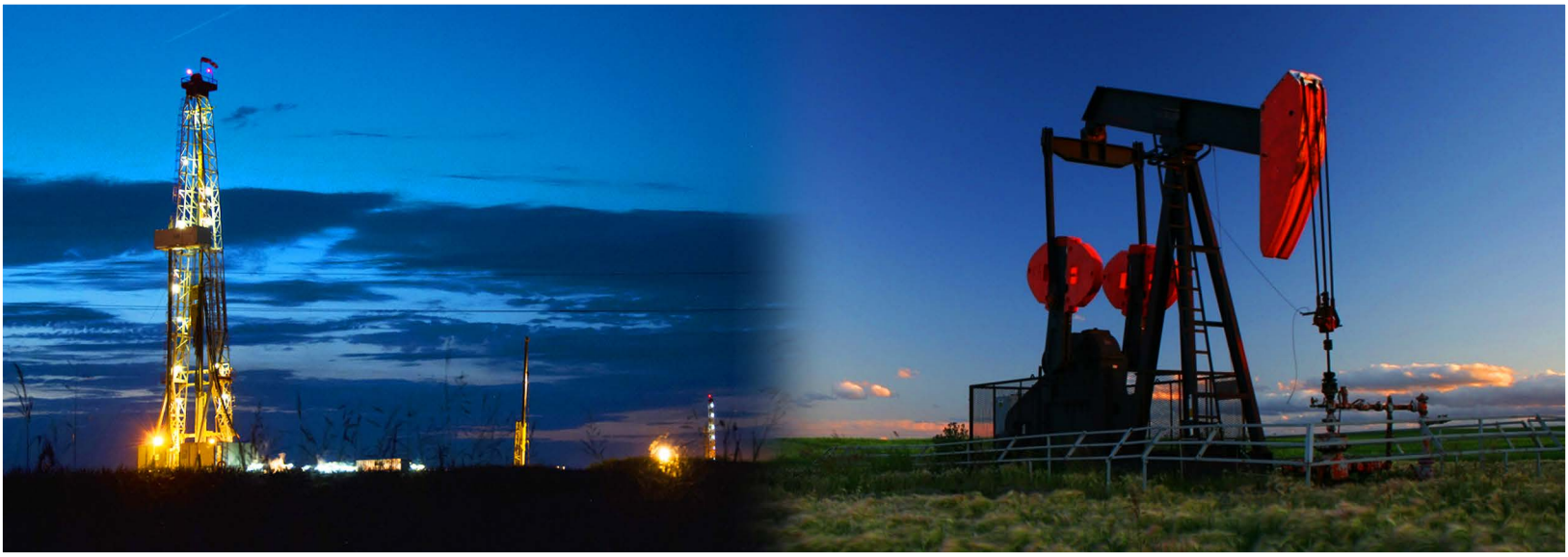
NATIONAL ENERGY TECHNOLOGY LABORATORY

Research Portfolio Report



Small Producers: Operations/Improved Recovery

U.S. DEPARTMENT OF ENERGY

Cover image: **Drill rigs and pump jacks are some typical tools used in natural gas and oil operations and for improved recovery**

Research Portfolio Report

Small Producers: Operations/Improved Recovery

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The project data, photos, and graphics provided in the project summaries that follow the introduction come from available project documentation—including final reports, fact sheets, NETL project summaries, RPSEA monthly reports, and project websites—and through the generous assistance of Principal Investigators, industry partners, RPSEA, and NETL staff.

Executive Summary

The Department of Energy's (DOE) Office of Fossil Energy has a long history of investments that focus on improving recovery from and reducing the operating costs of mature domestic oil and natural gas fields while maintaining the integrity of the environment. These investments have supported the thousands of independent operators and small producers that do not (typically) have an R&D budget to develop and/or test new technologies. Programs such as the "Technologies for Independents" and "Stripper Well Program" that were implemented in the 1990s and early 2000s are prime examples as well as early research in the 70s and 80s. For example, smaller-sized, independent operators produce nearly all of the methane from coal seams (coalbed methane) in the U.S. DOE's early research investment into coalbed methane during the late 1970s and early 1980s as well as research by the Gas Research Institute (now GTI) helped spark a 34 to 1 return on investment and led to coalbed methane transitioning into an important component our national energy supply.

Smaller-sized, independent operators produce nearly all of the methane from coal seams (coalbed methane) in the U.S.

Today, most of these investments are through the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research Program, which was initiated through Section 999 of the Energy Policy Act of 2005 and is implemented and overseen by the Research Partnership to Secure Energy for America and NETL's Strategic Center for Natural Gas and Oil.

Projects highlighted in this report have resulted in significant achievements, including **new tools** to assist small producers with planning new wells and infrastructure and meeting regulatory requirements; **innovative laboratory and field experiments** that led to the development of **novel technologies**; successful **demonstrations** of technologies to reduce cost and increase production; and **technology transfer** for the commercialization of scalable systems.

The Small Producers[1] (SP) portfolio includes research and development (R&D) funded through annual appropriations and the Small Producers element of Section 999. The overarching goal of research in the SP portfolio is to carry out research, development, and demonstration efforts that assist small producers in reducing costs and increasing the efficiency of exploration and production of oil and natural gas in mature onshore oil and gas fields, while focusing on safety and the reduction of environmental impacts.

The SP portfolio is unique in that mature assets form the foundation of the program, and a development infrastructure for those assets is already in place. The portfolio of projects has yielded demonstrable, measurable results, including **increases in gas and oil production and recovery** that **successfully leverage** decades of economic and environmental **investments in existing infrastructure** and support thousands of small energy producers located throughout the U.S. The R&D efforts of the SP portfolio have played a vital part in **developing and proving technologies** that maximize production from mature fields, **reducing** the **operating costs** of those fields while **minimizing** the **environmental impact** of further developing them, **increasing revenues** for states and the federal government, and **creating** high-paying **domestic jobs** in rural areas of the country**.** For example, in its 2012 report "Marginal Wells: Fuel for Economic Growth" the Interstate Oil and Gas Compact Commission states that marginal oil and natural gas produced in 2012 was worth $30.8 billion. In an earlier 2004 study, they determined every dollar of marginal oil and gas production creates nearly a dollar of economic activity and nearly 10 jobs are dependent upon every million dollar of marginal oil and gas produced.

SP research includes addressing the technology challenges of managing water production, improving recovery, and reducing operating costs. This report highlights many of the accomplishments achieved by projects in the Operations/ Improved Recovery bin of the SP portfolio. These include:

- A study of Arbuckle formation reservoirs in Kansas demonstrated the possibility of using near-miscible CO_2 flooding to extend the life of mature oilfields and enable the recovery of between 250 million and 500 million barrels of oil.
- Prototypes of the multiphase (gas and liquids) OsComp compressor were developed for wet gas applications in small volume producing situations.
- An environmentally-friendly soil amendment to remediate oilfield brine-contaminated soil was developed.
- An iPhone app called "Pumper's Friend" allows the pumper/well tender to quickly gather and transmit field data more accurately and to review well performance at the well site.

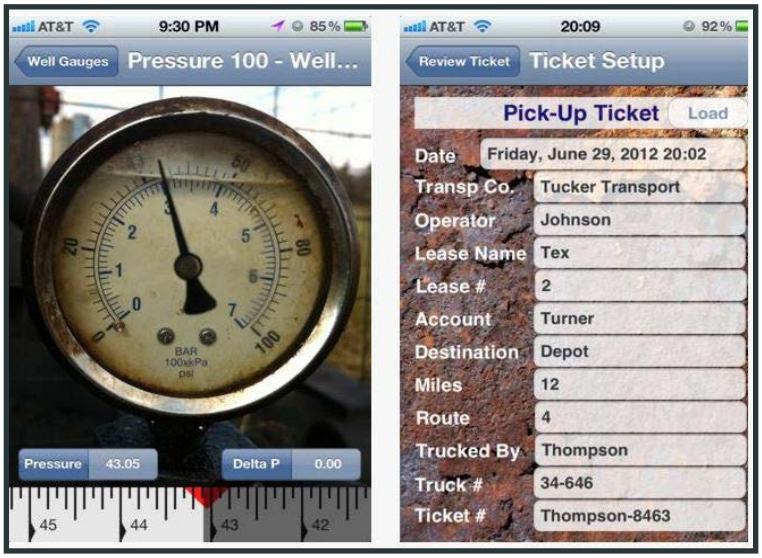

Image caption: *An iPhone app called Pumper's Friend allows the pumper/well tender to quickly gather and transmit field data. (Screenshots from Pumper's Friend app site on the Apple iTunes App Store.)*

1 SEC. 999G (7) of EPAct reads, in part: The term "small producer" means an entity organized under the laws of the United States with production levels of less than 1,000 barrels per day of oil equivalent.

Introduction

The role of independent producers in domestic onshore petroleum production is significant; they account for 74 percent of onshore natural gas production, 67 percent of onshore oil and condensate production, and operate about 80 percent of America's 800,000 producing wells. Their role in developing technologies that move the industry forward cannot be understated: independent producers are behind every major onshore discovery made since 1990[2]. Despite this, economic and technical uncertainties frequently hinder continued production of mature wells. This is particularly true for the smaller independents that operate most of the "stripper" wells (i.e., economically marginal oil and gas wells producing from mature fields).

The SP portfolio is designed to give small producers promising options for prolonging the productive life of oil fields. It provides research, development, and demonstration efforts that result in reduced costs and increased efficiency of exploration and production efforts while ensuring public safety and protecting the environment.

The research projects within the SP portfolio have been categorized into "bins" of projects that are focused on a common topic. This Research Portfolio Report provides a snapshot of results and accomplishments to-date for active and completed projects in the SP portfolio grouped into the Operations/ Improved Recovery bin. The first section of this report provides an overview of the bin. Project summaries that include the objective, research conducted, results and other pertinent information for each of the projects are provided in the pages that follow.

2 Small Producers: Mission. http://www.rpsea.org/small-producer-program/

What is operations/improved recovery research?

As oil and natural gas resources are produced over many, many decades, the remaining resources are not always easily or economically recoverable, putting these resources at risk of being prematurely abandoned, leaving significant quantities of oil and natural gas behind. The research conducted as part of this SP portfolio is focused on reducing operational expenses and/or improving recovery and often leads to field applications that are designed to demonstrate new commercial technologies. Because small producers often lack the resources necessary to move technology from R&D to field operations, most projects in this portfolio are performed by a consortium of two or more organizations and a small producer. Together, technology providers and small producers with common challenges perform R&D to develop, apply, and commercialize economically and environmentally sustainable technologies, methods, and tools to enhance production and extend the life of mature fields.

Development Strategies for Maximizing East Texas Oil Field Production

The goal of this project was to evaluate deepening and behind-pipe opportunities and enhanced oil recovery (EOR) potentials to maximize recovery from the East Texas Oil Field (ETOF), a giant mature and marginal field currently operated by 114 small producers. Depositional environments of lower stringer sandstones in the northern and middle parts of the ETOF were mapped using >600 wells and deepening candidates were identified based on architecture of depositional systems. With the help of results from this study, 8 out of 15 workover/recompletion targets successfully produced more than 140,000 STB of crude at a low cost (approximately $1 million).

Additional details on this project are available on p. 15.

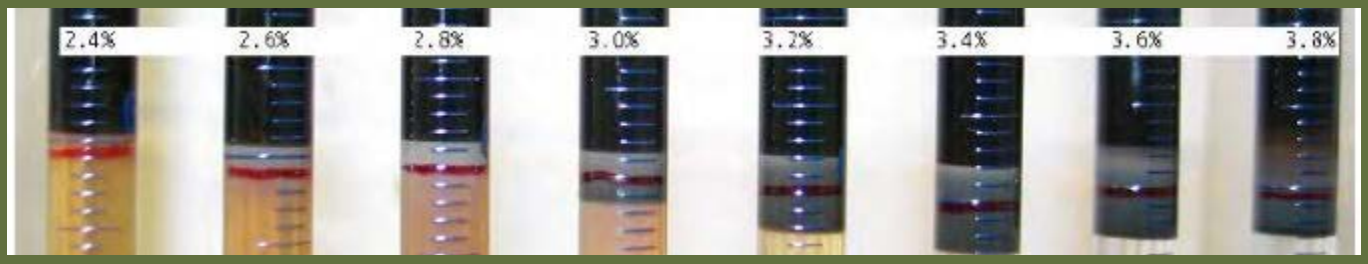

Image caption: **Salinity scan results from one of the tested formulations.**

The major areas of focus in this SP bin include developing and demonstrating technologies that:

- Mitigate environmental impacts from past or current operations in mature fields
- Reduce costs and improve efficacy of well intervention and drilling operations
- Extend the life of mature fields through environmentally-safe efficiency improvements
- Reduce operating costs through more effective and efficient compliance with operating regulations

Why conduct this research?

As previously mentioned, small producers contribute significantly to domestic oil and gas production. More than 10,000 independent producers are dispersed across multiple oil and gas production regulatory jurisdictions throughout the country. These producers usually have limited access to internal research capabilities, and have fewer opportunities to capitalize on new technologies. To prosper, they must respond to an ever-changing regulatory landscape and unpredictable market demands while also ensuring optimal safety and environmental sustainability. The SP portfolio helps mitigate the risks normally associated with production activities and provides a basis for technology transfer efforts, which encourages the adoption of appropriate technology applications throughout the small producer community.

Accomplishments

Accomplishments from the Operations/ Improved Recovery bin include the development and successful demonstrations of novel technologies for enhanced oil recovery, the testing of novel water flooding conformance control techniques, and the creation of useful online tools for regulatory compliance. With a number of the projects in the bin already completed, some project deliverables have already been submitted.

The following selected examples of accomplishments from research projects in this bin illustrate how the program is helping the small producer industry:

- **Development Strategies for Maximizing East Texas Oil Field Production** – By the time this project was completed in June 2014, 8 of 15 workover and recompletion targets successfully produced more than 140,000 stock tank barrels of crude oil for about $1 million. The cost to benefit is substantial: the University of Texas' Bureau of Economic Geology created more than $13 million in additional revenues, demonstrating their strategies offer considerable benefits for small producers.
- **Identifying and Developing Technology that Enable Small Producers to Pursue Residual Oil Zones** – Residual oil zones (ROZ) can contain 20 to 40 percent residual oil trapped in pore spaces that cannot be produced using conventional technologies. Researchers at University of Texas of the Permian Basin continue to develop technologies for recovering that oil and locating higher quality portions of recoverable ROZ. A ROZ recovery project using CO_2 flood is underway in the Seminole field, and projections indicate this and similar projects may recover 200-300 million barrels of additional domestic oil.
- **Well Site Soil Remediation** – Clean Tech Innovations LLC (Bartlesville, Okla.) used Stripper Well Consortium (p. 24) funding to develop an environmentally friendly soil amendment to remediate oilfield brine-contaminated soil. This rapid, simple, economic, and dependable remediation technology uses a proprietary component along with a highly soluble calcium source and fertilizer. The product is easy to apply, lower cost than other available technologies, and has been successfully demonstrated at multiple sites across the United States.
- **Alkaline Surfactant Polymer (ASP) Flooding in Illinois Basin** –The University of Illinois and Rex Energy Corporation (Bridgeport, Ill.), developed a process for the co-injection of alkali and surfactant with a polymer to increase oil recovery in a 15-acre pilot flood in the Lawrence Field of the Illinois Basin. This helped release the oil that was previously difficult to extract, increasing yield from 16 barrels per day to 65–75 barrels per day. Due to this demonstrated success, Rex Energy has plans to expand testing to a 58-acre portion of the field and will continue the project, utilizing ASP technology in a 351-acre parcel immediately south of the current operation. With continued success and private investment in these ASP pilots, an estimated 130 million barrels of additional oil could be recovered from the Lawrence Field.
- **Compressors that optimize existing technology for wet gas applications in a small package** – Prototypes of the multiphase compressor have been developed by OsComp Systems, Inc. for testing. These compressors can be used as a multiphase compression solution for wet gas applications in small producer environments.
- **CO_2-EOR planning sofware suitable for use by smaller producers seeking to determine if carbon dioxide injection makes sense** – A new, easy-to-use software package has been developed, tested, and made available by Nitec, LLC for producer interested in completing quick evaluations of the potential for applying this EOR technique on their leases. As of December 2014, more than 80 copies of the software had been downloaded from the COZView/ COZSim website.

