the ENERGY lab

E&P Focus

Spring 2013 Oil & Natural Gas Program Newsletter

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U.S. DEPARTMENT OF ENERGY

Developing Alaskan Arctic Potential

A 2007 report, updated in 2009, commissioned by the National Energy Technology Laboratory (Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline?) concluded that the future for Alaska North Slope (ANS) oil and gas ranges from "very promising" to "limited". Which depends on how many of the following assumptions apply: (1) the 1002 Area of ANWR is opened for exploration and development, (2) exploration is allowed in the most prospective areas of NPRA, (3) the Beaufort Sea OCS and Chukchi Sea OCS are available for exploration and development without major restrictions on area or timing, (4) an ANS natural gas pipeline for major gas sales is operational by 2018 to 2020, (5) oil and gas prices recover to favorable high values in the near future, and (6) state of Alaska and federal fiscal policies remain stable and supportive of the huge investments that will be required. The future prospects become progressively less promising as these assumptions are removed. For the most part, the sharp drop in oil prices (and corresponding drop in gas prices) starting in mid-2008 and continuing to the present will no doubt adversely impact exploration and development planning and activities in the Arctic region in the near-term as oil companies review their economic situation. However, favorable world oil prices and domestic gas prices will most likely recover as the economy recovers, thus possibly changing the timing of some activities, but with minimal impact on the overall scope of Arctic exploration and development planning.

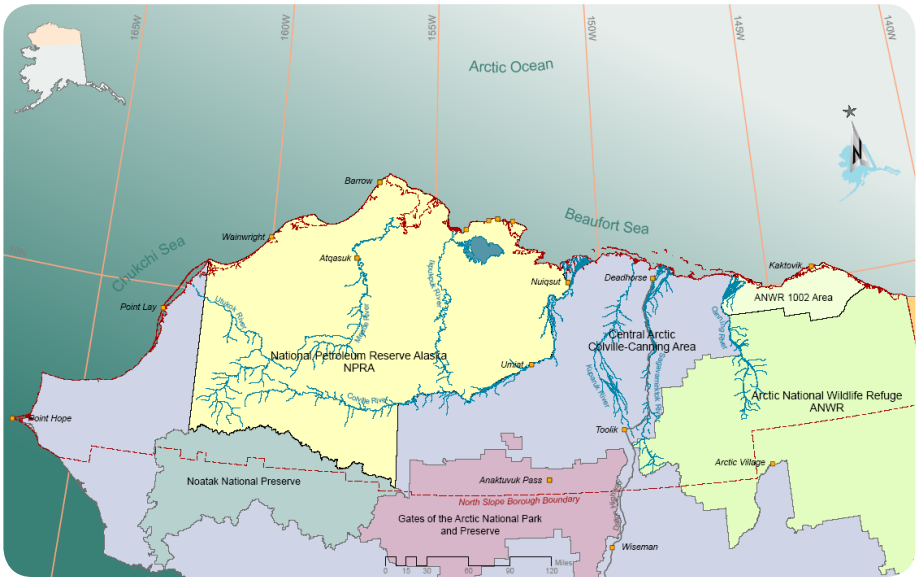

Figure 1. The North Slope, Alaska, and adjacent Chukchi and Beaufort Seas. (map by Mapmakers Alaska, Palmer, AK)

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Commentary

As shale production moves the nation toward an energy future unimaginable less than a decade ago, research progresses within NETL to secure the next generation of oil and natural gas production potential. Quite possibly, the most dramatic potential lies in Alaskan Arctic regions and the deepwater and ultra-deepwater areas of the Gulf of Mexico, , two environments that raise significant challenges to traditional development. Efforts at NETL aim to address these challenges.

Realizing Arctic potential is crucial. The U.S. Energy Information Administration (EIA) estimates that the region contains nearly 30 billion barrels of possible, potential and proved oil reserves and 221 Tcf of natural gas, with a total possible BOE in-place of nearly 67 billion barrels. However, due to its climate and remote location, the Arctic area of Alaska will not give up these reserves easily. A number of challenges must be overcome for profitable development of Arctic oil and natural gas, among them:

- Equipment needs to be specially designed to withstand the frigid temperatures.
- Environmental, topological, hydrological and climatic risks and consequences are higher in the Arctic and mitigation techniques more complex. Therefore, spill response must necessarily be integrated into drilling and production operations
- On Arctic lands, poor soil conditions can require additional site preparation to prevent equipment and structures from sinking.
- Long supply lines and limited transportation access from the world's manufacturing centers require equipment redundancy and a larger inventory of spare parts to ensure reliability, while increasing transportation costs.
- Employees expect higher wages and salaries to work in the isolated and inhospitable Arctic.

Natural gas development could be especially challenging. Although the Arctic is rich in natural gas, the development of Arctic natural gas resources could be impeded by the current low market value of natural gas relative to that of oil. Furthermore, natural gas consumers live far from the region, and transportation costs of natural gas are higher than those for oil and natural gas liquids.[1]

Deepwater and ultra-deepwater development in the Gulf of Mexico is equally daunting. Operational water depths are approaching 10,000 feet (with some drilling exceeding that depth), strong currents and their effects on equipment and operations require additional study, the marine environment must be protected, operations are subject to interruption (at best) by strong seasonal weather and costs are very high. But, as with Arctic resources, the prize is large and important to the nation. According to EIA, proved deepwater and ultra-deepwater oil reserves, at some 3.35 billion barrels, represent about 15% of the nation's total proved reserves. Deepwater gas reserves are also important, standing at an estimated 6 Tcf, or a bit more than 2% of

total U.S. gas reserves.[2] Unlike Arctic Alaska, the deepwater and ultra-deepwater Gulf of Mexico has seen large scale drilling and development programs. Yet the challenges listed above still remain. These challenges will become more important, and larger, as the industry reaches into deeper and deeper water thought to hold additional significant reserves.

In this issue, you will find detailed discussions of selected projects undertaken and/or funded by the Department of Energy to address the challenges that must be overcome to develop the immense oil and gas resources of the Alaskan Arctic, and the deepwater and ultra-deepwater regions of the U.S. Gulf of Mexico. It is an integral part of our commitment to secure America's future energy supplies.

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

The Editor, NETL Strategic Center for Natural Gas and Oil

[1] *Arctic Oil and Natural Gas Resources*, Today in Energy, U.S. Energy Information Administration, http://www.eia.gov/todayinenergy/, January 2012

[2] *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Proved Reserves*, U.S. Energy Information Administration, Office of Energy Statistics, various years.

Oil and natural gas liquid (NGL) production from Alaska's North Slope began in 1977 and increased to 2.2 million barrels per day by 1988, representing 25% of the U.S. domestic production. Production has since declined to about 550,000 barrels per day in 2012, but still represents about 8.5% of U.S. domestic production. All oil production to date has been from fields in the Central Arctic (Colville-Canning area) on state lands and adjacent waters of the Beaufort Sea. (Note: The Northstar Unit produces from both state and federal waters in the Beaufort Sea). The remaining technically recoverable oil from these fields is about 6.1 billion barrels. Discovered, technically recoverable natural gas resources on the Alaska North Slope are estimated to be about 35 trillion cubic feet. No natural gas is currently exported off the North Slope because there is no gas pipeline to transport the gas to markets.

