the hot water by-pass to the trailer and the final connections to the Green Machine were made-up with high pressure hoses.

Dixie Electric Co-Op agreed to "net meter" the electricity generated by the Green Machine and credit the electrical production at retail rates which allowed for the generated electricity to be kept "inside the fence".

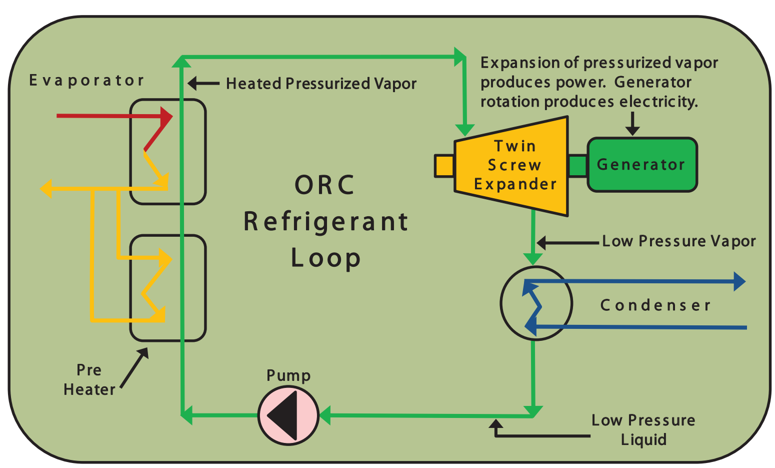


Figure 1. ORC Generator Schematic.

Figure 2. GCGE conducts operations training for Denbury personnel.

Lessons Learned

The six month demonstration successfully concluded in November 2011, with 1,136 total runtime hours, and provided excellent insight for future installations (Table 1). The high summer temperatures reduced the temperature differential (ΔT) between the hot water temperature and the condensing temperature so much that the equipment was programmed to shut down when the ambient temperature was above 92° F. Future shut downs could be avoided by using larger condensing fan units. The larger size condensers could have added up to 40 percent more output KWh by increasing the heat transfer surface area for the refrigerant, thus allowing the temperature differential to increase. Because the hot water by-pass valve became clogged, requiring a replacement valve to be installed, it was determined that the by-pass valve used for produced water applications must have a different design.

Gross Power Output	19 – 22 kWe
Runtime Hours – Demonstration	1,136
Parasitic Load Breakdown	Feed Pump: 1 – 4 kWe: Fans: 0.1 – 6kWe
Ambient Temperature (hourly)	60 – 105°F
Relative Humidity	50 – 100%
Generator Output (hourly)	8 – 30 kWe
Brine Flow Rate (daily)	120 GPM
Brine Inlet Temperature (daily)	204°F

Table 1. Green Machine power production statistics

Geothermal Brine Issues

Water corrosion and mineral build up in the ORC's heat exchangers was a major challenge leading up to this demonstration. The investigators understood going into the demo that brazed plate heat exchangers are not optimally suited for brine as they have clogging and stress corrosion cracking issues. Their assessment of the chosen heat exchanger design concluded it would not be sufficient for long term operation. However, a six- month, 1,000 hour test run operating with the installed heat exchangers had no issues. The addition of a similar plate and frame heat exchanger would allow material options, cleaning ability and would extend heat exchanger life. The use of a small metering pump to add a scale inhibitor to the produced water ahead of the Green Machine is another potential solution.

Economics

A review of the demonstration, and subsequent cost analysis, confirm the economic benefits of the application. A post project analysis concluded that the Green Machine's power generation offset about 20 percent of the energy required to run the down-hole pump on the oil well, providing an attractive payback at oil and gas sites where cost of power is over $.08/kWh, and where producers see the environmental value in electricity from waste heat, either as a public relations benefit or acting on corporate social responsibility metrics.

For wells with increased produced water flow and/or temperature, the Internal Rate of Return (IRR) and Net revenue will be substantially greater. For example a single well that can produce 65 kWh using the ElectraTherm Green Machine, the IRR would be 25% with a $.028/kW 20 year cost of power and net revenue of $1,160,000 over the life of the equipment. This will provide the incentive for oil and gas producers to continue producing long after current wells are usually shut in due to increasing produced water. It may also be an incentive for oil and gas producers to consider bringing wells into production that, until now, would not have been produced due to unacceptable projected produced water volumes.

Conclusions

The demonstration at Denbury's Laurel site provides insight from lessons learned into the ability of future applications to reduce installation time, increase efficiency, generate additional power and minimize maintenance. This kind of co-generation can be particularly effective in reducing the energy costs for pumping geographically remote oil wells, an increasing need in the United States.

However, some hurdles remain in developing co-produced fluid opportunities. Economics will play a critical role in the growth of this industry. Depending on criteria, there is an attractive return on investment in locations where the cost of power is $.10/kWh or higher. In locations where the cost of power is less than $.10/kWh, additional incentives or corporate objectives would be necessary to make the opportunities attractive.

Environmental Impact

This technology contributes directly to the reduction of harmful emissions to the atmosphere. The total electrical production was 19,180 Kwh and this is equivalent to the offset of 172 tons of CO_2. Using what was learned regarding the air cooled condenser and with over 150 GPM produced water flow and a net output of 38 kWh, 360 tons of CO_2 can be offset according to a CO_2 emissions calculator found at the Carbonify web site (www.carbonify.com). At the same time, it supports water conservation, which is a major consideration during periods of extreme drought such as those recently experienced in the southern and mid-continent areas of the U.S.

For additional information about this project contact Chandra Nautiyal at NETL (chandra.nautiyal@netl.doe.gov or 281-494-2488) or Robin Dahlheim at Gulf Coast Green Energy (robin.gcge@gmail.com or 512-517-6793).