- **Low Cost Application for Well Data Gathering** – Merritt Inc. (Upland, Ind.)—through Stripper Well Consortium (p. 24) funding—developed an iPhone app called "Pumper's Friend" for collecting digital data from mature oil and natural gas fields with low volume stripper wells. The app allows the pumper/well tender to quickly gather and transmit field data more accurately and to review well performance at the well site. This capability leads to more efficient operation of the well and increased production.

What are the benefits of operations/improved recovery research?

R&D projects that provide demonstrations of low-cost technologies for improving production and/or minimizing operation costs are key to supporting small producers—the primary oil and natural gas producers in this country. Ongoing and environmentally-sound development of domestic energy resources will help provide a more robust and stable domestic energy portfolio and lead to economic benefits. A diverse portfolio of domestic energy sources will ultimately be a cornerstone in building greater energy independence and national security.

Other benefits resulting from this R&D include:

- Successful demonstrations will introduce new production improvement processes ideally suited to small producers.
- New environmentally-friendly production-enhancement processes provide benefits over conventional hydraulic fracturing treatments, including lower hydraulic horsepower requirements, reduced footprint, simpler execution, lower water utilization, and the use of non-damaging biodegradable polymer-based fracturing fluids.
- Research supporting small producers leads to an increase in high-paying jobs and tax revenue associated with expanded oil and natural gas production. A study conducted for the Independent Petroleum Association of America (IPAA) illustrated that U.S. workers employed by independent producers were paid $148 billion and paid $30 billion in federal, state and local taxes. Combined with taxes paid by independent companies, the total tax contribution in 2011 was $67.7 billion.
- New methods that allow producers to use resources more efficiently and with fewer chemicals in hydrocarbon production and treatment process reduce the cost of environmental compliance.
- Extending the life of mature wells reduces the need to develop new well locations, reducing environmental impacts and costs.
- New technologies, datasets, tools, and methods protect the environment from surface disruptions associated with well development, including well site construction. They can also minimize air emissions, noise, and the impact on the visual landscape and surface water.
- The U.S. has significant hydrocarbon resources that can be produced to provide economic benefits for all Americans. New technologies to fully develop those resources safely and sustainably help secure our energy future.

CO_2-EOR Planning Software Helps Small Producers Conduct Quick Evaluations

The easy-to-use COZView/COZSim software available online allows small producers to quickly evaluate whether or not CO_2 injection makes sense for their lease.

Additional details about this project are available on p. 42.

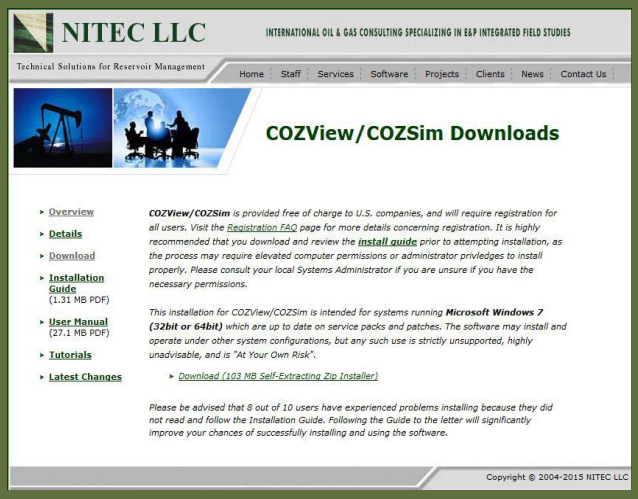

Image caption: *Surface configuration of a low production Appalachian Basin well*

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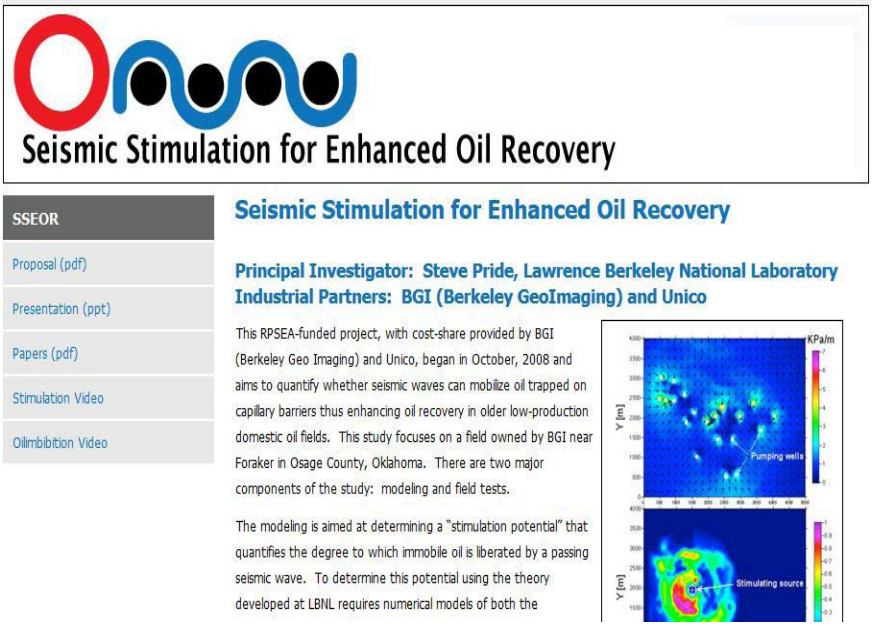
Seismic Stimulation to Enhance Oil Recovery

Objective: To perform a well-controlled field test of seismic stimulation in a mature oil field and to model the mechanisms involved to determine where seismic stimulation might be best applied.



Research Conducted: Seismic stimulation may help "shake loose" oil to increase production in mature fields where production is declining. The objective of this project is to determine if seismic stimulation can mobilize oil trapped on capillary barriers to enhance oil recovery in older, low-production domestic oil fields. This study is focused on the Foraker oil field in Osage County, Oklahoma.

There are two main components of the study: modeling and field tests. The modeling component is designed to determine a stimulation potential, which quantifies the degree to which immobile oil is liberated by a passing seismic wave. To determine this potential, numerical models of both the production gradients in the field and the seismic-wave amplitudes were created.

Seismic stimulation is ideally suited for small producers because it is inexpensive compared to other enhanced oil recovery techniques, it stimulates all parts of the reservoir instead of only where injected fluids are delivered, and it has no known environmental impact. Additionally, seismic stimulation can be used to replace water floods in reservoirs that have not been previously swept.

The project team predicts that seismic stimulation will mobilize trapped oil and increase oil production when two dimensionless criteria are met:

1. The static-force requirement: when a seismic wave pushes on a trapped oil bubble, the radius of curvature of the downstream meniscus of the bubble is reduced sufficiently to get through the pore-throat constriction that is blocking its downstream progress.
2. The dynamic requirement: in a cycle of the time-harmonic stimulation, the meniscus has enough time to advance through the constriction before the seismic force changes direction and begins to push the meniscus upstream.

For the field test, the field was equipped to monitor well-by-well production data. Monitoring began in September 2010. The team suggests further numerical studies be conducted to investigate simulations in three dimensions, work with more grains in each flow cell, apply stimulation for many hundreds or more of seismic wave periods, and use alternative methods to simulate how oil becomes trapped in the system in the first place.

The project team created a project website. It can be accessed at: http://esd.lbl.gov/research/projects/sseor/

Results:

- Built the seismic stimulation source [created by Applied Seismic Research (ASR)]. The plan was to place the seismic stimulation source in a well at reservoir depth and run it continuously for 8 months. Although the theoretical and numerical modeling of seismic stimulation for enhanced oil productivity was performed by Lawrence Berkley National Laboratory (LBNL), the cost-share partners on this project, BGI and then Sandridge Energy, were never able to get the seismic source provided by ASR to function properly in the field and so actual production data collected during seismic stimulation was never collected and compared to the theoretical/numerical predictions.
- Received updated production data (pre-stimulation) from Sandridge and determined the best strategies for analyzing/presenting the data for trend analysis. Issues with deployment in the field (noted in the bullet above) have developed

Seismic Stimulation to Enhance Oil Recovery

limiting field data to date. Should producers have an interest in field testing, Lawrence Berkeley can be contacted via the contact information provided in Key Contacts.

- Attempted well-by-well monitoring via two trailer-mounted coriolis meters. The meters were to monitor total fluid production and oil cut from a well for 24 hours before moving to the next well. Because the gas-phase separators did not work properly, this approach to production monitoring was abandoned late in the fall of 2011; however, the project team developed an alternative monitoring program based on tank batteries. The tank batteries allowed the team to monitor production from small groups of two to four wells instead of individual wells.
- Discovered that a reliable meter that can make accurate readings of oil cut in the presence of gas in the fluid stream did not exist at the time of this study; such a meter at an affordable price would be of value to operators.

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Lead Performer: Lawrence Berkley National Laboratory

Steven Pride, Lawrence Berkley National Laboratory; 510-495-2823, Srpride@lbl.gov

Project Number: 07123-06

Period of Performance: 9/2008-12/2014

Additional information about this project is available on the RPSEA website.

Development Strategies for Maximizing East Texas Oil Field Production

Objective: To develop techniques and methods to increase short term oil production and maximize long-term recovery in the East Texas Oil Field (ETOF).

Research Conducted: The ETOF is a large, mature, and marginal field[1] operated primarily by 117 operators—114 of whom are small producers. Cumulative production over the last 84 years has made the ETOF the second most productive field in the United States; however, the estimated 1.5 billion barrels of oil remaining in the aging field are difficult to recover. Most of the current operators do not have sufficient expertise or resources to develop methods to revitalize production. Thus, the project team identified two primary objectives for this demonstration project:

1. To locate well-deepening and water-flooding targets, guided by depositional trends revealed by detailed mapping of reservoir geology.
2. To conduct a feasibility study on oil recovery using enhanced oil recovery (EOR) methods.

The project team performed area studies, field tests, and EOR laboratory and field demonstrations to develop an integrated characterization of the geologic and engineering features of more than 10,000 wells spanning over approximately 150 square miles.

To determine the well-tops, calculate net sandstone, and map depositional trends and reservoir architecture, the team initially collected approximately 5,000 wireline logs from both the East Texas Engineering Association and individual operators, and then entered the information into databases. The top of the main Woodbine sandstone formation was selected in all wireline logs in this study. The top of the Buda formation was identified in deep wells, and the base of the main Woodbine sandstone was chosen as the upper boundary of lower stringers.

The team then entered the data into a database and analyzed it to characterize the geology and petrophysical properties and complete geologic correlation before mapping. Based on the mapped architecture of the depositional systems of the lower stringer sandstone in the northern and middle sections of the ETOF, researchers strategically targeted workover, mini-waterflood, and deepening and recompletion sites for short-term field-demonstration projects. In areas lacking new deep wells, researchers determined depositional trends from logs in older wells to select deepening targets. Candidates within the ETOF project area with untapped, unswept, or poorly swept remaining mobile oil were selected; these results enabled researchers to make estimates about the recoverable remaining oil. In all, 60 wells from areas around the Castleberry Survey were selected.

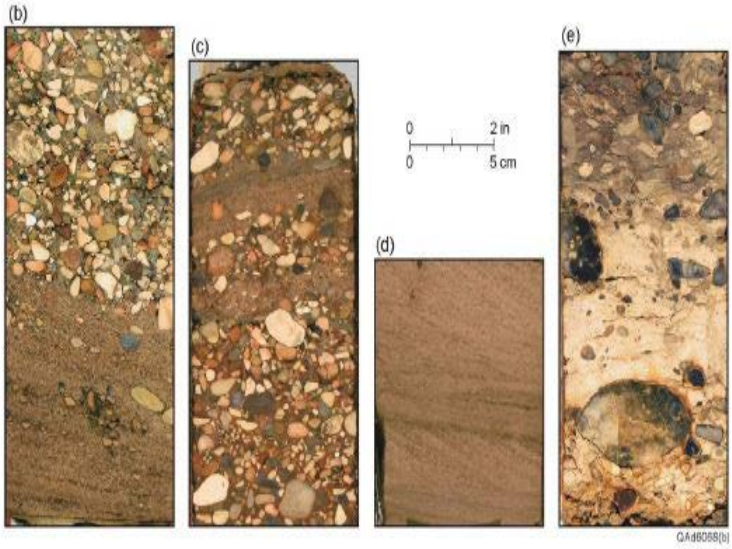
Industry partners chose not to invest in the planned waterfloods in favor of expanding their deeping programs, so this aspect of the research was not completed.

Results:

- Successfully produced more than 140,000 stock tank barrels of crude oil at a low cost (about $1 million) from 8 of 15 workover and recompletion targets (as of June 2014). They have generated more than $13 million additional revenues, demonstrating considerable benefits for small producers
- Successfully demonstrated eight workover/deepening/recompletion projects and conducted a laboratory study on CO_2 and surfactant floodings.
- Demonstrated that repair and maintenance significantly improved well productivity. When performed routinely, these are the most economical workovers for increasing production in mature fields.
- Stopped the decline of the ETOF through a combination of this work and operator-initiated deepening. Despite an overall reduction in the number of producing wells, production has been sustained at approximately 11,000 bbl/day since 2010.
- Developed a GIS database with well locations, raster logs, production data, and depositional-trend maps are available to operators in the field, benefiting all small producers operating in the ETOF.
- Developed and demonstrated low-cost, low-risk, profitable techniques for increasing short-term oil production and maximizing long-term recovery for small producers in ETOF. The methods used can be applied to similar mature and marginal fields in the U.S. operated by small producers.
- Provided results that serve as an important geologic and engineering research source for all operators in the field and have already been efficiently transferred into production enhancement for many operators.

1 A marginal field is one that may not generate enough net income to make it practical to continue development. Marginal fields may become commercially viable when technical or economic conditions change.

Development Strategies for Maximizing East Texas Oil Field Production



(b, c) Chert pebble conglomerate interbedded with very coarse-grained sandstone. (d) Crossbedded, coarse-grained sandstone. (e) Unconformity at base of Austin Chalk.

- Discovered that miscible CO_2 flooding in ETOF cores resulted in 70 percent oil recovery—lower than recovery in Berea sandstone cores (85 percent). Oil recovery by alkaline-surfactant-polymer (ASP) flooding in Berea and ETOF cores was also lower—90% and 28%, respectively. Additionally, the optimal three-phase condition was not achieved in the ETOF core flooding. Recovery in ETOF cores may have been reduced by high adsorption of surfactant by the clay minerals, and further research is needed.
- Researchers suggest further laboratory studies into alkaline-surfactant-polymer (ASP) systems in order to find optimal compositions for the ETOF.