From an exploration perspective, the North Slope and adjacent areas are not representative of mature petroleum provinces. The majority of the wells in both the state onshore and nearshore Beaufort Sea are clustered along the Barrow Arch trend, with a drilling density of approximately one exploration well per 22 square miles. Only 45 of the 301 North Slope exploration wells have been located south of 70º north latitude. This area, which constitutes nearly 75% of the state acreage, has a well density of one well per 383 square miles. In the short term, 2005 to 2018/2020, exploration efforts are forecast to result in the addition of about 2.9 billion barrels of economically recoverable oil and 12 trillion cubic feet of economically recoverable gas. Oil exploration is expected to target primarily oil resources in the Central Arctic on state lands and adjacent state waters, NPRA, and the Beaufort Sea and Chukchi Sea OCS. Gas exploration is expected to begin in earnest when a gas pipeline is assured and will initially target the Central Arctic foothills area, south of the current oil producing area. In the long term, 2018/2020 to 2050, exploration success and development is expected to involve activities in all five sub-provinces and under optimistic assumptions is estimated to total 28 billion barrels of economically recoverable oil and 125 trillion cubic feet of economically recoverable gas. The expected oil and gas reserve additions are widely distributed among all the geographic areas.

For the interval from 2005 to 2050, the forecasts of economically recoverable oil and gas additions, including reserves growth in known fields, is 35 to 36 billion barrels of oil and 137 trillion cubic feet of gas. These optimistic estimates assume oil and gas prices recover in the near future, stable fiscal policies continue, and all areas are open for exploration and development. Under this optimistic scenario, the productive life of the Alaska North Slope would be extended well beyond 2050 and could potentially result in the need to refurbish the Trans Alaska Pipeline System (TAPS) and/or add a new pipeline and add capacity to the gas pipeline.

The forecasts become increasingly pessimistic, however, if the assumptions are not met, as illustrated by the following scenarios.

1. If the ANWR 1002 area is removed from consideration, the estimated economically recoverable oil is 29 to 30 billion barrels of oil and 135 trillion cubic feet of gas.
2. Removal of both ANWR 1002 and the Chukchi Sea OCS results in a reduction to 19 to 20 billion barrels of oil and 85 trillion cubic feet of gas.
3. Removal of ANWR 1002, Chukchi Sea OCS, and the Beaufort Sea OCS results in a reduction to 15 to 16 billion barrels of oil and 65 trillion cubic feet of gas.

4. Scenario 3 and no gas pipeline reduces the estimate to only 9 to 10 billion barrels of oil (any gas discovered will likely remain stranded).

With the Bureau of Safety and Environmental Enforcement's approval of Shell's preparatory drilling activities in both the Beaufort and Chukchi seas it is unlikely that the pessimistic scenario's will play out, barring an environmental accident.

The NETL study also examined two resource development cases related to the presence or absence of significant natural gas sales arising from construction of a gas pipeline.

1. The assessment for the No-Major-Gas-Sales case results in an estimate of remaining technically recoverable oil of 7.3 billion barrels for the fields analyzed (i.e., currently producing fields, known fields with pending or announced development plans, and known fields with near-term development potential).
2. For the Major-Gas-Sales case, the development of the Point Thomson field is estimated to result in an additional 400 million barrels of recoverable oil and condensate. A reserve decline in the Prudhoe Bay field is estimated to be about 234 million barrels of oil, resulting in an estimate of about 6.56 billion barrels of remaining technically recoverable oil from the known Alaska North Slope fields. The estimated gas reserves in the Prudhoe Bay and Point Thomson fields will provide 32 trillion cubic feet of the 57.5 trillion cubic feet of natural gas required to support a gas pipeline project at 4.5 billion cubic feet per day for a 35-year life.

The TAPS minimum flow rate of about 200,000 barrels of oil per day will be reached in about 2045, absent new developments or reserves growth beyond the forecasted technically remaining reserves. An Alaska gas pipeline and gas sales from the Point Thomson field and the associated oil and condensate would provide another boost to oil production but would not extend the life of TAPS. A shutdown of TAPS would potentially strand about 1 billion barrels of oil reserves from the fields analyzed.

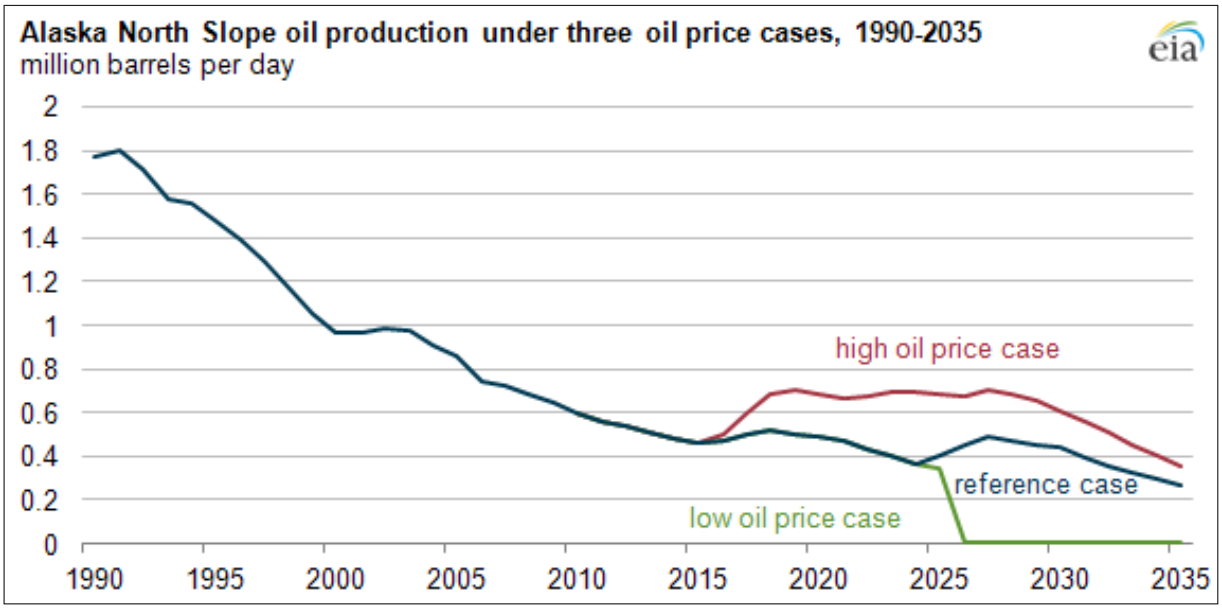

Figure 2. Alaska North Slope oil production under three oil price cases, 1990-2035 million barrels per day.

Exploration in the 1002 Area of ANWR (including native corporation in-holdings and state Beaufort Sea waters) is highly significant because this sub-province contains an estimated 10.3 billion barrels of oil in 1.9 million acres (5,475 barrels of oil per acre). In comparison, NPRA contains an estimated 10.6 billion barrels of oil in 24.2 million acres (440 barrels per acre). Opening the ANWR 1002 Area would significantly increase exploration activity and increase the potential for discovery of additional oil and gas reserves. The geological evidence for the Alaska North Slope areas indicate that oil and gas fields of sufficient size could be found to support development, provided oil and gas prices are adequate and the fiscal and regulatory environment are supportive of the large investments that will be required.

Issues that have the potential for preventing development of a given field or set of fields on the Alaska North Slope include: land access, extent of requirements for dismantlement, removal, and restoration of facilities and infrastructure, marine mammal protection with respect to development of offshore resources and potential impacts on bowhead whales (a species listed under the Endangered Species Act), water availability for constructing ice roads and exploration pads, and gravel availability for constructing development and production facilities and roads. Some may be solved by further advances in technology, while others may ultimately prevent development in a given location.

