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E&P Focus

Summer 2011 Oil & Natural Gas Program Newsletter

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U.S. DEPARTMENT OF ENERGY

Creating Extensive, Conductive Hydraulic Fractures in Low Permeability Gas Reservoirs

The key to producing gas from tight gas reservoirs is to create long, highly conductive hydraulic fractures to stimulate gas flow from the reservoir to the wellbore. To maintain conductivity in the fracture, it is also important to pump sufficient quantities of an effective propping agent into the fracture (Figure 1).

Current hydraulic fracturing methods in tight gas reservoirs have been developed largely through an ad-hoc application of low-cost water fracs, without much effort to optimize the hydraulic fracturing fluid and overall fracturing process. The widespread use of water fracs instead of gel fracs is in part due to the complex problem of gel damage, a reduction in permeability that occurs due to a combination of factors —plugging of the proppant pack inside the fracture, filter cake deposition on the fracture walls, and fracture fluid invasion into the formation adjacent to the fracture walls.

This project, partially funded by NETL, aims to develop improved techniques to optimize design of the fracturing treatment and fluid type in low permeability formations. The first phase of the project is focusing on the analysis of production data from thousands of wells to quantify the effect of the volume of proppant and type of fluid used on the long-term production behavior of tight gas wells. The second phase of the project will involve laboratory studies of the mechanisms of proppant interaction with the fracture walls and creation of fracture conductivity, using dynamic fracture conductivity testing procedures. Results of the field and laboratory studies will be

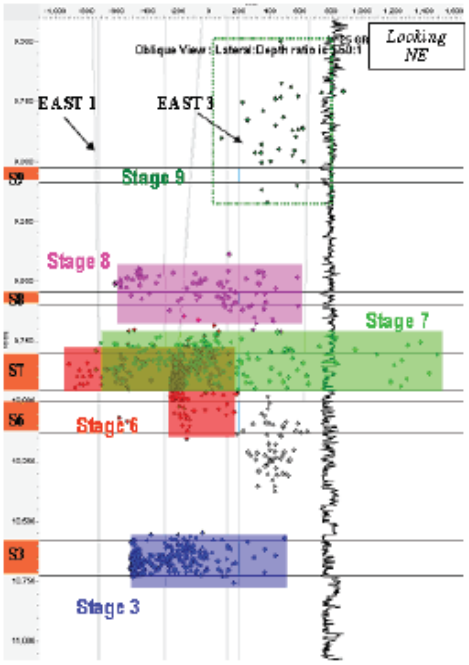

Figure 1: Illustration of side views of microseismic events for a well in the Jonah Field of Wyoming, shows created fractures for five different fracture treatment stages that highlight variation in fracture length among stages (Courtesy Pinnacle a Halliburton Service, SPE 102528)

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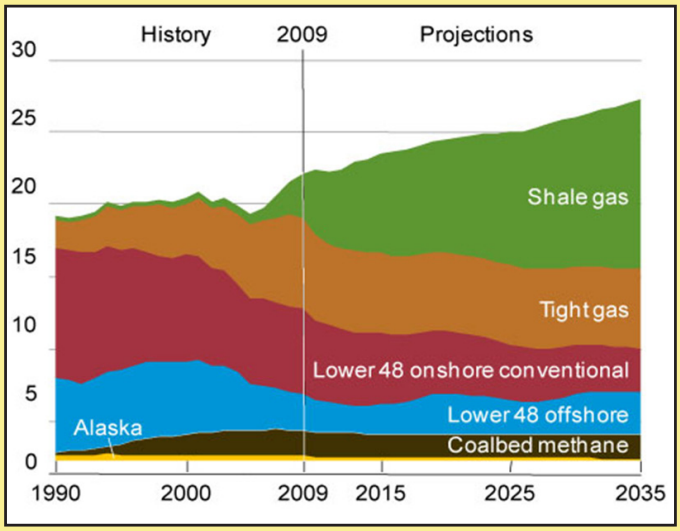
Commentary

Hydraulic Fracturing is Front and Center

As the nation moves toward economic recovery, the role of natural gas as a clean source of energy is expected to become more important both in fueling growth and meeting environmental goals. Our colleagues in the Energy Information Administration have developed a reference case (Annual Energy Outlook 2011, see figure) in which shale gas production will increasingly be relied upon as a key energy source for the nation. The primary drivers of the projected increase in shale gas production will be, as they have been, horizontal well drilling and multi-stage hydraulic fracturing.



U.S. Natural Gas Production, 1990-2035 (trillion cubic feet per year)

Source: Annual Energy Outlook 2011, U.S. Energy Information Administration, April 26, 2011, http://www.eia.gov/forecasts/aeo/chapter_executive_summary.cfm#domestic

Hydraulic fracturing is not a new technology. The first two commercial fracturing jobs were performed by Halliburton Oil Well Cementing Company on March 17, 1949. By the end of that year, 332 wells had been treated, with an average production increase of 75%. Early fracture treatments were performed, primarily, with crude or refined oil and river sand. Water was introduced as a fracturing fluid in 1953, coinciding with the development of a number of gelling agents. Gelled fluids allowed more and larger size proppants to be carried in suspension, resulting in major increases in the size of fracture treatments. For stretches in the mid-1950s, as many as 3,000 fracture treatments a month were performed. Through the decades to the mid 1990s, fracturing technology advanced and the size of fracturing programs increased. Since then, the increase in the number and size of slick-water (non-gelled fluid) fracturing treatments has been driven by shale gas development. NETL has been at the forefront of this growth, supporting

technology to improve the understanding of fracture propagation, to improve fracturing technology, to improve productivity from fractured wells and to ensure that hydraulic fracturing is carried out in an environmentally responsible manner. It is estimated that fracturing has increased U.S. recoverable reserves of oil by at least 50% and of natural gas by 90%.[1]

But, as beneficial as hydraulic fracturing has been to the energy needs of the nation, it has recently been tagged as a risky operation and a source of water pollution. This has led to bans, and attempted bans, on the use of hydraulic fracturing in several states and in multiple communities, most notably in the Marcellus Shale play. There are a number of real and pseudo issues that have contributed to this situation.

In terms of real issues, the most pressing is the large volume of clean water required in fracturing and the need to treat that water after flowback before it can be returned to the environment or reused in a subsequent fracturing operation. The problem can be acute in areas with a paucity of fresh water such as the Eagle Ford and Bakken Shale plays. NETL has been instrumental, through a number of research projects, in furthering water clean-up technology. Some of those projects are highlighted in this issue. A second real issue is the type and concentration of chemicals used in fracture treatments. While the chemicals in fracturing fluids are employed in small concentrations, the industry has been pressed to list those chemicals in a format available to the public. NETL has supported a project that has created a publicly accessible website for the voluntary listing of chemical compositions of fracturing fluids.

Other issues are not so easily addressed, primarily because they may be more correlative than causal. At the top of this list is the question of methane in ground water and water wells. There is considerable public concern that fracture treatments may, inadvertently, frac into underground sources of drinking water. This has led to the bans and attempted bans mentioned earlier. The same issue of methane in water has been raised in relation to well completion integrity and cement failure. There is also a perception that fracture treatments (or the disposal of fracturing wastewater by underground injection) may induce low level seismic activity. While links continue to be investigated, fracturing operations in western Arkansas were recently halted following increased seismic activity in the area.

Overarching all of these issues is the need for comprehensive programs to better identify, quantify and mitigate the risks related to hydraulic fracturing introduced above. NETL has been on the front line of efforts to advance these programs. Late last year, we joined several other governmental agencies in advising the U.S. Environmental Protection Agency's (EPA) Science Advisory Board about ongoing research on fracturing issues and specifically on issues related to the impact of fracturing on drinking water. The EPA's research seeks to answer two questions. First, can hydraulic fracturing impact drinking water resources and second, if so, what are the conditions associated with any potential impacts to drinking water resources due to hydraulic fracturing activity?

Within DOE, the Natural Gas Subcommittee of the Secretary of Energy's Advisory Board has been tasked with developing recommendations to address issues related to hydraulic fracturing. The subcommittee will identify any immediate steps that can be taken to improve safety and environmental performance of hydraulic fracturing in shale formations, and provide advice to DOE and other agencies on practices for shale gas extraction to ensure the protection of public health and the environment.

In another instance of inter-agency cooperation, a NETL field research project has been selected as one of several case studies in EPA's ongoing evaluation of the potential impact of hydraulic fracturing on underground sources of drinking water. NETL is leading a team from multiple agencies to build a comprehensive, pre-drilling, pre-fracturing data set that accurately characterizes the surface and subsurface environment prior to development. This will be an important baseline in determining the actual footprint of Marcellus drilling activity. The research will be carried out at a Marcellus Shale development site operated by Range Resources-Appalachia in Washington County, Pennsylvania. The plan calls for one year of environmental monitoring to establish baselines before any development takes place. Monitoring will continue through road and pad construction, drilling and fracturing of two horizontal wells in July 2012, and for at least one year of subsequent production.

Through internal programs and cooperative initiatives such as these, we continue our commitment to the development of the nation's indigenous energy resources. We are confident that, going forward, this commitment will be instrumental in increasing the supply of domestic natural gas in the safest and most environmentally sustainable manner possible.

We hope you enjoy the issue. As always, your comments are welcome.

[1]Montgomery, Carl and Smith, Michael, "Hydraulic Fracturing: The Fuss, The Facts, The Future, *Journal of Petroleum Technology*, December 2010, pp. 26 – 32.

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

used to recommend new procedures for fracturing low permeability formations.

The project is being undertaken by a team of researchers from the Crisman Institute in the Department of Petroleum Engineering at Texas A&M University, with cost sharing and technical support from four industry partners: Carbo Ceramics, BJ Services, Halliburton and Schlumberger.

