
Advanced Oil & Gas Exploration and Production Technology

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Credit: 7 PDH

Gilbert Gedeon, P.E.

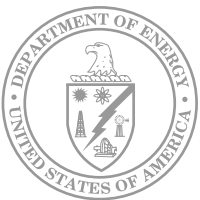
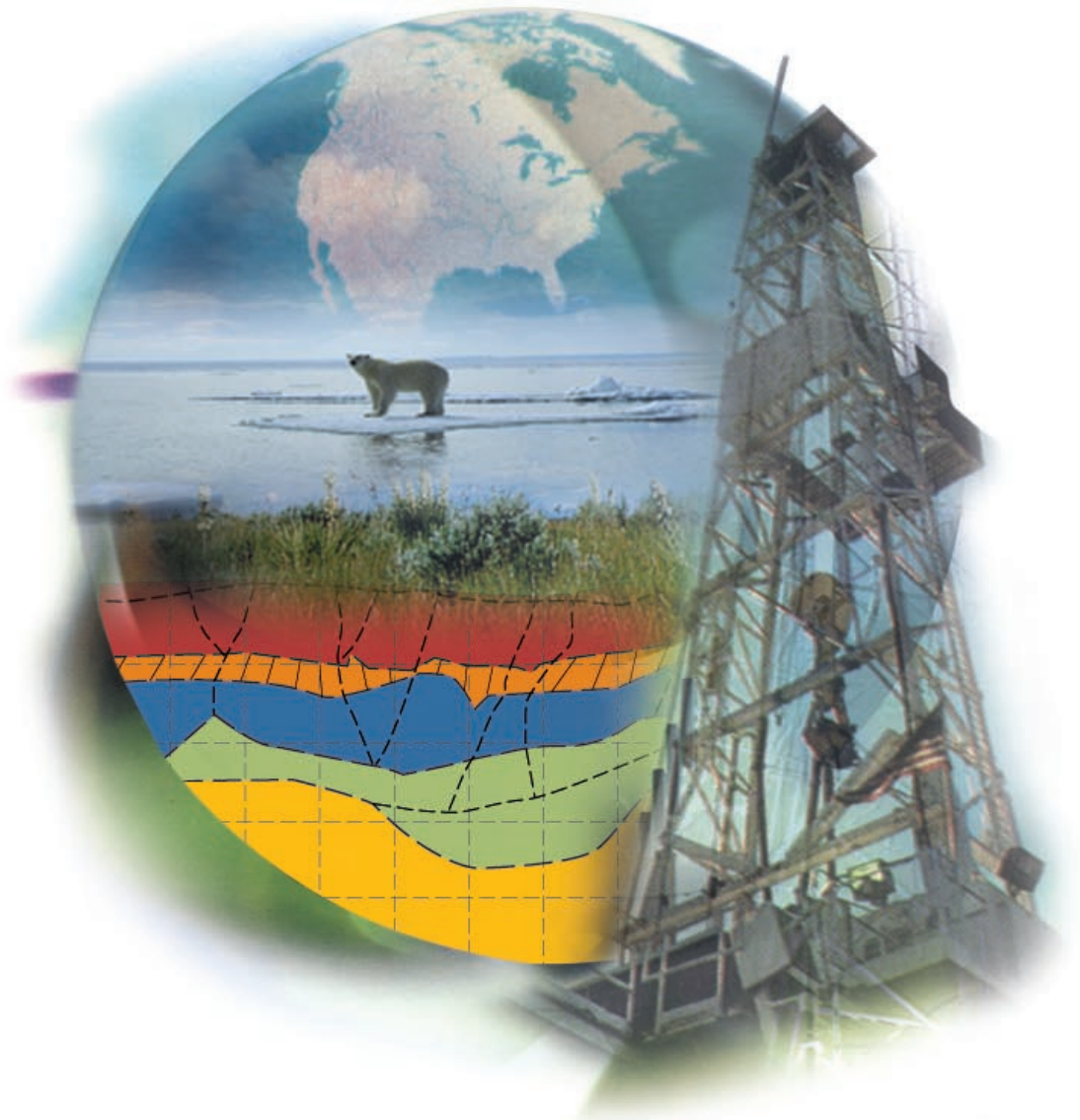


Continuing Education and Development, Inc.
22 Stonewall Court
Woodcliff Lake, NJ 07677

P: (877) 322-5800
info@cedengineering.com

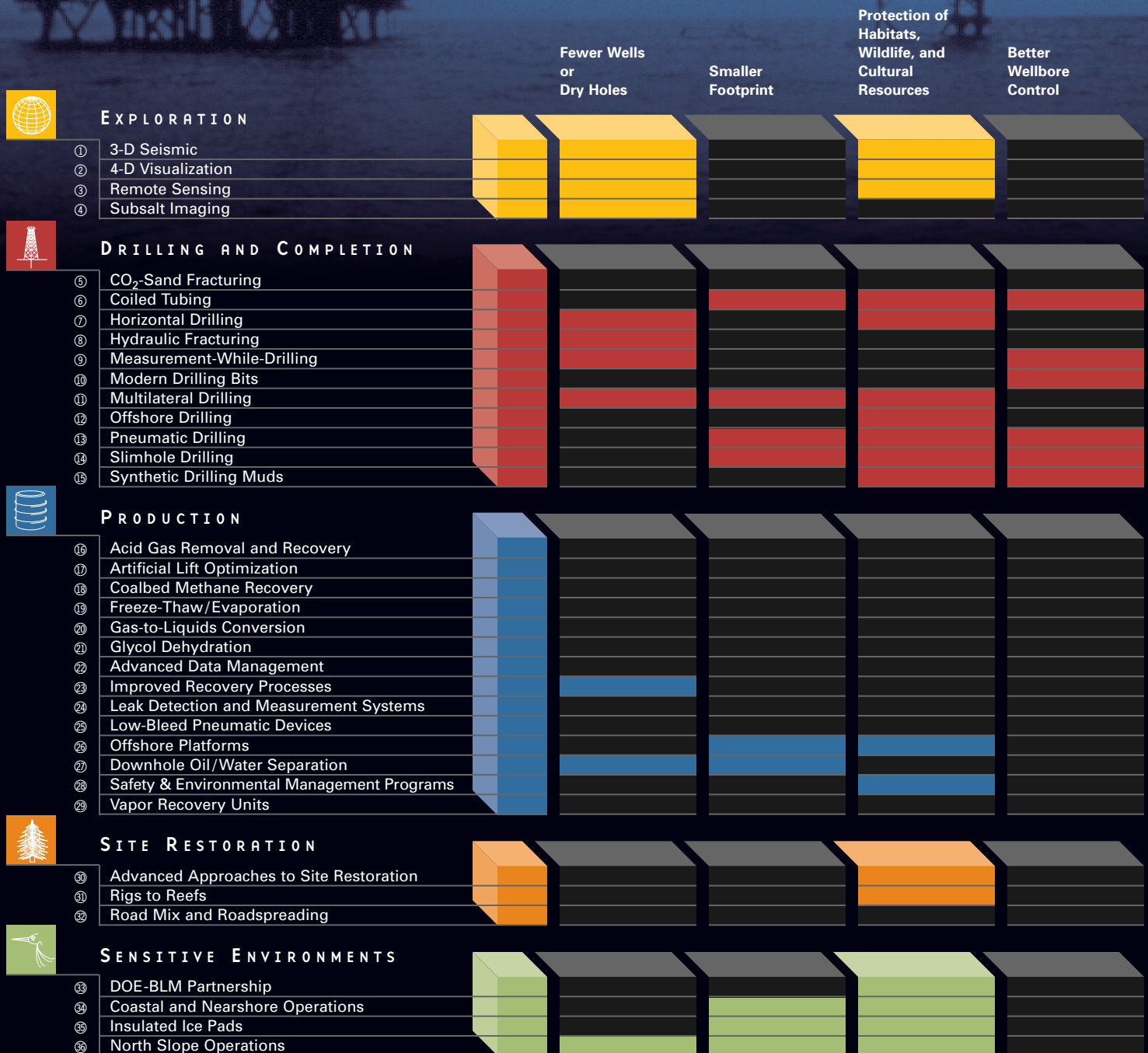


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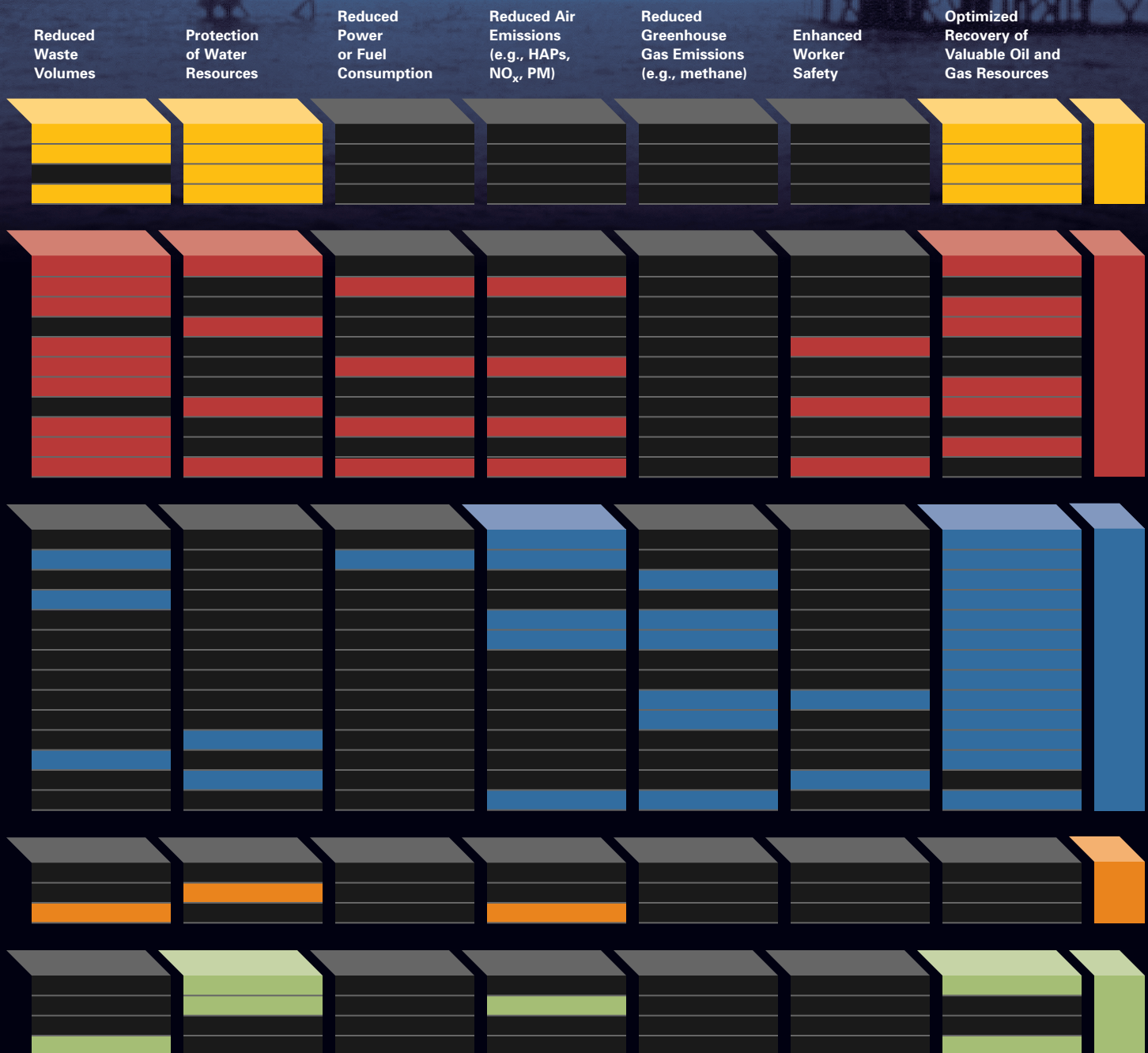


ENVIRONMENTAL BENEFITS
of ADVANCED OIL *and* GAS EXPLORATION
and PRODUCTION TECHNOLOGY

TECHNOLOGY



FACT SHEETS



The technologies described in these Fact Sheets are merely representative of the numerous advances in exploration and production technology over the last three decades and, as such, are not intended as an exhaustive inventory of these advances.



SUMMARY

Advances in 3-dimensional (3-D) seismic technology over the past 25 years have enabled oil and gas producers to evaluate prospects more effectively, drill fewer exploratory wells, and develop fields more efficiently. The result is decreased environmental impact and increased profit. To establish a visual orientation of the subsurface without drilling, energy waves directed downward through the earth's strata are reflected off the rock layers and sent back to the surface. The resulting data undergo complex processing and interpretation and provide explorationists with a 3-D visual characterization of the subsurface's geological features. This allows detailed assessment of the opportunities and risks of developing a reservoir, an increasingly important capability as the search for resources pushes into new exploration frontiers, such as deepwater and subsalt formations.

TECHNOLOGY

Locations: Worldwide, onshore and offshore

3-D Seismic

BLUEPRINT ON TECHNOLOGY

1

Two decades of successively better geologic interpretation demonstrate tangible results and environmental benefits

From 2-D to 3-D technology

UNTIL THE 1960s, developers had to rely on inaccurate, low-resolution analog data in planning their exploration investments. In the 1970s, improved 2-D seismic techniques enabled explorers to characterize subsurface opportunities with greater effectiveness. Now, with 3-D seismic, they can establish more accurate 3-D characterization of geologic structures. Reservoir characterization is key across all stages of a hydrocarbon field's life. Seismic information, critical during the exploration and appraisal phase, is now used for development until

the field is abandoned. In the last 20 years, the discovery cost has decreased from \$20 per barrel with 2-D seismic to just under \$5 per barrel with 3-D seismic. Better geologic representations, coupled with advanced drilling and production technologies, also lead to increased recovery efficiencies.

Several major improvements in 3-D surveying occurred during the 1990s, in seismic data acquisition, processing, computer hardware, and interpretation and display. Particularly remarkable have been the hardware improvements. Within the last five years, recording systems have

increased capacity from 48 to 2,000 channels, as many as 32 seismic data lines can be recorded in a single pass, and satellite navigation systems have evolved to pinpoint accurate positioning of sources and receivers. At the same time, technological improvements have reduced computing time and lowered costs. 3-D stack-time migration can now be performed in a few hours on massively parallel processors, and between 1980 and 1990, costs dropped from \$8 million to \$1 million for a 50-square-mile survey using 3-D post-time depth migration. By 2000, costs for an equivalent survey are expected to be near \$90,000.

ECONOMIC BENEFITS

Helps explorers to better identify oil and gas prospects

More effective well placement improves development of resources

Fewer dry holes ultimately reduces drilling and exploration costs

Can substantially improve project economics by reducing overall drilling costs

Exploration time relative to successful production is cut

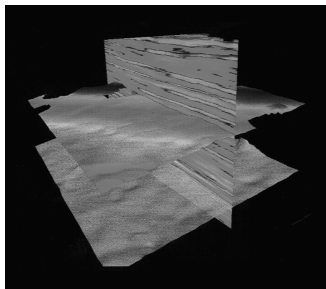
ENVIRONMENTAL BENEFITS

More accurate exploratory well-siting reduces the number of dry holes and improves overall productivity per well drilled

Less drilling waste is generated

Better understanding of flow mechanics produces less water relative to oil and gas

Overall impacts of exploration and production are reduced because fewer wells are required to develop the same amount of reserves



3-D seismic has now gained widespread acceptance. Whereas by 1980 only 100 3-D seismic surveys had been done, by the mid-1990s an estimated 200–300 3-D seismic surveys were being conducted annually. Offshore growth has been tremendous: in 1989, only 5 percent of the wells drilled in the Gulf of Mexico were based on 3-D seismic data; by 1996, nearly 80 percent used 3-D seismic. Onshore, 75 percent of all surveys were conducted with 3-D seismic by 1993.

Answering environmental and safety challenges

Today, producers are working to assess and minimize the impact of 3-D seismic equipment and crews on

sensitive environments. Explosives used to generate sound waves recorded by a seismograph can now be replaced where necessary by vibrating technology that sends an acoustic signal. Offshore seismic surveying now relies on the use of compressed air guns to ensure protection of marine life. Depending on the kind of information needed, the geology expected, the nature of the field, and the costs, 3-D seismic exploration can be customized to protect the specific terrain. For example, in mountainous terrains, standard seismic techniques (2-D) required densely gridded surveys for accurate geologic descriptions. 3-D acquisition techniques allow for more widely spaced, less invasive surveys while providing better quality data.

Advancements in 3-D data processing also allow for survey acquisition in areas congested with urban or industrial noise sources.

CASE STUDIES

Success in the Field

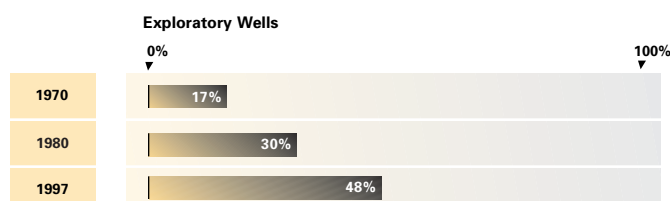
3-D seismic highly effective for portfolio management at Amoco

Amoco Corporation established an exploration drilling success rate of 48 percent for its 3-D seismic exploration activities between 1990 and 1995. By contrast, its exploration success rate for wells drilled without the benefit of 3-D seismic was only 13 percent. To evaluate the effectiveness of using 3-D, data were collected on 159 seismic surveys and a control group of 15 other prospects. 3-D proved extremely valuable at defining geometries, particularly in the North Sea and Gulf of Mexico. Where conventional surveying turned up eight prospects, 3-D narrowed these down to two. In addition, while all eight had been given an economic success probability of between 22 and 53 percent, 3-D seismic correctly predicted that the two selected had a potential success rate of 60 percent.

METRICS

Exploration success in the United States

Advances in 3-D seismic and drilling and completion technology dramatically increased drilling successes.



Source: Energy Information Administration, 1998

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Edith C. Allison
(202) 586-1023
edith.allison@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



SUMMARY

Three-dimensional (3-D) seismic technology has revolutionized oil and gas exploration and served as a springboard to visualization technology. Now emerging visualization and 4-D time-lapse monitoring technologies are improving interpretation of the data 3-D seismic imaging provides. Invaluable in locating bypassed reserves in existing formations and discovering new resources, seismic reservoir characterization can now incorporate perceptual cues such as projection, lighting and shading, depth, motion, and transparency. This technology enables a more consistent, detailed picture of a complex formation. 4-D monitoring goes one step further, providing a dynamic picture of hydrocarbon flows and other reservoir changes over time, information valuable for both exploration and reservoir management of existing resources.

TECHNOLOGY

Locations: Worldwide, onshore and offshore

4-D Visualization

BLUEPRINT ON TECHNOLOGY

Evolving seismic technologies improve accuracy and interpretation, allowing operations to be tailored to protect the environment

Adding a fourth dimension—time

PETROLEUM ENGINEERS, geologists, and planners have a far better understanding of the geologic structures of potential hydrocarbon-bearing formations now that reservoir images are projected in three dimensions. Four are better still, largely due to DOE-supported research. A reservoir's fluid viscosity, saturation changes, temperature, and fluid movements can be analyzed by time-lapse monitoring in three dimensions. The time-lapse picture is built out of data re-recorded at intervals, compared and plotted by computer onto a 3-D model. Engineers can view changes

occurring over time and link these to static and dynamic reservoir properties and production techniques. They can then follow the consequences of their reservoir management programs and make predictions as to the results of future activities. 4-D monitoring is an offshoot of the computer processing techniques developed for 3-D seismic interpretation.

With improved visualization techniques, petroleum engineers, geologists, and geophysicists are integrating many types and ages of data (well logs and production information, reservoir temperatures and pressures, fluid saturations, 2-D and 3-D

seismic data) into time-lapse imagery and reservoir performance modeling. As this time-dependent tool is correlated with physical data acquisition, more accurate characterization of subsurface reservoirs will be possible, pushing maximum recovery efficiencies.

Geologists and planners are better able to understand the structure of promising formations. As computing science advances, further gains will be made. Already, audio technology is being added, both for controlling images and presenting complex geological data so that scientists can share data in real time from remote locations.

ECONOMIC BENEFITS

Improved recovery due to precise placement of injector wells and infill drilling

More efficient operations due to better identification of drainage patterns

Lowered operating costs because of improved program timing and fewer dry holes

Increased identification and ultimate recovery of as yet untapped resources

ENVIRONMENTAL BENEFITS

Reduced drilling due to more successful siting of wells, with greater recovery from existing wells

Less drilling waste through improved reservoir management

Lower produced water volumes through better well placement relative to the oil/water interface in the formation

Increased ability to tailor operations to protect sensitive environments



CASE STUDIES

Success in the Field



4-D seismic in Indonesia

The Duri field in central Sumatra was the first 4-D project of its kind. Today over 60 time-lapse projects follow its lead. Producing 300,000 barrels of oil per day, the PT Caltex Pacific Indonesia project is the largest steamflood in the world. In 1992, Caltex began 4-D recording in a series of eight surveys to determine whether time-lapse could successfully monitor a steamflood. The goal: to improve oil recovery and cut energy use. The data generated helped direct the injection process and identify both swept and unswept zones. Due to the project's success, Caltex started baseline surveys in six new areas, and other companies are also initiating use of time-lapse monitoring.

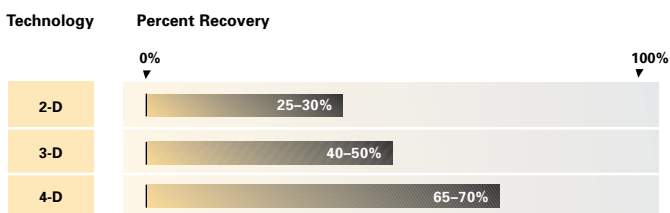
Immersed in 3-D visualization at ARCO

The ultimate formation viewing experience is to be immersed in a walk-in virtual reality cube that replicates geophysical features. In ARCO's Immersive Visualization Environment, images from projectors and mirrors outside the cube are projected onto three 10-foot walls of seamless screens. An electromagnetic tracking system orients the viewer's perspective, and stereoscopic goggles use alternate left- and right-eye images and infrared timing devices to create 3-D effects.

ARCO's exploration teams have used the facility to study data from the North Sea, Alaska's North Slope, and a project near the Philippines, using its superior visualization capabilities to produce solutions to drilling problems. In the North Sea's Pickerill field, for example, drilling plans for a multilateral hole were complicated by pressure changes among the reservoir's different compartments and drilling hazards above the reservoir. Adjustments to the original drilling plan were dictated by judgments made in the Visualization Environment, avoiding potential problems.

METRICS

Estimated recovery for oil-in-place at BP Amoco/Shell's Foenhaven field in offshore U.K.



Source: Hart's Petroleum Engineer International, January 1996

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Edith C. Allison
(202) 586-1023
edith.allison@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



SUMMARY

Used in conjunction with other exploratory techniques, such as 3-D seismic imaging, remote sensing systems detect and map concentrations of hydrocarbons with greater accuracy than other technologies alone, and with less environmental impact. Technologies such as satellite imagery, aeromagnetic surveys, and gravimetry are now being applied by the largest exploration companies to attempt to detect the vertical or near-vertical migration of oil and gas to the earth's surface and help identify promising geologic structures. These systems measure gases, solids, and liquids, using their physical properties to attenuate or reflect beams of electromagnetic energy. Resulting geophysical data are processed into easily understood images and maps, and form an integral part of current onshore and offshore programs throughout the world.

TECHNOLOGY

Locations: Worldwide (especially deepwater)

Remote Sensing

BLUEPRINT ON TECHNOLOGY

Remote exploration helps pinpoint hydrocarbon resources, pollution sources, and sensitive environments

Enhanced satellite imaging systems

OPTICAL SATELLITE imagery has been the predominant source of data for identifying and mapping onshore geology since the early 1970s, when the first Landsat Earth Observation satellite was launched. Today, satellite imagery, onshore and offshore, is also provided by radar satellites very sensitive to the earth's surface contours. For example, various types of satellites can see through 70 feet of clear water and up to 20 feet beneath the surface. Early optical satellites depended on visible or near-infrared light to collect energy reflected from the earth's surface. By contrast, radar

satellites emit energy at microwave frequencies, enabling them to acquire imagery under nearly any atmospheric condition. Sophisticated digital image processing systems can now convert and sort raw satellite data into thematic maps that point to the location of productive formations, even detecting oil and gas seepages that indicate migration pathways from undrilled traps. Similarly, remote sensing techniques can also identify hydrocarbon spills and leaks in remote areas, such as along pipelines.

Current multispectral satellites such as the Landsat Thematic Mapper create

images by gathering up to seven bands of light spectra in prism-like fashion. In 2000, when the U.S. Navy plans to launch its Navy EarthMap Observer satellite, an exciting new satellite technology called hyperspectral analysis, accessing upwards of 200 bands of light, will further increase imaging accuracy.