Unconventional Sources

Development of advanced enhanced oil recovery technologies, especially for "heavy oil," to increase the recovery from known fields is critical for maintaining TAPS through-put. Heavy oil is a dense, viscous type of crude oil with an API gravity between 10° and 20°. Generally, this oil has a viscosity between 100 and 10,000 centipoise, and does not flow readily in the reservoir without dilution and/or the introduction of heat. Particular emphasis needs to be placed on evaluating technologies that could help recover more of this underdeveloped heavy oil resource in Alaska. Advanced oil recovery technologies, such as miscibility enhanced CO_2-EOR will be essential for recovering more from the largely undeveloped heavy oil resource.

Initial steps are being taken to produce a portion of the in-place oil resource from two large heavy oil reservoirs on the Alaska North Slope. The Schrader Bluff Formation in the Milne Point Unit experienced a steady growth in heavy oil production, reaching 19,000 barrels per day in 2003, from a few thousand barrels per day in the 1990s. It is now producing about 8,000 barrels per day. The West Sak Formation in the Kuparuk River Unit, after years of experimentation and delay, produced 18,100 barrels of heavy oil per day in 2007. Current production stands at about 15,000 barrels per day. Operator ConocoPhillips earlier this year announced proposed expenditures of $1 to $2.5 billion to drill as many as 115 additional wells at West Sak to increase reserves by 150 million barrels.

Further advances in heavy oil recovery technology, adapted particularly to the special geological, reservoir, environmental, and operational situations in Alaska, will be essential for increasing oil recovery from Alaska's large heavy oil endowment. Current research supported by the NETL's Arctic Energy Office is summarized below.

Use of Polymers to Recover Viscous Oil

Alaska's North Slope contains a very large unconventional oil resource—over 45 billion barrels of heavy/viscous oil. Production has been limited

to pools in the core area that flow with thermal or miscible gas injection/ water-alternating-gas, but the majority of the oil is stranded. The project will be valuable in establishing the most cost-effective path forward to develop Alaska heavy oil resources, studying both existing and new viscoelastic polymers to change the viscosity, new methods for improved injectivity during polymer injection, sweep efficiency enhancements, and effects of induced fracturing and formation parting.

Fluid and Rock Property Controls on Production and Seismic Monitoring Alaska Heavy Oils

A prime factor limiting the efficiency of heavy oil recovery is the heterogeneity of the system. Variability includes heavy oil with varying resin and asphaltene contents and rock matrices' with different porosities, permeabilities, connectivities, and mineral contents. Using seismic data, this study is attempting to characterize the reservoir fluid and rock properties such that a geophysical monitoring program can potentially be used to enhance heavy oil recovery.

Drilling and Production Testing the Methane Hydrate Resource Potential Associated with the Barrow Gas Fields–Phase 2

Previous research efforts funded by the DOE, supported the hypothesis that methane hydrates exist within the Barrow gas fields. Based on detailed reservoir modeling and other favorable conditions (i.e., formation gas composition, formation water chemistry, and reservoir pressure), it is believed that these accumulations may be interacting with the free gas reservoirs, providing pressure support through dissociation of the hydrates. During Phase 2 of the project, a production test well will be designed, drilled, logged, and cored, and a continuous reservoir surveillance and monitoring program will be implemented to prove the commercial potential of producing methane hydrate through depressurization dissociation from the gas zone underlying the hydrates.

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

The Umiat oil field contains light oil in a shallow, frozen reservoir and may be typical of an abundant supply across the Arctic permafrost. Most prior efforts researching how to produce in these strata of rock/ice/light oil at low pressures has been focused upon techniques for heavy oil in unconsolidated but unfrozen sands or on gas hydrates. This research project is developing a robust reservoir model to test possible production methods for Umiat and similar frozen reservoirs that do not use steam or a liquid that will freeze.

NETL Develops Strategic Partnership with the Alaska Center for Energy and Power

NETL has a particular affinity for Alaska. In 2001 the Department of Energy established the Arctic Energy Office and assigned its management to NETL. The mission of the Arctic Energy Office was to work with the University of Alaska-Fairbanks (UAF) to conduct research in the broad categories of fossil energy and remote electric power generation, where a five year contract was established to support that research. NETL's contract with the University expired in 2006, but as opportunities arose the Arctic Energy Office continued to work closely with the Petroleum Engineering Department and the Water and Environmental Research Center.

In 2006 the University formed the Alaska Center for Energy and Power (ACEP), which has become the University's gateway for energy related research. ACEP works to meet state, industry, and federal demand for applied energy research.

Because there is no power transmission grid system that serves Alaska's off-road communities, there are over 300 villages that rely upon diesel generators. Due to the high cost of fuel, which is often delivered only once or twice per year by barge, many communities are integrating wind turbines in an attempt to lower their utility costs. But integrating intermittent renewable resources in a microgrid environment also introduces reliability, power quality, and control system issues.

With this in mind, ACEP commissioned its new research facility in 2012, which was designed for testing a wide range of microgrid and distributed generation equipment (Figure 1). The entire lab can be programmed to work under various scenarios so as to mimic full scale village systems, complete with particular wind regimes. The lab contains a typical diesel generator, a wind turbine simulator, battery bank, programmable load bank, inverter and control systems. As intended, this facility has garnered the attention of industry, and various businesses have been negotiating with ACEP to use the lab for the testing and development of their products. The lab can also be used to train village power operators.

In addition to the new laboratory, ACEP established a hydrokinetic test site in Nenana, about 60 miles south of Fairbanks. With many of Alaska's communities located along major waterways or near tidal basins, there is significant interest from developers, utilities and communities to utilize

Figure 1. Alaska Center for Energy and Power Energy Technology Facility

this as an energy resource during ice-free months. The site is used to test hydrokinetic power-generation devices and technology under realistic Alaskan river conditions, and is largely funded by private industry.

As is true of the best research facilities, ACEP's real value is its people. ACEP works with approximately 25 affiliated faculty throughout the University system, numerous students and interns, and has 16 full time staff members that include research engineers, economists, and data specialists. With its extensive remote and Arctic-centric research expertise and capability, NETL and the Office of Fossil Energy find it duly beneficial to share resources and to partner with ACEP.

Likewise, ACEP recently confirmed NETL as a member of its External Advisory Council, where NETL will assist ACEP's Energy Fields of the Future subcommittee in identifying and developing new research directions associated with the vast fossil energy resources and technology development opportunities in Alaska.

In a similar advisory capacity, NETL and ACEP also share common ground in that they both serve the State of Alaska's Emerging Energy Technology Fund, which seeks to demonstrate emerging energy technologies that have a reasonable expectation to be commercially viable within five years. Specifically, the Arctic Energy Office serves on the fund's advisory committee, to review applications and to make recommendations to the grant administrator, the Alaska Energy Authority. ACEP serves the fund by providing the support and capability of their test beds to the grant applicants, as well as technical assistance to the advisory committee. In 2012 there were 16 projects selected totaling $8.9M, which were sponsored by the State of Alaska and the Denali Commission.

NETL is also engaged in discussions with ACEP to jointly address some of Alaska's energy needs. Along those lines, NETL is providing input to ACEP's economic model that compares energy development options that have been proposed by various private parties, state agencies and utilities that could potentially lower the cost of energy in Alaska's Interior. Fairbanks electricity rates are more than double the national average, and the cost of heating oil is forcing many residents to leave the area or to switch to wood heating. ACEP's economic model is a tool for comparing the numerous iterations for natural gas pipeline options against other options such as trucking liquefied natural gas from the North Slope, building a coal-to-liquids plant, or building a large dam.

Additional collaborations may extend into the larger entity of UAF, as they work toward establishing the Arctic Center for Oil Spill Research & Education. A-CORE is focused on the preparedness, prevention, response, monitoring, and mitigation of marine oil spills in the Arctic. Such challenges include cleaning up spilled oil in broken ice conditions, tracking the movement of oil, and simply working safely in a dark, cold and harsh environment. This is of vital importance as companies become increasingly interested in drilling in Arctic waters, and as retreating sea ice makes movement of oil tankers and other cargo through Arctic regions possible.