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Lead Performer: Bureau of Economic Geology

Fred Wang, Bureau of Economic Geology, Jackson School of Geosciences; fred.wang@beg.utexas.edu; (512) 471-7358

Project Number: 08123-16

Period of Performance: 10/2009-7/2014

Read/download the final report.

Field Testing and Diagnostics of Radial-Jet Well-Stimulation for Enhanced Oil Recovery from Marginal Reserves Enhanced Oil

Objective: To field demonstrate a newly-developed short radius drilling technology for production enhancement from low-permeability oil reservoirs.

Research Conducted: Well stimulation by radial jet or short radius drilling enhancement is an attractive technology for enhanced oil recovery for both existing and new field developments. By using the most advanced coil-tubing technologies, lateral holes with different geometries can penetrate compartmentalized formations that are bypassed during conventional water flooding or lie within the less permeable oil zones that cannot be sufficiently drained by conventional processes. The process can also allow safe stimulation of thin bypassed pay zones.

As part of the assessment, researchers will determine the feasibility and cost effectiveness of the method. Specifically, diagnostic methods for tracking the placement of laterals and optimizing the design of lateral patterns are being developed and field-validated for broad applications. Diagnostic techniques include the use of chip based accelerometers and gyroscopes, capable of being deployed in very small, autonomously operated sensor packages.

The researchers gathered geologic and petrophysical data, well history, and production history of the west Millman field in Eddy County, New Mexico. They characterized and modeled the target reservoir; the models were validated using history matching prior to running simulations.

Researchers collected information related to short-radius lateral drilling parameters from drilling professionals and companies to obtain design requirements for a piezoelectric accelerometer-based location sensor. A location sensor/data logger was developed for field testing.

If proven, this method of enhanced oil recovery will reduce the recovery cost and increase the availability of low-permeability oil reserves.

Results:

- Modeled the targeted test site and conducted simulations that indicate the potential exists for application of the short radius drilling technology.
- Performed 22 laboratory tests to validate and improve the design of the data logger and the data processing methods. Early on the velocity and distance drifted too much due to the bias of the sensor itself. The data analysis showed that the shorter the time that the data recorded, the less the velocity and distance drift.
- Determined that one way to reduce bias effects is to record data only when the actual test starts (when the data logger enters the horizontal portion of the lateral). Recording data in this way can also save flash memory. Because of the limited on processor chip memory, the size of the microcontrollers and the difficulty in identifying the true start point in real time, additional work integrated a chip based gyroscope to reduce drift.
- Developed all technology needed for the project. Field testing is scheduled for February of 2015. Following the stimulations, production response will be quantified and compared to simulation predictions. Economics of the technology will also be evaluated.

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Lead Performer: New Mexico Institute of Mining and Technology

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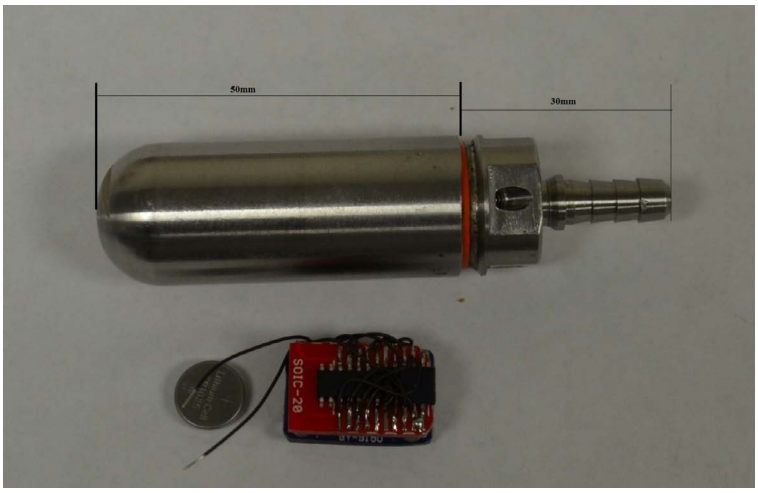
Project Number: 09123-03

Period of Performance: 3/2011–6/2015

Additional information on this project is available on the RPSEA website.



Custom jet tip with sensor package.

Recovery from the Bakken Shale Using Surfactant Imbibition Coupled with Gravity Drainage

Objective: To test the degree of imbibition for available waters in different portions of the Bakken shale found in North Dakota's Williston Basin, develop novel surfactant formulations to alter the wettability of the formation and increase oil displacement from the shale, and couple that surfactant with gravity to enhance oil recovery in fractures connected to horizontal wells.

Research Conducted: Surfactant imbibition is sometimes used in wells to improve the wetting state and improve recovery. The team first evaluated the degree of imbibition for available waters in different portions of the Bakken shale to determine the shale's true wetting state. This was important as changes in wettability cause changes to capillary pressure. When the pressure changes from negative to positive, imbibition mobilizes oil.

Once the wetting state was evaluated, researchers balanced the pH, salinity, and divalent cation content of the injected fluid to develop and optimize 17 different surfactant formulas with the potential to promote imbibition while minimizing formation damage. The team performed imbibition experiments; the results from these experiments led to the identification of a group of four surfactant formulations with a potential for increasing oil recovery from the Bakken shales at high temperatures and salinity.

The project team then produced a numerical model for the Bakken shale that incorporated the physics of surfactant imbibition and concurrent oil displacement. This model was used to assess and compare the proposed imbibition process with existing methods for completions within the Bakken shale. Simulations were run comparing the surfactant solutions with current production methods (including the huff-puff method). The results of these experiments indicated that enhanced oil recovery with surfactant imbibition could yield more than 10% of original oil in place within a few years in the Bakken well they used for the simulation. For Bakken cores, salinity was a requirement, as the surfactants did not imbibe effectively using distilled or low salinity water.

Results:

- Discovered through testing that imbibition rates increase as temperatures increase. However, cationic surfactants with fewer carbons had lower imbibition rates, while cationic surfactants with large carbon numbers exhibited fast imbibition rates and increased oil production at both high temperatures and at room temperature.
- Determined that ethoxylate nonionic surfactant, internal olefin sulfonate anionic surfactants, and amine oxide amphoteric surfactant were the most stable surfactants at temperatures between 105–120°C. They were all able to effectively imbibe displace oil at high temperatures. Proper cosurfactant formulations may increase oil recovery.
- Evaluated surfactant formulations and found that the formulations consistently altered the wetting state of Bakken cores from their initial oily-wet to intermediate-wet states toward water-wet.
- Found during simulations that the injection rate and production sequence appear to affect the rate of oil recovery and must be considered when field trials are designed.
- Learned that sodium carbonate—which was added to surfactant solutions to increase alkalinity—precipitated with divalent cations in brines. Sodium metaborate may be an effective alternative.
- Determined that a pilot demonstration may have a different predicted oil recovery factor because assumptions will vary from those used in the simulation model. Field development of a case design must also consider fracture geometry, distribution, and the loss of surfactants solutions used the process.
- Highlighted the need for future research into methods to increase the rate of fluid penetration or expand the contact area with the rock. Additionally, the team calls for an appropriate case design for demonstration and testing of similar methods in the field.

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Lead Performer: University of North Dakota

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Project Number: 09123-09

Period of Performance: 3/2011-3/2014

Read/download the final report.

Game-Changing Technology of Polymeric-Surfactants for Tertiary Oil Recovery in the Illinois Basin

Objective: To further develop functional polymeric surfactant (FPS) technology as an alternative chemical enhanced oil recovery (EOR) approach. The FPS technology is a single-component chemical that may replace traditional multi-component surfactant and polymer (SP) flood methods or alkaline surfactant polymer (ASP) flooding.

Research Conducted: The typical oilfield reservoir conditions from the Illinois Basin are being used to test and evaluate FPS EOR potential. Sixteen oil and brine samples from four different locations within the Illinois basin were collected. Screenings and other laboratory analyses were performed with model oil (dodecane [C_{12}]) and the collected basin samples.

Candidate FPS chemicals were identified for screening for EOR under conditions typical of Illinois Basin fields. Advanced molecular modeling techniques were used to gain an understanding of FPS functionality as an EOR agent and to assist in FPS formulation and synthesis. Laboratory screening procedures, including tests for solution viscosity, oil-water emulsion, interfacial tension (IFT), and oil displacement efficiencies, were systematically applied to candidate chemicals. Only potentially successful FPS candidates were selected for further development; for example, FPSs that did not pass emulsion tests were excluded from further tests, and those that did not pass filtration tests were not considered for subsequent core flooding tests.

The team performed EOR evaluations for the selected FPS chemicals through bench experiments. An economic analysis of FPS-EOR for the Illinois Basin was also performed. The project team estimated incremental oil production for a number of different chemical designs using laboratory data of the chemical physical properties and capability of mobilizing oil in core flooding experiments, plus the field description (reservoir geology, waterflooding performance, well information, etc.).

The advent of horizontal drilling combined with properly designed water injection systems and the use of chemicals and polymers will greatly enhance the recovery rates of the residual oil in place. A better understanding of Illinois Basin reservoir characteristics is needed and should lead to better predictions of the quantity and location of bypassed oil. This would allow for a more logical analysis of well locations and spacing.

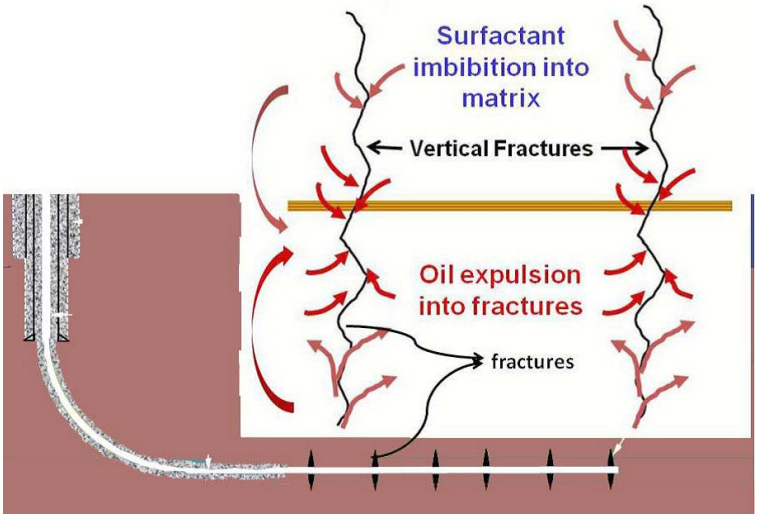

Illustration of hydraulic fracture distribution in Well #17450 and imbibition mechanism.

If FPS is developed into a cost-effective oil recovery method for domestic small oil producers, small producers may benefit economically as the technology may be less expensive than SP flooding and ASP oil recovery methods. Additionally, SP and ASP flooding techniques are often difficult for small producers to apply. As mature fields fields are produced by a significant number of small operators, the savings in materials cost, labor, and training expenses may allow continued production when it would otherwise not be feasible. The added revenue from continued production of mature fields is also a benefit. The project team estimates the potential for FPS-EOR technology at a minimum of 10% oil desaturation when applied in mature oil fields. In the US, this amounts to about 37 billion additional barrels of oil targeted by this technology.

Results:

- Developed three distinct series of FPS: Class A, a lab-graded FPS with significant changes in the chemical composition; Class B, which was specifically designed for improved oil recovery in the mature, tight sand, shale oil, and heavy oil fields, and Class C, a series designed to be cost-effectively scaled-up for production of large-quantity field applications.

Game-Changing Technology of Polymeric-Surfactants for Tertiary Oil Recovery in the Illinois Basin

- Developed laboratory screening procedures to identify and optimize FPS-flooding performance. Accomplishments also include confirming FPS chemicals can lower oil-water interfacial tension, reduce the viscosity of highly viscous oil, and minimally adsorb into reservoir rock.
- Determined from geological assessments of 13 potential trial sites in the Illinois Basin that most are suitable candidates for tertiary recovery methods involving FPS-flooding. Economic assessments indicate FPS-flooding is economically and technologically feasible for small producers who choose to implement EOR in their mature water flood reservoirs.
- Determined that both secondary and tertiary oil recovery is significantly overestimated with sandpack flooding; however, the method provides a quick and semi quantitative evaluation for optimizing FPS products.
- Found that some FPS formulations result in significant oil recovery compared to regular polymer flooding, while others yield poor results even when the oil-water interface tension is low. The team suggests that emulsion may be the key factor in FPS-related tertiary oil recovery.
- Determined that initial core flooding tests for FPS 212-181 were not as successful as the team anticipated, but FPS is promising for additional oil recovery. Water flooding recovered 66.74 percent original oil in place (OOIP). Following that with conventional P-flooding Hydrolyzed PolyAcrylaMide (HPAM) + brine flooding recovered another 13.81% OOIP. After the HPAM flood, FPS plus brine flooding was performed and recovered an additional 6.82% OOIP.
- Learned that if the same FPS flooding is conducted directly after water flooding, FPS 212-181 performs better, recovering 18.04% OOIP from core.

Typical Emulsification Test Result – FPS 228-73 with various salinities (%KCl as labelled) and a modelled oil component (Dodecane).

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Lead Performer: Power Environmental Energy Research Institute

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Project Number: 10123-03

Period of Performance: 4/2012-10/2014

Additional information about this project is available on the RPSEA website.

Field Demonstration of Chemical Flooding of the Trembley Oilfield, Reno County, Kansas

Objective: To demonstrate a chemical flooding application in the Trembley field in Reno County, Kansas and provide detailed field results of the flood to the small-producer community and oil and gas industry.

Research Conducted: Chemical flooding technology has the potential to significantly increase oil production in many of the mature oilfields in the U.S., most of which are operated by small producers and independent oil companies. Small producers have not employed chemical flooding technology because of the significant financial resources required and concern that even positive laboratory results may not translate to an increase in production in the field.

The project is being conducted in two phases. In Phase I, the project team designed the field demonstration via a systematic effort in which efficient chemical formulations were identified and tested in the laboratory. The formulations were rated using phase behavior studies and oil-recovery performance was tested in flow experiments. The field injection design was derived through (1) past field performance studies, (2) a tracer study, (3) a field injection test, and (4) simulation studies to predict performance during chemical flooding.

In Phase II, the project team will conduct field implementation and surveillance tasks as well as assemble and test an injection plant and train field personnel to operate it. Field injection will be monitored to ensure proper procedures are being followed. The project team will continuously analyze the performance of the flood, and a comprehensive analysis of the design and implementation of the field trial will be disseminated through reports, technical papers, and presentations to small producers and the industry.

The results generated during this project may promote chemical flooding technology to small producers, resulting in a significant increase in oil production with little environmental impact using existing technology infrastructure.

Results:

- Conducted a variety of core floods to identify the best combination of chemicals, concentrations, and volumes for reservoir oil recovery. A chemical formulation for use in the Trembley field has been identified.
- Injected oilfield tracers into three wells on Dec. 11, 2012. Two tracers were detected in separate production wells at very low concentrations at just over a year of water injection.
- Determined that surfactant retention in the carbonate reservoir rock material is not excessive as is seen in other carbonate formations. The work also indicates that a polymer preflush may reduce surfactant retention.

Ongoing Research: The production wells are being monitored to determine the full tracer responses. The tracer responses will be analyzed to estimate the volume of the reservoir that will be treated by the chemical flood. A chemical injection unit will be designed in order to implement the field trial.