Improved aeromagnetic surveys

Initially developed for military applications, aeromagnetic surveying has evolved into a productive exploration technology that can recognize the magnetic signature of potential hydrocarbon-bearing basins from altitudes over 10,000 feet. Using a

ECONOMIC BENEFITS

Increased exploratory success rates

Dramatically reduced exploratory costs

Access to geological data otherwise unobtainable

Increased recovery of resources from frontier basins

Identification of hydrocarbon "seeps" as distinguished from oil spills or pollution

ENVIRONMENTAL BENEFITS

Accurate identification of fragile ecosystems, enabling care when drilling

Increased ability to address environmental needs

Fewer dry holes and nonproductive exploratory wells are drilled

Improved characterization of earth's natural systems

Identification of spills and leaks in remote areas



magnetometer mounted on a magnetically cleaned aircraft, explorers are successfully mapping sedimentary anomalies critical to oil and gas exploration, detecting salt/sediment contact, mineralized shear zones, and intrasedimentary markers.

Recent improvements in magnetometer design, digital signal processing techniques, and electronic navigation technologies, in combination with faster sampling of the magnetic field and the use of more detailed survey grids, allow mapping of subtle magnetic signatures. These advances improve the interpretation and visualization of geological data.

Measuring gravity to gauge resources

Gravimetry measurement is now derived from both satellite and airborne observations. Gravity anomalies can be measured and mapped to give geoscientists an idea of the size and depth of the geological structures that caused them.

Satellite gravity imaging uses radar to measure undulations in the sea surface that reflect density variations in the earth's upper crust. This technology enables mapping of areas of mass deficit, where sedimentary deposition is likely to have occurred. Identification of such areas gives explorers a better idea of where hydrocarbons may be located.

Putting it all together

Exploration companies like BP Exploration, Exxon, Mobil, Texaco, Unocal, and RTX are tailoring their remote sensing programs to combine technologies as needed. Recent advances in radar imaging and sophisticated image-processing packages, combined with satellite-derived gravity and bathymetry data, for example, present new opportunities to use remote sensing for deepwater exploration. Remote sensing is now considered critical to such operations. It is also extraordinarily cost-effective.

CASE STUDIES

Success in the Field



Satellites help explore in the Caspian Sea

After water-level changes along the shallow coast of the Republic of Kazakhstan made their bathymetric maps obsolete, Oryx Energy and its exploration partner, Exxon, turned to remote sensing to gauge depths. Water depth fluctuations caused by wind can make movement of seismic and drilling equipment challenging. With satellite image processing technology, the team created new bathymetric maps (e.g., the 12,200 square km Mervyi Kultuk block, some 30 km south of the giant Tengiz field) and used these maps to position a successful new drilling program in one of the world's most productive oil exploration areas.

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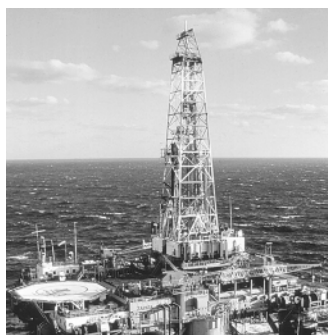
CONTACT



U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Edith C. Allison
(202) 586-1023
edith.allison@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Gulf of Mexico, West Africa, and other salt formations

Subsalt Imaging

SUMMARY

Now that most easily accessible domestic resources have been discovered, oil and gas explorers are investigating the promising but more inaccessible resources beneath saltsheet formations in the Gulf of Mexico. Large, irregular saltsheets may cover 60 percent of the slope beneath the Outer Continental Shelf in the Gulf and are found throughout the world. Advances in 3-D imaging technologies are crucial to providing reliable images of what lies below the thick layers. A 3-D prestack depth migration method of seismic data processing and an advanced marine magnetotellurics technique are now making it possible to image the structure and thickness of subsalt sediments. Together, these technologies provide sufficient information to help locate new oil or gas deposits, estimated at 15 billion barrels of oil equivalent in the Gulf of Mexico alone.

BLUEPRINT ON TECHNOLOGY

Interpretation of formations hidden under layers of salt allows more accurate siting of new reserves

Getting under the salt

DEVELOPING IMAGES of subsalt structures poses a critical challenge to exploration. Seismic imaging is based on the transmission of sound waves and analysis of the energy that is bounced back. But large amounts of energy are lost when sound waves pass through salt; thus, an extremely strong seismic source is required. Often seismic data are incomplete, preventing explorers from obtaining accurate readings of a structure's shape and thickness. Traditional imaging methods cannot deliver accurate readings when seismic sources are blocked by salt squeezed into sheets between sediment layers from an underlying salt base. The oil and gas sandwiched between the salt layers can only be

imaged by a combination of advanced seismic source technology, complex mathematical modeling simulations, and improved data processing and imaging techniques. DOE's public/private Natural Gas and Oil Technology Partnership has helped develop several such technologies, among them improvements to the speed and reliability of 3-D prestack depth migration, which creates a coherent image by processing as many as 25 million records.

Using electromagnetic resistance

As a part of this DOE partnership, the National Laboratories and industry are currently investigating the feasibility of marine magnetotellurics, which is ideal for subsalt exploration since it is

based on electrical resistance. Because salt's resistivity is 10 times greater than that of surrounding sediments, the contrast between salt and sediment resistance to low-frequency electromagnetic radiation from the earth's ionosphere makes it easier to map the extent and thickness of salt structures.

Stealth imaging breakthrough

The latest technology used to enhance seismic data is 3-D full tensor gradient (FTG) imaging, originally developed by the U.S. Navy during the Cold War for stealth submarines. A 3-D gradiometer survey takes real-time measurements of very small changes in the earth's gravity field, each relaying information directly related to mass and geometry of subsurface

ECONOMIC BENEFITS

More efficient exploration to pinpoint new oil and gas, reducing the financial risks

Cost-effective exploration: an average 30-image seismic survey costs \$500,000, while an MT survey covering the same area costs about \$50,000

ENVIRONMENTAL BENEFITS

Increased resource recovery due to better reservoir characterization

Better, more careful siting of new drilling operations

Reduced drilling wastes as fewer wells are drilled



geological bodies. FTG provides the depth and shape of almost any geological structure, independent of seismic velocities, allowing geoscientists to develop more complete images of complex salt formations. Two field tests have

demonstrated a significantly improved view of the Gulf's subsalt geology, and FTG promises to be an affordable tool with which to enhance existing 3-D seismic imaging technology in salt formations around the world.



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CASE STUDIES

Success in the Field



Beneath the Mahogany field salt

Drilling beneath the salt formations of the Gulf of Mexico, an exploration play spanning 36,000 square miles south of the Louisiana coast, began in the 1980s. A decade of unsuccessful exploration followed, and it took advanced subsalt technologies to break through the visual block. Nine subsalt discoveries were drilled in the play from 1990 to 1996, representing a phenomenal success rate of 35 percent. The centrally located Mahogany field (the Gulf's first commercial subsalt play) was discovered in 1993, and four wells were completed by 1997, now flowing at a daily rate of 15,000 barrels of oil and 35 million cubic feet of gas. Mahogany field's total reserves are estimated at 100 million barrels of oil-equivalent, and total recovery from this and the Gulf's other subsalt discoveries is estimated to be 650 million energy equivalent barrels, resources that would have remained inaccessible without advanced subsalt imaging technology. A new discovery, the Tanzanite field, is estimated to hold reserves of 140 million barrels of oil-equivalent. Due to the size of this discovery, subsalt exploration in the Gulf is likely to remain active. Future subsalt technology advances may be the key to discovering other large untapped fields. As technology progresses, so will resource recovery.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Edith C. Allison
(202) 586-1023
edith.allison@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Canada (commercial) and United States (demonstration only)

CO₂-Sand Fracturing

SUMMARY

Fracturing has been widely used since the 1970s to increase production from formations with low permeability or wellbore damage. Unlike conventional hydraulic and acid fracturing techniques, CO₂-sand fracturing stimulates the flow of hydrocarbons without the risk of formation damage and without producing wastes for disposal. A mixture of sand proppants and liquid CO₂ is forced downhole, where it creates and enlarges fractures. Then the CO₂ vaporizes, leaving only the sand to hold the fracture open—no liquids, gels, or chemicals are used that could create waste or damage the reservoir. Any reservoir that is water-sensitive or susceptible to damage from invading fluids, gels, or surfactants is a candidate. The process has had widespread commercial success in Canada, and recent DOE-sponsored field tests have demonstrated commercial feasibility in the United States.

BLUEPRINT ON TECHNOLOGY

In widespread use in Canada, a stimulation technique now successfully demonstrated in the U.S. has outstanding results without formation damage

Using CO₂ to fracture oil and gas reservoirs

RECOMPLETING AND fracturing an existing oil or gas well to stimulate production that has declined over time is significantly less costly than drilling a new well. First used in the mid-1930s, fracturing treatments inject fluids under high pressure into the formation, creating new fractures and enlarging existing ones. “Proppants” (usually large-grained sand or glass pellets) are added to the fluid to support the open fractures, enabling hydrocarbons to flow more freely to the wellbore. Fracturing is widely used to stimulate production in declining wells and to initiate production in certain

unconventional settings. More than one million fracturing treatments were performed by 1988, and about 35 to 40 percent of existing wells are hydraulically fractured at least once in their lifetime. More than eight billion barrels of additional oil reserves have been recovered through this process in North America alone. Yet conventional fracturing technology has drawbacks. The water- or oil-based fluids, foams, and acids used in traditional fracturing approaches can damage the formation—for instance, by causing clay in the shale to swell—eventually plugging the formation and restricting the flow of hydrocarbons. Conventional fracturing also

produces wastes requiring disposal.

An advanced CO₂-sand fracturing technology overcomes these problems, and is providing a cost-effective process for stimulating oil and gas production. First used in 1981 by a Canadian firm, the process blends proppants with 100 percent liquid CO₂ in a closed-system-pressurized vessel at a temperature of 0°F and a pressure of 300 psi. Nitrogen gas is used to force the resulting mixture through the blender to the suction area of the hydraulic fracture pumping units and then downhole, where it creates and enlarges fractures. The CO₂ used in the process

ECONOMIC BENEFITS

Eliminates hauling, disposal, and maintenance costs of water-based systems

Can significantly increase well productivity and ultimate recovery

CO₂ vaporization leads to fast cleanup, whereas water-based fluids sometimes clean up slowly, reducing cash flow

Recovery of valuable oil and gas is optimized

ENVIRONMENTAL BENEFITS

Using liquid CO₂ creates long, propped fractures without formation damage

No wastes requiring disposal are created

Conventional fracturing gels and chemicals, which may damage the flow path between wellbore and formation, are not used

Groundwater resources are protected

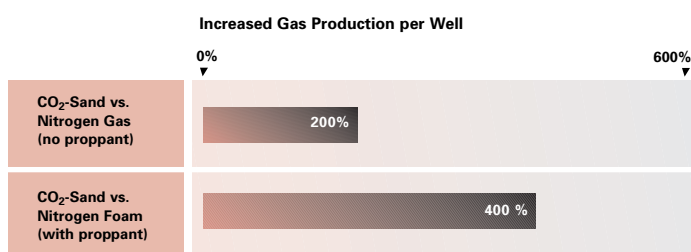


vaporizes, leaving behind a dry, damage-free proppant pack. The technology has gained widespread commercial acceptance in Canada, where it has been used some 1,200 times. In the United States, use has been limited to demonstrations—many sponsored and cofunded by DOE—taking place over the last two years in about 50 wells in Kentucky, Ohio, Pennsylvania, Tennessee, Texas, New York, Colorado, and New Mexico.

CO₂-sand fracturing treatments average from \$30,000 to \$50,000, depending on well depth and rock stresses. While often higher-cost than conventional methods, these costs are offset by savings realized through eliminating both swab rigs and the hauling, disposal, and maintenance costs associated with water-based systems. As in conventional fracturing, CO₂-sand treatments can significantly increase a formation's production and profitability.

METRICS

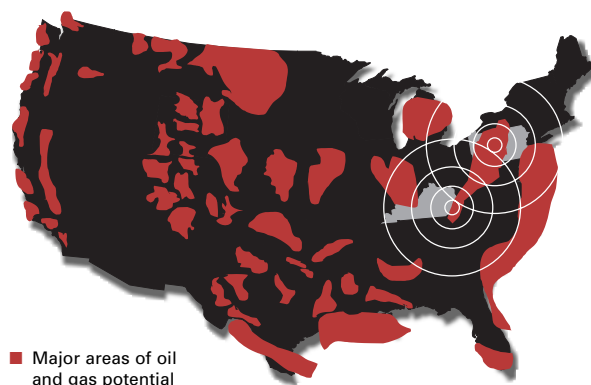
Results of fracturing technique tests in Devonian Shales wells after 37 months



Source: Arnold, *Hart's Petroleum Engineer International*, January 1998

CASE STUDIES

Success in the Field



Successful DOE-sponsored field tests

The U.S. Geological Survey estimates that 200 to 400 trillion cubic feet of natural gas resources exists in unconventional settings in the United States. Developing cost-effective advanced fracturing techniques is crucial in our quest to recover these resources. A number of field-test fracturing projects sponsored by DOE recently evaluated and proved CO₂-sand technology's effectiveness in gas recovery. In the Devonian Shales in Kentucky, four of 15 gas wells were stimulated with CO₂-sand mixture, seven with nitrogen gas and no proppant, and four with nitrogen foam and proppant. After 37 producing months, wells stimulated with the CO₂-sand process had produced four times as much as those treated with foam, and twice as much as those stimulated with nitrogen gas. In central Pennsylvania, three gas wells were stimulated using CO₂-sand fracturing. Immediately after fracturing, two of the wells exhibited production increases of 1,000 percent and 600 percent. Over a year and a half later, production from the wells had increased 620 percent, 300 percent, and 240 percent, respectively.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, onshore and offshore

Coiled Tubing

SUMMARY

Continuous coiled tubing can dramatically increase the efficiency, profitability, and productivity of drilling for oil and gas. Whereas in conventional drilling operations, the drilling pipe consists of several jointed pieces requiring multiple reconnections, a more flexible, longer coiled pipe string allows uninterrupted operations. A cost-effective alternative for drilling in reentry, underbalanced, and highly deviated wells, coiled tubing technology minimizes environmental impacts with its small footprint, reduced mud requirements, and quieter operation. Quick rig set-up, extended reach in horizontal sidetracking, one-time installation, and reduced crews cut operating costs significantly. For multilateral and slimhole reentry operations, coiled tubing provides the opportunity for extremely profitable synergies.

BLUEPRINT ON TECHNOLOGY

Successively better coiled tubing technologies drive improvements in cost, productivity, and efficiency of drilling operations, while reducing environmental impact

A strong portfolio of benefits

PARTICULARLY VALUABLE in sensitive environments such as Alaska's North Slope, coiled tubing technology has far less impact on a drilling site than conventional equipment, in addition to performing drilling operations more efficiently and cost-effectively. Although the first coiled tubing units were built in the 1950s, only after rapid technological advances in the late 1980s did the technology start to gain industry-wide recognition. From 533

operating units in 1992, usage has grown to some 730 units in 1998, and many drilling companies are now revising their rig portfolios.

In a variety of drilling applications, coiled tubing eliminates the costs of continuous jointing, reinstallation, and removal of drilling pipes. It is a key technology for slimhole drilling, where the combination can result in significantly lower drilling costs—a typical 10,000-foot well drilled in southwest Wyoming costs

about \$700,000, but with coiled tubing and slimhole, the same well would cost \$200,000 less.

Reduced working space—about half of what is required for a conventional unit—is an important benefit, as are reduced fuel consumption and emissions. A significant drop in noise levels is also beneficial in most locations. The noise level at a 1,300-foot radius is 45 decibels, while at the same radius a conventional rig has a 55-decibel level.

ECONOMIC BENEFITS

Increased profits, in certain cases, from 24-hour rig set-up and faster drilling

Smaller drilling infrastructure and more stable wells

No interruptions necessary to make connections or to pull production tubing

Reduced waste disposal costs

Reduced fuel consumption

Increased life and performance from new rig designs and advanced tubulars, reducing operating costs

ENVIRONMENTAL BENEFITS

Reduced mud volumes and drilling waste

Cleaner operations, as no connections to leak mud

Reduced operations noise

Minimized equipment footprints and easier site restoration

Reduced fuel consumption and emissions

Less visual impact at site and less disturbance, due to speedy rig set-up

Reduced risk of soil contamination, due to increased well control

Better wellbore control



Technology advances in the '90s

Dramatic advances have recently brought new coiled tubing technology to market. For example, new designs from leading drilling service companies have eliminated coiled tubing rigs' guide arches; in these new designs, eliminating the bending in the tubing at the guide arch has significantly increased its life. The newest advance is an electric bottomhole assembly offering immediate data feedback on bottomhole conditions, reduced coiled tubing fatigue, maintenance of bit speed independent of flow rate, and improved reliability. New materials like advanced titanium alloys and advanced metal-free composites have improved the reliability, performance, corrosion-resistance, weight, and cost-effectiveness of coiled tubing assemblies. In certain cases, titanium tubing offers an estimated reeling cycle life 5 to 10 times greater than steel.



Photo: WZI, Inc.

CASE STUDIES

Success in the Field

At Lake Maracaibo field

Advanced coiled tubing drilling is helping operators optimize resource recovery at Venezuela's Lake Maracaibo field. Baker Hughes INTEQ's first-of-its kind Galileo II hybrid drilling barge, containing 2 3/8-inch coiled tubing and slimhole drilling measurement-while-drilling tools, drilled its first well at the end of 1997. It was the first time an underbalanced well had been drilled on Lake Maracaibo, and it promises good results. Galileo II's unique design is also expected to significantly increase the life of its coiled tubing, ultimately reducing operating costs. Operating in a fragile lake ecosystem presents unique waste management challenges, and all drill cuttings and waste mud are transported back to shore for disposal.

METRICS

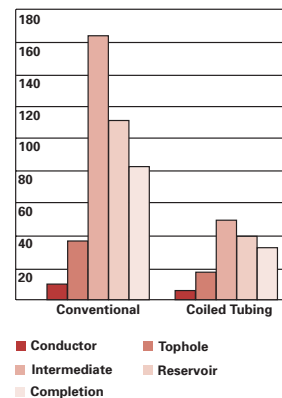
Field trials in the Netherlands demonstrate environmental benefits

Fuel Consumption and Gas Emissions:
Coiled Tubing vs. Conventional Rigs

		Med Workover Rig	Land Drilling Rig	Coiled Tubing Drilling Unit	
Diesel m ³ /month			35	160	25
Gas Emissions kg/day	CO ₂	3,293	15,055	2,122	
	CO	3.7	16.8	2.5	
	NO _x	4.6	21	2.1	
	HC	3.9	17.8	2.8	
	HC (Gas)	1.8	8.4	1.1	
	SO ₂	4.2	19.4	2.2	

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Conventional drilling fluids volume compared with coiled tubing volumes (m3)



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CONTACT



U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, onshore and offshore

Horizontal Drilling

SUMMARY

Horizontal drilling targets oil or gas in thin, tight reservoirs, reservoirs inaccessible by vertical drilling, and reservoirs where horizontal wellbores significantly increase flow rates and recovery. Horizontal wells maximize utilization of drilling sites and infrastructure. While vertical wells drain oil from a single hole and have limited contact with oil-bearing rock, horizontal wells penetrate a greater cross-section of the formation, allowing substantially more oil to drain. A horizontal well is drilled laterally from a vertical wellbore at an angle between 70° and 110°. It can tap the hydrocarbon supplies of a formation without further environmental disturbance, of particular value in sensitive areas.

BLUEPRINT ON TECHNOLOGY

Without any increase in environmental impact, horizontal drilling allows developers to reach reserves beyond the limits of conventional techniques

Breaking geologic barriers

THE CURRENT BOOM in horizontal drilling is due to rapid developments in technology over the past two decades. Although several horizontal wells were successfully drilled between the 1930s and 1950s, these were limited to expensive 100- to 200-foot forays. Interest waned in such onshore applications after the development of hydraulic fracturing technology made vertical wells more productive. The offshore industry continued to pursue horizontal drilling, but the limitations of the available equipment often resulted in ineffective, expensive, and time-consuming drilling operations.

In the mid-1970s, several significant technology advances started breaking down these barriers. Steerable downhole motor assemblies, measurement-while-drilling (MWD) tools, and improvements in radial drilling technologies were the breakthroughs needed to make horizontal drilling feasible. Short-radius technology had been developed in the 1930s, the earliest curvature technique used to drill laterals; in the 1950s, long-radius technology allowed lateral displacement away from the rig to penetrate the reservoir. Then, in the 1970s, medium-radius techniques permitted re-drilling horizontal intervals from existing wellbores, and with this advance producers could build rapidly to a

90° angle. Today, horizontal wells are being drilled longer and deeper, in more hostile environments than ever before.

Horizontal drilling is now conventional in some areas and an important component of enhanced recovery projects. At any given time, horizontal drilling accounts for 5 to 8 percent of the U.S. land well count. The Austin Chalk field has been the site of over 90 percent of the onshore horizontal rig count since the late 1980s, and still accounts for the majority of horizontal permits and rig activity in the U.S. today. Thirty percent of all U.S. reserves are in carbonate formations, and it is here that 90 percent of horizontal wells are drilled.

ECONOMIC BENEFITS

Increased recoverable hydrocarbons from a formation, often permitting revitalization of previously marginal or mature fields

More cost-effective drilling operations

Less produced water requiring disposal and less waste requiring disposal

Increased well productivity and ultimate recovery

ENVIRONMENTAL BENEFITS

Less impact in environmentally sensitive areas

Fewer wells needed to achieve desired level of reserve additions

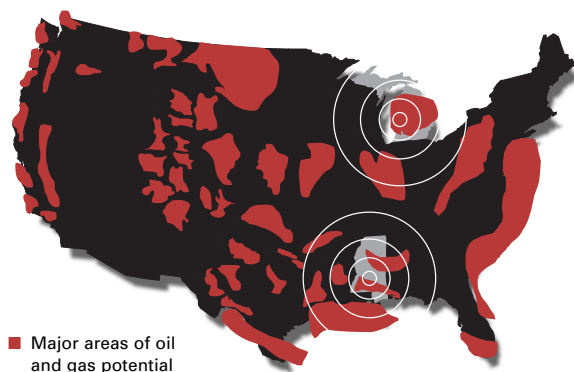
More effective drilling means less produced water

Less drilling waste



CASE STUDIES

Success in the Field



Success in the Black Warrior Basin

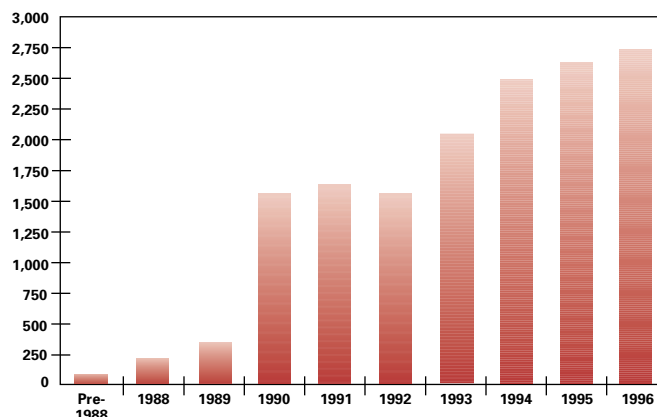
In 1993, after six years of production, the Goodwin gas field in the Black Warrior Basin was converted to gas storage by the Mississippi Valley Gas Co. Only conventional vertical wells had been drilled in the thin (10 feet), tight, abrasive formation. The operator successfully drilled and completed the first horizontal well in only 23 days, utilizing MWD and gamma ray tools, a short radius motor, and a polycrystalline diamond bit. Overall costs approached twice that of a conventional well in the field, but the deliverability of the horizontal well was six times that of a vertical well. Since one horizontal well is producing the equivalent of six vertical wells, maintenance and operating costs are lower, and fewer meter runs, flowlines, and other facilities are required.

New reserves in the Dundee Formation

Only 15 percent of the known oil located in the Michigan Basin's Dundee Formation had been produced when a DOE co-sponsored horizontal drilling project brought new life to the formation's exhausted Crystal field. The new horizontal well now produces nearly 20 times more than the best conventional well in its field—100 barrels of oil a day—and boasts estimated recoverable reserves

Worldwide Horizontal Wells

Number of Horizontal Wells



Source: Oil & Gas Journal, November 23, 1998

of 200,000 barrels. Success has spawned the drilling of nine other horizontal wells here, and nearly 30 others in geologically similar fields in the basin. If successful in other depleted Dundee fields, horizontal wells could produce an additional 80 to 100 million barrels of oil, worth about \$210 million in tax revenues alone.