Objectives and Potential Impacts

The goal of this project is to develop new methods for creating extensive, conductive hydraulic fractures in low permeability gas reservoirs. The plan is to evaluate fractured well productivity achieved using conventional fracturing practices; to dynamically measure conductivity created with high rate proppant fracturing in the laboratory; and to develop design models to implement the optimal fracture treatments determined from the laboratory and field data

Deliverables for this project will include: 1) a database of fractured well performance; 2) recommendations on methods to minimize gel damage; 3) guidelines for optimizing fracture conductivity under dynamic conditions; and 4) optimized tight gas fracturing treatment designs.

This research could lead to improved hydraulic fracturing practices in tight gas basins throughout the United States. Advances in hydraulic fracturing and mitigating gel damage have the potential to add substantial unconventional gas reserves to the nation's gas supply. Improved hydraulic fracturing practices resulting from this project could bring a significant portion of the nation's 293 Tcf of technically recoverable tight gas to market. The cumulative benefit would be determined by the total number of fields where the technology is ultimately applied. An incremental increase in domestic gas production would result in increased tax revenues, royalties, and regional economic benefits.

Assessment of Field Treatment Results

The research team has built an "advisory system" based on an assessment of treatment information collected under the project. The goal was to design a program that would suggest good completion and stimulation designs to help guide young and/or inexperienced engineers to better solutions. While not necessarily the optimal solution, the recommendations made by the advisory program are a very good reference point. The program uses information from reviewed literature and interviews with experts to build its decision trees. The decision trees are then used to generate suggestions based on information provided to the program by the user (e.g., reservoir properties).

The program allows the user to generate suggested solutions for single or multiple producible formations. Based on the reservoir properties input by the user, the program will suggest whether to drill a vertical or horizontal well, and will compute the best completion package for the well. The program assumes any well will be hydraulically fractured, and thus the basis of any completion design recommended by the program is cased and perforated.

The user is also able to make inputs regarding the design of a stimulation treatment. The stimulation design section of the program is the most sophisticated and involved with regard to user interaction. The program includes suggestions on injection methods, fracture fluid design, fracture fluid additives, proppant types, proppant concentrations, and optimal fracture half-lengths using several models.

After completion, recommendations from the Tight Gas Advisory System were compared to leading expert's designs for comparable inputs, with promising results. The research team is currently in the process of beginning a more involved field and application study of the software with Newfield Exploration Company. The team will compare current hydraulic fracturing designs in the field to ones recommended by the system. Production data will be computed with prediction software.

Dynamic Conductivity Testing

The second phase of the project involves the measurement of fracture conductivity under dynamic pressure and stress conditions that approximate those that occur in situ. This approach provides a more accurate picture of the impact of various fluid and proppant combinations on fracture conductivity after closure. Figures 1 and 2 show photos of the actual equipment. A special software system is also used to record data (load, differential pressure and nitrogen flow rates) in real time. Sixty mesh screens are installed in the high pressure vessels downstream of the conductivity cells to prevent plugging of the back pressure valves in the return line during the fracture conductivity measurement stage of the experiment.

The research team developed an experimental schedule to identify the most important parameters affecting dynamic fracture conductivity. Variables that may have an influence on dynamic fracture conductivity include: amount of breaker, nitrogen rate(laboratory analog for field flow back rate), temperature (150 and 250 °F), polymer loading (10 and 30 lb/Mgal), closure stress (2000 and 6000 psi), and proppant concentration (0.5 and 2 ppg). These factors will be varied to collect data that characterize their impact on fracture conductivity.

In the future, the group will use full factorial experiments to refine the information derived from the screening experiments and develop a statistical model. The end point of this process is the determination of the levels of the critical variables that will result in the best system performance.

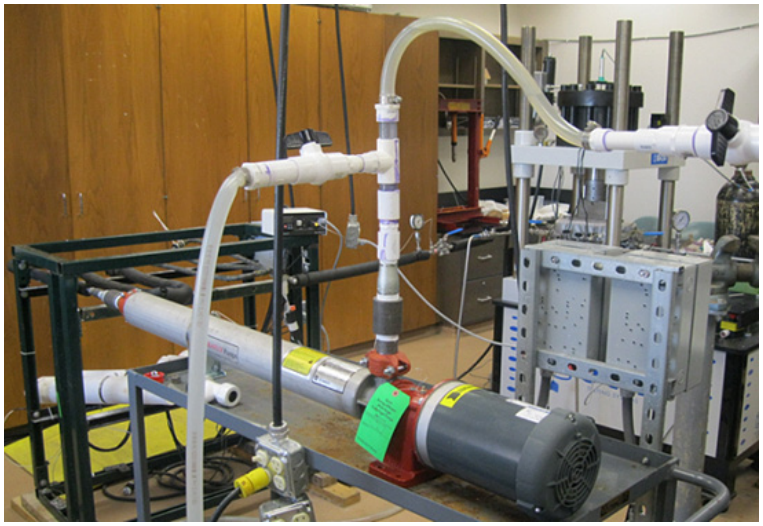


Figure 1: Dynamic Fracture Conductivity Measurement Laboratory Setup

Figure 2: Hydraulic Load Frame – red arrows show flow direction during slurry pumping (note conductivity cell not in picture)

Modeling of Gel Cleanup

Gel damage is a very complex problem and this phenomenon includes proppant pack damage inside the fracture, filter cake deposition at the fracture face, and fracture fluid invasion in the formation adjacent to the fracture.

The group investigated the process of displacement of gel by gas and modeled two-phase flow at the pore scale to obtain a better understanding of fracture fluid clean up mechanisms. Fracture clean up efficiency is believed to be a function of basic parameters such as proppant size, fluid rheology and imposed pressure gradients. Computational fluid dynamics software was used to investigate the complex flow mechanism in porous media. Equations for gas and gel flow in a fracture were developed by the capillary bundle method. In this model, the flow channel in the propped fracture is represented by a bundle of tubes. The tubes near the wall are full of the filter cake, and the other tubes are full of original gel.

These equations describe when the gel starts to move and the velocity profile of both the gel and the filter cake once the yield point of the filter cake is exceeded. For this idealized case, the equations of motion and momentum in porous media are solved analytically with appropriate boundary conditions. Gel cleanup mechanism patterns were identified for this system under imposed pressure gradients (Figure 3). If the pressure gradient is large enough, the gel and filter cake will be mobile as shown in Figure 3. However, the filter cake has a lower velocity because of higher yield stress. If the pressure gradient is small, only the gel layer will flow and filter cake is left immobile near the fracture wall. Also, the displacement of the gel by gas is not piston-like; therefore, in some of the pores, there is a mixture of the gas and the gel.

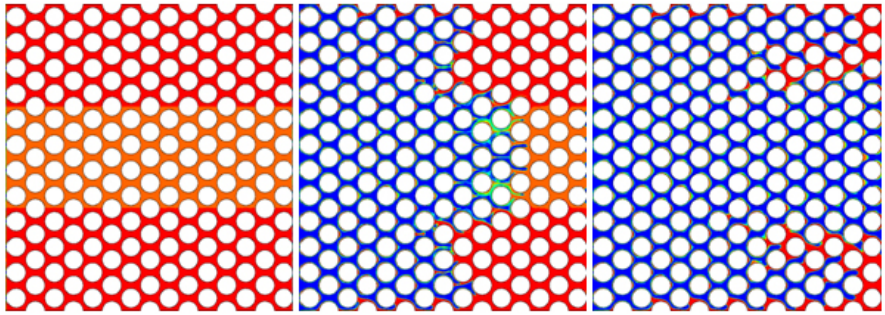


Figure 3: Three phase (gas=blue, gel=orange, filter cake=red, gas and gel=green) distribution during cleanup in porous media

Measurement of Yield Stress

To study the relationship between yield stress and polymer concentration experimentally, the group developed and setup a yield stress testing apparatus and conducted experiments to determine the relationship between yield stress, guar concentration and breaker concentration. The major conclusions were:

1. Guar concentration has a significant impact on yield stress of fracturing fluid. The yield stress is very low when the guar concentration is 40lb/Mgal or less. Increasing guar concentration will increase yield stress rapidly.

2. Yield stress decreases dramatically when breaker is added to fracturing fluid. The yield stress becomes zero when the breaker concentration reaches some critical value. The relationship between guar concentration and optimal breaker concentration is almost linear.

For more information on this project, contact Dr. Ding Zhu at Texas A&M University (979-458-4522 or ding.zhu@pe.tamu.edu) or Charlotte Schroeder at RPSEA (281-313-9555 or charlotte.schroeder@rpsea.org).

Advanced Fracture Modeling Techniques Set to Enhance Gas Production in Mesaverde Group Reservoir Rocks

Research combining natural and hydraulic fracture data into a multiphase, discrete-fracture fluid flow model that simulates gas production from Mesaverde reservoirs will be used to optimize gas production from selected tight gas formations in the Uinta Basin. The work, partially funded by NETL and undertaken by the University of Utah, the Utah Geological Survey, Golder Associates, Utah State University and Itasca Houston, Inc. began in September 2008 and will be completed in October 2012.

Project Overview

Mapping and characterizing natural fracture systems and understanding their interactions with induced fractures is critical for optimizing gas production from tight reservoirs. Tight reservoirs have ultra-low matrix permeability, so natural fractures are needed to provide pathways for gas to flow through the rock. Hydraulic fracturing treatments that reactivate and intersect the natural fracture network can improve gas flow and provide connections between the natural fracture network and the well bore. These connections can make the difference between a dry well and one that produces economic quantities of gas.

This project focused mainly on tight Mesaverde Group reservoirs in the Uinta Basin, which have permeabilities ranging from 0.01 to 0.1 millidarcies. Successful exploitation of this resource depends on how well the natural fracture systems are developed and understood, and how effectively they are connected to the production system by hydraulic fracturing.

The project team utilized available log, core, outcrop, and seismic data to create a comprehensive natural fracture map for targeted reservoir formations. Geomechanical tools were used to represent hydraulic fracture propagation patterns and characteristics. The natural and induced fractures were incorporated into an existing reservoir simulator developed at the University of Utah. Finally, gas production and drainage potential of the fracture network was evaluated.