Trial Demonstrates Ultra-High Salinity Brine Pre-treatment

Managing produced water and frac flowback brines from petroleum operations represent a significant expense to companies developing new energy reserves. The industry has come to realize that these brines offer a viable source of water resources for oil-field reuse. A major obstacle to reuse is the presence of contaminants in the brines that could damage wells if used in subsequent drilling or fracturing operations. Such contaminants, if not removed, will not only prevent any reuse but will also impede disposal. The challenge is to identify technologies and approaches for treating the frac water that returns to the surface following a frac job (frac flowback water) for beneficial re-use in other applications, thereby conserving local freshwater supplies. A project managed by the Texas A&M Global Petroleum Research Institute (GPRI), with funding from NETL, is conducting a trial field demonstration to treat frac flowback water for reuse to address these issues. Project participants include Argonne National Laboratory, Los Alamos National Laboratory, Houston Advanced Research Center, Sam Houston State University, Rensselaer Polytechnic Institute, New York State Research Development Authority, MI SWACO, ABS Systems, Polymer Ventures, Norse Energy, Hach, GE Analytic and GSI Environmental.

The project objective was to develop a mobile, multifunctional water treatment capability designed specifically for "pre-treatment" of field waste brine. A comprehensive analytical test program was planned to provide on-site monitoring of the process. An additional objective, required because of the unavailability of brine from Marcellus wells, was to identify and test ultra-high salinity brines from the Herkimer formation. Herkimer wells, producing from the Silurian geologic trend, represent an analog to Marcellus brine. An extra incentive to test the Herkimer formation was that information from these brines can be used to characterize the Utica Shale brines.

Mobile Unit Design

The GPRI Designs™ Desalination Technology treatment trailer employs a multi-stage treatment train similar to that seen in larger facilities. Eight different components were evaluated during the trials: two types of oil and grease removal; one benzene, toluene, ethylbenzene and xylenes

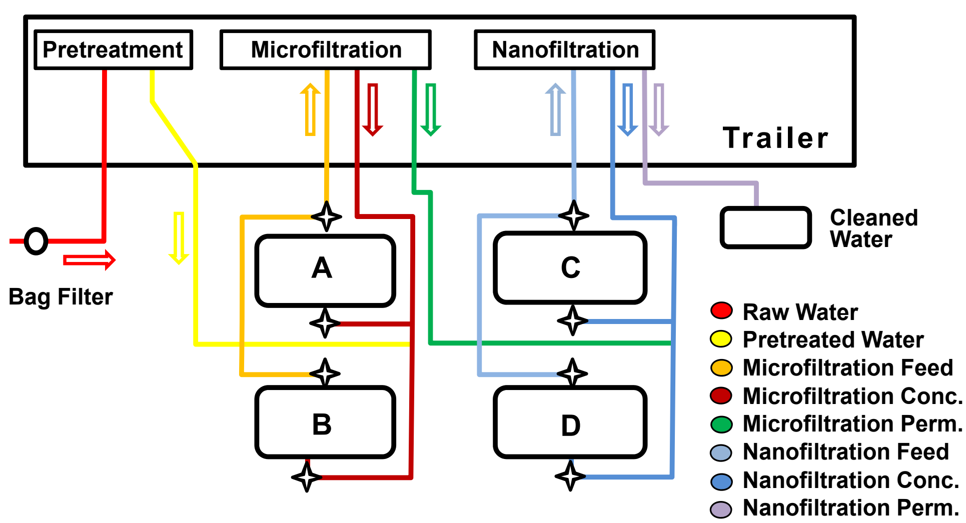


Figure 1: Schematic of Process Train

Figure 2. The mobile laboratory at the New York field site. Also shown is the environmental "apron" placed to catch spills.

(BTEX) removal step; three micro-filters; and two different nanofilters. The performance of each technique was measured by its separation efficiency, power consumption, and ability to withstand fouling.

The unit utilizes media filtration for the first step of the cleanup process. All filters and devices in this segment are made for only one pass by the treated liquid. The design uses an external bag filter, an internal bag filter and cartridges for the removal of oil and grease. The last filter of this unit is a packed bed designed to remove BTEX from the water. The minimum throughput is 2 gallons/minute for steady-state conditions and up to 4 gallons/minute for recharge of the next unit in the train. The train steps or sections are shown in Figure 1. Flexibility is achieved by dual, side-by-side tanks for inlet brine and outlet brine for each step in the process train. All fluid tanks were placed on environmental mats to prevent any spillage of brine onto the ground.

The Microfiltration unit is a continuous flow unit which concentrates the fluid in the tank being treated. For that reason there are two tanks A and B. When the system is started the prefiltration unit, if capable, will flow at 4 gallon/minute to fill both A and B. When filled, the pretreatment flow is reduced to 2 gallon/minute, the microfiltration is begun and the permeate from this process is used to fill tanks C and D. When they are filled, nanofiltration is begun at a permeate rate of approximately 2 gallons/minute.

Field Operations

The field trial was conducted over a four-week period in Chenango County, New York. The field trial in this county was only possible through the cooperation of Norse Energy, a local operator. Field trials of the unit were conducted in the Eagle Ford Shale in early 2010. In August, the unit was moved to New York. Figure 2 shows the unit on site in New York. All field brines were stored in a 100 barrel supply tank. All processed brine and waste fluids were pumped to a 100 barrel disposal tank.

Field Trials: Media and Membrane Operations

Field trial results were performed to confirm or counter results of pilot plant and yard tests of oil removal systems. Based upon the results of yard tests

Figure 3a. Oil and grease removal cartridges.

Figure 3b. BTEX removal cartridges by ABS Materials Inc.

Figure 4a: Membrane process train. The brine treatment process train is located on one side of the laboratory above a grated area serving to collect any spilled water.

and early work in the Eagle Ford Shale trial runs, the mobile water treatment unit was equipped with media filters to remove hydrocarbons before treatment to remove TSS.