ACEP and NETL look forward to a most productive relationship, where they will efficiently leverage the strengths of their respective institutions, to jointly address Alaska's unique energy challenges and opportunities.

Deepwater and Ultra-Deepwater Produced Water Discharge

Produced water consists of formation water (the water present naturally in the reservoir), flood water previously injected into the formation to maintain pressure, and/or, in the case of some gas production, condensed water (ANL, 2004). In 2005, nearly 107 million barrels of water were produced daily in offshore operations worldwide, together with 120 million barrels of oil equivalent. About forty percent of the daily water production (44 million barrels of water) was discharged offshore.

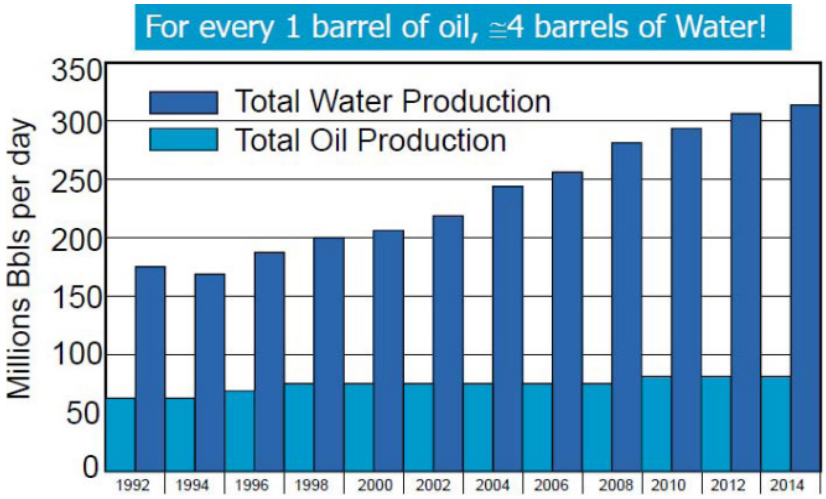

Figure 1. Global Oil and Water Production History and Forecast (TUV-NEL, 2010)

This highlights a major issue for the oil and gas industry. As forecast oil production remains consistent, produced water from this production continues to increase. The handling of produced water will become increasingly more important and appears to be a challenge that will not go away (Figure 1).

Offshore Handling of Produced Water

Current discharge of produced, treated water from offshore development is only done through topsides facilities. According to the International Association of Oil and Gas Producers 2005 study, the produced water industry has shown results that looked at the discharge in the world's oceans over the past 30 years. The results showed that no abnormal effects to the marine life have taken place and suggested the current regulation levels set forth in the industry are safe for the environment (OGP, 2005). Gas wells tend to produce low volumes of water with relatively high concentrations of organic contaminants. Oil wells, in contrast, generally produce higher volumes of produced water. These volumes increase with time and can, for mature fields, reach over 10 times the volume of oil produced (ANL, 2004).

The composition of produced water is complex and varies widely. It is determined by the characteristics of the reservoir and by the maturity of production. One of its major constituents is inorganic salts, which make it similar to seawater, although salinity can range from almost fresh to fully saturated (ANL, 2004). Produced water from oil fields, offshore and onshore, as well as wastewater from the refineries, can contain fair amounts of free and floating oil. It must be removed before subsequent biological treatment and/or discharge to the environment. At present the available technology employs several steps to remove this free and floating oil. Oil-water separation is a commonly performed task in most oil production and processing facilities, and there are numerous current

methods (ANL, 2004).

Typically, the industry uses three different stages in the process. However, their combined use may not be required, depending on the water quality to be processed. The typical first stage is a separator employing the difference in specific gravity of the oil, water and suspended solids in a process that is based on the principles of Stokes Law. It often requires a secondary treatment device as the separation efficiency is less than ideal. Secondary separation devices can include hydrocyclones or compact floatation units used to enhance coalescence of the oil phase and settlement of suspended solids. For the final stage, where the amount of oil and suspended solids is relatively low, induced gas flotation (IGF) and dissolved gas flotation (DGF) devices can be employed to enhance flotation and separation of the oil and suspended solids, as well as the use of advanced filtration systems with coalescence components (Figure 2).

Topside Technologies

In addition to gravity and flotation/filtration devices, a number of other topside treatment technologies are available for removing dispersed and dissolved oil and reducing toxicity of produced water. These technologies include:

- Absorption / adsorption / extraction (granular activated carbons macro porous polymer extraction, etc.),
- Advanced oxidation processes (AOP),
- Biological (bio reactors), and
- Hybrid (combination of various technologies, (e.g. Compact Flotation Units).

Most of the mechanical methods are now well established. Technologies such as hydrocyclones and gas flotation units, with and without the use of chemicals, are regularly applied offshore for produced water treatment to meet typical produced water discharge standards. Electrodialysis and reverse osmosis have been commonly used for sea water desalination purposes. They are the two technologies that have been considered for removing salts from produced water. However for both technologies, it is extremely important to remove oil and solids as a pre-treatment. In reviewing all these technologies, none have yet been deployed in a subsea production system. Only basic separation and subsea reinjection techniques have been used in subsea systems.

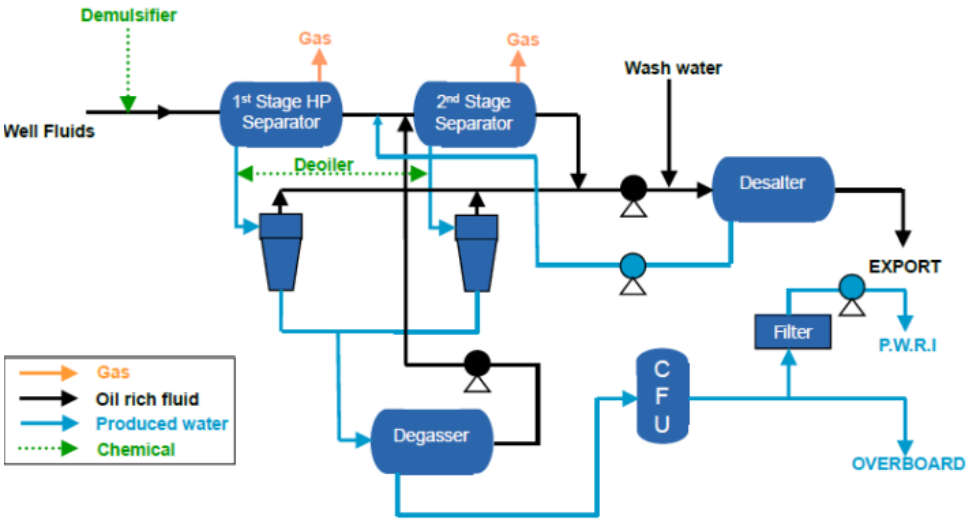

Figure 2. Block Diagram showing typical produced water treatment system. (Courtesy of TUV/NEL, 2010)

State of the Art Technologies

From the review of the state of art in topsides and subsea technologies relevant to seabed produced water treatment and discharge, the following main findings emerge:

- Available offshore water treatment technologies are primarily used in topsides, which treat the produced water for discharge to sea. There is a very limited number of subsea projects which separate oil and water. There is no subsea water treatment for discharge.
- Topsides water treatment generally requires a number of systems which involve a separator, CPI separator / hydrocyclones / skimmer, and induced gas flotation. Filtration is sometimes required after the tertiary system as a polishing step to achieve low oil and grease concentrations. Membrane filtration is sometimes required to remove dissolved organics. A recent advance in filtration is to infuse hydrophobic polymer to filters to reduce the effluent oil and grease concentration.
- Subsea separation technologies have focused on two-phase gas/liquid separation. The installations with oil/water separation were intended for injecting water to wells, which allows much higher oil-in-water content than discharge limitations. Suspended solids in the water are major challenges for injection.
- Compact subsea oil/water separators and desanders for deepwater have been developed and will be installed in the near future. Multiple technologies in this area are under development.
- Currently, subsea oil/water separation systems do not meet discharge limitations on oil and grease concentrations. They can achieve oil-in-water concentration of several hundred ppm, which is about 10 times the discharge limit.