University of Utah led the project and provided its in-house, finite element code for modeling and predicting production from tight gas reservoirs. Utah State University and Utah Geological Survey contributed to geological and geomechanical aspects of the project. Golder and Associates provided Fracman and FRED software for developing the static fracture model, and Itasca contributed to modeling the growth of hydraulic fractures in Uinta Basin reservoirs. Deliverables for this project include a series of reports on the various tasks as they are completed and a final report integrating the results of the project and providing guidelines for its application elsewhere.

The Greater Natural Buttes (GNB) gas field which covers about 400 square miles in Uintah County, Utah was the subject of the study. The project team selected Section 10 in the north-central portion of GNB for detailed modeling, after a series of discussions with the operator, Anadarko.

Geologic evaluation consisted of log and core evaluation and detailed fieldwork including outcrop and surface fracture analysis. The team constructed well log cross sections to correlate the Mesaverde Group in Greater Natural Buttes field to the outcrops of the Mesaverde in the Vernal area where Utah State University studied fractures in the exposed Mesaverde. An example cross section of those assembled is shown in Figure 1.

The core of the Sego and Castlegate Sandstones of the Mesaverde Group from the NBU 253 well in the study area was described. The core is housed at the Utah Geological Survey Core Research Center in Salt Lake City, Utah. Lithology and bedding features were described, and each fracture in the core was described, measured, and photographed.

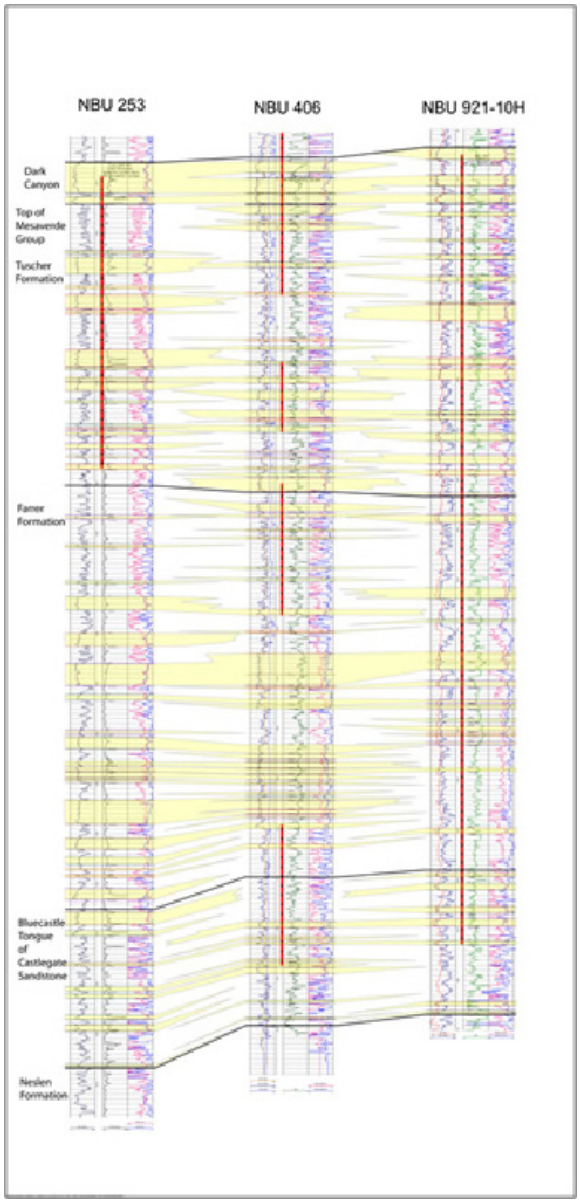


Figure 1: Detailed cross-section in Section 10 of the Greater Natural Buttes field.

The geologic team constructed an initial static fracture model. A wider array of data in the field was used to refine this geologic description of fractures. The geomechanical program 3-DEC from Itasca was used to study the influence of natural fractures on hydraulic fracturing. A sample simulation showing the pore pressure distribution profile at the end of a hydraulic stimulation treatment (plan view) illustrates the influence of the fracture network (Figure 2). In the first quadrant where natural fractures are closely spaced, injection fluid tends to follow the paths of least resistance, and no longer results in a simple elliptical pressure diffusion front as assumed by analytical models.

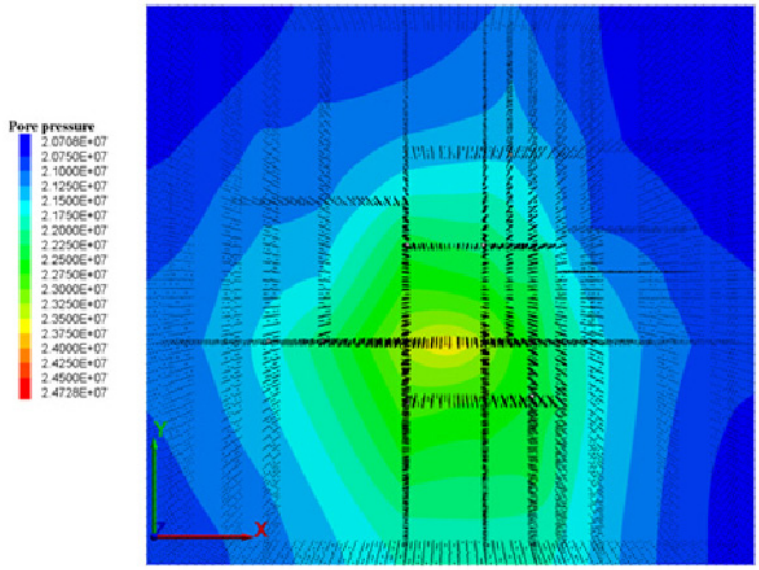


Figure 2: Results of 3-DEC modeling showing a plan view of the pore pressure distribution profile at the end of a hydraulic stimulation treatment.

The static fracture models created by the geologic team were used to study the propagation of hydraulic fractures in the domain populated by natural fractures. The team also added geomechanical simulation capability to the current reservoir simulation framework. In this task, the project team ran coupled flow simulations for selected study sites, using the University of Utah's simulator. The simulation results were used to evaluate gas production potential of the tight gas formation, using a realistic geometry of natural fractures, hydraulic fractures, and the well bore. Results indicated that the natural fracture characteristics may change due to the creation of the hydraulic fracture. Originally connected fractures may get isolated. Water blockages may also result in systems with unfavorable relative permeability characteristics.

Potential Impacts

Adoption of the methodologies developed during this project could bring increased quantities of Uinta Basin tight gas to market. The Mesaverde Total Petroleum System in this basin has significant potential, with an estimated 5 to 14 TCF of undiscovered gas remaining in the ground. If only a modest, 10% increase in gas recovery resulted from the application of the knowledge developed from this research, it would mean added gas reserves on the order of 1 TCF.

The use of better tools for understanding hydraulic fracture propagation, could lead to more efficient stimulation treatments, not only for the Uinta Basin, but for tight gas reservoirs in other basins as well. The cumulative benefit would be determined by the total number of fields where the technology is ultimately applied. The national economic benefit from any incremental increase in domestic gas production would be an increase in tax revenue, royalties and regional economic benefits, as well as a reduction in consumer energy prices that would accompany growth in supply.

For additional information about this project, contact Charlotte Schroeder at RPSEA (cschroeder@rpsea.org or 281-313-9555) or Milind D. Deo at the University of Utah (milind.deo@utah.edu or 801-581-7629).

DOE Research Seeks to Improve Fracturing Performance in Gas Shales

A project being undertaken by the University of Texas at Austin, with co-researchers Daneshy Consultants International and BJ Services, aims to develop non-damaging, productivity enhancing, low environmental impact fracturing techniques for gas shale reservoirs and demonstrate their performance through field tests. The project, which will be completed in April of 2012, is funded by NETL through the Research Partnership to Secure Energy for America (RPSEA).

Background

The efficiency of hydraulic fracturing as a means for enabling the economic viability of wells completed in the Barnett Shale and also in other, more recently developed, unconventional shale gas reservoirs needs to be improved. Permeability reduction caused by the fracturing fluid and limited fracture length appear to limit productivity in new plays. Non-damaging fracturing fluids and ultra-light-weight proppants that minimize the volume of water that must be utilized and disposed of are needed. Ultra-light-weight proppants and foam fluids could be combined to meet this need.

This project is being carried out in two phases: fluid development and field demonstration. The first phase includes three elements: (1) determination of physical/mechanical properties of ultra-low density proppants developed by BJ Services at different closure stress and temperature environments; (2) development of new conventional and foam fracturing fluids with low liquid content, environmental sensitivity and reduced use of polymers; and (3) development of an engineering methodology utilizing these new systems for fracture treatments in Barnett Shale gas wells. The second phase is a field demonstration of these new fracture treatment systems and post-fracture treatment evaluation.

Benefits Could Be Large

The impact of this project could be a significant improvement in the productivity of the typical Barnett Shale gas well. This would result in accelerated gas production and increased reserves per well across the remaining undeveloped areas of the Barnett play. To the degree that the methodology could be applied to other shale gas plays, it would result in accelerated production and increased reserves in those plays as well. It might also have applicability to tight gas sands. In addition, there may be an economic enhancement and an environmental benefit resulting from a reduction in the volume of water required for fracturing treatments (up to an order of magnitude lower than conventional slick water treatments).

Determining proppant properties. The research team at the University of Texas has determined the physical properties of three ultra low density proppants developed by BJ Services and their chemical compatibility with existing fracturing fluids. These properties include sphericity, size distribution, and density. The three samples were a polymeric material (ULW-1), a resin impregnated walnut hull material (ULW-2), and a resin coated ceramic material (ULW-3). A comparison of the relative size, density and sphericity of these three proppants are shown in Figure 1. In the case of the Riley's Sphericity measurement, a value of 1 indicates complete sphericity and a value < 0.6 indicates extreme angularity.