Hydrocarbon Removal

Oil and grease removal media cartridges from Mycel[1] and Polymer Ventures[2] and ABS[3] BTEX removal media were all employed. Oil and grease removal is accomplished with the use of oleophilic cartridge filters in the blue filter housings in Figure 3a. BTEX Removal is accomplished by the use of ABS media material contained in additional filter housings (Figure 3b). Micro-filtration is used to remove solids from the process stream. The process train can be switched to evaluate different types of micro-filtration allowing different types of membranes to be evaluated in side-by-side comparisons.

Suspended Solids Removal

One feature of the A&M system is the use of micro-filtration to remove suspended solids from the brine stream. By eliminating the conventional flocculation, precipitation, and filtration step, the process train becomes a more compact system and one that uses fewer chemicals. The key to successful adoption of micro-filtration for solids removal lies in the design of the process train that avoids filter fouling. The system being trialed in New York has been tested for over 5 years in the pilot plant and in earlier trials (Figures 4a and 4b).

Microporous membranes are designed to retain all particles above their pore size ratings, while an asymmetric membrane is characterized by a thin skin on the surface of the membrane, rejection occurs only at the surface, and retained particles above the nominal molecular weight cut-off (MWCO) do not enter the main body of the membrane[4]. MWCO is the ability of a membrane to reject the species of certain molecular weight measured as Daltons.

Spiral wound and hollow fiber MF membranes are made of polymeric materials, for the most part asymmetric. A list of commonly used polymers includes Teflon (PTFE), polyvinylidene fluoride (PVDF), cellulose acetate, polysulfone, nylon and polycarbonate. Non-polymeric submicron membranes manufactured from durable materials such as ceramics and metallic are also used for MF separation. UF membranes provide a more complete rejection of materials, including some high molecular materials such as soluble, high molecular weight synthetic materials. UF membranes are typically asymmetrical polymeric membranes like the MF membranes

Figure 4b: A close-up view of the high pressure micro-filtration components of the process train.

The A&M system uses UF membranes that can be reverse washed to reduce fouling. Best results were found with pressurized hollow fiber, ceramic, and a stainless steel. The field trials offer a way to differentiate the effectiveness of the alternatives therefore all three types were employed in the trial, ceramic, stainless steel, and capillary hollow fiber.

First, filtration rate as a function of throughput (elapsed time) was measured. Then turbidity (NTU) was monitored. Finally the output flow rate was recorded at periodic intervals. Figure 5 shows a typical days run taken from the data acquisition system. Although not shown, flow rate of effluent (permeate) was constant (2 gpm). A six-hour run represents approximately 350 gallon throughput.

All micro filters clarified the brines. The hollow fiber configuration is preferred because it offers the unique benefits of high membrane packing densities, sanitary designs and the ability to withstand permeate back pressure, thus allowing flexibility in system design and operation. The geometry allows a high membrane surface area to be contained in a compact module. This means large volumes can be filtered, while utilizing minimal space, with low power consumption. Disadvantages are that this module is intolerant to large pressure changes and is readily plugged by particles. Measurement of plugging is critical.

Nano-Filtration (Alkalinity TDS Reduction)

The use of nanofiltration to selectively remove alkalinity and certain undesirable dissolved materials is a new concept not yet embraced by industry. The object of “shaving” or removing a portion of the divalent ions is to create thermodynamically stable brine that does not form precipitates when exposed to the atmosphere, such as in frac ponds or frac tanks. Since commercial nanofiltration is used to remove sulfate ions in food applications, it is clear that similar techniques can be employed in field operations to treat frac flow back brine. Additionally the offshore O&G industry has begun to adopt such treatment to treat seawater to remove sulfates before injection. Such treatment reduces the tendency of sea water injection systems to cause both wellbore permeability reduction (insoluble metal sulfate salts) as well as ameliorating bacterial bio-fouling and reservoir souring caused by sulfate reducing bacteria. In New York, two different nanofilters were employed; both were effective in removing ions. Both produced good flux at low pressures and correspondingly low power requirements. The filters, originally manufactured to remove contaminants from raw milk, are extremely effective in removing sulfate ions and other alkaline metal ions from brines. The importance of such "shaving of alkalinity is that the resultant water, although still highly saline, becomes thermodynamically stable and much more resistant to bacterial contamination and fouling.

Importance of Water Quality for Beneficial Re-Use as Fracturing Fluids

Figure 5a and 5b show a before and after sample of frac pond brine taken in February 2011 at the shake down run of the mobile lab in South Texas. The first photo is typical of what frac pond water in the South Texas environment looks like after two weeks. Bacterial growth, iron sulfide scale formation and alkalinity scale drop out create an intractable fluid, one that will harm any well it is used to frac, even diluted. Closed loop systems in frac tanks are as problematic because such brines are not observed before pumping, and as iron rust and contamination build up, nothing is done to prevent those contaminants from being injected in the reservoir and causing formation damage in the pay zone of the well.

Operating Cost of the Process Train

The mobile unit has been designed to monitor power loads (kWh or hp) of the various pumping and treatment combinations of water pretreatment. Pre-treatment processing operates at pressures below 500 psi, thus reducing construction costs and lowering power costs of the low pressure pumping system. The "thoughput-gpm" depends upon the separation efficiency of the filtration component which, in turn, depends upon the composition of the raw water stream. The higher the salinity, the more energy is needed to pump brine through the membranes.

Results and Conclusions from Field Trial

Media Filtration – Media used to remove hydrocarbons from the produced water functioned satisfactorily in the field trial. Because of the relatively low concentrations of oil and grease, TOC, and BTEX in field brine samples, the components were not subjected to rigorous operations.