METRICS

In the United States, according to a recent DOE study, horizontal drilling has improved:

Potential reserve additions—by an estimated 10 billion barrels of oil equivalent, nearly 2% of original oil-in-place

The average production ratio—now 3.2:1 for horizontal compared to vertical drilling based on field data, even though the average cost ratio is 2:1

Carbonate numbers are even better—production is nearly 400% greater than vertical wells, yet costs are only 80% more

Source: U.S. Department of Energy and Maurer Engineering, Inc., 1995

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, onshore and offshore

Hydraulic Fracturing

SUMMARY

Routinely applied to over half of U.S. gas wells and a third of oil wells, hydraulic fracturing has been proven to enhance well performance, minimize drilling, and recover otherwise inaccessible resources. It makes the development of some low-permeability, tight formations and unconventional resources economically feasible. When the flow of hydrocarbons is restricted by formation characteristics, injecting pressurized fluids and solid additives can stimulate wells to increase production. Fluids are pumped into the formation at pressure great enough to fracture the surrounding rock. A proppant slurry follows, biodegrading to sand proppant that holds the fractures open, allowing free passage of fluids to the wellhead. So successful has this technology been that the industry currently spends a billion dollars annually on hydraulic fracturing.

BLUEPRINT ON TECHNOLOGY

Assisting operators to bring new life to mature fields and make unconventional fields commercially viable

Stimulating wells to deliver more

FIRST INTRODUCED IN 1947, hydraulic fracturing quickly became the most commonly used technique to stimulate oil and gas wells, ultimately enabling production of an additional eight billion barrels of North American oil reserves that would otherwise have been unrecovered. By 1988, fracturing had already been applied nearly a million times. Each year, approximately 25,000 gas and oil wells are hydraulically fractured.

Fracturing is generally used to regain productivity after the first flow of resources diminishes. It is also applied to initiate the production process in unconventional forma-

tions, such as coalbed methane, tight gas sands, and shale deposits. Improvements in fracturing design and quality control have enabled operators to successfully apply fracturing techniques in more complex reservoirs, hostile environments, and other unique production settings.

New advances

The DOE-led Natural Gas and Oil Technology Partnership has promoted many of this decade's fracturing advances. These include the use of air, underbalanced drilling, and new fracturing fluids to reduce formation damage and speed well clean-up. Improved log interpretation has improved identification of productive pay zones. Improved borehole tools help

map microseismic events and predict the direction and shape of fractures. New 3-D fracture simulators with revised designs and real-time feedback capabilities improve prediction of results.

Advanced breakers and enzymes that minimize the risk of formation plugging from large-volume hydraulic stimulations are the latest advances to protect the environment and increase ultimate recovery. In addition, emerging technologies developed by DOE and the Gas Research Institute, such as microseismic fracture mapping and downhole tiltmeter fracture mapping, offer the promise of more effective fracture diagnostics and greater ultimate resource recovery.

ECONOMIC BENEFITS

Increased well productivity and ultimate recovery

Significant additions to recoverable reserves

Greatly facilitated production from marginal and mature fields

ENVIRONMENTAL BENEFITS

Optimized recovery of valuable oil and gas resources

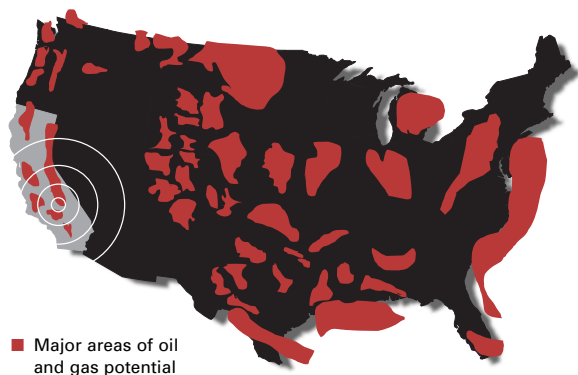
Protection of groundwater resources

Fewer wells drilled, resulting in less waste requiring disposal



CASE STUDIES

Success in the Field

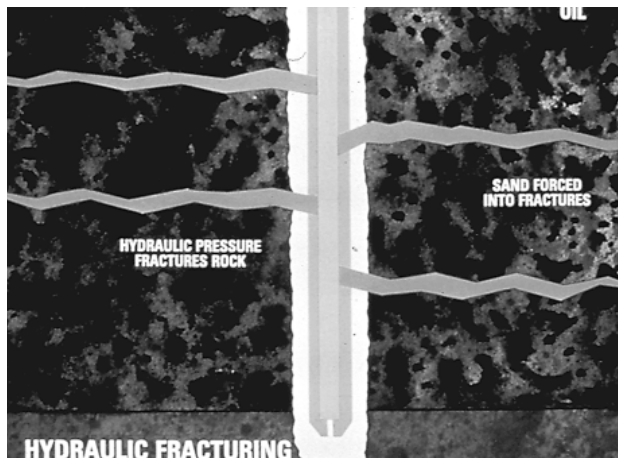


■ Major areas of oil and gas potential

Increased profits from the once declining Lost Hills field

Refined fracturing methods and improved quality control have brought increased productivity and profitability to a field that once resisted development. The Lost Hills field in California contains an estimated two billion barrels of oil-in-place, but since its discovery in 1920 it has produced only a fraction of its potential. The field has very low permeability and it lacks a strong natural fracture network, which restricts the flow of resources. This makes the field difficult to produce at acceptable rates without fracture stimulation.

Although hydraulic fracturing began in Lost Hills during the '60s and '70s, completion results were poor because of small proppant volumes and inefficient fracture fluids. Between 1987 and 1990, Chevron initiated massive hydraulic fracture stimulation. Although productivity increased significantly, costs were high and the work was not as profitable as anticipated.



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In 1990, Chevron and Schlumberger Dowell formed a partnership aimed at improving fracturing efficiency, reducing costs, and increasing productivity. One result is that multiple wells are now stimulated from fixed equipment locations. Since its implementation in late 1992, this central site strategy has been used to fracture more than 100 wells, using some 200 million pounds of proppant. The strategy has lowered costs by reducing personnel, well completion time, and equipment mobilization, while improving environmental management and safety controls. Along with fracture design changes, this has reduced overall fracturing costs by 40 percent since 1988. These efforts played a large part in the field's 250 percent production increase between 1989 and 1994—from 6,000 barrels to more than 15,000 barrels of oil per day.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, onshore and offshore

Measurement-While-Drilling

SUMMARY

Measurement-while-drilling (MWD) systems measure downhole and formation parameters to allow more efficient, safer, and more accurate drilling. These measurements can otherwise be obtained only by extrapolation from surface measurements. MWD systems calculate and transmit real-time data from the drill bit to the surface, avoiding the time-lag between occurrence and surface assessment and significantly improving drilling safety and efficiency. Without this analysis of bottomhole conditions, it is sometimes necessary to abandon a hole for a new start. MWD reduces both costs and environmental impacts because measurements and formation evaluation occur before formation damage, alteration, or fluid displacement have occurred. Of particular use in navigating hostile drilling environments, MWD is most frequently used in expensive exploratory wells, and in offshore, horizontal, and highly deviated wells.

BLUEPRINT ON TECHNOLOGY

High-tech tools that deliver real-time bottomhole data prevent excessive formation damage and make drilling significantly more precise and cost-effective

More information for better drilling

MWD TECHNOLOGY is critical as operators seek to reach deeper and farther for new hydrocarbon resources. A real-time bit navigation and formation evaluation aid, MWD uses tools such as triaxial magnetometers, accelerometers, and pressure sensors to provide vital downhole data concerning directional measurements, pore pressures, porosity, and vibration. This provides for more effective geosteering and trajectory control, and safer rig operations. Novel equipment transmits bottomhole information to the surface by encoding data as a series of pressure pulses in the wellbore's mud column or by

electromagnetic telemetry. Surface sensors and computer systems then decode the transmitted information and present it as real-time data.

In normal drilling environments, MWD is used to keep the drill bit on course. MWD is also valuable in more challenging drilling environments, including underbalanced, extended-reach, deviated, and high-pressure, high-temperature drilling. In underbalanced directional drilling, MWD monitors the use of gas injected to maintain safe operating pressure. In deviated and horizontal wells, MWD can be used to geologically steer the well for maximum exposure in the reservoir's most productive zones.

Evaluating the formation

Prior to the spread of MWD systems in the late '70s, bottomhole conditions were monitored by time-consuming analysis of cuttings and gas intrusion, and by after-the-fact wireline steering measurement that necessitated frequent interruptions for pipe removal. Today, the continuous flow of MWD information improves formation evaluation efforts as well as drilling progress. Over successive periods, MWD data can reveal dynamic invasion effects, yielding information on hydrocarbon mobility, gas-oil-water contact points, and formation porosity. Future advances in MWD technology, such as MWD acoustical loggers with digital signal processing

ECONOMIC BENEFITS

- Improved drilling efficiency and accuracy
- Timely formation evaluation
- Reduced operating costs and financial risks
- Improved rig safety

ENVIRONMENTAL BENEFITS

- Less formation damage
- Reduced possibility of well blowouts and improved overall rig safety
- Reduced volume of drilling waste as fewer wells drilled overall
- Better wellbore control



and DOE-sponsored research into ultra-deep-water MWD technologies, promise to enhance operations even further.

Contributing dramatically to operational safety

Operators seeking to control drilling operations and enhance rig safety in difficult environments such as deepwater drilling find MWD a valuable tool. In combination with advanced

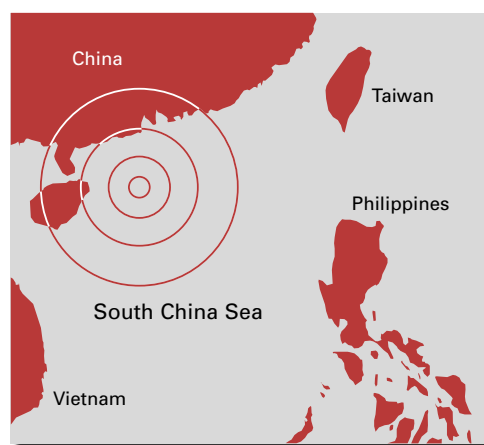
interpretive software applications, MWD is helping deepwater operators better forecast and measure a formation's pore and fracture pressures. More accurate geopressure estimates can prevent dangerous well blowouts and fires. In the unlikely event of a deep-water blowout, MWD equipment is a crucial tool in assisting operators to drill and steer a relief well to regain control of the well.



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CASE STUDIES

Success in the Field



Extended reach in the South China Sea

In the South China Sea, MWD technology was critical in helping operators drill a 5-mile extended-reach well to a then world-record horizontal displacement of nearly 26,500 feet, at a true vertical depth of approximately 10,000 feet. It effectively "steered" the well to access the most productive zones at a final hole angle of 54°. In combination with other advanced drilling and completion technologies, MWD technology permitted operators to access this otherwise uneconomical, remote offshore field, completing the project in approximately 100 days at a cost of \$24 million. As of June 1997, this once-bypassed field was producing 7,000 barrels of oil per day.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



SUMMARY

Dramatic advances in drill bit technology have improved drilling performance significantly while cutting wastes and environmental impacts. Although the choice of bit represents only 3 percent of the cost of well construction, bit performance indirectly affects up to 75 percent of total well cost. Faster rates of penetration and greatly extended bit life, the result of advances in materials technology, hydraulic efficiency, cutter design, and bit stability, now allow wells to be drilled more quickly, more profitably, and with less environmental impact. The improvement to an operator's cost-efficiency from these advances is striking. Today, selection of the appropriate bit has become critical both in establishing the overall economics of field development and in minimizing the environmental impacts of drilling.

TECHNOLOGY

Locations: Worldwide, onshore and offshore

Modern Drilling Bits

BLUEPRINT ON TECHNOLOGY

Evolving bit technology allows operators to drill wellbores more quickly and with less environmental impact

The diamond success story

FROM USE IN ONE percent of total worldwide drilling in 1978, to an estimated 25 percent in 1997, diamond drill bits, which use cutters consisting of a thick layer of tungsten carbide permeated with bonded diamond particles, have been one of the success stories of the last 25 years. Natural diamonds, synthetic diamonds, and diamond composites are now routinely used within

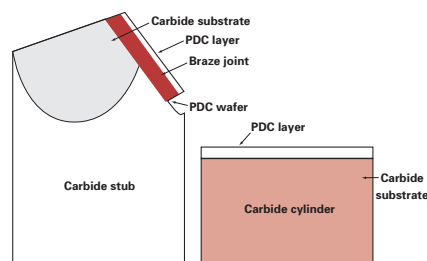
insert-bit cutting structures, and, although originally developed for hard formations, polycrystalline diamond compact (PDC) bits have proved their value in soft- and medium-hard formations too. Today, PDC bits are most applicable in areas with relatively soft formations or where drilling is expensive, such as offshore locations and remote wells. In parallel with PDC development, roller cone bits have also been improved. The National Petroleum Council estimates that improvements in drilling efficiency from advances such as those in bit technology have reduced underlying drilling costs by about 3 percent annually

over the last 50 years. As materials technology, hydraulics, and bit stability continue to improve, so will drilling performance and environmental protection.

Matching the bit to the formation

By helping operators choose the best bit for the job, computerized drill bit optimization systems have improved the way bits are being selected and used. These systems match an individual formation to the most effective milled-tooth, tungsten carbide insert and PDC bit to complete the job for the least cost per foot. They also prescribe other design parameters such as hole gauge and hydraulic requirements to help determine optimal cutting structure.

PDC Cutter Components



Source: Petroleum Engineer International, 1993

ECONOMIC BENEFITS

- Increased rates of penetration
- Fewer drilling trips due to greater bit life
- Reduced power consumption
- Improved drilling efficiency and hence viability of marginal resources

ENVIRONMENTAL BENEFITS

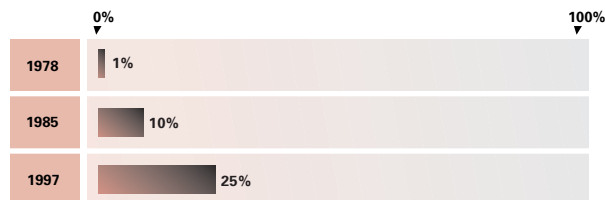
- Reduced power use and resultant emissions
- Less drilling waste
- Reduced equipment mobilization and fewer rigs
- Less noise pollution
- Better wellbore control and less formation damage



METRICS

Increases in diamond bit drilling

In 1978, approximately 1 percent of the total footage drilled worldwide was drilled with diamond bits; in 1985, it was approximately 10 percent; by 1997, that figure was an estimated 25 percent. Also, between 1988 and 1994, advances in PDC technology increased the average footage drilled by over 260 percent, from approximately 1,600 feet to 4,200 feet per PDC bit.



Source: Rappold, *Oil & Gas Journal*, 8/14/95

CASE STUDIES

Success in the Field



Switching to new drill bits saves time and money

Using a specialized bit optimization system, Anadarko Petroleum has demonstrated significant efficiency improvements. For example, drilling time was reduced by 8 to 12 days in Algeria, with savings of \$250,000 to \$350,000; and a Mississippi project saved 15 days and \$200,000. Ultimately, impacts on the environment were appreciably lessened.

Petroleum Development Oman found that rates of penetration dropped from 26 feet per hour to under 10 feet per hour when drills using tungsten carbide inserts hit the hard Khuff Formation. Switching to a new generation PDC bit with carbide-supported edge cutters resulted in a new rate of 23.6 feet per hour in the Khuff. The entire section was drilled in one run, at half the cost of the same section in a similar well. Another well drilled in the comparable Zauliyah field resulted in a rate of 34 feet per hour at a cost of \$34 per foot, nearly half the cost of drilling a comparable well in the area with an earlier-generation bit.

When Chevron switched to new generation polycrystalline bits at its Arrowhead Greyburg field in New Mexico, the rate of penetration increased more than 100 percent. Chevron had been experiencing problems using 3-cone bits and thermally stabilized diamond bits. Switching to PDC bits with curved cutters significantly increased drilling efficiency, while reducing environmental impacts.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, onshore and offshore

Multilateral Drilling

SUMMARY

Multilateral drilling creates an interconnected network of separate, pressure-isolated, and reentry-accessible horizontal or high-angle wellbores surrounding a single major wellbore, enabling drainage of multiple target zones. In many cases, this approach can be more effective than simple horizontal drilling in increasing productivity and enlarging recoverable reserves. Often multilateral drilling can restore economic life to an aging field. It also reduces drilling and waste disposal costs. Today, in a wide variety of drilling environments, both onshore and offshore, from the Middle East to the North Sea and from the North Slope to the Austin Chalk, multilateral completions are providing dramatic returns for operators.

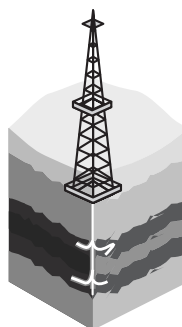
BLUEPRINT ON TECHNOLOGY

New lateral drilling developments provide dramatic returns for operators, with less waste, smaller footprints, and increased site protection

From horizontal to multilateral branching wellbores

HORIZONTAL DRILLING provoked a surge of interest in the 1980s as a way to contact more oil reserves, penetrating a greater cross-section of the oil-bearing rock with a single wellbore and intersecting repeatedly the fractures that carry oil to a producing well. Today, declining production, flat prices, and heightened environmental awareness have led the exploration and production industry to develop advanced drilling and completion technologies that

permit wells to branch out multilaterally, in certain cases saving both time and money compared to horizontal drilling. In many cases, such as deep reservoir production, it is more efficient to create a connected network than to drill multiple individual horizontal wellbores.



Multilateral drilling is of greatest value in reservoirs that:

- Have small or isolated accumulations in multiple zones
- Accumulate oil above the highest existing perforations
- Have pay zones that are arranged in lens-shaped pockets
- Are strongly directional
- Contain distinct sets of natural fractures
- Are vertically segregated, with low transmissibility

ECONOMIC BENEFITS

- Improved production per platform
- Increased productivity per well and greater ultimate recovery efficiency
- New life for marginally economic fields in danger of abandonment
- Reduced drilling and waste disposal costs
- Reduced field development costs
- Improved reservoir drainage and management
- More efficient use of platform, facility, and crew

ENVIRONMENTAL BENEFITS

- Fewer drilling sites and footprints
- Less drilling fluids and cuttings
- Protection of sensitive habitats and wildlife



CASE STUDIES

Success in the Field



"[With advanced re-entry multilateral technology] we are seeing the potential to reduce by half the costs associated with subsea developments. In some cases, this will make what were previously marginal or non-economic discoveries economical."

ALI DANESHY
Vice President, Halliburton

**Norsk demonstrates the future of offshore drilling**

A highly successful offshore project in Norway is showcasing the reduced environmental impacts and increased economic benefits of multilateral completions. In March 1997, Norsk Hydro a.s. and Halliburton Energy Services drilled the world's first subsea multilateral with reentry access in Norsk's Troll field. The companies estimate that the economic benefits will be 50 percent greater than those from fixed platforms. By reducing the systems required to access the subsea reservoir, the project cuts both costs and impact on the environment and leads the way for subsequent offshore drilling operations.

New life for old wells: pentalateral drilling in the Middle East

Mounting evidence demonstrates that multilateral drilling can bring new life to old wells. In the Arabian Gulf recently, a significant reduction in production that may have spelled well closure in the past was instead the stimulus to drill five lateral branches into new pay zones. The lateral wells were drilled in only 19 days, reaching some 5,000 feet of new producing formations. Since the new zones consisted of relatively soft limestone layers separated from each other by dolomites, drilling presented few problems. Dramatically increased production rates covered costs in just six days. In all, production increased 2.7 times as a result of the multilateral completions.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Deepwater—Gulf of Mexico, West Africa, North Sea, Brazil, others

Offshore Drilling

SUMMARY

Recent exploration successes in deepwater plays in the Gulf of Mexico are of crucial importance in providing a vital new domestic resource. Technological advances are increasing operators' ability to take advantage of these finds, while reducing the dangers and uncertainty inherent in deepwater operations. Without such progress, much of the Gulf's resources may remain undeveloped. A major concern for operators is the safety of deepwater exploratory operations, especially as the industry moves toward depths of 10,000 feet. To ensure stability and efficiency at such depths, advanced dynamic positioning technology is now being used. This includes thruster units and sophisticated computer and navigation systems to hold a new generation of drillships, floating production, storage, and offloading systems, and survey vessels on location without anchors or mooring lines.

BLUEPRINT ON TECHNOLOGY

Technology advances in dynamic positioning expand opportunities for deepwater drilling with reduced environmental impact

Deepwater opportunities

THE GULF OF MEXICO'S deepwater reservoirs have become America's new frontier for oil and gas exploration. Production potential from proved and unproved reserves in deepwater areas is estimated to be roughly 1.8 billion barrels of oil and 5.8 trillion cubic feet of natural gas. Consequently, drilling in the Gulf's Outer Continental Shelf has increased greatly over the last 10 years. Today, deepwater drilling from permanent structures and wild-cat wells is at an all-time high. In October 1997, a record 31 temporary and permanent deepwater rigs were drilling in water depths greater than 1,000 feet, as compared to only nine in 1990.

Production from deepwater wells is increasing too. In 1985, for example, less than 2 percent of the Gulf's total oil production was from deepwater wells. By 1996, over 17 percent of the Gulf's oil production came from deepwater wells. Natural gas production from deepwater areas in the Gulf has also increased—from less than 1 percent of total production in 1985—to nearly 6 percent in 1996.

Improving station keeping

Dynamic positioning systems compensate for the effects of wind, waves, and current, enabling mobile offshore drilling units to hold position over the borehole, maintaining within operational limits lateral loads on the drill stem and marine riser. Improved

dynamic positioning systems, in combination with improved onboard motion compensation systems, are expanding the range of water depths and environmental conditions within which drilling operations can be safely conducted.

Azimuthing thruster units, often retractable so as to enable shallow water maneuvers, are the backbone of the dynamic positioning system. Ship-based computers and satellite-linked navigation units control the vessel's rudder, propellers, and thrusters using input from various monitoring systems, such as gyrocompass wind sensors, real-time differential global positioning systems, micro-wave positioning systems, underwater sonar

ECONOMIC BENEFITS

Minimized positioning and transit times for deepwater exploration

Reduced operating costs in deepwater exploration operations

Improved access to deepwater and ultra-deep-water resources that might otherwise have remained undeveloped

ENVIRONMENTAL BENEFITS

Less disruption to seafloor ecosystem

Reduced environmental impacts due to increased operational stability

Enhanced deepwater operational safety



beacons, and hydro-acoustic beacons. If the wind or tide swell moves the ship from its desired station, guided thrusters can automatically hold the vessel's orientation and position. They can also move it to a new position in the event of extreme weather.

A new equipment market

The trend toward long-term, ultra-deepwater exploratory operations has substantially increased

demand for dynamically positioned vessels. The harsher environments of deeper offshore plays has accelerated demand for dynamically positioned drillships, semisubmersible rigs, seismic survey vessels, floating production, storage, and offloading systems, pipelayers, shuttle tankers, and standby support vessels. The benefits of dynamic positioning include:

Cost-effectiveness

When permanent or disconnectable moorings become excessively difficult or expensive, or when low-cost fuel is available, dynamically positioned systems may be highly cost-effective. Given today's technology, it would be practically impossible to conduct ultra-deepwater exploratory operations without dynamic positioning technology.

Operational flexibility

These systems allow vessels to move readily from one location to another during exploratory operations, eliminating the cost and

time of setting and removing mooring lines. Such flexibility, vital during hurricane season, may ultimately reduce operating costs.

Safety

The precise positioning afforded by these systems contributes significantly to both environmental protection and worker safety during offshore operations. The safety of operations involving diving support vessels, deepwater drillships, or shuttle tankers, for instance, is often enhanced by the degree of operational precision provided by dynamic positioning systems.



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The forces of wind, waves, and ocean currents cause exploration and drilling support vessels to sway, yaw, and move off course. To counter this, dynamic positioning technology stabilizes deep-water site equipment, allowing exploratory operations in waters too deep for conventional mooring systems.

METRICS

Steady drilling from dynamic positioning

Today's advanced dynamic positioning technology enables drillships to maintain station with maximum excursion levels below 1% of total water depth. At a water depth of 5,000 feet, for example, these advanced systems are able to keep a 200-yard-long, 30-story-high drillship within 50 feet of station.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, onshore and offshore

Pneumatic Drilling

SUMMARY

Pneumatic drilling is an underbalanced drilling technique in which boreholes are drilled using air or other gases as the circulating agent. In certain cases this air drilling technique offers the promise of mudless drilling. By using nitrogen, air, or natural gas in place of oil- or water-based muds, producers can both eliminate drilling fluids that need disposal and ensure that drill cuttings are not tainted by chemicals or oil. Although it is suitable only for certain formation types and lithologies and can create potentially explosive downhole conditions—and is not therefore likely to become widespread—this technique is a very attractive environmental prospect, offering significant operational benefits.