Deepwater seabed treatment and discharge of produced water and/or solids will likely require significant power for pumping the large volume of water and to overcome the pressure difference between the seabed hydrostatic pressure and the treatment system pressure, which may be much lower. Current technology can provide the power required. Several deepwater projects already use significant power for seabed pumping.

U.S. Regulatory Issues

The Clean Water Act prohibits all discharges of pollutants unless they are authorized by National Pollutant Discharge Elimination System (NPDES) permits. The Act also requires that NPDES permits first limit pollutants based on economically achievable treatment technologies and then include additional limits as needed to protect water quality (EPA, 2011).

Regulations are changing. New point sources and existing point sources of pollutants have different NPDES regulations. New sources are subject to more rigorous effluent limits than existing sources based on the idea that it is cheaper to minimize effluent pollutants if environmental controls are considered during plant design than if an existing facility is retrofitted.

New source discharges must comply with standards based on the performance of demonstrated technology with the greatest degree of effluent reduction. These new source performance standards (NSPS) should represent the most stringent numerical values attainable. NSPS are based upon the best available demonstrated control technology and are at least as stringent as best available technology (EPA, 2011).

The NPDES guidelines define a new source as any area in which significant

site preparation work is done. EPA interprets "significant site preparation" for offshore effluent guidelines as "the process of clearing and preparing an area of the ocean floor for purposes of constructing or placing a development or production facility on or over the site." Thus, development and production facilities at a new site would be new sources. Development and production facilities are existing sources if significant site preparation work took place before NSPS became effective. Exploratory wells are not considered new sources because site preparation is not considered significant (EPA, 2011). Currently, there are no regulations governing produced water disposal at the seabed.

The oil-in-water content serves as the primary target for worldwide regulations, and toxicity is commonly addressed with dilutions of seawater. Measurement, monitoring and reporting requirements vary worldwide by region, but all require sampling and measuring/testing of the samples. A single method of measuring is specified in the U.S. regulations.

The following are some of the regulatory impacts on seabed discharge of produced water and/or solids:

- Sand cannot be discharged in U.S. projects.
- There is no current regulation on suspended solids. However, suspended solids tend to have oil adhering onto them. Excessive amounts of suspended solids in produced water can make the discharge exceed the oil-in-water content limit. Therefore, some measure of suspended solids removal should be included in the water treatment equipment.
- The current approved methods for oil and grease monitoring are based on laboratory testing of water samples. With the U.S. regulations, the minimum sampling and testing frequency is once per month which makes subsea monitoring feasible with available technology such as ROV access, although it can be expensive. The U.S. regulation does not provide any means of using online monitoring to substitute for laboratory measurements.
- The U.S. regulations allow the toxicity criteria to be met through dilution.
- The U.S. regulations require daily visual sheen monitoring. For developments that will potentially discharge produced water at seabed, which are typically subsea tieback developments with a potential long offset, daily observation of visual sheen may be challenging. Additionally, the water sampling requirement after observing a sheen (within 2 hours after a visual sheen is observed) may also be challenging to meet.

Marine Life Issues

Many studies have been done to test the effects of produced water on marine life. The process that produced water goes through upon discharge is important in determining how it will affect the surrounding marine life.

First, the discharged, treated produced water goes through two phases of dilution. The first phase of dilution happens within the first few tens of meters where it dilutes by 30 to 100 fold.

The second phase happens 500 to 1000 meters away from the discharge point where the produced water dilutes by 1000 to 100,000 fold (OGP,2005). Secondly, low molecular weight hydrocarbons volatilize into the air or are degraded by photolytic or biological processes. Also, the

produced water constituents are exposed to several chemical processes including precipitation, hydrolysis, oxidation, and complexation upon discharge. Next, the constituents adsorb on the suspended solids. The rate of adsorption depends on the amount of suspended solids and the adsorptive tendencies of the constituents(OGP,2005). Finally the constituents begin to biodegrade. The rate of biodegradation depends on each constituent's chemical structure. Naturally occurring bacteria in marine environments also control biodegradation of produced water constituents (ANL, 2004).

Field studies were done near Norway in a region with a high density of produced water discharge, which accounts for nearly 70% of all the water discharged in the North Sea. At a distance of 10 km from the discharge point, aromatic hydrocarbons could be detected; however it was only within 500m that the concentrations of hydrocarbons could cause a rise in biological effects. Fish were also tested in this study and results show that current regulations leave only a minor risk to marine life. Dilution models are often used today to understand this process (OGP,2005).

In the early 1990's a study was done in the Gulf of Mexico which compared the bioaccumulation of target chemicals in edible and inedible tissue of fish collected at GOM platforms discharging >4,600 bbl/d of treated produced water to that of fish collected at platforms with no produced water discharges. None of the target chemicals were present in edible tissues at concentrations that might be harmful to the fish or to human health. Also, there were no major differences in tissues collected from discharging sites as opposed to non-discharging sites. The few observed elevated concentrations were distributed equally between the discharging and non-discharging sites, suggesting that produced water discharge was not the source of the elevations (OGP,2005).