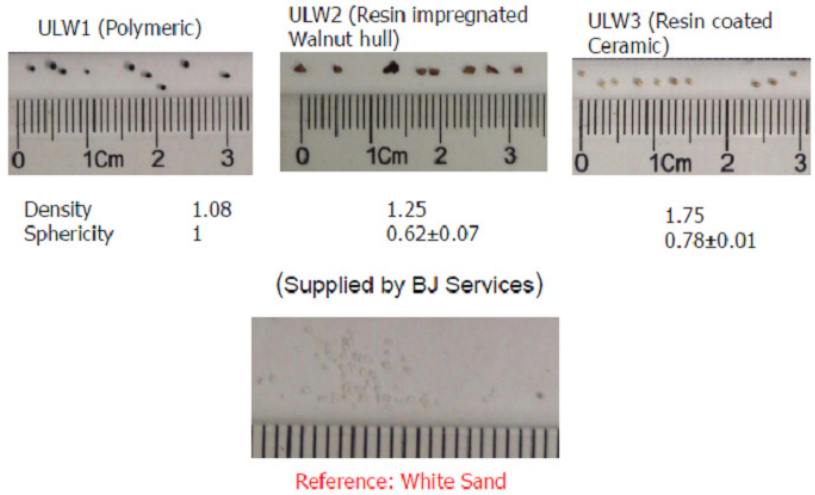


Figure 1: Comparison of ultra-lightweight proppants

To assess the proppants' mechanical behavior, researchers performed a strength test in a Humboldt material testing machine. The proppant particle/pack is placed between the extended portions of the base and the cap, where it is tested for its strength (Figure 2).

The tests were performed on several samples of the three types of proppants at room temperature and also at an elevated temperature encountered in Barnett Shale. Other mechanical properties determined included crush strength and deformability. Tests were repeated at various temperatures and closure stress regimes, and the chemical properties were determined. The purpose of these tests was to ensure that there are no undesirable reactions among the fracturing fluids, additives and proppants. It was determined that all of the ULW proppant packs can endure stresses similar to those expected in the Barnett Shale (~4000 psi), and that ULW1 (polymeric) and ULW2 (resin impregnated hulls) produce only a very small amount of fines.

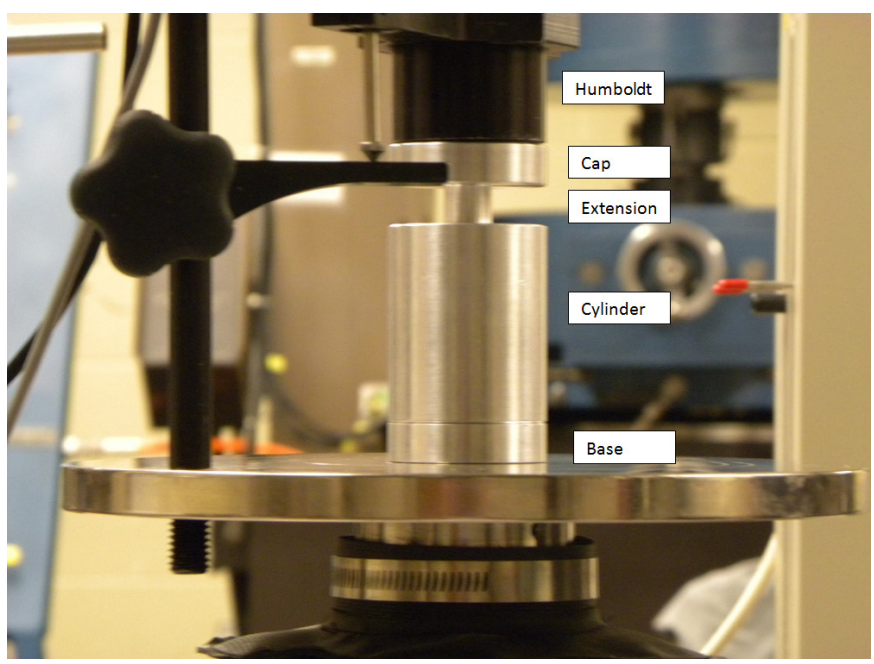


Figure 2: Image of the strength test tool placed on the Humboldt Master Loader-3000

Determining flow capacity. This task consisted of determining the flow capacity of each proppant (with slick water and foams) under several different combinations of temperature, closure stress, and proppant concentration, using anAPI conductivity cell. It was determined that fracture conductivity is about 10 md-ft at 4000 psi overburden stress, large enough for shale stimulation. Conductivity decreases to about 1 md-ft at 6000 psi (Figure 3). Also, the fracture conductivity of the sub-monolayer is comparable to that of the multilayer.

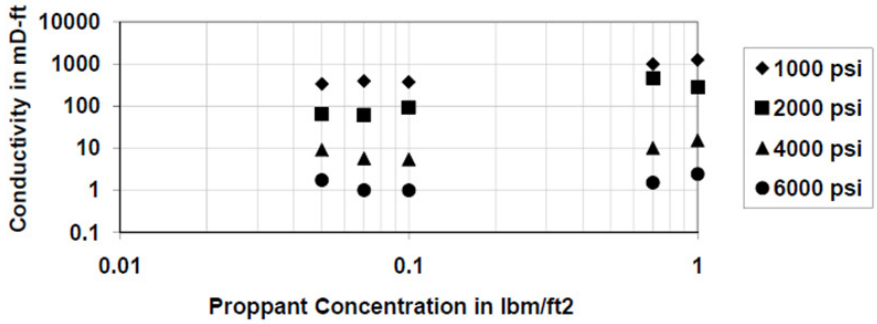


Figure 3: API conductivity as a function of proppant concentration for ULW-1 (polymeric) proppant

Formulating foam fluids. Foam fracturing fluids were formulated with an emphasis on low liquid content, environmental sensitivity, and reduced use of polymers. The task involved the determination of rheological properties of various quality foams, selection of a suitable polymer content to yield a foam with suitable rheological properties, and determination of the foam bubble size and its relationship to viscosity and rheological properties at different shear rates and foam qualities. The research team determined that foams can be formulated that are stable during the fracturing process, the proppant settling velocity increases with proppant density in water (settling is negligible in foams in static tests), and foam viscosity increases with quality and pressure and decreases with the shear rate (Figure 4).

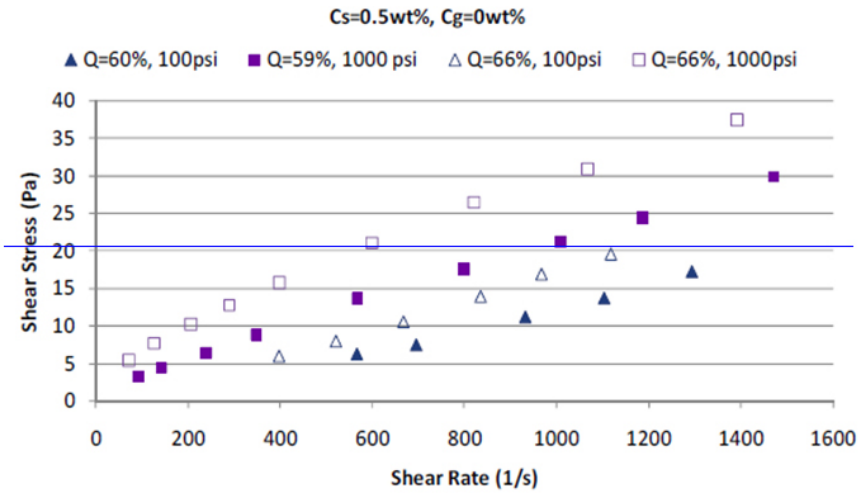


Figure 4. Relationship between shear rate and shear stress for foams of various qualities at 100 and 1000 psi

Collecting fracturing data. Engineering data related to combined fluid-proppant systems is currently being collected, including fluid leak-off coefficients (at various foam qualities and temperatures) and friction pressure for flow in both the tubing and fracture. The collection of some of this data has required the development of special testing equipment and algorithms, since foam quality is a dynamic property.

Designing fracture treatments. New fracture treatment designs are being developed for Barnett Shale gas wells. Effective field use of the new materials requires a step-by-step procedure, including guidelines for fluid selection and formulation to match formation properties, selection of proper pad volume, selection of proppant concentration and volumes of slurry containing the proppant, and a basic pumping schedule. Barnett Shale formation characterization data has been obtained from a field operator research partner. Also included in the designs will be computations of expected surface pressures. Since the main purpose of the fracturing treatment is to create a long propped fracture, the designs will include estimates of the created fracture geometry, as well as an estimation of the production increase that will result from the treatment.

Performing field tests. In Phase II of the project, several treatments will be designed and executed in Barnett Shale gas reservoirs and the results will be compared with existing treatment methods. Two to five treatments (depending on cost) will be designed for a single field where there are comparable wells already stimulated in a traditional way available for comparison. This phase will require close collaboration among The University of Texas, BJ Services, and the field operator. It is anticipated that the engineering work will be done at University of Texas, equipment selection and mobilization will be carried out by BJ Services, and the operator will supervise the actual field execution.

Evaluating fracture treatments. The fracture treatments performed during the field tests will be evaluated from several different perspectives: simplicity and ease of fracturing fluid preparation and mixing, ease of proppant handling and pumping, ease of CO_2 use, reduction of fracturing fluid volume, treatment clean-up, and productivity improvement. Production data will be analyzed before and after the stimulation to establish the effectiveness of the new technology.

For additional information about this project contact Charlotte Schroeder at RPSEA (cschroeder@rpsea.org or 281-313-9555) of Dr. Kishore K. Mohanty at the University of Texas (kishore.mohanty@engr.utexas.edu or 512-471-3077).

Sustaining Hydraulic Fracture Area and Conductivity in Gas Shale Reservoirs

TerraTek and Texas A&M University, with funding from NETL through the Research Partnership to Secure Energy for America (RPSEA) are working with industry participants EnCana Oil & Gas, Shell E&P, and Pennsylvania General Energy, to develop and present solutions leading to increased production and recoverable gas reserves by targeting two main factors leading to marginal production: loss of productive fracture surface area and loss in fracture conductivity. This study is being conducted on three main shale plays, the Barnett, Haynesville, and Marcellus.