BLUEPRINT ON TECHNOLOGY

Unlike conventional mud-based drilling, air drilling significantly reduces or eliminates drilling fluid additives and prevents formation damage

Protecting low-pressure formations and maximizing production

UNDERBALANCED drilling offers significant advantages over conventional systems in low-pressure or pressure-depleted formations. Pressure overbalances in conventional drilling can cause significant fluid filtrate invasion, and lost circulation in the formation. Expensive completions, decreased productivity, and high mud and mud-removal costs can then plague drilling operations, but these can be avoided by using underbalanced conditions. By lowering downhole pressure using

a noncondensable gas in the circulating fluid system, underbalanced pneumatic drilling can prevent difficulties commonly encountered when reservoir pressures are lower than the hydrostatic pressure exerted by traditional water-based drilling fluids. Depending on the environment, gas may be used alone or with water and additives. When drilling fluid is needed for well control, gas is mixed with lightweight drilling fluids.

In general, pneumatic drilling is used in mature fields and formations with low downhole pressures, in

open-hole completions, and in fluid-sensitive formations. It is an important tool in drilling horizontal wells, which must expose a large amount of reservoir face to be productive, and have minimum damage from fluids invasion. As horizontal drilling increases in popularity, underbalanced pneumatic drilling will become more widespread, because it can penetrate the reservoir without damaging the formation or its productive capacity.

Air drilling techniques to suit

Air dust drilling is a dry technique that relies on the annular velocity of air to

ECONOMIC BENEFITS

Substantially less fluid and waste requiring disposal

Increased rates of penetration and longer drill bit life

Indication and evaluation of productive zones and more effective geosteering of the well by monitoring flow of produced fluids

Potential elimination of waste pits gives access to restricted areas

ENVIRONMENTAL BENEFITS

Greatly reduced drilling fluids and chemical-tainted cuttings

Decreased power consumption and emissions

Better wellbore control and less damage to formations

Fewer workover and stimulation operations needed

Potential for smaller drilling footprints and less impact on habitats, wildlife, and cultural resources

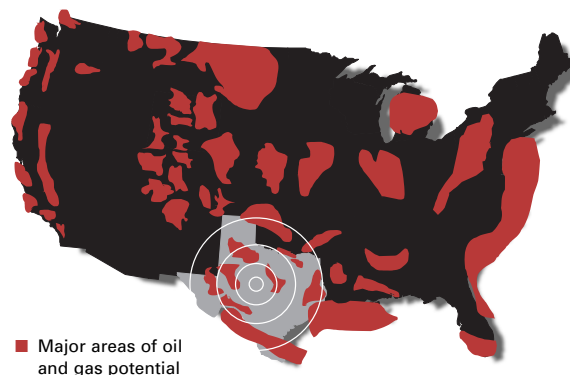


transport cuttings. It is typically employed in drilling dry formations, or when any water influx is low enough to be adsorbed by the air stream. If excessive water influx precludes its use, *air-mist drilling* is employed instead, using an air-injected mud that returns to the surface as mist. Sometimes *foam-drilling* is required, using a stable mixture of water and compressed air with detergent and chemicals. When the water influx is too great to be removed through mist or foam, *aerated mud drilling*, a technique in which air is injected into viscosified fluid or mud in order to reduce the weight of the fluid column on the formation, combines the best properties of conventional and air drilling to provide an effective solution.

A new waste management technology enables operators to eliminate the earthen waste pits used to catch effluent created while drilling with an air- or air-mist system. Liquids and solids in the effluent are separated and treated, and gases are exhausted. By eliminating the environmental risks associated with pits, drillers can operate in otherwise restricted areas, such as State parks and within city limits. Initial field tests indicate that this technology can handle continuous liquid volumes of 90 barrels per hour and solid volumes of 14 barrels per hour.

CASE STUDIES

Success in the Field



Accessing new supplies in the Carthage field

Selected as the most viable technique to prevent damage to an extremely low-pressure reservoir, pneumatic drilling made history as the first air-drilled horizontal well in the Carthage field in Texas. Air drilling successfully increased gas recovery from depleted zones without wellbore skin damage, which would have restricted the reservoir's productive flow. Drilled in December 1995, the Pirkle 2 well had by the end of April 1997 produced 530 million cubic feet of gas at a rate of 1.1 million cubic feet per day. The well was drilled with compressed nitrogen into the Cretaceous Frost "A" zone at 6,000 feet true vertical depth; it produces through a 1,400-foot lateral well with bottomhole pressure of 185 psi. The operation successfully met the economic criteria of producer OXY USA Inc., which had determined that the well's production rate would have to at least double that of a standard vertical well to be economically viable.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, onshore and offshore

Slimhole Drilling

SUMMARY

Improved slimhole drilling technology brings the twin advantages of environmental protection and economical results to oil and gas exploration and production. (For example, a conventional well drilled with a 12.25-inch bit and a 5-inch drill pipe becomes a slimhole when using a 4-inch bit and a 3.7-inch drill pipe.) Slimhole rigs are defined as wells in which at least 90 percent of the hole has been drilled with a bit six inches or less in diameter. Slimhole rigs not only boast a far smaller footprint and less waste generation than conventional operations, they can also reduce operating costs by up to 50 percent. The technique is proving a low-cost, efficient tool with which to explore new regions, tap undepleted zones in maturing fields, and test deeper zones in existing fields.

BLUEPRINT ON TECHNOLOGY

Technology advances in less invasive slimhole drilling increasingly valuable in exploration and production

Narrow boreholes prove highly effective

POTENTIALLY APPLICABLE to more than 70 percent of all wells drilled, slimhole drilling holds promise for improving the efficiency and costs of both exploration and production. Although the technique was first used in the oil and gas industry in the 1950s, its acceptance has been hampered until recently by concerns that smaller boreholes would limit stimulation opportunities, production rates, and multiple completions. Advances in technology, coupled with a growing record of success, have

dispelled these concerns, making slimhole an increasingly attractive option for reservoir development. Today, slimhole drilling is employed throughout the lower-48 States and the Gulf of Mexico, especially in the Austin Chalk fields of South Texas. Globally, slimhole drilling has been used in a wide range of onshore and offshore settings.

As an **exploration** tool, slimhole drilling for stratigraphic testing provides geologists with a clearer picture of the local geography, refining seismic interpretation. Such

testing, combined with other technologies such as continuous coring, yields valuable information for increasing success rates in exploration.

In the **production** arena, improved slimhole drilling offers a viable means of recovering additional reserves from existing reservoirs, including economically marginal fields. Resources in pay zones bypassed in the original field development can be cost-effectively accessed through the existing wellbores, thereby extending the productive life of the field.

ECONOMIC BENEFITS

Smaller drilling crews and less drilling time mean up to a 50 percent reduction in costs

Slimhole drilling is critical for adding millions of barrels of oil to the Nation's reserves

Slimhole is feasible in a wide range of operations and capable of reducing exploration and development costs around the United States

ENVIRONMENTAL BENEFITS

A slimhole rig occupies far less space than a conventional rig—the entire footprint including site access can be up to 75 percent smaller

The rig requires far less drilling fluid and produces far fewer cuttings for disposal

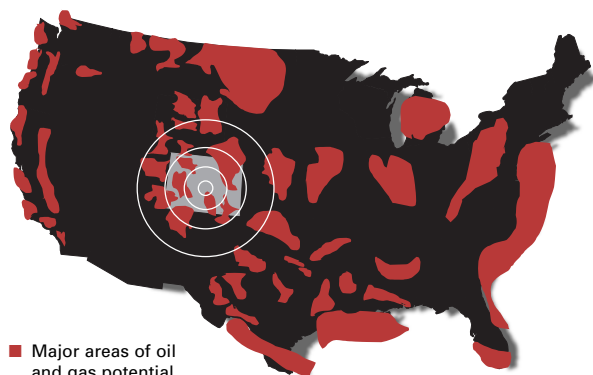
Reduced volume and weight of equipment favors use in sensitive environments, such as rainforests and wetlands, particularly in helicopter-supported campaigns

Better wellbore control



CASE STUDIES

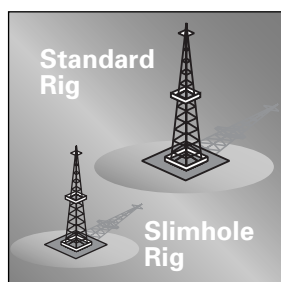
Success in the Field



In Wattenberg field

An eight-well field test conducted by HS Resources Inc. in 1996 in the Denver-Julesburg Basin's Wattenberg field successfully demonstrated that slimhole lateral wells could be drilled from inside an existing 4.5-inch cased producing vertical well. These lateral wells with 2.375- and 2.875-inch liners are considered the first lateral cementing operations of this size liner in the Rocky Mountain region and the first reported lateral drilling in Colorado using coiled tubing. The project's success led HS

Resources to begin additional slimhole drilling in 1997 and is significant for several reasons. First, this approach allows production of additional reserves with minimal impact on an active agricultural area. Second, it reduces operating costs by commingling production from both vertical and lateral wellbores.



At the Austin Chalk fields

More than 100 horizontal slimhole well reentries have been drilled by Slim Dril International, demonstrating a successful way to discover and tap otherwise inaccessible reserves of domestic oil. The company also used slimhole to deepen a conventional well to a depth of 22,000 feet, using mud motors to test a producing field. This advancing technology is extending the life of wells both at Austin Chalk in south Texas and in the Gulf of Mexico, and could potentially add millions of barrels of oil to our Nation's reserves.

METRICS

A Head-to-Head Comparison

At a drilling depth of 14,000 feet, here is how a slimhole rig with a 4-inch diameter performs versus a conventional drilling operation with an 8.5-inch diameter:

Fuel consumption	75% less
• Installed power	1,350 vs. 4,000 kilowatts
• Mud-pump power	330 vs. 3,200 horsepower
Drillsite area	75% smaller
Mud cost	80% less
• Active mud volumes	50 vs. 1,500 barrels
Rig weight	412,000 vs. 3,400,000 pounds
	150 vs. 500 helicopter lifts
	12 vs. 65 Hercules loads
	18 vs. 55 truckloads
	Drillstring weight: 37 vs. 150 tons
Drilling crew size	Staff of 3 or 4 vs. 6
Camp size	Staff of 30 vs. 80

Bottom Line:

Potential well cost-savings of 50%

Source: Nabors Industries

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, deepwater

Synthetic Drilling Muds

SUMMARY

Drilling fluids are essential to carry cuttings to the surface, maintain pressure balance and stability in the borehole, lubricate and clear the drillstring and bit, and prevent the influx of other fluids. Today's advanced offshore drilling practices include the use of synthetic-based muds (SBMs), which combine the higher performance of oil-based muds (OBMs) and the lower toxicity of water-based muds (WBMs). SBMs are a high-performance, environmentally friendly choice for complex offshore drilling environments. Management of fluids and cutting wastes is a significant responsibility for the industry, and in remote offshore areas can entail significant expense. Compared with OBMs, drill cuttings from SBMs can be safely discharged in many offshore areas, significantly reducing disposal costs and environmental impacts.

BLUEPRINT ON TECHNOLOGY

New synthetic drilling muds combine the performance of oil-based muds with the easier, safer disposal of water-based muds

Conventional versus new muds

NEARLY ALL WELLS less than 10,000 feet and 85 percent of deeper wells are drilled with water-based muds (WBMs), making them the most commonly used muds both onshore and offshore. With a 90 percent water base, WBMs and associated cuttings can typically be discharged on-site.

However, they are often not technically feasible or cost-effective in complex drilling situations. As such, oil-based muds (OBMs) are often the drilling fluids of choice in deep, extended-reach, high-angle, high-temperature, and other special drilling environments, greatly outperforming WBMs. But their diesel or mineral oil base means that although they effectively min-

imize drilling problems, OBMs cannot be discharged on-site. At remote offshore sites, operators must incur the expense, logistical problems, and environmental risks of shipping OBM wastes back to shore for disposal.

The development of synthetic-based muds (SBMs) was driven by industry's need for a drilling fluid with lower

ECONOMIC BENEFITS

Improved drilling speeds, lower operating costs, and shorter completion times (versus WBMs)

Reduced downtime from common drilling problems (versus WBMs)

Minimal to no waste hauling and disposal costs (versus OBMs)

Reduced drilling costs as SBMs can be reconditioned and revised (versus WBMs)

Increased access to resources by high-angle, extended-reach, and horizontal wells (versus WBMs)

ENVIRONMENTAL BENEFITS

Lower concentration of inherent contaminants, such as complex hydrocarbons (versus OBMs)

Safe discharge of drill cuttings (versus OBMs)

Less waste than WBMs, as SBMs are reusable

Faster drilling, so reduced power use and air emissions (versus WBMs)

Smaller footprint, as SBMs facilitate extended-reach and horizontal wells (versus WBMs)

Increased worker health and safety—volume and toxicity of irritating vapors lower than OBMs

Reduced air pollution because SBMs are not transported to shore for disposal (versus OBMs)

Reduced landfill usage

Increased wellbore control (versus WBMs)



disposal costs than OBM and higher levels of performance than WBM. In general, SBM performance is comparable to that of OBM, and in some cases superior. They are manufactured by chemical synthesis from basic building blocks of relatively pure materials, forming highly uniform products. By varying the components and manufacturing conditions, different SBMs can be created that exhibit varying rheological properties and environmental

performance parameters. Current synthetic fluids fall into several groups: polyalphaolefins (PAOs), linear alpha olefins (LAOs), internal olefins (IOs), fatty acid esters, and others.

Comparing costs

Although more expensive on a per-barrel basis, SBMs can reduce overall drilling expenses. When measured against WBM, SBMs can shorten drilling time. Compared with OBM, SBMs offer lower disposal costs.

METRICS

Advantages of synthetic muds as demonstrated by Marathon Oil in the Gulf of Mexico

Footage Drilled	Footage per Day	Mud Cost in \$ Millions	Cost \$ per Foot	Total Well Cost in \$ Millions	Total Days
WBM Wells					
17,981	138	1.3	74	11.6	163
16,928	63	2.5	150	18.3	326
17,540	82	—	—	9.6	214
17,142	101	1.6	90.4	12.7	197
17,381	215	—	—	10.1	77
SBM Wells					
16,842	301	0.8	48	5.0	50
18,122	275	1.7	94	7.8	75
17,250	431	0.8	45	3.7	33

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CASE STUDIES

Success in the Field



Proof in the Gulf

A set of Gulf of Mexico wells with similar characteristics were the scene for a comparative study of the relative merits of SBMs and WBM. Marathon Oil drilled five wells with WBM and three with SBMs, and found that SBM performs with greater overall efficiency. For example, the SBM wells averaged 336 feet per day and 53 days per well, compared to 120 feet per day and 195 days per WBM well. Despite higher per-barrel costs, SBM resulted in lower total drilling mud costs and downtime costs. Overall, total drilling and completion costs for the SBM wells were in the range of \$3.7 to \$7.9 million per well, compared with \$9.6 to \$18.3 million for WBM wells. Combined with significant increases in productivity and decreased environmental impacts, these results proved that SBM was the better performer for these wells.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, onshore and offshore

Acid Gas Removal and Recovery

SUMMARY

Before natural gas can be transported safely and economically, hydrogen sulfide (H_2S), a highly poisonous acid gas, and other acid compounds such as carbon dioxide (CO_2) must be removed from the raw gas stream in order to meet pipeline sales contract specifications. Sulfur recovery plants are used in tandem with acid gas removal (sweetening) operations to avoid emitting unacceptable quantities of sulfur compounds to the atmosphere. Improvements in gas sweetening, in conjunction with advanced sulfur recovery technologies, make it possible to practically eliminate noxious emissions and recover nearly all the acid gas stream's elemental sulfur for later sale or disposal.

BLUEPRINT ON TECHNOLOGY

Improved technology and practices “sweeten” sour gas for pipeline use and achieve nearly 100 percent sulfur recovery, greatly reducing air emissions

Sweetening natural gas

A RECENT GAS RESEARCH Institute survey concluded that approximately 24 percent of the raw natural gas produced in the lower-48 States contains unacceptable quantities of H_2S , CO_2 , or both. To sweeten the high acid content “sour” gas, it is first pre-scrubbed to remove entrained brine, hydrocarbons, and other substances. The still sour gas then enters an absorber, where lean amine solution chemically absorbs the acid gas components, as well as a small portion of hydrocarbons, rendering the gas ready for processing and sale. An outlet scrubber removes any residual amine, which is regenerated for recycling. Hydrocarbon contaminants entrained in the amine can be separated in a flash

tank and used as fuel gas or sold. Process efficiency can be optimized by mixing different types of amine to increase absorption capacity, by increasing the amine concentration, or by varying the temperature of the lean amine absorption process.

Recovering sulfur

Once acid components have been removed from the gas stream, sulfur recovery plants can minimize sulfur emissions and maximize recovery of elemental sulfur—environmental regulations commonly require sulfur recovery levels well over 99 percent. The Claus sulfur recovery process, first developed over 100 years ago, is still the most widely used process today. Between 90 and 95 percent of the total sulfur recovered worldwide

uses a variation of this process. Typically, the acid gas feed is partially oxidized to produce SO_2 , which is then catalyzed with the remaining H_2S to produce elemental sulfur, of which approximately 94 to 97 percent is recovered for sale. Most Claus plants contain two or three catalytic stages to enhance recovery. To reach higher recovery levels, a sub-dewpoint Claus process is employed, which operates at a lower temperature, causing sulfur condensation and higher recovery. A tailgas cleanup unit is required to obtain sulfur recovery levels as high as 99.9 percent. This converts the sulfur compounds in the tailgas back to H_2S , then transfers it to a low-pressure amine sweetening unit, which recycles the H_2S with some CO_2 to the

ECONOMIC BENEFITS

Increased access to sour natural gas resources

Sale of recovered sulfur as a commodity

ENVIRONMENTAL BENEFITS

Improved air quality through increased sulfur recovery



PRODUCTION

Claus unit for reprocessing. In most sulfur recovery processes, a tailgas thermal oxidizer incinerates nearly all remaining sulfur compounds and other contaminants before venting it to the atmosphere.

Alternative acid gas disposal methods

In cases in which it is not economically feasible to recover elemental sulfur for sale, industry is developing advanced acid gas disposal techniques. In Canada, for

example, where operators have typically flared recovered acid gases if unable to recover sulfur economically, acid gas is now being dissolved in oil field produced water at the surface and injected into subsurface formations. This practice, although still being demonstrated, potentially offers producers a low-cost, environmentally sound acid gas disposal technique when sulfur recovery is not economic.

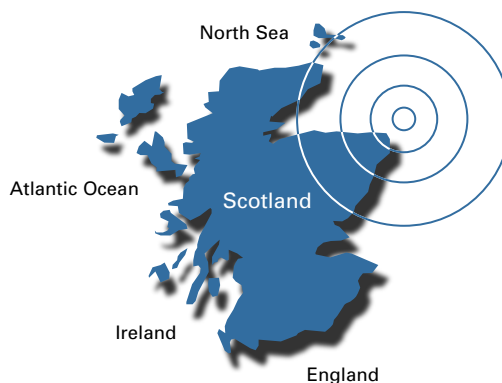


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Aerial view of pipeline transporting recovered sulfur to market

CASE STUDIES

Success in the Field



The Scott field experience

Scott field, 130 miles northeast of Aberdeen, Scotland, is the United Kingdom's largest offshore project this decade. Recoverable reserves are estimated at 450 million barrels of oil and 287 billion cubic feet of associated gas. In addition to subsea facilities, the development has twin connecting steel platforms, including a process/drilling platform, drilling and gas treatment modules, and a flaring unit.

Developer Amerada Hess Ltd. realized that offshore production could begin several months before availability of permanent onshore gas processing facilities at Mobil North Sea Ltd.'s St. Fergus terminal, which was scheduled to come on-line on April 1, 1994. To permit early production, temporary gas sweetening equipment was installed in April 1993 to attain pipeline specifications. A single, fixed-bed reactor sweetening unit enabled H_2S content to be reduced by nearly 95 percent. By the middle of October, the Scott field development was producing, treating, and exporting gas, approximately five months ahead of schedule.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Ralph A. Avellanet
(202) 586-8499
ralph.avellanet@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



SUMMARY

As reservoir pressure declines, natural processes no longer push the oil to the surface. Artificial lift technology, which includes sucker-rod pumps, electrical submersible pumps, hydraulic jet pumps, plunger lifts, progressing cavity pumps, and gas lift systems, is now used to produce some 65 percent of all oil. Performance of artificial lift systems has been optimized through recent innovations in artificial lift equipment, improved operational design and parameters, and real-time data collection, automation, and control technologies. System optimization not only maximizes production efficiency, but can also decrease on-site power use and extend equipment life. Results include improved profitability, reduced workover wastes, and lower air emissions.

TECHNOLOGY

Locations: Worldwide, onshore and offshore

Artificial Lift Optimization

BLUEPRINT ON TECHNOLOGY

Reduced emissions during production and increased productivity result from increasing the efficiency of the systems that raise oil to the surface

Practical measures with attractive environmental and productivity paybacks

SUCKER-ROD PUMPS, the most prevalent form of artificial lift, use arm-like devices to provide up-and-down motion to a downhole pump. Such rod pumping, most effective in relatively shallow and low-volume wells, can be optimized to increase lifting efficiency and minimize energy consumption. Surface and downhole energy losses can be reduced by adjusting key design parameters like pumping mode selection, counterbalancing (to balance loads on the gear box during the pumping cycle), and rod string design.

A number of other advanced artificial lift technologies

and practices have improved efficiency in recent years. Real-time data collection, automation, and control techniques now allow operators to monitor pumping performance and downhole conditions continuously, and to control operations accordingly. Variable-speed motors tailor pumping operations to changing conditions. New low-profile rod pumps are attractive options in sensitive urban, residential, and agricultural areas, as well as on crowded offshore platforms.

Gas lift, another common form of artificial lift, pumps natural gas down the well's annulus and injects the gas into the production tubing near the bottom of the well. The gas expands within the

production tubing stream, allowing liquid hydrocarbons to be carried to the surface. Gas lift is commonly used when natural gas is readily available, and is especially prevalent offshore. Each gas lift well has an optimum injection rate and pressure. Since the injected gas raises the back pressure in the flow line leading to the field's separation and processing facilities, back pressure in one well affects all wells sharing common flow lines. Using advanced modeling techniques to develop models of multiflow characteristics and to optimize parameters, operators today can design complex gas lift systems that maximize production from all wells in a network, given the system's constraints.

ECONOMIC BENEFITS

Enhanced efficient production from existing wells

Lower equipment maintenance costs

Lower on-site power consumption and costs

ENVIRONMENTAL BENEFITS

Increased equipment life and fewer failures result in less workover and recompletion operations, reducing the volume of workover fluids and other wastes

Reduced air emissions due to lower power consumption



C A S E S T U D I E S

Success in the Field



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Optimization of sucker-rod pumping can increase production efficiency and minimize energy consumption.

Optimizing artificial lift in Oman

For Petroleum Development Oman (PDO), real-time automation and optimization software was the key to increasing production by some five percent, while saving \$7 million annually. Power consumption was reduced and the mean time between pump failures was increased by 35 percent.

PDO used the Shell Oil Foundation System (SOFS) to monitor, control, and optimize over 1,200 wells and production facilities, including both beam-pump and gas lift operations. It collected load, position, and operational data from 900 individual beam pumps and then modeled downhole conditions. The system enabled pumps to be remotely started, stopped, and adjusted, providing an on-line tool to evaluate and optimize pump designs and predict pump performance.

PDO also applied the SOFS to gas lift wells in the Yibal field, creating gas lift performance models for each of 320 wells, matching them to actual field measurements, and using the resulting performance curves to calculate optimal production rates for given lift-gas availability. In a pilot demonstration, 52 wells in the Yibal field were

also fitted with electronic instruments to measure lift-gas injection pressure and flow, and tubing-head and casinghead pressures. Ten months of data were used to adjust lift rates, valve settings, and completion strings as necessary. As a result, PDO optimized wells in real-time, achieving a five percent increase in oil production and a 10 percent reduction in the volume of lift gas used. So successful was the pilot effort that PDO decided to extend the program to the entire field.



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C O N T A C T



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

George Stosur
(202) 586-8379
george.stosur@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



SUMMARY

Only 30 years ago, coalbed methane was viewed primarily as a hazard by the mining industry. To ensure mine safety, ventilation and degasification systems emitted this gas to the atmosphere. Methane is now considered a potent greenhouse gas thought to contribute to global warming. It is also a valuable and significant resource with potential recoverable domestic quantities estimated at 40 to 60 trillion cubic feet. Since the 1970s, Federal tax credits, intensive government and industry R&D efforts, and rapid technology growth have motivated improvements in coalbed reservoir characterization, reservoir engineering, and completion technology. These advances have spurred coalbed methane production and reserve growth, making this unconventional resource a significant component of our domestic natural gas supply.

TECHNOLOGY

Locations: Worldwide onshore

Coalbed Methane Recovery

BLUEPRINT ON TECHNOLOGY

Technology has reduced greenhouse gas emissions by transforming coalbed methane into an energy resource

Producing coalbed methane

LARGE AMOUNTS OF methane are stored within coal's internal structure. Most coalbeds are aquifers, in which water pressure holds the gas in an adsorbed state. To produce the methane, water must be pumped from the coal seams to decrease reservoir pressure and release the gas. After desorption from the coal matrix, the gas diffuses through the coal bed's cleats and fractures toward the wellbore.