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Lead Performer: University of Kansas Center for Research

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Project Number: 11123-28

Period of Performance: 11/2012–8/2016

Additional information about this project is available on the RPSEA website.

Next Generation Surfactants for Improved Chemical Flooding Technology

Objective: To characterize and test current and next generation high-performance surfactants for use with improved chemical flooding technology in the Oklahoma's Pennsylvanian-aged (Penn) sand reservoirs.

Research Conducted: Surfactant enhanced oil recovery (EOR) methods mobilize residual oil through the use of injected surfactant solutions that bring oil-water interfacial tension (IFT) to ultra-low levels. These surfactant formulations have been difficult to develop because they must be stable in reservoir brine.

The project team identified six target reservoirs, then tailored surfactant formulations that are stable in the reservoir brines and produce ultra-low IFTs for these reservoirs. To select surfactants, the team used both the trial-and-error method and the application of the Hydrophilic-Lipophilic Deviation (HLD) relation. To apply HLD relation, they measured the characteristic curvatures (Cc) of 28 different surfactants typically used in EOR operations. Those surfactants included a set of novel petroleum sulfonates, commercialized extended surfactants (alkylethoxy-propoxy sulfates), and a new series of disulfonates enhanced for microemulsion formation.

Researchers studied the relationships of the new surfactants, co-surfactant concentrations, and pH. They also conducted two studies on surfactant adsorption. One explored the prevention of surfactant adsorption with the use of sacrificial agents. The second study investigated the effect of inorganic electrolytes on surfactant adsorption. Optimal salinity, surfactant Cc, critical microemulsion concentration (CμC), and how those factors correlated with ultralow IFC at concentrations below the CμC was also explored. Additionally, field tests were conducted, consisting of a single-well tracer test (SWTT), followed by a surfactant/polymer chemical flood and a final SWTT.

The development and characterization of new surfactants that are stable in high-salt environments will enable small oil producers to recover more oil in mature fields efficiently and cost effectively, while maintaining the integrity of the rock formation and leaving the formation environmentally sound. The resulting increase in oil from domestic reservoirs may also reduce the volume of imported petroleum.

Additionally, this study may result in a reduction of surfactant concentrations used in EOR. The results of this work may lead to the design of IFT formulations with ultralow adsorption on reservoir rock. This would advance the commercial viability of surfactant flooding technology.

Results:

- Discovered that the method of adsorption for a given surfactant does not change in the presence of salt.
- Confirmed laboratory observations via field study results on the effectiveness of surfactant formulation in high-salinity brine. A single-well tracer test (SWTT) completed in October 2011 indicated that approximately 70% of the residual oil was mobilized in a single permeable zone. Another SWTT, conducted in November 2011 at a different reservoir, indicated that the residual oil recovery rate in the target zone was 87%.
- Discovered that an ultralow IFT can be achieved without the formation of a microemulsion. This will allow recent design equations for microemulsion formulations to be used when designing surfactants that must produce ultralow IFTs at concentrations below those that allow middle phase microemulsions to form.
- Discovered while analyzing salinity scans using toluene that the assumption for constant k values ($k_{toluene} = k_{benzene}$) may not be valid for the surfactants in this study. The salinity scans for three surfactants were repeated using benzene, and refined Cc values were calculated. Deviations range from 7% to 400%. Researchers continue to repeat the salinity scans for all tested surfactants to determine correct $k_{benzene}$ and $Cc_{benzene}$ values. Additionally, the Pf calculation was modified to account for multiple and branched hydrophobes, which improves the correlation between the calculated Pf and the measured Cc.
- Noted that with future work to identify critical stabilization factors, a specific surfactant formulation may someday need only minor adjustments in the mixed surfactant ratios to be used in reservoirs other than the one for which it was originally developed.

Next Generation Surfactants for Improved Chemical Flooding Technology

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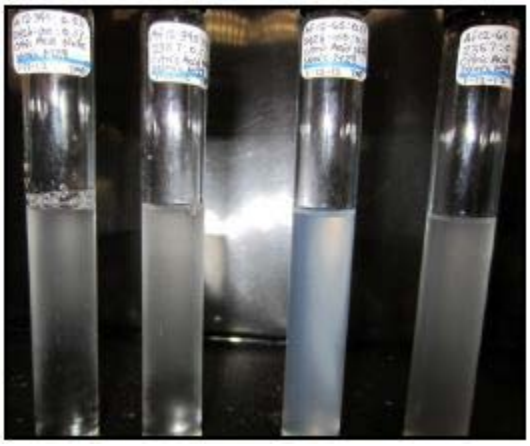
Project Number: DE-FE0003537

Period of Performance: 6/2010-5/2012

Read/download the final report.



Surfactant stability results. Mimic reservoir M brine without iron with citric acid.

Stripper Well Consortium

Objective: To keep stripper wells productive in an environmentally-safe manner, while maximizing the recovery of domestic hydrocarbon resources.

Research Conducted: The purpose of the Stripper Well Consortium (SWC) is to offer a cost-efficient conduit for the development, demonstration, and deployment of technologies that maximize the recovery of domestic hydrocarbon resources.

The consortium allows operators to draw on resources and experiences to analyze causes of premature well declines and apply the latest technologies to prevent or correct those declines.

Generally, research topics co-funded by the SWC falls into three broad areas that reflect key challenges to stripper well productivity: reservoir remediation, wellbore clean-up, and surface system optimization. Specific research projects and proposals are developed and submitted by full members, and selected proposals are funded on an annual basis. Funded participants must contribute at least 30 percent of the cost of each project.

Since June 2010, the SWC has funded a total of 14 projects. Research projects have included:

- An economical chemical delivery system that reduces wellbore corrosion and lowers maintenance costs.
- A low-cost control box to optimize production
- A pumper and well tender application for smartphones
- A low-cost soil amendment technology to remediate brine contaminated soils

Stripper wells account for 77 percent and 63 percent of the U.S.'s total oil and gas wells respectively, and that number is likely to grow; nearly all wells will decline to stripper status at some point as they age. The benefits to developing inexpensive technologies to keep these wells productive and contributing to the nation's energy supply are broad.

These marginal wells are largely owned and produced by independent operators. Although each well may be relatively insignificant on its own, as a whole, stripper well operations provide many jobs, support the growth and stability of the domestic petroleum industry, and represent much of the nation's remaining oil and natural gas resource. Once a stripper well is plugged, those resources are usually lost and the well abandoned because of the prohibitive costs associated with drilling, completing, and equipping new wells.

The research funded by the SWC will advance the technologies needed to continue the recovery of crude oil and natural gas in these marginal wells—a significant contribution to our nation's energy security.

Results: Since the SWC became active in 2001, they have provided funding for an average of 8 projects per year. As of December 2014, 96 projects in total have received cost-share funding under the SWC program. The following accomplishments have been achieved during this project period:

- Developed an iPhone app called "Pumper's Friend" allows the pumper/well tender to quickly gather and transmit field data more accurately and to review well performance at the well site.
- Developed a soil amendment product that restores sodium-contaminated soils from oilfield brine spills. The product was demonstrated to restore grass growth 2 – 6 weeks after remediation.
- Developed a near-isothermal multi-phase compression technology prototype that is capable of dramatically improving the economics of wet and dry natural gas production. The technology is in the process of being field demonstrated.
- Demonstrated the "Hyper Scratcher" technology nationwide. The technology has unique properties which enable it to combine mechanical and chemical components from cleaning wellbore casing.
- Developed a novel hydraulic diaphragm submersible pump (Pumping Solutions, Inc., now part of Smith Lift LLC) that continuously cleans stripper wells. It also pumps gas/liquid mixtures, can be pumped dry, maintains a constant output, and reduces electric costs.
- Developed a Gas Operated Automatic Lift (GOAL) PetroPump (Brandywine Energy & Development Company). The GOAL PetroPump removes fluid from the wellbore more efficiently than other available plungers lift systems and results in significant increases in gas yields. The plunger lift system does not require an external energy source.

Stripper Well Consortium

- Developed a pre-Pump-Off Controls system (Oil Well Sentry, Inc.). These technologies eliminate problems caused by fluid level in beam-pumped wells. The system shuts off the beam pump motor or engine when the well is pumped off. Field tests showed the system significantly increases production while decreasing energy consumption by 30 percent.
- Created vortex surface tools (Vortex Flow Tools LLC) that represent research, development, and technology transfer successes, as hundreds have been installed in gas-gathering and production lines across the United States. The mechanism of the flow unit can be compared to a tornado. It uses produced natural gas to accelerate water velocity, reduce friction, and lift and remove fluids. The flow unit increases production and reduces the down-time by reducing water contamination in gas gathering and flow lines.
- Developed three stripper well technologies (Tubel Technologies, Inc.): 1) a low-cost, real-time, down-hole wireless gauge for measuring temperature and pressure and other parameters; 2) a plunger lift optimization process that provides the operator information about plunger performance and identifies wells in which the plunger is not operating optimally; and 3) an upgrade plunger lift process that transfers information wirelessly to remotely-located control room.

Ongoing Research: The SWC is conducting a study which will review the technology developed through the SWC., summarize key technology and commercial trends in stripper well and unconventional resource industries, investigate the common ground in the technical and operational aspects of both stripper wells and unconventional wells and identify teh specific technologies and practices that will benefit both, and identify technology gaps and innovation needs for the stripper well industry. These results will be presented at the final SWC Technology Transfer Meeting on July 9, 2015, and the report will be posted on the SWC website.

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Project Number: DE-FE0003616

Period of Performance: 6/2010-7/2015

More information about the SWC can be found at: http://www.energy.psu.edu/swc/

Documents related to projects supported by the SWC between 2001 and 2006 can be accessed at:

http://www.alrc.doe.gov/technologies/oil-gas/publications/SWCReports/index.html

Bridging the Gap between Chemical Flooding and Independent Oil Producers

Objective: To design efficient chemical flooding processes that are necessary for independent oil producers to make an informed assessment for implementation of a pilot or demonstration project.

Research Conducted: Recent advances in chemical development and modeling increase the potential to recover vast amounts of residual oil left behind after primary recovery and waterflooding processes. In addition to increasing the amount of oil that can be recovered from a given field, these advances also increase the number of fields to which these processes are applicable.

Design 'templates" of chemical floods provide the basis for demonstration projects and a starting point for independent oil operators to assess the potential for implementing new chemical flooding technology. Government-sponsored field projects that demonstrate the benefits of new technologies to independent oil producers can be used to promote and advance their widespread implementation.

Nine independent oil companies that produce oil from ten Kansas fields (Berexco Inc., Cimarex Energy Company, Colt Energy Inc., Merit Energy Company, Murfin Drilling Co. Inc., Oxy USA Inc., PetroSantander (USA) Inc., Vess Oil Corporation, and Stelbar Oil Corporation Inc.) provided data and samples from their leases. The researchers completed geological analyses of the oil leases.

The project team conducted laboratory work to identify efficient chemical systems and test the oil recovery performance of the systems. Efficient chemical systems were identified for crude oils from nine of the reservoirs/leases through phase behavior studies where the behavior of various aqueous surfactant/polymer systems was observed before and after they were mixed with a crude oil. The team conducted coreflood experiments using quarried Berea sandstone and Indiana limestone to determine oil recovery performance of the identified chemical systems. Performance was measured as the percentage of oil recovered from cores initially at a waterflooded residual saturation.

The work provided the design templates required to demonstrate chemical flooding processes.

This research project, in conjunction with subsequent successful field demonstration projects, could greatly increase the interest of oil operators in pursuing and implementing chemical flooding applications. Successful field demonstration projects increase the comfort level of independent producers when they are considering implementing new technology. Widespread implementation and acceptance of new chemical flooding technologies could significantly bolster U.S. enhanced oil recovery production, increase ultimate recovery, and help reduce U.S. dependence on foreign oil.

Core #32 section 6 at the end of oil flood.

Results:

- Completed laboratory tests to identify surfactant systems for chemical flooding applications in Kansas oil leases. Chemical systems for seven crude oils were effective in recovering oil from Berea sandstone cores. Synthetic field brine resident in the core at the start of the chemical flood did not negatively affect oil recovery.
- Tested over 15,000 formulations were tested. Chemical systems that meet all the phase behavior criteria for efficient oil recovery were identified for nine crude oils. Core flooding tests to determine oil recovery performance were conducted with chemical formulations for nine oils. Tertiary oil recovery was greater than 90 percent for seven of the oils.
- Discovered that most of the Kansas crude oils responded fa-

Bridging the Gap between Chemical Flooding and Independent Oil Producers

vorably to chemical systems that contained two surfactants: an alcohol propoxy sulfate and an internal olefin sulfonate. This system also required relatively high concentrations of alcohol solvents. The performance of the chemical systems in phase behavior studies was enhanced with the addition of sodium carbonate (alkali). All of the crude oils had low acid numbers, negating the use of alkali in the chemical system for soap production.

- Conducted basic economic analyses of chemical flooding field applications using the results of laboratory and geological studies prepared for each lease and the field data obtained from the operators. Consultations with the operators of these leases resulted in a research proposal: "Field Demonstration of Chemical Flooding of the Trembley Oilfield, Reno County, Kansas" submitted to Research Partnership to Secure Energy for America to extend project work to field-testing through a partnership with the University of Kansas and Berexco, Inc., SNF Holding Co., and Huntsman Petrochemical Inc. (See project 11123-28 on p. 21)
- Conducted chemical floods with formulations for Wahrman crude oil in Indiana limestone cores. Oil recoveries were 50 percent or less in the Indiana limestone cores for the same chemical formulation that resulted in 90+ percent recoveries in Berea sandstone cores. An alternate system containing an alcohol propoxy sulfate and an ethoxylated alcohol without alcohol co-solvent recovered 80 percent of the Wahrman crude from a limestone core. Tracer experiments showed significantly larger mixing zones in the limestone cores. Dilution of the chemical slug due to greater mixing in the limestone cores contributed to the lower oil recoveries.

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Project Number: NT0005679

Period of Performance: 10/2008-3/2012

Read/download the final report.

Novel Self-Thickening Chemicals for Improved Conformance Control

Objective: To identify single chemical agents that self-thicken when dissolved in salt water and increase viscosity with time.

Research Conducted: The technical approach for this laboratory study was to identify available self-thickening systems that were expected to have the desired physical properties, screen these systems to identify the best candidates, and conduct flow-through through porous media laboratory experiments to confirm the desired properties were present. The chemicals could be applied for selectively slowing or blocking high flow water channels in subsurface oil reservoirs and selectively blocking flow in previously watered-out channels. The effect would be decreasing water and increasing oil flow and production.

The project team identified five synthetic polymeric-surfactant polyacrylamide with two or more chemical groups and performed static ageing tests. A static concentration of these chemicals was dissolved into various salt solutions, including sodium chloride, potassium chloride, and calcium chloride, encompassing a range of dissolved salt concentrations. One set of samples was aged at room temperature, and a second set at 50° C. At specific time intervals, sample bottles were selected and the bulk viscosity was measured at their ageing temperature. The solution viscosities were measured more frequently at the beginning of the experiment to ensure no early fast dynamic reactions were missed. Of the copolymers investigated in detail, two exhibited distinct increases in solution viscosity versus time. One was selected for further testing.

Researchers then conducted flow tests by injecting the age chemicals into sand packs at a constant rate and at room temperature. For each chemical, the test was performed three times: with fresh, un-aged solution and again with the solution aged for two different lengths of time. The injection pressure was measured for several pore volumes injection. The chemical solution was injected at two different rates and the resistance factor (RF) was determined for each solution injection at two injection rates. After the RF was determined, the brine solution was injected again with two different flow rates determine the residual resistance factor (RRF).