Micro-filtration – The use of micro-filtration to remove TSS from the process stream was a success. Key parameters (fouling tendency and solids removal) were nominal for the entire duration of the trial. Of the three types of filters evaluated, the capillary hollow fiber Koch

Figure 5a. Before and after Frac pond Samples

Figure 5b. Before and after frac pond brine after three weeks aging

membrane gave the highest flux rate.

Nano-filtration – Utilization of NF as a means of reducing TDS has been shown to be effective in short term trials if the incoming brine was solids free (as measured by turbidity readings). The same performance was observed in the extended tests. Three brands of NF were employed. All performed well with no deterioration in flux observed over the duration of the trial.

Analytics – One of the reasons for the successful field trial was the support of analytical services providers who provided both equipment and field personnel to monitor performance of the components of the process train. Measurements of water quality at each step of the process assured that the following step had the best possible chance of success in extended run times.

Overall, the field trial was a success. Of the four field brines evaluated, three were treated with minimal problem. Over 6,000 gallons of brine were processed. Using a power cost of $0.10 per kwh, media pretreatment power use averaged $0.004 per barrel, solids removal $0.04 per barrel and brine "softening" $0.84 per barrel. Total power cost was approximately $1.00 per barrel of fluid treated.

For additional information about this project contact John Terneus at NETL (john.ternius@netl.doe.gov or 304-285-4254) or Dave Burnett at Texas A&M University (burnett@pe.tamu.edu or 979-845-4254)

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Lateral Rejuvenates Production in Mature Field

W. Lynn Watney, Kansas Geological Survey

With support from the NETL, researchers at the Kansas Geological Survey at the University of Kansas, together with American Energies Corporation in Wichita, Kansas, tested the efficacy of drilling a cost-effective horizontal well in Unger Field in Marion County in central Kansas to contact new oil and revive the field. The Unger field, discovered in 1955, has produced 8.6 million barrels from the Hunton dolomite at a depth of approximately 2800 ft. Originally 76 wells were drilled on a 40 acre pattern; 17 wells remain.

In attempting to pump off existing vertical wells in the 57-year-old field, the producer observed slight increases in oil production, including wells near the original oil/water contact (OWC), suggesting that more could be drained at higher fluid withdrawal rates. But, strong pressure support throughout the thin (11 to 25 ft) reservoir and high water cut (99%) would limit this method of oil recovery from existing wells. However, the potential for undrained oil made Unger Field a good candidate for a horizontal well.

Characterization of the Hunton reservoir at the Unger Field was done by analyzing cutting descriptions, old suites of wireline logs, and production records. The primary productive reservoir lithofacies is a dolomite with good (up to 20%) intercrystalline porosity calculated using old micrologs and neutron count logs. The top of the Hunton dolomite is a regional unconformity against which four distinct, correlatable porous layers subcrop diagonally over a northwest-trending anticline forming lobes of thicker porous carbonate.

The location of the horizontal well was selected to be high on the eastern flank parallel to the crest of the anticline. Well trajectory was opposite to a northwest trending fault that was believed to define the western flank of the anticline. The horizontal well was to intercept the lobes of the porous Hunton reservoir to tap undrained oil. The original oil column is 40 ft, corresponding to the relief on the locally developed anticline, so the lateral was well above the original OWC.

A local, doubles (60 ft stands) drilling rig with a duplex pump was used to drill the conventional lateral. Although the rig was small and limited the length of the lateral, it was deemed technically and economically appropriate for the size of the shallow, thin reservoir target (Figure 1). The drilling company had previous experience in this area which helped ensure that the rig and crew was prepared for the task, although this would be the first lateral drilled by the rig. A management team with prior experience assisted in the well design and implementation, which factored into the well's success.

The well was spudded on January 6, 2011 and the rig was released 18 days later. The length of the lateral was 1,137 ft, with a maximum of 8 degrees per 100 ft build through carbonates and shales of Mississippian and Upper Devonian age. The structure ran lower than projections, requiring an additional 340 ft of hole at 88 degrees to horizontal before the Hunton reservoir was intercepted. Seven-inch casing was set at 3,470 ft and the lateral was drilled to 4,613 ft.

Azimuthal gamma ray was used to aid in the "soft" landing in the Hunton following higher stratigraphic markers during the turn. Shortly after entering the Hunton, a strong show of oil was encountered in the cuttings

Figure 1. C&G Drilling's Rig #2, a doubles rig, provided an efficient, inexpensive option for drilling the Rood #1-19 well.

and in the mud pit. Drillpipe conveyed logs, including triple combo and microresistivity imaging, confirmed 200 ft of Hunton "sucrosic" dolomite pay (3880-4080 ft), with mixed high and low water saturation ahead of the pay in similar rock and generally higher water saturation in less porous cherty dolomite beyond the pay. The image log confirmed that the higher water saturation zones were more heavily fractured and that the fractures were predominantly oblique to the borehole and parallel to maximum horizontal compressive stress (Figure 2). A nearby vertical well was located in a fracture cluster, suggesting that at least some of the vertical wells are, primarily, draining the areas of higher water saturation.

The post-drill logging was instrumental in isolating the pay with fewest fractures, permitting the completion with a slotted liner and packer. A sucker rod pumping unit was initially installed in March. The well was put on production in April 2011 with initial rates of 6 bopd and 600 bwpd. A progressive cavity screw pump was subsequently installed and production increased to 15 bopd and 1,600 bwpd, a water cut similar to the rest of the field. Notably, the oil production increased in adjoining wells between March and December 2011, from 29 bopd and 8,400 bwpd to 64 bopd and 16,000 bwpd.

No decline in the fluid level in the lateral well has been noted (300 ft from surface), but the increased oil production from nearby wells suggests that the reservoir is starting to dewater and may contain a weaker edge water drive than thought. American Energies plans to install a submersible pump in August 2012 to substantially increase the fluid volume and will work over an existing Arbuckle well to dispose of the produced water. It is anticipated that the projected increase in production in the lateral well will further dewater the more highly fractured zone, thereby releasing more oil from the matrix porosity.