Some coal seams are too deep to be profitably mined, but methane production may be feasible. In these cases, operators drill into the coal seam, insert production piping, and then perforate opposite the target zone. Typically, the reservoir is then hydraulically fractured to enhance natural fractures or create new ones. Such "stand-alone" coalbed

methane sites often require substantial initial dewatering to reduce reservoir pressure, although produced water tapers off as methane production increases. Produced water disposal presents major economic and environmental challenges for operators—these costs alone can determine the feasibility of coalbed methane projects. In areas such as Alabama's Black Warrior Basin, produced water can be used for irrigation or treated and discharged into surface waters. In regions where these waters are more saline, they are reinjected into subsurface geological formations, or in some cases recycled in fracturing applications. In the future, emerging technologies using evaporation, reverse osmosis, ion exchange, and wetlands construction promise more cost-effective water management.

Capturing coal mine emissions

Reduction in reservoir pressure during underground mining operations releases coalbed methane into the mine. To ensure mine safety, this methane is typically vented into the atmosphere in significant volumes—an EPA profile of 79 underground mines in 1996 indicated that they emitted an estimated 46 billion cubic feet of methane. But technological advances, along with utility industry restructuring, utility offset projects, and "green" pricing, are motivating operators to add methane recovery units to their ventilation and drainage systems. Also, the U.S. Environmental Protection Agency's voluntary Coalbed Methane Outreach Program is assisting coal mine operators to identify and exploit ways to recover and use or sell methane. As a result, coal mine methane

ECONOMIC BENEFITS

Lower operating costs and increased profitability if recovered gas can be used to fuel on- or off-site facilities or to generate electricity for site use or sale

Depending on quality, recovered gas can be marketed through pipeline sales

ENVIRONMENTAL BENEFITS

Significantly reduced methane emissions

Optimized recovery of valuable natural gas resource



PRODUCTION

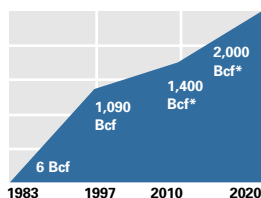
recovery has risen more than 50 percent since 1990.

As technology improves, coal mine methane recovery is likely to increase. Several prototype technologies for using low and variable quality coal mine methane are under demonstration. In the UK, an operator is recovering methane from poorly sealed vent holes in abandoned mines. In the United States, DOE-sponsored field trials in recent years have focused on recovering gob gas.

METRICS

Coalbed methane production growth in the United States

Billions cubic feet (Bcf)

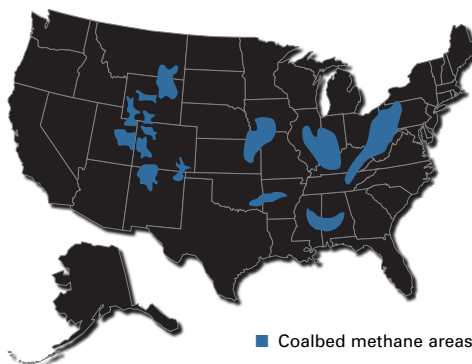


* Estimates assume high technology progress.

Source: Energy Information Administration; Kuuskraa; Gas Research Institute

CASE STUDIES

Success in the Field



■ Coalbed methane areas

Enhanced recovery in the San Juan Basin

Several advanced technologies are in use in the San Juan Basin of northwest New Mexico and southwest Colorado. In the overpressured, highly permeable San Juan Basin fairway, open hole cavitation completions are outperforming conventionally cased and fractured completions by factors of three to seven. In this technique, repeated high-rate, high-pressure injections of air-water mixtures into the coal seam are followed by rapid blowdown. This promotes sloughing of coal into the wellbore, which increases its radius and induces tensile and shear fractures.

San Juan operators are also field testing two new enhanced coalbed methane (ECBM) recovery technologies—displacement desorption with injected carbon dioxide (CO₂) and partial pressure reduction with injected nitrogen. Amoco successfully conducted the first nitrogen flooding field test in 1993 at its Simon 15U-2 well, increasing production fivefold in one year. At Amoco's Tiffany Project, 24 million cubic feet of nitrogen is injected daily into 13 injection wells—the largest commercial demonstration of this technology to date. Since full-scale injection began January 31, 1998, total gas production from 35 production wells has increased from 5 million cubic feet to 17 million cubic feet per day. Furthermore, Burlington Resources is testing CO₂ flood technology at a four-well project at its Allison Unit, with encouraging preliminary results.

In a recent study outlining promising technologies for reducing greenhouse gas emissions, U.S. National Laboratory directors concluded that coalbed sequestration technology is critical. For example, future technology could inject CO₂ from a powerplant stack into coal seams to enhance coalbed methane production, then cycle the methane back to fuel or co-fire the plant, thereby eliminating significant CO₂ emissions.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Ralph A. Avellanet
(202) 586-8499
ralph.avellanet@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



T E C H N O L O G Y

Locations: Rocky Mountains, Northern Great Plains, and Canada

Freeze-Thaw/Evaporation

S U M M A R Y

A new freeze-thaw/evaporation process purifies produced waters from oil and gas production operations by separating out dissolved solids, metals, and chemicals. These typically brackish waters can be made suitable for beneficial use, significantly lowering environmental risks and furthering resource management. Initial field tests indicate that, under specific climatic and operational parameters, the freeze-thaw/evaporation process is highly effective. In these cases, the volume of produced water can be reduced by 80 percent if it is frozen until its solids-laden brine separates, and the resulting purified water thawed and drained off for use or discharge. The isolated pollutants, which can include heavy metals and naturally occurring radioactive materials, are then disposed of separately. For volumes greater than 500 barrels per day, disposal costs and environmental risks can be cut dramatically.

B L U E P R I N T O N T E C H N O L O G Y

New approach promises substantial reductions in produced water volume and associated environmental risks

From wastewater to beneficial by-product

PRODUCING WELLS generate an average of six or seven barrels of produced water per barrel of oil. This ratio generally increases as the field matures, and it may rise as high as 100:1 for marginally productive wells. Due to its sheer volume, the near 15 billion barrels of wastewater generated by exploration and production activities annually is a matter of potential environmental concern.

Produced water handling, treatment, and disposal are expensive. Class II wells for enhanced oil recovery or subsurface disposal wells cost

from \$100,000 to \$1 million each. Water handling costs usually increase as a field matures, eroding profit margins. Most oil fields lose economic viability when the ratio is between 10:1 to 20:1, even if they still hold producible resources. Water-handling costs are often the main factor leading to well abandonment and may make development of unconventional resources, such as coalbed methane, economically unfeasible.

Although not considered hazardous waste under existing Federal legislation, produced waters are governed by Resource Conservation and

Recovery Act nonhazardous waste provisions as well as by the Clean Water Act and the Safe Drinking Water Act. Through cost-effective freeze crystallization and evaporation processes, they can be separated into fresh water, concentrated brine, and solids.



Photo: Hart Publications, Inc., and Gas Research Institute

Start-up of freezing operations

E C O N O M I C B E N E F I T S

A low-cost, energy-efficient method of purifying produced water volumes greater than 500 bbl/day

Reduction of water treatment and disposal costs. DOE-supported field tests in the San Juan Basin estimate treatment costs of 25¢ to 60¢/barrel, compared to current disposal costs of about \$1/barrel in New Mexico

Extended life for mature fields in certain regions

Improved economic feasibility of developing marginal or unconventional resources

E N V I R O N M E N T A L B E N E F I T S

Produced water volume requiring disposal reduced by 80% in preliminary field tests

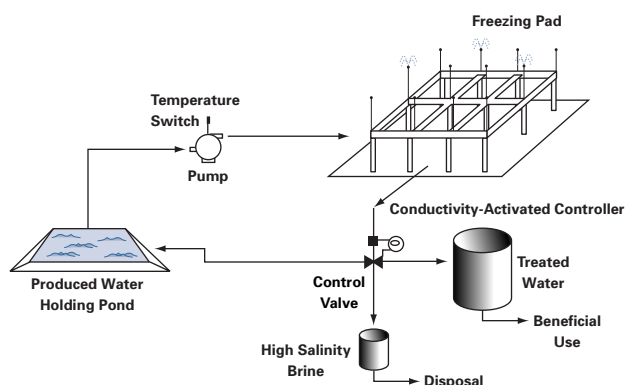
Creation of fresh water to enhance agricultural development in the arid western United States



PRODUCTION

HOW THE TECHNOLOGY WORKS

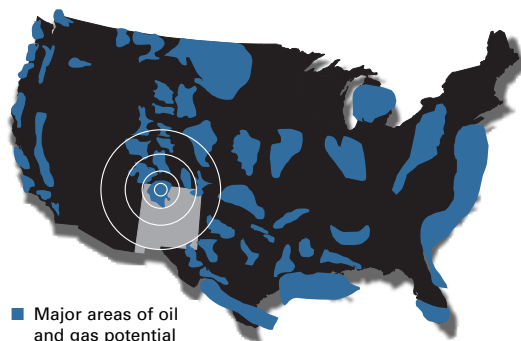
- Produced water is placed in a holding pond.
- When ambient temperature drops below 32°F, water is sprayed on a freezing pad.
- Due to its higher density, brine with elevated concentrations of total dissolved solids separates from the ice.
- When ambient temperature rises above 32°F, ice on the pad melts and purified water drains.
- Brine is disposed of; purified water is discharged or stored for later beneficial use.
- In summer, natural evaporation from the holding pond is substituted for freezing cycles.



Source: Hart Publications, Inc., and Gas Research Institute

CASE STUDIES

Success in the Field



Successful DOE-sponsored tests in New Mexico

In 1996, a joint DOE-, Amoco-, and Gas Research Institute-sponsored project reported that the freeze-thaw/evaporation process could economically cut produced water disposal volumes by more than 80 percent and produce purified water suitable for beneficial use or surface discharge. Total dissolved solids concentrations at Amoco's Cahn/Schneider evaporation facility in the San Juan Basin, for example, were between 200 and 1,500 mg/l for the waters resulting from the process, compared with 11,600 mg/l in untreated waters. In addition to this near 92 percent reduction, organic and metal constituents were also significantly reduced in the processed water. In the winter of 1996-97, a more extensive evaluation conducted in more typical weather conditions resulted in almost identical outcomes. These field tests demonstrate the technology's commercial viability for high retention operations in areas with subfreezing winters and warm, dry summers, such as the Rocky Mountains and Northern Great Plains and much of Canada.

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CONTACT



U.S. Department of Energy Office of Fossil Energy

1000 Independence Avenue, SW
Washington, DC 20585

H. William Hochheiser
(202) 586-5614
william.hochheiser@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



SUMMARY

Evolving gas-to-liquids (GTL) technology offers the promise of accessing our vast but remote and uneconomic natural gas resources in Alaska's North Slope and the deepwater Gulf of Mexico, significantly increasing our Nation's energy and economic security. GTL technology, on the brink of widespread commercial viability, chemically alters natural gas into stable synthetic liquid hydrocarbons that are far more environmentally friendly and efficient than conventional petroleum-based liquid fuels. Globally, the technology could bring some of the estimated 2,500 trillion cubic feet of known but currently untapped gas to market, accessing an abundant fuel source to produce liquid transportation fuels fully compatible with our existing transportation infrastructure.

TECHNOLOGY

Locations: Stranded natural gas resources worldwide

Gas-to-Liquids Conversion

BLUEPRINT ON TECHNOLOGY

Gas-to-liquids conversion taps remote sources of gas to produce cleaner transportation fuels and promote energy security

Developing and transporting remote gas resources

ROUGHLY HALF THE world's natural gas is unused because remote locations makes it too expensive to transport to market via conventional gas pipelines or as cryogenically generated liquefied natural gas, due to distance, climate, environmental concerns, political uncertainty, and the large capital investments required. On Alaska's North Slope alone, for example, approximately 25 trillion cubic feet of producible gas-in-place could be accessed with a cost-effective approach such as GTL technology, with the converted liquid transported through existing pipelines and tankers.

The promise of gas-to-liquids

In 1923, German scientists Franz Fischer and Hans Tropsch introduced the first GTL conversion process. The technology can produce a variety of chemicals and fuels—of particular interest is its ability to yield large volumes of sulfur-free diesel fuel. The process involves reforming natural gas into synthesis gas ("syngas") by combining the gas with steam, air, or oxygen, then converting the synthesis gas to liquid hydrocarbons through catalytic reaction, typically with an iron- or cobalt-based catalyst. The liquid products are hydrocracked and stabilized to create transportation fuels and chemicals. Until recently, this process has not been

competitive in the petroleum marketplace, although it had been used for political reasons in noncompetitive economies such as Nazi-era Germany and apartheid-era South Africa. Dramatic recent advances in GTL technology focus on improved processes and catalysts, which are reducing costs enough to be more competitive with petroleum-based fuels, depending on gas costs and oil prices.

GTL's potential to fundamentally alter oil and gas markets worldwide has generated significant private sector research and development efforts, and sparked numerous small-scale and pilot studies. The Department of Energy is committed to a

ECONOMIC BENEFITS

Access to remote uneconomic natural gas resources

Prolonged access to Alaskan crude oil as a result of sufficient Trans-Alaska Pipeline System (TAPS) utilization

Creation of a gas-to-liquids industry resulting in thousands of new domestic jobs and potentially billions of dollars in new investments

ENVIRONMENTAL BENEFITS

Reduced emissions of greenhouse gases and other air pollutants compared with conventional petroleum-based fuels

Optimized recovery of valuable gas resources

Reduced flaring of associated gas in remote fields



PRODUCTION

goal of 200,000 barrels per day of GTL production by 2010 (assuming Alaskan North Slope gas is no longer required for reservoir repressurization), and it plays an active role in technology advances through support of a variety of research and assessment projects. It recently concluded an eight-year, \$86 million cost-sharing agreement with a consortium of research and private sector parties. The consortium, led by Air Products and Chemicals, Inc., is working on a revolutionary ceramic membrane technology that promises to cut GTL production costs substantially.

Far-reaching impacts of commercial GTL application

GTL technology mounted on barges or offshore platforms could bring to market liquid transportation fuels from deepwater Gulf of Mexico sites without gas pipeline access. In Alaska,

converted gas from the North Slope could be transported through the existing Trans-Alaska Pipeline System (TAPS), from Prudhoe Bay to Valdez, where tankers would deliver these liquids to market. This would have major ramifications for Alaska's oil and gas industry and the state's overall economy. Due to the approximate annual 10 percent decline in Prudhoe Bay oil production rates, pipeline flow may fall below the minimum volume required for cost-effective operations within the next two decades, eventually requiring that the pipeline be shut in. GTL technology could extend TAPS' life by more than 25 years and prevent shut-in of as many as 200,000 barrels per day of the last remaining North Slope crude, protecting valuable jobs and revenue.



Zero sulfur, zero aromatics, high cetane diesel fuel made by Rentech, Inc., a small fuel development company based in Denver, Colorado.

Photo: Rentech, Inc.

ENERGY EXPERTS

The GTL revolution

"GTL will revolutionize the gas industry the way the first LNG plant did...[w]e expect to see a 1-2 million barrels per day GTL industry evolving over the next 15-20 years to the tune of 25-50 billion dollars of investment."

- ARTHUR D. LITTLE, INC.

"We're looking to open the door to a vast resource of natural gas that is today beyond our economic reach. This research...could pioneer a way to tap that resource and convert it into valuable liquid fuels that America will need in the 21st century."

- FORMER SECRETARY OF ENERGY FEDERICO PEÑA

"The cost-effective conversion of natural gas to clean liquid transportation fuels...offers a significant potential for greenhouse gas emissions reduction while allowing greater use of domestic natural gas supplies."

- NATIONAL LABORATORY DIRECTORS, DEPARTMENT OF ENERGY

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Ralph A. Avellanet
(202) 586-8499
ralph.avellanet@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



T E C H N O L O G Y

Locations: Worldwide, onshore and offshore

Glycol Dehydration

S U M M A R Y

The U.S. natural gas production sector operates some 37,000 glycol dehydration systems, which are designed to remove water from unprocessed gas production streams to produce pipeline quality gas. But during dehydration, these systems typically vent methane and other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) into the atmosphere. Methane, a potent greenhouse gas, is thought to contribute to global warming, and reducing these emissions is of critical environmental importance. Better dehydration systems management, including optimization of glycol circulation rates and installation of flash tank separator-condensers, enables producers to capture up to 90 percent of methane and other emissions. These processes reduce greenhouse gas emissions, improve air quality, and recover substantial gas for on-site use or pipeline sale.

B L U E P R I N T O N T E C H N O L O G Y

Effective management of dehydration systems reduces greenhouse gas emissions, improves air quality, and recovers substantial saleable natural gas

Improved practices and technologies

AFTER REMOVING water from a stream of wet natural gas, a typical dehydration system circulates triethylene glycol (TEG) through a reboiler unit to boil off the water and gaseous compounds so that the “wet” TEG can be recycled. At the reboiler, however, methane, and in some cases other VOCs, and HAPs such as benzene, toluene, ethyl benzene, and xylene (BTEX), are vented to the atmosphere. The amount of methane and other compounds vented is directly proportional to the

rate at which the glycol circulates through the dehydration system. If the circulation rate is higher than needed to achieve pipeline quality gas, more methane and other compounds are emitted, with no real improvement in the quality of the gas stream.

Consequently, producers are reducing air emissions and recovering valuable methane by combining two advanced practices: first, by installing flash tank separators and condenser units at the reboiler to capture methane, VOCs, and HAPs before they are vented to the atmosphere; and

second, by adjusting glycol circulation rates to optimal levels. Using a simple mathematical model, engineers can determine an optimal circulation rate, based on the characteristics of the particular gas stream, the pipeline’s water content requirements, and the operator’s production needs. These two processes, used in combination, yield significant environmental benefits for the producer in addition to attractive economic benefits, since the recovered methane can be used as on-site fuel or compressed and reinjected into the sales pipeline.

E C O N O M I C B E N E F I T S

Reduced energy consumption for circulation pumps and reboiler

Lower operating costs if captured methane is used to fuel on-site equipment

Increased saleable gas

Potential for increased recovery of natural gas liquids

E N V I R O N M E N T A L B E N E F I T S

Reduced greenhouse gas emissions

Improved local air quality due to reduction in BTEX and VOC emissions

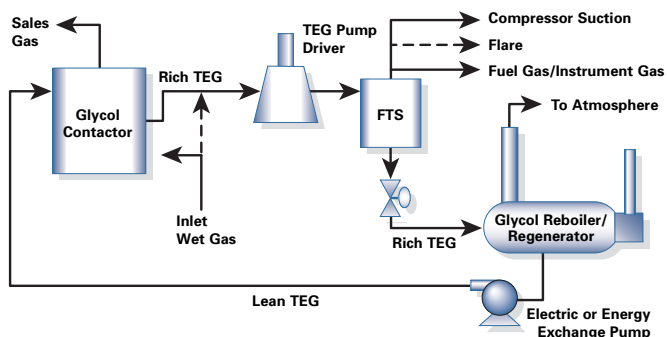
Enhanced regulatory compliance for upcoming Federal E&P Maximum Achievable Control Technology (MACT) requirements



PRODUCTION

HOW THE TECHNOLOGY WORKS

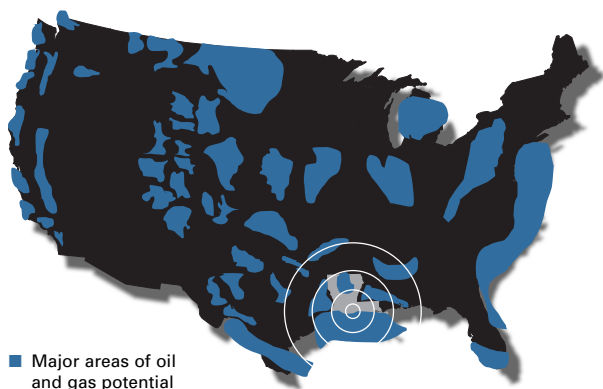
Flash Tanks produce a drop in pressure that causes the methane to vaporize ("flash") from the glycol stream.



In a dehydration process with a flash tank separator, "lean" TEG is sent to the contactor, where it strips water, methane, BTEX, and other compounds from the gas stream before entering the separator. Here pressure is stepped down to fuel gas system or compressor suction levels, allowing most of the methane and lighter VOCs to vaporize (flash). The flashed methane can be captured and used as fuel gas or compressed and reinjected into the sales line. The TEG flows to the reboiler, where water and remaining gases are boiled off, and it is recycled back to the contactor. To prevent discharge of HAPs and VOCs not recovered through the flash process, dehydration systems can also be fitted with air- or water-cooled condensers, which capture additional compounds as they move through the reboiler stack.

CASE STUDIES

Success in the Field



Lower emissions plus lower costs in Louisiana

In the early 1990s, Texaco retrofitted 26 of 27 field-based glycol dehydration systems with flash tank separator-condenser units to reduce emissions of VOCs and BTEX in response to the State of Louisiana's emission control program. In addition to greatly

reducing these emissions, it soon became clear that the units also recovered substantial amounts of methane. To determine exactly how much, Texaco staff conducted empirical measurements and used a computer-based dehydrator emissions model developed by the Gas Research Institute. Additional tests analyzed the extent to which flash methane and condenser BTEX recoveries were affected by variances in separator temperature and pressure, and circulation rates.

Results showed methane capture of some 104 thousand cubic feet per day, nearly 38 million cubic feet per year. In total, methane emissions from these units were reduced by 95 percent, from 500 tons to less than 25 tons per year. Under a wide range of tested separator pressures and temperatures, flash methane recoveries ranged from 90 to 99 percent, and condenser BTEX recoveries ranged from 69 to 98 percent. Texaco also found that reducing higher than necessary circulation rates resulted in concomitant emission reductions, even without separator-condenser installation. As an added benefit, Texaco routed the captured gas into a low-pressure gathering system for recompression and subsequent use in its field operations, thus lowering total operating costs.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Ralph A. Avellanet
(202) 586-8499
ralph.avellanet@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



SUMMARY

The exploration and production (E&P) industry is among the most data intensive in the world; various data—from geological to technical to regulatory—must be managed by both industry and government. Advanced data management systems are key to increasing the efficiency of oil and gas recovery and making effective regulatory and policy decisions. With participation by industry, State regulators, and DOE, numerous efforts are under way, such as standardized data collection of State oil and gas statistics, risk-based decision making, detailed online digital atlases of oil and gas plays, and validation methodology for Area of Review (AOR) variances. Initiatives such as these reflect advanced computer technology capabilities, handling massive amounts of data more quickly and cheaply than ever.

TECHNOLOGY

Locations: United States

Advanced Data Management

BLUEPRINT ON TECHNOLOGY

Data management tools improve information access, increasing resource recovery efficiencies and informing regulatory and policy decisions

E&P data management

E&P DATA GENERALLY fall into five major categories: environmental, geologic, exploration and production, regulatory, and technology. Advanced data management techniques enable: (1) better regulatory, enforcement and compliance decisions; (2) more informed government program and policy decisions; and (3) more efficient oil and gas recovery. “Data management” has different meanings for different technologists. For example, geophysicists may want to interpret 3-D seismic data to locate oil and gas resources, and petroleum engineers may want to interpret production data to enhance recovery; whereas State regulators might use online permitting and

compliance data to improve decision-making processes; versus environmentalists, who need habitat surveys and emission reports to inform policy debates. Both government and industry seek to improve their data management systems to support these goals.

Comprehensive State data facilitate decisions

States and DOE are collaborating to enhance State-level oil and gas data collection and management efforts. For example, with DOE support, the Interstate Oil and Gas Compact Commission (IOGCC) is cataloging State data collection efforts and management capabilities and devising uniform standards for State permitting, production, and well statistics.

IOGCC and DOE are also bringing key E&P data online to facilitate decision making by industry and States. These efforts include DOE’s *Environmental Compliance Assistance System*, which provides information regarding Federal E&P environmental regulations, and IOGCC’s framework for helping States develop permitting and regulatory compliance assistance programs.

Enabling cost-effective regulation

Developed by the Ground Water Protection Council with funding from DOE, the Risk-Based Data Management System (RBDMS) was originally designed to manage data for underground injection control programs, enabling

ECONOMIC BENEFITS

Better data access facilitates more effective business and investment decisions

Risk-based regulatory decisions lower environmental costs and increase operational efficiency

More efficient recovery of oil and gas resources, through improved prospect identification and targeting

ENVIRONMENTAL BENEFITS

Better regulatory and policy decision-making processes, leading to enhanced environmental protection

Risk-based regulatory structures focus industry and government activities on areas of greatest potential risk



more effective regulatory and operational decision making. The system has been so well received that it is being modified by individual States to include production, geological, and waste management data, as well as enforcement and permitting data. Initial RBDMS success has prompted more than 20 States to form a users' group to help each other implement the system.

Improving AOR verification

Under the Safe Drinking Water Act, operators are required to conduct quarter-mile AOR analyses of disposal and injection wells, but AOR variances may be granted in specific cases. With DOE and American Petroleum Institute support, the University of Missouri-Rolla has developed a scientific methodology for validating AOR variance requests that is expected to provide industry cost savings exceeding \$300 million. DOE has also supported development of data man-

agement tools and Geographic Information Systems (GIS) to help regulators conduct AOR and variance analyses statewide.