A second series of sand pack flow tests was then conducted. The baseline was set with fresh solution injected into a sand pack and flushed quickly with brine. Two additional packs were then flushed with brine that had been aged for varying lengths of time. This test was to determine the effect of the expected increase in solution viscosity as it ages in-situ. Each pack was restarted with a constant-rate injection of brine while the injection pressure was recorded. The pressure is expected to be higher for sand packs with longer aging time, reflecting the in-situ self-thickening effect of the injected chemical solution.

If successfully developed, the chemical thickening agent may have the environmental benefit of decreasing the volume of produced water.

Water injected after treatment would be diverted into oil-rich, previously un-swept areas of the reservoir, allowing for the recovery of additional oil. The chemistry of the self-thickening agents will make it possible to match a self-thickening product with available produced water. It may be possible to re-use produced water as supplemental make-up water in stimulations.

Results:

- Demonstrated that it is feasible to develop modified polymer chemistries that exhibit the property of spontaneous "self-thickening" when dissolved in the right combination of brine salinity and temperature.
- Illustrated through the static ageing experiment that as much as a 10-fold increase in viscosity can be achieved after an ageing time of two months.
- Discovered that the injection pressures were similar for the 1% NaCl brine post-flush after 1 day ageing and after 5 days of ageing time. The additional ageing time should have created a significantly greater solution viscosity for the polymer. The RRF values are roughly the same in each case when the steady-state inlet pressures measured during brine injection at the same flow rates. One possible explanation is that the brine displaced a more viscous in-situ polymer solution.

Novel Self-Thickening Chemicals for Improved Conformance Control

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Lead Performer: ChemEOR

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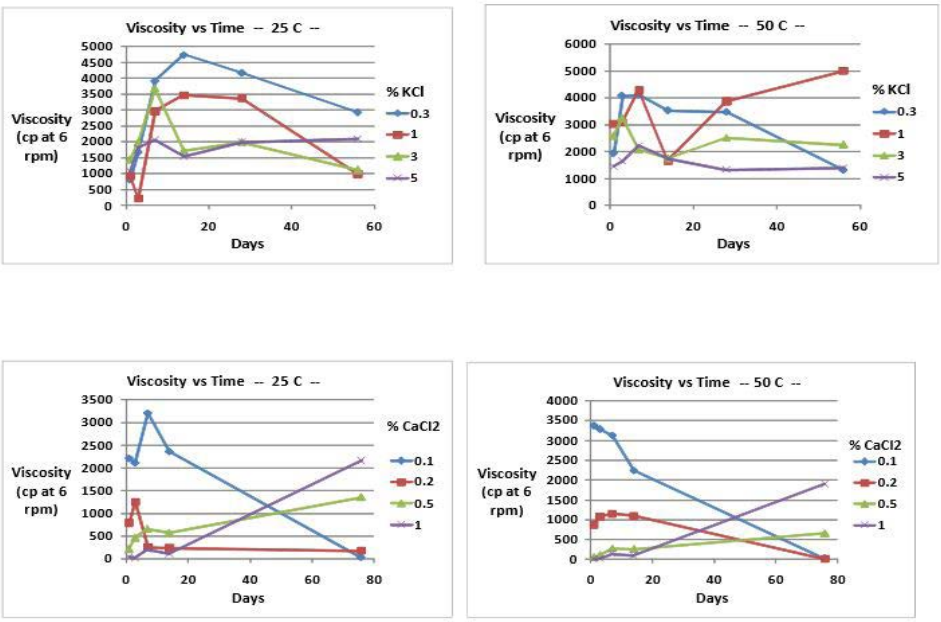
Project Number: DE-SC0004194

Period of Performance: 6/2010-3/2011

Read/download the final report.



Time dependent viscosity behavior of the product Polymer 1 in different brines.

Characterization of Potential Sites for Near Miscible CO_2 Applications to Improve Oil Recovery in Arbuckle Reservoirs

Objective: To aid in the prediction of improved oil recovery using a near-miscible CO_2 flood in the Arbuckle formation.

Research Conducted: Arbuckle reservoirs are a significant resource in Kansas for improved oil recovery. These reservoirs have produced an estimated 2.2 billion barrels of oil representing 35% of the 6.1 billion barrels of total Kansas oil production. Most Arbuckle reservoirs have active water drives, which have maintained reservoir pressure at 1000-1100 psi for nearly 50 years even though millions of barrels of fluid have been produced. It is theorized that any attempt to raise the reservoir pressure in the Arbuckle would simply push back this aquifer influx and not achieve the desired pressure rise. Initial studies of CO_2 miscible flooding indicated that miscibility is not achievable at the reservoir operating pressure in most Arbuckle reservoirs, where the minimum miscibility pressure is commonly 1350-1500 psi; however, the core flow test in the precedent laboratory study indicated that at least 50% of remaining oil could be recovered by CO_2 injection at current reservoir operating pressure, i.e., near-miscible conditions.

The researchers developed a new geological model based on an integrated methodology for generating porosity-permeability profiles and rock types at well locations where no core data was available. A computational study was combined with field testing to demonstrate feasibility. Sequential Gaussian simulation was used to populate porosity and permeability in the final geological model, which captures the characteristics of geologic trends and retains reservoir heterogeneities. In the subsequent computational studies, the effect of the CO_2 injection scheme and pattern on oil recovery efficiency were examined. The researchers conducted a single well pilot test, which consisted of a single well chemical tracer test before and after CO_2 injection on a selected well producing from the Arbuckle formation. The team then determined the effectiveness of CO_2 displacement efficiency by the reduction of oil saturation measured from the tracer tests.

Oil displacement by injection of CO_2 at near-miscible conditions would result in more effective recovery of reserves. It is implicitly hoped that this work will be instrumental in promoting the practice of improved oil recovery using CO_2 injection at near-miscible conditions.

Results:

- Identified a reduction of oil saturation from 0.23 to 0.20 following CO_2 injection through pilot testing. This represents a 13% improvement of oil displacement resulting from injection under near-miscible conditions.
- Examined the effect of the CO_2 injection scheme and pattern on the oil recovery efficiency through computational studies. Displacement efficiency was found to vary slightly with different injection patterns and schemes. In general, displacement efficiency at near-miscible conditions is improved from 39% to 46% on average with continuous injection and to 49% with WAG injection. The oil mobilized by CO_2 displacement is observed in the model at production wells in the target lease and in surrounding leases.
- Demonstrated that oil displacement by injection of CO_2 at near-miscible conditions is feasible and effective. The gross utilization and net utilization of CO_2 calculated from the model are higher than those most commonly observed in miscible flooding operations.

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Lead Performer: University of Kansas Center for Research

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Project Number: 09123-18

Period of Performance: 2/2011-9/2014

Read/download the final report.

Identifying and Developing Technology for Enabling Small Producers to Pursue the Residual Oil Zone (ROZ) Fairways of the Permian Basin, San Andres

Objective: To delineate the presence and size of residual oil zone (ROZ) resources in ROZ fairways in the Permian Basin of Texas and New Mexico.

Research Conducted: In the Permian Basin of Texas, thick ROZs exist immediately below many oil fields that are productive from the San Andres dolomite. The zones are also present between fields and can contain 20 to 40% residual oil in pore spaces. This oil cannot be produced by conventional production techniques, including water flooding. A ROZ CO_2 flood is underway in the Seminole field, and early projections suggest the project may recover 200-300 million barrels of additional domestic oil. In addition to examining the Texas resource in more detail, the study intends to develop technology for finding the higher quality portions of the ROZ resource recoverable with CO_2 EOR directed toward the small oil producers within the Permian Basin and other ROZ basins within the U.S.

Collection, documentation, identification, and interpretation of ROZ-related data from cores, mudlogs, and electric logs data for the San Andres in the Gaines, Yoakum, Terry, & Dawson county area was completed. The data was used to generate cross sections and complete log analyses and evaluate the ROZ potential in this particularly rich resource 4 county area. The team evaluated the 4 counties. Those counties have been divided into trend areas and intervals of good and poor ROZ potential, and are estimated to have 107 billion barrels of oil (BBO) in place. Of that, 67 BBO have been deemed high quality (>8% porosity and 25% oil saturation).

Additionally, the team obtained ROZ cores from Gaines county and Yoakum county. The data review methodology and facies model are helping to construct a "cookbook" guide for others searching for ROZ resources.

In August 2014, team members presented a forum on residual oil zones in Steamboat Springs, Colorado. Attendees included a diverse group of U. S. and international companies, Wyoming's Enhanced Oil Recovery Institute and North Dakota's Energy & Environmental Research Center. A similar ROZ forum was presented to a different set of U.S. and International companies at the December 2014 CO_2 Flooding Conference in Midland, TX.

Development of a successful practice of ROZ characterization and suitable tertiary recovery methods have already led to national and international interest related to both ROZ EOR and associated CO_2 Sequestration which will undoubtedly lead to the recovery of billions of barrels of additional domestic oil, much of it by small producers in the Permian Basin and elsewhere. The benefits are expected to extend to CCS since approximately 1 ton of CO_2 is incidentally stored for every 2 barrels of oil produced during the CO_2 EOR process.

Results:

- Generated a regional facies distribution model for the ROZ using ROZ cores from Gaines and Yoakum counties, along with cores from the DOE-sponsored Goldsmith project.
- Observed and improved understanding of the difference between ROZ and main pay zone reservoirs. Some of the differences in the rock and fluids can be attributed to microbial processes which are now better understood. These understandings have helped explain the high residual oil saturations being observed at least in carbonate reservoirs.

Ongoing Research: As the ROZ-related data is collected and interpreted, two other activities are being conducted in parallel. First, a generalizable methodology for ROZ characterization is being developed; and second, a ROZ cookbook containing all of the data and methods developed under the present project and the preceding RPSEA project is being assembled (08123-19). Word of mouth communications and presentation at the CCUS, EORI and PCOR Annual meetings have led to international interest from Chinese, Saudi Arabian, Australian, Columbian, Brazilian, and Indonesian state and private petroleum entities.

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Lead Performer: University of Texas of the Permian Basin

Robert Trentham, the University of Texas of the Permian Basin

Project Number: 10123-17

Period of Performance: 6/2012–12/2015

Additional information about this project is available on the RPSEA website.

Producing Light Oil from a Frozen Reservoir: Reservoir and Fluid Characterization of Umiat Field, National Petroleum Reserve, Alaska

Objective: To develop a robust geologic model that includes both the sedimentologic and structural characteristics of the reservoir; upscale the geologic model into a reservoir model; collect the necessary fluid and reservoir properties data for the simulation; and test possible production methods via desktop simulation.

Research Conducted: In the Umiat oil field in Northern Alaska, light oil is trapped in a shallow, frozen reservoir consisting of multiple shallow marine sands of the Cretaceous Nanushuk Formation (Fm.). Although Umiat was discovered in the 1940s, little is known about how to maximize conventional oil production from a frozen reservoir and no characterization exists of a rock, ice, and light oil system at low pressure. The goal of this project was to collect and analyze the information needed to learn how to produce this shallow, frozen reservoir.

The team analyzed core descriptions and well logs taken in the 1940s and 1950s from twelve legacy wells at Umiat oil field. Related field work focused on describing outcrops of the Umiat reservoir. Samples were collected for diagenetic studies and pore structure analysis. Horizontal and vertical permeability measurements were also taken in major lithofacies in both core and outcrop.

To develop a structural model of natural fracture distribution, team scientists examined both the structural geometry and the distribution of fractures in the Umiat structure and in the nearby, well-exposed Big Bend anticline.

Researchers designed and built an experimental apparatus that allowed them to study the relative permeability of oil and gas in ice. Six representative core plugs were studied to investigate two-phase fluid flow properties at temperatures ranging from room temperature to simulated permafrost conditions in Umiat porous media.

The team also built a static property model of the reservoir that incorporated new geologic data, including porosity and permeability anisotropy trends and structural geometry. Applying that model using average observed porosity and water saturation (SW) values produced an estimated original-oil-in-place (OOIP) value of approximately 1.52 billion barrels and 99 bcf of associated gas.

The team used a wagon-wheel pattern for the simulation because it was the most efficient pattern for accessing the maximum amount of the reservoir interval while minimizing the surface footprint. To reduce the costs and surface impact, five pad locations were used in the simulation, with a combination of 85 producers and 25 injectors. Three different scenarios were evaluated: no gas injection, cold gas injection with bottom hole injection pressures (bhip) of 400 psi, and cold gas injection with a bhip of 600 psi.

The results will provide important information concerning production methods for this and similar frozen reservoirs in northern Alaska and other arctic regions. If the resources in this region are successfully tapped, the products will increase the supply of domestic oil and gas.

Because permeability patterns can be linked to the identified lithofacies and facies associations, predictions of permeability and permeability anisotropy across the field can now be made.

Results:

- Discovered that the main reservoir interval at Umiat field, the Lower Grandstand, may contain more than 1 billion stock tank barrels of high-quality crude oil. Although the team's simulations suggest that recovery from the Umiat reservoir will be relatively low (12-15%) using cold gas injection, the volume of oil in place makes it of interest to industry.
- Discovered through simulation results that recovery will be very sensitive to injection pressure and permeability anisotropy. Increases in injection pressure lead to higher average reservoir pressure and increased oil production. Conversely, higher permeability anisotropies reduce the effectiveness of cold gas injection, reducing recovery.
- Developed the most detailed and accurate geologic model of the Umiat reservoir to-date, including an evaluation of permeability anisotropy by facies and depositional environment. Work from this project also indicates two major fracture networks are present in the Umiat structure: one approximately perpendicular to the structure and a second approximately parallel to the structure. These fractures could play a major role in enhancing vertical permeability

Producing Light Oil from a Frozen Reservoir: Reservoir and Fluid Characterization of Umiat Field, National Petroleum Reserve, Alaska

and vertical connectivity in a reservoir that is otherwise highly compartmentalized.

- Successfully generated unique gas-oil relative permeability data for frozen rocks. To the best of the team's knowledge, it is the first such data ever to be published in open literature on flow through porous media.
- Discovered that lowering the temperature of porous medium significantly below 0°C results in a reduction of oil relative permeability.
- Recognized natural fractures in both the core and subsurface for the first time. If these fractures are open and contributing to flow, recovery from the Lower Grandstand may reach the upper range of the simulation estimates.
- Developed an experimental technique to determine the relative permeability of oil and gas in the presence of ice. The approach can be used to evaluate relative permeability in similar reservoirs.
- Discovered that a simple water-based mud may not a viable option in this cold environment. Scientists recommended that new fluids be tested, including different salts, brines, polymers and oil-based fluids. These fluids should be tested at low temperatures to determine the potential for formation damage, the fluid properties under these conditions and to ensure that the freezing point of the fluid is below that of the reservoir.