Concepts for Discharge of Produced Water at the Seabed

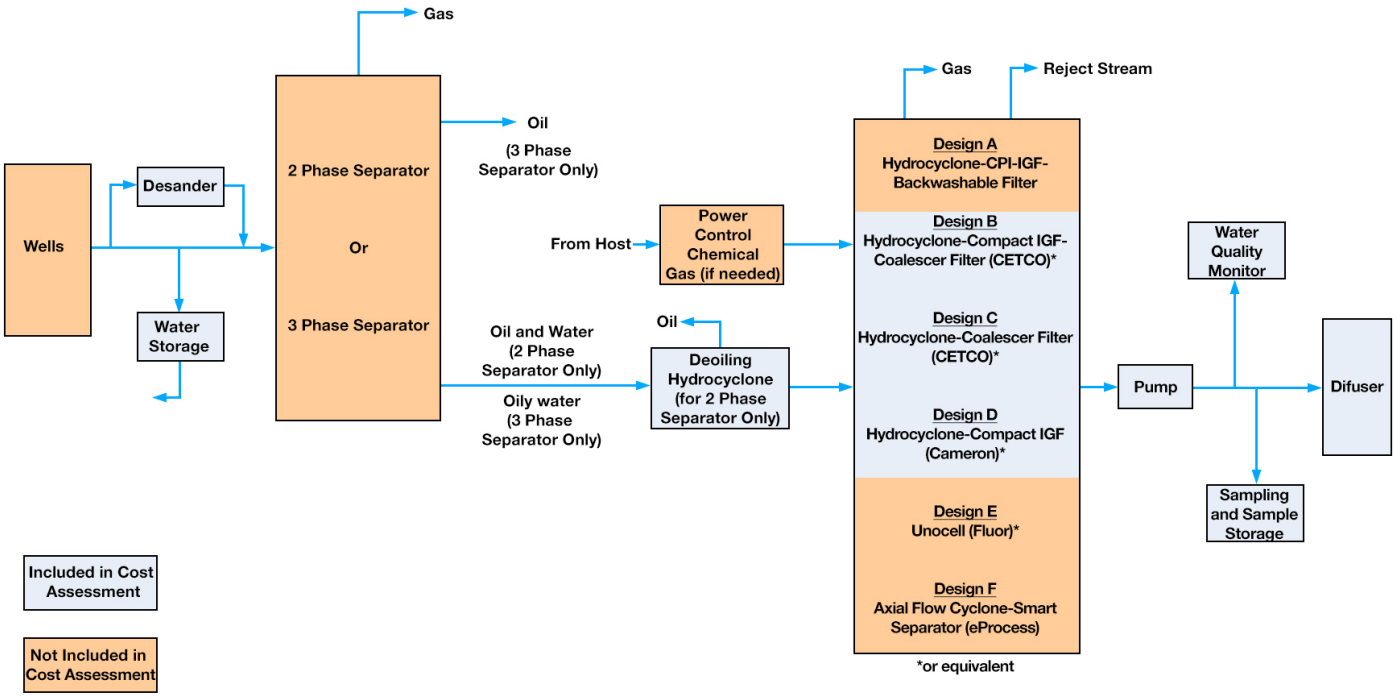

Figure 3. Subsea Produced Water Treatment and Discharge Concepts

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TUV-NEL, Figure 1 data chart courtesy of TUV-NEL Produced Water Group Workshop 2010.

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Subsea Produced Water Treatment Concepts

The flow diagram (Figure 3) is shown to illustrate how a subsea processing system will look with a subsea produced water treatment system.

Design A is mostly a straightforward migration of topsides water treatment technology to subsea; as such, it is not considered a feasible design for subsea but is provided only as a reference point. The key factor making this design not feasible is the corrugated plate interceptors for which we have not found compact versions suitable for subsea applications in 5000 – 8000 ft water depth.

We consider that Designs B, C and D are designs for which additional work on the technology gaps have good potential of progressing the technology to project ready status in the next 3-5 years. Therefore these designs are selected for further assessment in the current study.

While the key technologies for Designs E and F are also likely to progress to project ready status in the next 3-5 years, they are more focused on single supplier/vendor proprietary technology than Designs C, D and E, and therefore not further assessed in the current study.

Summary

Although discharging produced water to the ambient seawater from topside is standard practice in the industry, with proven technology, several obstacles must be overcome to do this subsea at the seabed. Today's topside technologies are meeting discharge criteria set forth by the toughest regulators around the world and studies show that the marine life is not adversely affected by these practices.

No known subsea production system has ever used any form of the typical produced water treatment technologies on topside offshore facilities. However, after a long review of the top processes and technologies being used in the industry today, subsea processing of produce water and discharge to the seabed should be achievable, with development and qualification of technology in the next 3-5 years.

It is estimated that, with a continuously funded technology development program, the timing for the conceptual design to become project ready is:

- Design B (hydrocyclones, Compact Flotation and Coalescing Filters): 2017
- Design C (hydrocyclones and Coalescing Filters): 2017
- Design D (Compact Flotation): 2015

Intelligent Production System for Ultra Deepwater with Short Hop Wireless Power and Wireless Data Transfer for Lateral Production Control and Optimization

Introduction

A project being conducted by Tubel, LLC, in partnership with the University of Houston and funded by the National Energy Technology Laboratory (NETL,) seeks to develop a sensor and power deployment system for horizontal wells and lateral sections in ultra deepwater (UDW) to control and monitor hydrocarbon production. This "next generation" system can also be used to provide power in lower completions to bring gauges near the perforations on an upper and lower completion well. The new technology will provide a unique method for optimizing multilateral well performance in a number of areas, outlined below.

Increasing the production of UDW oil and gas resources – Today a large portion of the wells drilled in ultra deepwater are multilateral wells or utilize lower and upper completions deployed separately. The inability to deploy hydraulic lines and electrical cables in laterals and lower completions prevents the use of intelligent completion systems in those laterals and lower completion strings, potentially reducing hydrocarbon production and reducing the production life of the wells since production is controlled with little knowledge of the production pressures, water movements, reservoir status and hydrocarbon production sources in the well and laterals. As a result, it is necessary to intervene in the wells using production logging tools to determine the reservoir and production status. These interventions are costly, requiring that the well be shut in, and creating the potential for fishing stuck tools. In addition, tools have to be deployed in the wells to open or close flow control devices, a costly and, potentially, risky operation. This proposal outlines a next generation intelligent production system (IPS) with ultra low power modules and wireless power transfer. The system is deployed inside laterals in ultra deepwater wells for remote production control. The IPS can also be deployed in lower and upper completions in deep wells.

The IPS transfers power wirelessly from the mainbore into the lateral to power gauges, flow control systems and communications modules. Short-hop, two- way communication between the mainbore and the laterals allows for data and commands to be transferred between a remote location at the surface and the laterals. Ultra low power gauges provide real time status information on the reservoir and production while multiple, electrically-operated flow control systems manage hydrocarbon transfer from the reservoir into the production tubing. The system will also reduce significantly the completion costs and complexity due to the elimination of multiple hydraulic lines deployed in the well. Instead, a single electric line will provide power and communications. The system will also reduce the number of penetrations required in subsea wellheads.

Reducing the costs to produce UDW oil and gas resources – Some of the main areas of significant costs for the production in UDW include water production and processing, intervention in wells requiring production shut in, and intervention risks associated with the deployment of equipment in the well. The IPS will reduce significantly these costs since it will eliminate and/or delay interventions into the wellbore by controlling production

remotely in the laterals as well as being able to reduce, delay, and sometimes eliminate, the production of water to the surface.

Increasing the efficiency of exploitation of such resources – The ability to monitor the reservoir, production tubing events and the ability to control remotely the flow of hydrocarbon and water from the reservoir to the production tubing can significantly increase production efficiency and reduce the time required to identify problems in production operations.

Improving safety and environmental performance by minimizing environmental impacts associated with UDW exploration and production – The ability to reduce the number of wells drilled and minimize the number of interventions in the well will positively affect the environment and increase significantly safety during the production of hydrocarbons.

Project Description

The system will be composed of the following six modules:

1. A low-power, electrically-operated flow control system that will open, close or choke the flow of hydrocarbon from the reservoir into the production tubing. Multiple flow control systems will be deployed in the horizontal section of the well to divide the lateral into multiple zones and to equalize the pressure in the lateral. The equalization will allow for the production from all sections of the lateral instead of having the production coming primarily from the entrance of the lateral.
2. An instrumentation system that will be composed of the following four sensors:

   a. Pressure gauge – provide pressure information from the reservoir and production tubing using a new micropower technology.

   b. Gamma ray detector –will monitor water production since there has been some evidence that gamma activity in the formation increases with higher water production.

   c. High resolution quartz temperature sensors – will provide a distributed temperature system throughout the lateral using micropower electronics and digital addressing.

   d. Flow meter – will utilize a small pressure change methodology to track fluid flow. The pressure detectors will be deployed in clusters where fluctuations in pressure generated by the flow in the tubing can be converted into flow measurements.
3. A two-way communications system for all modules deployed in the laterals and mainbore will allow for transfer of commands and data between the surface and downhole.
4. A wireless power and communications transfer that will provide power transfer from the mainbore to the lateral as well as a short-hop, two-way data transfer to and from the lateral and the lower completion. The power transfer will allow for power to be available in the lateral for the operation of sensors and flow control systems to optimize production from the laterals and to stop the areas which produce water. Electromagnetic techniques developed over the past 18 months will provide the foundation for wireless power transfer

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and communications.