Enhancing oil and gas recovery

Partnering with States and the Gas Research Institute, DOE is supporting both print and digital atlases of producing regions in the United States. For example, a DOE-supported consortium is using GIS technology to develop a digital atlas of oil and gas plays and fields specific to Kansas, Nebraska, the Dakotas, and parts of Montana and Colorado. In these mature regions, advanced technology and data management are seen as the best approaches to extend production and prevent premature well abandonment. To help operators recover more original oil-in-place, the atlas, which currently covers only Kansas, will provide extensive production, petrophysical, and

geological data, sophisticated digital maps and imagery, as well as field-specific information on recovery technologies and engineering methods for identifying new or unswept zones.

Electronic permitting in Texas

Through a new DOE-sponsored pilot program, the Texas Railroad Commission is developing a paperless, digital on-line permitting system, which will save the State's operators and regulators millions of dollars and countless labor hours. This fully digital approach will soon enable operators to submit an electronic permit application via an Internet-linked computer, complete with supporting graphical or text attachments. The operator's identity will then be authenticated, and permit fees paid through a secure on-line transaction. Within hours—perhaps the same day, rather than the days or weeks now

required—the producer will be notified electronically whether the application has been approved. Although the expected savings per permit application may be relatively small, overall cost savings are expected to be significant; annual savings from drilling permits alone are estimated at between \$3 million and \$6 million.

Advanced computing leads the way

The Oil and Gas Infrastructure Project—part of DOE's Advanced Computational Technology Initiative—has explored implementing inexpensive mechanisms for online access to well-level oil and gas data from Texas, California, and other States. Such mechanisms enhance producers' access to production and geological data, ultimately enabling more efficient resource recovery.

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CONTACT



U.S. Department of Energy Office of Fossil Energy

1000 Independence Avenue, SW
Washington, DC 20585

Nancy L. Johnson
(202) 586-6458
nancy.johnson@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, onshore and offshore

Improved Recovery Processes

SUMMARY

The goal of evolving oil recovery technologies is increased reserves with less drilling. Despite significant technology advances in primary and secondary production, much of a reservoir's original oil-in-place remains untapped after these phases of the production cycle. Coupled with advanced field management practices, new enhanced oil recovery (EOR) technologies—such as thermal, gas, and chemical techniques—can significantly increase production in some maturing fields. The United States leads the world in sophisticated EOR technology, which currently accounts for about 12 percent of domestic daily crude oil production, a 140 percent increase from daily EOR rates only 15 years ago. In addition to preventing premature abandonment of significant domestic oil resources, these technologies could potentially recover half of the Nation's 350 billion barrels of “discovered, but unrecoverable” original oil-in-place.

BLUEPRINT ON TECHNOLOGY

Thirty years of continuous improvement in enhanced recovery technology has led to significant reserve additions and less drilling

Getting more oil from existing fields

PRODUCTION AT MOST oil reservoirs includes three distinct phases: primary, secondary, and enhanced recovery. During primary recovery, which uses natural pressure or artificial lift techniques to drive oil into the wellbore, only about 10 percent of the oil-in-place is generally produced. Shortly after World War II, producers began to conduct secondary recovery techniques to extend the productive life of oil fields, increasing ultimate recovery to more than 20 percent. Gas injection, for example, can maintain reservoir pressure and keep fluids moving; waterfloods are used to displace oil and drive it to the wellbore. In recent decades,

the development and continued innovation of EOR techniques has increased ultimate recovery to 30 to 60 percent of a reservoir's original oil-in-place. In the United States, three major categories of EOR technology—thermal, gas, and chemical—dominate EOR production.

Even though improved EOR technology can significantly extend reservoir life and has been successfully used since the 1960s, historically high costs have limited widespread application. In the last decade, however, dramatic improvements in analytic and assessment tools have led to a greater understanding of reservoir geology and the physical and chemical processes governing flows in porous media.

Today, unconventional approaches such as fieldwide development using strategically placed horizontal wells, or microbial injection to improve recovery may lead to new classes of EOR technology. Innovations in thermal recovery include radio frequency heating, and enhanced gravity drainage with steam in vertically parallel horizontal wells.

Thermal recovery

Thermal recovery techniques account for some 59 percent of daily U.S. EOR production. Used in individual wells or fieldwide, *steam injection and flooding* provide effective recovery of heavy, viscous crudes, which must be “thinned” to enable oil to flow freely to the wellbore. The most common domestic EOR

ECONOMIC BENEFITS

Worldwide production of approximately 2.3 million barrels per day (760,000 barrels per day in the United States) that would otherwise remain untapped

Potential recovery of up to half of the 350 billion barrels of discovered, currently unrecoverable, domestic oil

Increased production from marginal resources

ENVIRONMENTAL BENEFITS

Fewer new wells drilled due to increased reserves from existing fields

Less environmental impact due to reduced abandonment of marginal wells and offshore platforms



practice, this process has contributed directly to improved burning efficiencies of both gas and oil, and spawned the cogeneration industry, which uses clean-burning natural gas to create both steam and electricity at attractive prices for oil field operators and utilities. In California alone, for example, existing cogeneration plants generate enough electricity to supply 4.1 million homes. A second type of thermal recovery, *in-situ combustion*, injects air or oxygen into the formation and uses a controlled underground fire to burn a portion of the in-place crude. Heat and gases move oil toward production wells. This process is highly complex, involving multiphase flow of flue gases, volatile hydrocarbons, steam, hot water, and oil, and its performance in general has been insufficient to make it economically attractive to producers.

Gas-immiscible and -miscible recovery

Accounting for 40 percent

of daily EOR production, gas injection is the second most prevalent technology currently in domestic use. Two basic forms exist: immiscible, in which gas does not mix with oil; and miscible, in which injection pressures cause gas to dissolve in oil. *Immiscible injection*, which can use natural gas, flue gas, or nitrogen, creates an expanding force in the reservoir, pushing additional oil to the wellbore. *Miscible gas injection* dissolves propane, methane or other gases in the oil to lower its viscosity and increase its flow rate. In place of the costly hydrocarbon gases used in some EOR projects, miscible gas drives also frequently use carbon dioxide (CO₂) and nitrogen. CO₂ flooding has proven to be one of the most efficient EOR methods, as it takes advantage of a plentiful, naturally occurring gas and can be implemented at lower pressures.

Chemical recovery

Chemical recovery techniques account for less than

one percent of daily U.S. EOR production. In an enhanced waterflooding method known as *polymer flooding*, high molecular weight, water-soluble polymers are added to the injection water to increase its viscosity relative to that of the oil it is displacing, raising yields since oil is no longer bypassed. In another chemi-

cal recovery technique, *surfactant flooding* (also known as micellar-polymer flooding), a small slug of surfactant solution is injected into the reservoir, followed by polymer-thickened water and then brine. Despite its very high displacement efficiency, this technology is hampered by the high cost of chemicals and their environmental impact.

CASE STUDIES

Success in the Field

Steamflooding increases reserves fivefold at Kern River field

Discovered in 1899 by hand digging a 40-foot well, the giant Kern River field near Bakersfield, California, had nearly 600 wells by 1904. At its peak, primary production was 47,000 barrels/day, but had declined to 9,000 by 1954. Installing bottomhole thermal heaters in the 1950s succeeded in making oil less viscous so that it flowed more easily. Surface steam injection followed in the 1960s, and ultimately fieldwide steamflooding brought production to a peak 140,000 barrels/day in 1986. Production from the field was still over 134,000 barrels/day in 1997. Overall, thermal EOR has increased recovery from 10 percent of oil-in-place to over 40 percent, with ultimate recovery of 50 percent from this 3.5 billion-barrel field. Production is nearly five times greater than possible with primary recovery technology alone. Field life has been doubled, and on its 100th birthday in 1999, Kern River field will still have 7,000 producing wells.

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CONTACT



U.S. Department of Energy Office of Fossil Energy

1000 Independence Avenue, SW
Washington, DC 20585

George Stosur
(202) 586-8379
george.stosur@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, onshore and offshore

Leak Detection and Measurement Systems

SUMMARY

Leak detection and measurement systems play an essential part in controlling emissions of methane—a potent greenhouse gas and valuable energy product—from the Nation's massive oil and gas infrastructure. Significant amounts of methane are emitted to the atmosphere during production, transmission, processing, storage, and distribution. New technology facilitates accurate, efficient leak detection and measurement by ensuring equipment and pipeline integrity and timely maintenance and repair. These controls capture saleable natural gas, create safer work places, and protect our environment.

BLUEPRINT ON TECHNOLOGY

New devices to detect and measure gas leaks aim to eliminate greenhouse gas emissions

Overcoming the limitations of conventional systems

MANAGING LEAKS IN the U.S. oil and gas infrastructure is a formidable task. This complex infrastructure involves nearly 885,000 producing oil and gas wells and related equipment, 265,000 miles of natural gas transmission pipeline, and about 1.5 million miles of distribution pipeline. New technologies overcome drawbacks in standard industry approaches, such as “leak concentration measurement” techniques. These use hand-held instruments, such as organic vapor analyzers (OVAs) equipped with flame ionization detectors, to sample methane concentrations around leaking components. The leak flow rate can be estimated by the predicted relationship between concentration and leak rate. Such

devices are easy to use, but accuracy rates are low. Distortions up to three orders of magnitude can occur due to wind conditions, leak velocity, the shape of the component, and the surface distribution of the leak.

Another conventional practice, “bagging,” measures leaks by enclosing a component in a nonpermeable bag, adding air (or nitrogen), and then measuring an exhaust stream with an OVA. While highly accurate, bagging is costly, labor-intensive, time-consuming, and impractical when large numbers of components must be tested and measured.

High-flow samplers

Advanced technologies equip the industry to detect leaks with better accuracy and efficiency. The High-Flow

Sampler, developed by the Gas Research Institute (GRI) and Indaco Air Quality Services, Inc., samples the air surrounding leaking components using a pneumatic air mover, thus eliminating the need for bagging. Although more expensive than conventional tools, this technology offers the accuracy of bagging and the ease and speed of leak concentration measurements. It can also measure much larger leaks than standard instruments, which typically malfunction above leak detection ranges of 10,000 parts per million.

Backscatter absorption gas imaging

Another new technology, backscatter absorption gas imaging (BAGI), is a state-of-the-art, remote video-imaging tool developed by Sandia National Laboratories, with

ECONOMIC BENEFITS

More accurate information on leak characteristics and emissions, leading to successful, cost-effective leak reduction strategies

Increased recovery and usage of valuable natural gas

ENVIRONMENTAL BENEFITS

Reduced emissions of methane, a potent greenhouse gas

Enhanced worker safety due to more effective and efficient leak detection



PRODUCTION

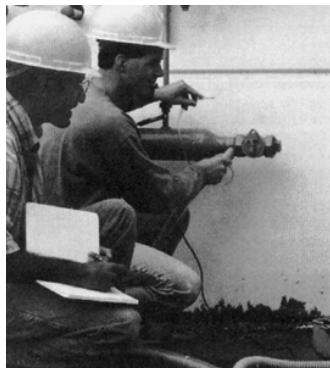


Photo: Hart Publications, Inc., and Gas Research Institute

support from GRI and DOE. Whereas other surveys are performed with manually scanned point sensors, BAGI technology uses infrared laser-illuminating imaging. If a gas plume is present and resonating within the illumination wavelength, the plume attenuates a portion of the laser backscatter and appears as a dark cloud in the real-time

Field trials of the new High-Flow Sampler promise more effective leak detection and measurement.

video picture. The equipment can be tuned to the absorption resonances of a wide variety of gases. Remote video imaging, with the superior efficiency of covering an entire area at one time, could greatly simplify leak detection. The latest field trials indicate an impressive detection range, with flow rates as low as 0.1 standard cubic feet per hour at distances from up to 100 meters, and leaks as low as 0.02 standard cubic feet per hour at closer distances. Estimates are that BAGI will increase area leak search rates by a factor of 100 versus existing technology.

CASE STUDIES

Success in the Field



High-tech sampling and imaging matched by effective low-tech approach

In June 1995, a Unocal Spill Prevention Task Group used Labradors and Golden Retrievers to detect underground pipeline leaks in the 40-year-old Swanson River Field in Alaska's Kenai National Wildlife Refuge. The dogs, originally used in law enforcement, were retrained to recognize a nontoxic odorant (Tekscent) injected in the pipelines. In widely ranging temperatures, the dogs successfully detected two faulty valve box seals and leaks in pipelines down to 12 feet underground or under 3 feet of snow. The team inspected about 18 miles of pipelines in two weeks. Unocal's use of this and other innovative environmental technologies earned them an U.S. Department of the Interior "National Health of the Land" environmental excellence award in May 1997.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Christopher J. Freitas
(202) 586-1657
christopher.freitas@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



T E C H N O L O G Y

Locations: Worldwide, onshore and offshore

Low-Bleed Pneumatic Devices

S U M M A R Y

Throughout all sectors of the natural gas industry, pneumatic valves, regulators, and sensors use pressurized gases to control or monitor critical equipment. As part of normal operations, pneumatic devices release natural gas, primarily methane, to the atmosphere. Within the industry, pneumatic devices are the single largest source of methane emissions, venting nearly 50 billion cubic feet annually. Older designs leak, or “bleed,” an average of 140 thousand cubic feet per year per device, a volume equivalent to an average household’s annual use, whereas newer, low-bleed designs emit an annual average of only 8 to 12 thousand cubic feet. Replacing or retrofitting devices, or improving maintenance, can reduce gas emissions substantially, reducing greenhouse gas emissions and potentially saving the industry millions of dollars in lost methane.

B L U E P R I N T O N T E C H N O L O G Y

Energy-efficient “low-bleed” pneumatic devices can dramatically reduce methane emissions and recover lost gas resources

Protecting the ozone layer and saving valuable gas

THE NATURAL GAS production sector uses pneumatic devices to control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. Approximately 250,000 pneumatic devices are used in the production sector alone, venting an estimated 35 billion cubic feet of methane annually, 70 percent of total methane emissions. Specific bleed rates are a function of the design, condition, and specific operating conditions of the device. By definition, a high-bleed device leaks more than six standard cubic feet per hour, although industry

operators estimate that most devices typically bleed about three times that rate.

Aggressive replacement, retrofitting, inspection, and maintenance

New, technically advanced low-bleed devices and retrofit kits offer comparable performance characteristics to high-bleed models, yet reduce methane emissions considerably—on average, they vent 90 percent less methane. Although low-bleed devices typically cost more than their high-bleed equivalents, cost-benefit analyses show that replacement or retrofit project costs are typically recouped within months. While it may be impractical to replace all an operation’s high-bleed

devices at once, operators are finding successful alternatives, such as combining replacements and retrofits, or installing a low-bleed device when an existing device fails or is no longer efficient.

Others have implemented aggressive inspection and maintenance programs. By cleaning and repairing leaking gaskets, fittings, and seals, operators are able to reduce methane emissions substantially. Other effective practices include tuning the device to operate in the low or high end of its proportional band, minimizing regulated gas supply, and eliminating unnecessary valve position indicators.

E C O N O M I C B E N E F I T S

Increased operational efficiency, as retrofit or replacement can provide better system-wide performance, reliability, and monitoring of key parameters

Increased saleable product volume, as leaks are minimized

E N V I R O N M E N T A L B E N E F I T S

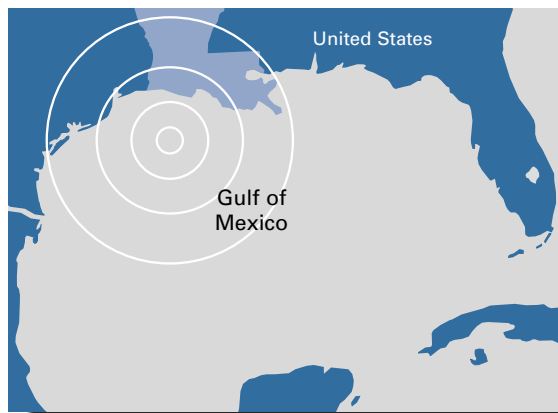
Reduced greenhouse gas emissions

Conservation of valuable gas resources



CASE STUDIES

Success in the Field



Chevron retrofits reduce emissions by 90 percent

Chevron installed a low-bleed retrofit valve kit on liquid level and pressure controllers on two platforms in the Vermilion field's blocks 245 and 246, roughly 60 nautical miles south of the Louisiana coast in the Gulf of Mexico. During this pilot test in January 1995, 19 devices were tested on one platform and 30 devices on another. The retrofits yielded average reductions in bleed rates of more than 90 percent. A cost-benefit analysis showed that the retrofitting costs would be recovered in less than two years, with specific payback periods based on the characteristics of the device retrofitted and an assumed natural gas wellhead price of \$1.50 per thousand cubic feet.

METRICS

Since 1991, EPA Natural Gas STAR Producer members, who account for approximately 35 percent of the Nation's natural gas production, have reduced methane emissions from pneumatic devices by nearly 11.5 billion cubic feet, worth an estimated \$23 million.

Marathon survey drives inspection, repair, and replacement program

As an EPA Natural Gas STAR Program partner, Marathon Oil Company recently surveyed more than 155 pneumatic devices at 50 U.S. production facilities. Results indicated that Marathon devices were bleeding 5.1 million cubic feet of methane per year, on par with the annual gas consumption of 57 residential consumers. Consequently, Marathon has now implemented a comprehensive program to inspect, repair, and replace its high-bleed pneumatic devices, saving gas and reducing emissions. In fact, Marathon determined that purchasing expensive leak detection equipment was not even needed to conduct such surveys; only listening was required, because "control devices with higher emissions [could] be identified qualitatively by sound."

Gas Saved by Retrofitting Controllers at Chevron

Location	Unit	Service	Before Retrofit (scf/day)	After Retrofit (scf/day)	Savings (scf/day)
V245 "F"	Fisher 2900	Oil Dump	438	43	395
V245 "F"	Fisher 2900	Suction Scubber	211	0	211
V245 "F"	Fisher 2900	Gas Filter	397	1	396
V246 "D"	Fisher 2900	Oil Dump	328	81	245
V246 "D"	Fisher 2900	Water Dump	567	0	567
Average			388	25	363
V246 "D"	Fisher 2900	Water Skimmer	508	177	331
V245 "F"	Fisher 4150	Fuel Gas Reg.	145	0	145
V245 "F"	Fisher 4160	Sales Gas Reg.	108	0	108
V245 "F"	Fisher 4160	Makeup Gas Reg.	534	12	522
Average			262	4	258
V246 "D"	Fisher 2900	Oil Dump	950	4	946

©SPE 37927, 1997

Advanced technology, combined with improved maintenance practices, can reduce methane losses from pneumatic devices by approximately 90 percent.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

George Stosur
(202) 586-8379
george.stosur@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



Locations: Deepwater areas of Australia, Brazil, Gulf of Mexico, North Sea, Southeast Asia, West Africa, and elsewhere

T E C H N O L O G Y

Offshore Platforms

S U M M A R Y

Finding economically viable methods to tap vast deepwater resources is driving innovations in offshore technology. Potential payoffs are immense. An estimated 90 percent of undiscovered global reserves are under 3,000 feet or more of water. Between 1996 and 1998, nearly 75 percent of the 66 oil discoveries greater than 100 million barrels were offshore. Effective new technology includes advanced tension leg platforms (TLPs) and mini-TLPs, which are lower-cost, small-footprint platforms suited to marginal fields. Other offshore platforms include spars, now designed to operate in depths of up to 8,000 feet, semisubmersible floating production systems (FPS), and new-generation floating production, storage, and offloading systems (FPSOs). Ongoing technology refinement continues to optimize recovery, reduce costs, and minimize environmental risks and impacts.

B L U E P R I N T O N T E C H N O L O G Y

Advanced offshore platform technology reduces project duration, costs, and impacts on marine environments

Enhanced recovery with fewer risks

PLATFORM DESIGN is key to cost-effective deepwater field development. Variables include field remoteness, size, and characteristics, water depth and condition, and weather patterns. Today, eight floating TLPs, moored to the ocean floor with high-strength tendons that provide vertical and lateral stability, operate in large, multi-well fields worldwide. TLPs offer the advantages of fixed platforms—space for crew quarters, drilling rigs, and production facilities—with lower investment costs. Maturation of TLP technology has enabled more aggressive production schedules and less exposure to economic risks. Platform construction time has been

cut in half. Today's TLP can withstand hurricane-force winds and waves, and its deepwater limits are being extended, perhaps to 6,000 feet. High-performance composites, stepped tendons, cables, and other options can increase tendon stiffness and reduce vertical motion in harsh ocean settings. The conceptual raft TLP, a submerged hull tensioned to the sea floor, would also minimize motion at reduced cost.

TLP innovations have spawned mini-TLPs with small footprints and permanent tension leg moorings that allow installation close to other platforms. The required investment in conventional TLPs can make their use for smaller discoveries unprofitable. Less costly mini-TLPs

can be constructed and deployed swiftly in marginal deepwater fields.

Spar drilling and production platforms—large, cylindrical platforms supported by buoyancy chambers and fastened with catenary mooring systems—have been used for research, communication, storage, and offloading for more than 30 years. The first spar production platform, installed in 2,000 feet at the Gulf's Neptune Field in 1996, was designed for maximum production of 25,000 barrels of oil per day and features a 707-by-72-foot hull enclosing buoyant risers and surface wellheads. Advances have led to units designed to operate in more than 8,000 feet of water. Inherent design versatility and optional hulls

E C O N O M I C B E N E F I T S

Recovery of significant deepwater oil and gas reserves that may otherwise remain undeveloped; enhanced recovery of marginal resources

Combined with advanced subsea completion technology, shorter construction and development schedules, leading to reduced costs

FPSO and FPS deployment facilitates low-cost field abandonment

E N V I R O N M E N T A L B E N E F I T S

Optimized recovery of valuable deepwater oil and gas resources

Shorter construction and production schedules ultimately reducing operational footprints, and protecting marine habitats and ocean resources



PRODUCTION

(“classic” and “truss”) allow flexibility of use, from storage to any combination of drilling, production, and workover, decreasing financial risk. Spars, easily relocated and reused, are also attractive for marginal fields.

Marginal fields, mild climates, and shallow depths were the criteria for using the first FPSO and FPS 20 years ago, but today an estimated 80 units operate worldwide in varied climates and depths. Enhanced FPSOs have a compression system for gas lift, injection, and export, desalters, water injection and natural gas liquids recovery systems, as well as a conventional production system.

FPSOs are selected in remote locations lacking pipelines and fixed infrastructure, marginal fields, and depths too great for fixed platforms, whereas FPSs are used where infrastructure connections are available. Combined with subsea completion technologies, FPSO and FPS platforms are considered critical to industry’s move toward 10,000-foot water depths, and many believe that this combination offers the most viable option over 5,000 feet. Compared with spars and TLPs, deepwater subsea completions offer shorter development schedules and more flexibility in location and well number.



CASE STUDIES

Success in the Field



Ram-Powell TLP

Production began in September 1997 at the \$1 billion Ram-Powell Unit, a 41,000-ton, 3,570-foot high TLP in the Gulf of Mexico about 80 miles south of Mobile, Alabama. A development joint venture between Shell, Exxon, and Amoco, Ram-Powell employs a permanent crew of 110 and has peak gross production capacity of 60,000 barrels of oil and 200 million cubic feet of gas per day. Twelve 28-inch diameter tendons, each about 3,145 feet long, support the unit in more than 3,200 feet of water, a new depth record for a permanent production platform. Ram-Powell can drill down to 19,000 feet below the sea floor, and has complete oil and gas processing separation, dehydration, and treatment facilities. Estimated recovery from this project is approximately 250 million barrels of oil equivalent.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

George Stosur
(202) 586-8379
george.stosur@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



SUMMARY

New downhole separation technologies promise to cut produced water volumes by as much as 97 percent in applicable wells. Usually, both water and oil are pumped to the surface for separation, but novel mechanisms installed below the surface can now separate the formation's oil and water in the wellbore. Oil is then produced, but water is directly pumped into a subsurface injection zone. This minimizes environmental risks and reduces fluid lifting and disposal costs. Downhole separation can also increase oil production significantly, and this, combined with reduced operating costs, could potentially extend the life of marginal wells or reactivate shut-in wells. Field testing and demonstration projects are currently under way in numerous projects throughout the United States and the world.

TECHNOLOGY

Locations: Worldwide, onshore and offshore

Downhole Oil/Water Separation

BLUEPRINT ON TECHNOLOGY

Emerging technologies for downhole fluids separation can reduce the volume of produced water brought to the surface, while increasing oil recovery

Conventional surface separation

IN TODAY'S TYPICAL oil well, produced water and oil are pumped to the surface for separation, after which the oil is pumped off and the water treated, then reinjected into the ground. This approach brings contaminants up through the well piping, and incurs significant water lifting and handling costs. Emerging downhole separation technologies can minimize the environmental risks associated with produced water handling, treatment, and disposal, and greatly reduce the costs of lifting and disposing of the produced water.