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Project Number: DE-FC26-08NT0005641

Period of Performance: 10/2008-12/2012

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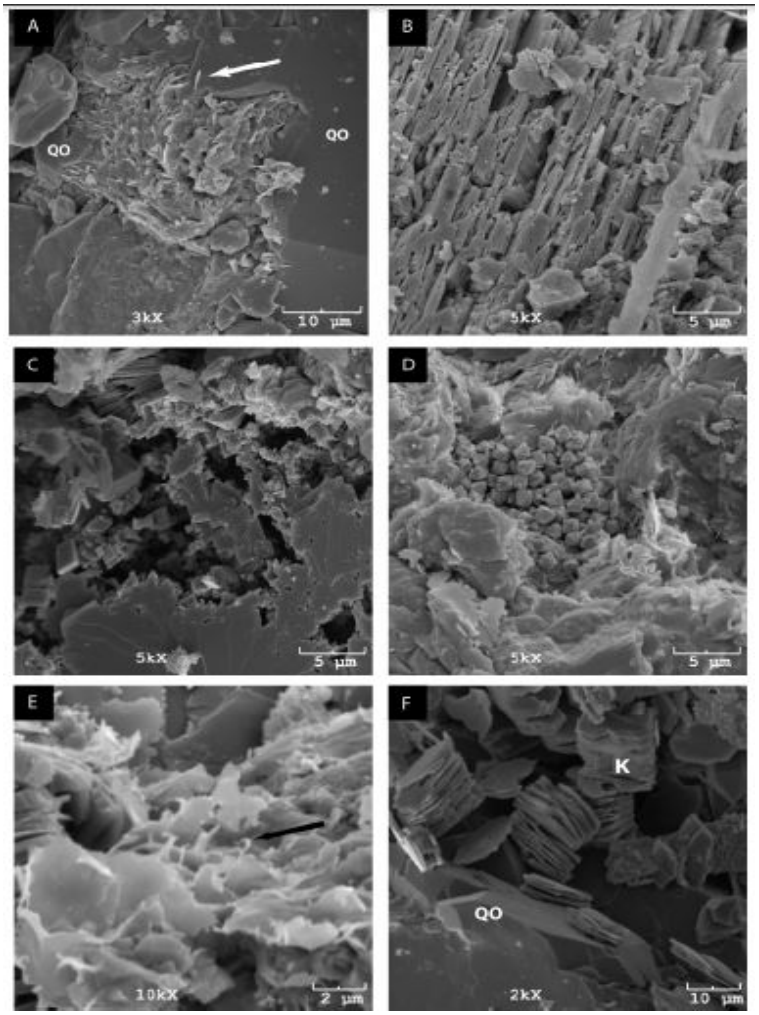

Scanning electron microscope (SEM) micrographs of diagenetic mineral phases.

Reservoir Characterization of Bridgeport and Cypress Sandstones in Lawrence Field Illinois to Improve Petroleum Recovery by Alkaline-Surfactant-Polymer Flood

Objective: To test the suitability of ASP flood technology as an enhanced oil recovery technique for increasing oil production from the two most productive reservoirs in the Lawrence Field and to expand the employment of ASP flood technology from small, limited pilots in the Pennsylvanian Bridgeport and Mississippian Cypress sandstones to the remainder of the Lawrence Field.

Research Conducted: The Lawrence Field in the Illinois Basin has produced in excess of 410 million barrels of oil since 1906 utilizing both primary and secondary recovery (water flood) methods. The field currently produces with a less than two-percent oil cut and, like many mature fields in the United States, is approaching its economic limit. This is despite the fact that Lawrence Field contains a significant volume of potentially recoverable oil. Alkaline-Surfactant-Polymer (ASP) flood technology offers some promise for the recovery of this remaining oil.

The project team collected data from the 25 largest Cypress fields and the 25 largest Pennsylvanian fields in Illinois and formatted it into tables to assess ASP flood technology in this region. The team also assessed basins within the United States that were conducive to ASP flooding.

The project team characterized pilot areas for the Bridgeport and Cypress Sandstone reservoirs. An expansion area of approximately 5.5 square miles was established for reservoir characterization. The project team completed research that emphasized understanding the complex relationship of depositional environment and facies variation within a rapidly altering sequence stratigraphic framework and how it relates to reservoir compartmentalization and flow unit modeling. Petrographic analyses, with emphasis on the characteristics that positively and negatively affect the reservoir properties of the separate reservoir facies, were defined. Over 800 feet of core samples from 15 separate wells were photographed and described in the expansion area.

In order to help characterize the complex systems and visualize the complexities within the Lawrence Field, a strategy was developed to utilize a conceptual geologic model to guide the construction of geocellular models of the reservoir architecture. The process combined both traditional and geostatistical methods to create a beneficial check and balance loop where the geocellular and the geological models complement each other. The geostatistically generated geologic model (porosity, permeability, thickness, geometry, and depth) was also used as input to the reservoir simulation model.

Rex Energy Corporation used the data generated in this study to introduce chemical flooding in stages, with the first flood initiated in 2010 and a second offset pilot project initiated in 2011.

Results:

- Reported a positive response from Rex Energy Corporation on its 2010 ASP Middagh pilot project in the Pennsylvanian Bridgeport B reservoir in the Lawrence Field. Total pattern production increased from 16 BOPD and stabilized at a range of 65–75 BOPD in the last three months of 2011. Peak production rose to more than 100 BOPD. Oil cut in the pilot increased from one to approximately twelve percent with individual wells showing oil cuts greater than 20 percent.
- Determined from the substantial increase in production following the ASP flood in the Middagh pilot that there was likely sufficient remaining unswept petroleum to warrant expansion to larger areas of Lawrence Field. Thus, Rex Energy expanded testing to a 58-acre portion of the field. In 2013, Rex Energy employed ASP technology in a 351-acre parcel immediately south of the current operation. With continued success and private investment in these ASP pilots, the entire Lawrence field may once again be revitalized.
- Discovered that the more consistent the geostatistical model is to the actual geology, the more relevant the simulation model results will be and greater the likelihood of the success of an enhanced oil recovery (EOR) project.
- Determined that each potential EOR reservoir must be evaluated separately. It was particularly important to define reservoir geometries and to establish the location of reservoir boundaries to ensure economic strategies for injecting fluids.

Reservoir Characterization of Bridgeport and Cypress Sandstones in Lawrence Field Illinois to Improve Petroleum Recovery by Alkaline-Surfactant-Polymer Flood

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Project Number: NT0005664

Period of Performance: 9/2008–3/2013

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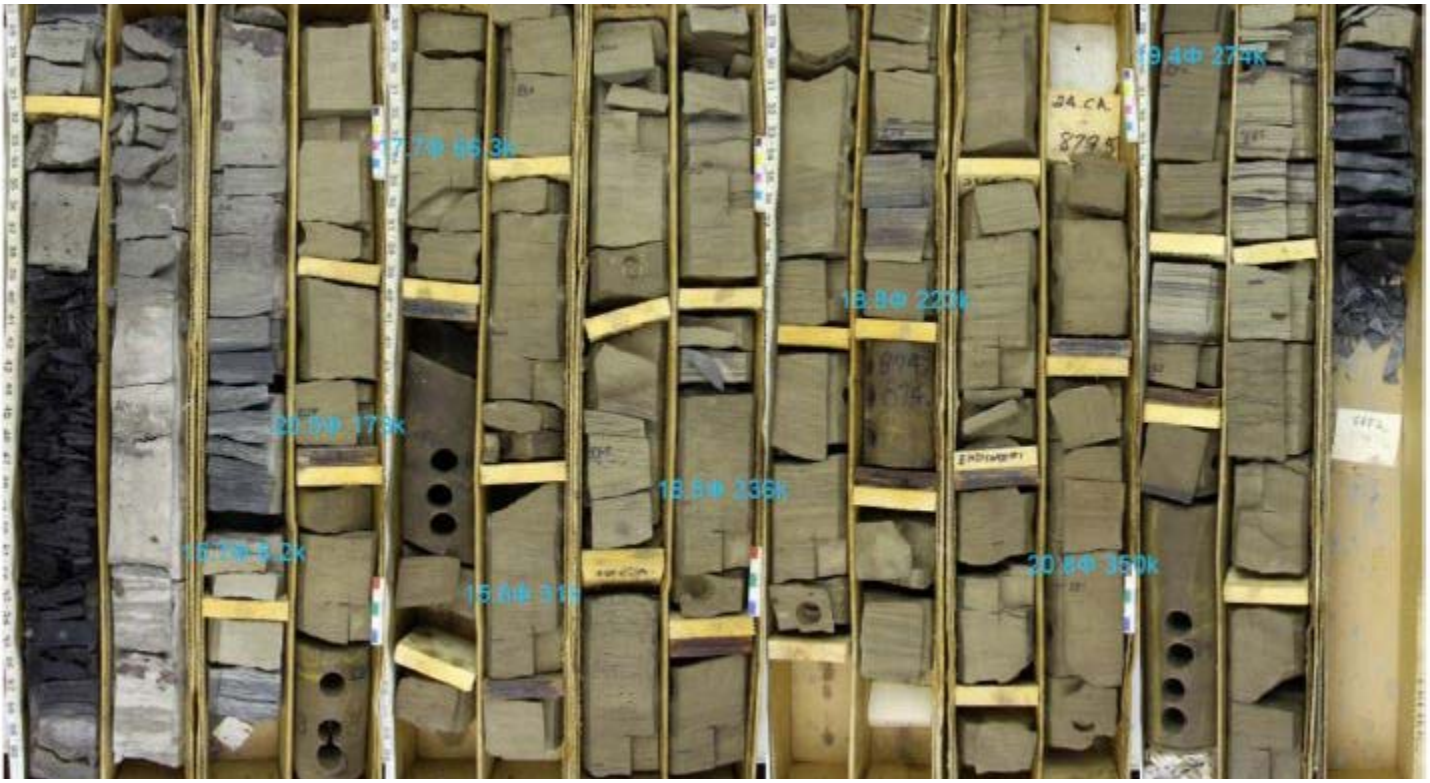

Core from the Johnson #32 well showing typical succession and arrangement of facies of the Bridgeport B in Section 32.

Upstream Ultrasonic Processing for Small Producers: Maintenance for Paraffin Management in Production Tubing Using Non-Invasive Ultrasonic Technology

Objective: To demonstrate the cost savings associated with adopting ultrasonic preventative maintenance measures for oil well production tubing that suffer from frequent paraffin wax plugging; these measures would replace the existing methods (i.e., constant remedial maintenance or resistive-heating based preventative methods).

Research Conducted: Accumulation of paraffin deposits in production tubing/flow lines is a major and costly problem for the upstream oil industry. The problem is typically approached reactively; the deposits accumulate and then a costly solution is applied (e.g., scraping, hot oiling, and chemical treatments). Maintaining temperature above the wax appearance temperature can be used to prevent paraffin deposition. Downhole resistive heating (heat tracing) systems are a mature, commercially-available option for preventative maintenance; however, resistive heating systems and associated insulation make this solution too costly for most small producers.

Pacific Northwest National Laboratory (PNNL) has developed and tested a noninvasive ultrasonic liquid processing technology that is installed around the outside of production tubing and takes advantage of the inherent ultrasound-absorptive properties of oil to preferentially heat the oil first, and then the production tubing through thermal equilibration. In Phase I of this two-phase project, the performance of the technology will be modeled and tested and compared with remedial methods and resistive heating methods. The capital and operating costs of these methods will also be compared. Phase 2 includes field testing of an engineering test unit (prototype) in an oil well to be identified by a small producer partner upon completion of the economic analyses.

The researchers have completed the design, assembly, and first functional test of a resonance tracking lab prototype system for the proposed ultrasonic piezoelectric elements.

PNNL completed modifications to the heavy oil flow loop to accommodate sonication and monitoring during testing.

Developed prototype electronic units for ultrasonic resonance tracking and electrical impedance matching that will work with the sonication system to optimize its efficiency during operation as temperature, production contents in the tubing, and other system factors change (e.g., power; system age; tube coupling).

They have also completed development of the data acquisition system (DAS) software, which will log data from the flow loop sensors and electronics.

The ultrasonic technology has the potential to be less costly and more energy-efficient than trace heating systems, and thus feasible for implementation especially by small producers.

Results:

- Completed the first resonance tracking prototype and tested it with a piezoelectric element mounted to a pipe segment. The prototype tracked and adjusted the changing ultrasonic resonance when the empty pipe segment was filled with liquid, which changed the temperature and electro-mechanical properties of the load.

Ongoing Research: PNNL will complete shakedown testing of the heavy oil flow loop before commencing sonication testing in late FY 2014. Testing will be conducted with the prototype resonance tracking and impedance matching units to optimize system efficiency.

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Project Number: 11123-09

Period of Performance: 10/2013–10/2015

Additional information on this project is available on the RPSEA website.

Study and Pilot Test of Preformed Particle Gel Conformance Control Combined with Surfactant Treatment

Objective: To conduct extensive lab experiments and field demonstration tests of the (preformed particle gel) PPG and surfactant combination to increase understanding of the combined technology and identify where and how the technology can be applied most effectively.

Research Conducted: Excessive water production in mature fields can impact profitability. The total cost to separate, treat, and dispose of water associated with oil production is approximately $50 billion per year. A novel technology—PPG and surfactant combined in one enhanced oil recovery (EOR) process—may significantly reduce water production and improve both displacement and sweep efficiency.

The project has three major activities. The first activity is to test the extent to which the proposed novel EOR method—the coupled PPG and surfactant technology—can improve oil recovery and oil production rates and identify where the novel technology can be applied most acceptably. This activity will be completed in a lab through chemical interaction tests and core-flooding tests. The second activity is to optimize a field design by conducting lab tests and field data analyses and to execute the design by injecting PPG and surfactant into target wells. The third activity is to evaluate whether well candidates provided by SPs are suitable for PPG treatment and the coupled method.

The researchers have been conducting laboratory experiments to comprehensively evaluate the proposed novel EOR process, to screen the best PPGs and surfactants compatible with the formation fluids provided by small producer (SP) collaborators, and to select screen tracers for field applications. A coreflooding apparatus has been setup to test gel dehydration. Fluid samples (oil, formation water samples) have been collected from SP partners. A paper (SPE 169016) was submitted to *SPE Journal* for review.

In addition to demonstrating the effectiveness of the combined treatment, this project will help establish the injection procedures for most effective use and make them accessible to SPs via the Internet.

Results:

- Conducted a PPG treatment pilot test in leases operated by Colt Energy Company. Water injection pressure was increased and water production was reduced in adjacent wells.
- Successfully injected particle gels. The injection pressure increased during PPG injection, as expected. The water injection pressure increased after the PPG treatment. Excess water was shown after 30 minutes. The producer then was shut-in and pressure gage was put in to monitor the pressure. No particles were produced when the production was restarted.

Ongoing Research:

- Testing the extent to which the proposed forced imbibition technology can reduce water production and improve oil production, and to identify where the novel technology can be applied most acceptably through a series of lab tests;
- Screening PPGs and surfactants for pilot testing in wells operated by Blue Top Energy and provide an optimized treatment design by diagnosing reservoir problems and analyzing field data. The choice of the surfactant will be based on both its ability to reduce heavy oil viscosity by forming water-in-oil emulsion and the stability of the emulsion, which will be enhanced by adding nano-particles;
- Executing field pilot tests and monitoring production performance after treatment; and
- Evaluating the feasibility of PPG treatments or PPG combined with surfactant for the wells provided by SPs.

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Project Number: 11123-14

Period of Performance: 11/2012-08/2015

Additional information on this project is available on the RPSEA website.

Hybrid Rotor Compression for Multiphase and Liquids-Rich Wellhead Production Applications

Objective: To test and further develop OsComp System's hybrid rotor compression technology into a robust and commercially-viable solution which could be used as a multiphase compression solution for wet gas applications in SP environments.