5. A power and communications mainbore system that will perform the following three functions:

   a. Receive commands from the surface via cable and transfer the commands via wireless electromagnetic wave, short-hop communications into the lateral.

   b. Receive data from the laterals via short-hop communications and transfer the data to the surface via electrical cable.

   c. Convert DC power from the cable into AC power and transfer the power from the mainbore into the lateral using electromagnetic technology.

6. A surface system that will generate the DC power and also send commands into the well via electrical cable. The system will also monitor for data from downhole to the surface and decode, store and transfer the received data to a remote location.

The project will allow for the construction of a system composed of these modules. There will be two complete system prototypes manufactured for the project which will be used for field tests.

Potential Impact of the Project

This project will create the next generation IPS to control horizontal and lateral sections of a wellbore. The system will also allow for gauges and flow control in the lower completion in wells with a permanent lower completion and an upper completion. The system will provide a number of benefits including:

- Decrease in the number of interventions in the wellbore,
- Optimization of the production of hydrocarbons,
- Minimized production of water,
- Full control of the laterals,
- Instrumentation of the entire lateral,
- Increased hydrocarbon production over the life of the well,
- Deployment of gauges closer to the perforations in lower completions for deepwells,
- Improved ability to power the Lower completion from the Upper completion and to place gauges and control devices near the perforations, and
- A reduction in the number of penetrations in a wellhead by eliminating hydraulic line control and utilizing a single electrical line in the well.

The University of Houston will continue to carry out research on the wireless power transfer element of the system and focus the research for the deepwater environment. The work will develop information on the distance and efficiency on the wireless transfer, the design of the coils for optimum transmission of power, and effective wireless data transfer to and from the laterals.

Research Projects Addressing Technical Challenges to Environmentally Acceptable Shale Gas Development Selected by DOE

Fifteen research projects aimed at addressing the technical challenges of producing natural gas from shales and tight sands, while simultaneously reducing environmental footprints and risks, have been selected to receive a total of $28 million in funding from the U.S. Department of Energy's Office of Fossil Energy (FE). Approximately $8.6 million of the total value of the projects is provided via cost-share by the research partners, in addition to $28 million in federal funds. The research contracts will be administered by the Research Partnership to Secure Energy for America (RPSEA), under the management of FE's National Energy Technology Laboratory.

The projects, valued at just over $36.6 million over two years, add to the research portfolio for FE's Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research Program, which develops technologies and strategies to improve the safety and minimize the environmental impacts of oil and natural gas exploration and production.

The projects will address research needs primarily in four categories: (1) reduced environmental impacts, (2) improved water handling and treating methods, (3) enhanced characterization of shales, and (4) improved understanding of the hydraulic fracturing process.

Projects range from testing innovative technologies for cleaning fracture flowback water, to finding new ways to improve casing cement jobs, to increasing the understanding of the relationship between underground water disposal and induced seismicity.

The projects selected under the announcement include:

GSI Environmental, Inc. (Houston, TX)—Reducing the Environmental Impact of Gas Shale Development: Advanced Analytical Methods for Air and Stray Gas Emissions and Produced Brine Characterization. The research team will develop practical and cost-effective methods to address three environmental risks associated with shale gas development: potential emissions of volatile air contaminants from produced water impoundments, potential impacts of methane and other gases on groundwater resources, and ineffective treatment, disposal, or reuse of produced water. The research products will be scientifically based protocols for effective sampling, analysis, and interpretation of data during monitoring of waste streams.

CSI Technologies, Inc. (Houston, TX)—Development of Methods to Prohibit and Remediate Loss of Annular Isolation in Shale Gas Wells: Prevention and Remediation of Sustained Casing Pressure and Other Isolation Breaches. The objectives of this project include

the evaluation of sealants and devices capable of shutting off or preventing the formation of pathways for fluid communication in the casing/borehole annulus, and field testing of preventive and remedial protocols in both the Fayetteville and Marcellus shale plays.

The University of Texas at Austin (Austin, TX)—Relationships Between Induced Seismicity and Fluid Injection: Development of Strategies to Manage Fluid Disposal in Shale Hydrocarbon Plays. The research team will seek to learn why fluid disposal induces earthquakes in some areas and not in others, with the aim of developing improved injection technology that optimizes disposal volume and cost while avoiding induced seismicity. The project includes a survey of seismic activity in four basins; acquisition of data concerning injection locations, histories, and volumes; spatial and temporal correlation analysis of injection and earthquake activity; collection of structural data in study areas that show different levels of seismic activity; geomechanical and statistical analysis; and development of improved injection strategies.

University of Southern California (Los Angeles, CA)—Water Handling and Enhanced Productivity from Gas Shales. Using a combination of computer modeling, field tests, and laboratory experiments utilizing Marcellus Shale core samples, researchers will seek to improve understanding of the interactions between shale and fracturing fluids, and the impacts of such interactions on well productivity. The results will provide new guidelines on optimal choices for hydraulic fracturing treatment design and the treatment and reuse of fracture flowback water.

Colorado State University (Fort Collins, TX)—Development of GIS-Based Tool for Optimized Fluid Management in Shale Operations. The researchers will develop a GIS-based tool for optimizing fluids management decisions during shale gas development and production in the Wattenberg field in northeastern Colorado. Products will include case studies, user manuals, and online training materials to allow the tools to be applied in other natural gas basins.

Southern Research Institute (Birmingham, AL)—Advanced Treatment of Shale Gas Frac Water to Produce NPDES Quality Water. The goal of this project is further development and optimization of four advanced water treatment technologies: two for fracturing flowback water treatment and two for treatment and disposal of residual high solid slurry and concentrated brine. The technologies are magnetic ballast clarification, vortex-generating and nanofiltration membranes, hydrogel adsorption, and a combination of precipitation, solidification and stabilization.

Ohio University (Athens, OH)—Cost-Effective Treatment of Flowback and Produced Waters Via an Integrated Precipitative Supercritical (IPSC) Process. The objective of this project is to validate the performance and cost-effectiveness of the IPSC process to convert fracture flowback and produced water generated by unconventional

shale gas wells into a clean water product. This technology combines ultraviolet light treatment, chemical precipitation, and an advanced supercritical reactor incorporating a hydrocarbon reforming catalyst.

Battelle Memorial Institute (Columbus, OH)—Development of Subsurface Brine Disposal Framework in the Northern Appalachian Basin. This project will address the need for subsurface brine disposal options in the PA-OH-WV-KY area by compiling geological and reservoir data, developing geocellular models from logs and seismic data, and carrying out advanced reservoir and geomechanical simulations to better understand the geologic setting, reservoir dynamics, geomechanical issues, and subsurface effects of brine disposal. Maps, geologic cross sections, an inventory of reservoir parameters, and practical guidance for injection operations will constitute the final deliverables.

Drexel University (Philadelphia, PA)—Development of Plasma Technology for the Management of Frac/Produced Water. The objective of this project is to further develop an integrated plasma water treatment system for improved management of fracturing flowback and produced water. The system will include plasma-induced water softening, plasma-assisted self-cleaning filtration, and vapor-compression distillation.

Colorado School of Mines (Golden, CO)—Advancing a Web-Based Tool for Unconventional Natural Gas Development with Focus on Flowback and Produced Water Characterization, Treatment and Beneficial Use. The research team will develop a set of web-based tools that will support producers, regulators, and others in the effort to characterize, treat, beneficially use, and manage produced water and fracturing flowback water. Key elements include improved understanding of chemical compositions of flowback and produced waters, models to predict variability of produced water quality, a database of water qualities and quantities, and case studies from industry partners that illustrate and validate application of the tools.