The first horizontal for the small oil producer is deemed both a technical and economic success. The well's $850,000 cost can be recovered in a year from incremental oil recovery. There is also a potential to further isolate the non-fractured portion of the pay, with the option to set another packer to draw more fluid from the matrix porosity. The use of 3D seismic imaging to identify pay and fracture clusters has also been discussed, as has the possibility of drilling parallel to fracture clusters.

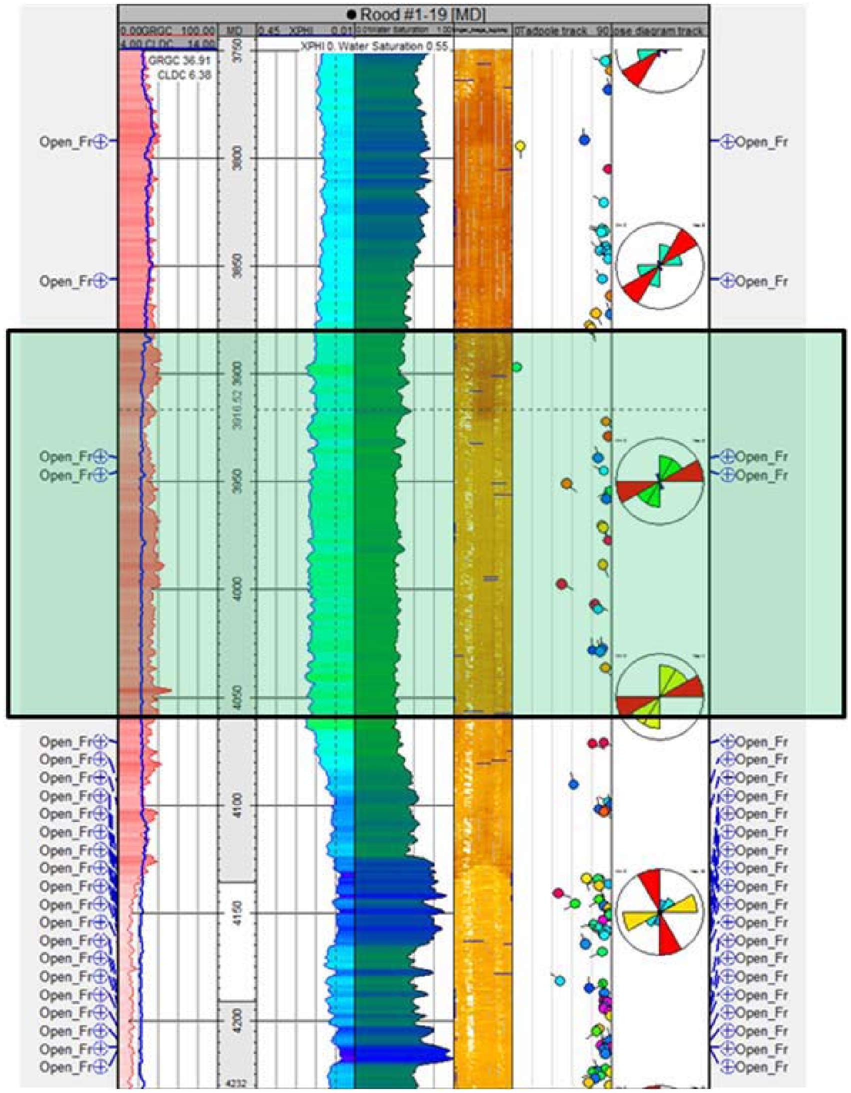

Figure 2. Interpretation of Triple Combo and Compact Micro Imaging (CMI) Logs (fracture log) confirmed 200 ft of Hunton "sucrosic" dolomite pay (3880-4080 ft)

The project clearly illustrates that what appeared to be a highly watered out, fractured carbonate reservoir has remaining areas that are undrained by the vertical wells. Lower cost horizontal wells can be used to redrill the field to intercept these bypassed areas. In this case, the objective was not to create more fractures to contact untapped pay, but to use a natural completion in a less fractured reservoir interval that had near-original oil saturation and attempt to maximize the recovery of oil. The natural fracture system is thought to be extensive in this dolomite reservoir and maximizing fluid withdrawal appears to be the optimal method to maximize incremental oil recovery. It appears that, even in proximity to old wells, there is oil to be produced by attempting to pump off the reservoir and allowing vertical wells to tap oil that is currently trapped in the matrix near these wellbores.

For additional information about this project contact Chandra Nautiyal at NETL (chandra.nautiyal@netl.doe.gov or 281-494-2488) or W. Lynn Watney at the University of Kansas (lwatney@ku.edu or 785-864-2184).

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NETL Monitors Environmental Impacts in Gas Production

Only a few years ago, the price of natural gas was rapidly increasing and many people were struggling to heat their homes. The main reason that prices have fallen since then is that production of natural gas increased from two non-traditional sources, coal beds and organic shales. Yet, effective production from unconventional gas resources requires well drilling and completion technologies that are too new for their environmental footprint to be well established. NETL is conducting research that accurately assesses the impact of unconventional gas development on the ecosystems where gas plays are located to provide regulators with an impartial, scientific basis for possible rulemaking. NETL is also actively developing cost effective technologies and management strategies to mitigate identified environmental impacts.

Horizontal Marcellus shale gas wells on a multi-well drill pad in southwestern Pennsylvania (Photo courtesy of Range Resources-Appalachia).

NETL researchers have used geophysicists to track saline water underground and to improve the way that saline water is treated and used at coal bed natural gas extraction sites in the western United States. They have also recently demonstrated that the water produced in the Powder River Basin of Wyoming can be used to irrigate crops using subsurface irrigation. In the eastern United States, NETL is leading a consortium of eight state and Federal agencies evaluating the environmental impacts of shale gas production that uses hydraulic fracturing and drill pads with multiple horizontal wells. Much of this research is briefly summarized below.