Project Overview

Over the past decade, natural gas production from unconventional reservoirs and particularly from tight shale reservoirs has become increasingly important. One industrial analyst estimates shale gas could account for as much as half the natural gas production in North America by 2020. More recently interest has spread to developing gas shale plays in Canada, and potential plays in Europe, Asia, South America, and Australia.

Shale reservoirs can be highly heterogeneous with rock matrix permeability in the nano-Darcy range. Horizontal wells with multiple hydraulic fractures create fracture networks with massive contact surface areas that are required to achieve satisfactory economic production. A crucial challenge for the industry today is that play economic viability depends on total field production and only a fraction (~30%) of shale gas wells show sustained long term production. Others are often characterized by marginal production rates and steep decline curves. Improving single well productivity continues to be the main challenge facing operators.

This project combined modeling, laboratory experiments and field testing to develop a set of metrics for quantifying the loss of fracture surface area and conductivity and for designing fracture treatments to minimize these impacts.

The reduction in area in fracture networks is being evaluated numerically using an Eclipse reservoir simulator coupled with geomechanical features for representing a variety of branching and interconnected fracture geometries under the variety of stress shadowing levels that result from the generation of fractures within a stiff matrix. These simulations model the presence of natural fractures, induced fractures, and variations in reservoir texture and rock fabric.

Many factors can affect fracture conductivity, including: fracture face roughness, shear displacement, proppant embedment, proppant crushing, proppant settling, proppant concentration, proppant type, water trapping, and stress regimes. In this project, the mechanisms responsible for reduction in fracture conductivity are being evaluated by laboratory tests designed to address the influence of shear displacements, rock deformation behavior, stress ramping (Figure 1), fluid-rock interaction and, proppant size and distribution under one and two phase flow.

Scope of Work and Project Objectives

The first step in the project was to evaluate the fundamental properties of fresh core samples from typical tight gas shale plays. The material property characterization was performed on representative samples of reservoir shales from the Barnett, Hyanesville, Marcellus and other plays, resulting in tabulated results of characteristic petrophysical, petrological,

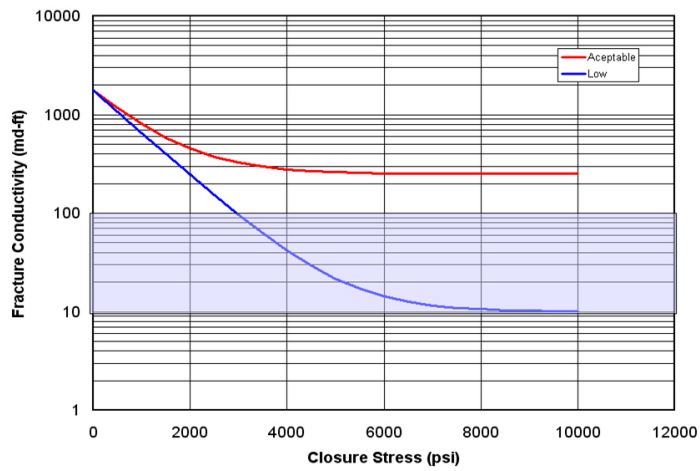


Figure 1: The effect of closure stress on fracture conductivity.

geochemical and mechanical properties for each of the reservoir rock types tested. Upon the completion of this task, work began on the fracture area and conductivity problems. Work has also begun on rock mechanical characterization and degradation of fracture area and fracture conductivity. Preliminary results support the expectation that rock rheological characteristics play an important role in fracture closure and conductivity loss (Figure 2).

The first objective of the investigating team was to evaluate the loss of connectivity between fracture branches, in fracture networks and at junctions, as a function of fracture stiffness, stress contrast, and orientation of the principal stresses with the fracture structures. To accomplish this the team conducted numerical modeling of fracture network geometries, and a parametric study of their propensity for isolating branches and developing local restrictions. The result was a set of metrics evaluating the fractures and the potential for the loss of effective fracture surface area for

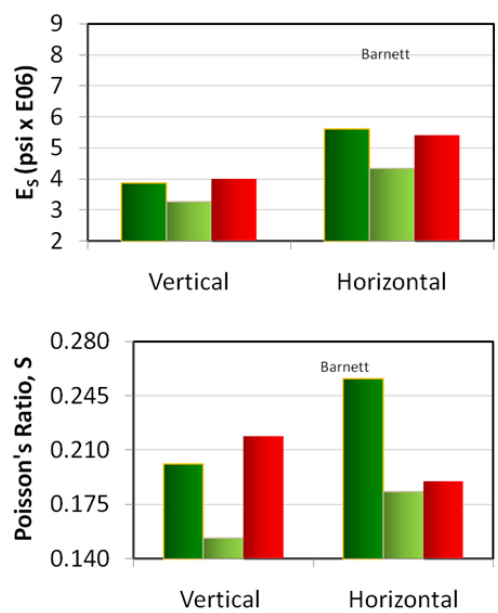


Figure 2: Mechanical anisotropy in Barnett Shale derived from material characterization of the reservoir's shale.

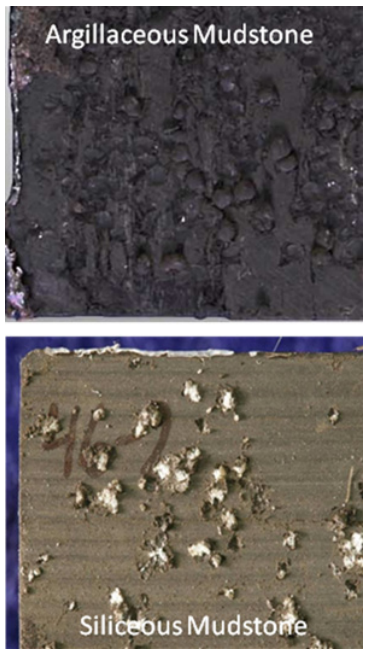


Figure 3: Characteristic mudstone types for the Barnett, Haynesville and Marcellus formations.

characteristic reservoir mudstone types (Barnett, Haynesville, Marcellus, and others) and for different fracture networks and depletion scenarios (Figure 3).

A second objective was the evaluation, theoretically and experimentally, of the conductivity of un-propped fractures of representative shale lithotypes subjected to appropriate in-situ stress histories. Parametric variables were mudstone type (e.g., clay-rich, silica-rich, calcareous) and fracture face characteristics (e.g., tortuosity, roughness and hardness). Other controlling parameters were shear displacement, potential for in-situ dilatancy, and stress history from shut-in through abandonment. Using these parameters, a methodology to estimate the loss of fracture conductivity for un-propped fractures was developed.

A third critical objective was the quantification of critical proppant concentration for satisfying minimal requirements of fracture conductivity for gas and water flow and to measure water production from fully saturated fractures during gas flow. Laboratory evaluations were conducted to evaluate fracture conductivity for gas and water, using the same representative material used for the assessment of conductivity of un-propped fractures, under various conditions of proppant size, grade, distribution and concentration, including temperature effects. Gas production tests were then undertaken on saturated samples. Subsequently, a methodology to define the minimal required proppant concentration for satisfying critical fracture conductivity necessary for the flow of gas and water was developed. Production tests followed to show water mobility (or retention) due to capillary forces induced by rock-water and rock-fluid interactions

Results from the three areas of investigation described above were then consolidated to evaluate the combined effects of fracture complexity for un-propped and partially propped branches due to inefficient proppant transport. The result was a set of metrics indicating the tendency for loss in fracture area and conductivity for characteristic reservoir mudstone types from the Barnett, Haynesville and Marcellus Shales.

Field testing and final products

The protocols that are developed following the characterization of fracture area and conductivity loss in laboratory as well as other planned experimental analyses, will be implemented in the field to assess their effectiveness by comparing the new methods with offset well results. The field tests are intended to provide guidelines and hydraulic fracture designs to enhance well performance. Following the field tests, a roadmap for reservoir characterization and production and recovery optimization will be created that includes preferred practices for reservoir characterization and fracture design in areas such as proppant pumping schedules, treating fluids and additives.

For more information about this project, contact Dr. Ahmad Ghassemi at Texas A&M University (ahmad.ghassemi@pe.tamu.edu or 979-845-2206) or Charlotte Schroeder at RPSEA (cschroeder@rpsea.org or 281-313-9555).

Cleaning Frac Flowback Water for Re-use Yields Multiple Benefits

The contribution to the U.S. energy supply from unconventional natural gas sources such as shale is increasing dramatically due, in large part, to advanced hydraulic fracturing. To release natural gas from a shale deposit, 3 to 5 million gallons of water plus hydraulic fracturing additives and proppants (sand) are pumped under high pressure down a shale gas well. Often, this water is trucked in from remote locations. About 20-80% of this water returns to the surface as "frac flowback water". Much of the flowback and produced water (collectively termed "frac water") has a high total dissolved solids (TDS) level (>50,000 ppm). Although frac water is increasingly being reused in subsequent hydrofracturing jobs, much frac water is still disposed of by deep-well injection. A significant problem in the Marcellus Shale play is that the number and capacity of nearby injection sites is severely limited. For example, since Pennsylvania has only seven class II injection wells, frac water is trucked into Ohio for disposal. In other plays, such as the Barnett, water availability for frac operations is limited. In addition, recent studies have shown that within a typical county-sized shale gas development area, the supply of frac water eventually exceeds the demand for source water for subsequent hydrofracturing operations. To avoid both supply and disposal limitations, and to thus enable further shale gas development, an economical process to recover frac water as clean water and salt is required. A research project being undertaken by GE Global Research (GEGR), with funding from NETL, is examining ways to pretreat frac water for thermal recovery of clean water and a salable salt product.