Three promising mechanisms for downhole separation

Downhole oil/water separation involves the use of mechanical or natural separation mechanisms in the wellbore to separate the formation's oil and water. Although not applicable to heavier, low-API gravity crudes, three basic downhole separation techniques are currently under development.

Gravity separation in the reservoir enhances and maintains the gravitational oil/water separation that occurs naturally in reservoirs. The normally level oil/water contact is skewed by the production process, which causes

the water/oil interface to rise in a phenomenon called "coning." When the tip of the water cone reaches the perforations in the well casing, the well begins to produce large amounts of water. This technique for downhole separation maintains a flat oil/water zone by using dual perforations in the well casing to produce water from below the zone (for downhole injection into another formation) simultaneously with oil from above the zone. This helps to maintain the natural oil/water gravity segregation and avoids coning.

ECONOMIC BENEFITS

Significant reductions in water lifting and disposal costs

Enhanced oil production

Increased access to marginal or otherwise uneconomic wells

ENVIRONMENTAL BENEFITS

Volume of produced water brought to surface reduced significantly, greatly minimizing risk from contaminants on the surface and to drinking water aquifers

Less drilling of new wells, due to greater recovery from existing wells

Reduced production footprints, as surface facilities may be smaller



PRODUCTION

Gravity separation in the well casing allows the produced fluids to separate naturally in the well casing, then uses a dual-action pump system (DAPS) to pump the oil up and inject the water downhole. The DAPS has two pump intakes that are positioned above and below the oil/water interface.

Hydrocyclone separation is a promising technique that uses centrifugal force to separate oil and water. Most such systems rely on electrical submersible pumps (ESPs) to push or pull water through the hydrocyclone. While this approach can handle larger volumes of fluids, the higher cost of the hydrocyclone and pump equipment has limited its use to date.

Although developed initially for onshore application, rapid advances in downhole separation technologies are heightening interest in offshore use. For example, a new generation of “intelligent,” computer-driven subsea downhole separation systems, currently under development, will remotely monitor and control fluid flow and downhole injection. These systems promise to be particularly useful in multilateral environments, by controlling downhole water injection into a dedicated lateral strategically placed to enhance water-flooding and pressure maintenance.

CASE STUDIES

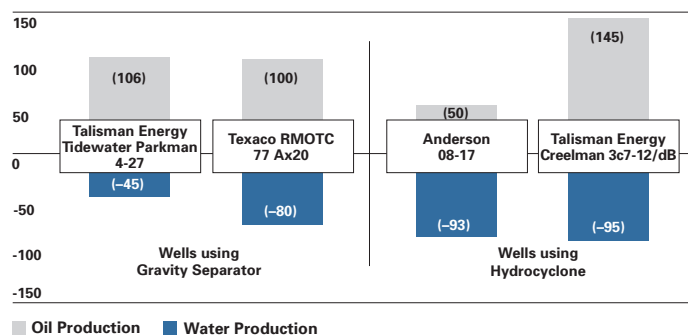
Success in the Field

Significant pilot results

A collaborative Mobil, BP Amoco, Texaco, and Chevron consortium (MoBPTeCh) was chartered to develop innovative solutions to common environmental problems in the oil and gas industry. MoBPTeCh has recently conducted extensive research on produced water downhole separation technologies, with 15 test wells in operation using gravity separation in the well casing. At this time, the project uses rod pumps only, but future tests with ESPs are expected to greatly increase the handling capacity of liquid volumes. Initial results indicate great potential for downhole separation technologies to reduce produced water volumes and increase production.

METRICS

Field trials in Canada and the United States show increased oil production and decreased water production



Source: Argonne National Laboratory, 1999

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Nancy L. Johnson
(202) 586-6458
nancy.johnson@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



T E C H N O L O G Y

U.S. Offshore (Gulf of Mexico, California, and Alaska)

Safety and Environmental Management Programs

S U M M A R Y

Offshore operations represent over one quarter of the Nation's oil and natural gas production. Since the early 1990s, Federal regulators and industry have successfully cooperated in the development and implementation of recommended practices for voluntary safety and environmental management programs (SEMP) for Outer Continental Shelf (OCS) operations. Using the SEMP approach, industry is responsible for voluntarily identifying potential hazards in the design, construction, and operation of offshore platforms and for implementing specific processes to improve safety and environmental protection. These measures are designed to reduce the risk and occurrence of accidents, injuries, and oil spills. By 1997, almost all OCS production operators were in the process of voluntary SEMP implementation.

B L U E P R I N T O N T E C H N O L O G Y

Implementation helps offshore operators avoid costly injuries, platform damage, and environmental incidents

Standards and training reduce human error

RESEARCH INDICATES that nearly 80 percent of offshore accidents are caused by human error, even when operations are fully compliant with regulations. In response to these risks, Minerals Management Service, in partnership with the American Petroleum Institute (API) and the Offshore Operator's Committee, has delineated voluntary standards that address human and organizational errors and help ensure worker safety and environmental protection as primary operating goals among offshore producers. *Recommended Practice for Development of a Safety and Environmental Management*

Plan for Outer Continental Shelf Operations and Facilities (RP 75), first issued by API in 1993, provides safety and operating guidelines for offshore operators of all sizes. These guidelines are especially valuable to small- and mid-sized producers, who may lack the resources and experience of larger companies in developing and implementing such policies. This cooperative relationship between industry and government represents a successful alternative to prescriptive regulations, with MMS' collaboration encouraging industry to focus on risk identification and mitigation instead of mere compliance. Because of widespread RP 75 implementation, MMS has recently

"We have seen strong evidence that adoption of SEMP can not only accomplish public objectives in the areas of promoting safety and environmental protection... it can also make good business sense by avoiding or containing accident and pollution costs. The vast majority of OCS operators have undertaken, in earnest, to develop and implement SEMP plans."

Minerals Management Service, 62 Federal Register 43346, 8/13/97

announced the continuation of its voluntary partnership with industry and sponsorship of joint industry workshops to share best management practices.

E C O N O M I C B E N E F I T S

Fewer accidents and equipment failures, thereby reducing operating and remediation costs

Potential avoidance of fines and litigation due to reduced risk of accidents and pollution

E N V I R O N M E N T A L B E N E F I T S

Reduced risk of spills, fugitive air emissions, blowouts, and accidents

Better protection of sensitive marine ecosystems and habitats

Enhanced worker safety, leading to fewer job-related injuries and illnesses



CASE STUDIES

Success in the Field

DOE and its partners blaze a trail to safety

To allay small- and mid-sized producers' concerns over the perceived costs and burdens of RP 75, DOE recently supported a real-world pilot implementation project with Louisiana-based Taylor Energy Company. The goal was to develop a single-model SEMP that could be shared throughout the industry, streamlining redundancies and reducing costs, particularly for smaller, independent companies.

Taylor, assisted by subcontractor Paragon Engineering Services, Inc., developed and implemented an 11-part SEMP at seven offshore platforms in the Gulf of Mexico. First, existing site safety procedures were updated for incorporation into the new safety program. Next, Taylor developed company-wide documentation of its safety and environmental program management, safety procedures, and safe drilling and workover practices, as well as a pocket-sized safety handbook summarizing these practices. In addition, Taylor performed risk-based hazard analyses at each site and issued site-specific operating procedures for startup, normal, and emergency response. Employee training on these general safety guidelines and all site-specific safety practice followed. Finally, Taylor audited the program to verify its successful implementation, using an OSHA-based audit protocol that included document review, visual inspection, interviews, and written testing.

While long-term outcomes are pending, Taylor's lost-time accident rate declined significantly at the pilot sites over the 30-month project period. DOE and MMS expect similar experiences at other companies, including eventual operating cost reductions due to SEMP and the resulting downward trend in accidents.

Taylor is sharing its experience and offering recommendations to others in DOE- and MMS-sponsored workshops and publications, including technical conferences, trade shows, and leading trade journals. These presentations have enabled many small- and mid-sized producers to learn firsthand about the program, leading to more effective SEMP implementation at their own facilities.



@SPE, 1993

An effective plan addresses how to:

- Operate and maintain facility equipment
- Identify and mitigate safety and environmental hazards
- Change operating equipment, processes, and personnel
- Respond to and investigate accidents
- Purchase equipment and supplies
- Work with contractors
- Train personnel

A fully implemented SEMP covers all phases of offshore operations, including design, construction, startup, operation, inspection, and maintenance of new, existing, or modified drilling and production facilities. (API RP 75)

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Nancy L. Johnson
(202) 586-6458
nancy.johnson@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



SUMMARY

Vapor recovery units can significantly reduce the fugitive hydrocarbon emissions vaporizing from crude oil storage tanks, particularly tanks associated with high-pressure reservoirs, high vapor releases, and larger operations. These emissions are typically made up of 40 to 60 percent methane, a potent greenhouse gas, along with other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). U.S. crude oil storage tanks emit an estimated 26.6 billion cubic feet of methane per year, representing a significant portion of the oil and gas industry's total annual methane emissions. While vapor recovery units are only feasible for a minority of existing tanks, this technology can capture over 95 percent of these emissions and compress them for use on-site or for sale. These units help protect our environment from harmful air pollutants and greenhouse gases.

TECHNOLOGY

Worldwide, onshore and offshore

Vapor Recovery Units

BLUEPRINT ON TECHNOLOGY

Vapor recovery units cut up to 95 percent of light hydrocarbon vapors vented from crude oil storage tanks, while recovering valuable gas

Resources that vanish into thin air

CRUDE OIL STORAGE tanks hold oil for brief periods of time to stabilize flow between production wells and pipeline or truck transport. During storage, light hydrocarbons dissolved in the oil vaporize and collect below the tank roof. The chief component of this gas is typically methane, although other gases such as propane, butane, ethane, nitrogen, and carbon dioxide may be present. These vapors also contain HAPs such as the BTEX compounds (benzene, toluene, ethylbenzene, and xylene). As the oil level in the tank fluctuates, these vapors often escape into the air, either through *flash losses* (due to

pressure changes during transfer of crude oil), *working losses* (due to the changing fluid levels and agitation of tank contents associated with the circulation of new crude through the tank), or *breathing losses* (due to daily and seasonal temperature and pressure variations). The amount of gas lost depends on the stored oil's gravity, the tank's throughput rate, and the operating temperature and pressure of the oil being added.

The advantages of vapor recovery

Vapor recovery systems can capture more than 95 percent of these fugitive emissions and recover substantial amounts of gas for use or sale. In addition to

onshore use, they are also employed in offshore settings such as marine crude oil loading terminals. Producers may opt to pipe the recovered vapors to natural gas gathering pipelines for sale as a high Btu-content natural gas, or to use the gas to fuel on-site operations. Alternatively, they may strip the vapors to separate natural gas liquids (NGLs) and methane. In some cases, vapor recovery units will reduce emissions to below the actionable levels set out in Title V of the 1990 Clean Air Act Amendments. By installing vapor recovery systems, producers may be able to avoid permitting charges, emissions fees, and other regulatory costs.

ECONOMIC BENEFITS

Lower operating costs if captured gas is used to fuel on-site equipment

Gas recovered for sale as a high-Btu natural gas

Gas recovered and stripped to separate NGLs and methane, if volume and NGL prices are sufficient

Potential avoidance of regulatory permitting and compliance costs

ENVIRONMENTAL BENEFITS

Significantly reduced greenhouse gas emissions

Improved local air quality, due to reduced emissions of VOCs and HAPs

Optimized recovery of a valuable natural resource



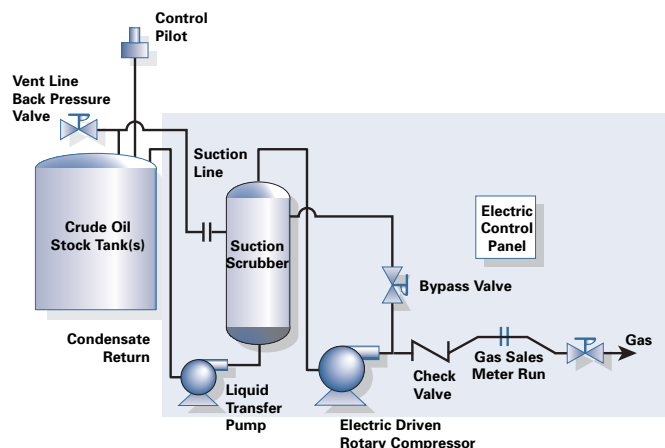
PRODUCTION

HOW THE TECHNOLOGY WORKS

In a typical recovery system, hydrocarbon vapors are drawn from the storage tank under low pressure, usually between 0.25 and 2 psi, then piped to a separator “suction scrubber,” which collects any condensed liquids. Any recovered liquids are usually recycled back to the storage tank. The vapors then are compressed, metered, reused, or resold.

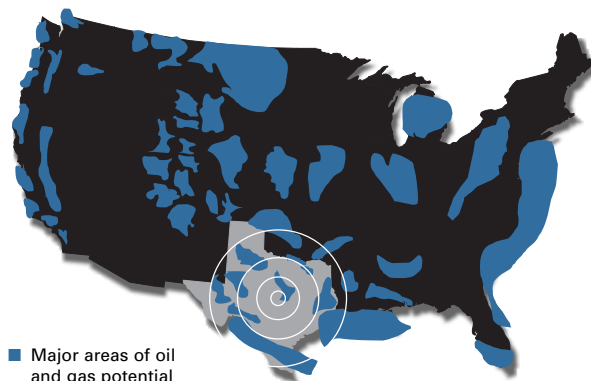
To prevent the creation of a vacuum in the top of the storage tank as vapors are removed, the unit is equipped with controls that shut down the compressor, permitting reflow of vapors into the tank as necessary. These systems can recover practically all the hydrocarbon vapors that would otherwise be lost to the atmosphere with negative environmental impacts.

Vapor Recovery Unit



CASE STUDIES

Success in the Field



Vapor recovery units succeed in the Austin Chalk field

In 1992–93, Union Pacific Resources (UPR) installed 27 vapor recovery units on its crude stock tanks in the Austin Chalk. UPR’s horizontal wells in the area are high-rate producers with high gas-to-oil ratios. Under these conditions, gas-oil separation is difficult, leading to high volumes of gas in the tanks. The vapor recovery systems proved very effective in reducing high emissions levels and generating profits. UPR recovered an average of 2,015 thousand cubic feet of gas per day, equivalent to the annual gas consumption of 23 residential consumers. The recovered natural gas netted UPR an additional \$700,000 in revenue over a one-year period.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585
H. William Hochheiser
(202) 586-5614
william.hochheiser@hq.doe.gov
Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide, onshore and offshore

Advanced Approaches to Site Restoration

SUMMARY

At the end of an oil or gas well's economic life, typically spanning 15 to 30 years, the well must be plugged and abandoned, all production equipment removed, and the surrounding area restored as closely as possible to its original state to prevent potential environmental or public health risks. To ensure the future ecological and economic viability of closed site lands, the industry is continually developing and applying innovative site restoration practices and technologies, including Risk-Based Corrective Action, soil bioremediation, and wetlands restoration. In addition, operators are actively supporting industry-led clean-up efforts such as those being carried out by the Oklahoma Energy Resources Board, a privatized state agency funded solely by industry's voluntary contributions.

BLUEPRINT ON TECHNOLOGY

Advanced technology and practices underscore a widespread commitment to environmental excellence

Closing sites

OF APPROXIMATELY 3.4 million oil and gas wells drilled in the United States since 1859, more than 2.5 million have been plugged and abandoned—a complex effort involving significant planning and expense. Onshore, wellbores are permanently plugged with cement to prevent any flow of subterranean fluids into the wellbore, thereby protecting groundwater. Waste-handling pits are closed, and storage tanks, wellheads, processing equipment, and pumpjacks removed. Offshore, wellbores are sealed below the sea floor and platforms are fully or partially removed, or toppled in place as part of artificial reef programs. About 17,000 onshore wells are plugged and abandoned annually, and 100 offshore platforms decommissioned each year.

Unplugged or orphaned wells with no existing owner or operator are largely a legacy of historic operations, when site restoration was not considered necessary. Today, a new approach to restoration integrates advanced technology, increased research and development, and a spirit of voluntarism and responsibility.

An exemplary model

A highly effective industry-led site restoration program is run by the Oklahoma Energy Resources Board (OERB), with near-unanimous support from Oklahoma producers and royalty owners, whose annual voluntary contributions solely fund this unique initiative. Since 1995, this privatized state agency has restored more than 1,000 orphaned and abandoned well sites across Oklahoma—with 500 more sites under

way—mitigating potential health and environmental risks and restoring blighted lands to the benefit of landowners, the community, and the environment, at no cost to the landowner. OERB's success demonstrates industry's commitment to preserving the lands on which it operates.

Diverse approaches

Rather than employing a “one-size-fits-all” approach to site restoration, industry is turning to flexible Risk-Based Corrective Action (RBCA) processes to ensure swift, efficient clean-ups. A joint American Petroleum Institute-Gas Research Institute (GRI) project has resulted in development of an E&P-specific set of RBCA tools to help operators undertake risk-based remedial planning. In this approach,

ECONOMIC BENEFITS

Reduced long-term environmental clean-up costs and lowered risk of future liability

Increased economic value of land returned to productive agricultural, residential, or commercial uses

ENVIRONMENTAL BENEFITS

Mitigation of potential public health and environmental risks

Restoration of sensitive habitats and ecosystems

Organic cleaning of petroleum-stained soil through bioremediation, maintaining and sometimes even improving soil health



human-health and ecological-risk analyses and decisions are integrated with the corrective action process, ensuring that remedial measures are appropriate given a specific site's characteristics and risk levels, and that resources are focused first on sites presenting the greatest potential risk.

Emerging bioremediation technology is a cost-effective tool with powerful environmental advantages. During E&P operations, soil layers can become stained with hydrocarbon molecules ranging from heavy crudes to volatile organic compounds. Bioremediation involves stimulating existing or placing carbon-eating microorganisms in stained soils to digest excess hydrocarbons or break them down into simpler, non-toxic compounds such as carbon dioxide and water. Bioremediation maintains the microbial populations needed to keep soil

healthy, and can also enhance soil health.

Within the natural gas industry, R&D efforts focus on remediating mercury-contaminated sites, which can entail potentially significant environmental and public health risks. In conjunction with DOE, GRI is examining the extent of the contamination, developing risk-based prioritization models, and testing advanced remediation technologies, including physical separation, chemical, and thermal techniques.

New techniques for restoring wetlands lost to saltwater encroachment are under development. For example, with assistance from DOE-funded research at Southeastern Louisiana University (SLU) is demonstrating that drill cuttings can be safely used to restore and create wetlands. Using SLU's unique temperature-

controlled mesocosm greenhouse facilities to simulate wetlands' full range of tidal fluctuations, researchers have

found that certain processed drill cuttings appear capable of supporting healthy wetlands vegetation.

CASE STUDIES

Success in the Field

Proactive, global, site restoration

Together with other companies and the State of California, Phillips Petroleum is leading the restoration of the abandoned 880-acre Bolsa Chica oil field near Huntington Beach, California. The project includes cleaning up old well sites and building a tidal inlet where waterfowl can rest and feed before migrating 3,000 miles across the Pacific Flyway.

In Phu Khieo, Thailand, Texaco restored a nonproductive exploratory drill site, although not legally obligated under Thai law, by treating drilling wastes, capping the site with clean topsoil, and building dikes to support rice paddies and sugar cane fields. The Thai government has since proposed Texaco's approach as a regulatory environmental management model.

Working with Kansas State agencies, Mobil E&P U.S., Inc. bioremediated hydrocarbon-stained soils at its Hugoton Gas Field. Using cow manure as a soil nutrient and microbial base catalyst, total petroleum hydrocarbon levels were reduced by more than 99 percent. At the project's conclusion, native grasses were planted to re-vegetate the area.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Nancy L. Johnson
(202) 586-6458
nancy.johnson@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Gulf of Mexico

Rigs to Reefs

SUMMARY

Industry, regulators, and environmentalists now recognize the advantages of toppling decommissioned offshore platforms and anchoring them on the sea floor as permanent artificial reefs. Under existing State programs, oil and gas companies can donate platforms to States for use as artificial reefs, along with a percentage of their cost savings to be used for reef maintenance and development. Designed for marine environments and impervious to displacement or breakup, these steel platforms make ideal reefs. Thriving habitats are typically well established on working rigs, and dismantling and moving them threatens these habitats. To date, more than 100 donated offshore platforms have been placed off the coasts of Texas, Louisiana, and other Gulf States, where they host complex ecosystems that attract fish and enhance commercial fishing and recreational activities.

BLUEPRINT ON TECHNOLOGY

Converting obsolete platforms into artificial reefs benefits marine habitats, commercial fishers, divers, vacationers, and the oil and gas industry

Removing rigs

THE U.S. MINERALS Management Service (MMS) requires removal of all platforms in Outer Continental Shelf (OCS) waters within one year from production shutdown. Currently, platform removals from the Gulf of Mexico OCS are averaging 100 platforms per year. MMS estimates that over half of about 3,900 remaining structures will require removal by 2000. For smaller structures in shallow waters, companies typically dismantle the platform using explosives, or sometimes torches or cutters, and then tow the deck and jacket

to shore for refurbishment or scrapping. This option is often elected when the platform is not located near a “rigs to reefs” zone.

Creating artificial reefs

When decommissioning in deeper waters (generally beyond 100 feet) at more remote locations, operators can reduce removal costs significantly by toppling structures (fully or partially) in place as artificial reefs, or towing them to a designated site for toppling. To date, about 10 percent of the Gulf’s platform removals have been converted to artificial reefs; this percentage is expected to

increase as more decommissioned deepwater platforms require removal.

The typical 20-story steel jackets that support offshore platforms provide acres of habitat for various underwater flora and fish species—within six months to one year of initial placement, platforms are covered with marine life. The submerged hard surfaces invite invertebrates such as barnacles, corals, sponges, clams, bryo-zoans and hydroids, which in turn attract resident reef fish such as snapper and grouper and transients like mackerel and billfish. Fish are also drawn by

ECONOMIC BENEFITS

Potential for significant reductions in platform removal and disposal costs, particularly in locations where partial removal is viable

Industry cost savings fund State reef maintenance and development programs

Enhancement of commercial fishing opportunities

Promotion of local tourism through enhanced recreational fishing and diving opportunities

ENVIRONMENTAL BENEFITS

Enhanced protection and nurture of complex marine ecosystems and habitats

Creation of new marine habitats

Reduced impacts of platform demolition and relocation

Increased recreational use of water resources



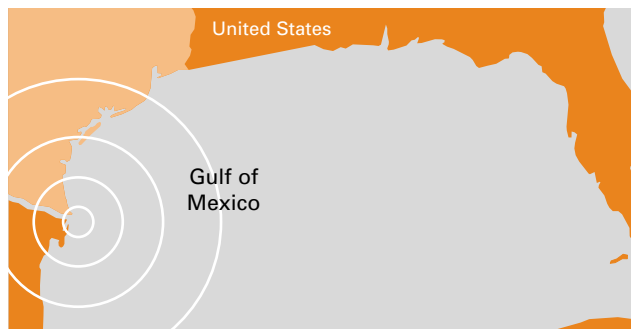
the shape, size, and openness of these structures, which attract an estimated 20 to 50 times more fish than the Gulf's naturally flat, soft bottom.

Removing platforms after shutdown threatens these complex fish populations as well as the commercial and recreational industries that rely on them. Through "rigs to reefs," industry and State governments are collaborating to ensure the greatest possible number of platform conversions, thereby protecting rich marine ecosystems and enriching the Gulf's commercial fishing and recreational opportunities.

The first planned rigs-to-reefs conversion took place in 1979, when an Exxon-owned subsea template located offshore Louisiana was moved to offshore Florida. The National Fishing Enhancement Act, passed in 1984, led to the development of the National Artificial Reef Program and formal support from MMS. State programs followed in Louisiana (1986) and Texas (1990); Mississippi, Alabama, and Florida have since formed their own programs. Today, artificial reefs exist around the world, with the Gulf of Mexico boasting the most extensive and successful conversions.

CASE STUDIES

Success in the Field

**Rig reefs boost tourism in South Texas**

Mobil Exploration and Production U.S., Inc., performed an environmentally outstanding conversion in 1994. Over a 75-day period, Mobil dismantled six platforms located in several South Padre Island blocks, moving four jackets 10 miles to Port Mansfield Liberty Ship Reef and two jackets 27 miles to Port Isabel. Mobil elected to cut away the platform legs rather than blast them, despite explosives being cheaper, faster, and more reliable. Mechanical cutting avoided undue harm and disruption to the rich marine life inhabiting the rigs offshore environmentally sensitive South Padre Island.