Environmental Study of a Sub-surface Drip Irrigation Site along the Powder River, Wyoming

The National Energy Technology Laboratory and the U.S. Geological Survey are collaborating with BeneTerra LLC to comprehensively monitor a sub-surface drip irrigation (SDI) system at a site in the Powder River Basin (PRB) of Wyoming. Irrigation water for the SDI system is coalbed natural gas (CBNG) co-produced water. The study is being conducted at the Headgate Draw area, located approximately 11 miles south of Arvada, Wyoming at the confluence of Crazy Woman Creek and the Powder River.

The study site encompasses six alfalfa fields and covers an approximate area of ½ square mile.

The CBNG waters are applied to the root zones of agricultural land; this style of irrigation is capable of applying two to three times more water on a site than traditional surface irrigation, and is designed to minimize environmental impacts by parking potentially detrimental salts below the land surface, but above the water table. NETL is investigating the transport and fate of the water and salts from the injected CBNG produced waters at the SDI site.

This study has shown that subsurface irrigation with CBNG produced water is an environmentally acceptable practice in the Powder River Basin of Wyoming. The Ca- and Mg- minerals in the native soil dissolve in the applied CBNG produced water to maintain a sodium adsorption ratio that sustains soil permeability (the primary concern when using high-Na produced water for irrigation). Geochemical modeling based on three years of soil mineralogy, soil chemistry, and groundwater chemistry data from the prospective study indicates that CBNG produced water can be applied by sub-irrigation for about 10 years at current application rates before adverse impacts to soil permeability result. This study provided the Wyoming DEQ with the scientific basis to approve sub-surface irrigation for the management and beneficial use of CBNG produced waters.

On the left, a researcher using a geophysical tool to assess the effects of subsurface drip irrigation (SDI) on soil conductivity; on the right, alfalfa being harvested from land irrigated with produced water through SDI.

Research on the Air Quality Impacts of Marcellus Shale Natural Gas Production

The development of shale gas resources requires horizontal drilling and multi-stage hydraulic fracturing, two processes that result in more air emissions than conventional natural gas. Horizontal drilling requires larger drill rigs with more horsepower that are operating longer to complete the long horizontal segments of shale gas wells. Similarly, hydraulic fracturing requires large volumes of water that often is hauled by truck to the well site. More than 500 truck trips are needed to transport enough water for the hydraulic fracturing of one well. The atmospheric emissions from trucks combined with the emissions from multiple, diesel powered, hydraulic fracturing pumps can cause a short-lived but significant impact to local air quality. Atmospheric emissions from the venting of condensate tanks, dehydrators, and the pneumatic valves are additional constant sources that persist as long as natural gas is being produced. On July 28, 2011, EPA announced its intention to limit air emissions from natural gas drilling.

NETL is leading several field studies to determine air quality impacts resulting from development and production of gas resources in the Marcellus shale. A field monitoring trailer that measures multiple atmospheric signals (e.g., ozone, particulates, organics, and other gases) is being deployed at a range of sites to document temporal atmospheric signals as a function of geography, season, operation, etc. The mobile air monitoring laboratory was deployed to the Allegheny National Forest (ANF) in north-central Pennsylvania for approximately one year (July 2010 - June 2011). The forest has historically been a productive area for oil and gas wells but the number of wells has increased significantly in the past few years as Marcellus shale gas wells have been drilled. Ambient concentrations of pollutants and other air quality parameters were determined at three monitoring sites within the ANF, two of which were downwind of areas with heavy oil and gas exploration and production, and one site in an area relatively uninfluenced by emissions from oil and gas operations to serve as a background location for pollutant concentrations. Results of this study are still being analyzed.

NETL's mobile air monitoring laboratory deployed in the Allegheny National Forest

Baseline Environmental Monitoring at a Marcellus Shale Gas Well Site

NETL is leading a consortium of eight state and Federal agencies evaluating the environmental impacts of shale gas production that uses hydraulic fracturing and drill pads with multiple horizontal wells. This effort was selected by EPA (one of the participating agencies) to be a "prospective case study" for their congressionally mandated investigation of the impact of hydraulic fracturing on sources of drinking water. The Marcellus Test Site differs from the other EPA case study sites (where only impacts to drinking water are being monitored) in that impacts to 1) air quality, 2) terrestrial and aquatic wildlife, 3) soil properties, 4) vegetation, and 5) landscapes (future land use) will also be considered.

NETL's mobile air monitoring station has already been moved downwind of the site to collect four seasons of background (baseline) environmental data before well construction begins. Monitoring of environmental parameters will continue through well drilling and completion, and for at least one year of well production. By providing a more complete understanding of the impacts of Marcellus Shale natural gas production on the local and regional environment, NETL can help ensure that development proceeds at a rate that protects the environment while ensuring an adequate domestic supply.

Large pond below proposed Marcellus shale gas well pad that currently supports an abundant and diverse fish population

Chemical and Microbiological Characterization of Water Co-produced with Marcellus Shale Gas

NETL microbiologists have determined that the microbial ecology of Marcellus Shale production water changes significantly with time as the water is stored in on-site pits and centralized impoundments. Changes in bacterial populations have been linked to the consumption of labile organic compounds used in hydraulic fracturing (particularly friction reducers) and to the amount of dissolved oxygen. Understanding the complex, ever-changing ecology of these waters is important when the water is to be re-used for additional well completions. Furtherance of this work is expected to lead to more environmentally acceptable biocides and new methods to manage the adverse impacts of bacteria on shale gas development and production.