Cleaning Options

Frac water recovery by thermal evaporation is commercially practiced in a growing number of shale gas applications. To avoid scaling on heat transfer surfaces and to enable reliable evaporator operation, incoming frac water must be pretreated to remove scale-causing ions such as iron and manganese as well as suspended solids and dissolved organics. Current pretreatment methods typically utilize flocculation, mechanical separation (e.g. inclined plate clarifier), and filtration (e.g. filter press). Current evaporation processes yield a distilled water product and a brine concentrate, which is typically disposed of by deep-well injection.

This project is focused on identifying economical pretreatment techniques to recover additional water and a salable salt (NaCl) product from high-TDS frac waters. The objective is to pretreat frac water to remove hardness, including barium and radium. Barium removal will enable the salt product to meet Toxicity Characteristic Leaching Procedure (TCLP) specifications. Radium is a key Naturally Occurring Radioactive Material (NORM). Radium removal will enable the salt product to be safely used, for example, as a road deicer, and will minimize worker radiation exposure.

Three pretreatment approaches for frac water softening were considered: chemical treatment, adsorption/ion exchange, and nanofiltration. Chemical treatment in the form of lime softening and optional sulfate precipitation for barium removal is practiced for softening chlor-alkali brine. Calcium hydroxide (lime) and/or caustic soda are added to precipitate scale-forming species. Lime softening may be conducted in a clarifier and generates a precipitate (lime sludge), which is filter pressed and may be either land filled or calcined to recover the lime.

Evaluation of the relative merits of the proposed pretreatment technologies for water and salt recovery first required a clear definition of the range of frac water feed composition to be treated. This project focused on the Marcellus Shale, but included frac water sample characterization from the Marcellus, Barnett, and Woodford Shales. In addition, target purity specifications were established for pretreated frac water to ensure economic operation of the thermal equipment.

Process material and energy balances were conducted for each process option in order to generate preliminary cost estimates. Each process option was evaluated with respect to performance and cost. In addition, consideration was given to the adaptability of each process to mobile operation.

Progress Towards Cleaner Water

Work on this project began in August 2009. In the project to date, GEGR has:

- Characterized frac water samples from seven Marcellus Shale wells (Pennsylvania), two Woodford Shale wells (Oklahoma), and three frac water disposal facilities in the Barnett Shale. Measured chemical composition including NORMS;
- Identified frac water composition and flow rate design ranges for fixed and mobile treatment systems;
- Ruled out ion exchange as a softening technique to remove high hardness levels (e.g. >5,000 ppm) based on cost and calculated volumes of regeneration chemicals and rinse water;
- Ruled out nanofiltration as a softening technique to remove high hardness levels based on the high volume of waste concentrate produced;
- Developed an Aspen™/OLI™ model for chemical treatment of frac water for hardness removal;
- Calculated material balances and costs for lime and sulfate precipitation frac water pretreatment (softening) processes;
- Summarized NORM composition data from 13 New York Marcellus gas wells (from NYSDEC SDGEIS report);
- Demonstrated importance of removing NORM from frac water for applications involving recovery of a salt product;
- Calculated material balance for sulfate precipitation pretreatment of frac water. Defined level of frac water 226Ra concentration for a given frac water barium concentration that would result in $BaSO_4$-$RaSO_4$ precipitate that is acceptable for RCRA-D landfill disposal. Presented paper on this topic at 2010 International Water Conference;
- Developed scintillation counting method and a gamma spectrometry method to measure NORM in both raw frac water and frac water that had been pretreated for NORM removal;
- Conducted lab experiments to demonstrate adsorption/ion exchange and chemical treatment processes for NORM removal from frac water;
- Identified technologically enhanced NORM (TENORM) disposal options and costs;

SUGGESTED READING

Hayes, Thomas, Techno-economic Assessment of Water Management Solutions, Marcellus Shale Gas Water Management Initiative, Canonsburg, PA, April 13-14, 2011.

Silva, J.M., Matis, H., and Tinto, J.V., NORM Removal from Frac Water in a Central Treatment Facility, International Water Conference, 2010, San Antonio, IWC-10-65.

- Assembled lab apparatus to simulate thermal brine concentrator and crystallizer (for thermal water and NaCl recovery);
- Conducted preliminary tests to characterize scaling during thermal frac water concentration.

This project initially targeted frac water softening as a pretreatment technique to enable higher water recovery and recovery of a salable salt product by thermal evaporation and crystallization. Preliminary investigation showed that NORM is rather prevalent in frac water, particularly in the Marcellus, and that NORM removal from frac water is an important step in recovering a salable salt product from NORM-containing frac water. GEGR has demonstrated on the lab scale both adsorption/ion exchange and chemical treatment as effective methods for NORM removal from frac water. GEGR conducted experimental and computational studies of the effectiveness and economics of each technique for a range of frac water composition.

Potential Impacts

While direct frac water reuse (as source water in subsequent hydrofracturing operations after minimal pretreatment) is an effective method for frac water disposal, frac water recovery to generate clean water and a salable salt product is essential to long-term shale gas development. Effective recovery and reuse of frac water will benefit the environment by greatly reducing the net consumption of fresh water. In addition, truck traffic, noise, and dust pollution will be significantly reduced. Finally, by not re-injecting frac water into disposal wells, the risk associated with long-term contamination of the water supply will be avoided.

For more information about this project, contact James Silva at GE Global Research (silva@ge.com or 518-387-6472) or Charlotte Schroeder at RPSEA (cschroeder@rpsea.org or 281-313-9555).

Solution for Cleaning Produced Water Models "Mother Nature"

A water treatment system that can turn wastewater into clean water has been shown to reduce potential environmental impacts associated with producing natural gas from shale formations in the Appalachian basin. Altela Inc.'s AltelaRain® 4000 water desalination system was tested at BLX, Inc.'s Sleppy well site in Indiana County, Pa. as part of a NETL-sponsored demonstration. During nine continuous months of operation, the unit successfully treated 77% of the water stream onsite, providing distilled water as the product. The average treated water cost per barrel over the demonstration period was approximately 20% lower compared to the previous total conventional disposal costs at the site. The system also significantly reduced the need for trucking wastewater from the site.

The Produced Water Problem

Produced water, water that comes to the surface during oil and gas production, is one part of a produced fluid mixture that also includes either liquid or gaseous hydrocarbons, dissolved or suspended solids, and produced solids such as sand or silt. Recently injected fluids and additives that may have been placed in the formation as a result of well completion (e.g., hydraulic fracturing fluids) or enhanced recovery operations can also be part of the produced fluid mixture.

Produced water handling and treatment represents an $18 billion annual cost to the oil and gas industry in the U.S.. The cost of disposing of produced water ranges from a low of $0.002 per gallon ($0.08/barrel) to a high of $0.30 a gallon ($12.00/barrel). By contrast, the cost of water acquired for agricultural irrigation can be as low as $0.0001 per gallon ($0.004/barrel) and municipal drinking water costs in the range of $0.001 per gallon ($0.04/barrel). The price of cleaning produced water is therefore as much as 300 times greater than the cost of acquiring water for municipal use, and as much as 3,000 times greater than that for agricultural irrigation water.

The separation, handling, and disposal of produced water represent the single largest waste stream challenge facing the oil and gas production industry. The cost of produced water handling and disposal includes lifting large volumes of water to the surface, separating it from the petroleum product, treating it, and then injecting it into the ground or disposing of it in surface evaporation ponds.

Historically, produced water generated at an oil or gas site is stored on-site in large tanks. Oil and gas companies must pay for disposal trucking companies to visit the site multiple times per week, pump the produced water out of the storage tanks and transport the waste to commercial underground reinjection sites. These disposal trucks must often travel great distances to the reinjection sites. When these trucks are unavailable or during periods of poor weather, many well sites in fields producing large volumes of water relative to the volumes of oil or gas must be shut down due to the inability to store and/or dispose of the produced water onsite.

In addition, many oil and gas operators are simply "pinching back" production due to the inability of onsite infrastructure to handle produced water volumes. Trucking costs alone can be in excess of $3 per barrel (bbl) and a disposal reinjection well can cost upwards of $4 million to drill. In many locations, total produced water disposal costs are greater than $5/bbl.

The Natural Cycle

Every water desalination system in the world relies on pressure to help drive the process – except Mother Nature. Reverse osmosis uses high pressure to force salt water through membranes. Other processes, like conventional thermal distillation, also use pressure differentials to desalinate water. But nature desalinates seawater at ambient pressure naturally, using solar energy to evaporate clean distilled water from undrinkable saltwater in the ocean. Without using any electricity or filters, nature desalinates brackish ocean water continuously. In the first step of the two-step hydrologic cycle, clean water is separated from its salts using just air as the separation medium and low-grade evaporative heat from the sun. In the second step of the hydrologic cycle, nature condenses clean water vapor from clouds into rain when the air rises and the temperature becomes too cold for the air mass to hold the water in vapor form any longer. The resulting rain is distilled water.

AltelaRain® mimics nature's hydrologic cycle exactly, but brings the two-step process closer together physically. It does this by taking advantage of the fact that the second condensation step gives off the same amount of low-grade heat energy as is required in the first evaporation step. The process reuses this energy over and over again, making 3 gallons of clean water from the heat energy that would usually only make 1 gallon. Thus, the system achieves 300% energy re-use (Figure 1).