The added time and expense of cutting and transport negated any cost savings, but Mobil still earned tremendous payback. Jeffrey Passmore of Mobil noted: "We were able...to give...structures with 15 to 20 years of [marine habitat] buildup on them." Jan Culbertson, Texas Parks and Wildlife Department, commented, "We almost begged Mobil to take the structures to Port Isabel. That's where our tourism dollars are. Mobil bent over backward to give us their structures in a natural state with no animals hurt or removed. We even had turtles living on the structures that we had to move out of the way. All the animals, the little blennies [fish] that were inside the barnacles, all made it to their new reef-site home."

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Susan Gregersen
(202) 586-0063
susan.gregersen@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: United States

Road Mix and Roadspreading

SUMMARY

Tank cleaning and other common exploration and production operations routinely generate large amounts of non-hazardous crude oil wastes sometimes suitable for use as road paving (road mix) materials. These hydrocarbon residuals act as binders, and can be mixed on-site with native soils or imported aggregate, then safely paved into roads. Similarly, another routine oilfield waste, produced water—the brine or brackish water extracted with oil or gas during the production process—can be used for road de-icing or dust control. Road mixing and spreading technology provides useful products, significant disposal cost-savings for producers, and conservation of limited landfill capacity. Minimizing landfill use also significantly reduces the potential for reactive hydrocarbon emissions and soil and water contamination. While this practice promises environmental benefits under certain conditions, application is limited and discrimination necessary.

BLUEPRINT ON TECHNOLOGY

Crude oil residuals and produced water can be safely and creatively recycled for road building, stabilization, de-icing, and dust suppression

Creative use of oilfield waste

AS LANDFILL AND other traditional disposal methods become more limited and costly, in some areas the petroleum industry is increasingly recycling various oilfield wastes as road mix material.

Paralleling the commercial road mixing process, the petroleum industry mixes crude oil residuals from tank cleaning, sump abandonments, and production flow-line leaks with imported aggregate (coarse binding materials) or native soils for

light duty road paving or dust suppression.

Tank residuals are the largest source of recycled binding agents. These residuals, made up of fine sediments or sands and heavy, low-volatility hydrocarbons that settle during storage, are periodically cleaned out of tanks by high-pressure water jets, creating a slurry that is dewatered to make sludge. The sludge—with cohesive and adhesive properties similar to commercial road mix materials—is mixed with aggregate, graded, and cured.

The resulting road mix can either be stockpiled or applied immediately with standard paver/spreader equipment, and compacted if necessary. Depending on final use, the hydrocarbon content of the raw materials, and the type of road mix needed, petroleum facilities may add commercial asphalt cements to their road mix.

Other oilfield wastes, such as completion and workover fluids and produced brine, are also suitable for roadspreading to suppress dust or de-ice unpaved roads. In northern

ECONOMIC BENEFITS

Significant reduction in costs and potential liability associated with management and disposal of nonhazardous oilfield wastes

More expensive alternatives such as paving would be necessary without recycled road mix

Landfill space conserved

Conservation of natural resources through product substitution

ENVIRONMENTAL BENEFITS

Reduced waste volumes to landfill or reinject into the earth's subsurface, thus reducing potential environmental risks and future liability

Reduced dust and particulate matter emissions from unpaved roads

Greatly reduced reactive organic hydrocarbon compound emissions, compared with landfill disposal

Demonstrated low hydrocarbon and metal leachability

Demonstrated nonhazardous by acute aquatic testing



States, using these wastes to de-ice roads instead of salt can conserve this limited natural resource.

Today, the petroleum industry uses most of its recycled road mix to develop access roads to remote exploration and production sites and to control dust in production areas. California operators have been using crude oil-impacted waste materials as road mix for nearly a century with no

adverse environmental impacts. Similarly, brine spreading to stabilize roadways and control dust has been used effectively in certain areas for years. The primary alternatives to road mixing and roadspreading are landfilling the solid wastes at an average cost of \$75 per ton, and subsurface reinjection of produced water for disposal or enhanced oil recovery, also very costly.



CASE STUDIES

Success in the Field

Roadspreading in Pennsylvania

A portion of the 1.7 million barrels of brine produced annually by Pennsylvania's oil and gas wells is spread on its unpaved secondary roads for dust suppression and road stabilization. To minimize environmental impacts from this practice, including the risk of contaminants leaching into surface or ground waters, the Pennsylvania Department of Environmental Protection (DEP) has developed mandatory roadspreading guidelines for brine generators, transporters, applicators, and roadway administrators.

Funded by a Federal Clean Water Act grant, the DEP tested water quality impacts along seven unpaved roadways in western Pennsylvania on which brine had been spread. Between 1992 and 1995, surface water samples were taken from culverts, road-side ditches, streams, and ponds at the selected road sites, while groundwater was sampled from monitoring wells installed to measure the impact of brine-spreading on water quality. Over the sampling period, lysimeters were used to determine whether brine had migrated from the roadbed. Soil and roadbed samples were also taken to identify any leaching or accumulation of heavy metals or other harmful pollutants. Through monitoring and subsequent analyses, the DEP concluded that although potential exists for harm to surface water and groundwater from brine migration or run-off, risks could be significantly minimized by controlling the frequency and application rate of brine and by following the roadspreading guidelines. Roadspreading offers a cost-effective means to recycle and dispose of a portion of Pennsylvania's produced water waste stream, with minimal environmental impact.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Nancy L. Johnson
(202) 586-6458
nancy.johnson@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: United States, onshore

DOE-BLM Partnership

SUMMARY

The Bureau of Land Management (BLM) and the Department of Energy (DOE) have joined forces to enhance protection of environmental and cultural resources on sensitive public lands. In these joint projects, advanced technologies and practices are shared across BLM, DOE, and the oil and gas industry to improve resource management and access to Federal lands. Currently, teams are studying issues such as the reversal of subsurface damage to freshwater aquifers at abandoned well sites in Oklahoma, the protection of archaeological remains in Nevada, and the improvement of air quality monitoring in remote Wyoming locations. In concert with Federal agencies striving to balance competing demands for the use of public lands, the DOE/BLM partnership seeks to ensure maximum resource recovery consistent with high levels of environmental protection and cultural sensitivity.

BLUEPRINT ON TECHNOLOGY

Strategic alliances leverage DOE and BLM resources and expertise to protect cultural resources and sensitive environments

The role of BLM

BLM OVERSEES 264 million acres of Federal land and 300 million acres of subsurface mineral resources, primarily in the western United States and Alaska, about an eighth of the land in the United States. Federal lands under BLM oversight include extensive grasslands, forests, high mountains, arctic tundra, and deserts, as well as many fish and wildlife habitats and archaeological and historical sites. These lands contain subsurface resources amounting to eight percent of the natural gas and five percent of the crude oil produced annually, in addition to resources like coal, forest products, grazing forage, and rights-of-way for

pipelines and transmission lines. Of the total \$1.4 billion in annual revenues these lands bring, nearly \$835 million, or 60 percent, is generated by royalties, rents, bonuses, sales, and fees from oil and gas operations. The total direct and indirect economic output of oil and gas production is estimated at nearly \$12 billion annually.

The role of DOE

DOE and BLM have entered into a memorandum of understanding (MOU) to help improve access to Federal land for oil and gas development, consistent with effective environmental protection. This includes technology transfer, data sharing, technical support, and sharing of

expertise. Cooperative efforts under this agreement have included DOE participation on BLM streamlining and environmental incentives teams and BLM contributions to DOE's oil and gas databases. In addition, as part of the MOU activities, DOE and BLM have formed a Federal Lands Technology Partnership to address access issues and provide technical support to Federal land managers. Fiscal year 1998 was the first year of DOE funding under this partnership. The two agencies solicited projects from BLM field offices and worked together to prioritize the proposals. Three resulting projects initiated this year are discussed here.

ECONOMIC BENEFITS

Enhanced Federal revenues from increased oil and gas production on public lands

Accelerated planning and permitting schedules, reducing development costs and time

ENVIRONMENTAL BENEFITS

Greater protection of environmentally and culturally sensitive areas

Increased, more efficient recovery of oil and gas on Federal lands



CASE STUDIES

Success in the Field

Well decontamination in Oklahoma

BLM recently discovered brine and salt water contamination of both soil and freshwater sources on land held in trust to the Pawnee Indians in Payne County, Oklahoma. Today, BLM and DOE are working together with the Oklahoma Energy Resources Board, an industry-funded, publicly chartered site restoration agency, to reverse subsurface damage to a freshwater aquifer and to restore the area's damaged grasses, shrubs, and trees. Knowledge gained in this project will apply to a wide range of water-injection and water-disposal well problems, and technology developed for salvaging the contaminated aquifer will benefit other damaged sites on public lands.

Archaeological and resource development in Nevada

BLM, DOE, and state agencies in Nevada are developing a predictive geographical information system (GIS) model that will help protect the rich archaeological remains of the northern Railroad Valley in Nye County, Nevada. This will enhance access to the area's rich oil and gas resources, often restricted by concerns about archaeological remains. A potentially powerful management tool, the model provides critical information on both subsurface resources and cultural sites, making it easier to determine lease boundaries, isolate sensitive areas, and accelerate resource development. For example, by identifying the likelihood of precious cultural resources in a specific area within the Nye Valley, the model will improve the routing of access roads and pad orientation, and help manage resource, range, wildlife, and recreation programs.

Air quality monitoring in Wyoming

Since ongoing air quality data is often unavailable in many remote areas, it is becoming increasingly difficult for land management



agencies to complete air quality impact assessments required as part of Environmental Impact Statements (EIS). Because new oil and gas development projects are permitted only on condition that air quality will not significantly deteriorate, future access to some resources may be denied where air monitoring data are insufficient, even in areas where actual air quality impacts would be minimal.

To address this concern, BLM and DOE, in collaboration with other agencies, are establishing a network of low-cost, portable, solar-powered monitoring stations in southwestern Wyoming, which has seen a marked increase in oil and gas development over the last five years. These stations will measure ambient air concentrations and calculate dry deposition of nitrogen oxides and sulfur oxides in remote areas where environmental concerns are high and development is likely to increase. This will greatly enhance permitting decisions and EIS preparation. Five aerometric stations currently used to measure climate and air quality parameters will be converted for operational air quality monitoring. Three will be mobile; the other two will remain fixed to provide long-term air quality data.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

H. William Hochheiser
(202) 586-5614
william.hochheiser@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Worldwide

Coastal and Nearshore Operations

SUMMARY

From Alabama's Mobile Bay to the North Irish Sea, operators are employing advanced exploration, drilling, production, and site restoration techniques to protect sensitive coastal wetlands and nearshore environments. For example, through collaborative planning with several Federal and State agencies and state-of-the-art drilling and site restoration technologies, Bright & Co. drilled an environmentally unobtrusive exploratory well on the Padre Island National Seashore. In conformance with extensive regulatory requirements, every phase of Bright's operation was designed to minimize environmental impacts, leaving virtually no footprint on the area. Although no hydrocarbon resources were found, the undertaking demonstrated that exploratory drilling can be done without disturbing coastal environments. The use of advanced technology helps preserve delicate ecosystems.

BLUEPRINT ON TECHNOLOGY

Cooperative planning, advanced technology, and detailed habitat enhancement render operations virtually invisible

Gulf coast breakthrough

A FEDERALLY MANAGED recreational area and wildlife and nature preserve, Padre Island National Seashore has 133,000 acres of beaches, grasslands, tidal flats, dunes, and ponds that are home to a huge variety of plant life as well as marine life, reptiles, sea turtles, coyotes, waterfowl, and more than 350 species of birds, including some threatened or endangered species. Hiking, camping, fishing, nature studies, and water sports attract some 800,000 visitors annually. This 80-mile long barrier island sits four feet above an underground freshwater aquifer, which is the primary source of drinking water for area wildlife and thus critical to the island's ecosystem. The island is also situated in a high-potential oil

and gas resource zone, challenging private parties who own subsurface oil and gas rights to develop these resources under the strict environmental regulatory oversight of several Federal and State agencies, including the U.S. Army Corps of Engineers, the National Park Service, and the Texas Railroad Commission.

Planning for all contingencies

Before Bright & Co. could begin drilling, the National Park Service required a comprehensive plan of operations, including a timetable and description of all proposed construction, drilling, completion, and production activities; spill control and site reclamation plans; environmental impact statements; and documentation of the

archaeological and cultural resources potentially affected by the operations. Bright & Co.'s plan included site management equipment to minimize the operation's footprint and safely manage wastes as well as a directional drilling strategy that would minimize contact with sensitive wetlands and environmental impacts. Upon plan approval, Bright & Co. also posted a \$200,000 performance bond, the estimated maximum cost of site reclamation and clean-up should an oil spill occur. Finally, a U.S. Army Corps of Engineers permit to build an access road across reclaimed wetlands was obtained, requiring Bright & Co. to compensate the 0.4 acres of nontidal wetlands lost to road construction with 0.8 acres of new wetlands.

ECONOMIC BENEFITS

Sensitive project execution averted potential negative impacts on a popular tourist area

Cost-effective, low-impact operations proven successful

ENVIRONMENTAL BENEFITS

Virtually no footprint following operation

Habitats, wildlife, and cultural resources intact and unmolested

Fresh and marine water resources meticulously safeguarded

Reduced air emissions and lower risk of fuel spills through use of electric equipment

**A “no footprint” drilling site**

Using 7,600 tons of imported, compacted caliche, Bright & Co. built a 1.6-mile, 14-foot wide access road to the drill site. They constructed a 300-foot square caliche pad, covered by a polyethylene liner, on which they mounted the drill rig, mud tanks, and pipe racks. The company then built a berm around the liner and sloped the pad to capture any discharges in a subsurface “cellar,” draining it with a centrifugal pump. A three-foot high levee ringed the pad perimeter, ensuring no groundwater contamination.

Advanced technology at work

Mesa Drilling Inc. drilled the well with a diesel-electric, silicon controlled rectifier unit, significantly reducing noise impact on visitors and wildlife. Most of the rig’s components were wheel-mounted, thus minimizing equipment mobilization across the beach. Electric mud pumps and draw works

reduced air emissions and potential oil leaks. An advanced closed-loop mud system collected drill cuttings in 85-barrel boxes mounted on tracks for immediate transport and disposal off site.

Bright & Co. employed directional drilling to hit the targeted pay zone—the Frio Marg A sand at approximately 7,500-foot true vertical depth—located beneath a large wetlands area. Directional drilling allowed Bright & Co. to avoid reclaiming additional wetlands for the drilling pad. An 8 3/4-inch polycrystalline diamond compact drill bit was selected to maintain direction and angle, prevent formation damage, and minimize drilling time and air emissions. At an average rate of 58 feet per hour over 14 days, the well was first drilled vertically to 1,830 feet, then angled 2 degrees per 100 feet, reaching an ultimate angle of 29 degrees and a measured depth of 8,900 feet. When no productive zones were found,

Bright & Co. plugged the well, removed the pad and access road, restored the

ground surface to its original contours, and reseeded with native grasses.

CASE STUDIES

Beyond South Padre Island

Advanced technology is enhancing access to oil and gas resources while protecting sensitive coastal and wetlands ecosystems throughout the United States:

In Mobile Bay, Alabama—a complex marine environment with important commercial fisheries and recreational facilities—ARCO’s Dauphin Island production facility has successfully minimized visual and environmental impacts while developing the area’s rich natural gas resources. Less than three miles from Dauphin Island residents, the ARCO platform’s unique structural design minimizes aesthetic drawbacks. The facility also used advanced horizontal drilling techniques to reduce the production footprint.

Covering 125,000 acres in southwest Louisiana, the Sabine National Wildlife Refuge sustains more than 250 species of birds, alligators, and marsh mammals, and is a major wintering ground for migratory waterfowl. In 1993, Vastar Resources selected the refuge’s Black Bayou as an exploratory prospect. In close cooperation with the U.S. Fish & Wildlife Service and other Federal and State agencies, Vastar used innovative drilling, waste minimization, and site restoration techniques to drill two exploratory wells in this fragile coastal wetlands area, with minimal impacts.

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Susan Gregersen
(202) 586-0063
susan.gregersen@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Alaska's North Slope

Insulated Ice Pads

SUMMARY

New, prefabricated insulation panels can be used to preserve ice drilling pads from arctic summer thaw, thereby extending the exploratory drilling season as much as 50 percent. Insulated pads permit ice pad construction prior to the winter drilling season, enabling drilling operations to begin some two months earlier than if the pad had been built in December for a mid-January drilling start—the typical exploratory drilling schedule. The extended season allows single-season well completions, which reduce seasonal equipment mobilization and environmental impacts, as well as associated costs.

BLUEPRINT ON TECHNOLOGY

Extending the drilling season with insulated ice pads can minimize environmental disruption and exploratory drilling footprints, while reducing costs

Drilling in the Arctic

CLIMATIC CONDITIONS on Alaska's North Slope have restricted the exploratory drilling season in remote Arctic environments to 135 to 170 days. The tundra has to be frozen solid enough to allow equipment transport to the drilling site as well as sustainable ice road and ice pad construction and maintenance. At its longest, the tundra travel season extends from November through May, although specific conditions dictate load weight on any given date. At the drilling site, ice pad construction, often as large as an acre, is usually begun in early December, although November is possible under optimal conditions. By mid-May, equipment must be removed to a non-tundra area. While conventional ice pads are far

less environmentally intrusive and less costly than gravel drilling pads, their impermanence means an additional round of equipment demobilization and storage at an off-site gravel pad. If, as is common, the exploratory well is not completed, remobilization the following season is necessary. Such operations entail environmental disturbance and additional costs.

Innovative insulated ice pads, however, can extend the available drilling season to a total of 205 days and effective well operations up to 160 days, potentially enabling completion of one or perhaps two exploratory wells in a single season. Single-season completions substantially reduce mobilization costs and related environmental effects, and also cut time between initial investment and returns.



ECONOMIC BENEFITS

Single-season exploratory well completions, greatly reducing mobilization costs

Valuable subsurface data one year earlier than would otherwise be possible, enhancing operational planning

ENVIRONMENTAL BENEFITS

Smaller footprints and less time on-site

Elimination of seasonal equipment mobilization, minimizing environmental impacts on land and air



CASE STUDIES

Success in the Field

Drilling two months earlier, saving more than \$2.3 million

When a BP Exploration (Alaska) Inc. (BPXA) engineering feasibility study indicated that constructing an insulated ice pad in March 1993 at Yukon Gold #1 on the North Slope would significantly extend the winter drilling season, BPXA built a 390-by-280-foot ice pad covered with nearly 600 wind-resistant insulating panels. Summer visits confirmed that the ice beneath the panels remained sufficiently frozen. When the panels were disassembled in October 1993, they had not bonded to the resting surface, or scattered, and nearly 90 percent were in excellent condition and reusable.

BPXA began drilling in mid-November, two months ahead of conventional Arctic practice. With such an early start, Yukon Gold #1 was completed in time to begin drilling immediately at nearby Sourdough #2, where the insulated panels were placed under the rig to give BPXA the option of leaving the rig on location over the summer and avoiding remobilization should the well not be completed before season's end. This was not necessary, however, as the Sourdough well was also successfully completed during the same season.

Overall, BPXA netted a cost savings of more than \$2.3 million from the two single-season completions. In addition, the tundra endured significantly less impact than would have been the case had seasonal equipment mobilization been required. Subsequent site monitoring showed no long-term environmental impacts.



METRICS

Results of a BPXA study, comparing drilling season length using conventional practices versus insulated ice pads

Time Period	Conventional	Insulated Ice Pad
Construction start date	December 1–15	Previous Winter
Start of rig mobility	December 15–31	October 7–21
Spud date for first well	January 15–31	November 7–21
Tundra-travel end of season	April 29–May 22	April 29–May 22
End of well operations	April 15–May 8	April 15–May 8
Total Season Available	135–170 days	175–205 days
Effective Well Operations Season	75–110 days	145–160 days

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CONTACT



**U.S. Department of Energy
Office of Fossil Energy**
1000 Independence Avenue, SW
Washington, DC 20585

Arthur M. Hartstein
(301) 903-2760
arthur.hartstein@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov



TECHNOLOGY

Locations: Alaska's North Slope

North Slope Operations

SUMMARY

North Slope oil and gas operations showcase a number of technological triumphs over powerful natural forces, enabling successful operations in this extreme, sensitive environment. Since these resources represent nearly a quarter of U.S. oil reserves, the need to access them has accelerated development of environmentally responsible, cost-effective practices and technologies. For instance, the difficulties of winter exploration have been mitigated by innovations such as ice roads and ice pads that have no lasting effects on delicate tundra. Drilling advances—extended reach drilling, coiled tubing drilling, multi-lateral completions and “designer” wells—are increasing resource recovery and reducing drilling costs, footprints, and waste volumes. Today’s exploration and production facilities are radically streamlined, occupying far less surface area than operations did 25 years ago.

BLUEPRINT ON TECHNOLOGY

Technology advances protect the environment and improve recovery under hostile arctic conditions

Low-impact operations increase resource recovery, reduce costs, and protect sensitive habitats

THE LARGEST OIL field in North America, the North Slope’s Prudhoe Bay has estimated total recoverable reserves of 13 billion barrels of oil and 46 trillion cubic feet of natural gas. Alaska is also home to diverse, unique, and fragile ecosystems, inspiring extensive Federal, State, and local regulatory protection. Since the onset of the North Slope oil boom in the late 1960s, operators have been forced to develop more cost-effective, less environmentally intrusive ways to develop these

resources. For example, the exploration sector has developed innovative ice-based transportation infrastructure serving remote locations, even during winters characterized by -70°F temperatures, 20-foot snowdrifts, and limited daylight. In the 1920s, road construction by bulldozing tundra proved disastrous. After only one season, the route was impassable when the permafrost thawed. Operators turned to gravel to insulate the permafrost and stabilize roadbeds, airstrips, and drilling pads, but gravel mining and construction are expensive and environmentally harmful. In the last decade, ice-based technology has

become the new standard for exploration. Its low-cost, low-impact performance continues to be refined by techniques like ice pad insulation, which can extend drilling seasons and reduce equipment mobilization. Where ice roads are impractical, low-pressure balloon-tire vehicles haul loads, leaving practically no footprint.

Recent advances in drilling technology are increasing North Slope E&P productivity and protecting the environment. Through-tubing rotary drilling, for example, allows new wells to be drilled through the production tubing of older wells, saving time

ECONOMIC BENEFITS

Enhanced resource recovery and more efficient operations

Lower operating costs

ENVIRONMENTAL BENEFITS

Reduced surface footprints and disturbance

Protection of sensitive habitats, wildlife, and cultural resources

Greater access to resources with fewer wells drilled, through advanced drilling technology

Reduced waste volumes requiring disposal, through innovative waste management and recycling techniques



and, potentially, up to \$1 million in operating costs per well. New directional drilling tools and an advanced form of horizontal drilling (“designer wells”) permit drillers to curve around geological barriers to tap small, difficult-to-reach pay zones. Another

advanced technology is coiled tubing, which allows extended-reach, directional drilling, and multilateral completions—all major contributors to increased resource recovery, reduced costs, smaller footprints, and less waste.

METRICS

Advanced technologies have significantly reduced the footprint of North Slope operations

- If Prudhoe Bay were developed with today’s technology, its footprint would be 64 percent smaller: the drilling impact area would be 74 percent smaller, roads would cover 58 percent less surface area, and oil and gas separating facilities would take 50 percent less space.
- A new 55-acre contractor base supports ARCO Alaska’s Kuparuk field; similar facilities built over 20 years ago occupy more than 1,000 acres.
- Surface wellhead spacing has been reduced from 145 feet to 35 feet onshore and 10 feet offshore.
- Production pads are dramatically streamlined: the 1971 Prudhoe Bay “A” Pad was built with 35 wells on 44 acres; the 1989 “P” Pad was built with 21 wells on less than 11 acres.

Source: Alaska Department of Natural Resources and BP Exploration (Alaska) Inc.

CASE STUDIES

Success in the Field

Improving waste management

North Slope operators are using advanced technology to manage drilling wastes more effectively. A 1988 ARCO pilot project demonstrated that processed drill cuttings could be safely used as road construction materials, since the cuttings’ composition was essentially identical to that of native gravel and surface soils. Based on these findings, in 1990 BPXA built a prototype grinding and injection facility that recycled recovered cuttings into construction gravel, and ground remaining waste for subsurface reinjection. By 1994, refined grind-and-inject technology enabled BPXA and other Prudhoe Bay operators to achieve “zero discharge” of drilling wastes, eliminating the need for reserve pits. These innovative strategies yield significant environmental benefits—decreased waste volumes, less mining of surface gravel, smaller pad sizes, and less surface disturbance.

Restoring affected areas

The fragile North Slope ecosystem makes site restoration and habitat enhancement a vital post-production process. In recent years, BPXA and ARCO Alaska have created artificial lakes by flooding abandoned gravel mining sites. This practice, encouraged by the Alaska Department of Fish and Game, creates overwintering habitats for fish and predator-free nesting areas for waterfowl. BPXA and the U.S. Department of Fish and Wildlife collaborated to restore 10 miles of habitat along Endicott Road, demonstrating that transplanting Arctic pendant grass effectively revegetated disturbed aquatic sites. This technique was also applied at BPXA’s BP Pad, where restoration began in 1988. Within three years, native vegetation was restored.

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