Finally, collaboration between researchers at the University of Pittsburgh and NETL has identified a unique isotopic signature for Marcellus Shale

Lined impoundments provide temporary storage for water needed for hydraulic fracturing and the water that rapidly flows back to the surface when the well is being prepared for production. (Photo courtesy of Energy Corp. of America) produced water that permits these waters to be distinguished from other sources of contaminated water in western Pennsylvania (e.g. water from coal mines). This methodology should theoretically allow researchers to calculate the contribution of Marcellus Shale produced water to the overall volume of flowback water from completed gas wells.

A Louisiana waterthrush (a stream valley-dwelling species) captured, tagged, and released in a disturbed area of the Wetzel Wildlife Management Area, Wetzel Co., WV

Other Environmental Aspects of Marcellus Shale Natural Gas Production

Another NETL study has examined the influence of unpaved roads built to service the oil and gas industry in the Allegheny National Forest on stream sedimentation and ecology. Two adjacent watersheds, similar in size and topography, but having either low or very high road density, were studied. The primary stream in each watershed was instrumented with water flow and quality monitors and directly monitored via satellite telemetry, in cooperation with the U.S. Geological Survey. A rainfall simulation device provided by Penn State's Center for Dirt and Gravel Roads was used to create repeatable simulated rainfall events, and runoff was collected from 14 different road sites. An average of 815 lb of sediment runoff per 0.6 mile of road was measured for the 30 min rainfall events. Macroinvertebrate populations indicative of stream health were collected by Clarion University of Pennsylvania personnel during the early summer, late summer, and fall from two sites in each watershed. Preliminary data analysis indicates that macroinvertebrate populations in both watersheds appear similar in terms of overall community richness and diversity, despite large differences in sediment runoff. This implies that the greater sediment loads of the oil and gas impacted watershed may be below the threshold needed to adversely impact macroinvertebrate populations. These results can potentially be extended to brook trout and some bird species that rely on macroinvertebrates as their primary food. The results also suggest that the presence or absence of specific indicator species may be a better indication of road-generated sediment impact than the more costly and time-consuming analysis of the total population.

The deciduous forests of the central Appalachians provide habitat for many bird species, including raptors and songbirds. Another NETL study, being carried out by West Virginia University, has established an important baseline of bird population data in an area impacted by both historic and current oil and natural gas industry activities. In addition to complete bird population counts, the study focuses on two forest songbirds that are of particular regional conservation concern, the cerulean warbler (a ridge top species) and the Louisiana waterthrush (a stream valley-dwelling species). The field-intensive research examines the distribution and abundance of these species relative to energy extraction-related activities in these two habitats. Birds that live at the forest edge have been found to be more abundant in areas disturbed by oil and gas activity due to forest clearing and road building. Long-term field studies such as this are required to fully understand the complex annual variations that occur in natural bird populations and to develop better management plans that optimize habitat protection and species diversity.

A cerulean warbler (a ridge top species) captured, tagged, and released in a disturbed area of the Wetzel Wildlife Management Area, Wetzel Co., WV

Vast Energy Resource in Residual Oil Zones, FE Study Shows

Billions of barrels of oil that could increase domestic supply, help reduce imports, and increase U.S. energy security may be potentially recoverable from residual oil zones, according to initial findings from a study supported by the U.S. Department of Energy's Office of Fossil Energy (FE). The recently completed study, conducted by researchers at the University of Texas–Permian Basin (UTPB), is one of several FE-supported research projects providing insight that will help tap this valuable-but-overlooked resource.

Residual oil zones, called ROZs, are areas of immobile oil found below the oil-water contact of a reservoir. ROZs are similar to reservoirs in the mature stage of "waterflooding," in which water has been injected into a formation to sweep oil toward a production well. In the case of ROZs, the reservoir has essentially been waterflooded by nature and requires enhanced oil recovery (EOR) technologies, such as CO_2 flooding, to produce the residual oil.

The UTPB study focused on understanding and modeling fluid flow within ROZs in the Artesia Fairway—a dolomitized trend in the San Andres formation containing oil-producing fields—of eastern New Mexico and west Texas. Utilizing geologic and production data, UTPB researchers determined that oil saturations within ROZs range from 20 percent to 40 percent, with an average of 32 percent, which is similar to that of mature, waterflooded reservoirs. The study also found that ROZs exist in all fields producing from the San Andres formation where it has been uplifted in the western part of the Permian Basin resulting in a tilted oil-water contact.

In another FE-sponsored research effort, UTPB is developing a state-of-the-art geologic and reservoir characterization model of the main pay zone and residual oil zone in the Goldsmith field, Ector County, Texas, where Legado Resources has initiated a CO_2-EOR pilot project. A numerical simulator will then be used to match past reservoir performance and to examine the performance of the CO_2 EOR flood under alternative flood design and operating practices. The goal of the research effort is to optimize the technical and economical performance of an ROZ CO_2 flood and transfer the knowledge to other operators. This will be the first publicly available comprehensive case study of a ROZ flood.

A third study, awarded to UTPB in June 2012, will further delineate the presence and size of ROZ areas in the Permian Basin of Texas and New Mexico using geophysical well logs and well test data, core and fluid samples, and water chemistry data. Researchers will also determine if 3D seismic can be used for identifying the higher quality portions of the ROZ resource to assist small oil producers within the Permian Basin and other ROZ basins in the United States.

According to the 2012 worldwide EOR survey published in *Oil & Gas Journal*, U.S. CO_2-EOR production is approximately 350,000 barrels of oil per day. There are currently nine industry ROZ CO_2-EOR pilot projects in the Permian Basin of Texas, accounting for approximately 10,000 barrels of oil per day. Results and findings from FE-supported research should help to increase recovery from this domestic resource and create American jobs.