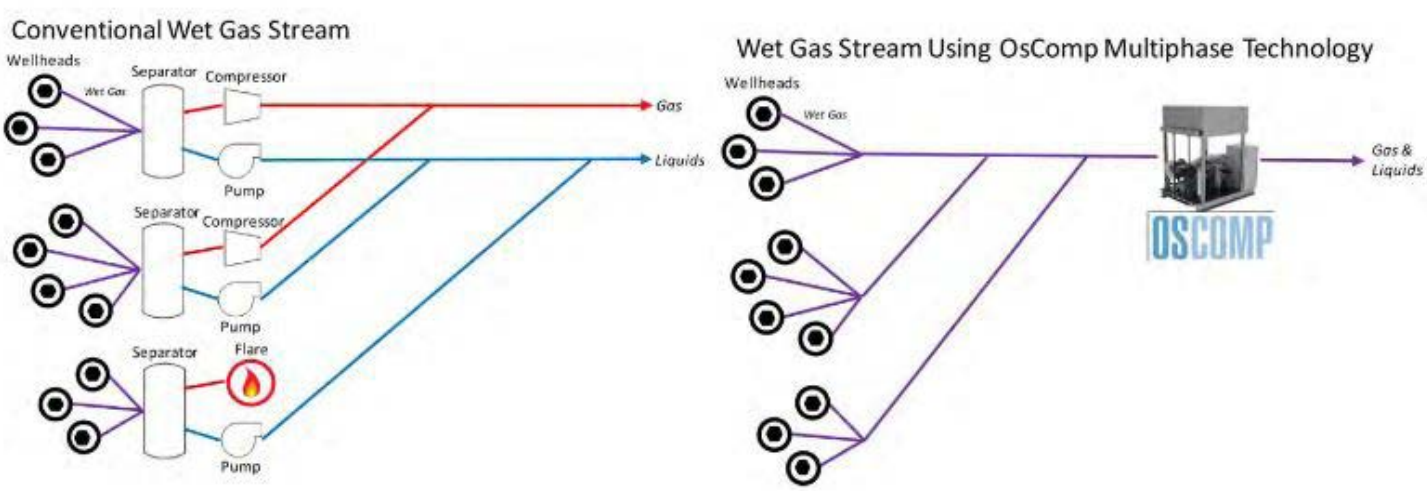
Research Conducted: Wet gas (gas that contains liquid content, even in small amounts) is becoming an increasingly large and important component of the energy landscape. Wet gas is considerably more difficult to produce because of the complex separation equipment required at wellheads in order to use compression technology. Small producers (SPs) who own and operate liquid-rich wells end up absorbing these equipment costs. They also have the challenges associated with transporting liquid and gas streams separately. The technology for operating wet gas wells also creates environmental issues, including fugitive hydrocarbon emissions, large wellhead footprints, and occasional flaring of gas or liquids at wellheads. Phase 1 of this project iterated upon the existing technology and optimized it for wet gas wellhead conditions and prove operation in a simulated environment. Phase II was to successfully demonstrate the technology through the installation and operation of a compression skid in the field at a SP's wellhead.

The project team tested and analyzed OsComp's pre-existing technology to inform the redesign of the system. The updated design was successfully built into a second generation prototype which was tested in OsComp's facilities under controlled conditions. Then OsComp's engineering team tested its compressor under controlled conditions to gain a full understanding of its capabilities. A complete compression system was designed and built around the OsComp compressor to allow for field testing.

OsComp Systems has developed a novel compression technology that has the capability to significantly benefit wet gas wellheads, particularly for SPs. OsComp's compressor combines novel hybrid rotor geometry with innovative cooling techniques to deliver a compressor capable of accommodating wet gas at high efficiencies and in a small footprint. With OsComp's compression technology, a multiphase stream can be pumped from the wellhead to a central facility for separation and processing. Eliminating the need for liquid separation at the wellhead eliminates fugitive emissions and allows for significantly smaller wellhead footprints. In addition, OsComp's wet gas compression system will be cost effective enough that some marginal wellheads which are otherwise uneconomical to produce can continue to operate.

Results:

- Successfully iterated from the Unit 1 design to the Unit 2 design. Additional comprehensive testing by the OsComp team will be able to further refine the design. Field demonstrations will prove preliminary reliability of the technology with full commercialization to shortly follow.



Schematic of conventional (left) versus OsComp (right) wet gas stream.

Hybrid Rotor Compression for Multiphase and Liquids-Rich Wellhead Production Applications

- Determined that the system was too complex to expect improvements on performance when only testing at a full system level, so a new plan of component and system level testing was initiated. This component level testing proved to be very successful and performance improved on several critical subsystems.
- Developed and tested two successive compressor prototypes. The testing shows very strong conceptual proof of concept, with the compressor being able to successfully accommodate multiphase flow through the machine without experiencing hydrolock conditions expected with conventional compression technologies.
- Encountered challenges during testing with achieving sufficient reliability of the machine, and so the initially planned field trials were pushed out in favor of additional lab testing and redesign efforts. The project culminated with significant strides made in working through many of the problematic components and subsystems of the compressor. In addition, private funds have been secured to allow development to continue, the successful completion of which will lead to future commercialization of the technology.

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Lead Performer: OsComp Systems Inc.

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Project Number: 11123-15

Period of Performance: 1/2013-5/2015

Read/download the final report.

Reduction of Uncertainty in Surfactant-Flooding Pilot Design using Multiple Single Well Tests, Fingerprinting, and Modeling

Objective: To advance the technology of surfactant polymer (SP) flooding—in particular for Oklahoma's Pennsylvanian-aged sandstone reservoirs and similar geological formations in other states that contain high total dissolved solids brines—through laboratory and field tests.

Research Conducted: Many mature reservoirs that have the potential for chemical enhanced oil recovery have high salinities that are problematic and challenging for process design. High salinities also make an alkaline surfactant polymer flood economically impossible and technically difficult due to the high cost of water treatment, sludge disposal, and potential scale problem in the formation. An SP flood may be an option for reservoirs containing brine having high total dissolved solids (TDS) and hardness.

Reservoirs containing brine with very high total dissolved solids and high hardness make the design of an SP flood difficult because surfactant tends to precipitate and separate under these conditions.

The project team evaluated optimal surfactant formulations in one-dimensional sand packs and coreflood tests using Berea sandstone, reservoir oils, and brines at reservoir temperatures. Reservoir oil and brine from a well site were characterized via lab studies to check phase behavior. The researchers also conducted fingerprinting via asphaltene analysis. (Asphaltenes have a highly porous structure and are capable of occluding molecular species within their networks, keeping them from biodegrading in situ.) Successful isolation of these species can identify, i.e., "fingerprint," a given crude and could help streamline the design of a chemical flood. Six multiple single well tests will be completed over a two-year period to verify the robustness of a new high TDS surfactant system and its ability to mobilize oil. Pre- and post-chemical flood tracer tests are being conducted to assess the residual saturation and oil recovery performance.

The combination of multiple single well tests, fingerprinting, and modeling can reduce the uncertainties associated with a pilot and incentivize small producers to utilize SP. The high TDS SP formulations used can mitigate environmental impact by eliminating the need for low salinity water for the flood. These innovations will lead to greater use of SP domestically, enabling mature resources to play a key role in U.S. oil and gas production.

Results:

- Successfully developed binary and ternary surfactant-only formulations (based on batch and sand-packed column experiments) for use in high salinity formations. The developed ternary surfactant-only system can markedly improve recovery of viscous oil as confirmed in sand-packed column and coreflood experiments.
- Confirmed laboratory results in situ in the presence of high-salinity formation water through the first single-well test. Results of the single-well test indicated that significant trapped oil (> 90% reduction of residual oil) could be mobilized from the target zone in a tight formation (i.e., permeability of 15 millidarcys).
- Initially observed that the ultra-low interfacial tension had been achieved using a ternary surfactant formulation with site crude; however, the resulting column tests did not show favorable oil recovery. Part of this poor performance was due to the tight formation at the low permeability H well site. The project team explored a surfactant-only formulation for tight formations in additional tests. A second set of column studies showed a marked increase in oil recovery.
- Introduced additional formulation modifiers (e.g., chelating agents and hydrophilic linkers averaging 300 to 600 mg/L) to improve the performance of the surfactant formulation (e.g., increasing the coalescence rate of the microemulsion and maintaining a stable solution over an extended period).

Ongoing Research: The project team plans to conduct additional single-well tests in different formations and locations to expand the applicable ranges of surfactant formulations while minimizing the design risks involved for the surfactant pilot test. A future pilot test at a sandstone reservoir to further evaluate the effectiveness of surfactant formulation and address technical issues related to scale-up is scheduled for late 2014.

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Project Number: 11123-24

Period of Performance: 1/2013–5/2015

Additional information about this project is available through the RPSEA website.

Reducing the Impacts of Deterioration of Cement Integrity on Small Producers

Objective: To develop a new technology to control, design, and characterize a novel oil well cement with exceptional physiochemical properties.

Research Conducted: Improper sealing of wells and cement deterioration can lead to accidental well leaks which can contaminate groundwater and the environment; since cement deterioration has such a potential environmental impact, ensuring cement integrity is vitally important to operators.

The team has completed a literature review on the technical subjects and synthesis and characterization of cement samples at high temperatures has started.

The micro reactor designed for high temperature and pressure was recieved and calibrated. Project scientists have begun to explore the processes of synthesis and self-assembly of cement.

The subcontract agreement between the consortium members (Rice and C-Crete Technologies) was executed. Key equipment is being put in to place.

Successful completion of this work is expected to increase cost-efficiencies and reduce risks throughout the productive life of wells. Small operators, specifically unconventional and deep-water producers, will benefit through an improvement in overall environmental safety and protection. This project's cement product may also help them meet current and future regulatory requirements.

Results:

- Optimized the concentration, reaction time, and post-processing procedure for achieving a relatively homogeneous distribution of spherical shaped C-S-H particles. Found that the calcium to silicon ratio (C/S) of these particles, which is important to the overall bulk strength, is dependent on reaction temperature.

Ongoing Research: The project team will identify temperature and pressure ranges that permit the stable synthesis of target nanoparticle (NP) compositions with controlled chemistry and structure. More specifically, they will develop a method for synthesizing cement samples that express a specific morphology and structure as a function of temperature and pressure.

To accomplish this, the team will use a double displacement methodology or pozzolanic reactions to prepare cement samples with controlled calcium (Ca) and silicon (Si) contents. With these samples, the team will investigate the effect of temperature at fixed pressures and pressure at fixed temperatures. They will also evaluate silicate polymerization using ^{29}Si nuclear magnetic resonance (NMR) to determine conditions under which the $Si_2O_7^{6-}$ ion is the dominant silicate form.

The project will also produce a protocol to control the size and shapes of cement NP and will use that protocol to produce stable and compact cylindrical cement samples. Researchers will evaluate the structural, compositional and mechanical properties of the new cement compositions with controlled nanoparticles.

Once a prototype is designed, a proof-of-concept prototype will be developed and tested against API standards to ensure technical and economic viability.

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Lead Performer: Rice University

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Project Number: 12123-42

Period of Performance: 6/2014-9/2016

Additional information about this project is available on the RPSEA website.

A Full-Featured, User Friendly CO_2-EOR and Sequestration Planning Software

Objective: To develop a tool that includes all significant physical and chemical factors that impact the flow and recovery of reservoir fluids, and to make the simulation modeling building and evaluation process fast enough so that an integrated feasibility study can be completed in a relatively short time period.

Research Conducted: The team developed an integrated software solution that includes a graphical user interface, numerical simulation, visualization tools, and optimization processes for conducting reservoir simulation of CO_2-(enhanced oil recovery) EOR. The tool was designed with state-of-the-art user interfaces and technically rigorous solutions to allow all small to mid-sized field operators to quickly design and optimize CO_2 EOR and sequestration operations.

Specifically, the team identified graphical user interface (GUI) layouts for the application, developed the structure of time-step calculations and routines associated with wellbore pressure drops, and integrated the HYPRE software package from Livermore National Laboratory for the linear solver and conductedtests to ensure well data information can be imported, exported, and displayed. The project team then developed the report generation routines, which writes the simulation results to an ASCII output file so it can be accessed by the user through the interactive user interface. The optimization module for the application was written and integrated.

To assist the users, the team wrote and provided a hyperlink to a searchable electronic user manual for each module and integrated it into the software. They also developed and tested interactive tutorials. The tutorials allow users to explore the software at their own pace based on interaction with individual screens.

The team enhanced the dynamic module development design such that it accommodated historical completion, production, injection, and pressure data for wells. They used a hypothetical data set to test the subroutines related to the module's data handling.

Once the intermediate testing of individual software modules was completed and the modules integrated, a case study involving a prospective CO_2-EOR candidate field in Wyoming was successfully performed.

Results:

- Led a user forum entitled "New Reservoir Simulation Software Designed to Aid Smaller Operators in Conducting More Rigorous Reservoir Studies." The forum was held at a workshop run by the Petroleum Technology Transfer Council (PTTC).
- Developed software as a result of this project advances technical CO_2 injection studies conducted by small and mid-sized oil field operators. The application meets an important need by allowing small producers' access to a development planning and economic analysis solution that is neither too simplistic nor too complex. Other solutions are often too time-consuming and delay operations at the develop stage or too expensive. Previous solutions are only available to major oil companies and large independents, practically speaking, due to the price (often greater than $500,000.00).
- Finalized the field-ready application and made it a freely to the public and businesses in the United States. The software's executable file can be downloaded from www.nitecllc.com. The team continues to enhance the software. An updated version of the software and a supplement to the user guide has been released.

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Lead Performer: NITEC

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Project Number: FE0006015

Period of Performance: 1/2011-1/2013

The final deliverable (i.e., the software application) can be downloaded from the NITEC website.

Investigation of Improved Conductivity and Proppant Applications in the Bakken Formation

Objective: To identify the factors that lead to the collapse of propped fractures in order to improve the lateral and vertical drainage of hydrocarbons from the Three Forks and Bakken Formations.

Research Conducted: Although propped fractures can be created to breach the lower Bakken Shale, field evidence suggests that operators are typically unable to sustain a hydraulic connection through this barrier. Although many factors contribute to the collapse, the research conducted for this project focused on laboratory testing to identify the factors responsible for the collapse of the propped fractures and the resulting loss of conductivity.

At the end of a hydraulic fracture treatment, the fluid that flows back to the surface includes fluids used to stimulate the well and formation fluids such as crude oil, gas, and formation water. This flow back exposes the proppant to formation fluids. The project team conducted laboratory tests to investigate the sensitivity of core samples taken from the Bakken and Three Forks formations to various fluids to examine potential strength degradation for both the rock and proppant.

The proppants used were Ottawa sand, resin-coated sand (RCS), and ECONOPROP ceramic proppant. The fluids used in the experiments included:

- Slickwater – mixture of polyacrylamide and freshwater.
- Cross-linked gel – guar polymer thickening agent, borate cross-linker, and freshwater.
- Gelled diesel – diesel fuel and phosphate ester.
- Bakken Formation crude – crude oil.
- Bakken Formation brine – highly concentrated saltwater

To conduct the fluid exposure tests, the rock and proppant samples were immersed in each fluid and sealed into a container. The containers were maintained in a sealed reactor at 250°F and 3000 psi for 30 days. Following exposure, the team examined rock and proppant strength. Brinell hardness testing of the fluid-exposed cores showed that slickwater decreases the hardness of the formation face for Middle Bakken formation, Lower Bakken shale, and Three Forks Formation samples. The Middle Bakken samples were more prone to strength loss when exposed to fluids than the other formation samples. The rocks exposed to gelled diesel experienced little change in hardness. Proppants exposed to Bakken Formation brine demonstrated an increase in strain relative to proppants that were not exposed. RCS lost strength upon exposure to all fluids compared to sand and ceramic, but was most affected by linked gel and Bakken oil and brine. The results suggest that a reaction in the fluid or that the high temperature and pressure with resin used in these experiments changes the stress–strain relationship for RCS.