The University of Texas, Bureau of Economic Geology (Austin, TX)—Understanding and Managing Environmental Roadblocks to Shale Gas Development: An Analysis of Shallow Gas, NORMs, and Trace Metals (Texas). The objectives of this study are to (1) enhance understanding of shallow gas deposits, naturally occurring radioactive materials, and metals (to better characterize the potential risk of groundwater contamination); and (2) enhance understanding of the nature and variability of fracturing flowback water (to better adjust and optimize flowback treatment).

Oklahoma State University (Stillwater, OK)—Petrophysics and Tight Rock Characterization for the Application of Improved Stimulation and Production Technology in Shale. The project team will develop new analytical standards for petrophysical characterization of shale and new analytical methods that can reduce cost and increase the reproducibility and reliability of shale characterization results.

Texas A&M University (College Station, TX)—Conductivity of Complex Fracturing in Unconventional Shale Reservoirs. The research team will conduct experiments to determine the effect of proppant type, size, and concentration on fracture conductivity in the Barnett, Fayetteville, and Eagle Ford shales. The results will be compared to production history observations to shed light on possible causes of fracture treatment failures and unexpected production performance declines, and to provide guidelines for improving hydraulic fracturing practices in these formations so that fewer wells are needed to develop the resource.

Texas A&M University (College Station, TX)—Fracture Permeability Caused by Shear Slip in Gas Shale Reservoirs. The objectives of this project are to investigate fracture permeability generation in shale, quantify how the fracture permeability changes with normal and shear stress and assess permeability regain when gas flows after shear slip by water pressure. The results will improve the ability to utilize the self-propping character of natural fractures to improve the performance of hydraulically fractured wells and to develop more efficient and less impactful well-stimulation designs.

Gas Technology Institute (Chicago, IL)—Advanced Hydraulic Fracturing. The research team will (1) develop a real-time hydraulic fracturing control methodology through coupled analysis of geophysical fracture diagnostic data and pumping pressure, rate, and fluid density; and (2) verify the results through extensive production testing. The work will produce improved guidelines for environmentally safe and economically optimal fracture stimulation of low permeability reservoirs, including the acquisition and use of high-resolution microseismic data for fracture mapping.

New Wastewater Treatment Facilities To Open With DOE-Tested Technology Marcellus Plants Employ Cost Effective, Energy Efficient AltelaRain® Technology

ALTELA®
Treating water naturally.

The sheer volume of wastewater produced by shale-gas drilling has created a need for cutting-edge water treatment technologies that are both cost effective and energy efficient. To meet this need, Altela Inc. and its joint venture partners installed two new wastewater treatment facilities in 2012 that use a unique, patented water desalination process called AltelaRain®, which was developed with support from the U.S. Department of Energy (DOE).

The new plants for treating, recycling, and disposing of Marcellus shale wastewater are located in Clarion and McKean Counties in western Pennsylvania. The AltelaRain® technology used at the plants employs a process similar to rain-making. Wastewater is heated until it evaporates,

producing clean water vapor that naturally separates from the contaminant particles. The water is then condensed and collected. "Our technology is not new. It has been around for four and a half billion years. We clean water in the same way that Mother Nature has been cleaning water since the beginning of time," said Ned Godshall, Altela's Chief Executive Officer.

While this process, called thermal distillation, is well known, the technology that Altela has pioneered is unique in its energy efficiency. Altela's method captures the heat produced during condensation and uses it in the evaporation process. "We're able to recapture energy and use it to heat up the next drop of water without pressure, and thereby without the higher operating and capital costs of competing desalination technologies," said Godshall.

The wastewater facility in McKean County is owned and operated by Casella-Altela Regional Environmental Services LLC (CARES), a joint venture between Altela and Casella Waste Systems Inc. Situated adjacent to the McKean County Landfill, the CARES facility uses landfill gas as its energy source. The Clarion plant is owned and operated by Clarion Altela Environmental Services LLC (CAES), a joint venture between Altela and ACI Energy Inc. This plant has the ability to utilize waste heat from ACI's waste-coal-fired Piney Creek Power Plant. Each facility is able to process up to 12,000 barrels of wastewater a day—about 500,000 gallons per facility. The purified water can then be reused for well operations or discharged back into surface waterways. These facilities don't just meet the Pennsylvania Department of Environmental Protection's recent changes to Chapter 95 discharge water quality requirements, they exceed them.

In 2010, the AltelaRain process was tested at BLX Inc.'s Sleppy well site in Indiana County, Pa., as part of a demonstration supported by DOE's Office of Fossil Energy. Over a 9 month period, 77 percent of the produced hydraulic wastewater was successfully treated onsite, resulting in clean, distilled water. Following the DOE-sponsored demonstration project, four AltelaRain® modules were sold and installed at a water treatment facility in Williamsport, Pa., which is capable of treating approximately 100,000 gallons of wastewater every day.

Technologies such as AltelaRain represent exciting advancements in environmental tools and processes that improve the management of water resources, water usage, and water treatment required for shale gas development across the United States. Use of the new CARES and CAES plants will increase environmental sustainability and stewardship by ensuring that wastewater is fully treated to clean-discharge standards and by reducing freshwater demand through wastewater recycling. It will also shorten the distance that water needs to be trucked, thus reducing wear and tear on Pennsylvania's roads.

Favorable Supplies, Costs, Environmental Profile for Natural Gas Revealed in New Department of Energy Study

The nation's large resource base of natural gas can be used for cost-effective power generation, with environmental burdens coming primarily from fuel combustion, not resource extraction, according to a new Department of Energy (DOE) study. The report, *Role of Alternative Energy Sources: Natural Gas Power Technology Assessment*, was prepared by the Office of Fossil Energy's National Energy Technology Laboratory (NETL). Analysts focused on seven criteria to evaluate the role of natural gas in the U.S. energy supply chain: resource base, growth, environmental profile, cost profile, barriers, implementation risks, and expert opinion from stakeholders in academia, government, and private industry. Four natural gas power technologies were evaluated: natural gas combined cycle, natural gas combined cycle with carbon capture and sequestration, gas turbine simple cycle, and the U.S. fleet baseload average.

The U.S. resource base for natural gas has exhibited recent growth that is expected to continue because of the expanded extraction potential of various shale gases. As an example, horizontal drilling and hydraulic fracturing could allow the technical recovery of natural gas from Marcellus Shale sufficient to provide 20 years' supply to the nation at historic demand levels. The growth in natural gas supply may be hindered by the possibility of surface water deterioration and legislative uncertainty. However, property engineered and implemented natural gas systems have favorable environmental and cost profiles in comparison to other energy sources.

The development of shale gas and other unconventional natural gas wells requires the use of technologies that could release higher levels of methane, a greenhouse gas (GHG), than do conventional well technologies. However, power plant GHG emissions far outweigh those of natural gas extraction and transport, and improvements to policy and technology could reduce these upstream burdens. The current fleet of baseload natural gas power plants running on the domestic profile of natural gas has lifecycle GHG emissions of 514 kilograms of CO_2 equivalent per megawatt-hour. If switched to an unconventional mix of natural gas, the lifecycle emissions of baseload power increase to 520 kilograms of CO_2 equivalent per megawatt-hour—an increase of only 1 percent. In addition to GHG emissions, the report also inventories other air emissions, water use and quality, and resource consumption.

Historically, the price of natural gas has been volatile. This price volatility is due to supply uncertainty driven by natural and economic variables. However, some utilities expect natural gas prices to stay low in the long term and have decided to invest in new natural gas power plants. At a natural gas price of $5 per million Btu , the cost of electricity delivered by a new natural gas combined cycle power plant is $53.4 per megawatt-hour. The report also includes the cost of electricity from other natural gas power systems, including simple cycle gas turbines and power plants with carbon capture, and evaluates the cost uncertainty caused by natural gas price volatility and capital cost contingencies.