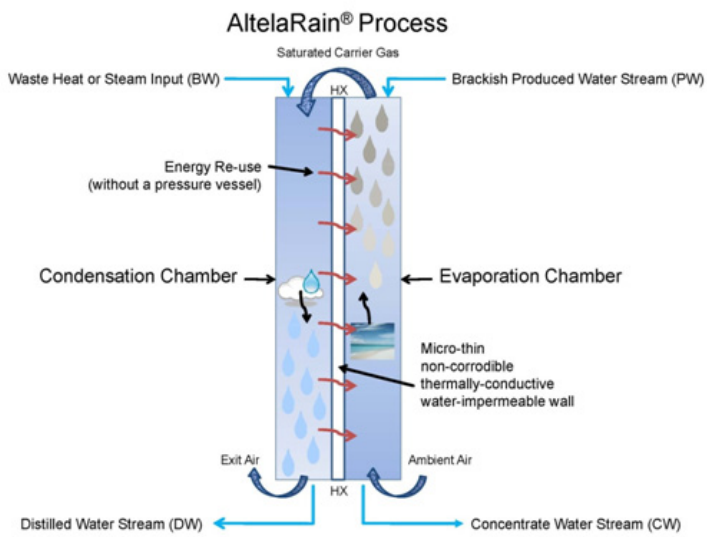


Figure 1: Altela's evaporation/distillation process mimic's nature but its reuse of heat goes one step further. Schematic courtesy of Altela, Inc.

Successful Field Demonstration

Based on field data generated from the NETL demonstration at the Sleppy well, Altela increased the efficiency of its technology by more than 30%. All of the clean water produced at the demonstration site was suitable for beneficial re-use by well operators for additional stimulations and was also suitable to be discharged to surface waterways, thus reducing the economic and environmental impacts of clean water usage.

As a result of the DOE demonstration project, the company designed larger towers for the system and four AltelaRain® 600 modules were sold

and installed in Williamsport, Pa. to treat approximately 100,000 gallons per day of produced and flowback water from hydraulic fracturing (Figure 2). This commercial installation is a 50-fold increase in capacity over the demonstration unit and represents the first of many planned facilities to be developed in the Marcellus Shale Basin and similar shale gas basins throughout the United States.

Figure 2: Developed as a result of lessons learned from the NETL funded field demonstration project, the Altela 600 module treats approximately 25,000 gallons per day, the equivalent of 600 barrels per day. Customized solutions are available in 50 barrel per day increments. Photo courtesy of Altela, Inc.

The Altela demonstration was one of nine research projects funded by NETL through the Office of Fossil Energy's Oil & Natural Gas Program in fiscal year 2009. The nine projects, which had a total value of $10.2 million ($7 million DOE; $3.2 million cost share), are developing environmental tools and technologies to improve management of water resources, water usage, and water treatment required for shale gas development across the United States. Several additional demonstrations focusing on other water treatment technologies will be conducted during the remainder of fiscal year 2011.

For more information on the Altela technology, contact Tom Carroll at Carroll Strategies (505-842-6600 or tc@carrollstrategies.net).

Website Promotes Transparency in Fracturing Fluid Chemical Content

A cooperative project among the Ground Water Protection Council (GWPC), the Interstate Oil and Gas Compact Commission (representing the oil and gas producing states) and the U.S. Department of Energy (DOE) has created a public access web repository called FracFocus that will enable operators to voluntarily list the various chemical constituents used in fracturing fluids on their well sites, providing factual information in layman's terms easily understood by the general public. The goal is a transparent interface between the oil and gas industry and the interested public that builds mutual trust and understanding.

In concert with this program, a similar group composed of GWPC and a national organization of state groundwater regulatory agencies has developed a Risk Based Data Management System (RBDMS), with funding from the Office of Fossil Energy's Oil and Natural Gas Program, part of the DOE. The project is overseen by NETL. Designed to enhance the exchange of information between oil and natural gas operators and state regulators, the system provides real-time online access to data and enables industry to reduce exploration and compliance costs and improve environmental performance. Both of these efforts are focused on facilitating the transfer of information among stakeholders with an interest in environmentally safe development of domestic hydrocarbon resources.

FracFocus

The primary purpose of this site is to provide factual information concerning hydraulic fracturing as it relates to groundwater. Its purpose is not to argue either for or against the use of hydraulic fracturing in natural gas production. It is also not intended to provide a scientific analysis of any groundwater contamination risks, real or perceived, associated with hydraulic fracturing. Nor does the site deal with constituents unrelated to the use of chemical additives in hydraulic fracturing (e.g., naturally occurring radioactive material or other constituents sometimes found in fracture flowback water). By design, this is a non-governmental site designed to supplement, not replace, state regulatory websites.

The website (http://fracfocus.org) went live on April 11, 2011. In just two months of operation, data related to more than 1,000 wells have been voluntarily uploaded into the FracFocus disclosure registry by 42 participating companies. The site has had more than 30,000 visits by people in 89 countries.

The FracFocus website and data repository has two parts: the Public Education Area and the Operator Uploading Area. The Public Education Area content includes educational materials that explain the hydraulic fracturing process. Users can also search the site database for individual, hydraulically fractured wells by state, county, API number, lease number or well number. Additional data fields provide the type of well (oil or gas) and the well's latitude and longitude location identifiers, and other information (Table 1a). Also listed are the chemicals added to the hydraulic fracturing fluids utilized in the well, along with an explanation of their purpose and toxicity (Table 1b). The Public Education Area is designed for ease of use, ease of understanding, and clarity and accuracy of content.

Fracture date:	The date on which the hydraulic fracturing associated with the record occurred.
State:	The name of the state in which the surface location of the well is found.
County:	The name of the county in which the surface location of the well is found.
API Number:	This number is assigned under a system developed by the American Petroleum Institute. API numbers are formatted as nn-nnn-nnnnn-nn-nn, with the first two numbers designating the state, the second three numbers designating the county within the state, and the next five numbers designating the particular well within the county. When present, the next two numbers are a directional sidetrack code to designate the number of horizontal or directional sidetracks from a single, vertical wellbore and the final two numbers are an event sequence code used to designate multiple activities conducted at a single well (e.g., recompletion or treatment).
Operator Name:	The name of the operating oil or gas company.
Well Name:	This is typically the name of the property owner upon whose land the well is located. In the case of multiple owners pooled under a single unit, the name of the majority property owner is often used. The number on the well may designate the chronological sequence of the wells drilled. However, this is not a universal naming convention.
Longitude:	The east-west location of the well in degrees, minutes and seconds.
Latitude:	The north-south location of the well in degrees, minutes and seconds.
Latitude/Longitude Projection:	The particular projection method for the longitude and latitude (e.g., North American Datum [NAD] 27 or 38).
Production Type:	This designates the well as an oil or gas well.
True Vertical Depth:	The absolute depth of the well measured vertically from surface to the deepest point of penetration.
Total Water Volume:	The total amount of water used as the carrier fluid for the hydraulic fracturing job. It may include recycled or newly acquired water.

Table 1a: FracFocus Data

In addition to the general information above, each record contains information about the specific chemicals used in the fracturing process for each well.

Trade Name:	The name of the product designated by the supplier.
Supplier:	The name of the service company that supplied the chemical.
Purpose:	The function served by the additive (trade name) in the fracturing process (e.g. surfactant, biocide, etc.)
Ingredients:	The scientific name of the chemical (e.g. Ethanol, Naphthalene, etc.)
Chemical Abstract Service (www.cas.org/expertise/cascontent/registry/regsys.html) or CAS number:	A number assigned by a division of the American Chemical Society for the purpose of indentifying a specific substance. You can learn more about the toxicity characteristics of chemicals by searching for the chemical using the name or CAS number on the USEPA National Center for Computational Toxicology (www.actor.epa.gov/actor/faces/ACToRHome.jsp) website. USEPA also maintains a Drinking Water Hotline that is available Monday – Friday from 8:30 AM – 4:30 PM (Eastern Time) at 1-800-426-4791.
Ingredient Percentage in Additive expressed as % by mass:	This describes the amount of ingredient within the additive (trade name) as a percentage of the total mass of the additive. Because the % mass of the additive may be expressed in its maximum concentration, the total % mass of ingredient percentage may exceed 100%
Ingredient Concentration in hydraulic fracturing fluid expressed as % by mass:	This describes the amount of ingredient as a percentage of the total mass of the fracturing fluid, including carrier fluids and additives. The total may not equal 100% due to the retraction of proprietary components in accordance with the Trade Secrets provisions of the Occupational Safety and Health Administration Act.

Table 1b: FracFocus Data

The Operator Uploading Area of the FracFocus website allows operators to easily upload data on hydraulically fractured wells and the parameters of the fracturing chemicals used on the wells. Operators are allowed to create accounts that may be accessed by representatives, supervisors or submitters. The representative home page allows the representative to add and manage supervisors, add and manage data submitters, and edit the account. The supervisor home page allows a supervisor to add and manage submitters. The submitter home page allows each submitter to download the Excel submission template and submit disclosure records. Detailed instructions on use of the Microsoft Excel template are provided through an on-line Users Guide.

Risk Based Data Management System (RBDMS)

A second cooperative project between GWPC, a national organization of state groundwater regulatory agencies and the U.S. Department of Energy, is the Risk Based Data Management System (RBDMS) located at http://rbdmsonline.org/GWPC. Like FracFocus, RBDMS includes a web based data repository. It was originally designed to help agencies manage oil and gas injection well data and evaluate the risk injection wells pose

to underground sources of drinking water (USDW). It is now also used to monitor the environmental effects of oil and gas exploration and production activities as well as coal, industrial and aggregate minerals mining operations. RBDMS facilitates the integration of oil and gas resource data and state source-water protection planning, a requirement of the Safe Drinking Water Act Revisions.

Among the suite of tools and data sets within RBDMS is a soon-to-be-launched hydraulic fracturing (HF) module. The module, set for release in the fourth quarter of 2011, was developed over the course of 2010 by water agencies in seven states. The module connects the RBDMS oil and gas module and the RBDMS for water data structures. It is now being developed for Pennsylvania and Colorado to track water quality data associated with hydraulic fracturing.

The HF Module contains a number of tables used to track hydraulic fracturing parameters. These include all of the elements listed in Table 2. By integrating the HF Module data with state agency USDW data, RBDMS users are able to more accurately calculate possible impacts on USDWs from hydraulic fracturing.