The team also performed crush tests with results consistent with the elastic strength results for the proppants and fluids. Overall results indicated that the ceramic proppant was comparatively unreactive but was stronger when compared to the other proppant types following fluid exposures.

The project scientists ran standard conductivity tests to measure propped fracture conductivity over time and evaluate the relative performance of proppant and formation rock. The tests were run using each of the three different rock types (Middle Bakken, Lower Bakken, and Three Forks) and each of the three proppant types. Each test was run at 6500 psi closure pressure for 50 hours. Researchers then increased the pressure to 8000 psi for 20 hours. Postmortem analysis allowed the team to evaluate the mechanisms that may contribute to reduced conductivity. These mechanisms include spalling, embedment, or proppant crush.

Ceramic and resin-coated sand proppants usually outperform sand in creating and maintaining reservoir conductivity; however, they are more expensive and not as readily available. This research demonstrates that testing could reveal other, more suitable proppants for a particular formation. Additionally, this work illustrates that careful selection of a proppant type and injection scenario is important as field evidence suggests that propped fractures in the Bakken lose hydraulic continuity over time.

Investigation of Improved Conductivity and Proppant Applications in the Bakken Formation

Results:

- Successfully measured the conductivity of Ottawa sand, resin-coated sand, and Econoprop lightweight ceramic proppants within fractures of the Middle Bakken, Lower Bakken, and Three Forks Formations at formation temperatures and pressures.
- Determined the strength of the three proppant types prior to and following fluid exposure using a Forney universal compression apparatus.
- Successfully evaluated the hardness of the Bakken and Three Forks rock cores prior to and following fluid exposure using a Brinell hardness testing methodology.
- Exposed rock and proppant samples to various fracturing and formation fluids in a reactor for 30 days at 3000 psi and 250 °F.
- Successfully cut friable Bakken and Three Forks rock cores into various shapes and sizes for testing using a waterjet cutting technique.
- Noted a decrease in conductivity within the Bakken Formation which may be caused by a variety of factors, including proppant, rock strength, formation embedment, and spalling. However, formation embedment and spalling do not appear be a factor within the Three Forks Formation. Therefore, it is important to evaluate conductivity and other factors using samples from the actual formation and the fracturing fluids that will be used.

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Lead Performer: University of North Dakota Energy and Environmental Research Center

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Project Number: DE-FC26-08NT43291 – 01.8

Period of Performance: 10/2008-12/2012

Read/download the final report.

Hoek cell apparatus for conductivity testing at reservoir conditions.

Evaluation of Key Factors Affecting Successful Oil Production in the Bakken Formation, North Dakota-Phase I and II

Objective: To quantitatively describe and understand the Bakken Formation in the Williston Basin by collecting and analyzing a wide range of factors that influence well productivity and oil recovery.

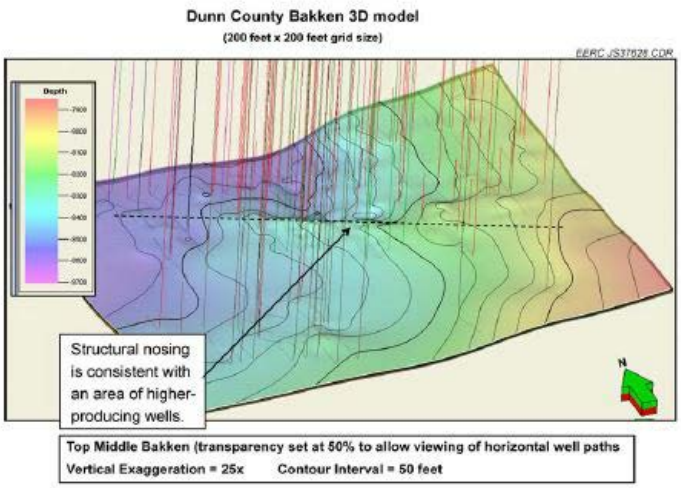
Research Conducted: It is estimated that total organic carbon (TOC) within the shales may be as high as 40%, and total hydrocarbon in the entire Bakken Formation may range from 200 to 400 billion barrels. Although numerous reservoirs throughout the formation are productive, some Bakken wells have yielded disappointing results.

Research for this project involved a robust, systematic, scientific, and engineering research effort to understand and unlock the vast resource potential of the Bakken Formation in the Williston Basin. Two North Dakota counties, Mountrail and Dunn, have relatively unique qualities and in this report, are considered subplays of the larger Bakken play. The project team focused on four broad topic areas during Phase I of this research program: geology, geochemistry, geomechanics, and engineering. Aspects of each area was evaluated and compared for each subplay. In Phase II, the study was expanded to include the Three Forks formation. The work in this phase focused on well completions; productivity; and geologic factors indicative of productivity, including geochemistry-related oil saturation, geomechanical properties related to the design of hydraulic fractures, and petrography for characterization of the rock fabric.

The benefits to this study include a better understanding of how to maximize production of the Bakken resources in North Dakota. Operators and stakeholders are now able to access a detailed comparison of the predictive value of various collected data sets from different geological settings within the Bakken play. Small producers and others may now incorporate information about the roles of geologic structure and geomechanics play in the design and operation of successful Bakken wells in North Dakota. The relationship between the Bakken and the Three Forks Formations with respect to oil production is also better understood.

Phase I:

Published papers, publicly-available technical presentations, and previously unavailable seismic survey data reviewed by the North Dakota Geological Survey (NDGS) were used to identify and evaluate geological characteristics likely to control the movement and production of oil. Structure, stratigraphy, lithofacies, pore pressure, and total organic carbon were investigated in detail. To evaluate selected geochemistry and petrological parameters across the study area, specifically clays (smectite and illite), TOC, and carbonates, samples from 26 Bakken wells were examined using x-ray fluorescence, x-ray diffraction (XRD), and scanning microprobe techniques. Six samples from the middle Bakken underwent geomechanical testing to provide more information about factors that may control the creation of natural and artificially induced micro- and macrofracture networks.



Model-generated oblique view of the structure of the middle Bakken in the Dunn County subplay area.

Phase II:

The first activity was the development of the Bakken decision support system (BDSS)—a geographic information system (GIS) and web-based analytical tool that includes a database of well file information (http://www.undeerc.org/bakken/).

The team then characterized the geomechanical properties of selected core material from the Bakken and Three Forks Formations in North Dakota's portion of the Williston Basin. Specifically, as part of this second activity, researchers conducted multistage triaxial testing to derive the peak strength characteristics of these formations.

The third activity continued geochemical evaluations of Bakken samples to evaluate potential relationships between geochemical and petrological properties of the Bakken and oil productivity.

Evaluation of Key Factors Affecting Successful Oil Production in the Bakken Formation, North Dakota-Phase I and II

To assess the potential relationships between the fluid saturation properties of the Bakken and oil productivity, researchers focused on evaluating water saturation data, oil saturation, and production data to determine if a correlation exists between water saturations calculated from well logs and oil production. Using geostatistical analysis techniques, they developed maps depicting water saturation, production water cut, and oil production. The team also completed petrographic assessments with a focus on the creation and analysis of thin sections of the reservoir zones within the Bakken and Three Forks Formations.

The fourth activity was establishing an industry advisory board. Three formal board meetings were held over the course of the project meetings to ensure the needs of stakeholders were being met. Members included the North Dakota Department of Mineral Resources (NDDMR), the North Dakota Petroleum Council, the North Dakota Geological Survey (NDGS) and WB Consulting.

Results:

- Analyzed historical production and stimulation techniques and evaluated data from two different areas of Bakken exploration and production within North Dakota, allowing the team to compare, contrast, and compile data into GIS database designed to support efficient interpretation of the data, allowing users to make comparisons between wells or areas of interest. Much of the work focused on a static petrophysical model of the Dunn County, ND study area, which describes the geological framework of the middle member of the Bakken. The model provides background to evaluate completion and stimulation strategies and will allow operators to correlate the parameters to potential well success.
- Added data on production, drilling, completion, and stimulation activities from hundreds of wells to the BDSS before the database was finalized for public launch. The project team collaborated with the North Dakota Geological Survey and oil companies to obtain Bakken core, which they used in geomechanical and geochemical laboratory experiments.

Phase I results:

- Production in Mountrail County is greater than and has more variability than production in Dunn County. This appears to be linked to greater total organic carbon (TOC) and shale thicknesses. Together, these factors can create greater pore pressure-related fracturing.
- Although the presence of structural elements is different in both Dunn and Mountrail County, it is consistent with areas of higher production. The influence of these structural elements on the creation of both natural and operationally induced fracture systems may be their major contribution to successful production.
- Areas of high production within Dunn County are associated along the Heart River Fault, which coincides with an area of high original TOC content.
- Lithology could potentially play a role in oil mobility. Improved understanding in this area may successfully guide the design of stimulation practices and provide insight regarding future exploration efforts.
- Multistage fracture completions appear to be outperforming lesser-stage completions when compared in proximity. It appears that in some areas, multistage hydraulic fracturing should improve the chances of greater oil production.
- Despite the lower per-foot drilling costs, many multilateral wells do not appear to have any significant production advantage.
- Well azimuth does not appear to be a factor in oil production.
- Longer lateral wells may produce more oil when compared to shorter laterals within proximity.

Phase II results:

- Multistage hydraulic fracturing is enhancing production in the Bakken and Three Forks Formations. The engineering aspects of the play have been thoroughly explained through the completion data collected from over 700 wells. Stimulation treatments can be improved with quality proppants and shorter treatment spacings along the lateral wellbore.

Evaluation of Key Factors Affecting Successful Oil Production in the Bakken Formation, North Dakota-Phase I and II

- Water and oil saturation data taken with water-cut data are useful for identifying and evaluating productive and nonproductive areas along the eastern edge of the Bakken play. They do not appear to correlate as well to production in the western portion of North Dakota, although more saturation data are necessary to fully evaluate this concept.
- Most identifiable porosity in thin-section samples was in partially healed microfractures or in residual hydrocarbon-filled accumulations. Observations of pore structures in thin sections showed them to be highly disconnected, while intragranular permeability was highly compacted and cemented. This agrees with the observation that productivity has been attributed to natural and/or induced fractures.
- Areas of North Dakota with have highly productive lithofacies within the middle Bakken tend to comprise geomechanically weaker rocks. Brittle rocks with high Young's modulus tend to propagate longer fractures.
- With respect to peak strength in the Bakken, sample data consistently fall in the 45,000-psi area, although the actual range was from 18,000 to 58,000 psi. Depth did not appear to affect mechanical strength, although deviations from the norm appear to be tied to microstructure and/or facies.
- Examination of data from horizontal wells in which the wellbore treatments have targeted softer rocks suggests that proppant placement in the near wellbore requires critical attention to maintain a good conductivity of fluids from the formation.

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Project Numbers: DE-FC26-08NT43291,

DE-FC26-08NT43291 – 01.2

Period of Performance: 10/2008-12/2012

Read/download the Phase I final report.

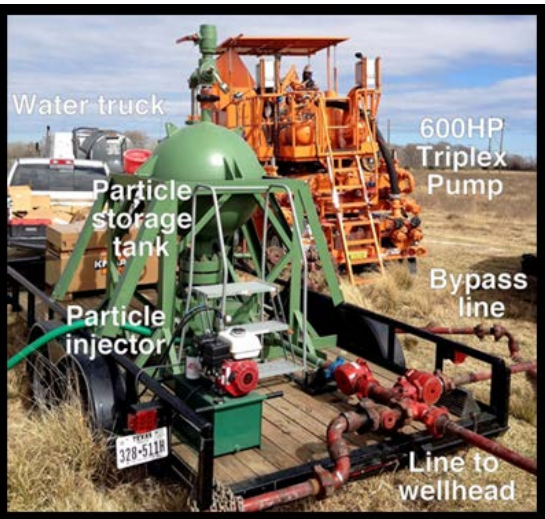
Read/download the Phase II final report.

Field Demonstration of Eco-Friendly Creation of Propped Hydraulic Fractures

Objective: To perform several field trials of Novel Production Enhancement Process (NPEP) on small producer (SP) wells. The treatment will be considered successful if it can be conducted in a timely and economic manner with little to no environmental impact and result in a substantial increase in production.

Research Conducted: The injection of proppants can overcome near-wellbore damage and increase flow capacity, especially in higher permeability reservoirs. A new process, NPEP, provides an ecologically-friendly alternative to traditional injection processes and materials; NPEP is comprised of a novel piece of equipment and a modified injection procedure and uses a biodegradable polymer containing a proppant that holds the fracture open once the polymer degrades. The method uses relatively small material volumes, low horsepower and pump rates, and has minimal environmental effects.

The researchers studied technologies, publications, articles, and patents across the petroleum industry to ensure their solution was new and innovative. They subsequently compiled a report summarizing the status of the technology and interest in the field of environmentally-friendly, non-damaging, and effective fracturing fluids. Field design protocol and simulation software were developed and used to determine test well candidates from wells operated by SPs participating in the project as an advisory group. Once the candidate wells were chosen, pre-job testing was performed on the wells and pumping and placement procedures were determined. Polymer materials were manufactured based on well criteria. The researchers conducted simulation runs and bench and pilot scale QC testing using the materials manufactured specifically for the project. Data gathered during and after the treatments was to be recorded, analyzed, and compiled into a report and a technical paper summarizing the work completed on the project. The researchers also plan to conduct instructional sessions for SPs so operators know how to utilize the process.



Equipment to inject polymer particles into a wellbore under pressure

NPEP has the potential to provide SPs with a simple, effective, low cost, and environmentally friendly tool for enhanced oil recovery. NPEP overcomes limitations of existing oilfield equipment and offers benefits such as eliminating the need for a blender and a chemical suspension package, offering the injection of multi-barrel volumes "on-the-fly" without passing through a pump, less hydraulic horsepower requirements, decreased footprint, simpler execution, lower water utilization, and the use of non-damaging biodegradable polymer-based fracturing fluid. It may allow zones which were considered to be economically unproductive to be tapped by SPs that have limited resources and smaller budgets. This increases the ultimate gas recovery and production from available reserves in the U.S. This technology can be especially beneficial when used on marginal wells known as stripper wells. These are wells that produce 10 barrels or 60 thousand cubic feet of natural gas per day. The oil and gas zones are typically only a few feet thick and would benefit greatly from a small fracture treatment.

Results:

- Performed five field trials of the equipment with successful rates. Particle injection was accomplished at fluid rates of 1-2BPM and 10-15% particle concentration by volume at pressures up to 2,900PSI. The viability of the product and process has been confirmed through laboratory and early field testing.
- Determined through computer treatment simulations that the potential exists for an equal or greater productivity increase versus classical hydraulic fracturing. Injection of the polymer and proppant resulted in a three-fold increase in fluid production.

Field Demonstration of Eco-Friendly Creation of Propped Hydraulic Fractures

- Considered additional applications for the equipment, and a procedure for using the equipment in the oilfield is being refined to further enhance the device's effectiveness and reliability.

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Period of Performance: 2/2013-10/2014

Additional information about this project is available on the RPSEA website.

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