DOE AWARDS $8.4 MILLION IN SMALL PRODUCERS PROGRAM

The U.S. Department of Energy has selected nine proposals for negotiations leading to an award totaling $8.4 million in federal funding in its Small Producers Program. These funds, added to $5.7 million in cost share by the industry participants, give the nine selections a total value of more than $14 million. These 2011 Small Producer Program selections add to the 21 existing projects. The research contracts will be administered by the Research Partnership to Secure Energy for America, under the management of the Office of Fossil Energy's National Energy Technology Laboratory. Brief descriptions of the selected projects follow:

- Cost-Effective Treatment of Produced Water Using Co-Produced Energy Sources Phase II: Field Scale Demonstration and Commercialization
  Project Leader: New Mexico Institute of Mining and Technology
  Participants: Harvard Petroleum Corporation, LLC
- Field Demonstration of Eco-Friendly Creation of Propped Hydraulic Fractures
  Project Leader: DaniMer Scientific, LLC
  Participants: CSITechnologies, LLC; Texas A&M University; EnerPol, LLC; Petroleum Technology Transfer Council; Ampak Oil Company
- Field Demonstration of Chemical Flooding of the Trembley Oilfield, Reno County, Kansas
  Project Leader: The University of Kansas Center for Research
  Participants: Berexco, LLC; SNF Holding Company; Huntsman Petrochemical, Corp.; EOGA IOR Services, LLC; Tracer Technologies International, Inc.
- Hybrid Rotor Compression for Multiphase and Liquids-Rich Wellhead Production Applications
  Project Leader: OsComp Systems, Inc.
  Participant: Red River Compression
- Study and Pilot Test of Preformed Particle Gel Conformance Control Combined with Surfactant Treatment
  Project Leader: Missouri University of Science and Technology
  Participants: Blue Top Energy, LLC; Colt Energy, LLC; TMD Energy; Baker Hughes Incorporated
- Basin-Scale Produced Water Management Tools and Options – GIS-Based Models and Statistical Analysis of Shale Gas/Tight Sand Reservoirs and Their Produced Water Streams, Uinta Basin, Utah

Project Leader: Utah Geological Survey
Participants: Anadarko Petroleum Corporation; El Paso Exploration & Production Company; EOG Resources, Inc.; QEP Resources, Inc.; XTO Energy, Inc.; Wind River Resources, LLC

- Reduction of Uncertainty in Surfactant-Flooding Pilot Design Using Multiple Single Well Tests, Fingerprinting, and Modeling
  Project Leader: The University of Oklahoma
  Participants: Mid-Con Energy Operating Company, Inc.; Mid-Con Energy III, LLC
- Upstream Ultrasonic Processing for Small Producers: Preventative Maintenance for Paraffin Management in Production Tubing Using Non-Invasive Ultrasonic Technology
  Project Leader: Pacific Northwest National Laboratory
  Participants: Falcon Exploration, Inc.; Baker Hughes Incorporated
- Water Management in Mature Oil Fields Using Advanced Particle Gels
  Project Leader: The University of Texas at Austin
  Participants: Missouri University of Science and Technology; Legacy Reserves LP; Hilcorp Energy Company

DOE AWARDS $35.4 MILLION TO ADVANCE SAFE AND RESPONSIBLE DEEPWATER DRILLING TECHNOLOGIES

Thirteen projects aimed at reducing the risks while enhancing the environmental performance of drilling for natural gas and oil in ultra-deepwater settings have been selected by the U.S. Department of Energy (DOE) for further development.

Negotiations for the new projects will lead to awards totaling $35.4 million, adding to the research portfolio of the Office of Fossil Energy's Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Program.

Research needs addressed by the projects include (1) new and better ways to monitor displacement during casing cementing using intelligent casing and smart materials, and (2)assessing corrosion, stress cracking, and scale at extreme temperature and pressure. All of the projects aim to develop and validate new technologies to enhance safety and environmental sustainability.

The total value of the projects is more than $56 million over 4 years with approximately $21.2 million of cost-share provided by the research partners in addition to the $35.4 million in federal funds. The research contracts will be administered by the Research Partnership to Secure Energy for America, under the management of the Office of Fossil Energy's National Energy Technology Laboratory. Brief descriptions of the selected projects follow:

- The Board of Regents of the University of Oklahoma (Norman, Oklahoma) — Intelligent Casing-Intelligent Formation Telemetry System.

- Brine Chemistry Solutions, LLC (Houston, Texas) — Corrosion and Scale at Extreme Temperature and Pressure.
- Colorado School of Mines (Golden, Colorado) — Hydrate Modeling & Flow Loop Experiments for Water Continuous & Dispersed Systems.
- Deepflex (Houston, Texas) — Qualification of Flexible Fiber Reinforced Pipe for 10,000-Foot Water Depths.
- Det Norske Veritas (Houston, Texas) — Ultra-deepwater Dry Tree System for Drilling and Production in the Gulf of Mexico.
- Doris, Inc. (Houston, Texas) — Low Cost Flexible Production System for Remote Ultra-Deepwater Gulf of Mexico Field Development.
- GE Global Research (Niskayuna, New York) — All Electric Subsea Autonomous High Integrity Pressure Protection System (HIPPS) Architecture.
- GE Global Research (Niskayuna, New York) — Qualification of Flexible Fiber Reinforced Pipe for 10,000-Foot Water Depths.
- NanoRidge Materials (Houston, Texas) — Ultra-High Conductivity Umbilicals: Polymer Nanotube Umbilicals.
- Remora Technology (Houston, Texas) — Deepwater Direct Offloading Systems, Phase 1.
- Stress Engineering (Houston, Texas) — Ultra-Deepwater Riser Concepts for High Motion Vessels.
- Stress Engineering (Houston, Texas) — Effects of Fiber Rope - Seabed Contact on Subsequent Rope Integrity.
- University of Houston (Houston, Texas) — Smart Cementing Materials and Drilling Muds for Real Time Monitoring of Deepwater Wellbore Enhancement.

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