Stimulation:	This table tracks data about a well's overall stimulation record, including date, formation name and interval.
Stage:	The second table tracks the pressure measured during the stage of treatment, duration of the stage, and the means of isolating the fracturing operation.
Water:	This table tracks the multiple possible sources of makeup water, including groundwater, well water, surface pond water, acid mine water, etc.
FracFluid:	The use of multiple fracturing fluids with respect to physical makeup is tracked here.
FracFluid Product:	Since each fracturing fluid batch can contain multiple products, this table links the FracFluid and Product Tables.
Product:	This table tracks trade name products for usage requirements, MSDS number for the product, secrecy determination, current registration, and disclosure.
Product Chemical:	Since many chemicals can be in multiple products, this table links the chemicals in the products along with the percent by weight of the chemicals in the products.
Chemical:	This table tracks each constituent chemical with respect to chemical name, CAS number, specific MSDS number for the chemical, and regulatory lists.
Flowback:	The HF fluids collected during the well treatment are tracked with respect to duration of flow, volume and containment methods in the Flowback table. Only one flowback occurrence is allowed.
Disposal:	Volumes disposed of and methods of disposal for fracturing fluids from each stage are tracked in this table.

Table 2: RBDMS HF Module Data Elements

By integrating the HF Module data with state agency USDW data, RBDMS users are able to more accurately calculate possible and probable impact on USDWs by hydraulic fracturing.

For more information on this project, contact Ben Grunewald at the Ground Water Protection Council (405-516-4972 or ben@gwpc.org).

NETL-Sponsored Project Improves Performance, Reduces Emissions for Natural Gas Industry

With funding from NETL, researchers at Kansas State University (KSU) are developing emissions control and monitoring technologies that can be applied to engines used in natural-gas-gathering systems. This alternative to engine replacement would provide the U.S. natural gas industry with a more efficient way to upgrade existing engines while mitigating greenhouse gases.

Thousands of reciprocating engines are now in service in the natural-gas-gathering industry. These engines are used to produce electricity for a leasehold, compress and re-inject natural gas for increased oil production, and compress natural gas so that it can be delivered to local gathering systems that feed into gas transmission pipelines. As the engines age, it is possible that most would need to be replaced in order to meet new federal EPA emissions regulations. Since engine replacement would be exceptionally costly to the industry, KSU is designing and testing retrofit technologies that can be installed on existing engines for a fraction of the cost.

Extensive field tests performed by KSU and their research partners—Innovative Environmental Solutions, El Paso Corporation, Pipeline Research Council International Inc., and Enginuity—have provided valuable insight into controlling emissions from gas-gathering engines. Currently available non-selective catalytic reduction (NSCR) systems were shown to simultaneously control both nitrogen oxides (NOx) and carbon monoxide (CO), but only within a very small operating window, and not on a consistent basis.

KSU is developing models that will be used to improve NSCR performance and to determine enhanced, reliable environmental control strategies. Studying the possible impacts of new EPA National Ambient Air Quality Standards and NOx levels on small-engine emissions, KSU researchers found that current emission compliance measures are based on plume models that were developed for larger emission sources. KSU's four-stroke cycle engine model and exhaust gas oxygen (EGO) sensor model will better predict emissions from small engines. Important developments and findings to date include the following:

- The EGO sensor model includes a simplified methane combustion mechanism and a newly developed kinetic model for CO formation and oxidation.
- Output from the EGO sensor model is comparable to experimental engine data and confirms that sensor output not only depends on the oxygen concentration, but also on the CO and hydrogen levels.
- A "lean shift" has been detected when methane is present in the exhaust emissions, creating a higher output voltage from the sensor;

this is due to the extra reducing species present that compete with the oxygen for the catalytic surface reactions.

- A modified reaction scheme has been used in the EGO model in order to optimize calculation time.
- Results of CO kinetics and emissions from the four-stroke cycle engine model are consistent with previous field tests. The model incorporates engine speed and inlet conditions in addition to trapped equivalence ratio.

The updated KSU models take into account small-engine characteristics and preferred catalytic conditions. Once validated, the models can be used in field engine control boards that can help meet new EPA emission standards by replacing outdated air fuel controllers.

Breakthrough Water Cleaning Technology Could Lessen Environmental Impacts from Shale Production

A novel water cleaning technology currently being tested in field demonstrations could help significantly reduce potential environmental impacts from producing natural gas from the Marcellus Shale and other geologic formations, according to NETL.

ABSMaterial's Osorb® technology, which uses swelling glass to remove impurities, has been shown to clean flow back water and produced water from hydraulically fractured oil and gas wells. Produced waters are by far the largest volume byproduct associated with oil and gas exploration and production.

NETL is addressing the need to clean large volumes of produced water by funding multiple projects to develop environmental tools and technologies, such as Osorb®, that will improve management of water resources, water usage, and water treatment during oil and gas exploration and production.

Two pilot-scale Osorb®-based water treatment systems have been built to date: a non-regenerating skid-mounted system which handles inputs of up to 40 gallons per minute, and a 60-gallon-per-minute trailer-mounted system that included a mechanism for Osorb® regeneration. ABSMaterials has used these systems on numerous water samples including flow back water from the Marcellus, Woodford, and Haynesville Shale formations and produced water from the Clinton and Bakken formations.

In independent testing, the skid-mounted system was found to remove more than 99 % of oil and grease, more than 90 % of dissolved BTEX (benzene, toluene, ethylbenzene, and xylenes), and significant amounts of production chemicals. Concurrent testing was performed using the trailer-mounted 60-gallon-per-minute system on produced water streams. One major oil services company conducted a full pilot test in the field using

produced water from the Clinton formation in Ohio in July 2010 and March 2011. These tests showed that total petroleum hydrocarbon levels were slashed from 227 milligrams per liter to 0.1 milligrams per liter.

The results of this project have led to commercial interest from several global energy companies and future collaborative efforts. ABSMaterials also plans to deploy a trailer-mounted, 72,000-gallons-per-day water purification system for field use in North America in mid 2011.

A number of existing treatment techniques separate dispersed oils from water, taking advantage of the density difference between oil and water. However, very few technologies effectively address dissolved hydrocarbons, slicking agents, and polymers that prevent flow-back water from being recycled or discharged.

Osorb®, a hybrid organic-inorganic nano-engineered structure, is a breakthrough in hydrocarbon removal technology that rapidly swells up to eight times its dried volume upon exposure to non-polar liquids. The swelling process is completely reversible—with no loss in swelling behavior even after repeated use—when absorbed species are evaporated by heating the material.

The ABSMaterials project was funded through the federal government's Small Business Innovation Research Program. It is the second project under Fossil Energy's Oil and Natural Gas Program to show significant success treating produced or flow-back water. Several other projects will be conducting demonstrations focusing on other water treatment technologies during the remainder of fiscal year 2011.

Fire in the Ice

NETL

Iġnik Sikumi #1, Gas Hydrate Test Well, Successfully Installed on the Alaska North Slope

To follow NETL's methane hydrate program, sign up for a free subscription to our Fire in the Ice newsletter at jennifer.presley@ib.netl.doe.gov

Newly Installed Alaska North Slope Well Will Test Innovative Hydrate Production Technologies

A fully instrumented well that will test innovative technologies for producing methane gas from hydrate deposits has been safely installed on the North Slope of Alaska. As a result, the "Iġnik Sikumi" (Iñupiaq for "fire in the ice") gas hydrate field trial well will be available for field experiments as early as winter 2011–2012.

The well, the result of a partnership between ConocoPhillips and NETL, will test a technology that involves injecting carbon dioxide (CO_2) into sandstone reservoirs containing methane hydrate. Laboratory studies indicate that the CO_2 molecules will replace the methane molecules within the solid hydrate lattice, resulting in the simultaneous sequestration of CO_2 in a solid hydrate structure and production of methane gas.

Methane hydrate consists of molecules of natural gas trapped in an open rigid framework of water molecules. It occurs in sediments within and below thick permafrost in Arctic regions, and in the subsurface of most continental waters with a depth of ~1,500 feet or greater. Many experts believe it represents a potentially vast source of global energy and NETL scientists have studied methane hydrate resource potential and production technologies for more than two decades. Researchers are addressing such important issues as seafloor stability, drilling safety, and a range of environmental issues, including gas hydrate's role in changing climates.

The recently completed operations include the acquisition of a research-level suite of measurements through the sub-permafrost hydrate-bearing sediments. The data confirm the occurrence of 160 feet of gas-hydrate-bearing sand reservoirs in four separate zones, as predicted, and provide insight into their physical and mechanical properties. An array of down-hole pressure-temperature gauges were installed in the well, as well as a continuous fiber-optic temperature sensor outside the well casing, which will monitor the well as it returns to natural conditions following the drilling program.

In coming months, field trial participants will review the data to determine the optimal parameters for future field testing. Current plans are to re-enter the well in a future winter drilling season, and conduct a 1-2 month program of CO_2 injection and well production to assess the efficiency of the exchange process. Following those tests, the remaining time available before the spring thaw (as much as 40 days) may be used to test reservoir response to pressure reduction in the wellbore. This alternative methane-production method, "depressurization," recently proved effective during short-term testing conducted by the governments of Japan and Canada at a site in northwestern Canada.

Upcoming Meetings and Presentations

July 27 – 28, RPSEA 2011 Ultra-Deepwater Technical Conference, The Woodlands, Texas, www.rpsea.org/en/cev/369/

August 14 – 19, Digital Rocks: Realizing Step Change in Value of Laboratory Data, Ojai, California, www.spe.org/events/11fus3/

August 17 – 19, SPE Eastern Regional Meeting, Columbus, Ohio, www.spe.org/events/erm/2011/

August 24, IPAA E&P Forum, Houston, Texas, rcarter@ipaa.org

August 24 – 25, Shale Energy Technology Conference, Houston, Texas, events@gulfpub.com

August 24 – 26, Eagle Ford Shale Workshop, Austin, Texas, www.spe.org/events/11asan/

September 21 – 22, SPE Liquids-Rich Basins Conference, Midland, Texas, www.spe.org/events/pbc/2011/

September 28 – 29, HPHT Drilling & Completion Conference, Houston, Texas, events@gulfpub.com