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NGOTP collaboration yields oil and gas R&D benefits

Natural Gas & Oil Technology Partnership

This is the first of four articles appearing in E&P Focus this year on the Natural Gas and Oil Technology Partnership.

Collaboration on oil and natural gas research among DOE's national laboratories has yielded significant energy, economic, and environmental benefits to America.

The Natural Gas and Oil Technology Partnership (NGOTP), launched in 1988, brings together the expertise of DOE's national laboratories in collaborative projects with each other and with the Nation's oil and gas producers, service companies, and academic institutions.

Since its inception, NGOTP and its predecessor entities have been the conduit for over $86 million in DOE funding for R&D programs in oil and gas technologies. The partnership has been the hub of more than 120 projects and workshops funded by DOE. NGOTP has contributed to critical advances in seismic imaging, basin analysis, computing, drilling, completion, and production technologies.

Early stages

In its early stages, a major focus of NGOTP was to apply the national defense capabilities of the Los Alamos and Sandia national laboratories to peaceful means: the exploration and production of oil and natural gas.

David J. Borns, current co-chairman of NGOTP and geotechnology/engineering department manager at Sandia National Laboratories, recalls the partnership's genesis in the late 1980s as a DOE response to an outreach by independent oil and gas producers who were whipsawed by several years of the worst market bust the industry had ever seen. The oil and gas industry had expressed an interest in benefiting from DOE laboratory expertise, equipment, and facilities and in gaining access to defense spin-off technologies that could have near-term applications in improving oil recovery.

"[New Mexico independent producer] George Yates got in touch with [New Mexico Sen.] Pete Domenici and asked how DOE could assist independents in oil recovery," Borns said, in recalling the program catalyst.

That step led to a memorandum of understanding (MOU) between the Los Alamos and Sandia labs to kick off an Oil Recovery Technology Partnership (ORTP). This initiative focused on getting input from industry up front to prioritize research needs and throughout the program to review projects, with a special emphasis on independents. George Yates's own company, Harvey E. Yates Co. (Heyco), Roswell, NM, was a participant in the first project begun under ORTP.

The program was operated through DOE's Office of Fossil Energy under the oversight and control of the agency's National Energy Technology Laboratory oil and gas program and the policy and administrative guidance of DOE's Albuquerque Operations Office. The ORTP Partnership Office was established under co-chairs Robert J. Hanold at Los Alamos National Laboratory (LANL) and David A. Northrop at Sandia.

> **"There's still a role for the labs to play [in oil and gas research], and not just to compete with each other. That's why I've held on—I'm a zealot."**
>
> *— NGOTP Co-Chairman David J. Borns*

The initial MOU called for an emphasis on seismic technology—specifically crosswell seismic—and on helping independents improve oil recovery. The first four projects, awarded in FY1989-90, were:

- Stresses and Fractures in a Low-Permeability Oil Reservoir (Heyco and Sandia), which sought to apply Sandia technologies and experience developed for tight gas sands to low-permeability oil reservoirs in the Permian Basin.
- Microseismic Monitoring of the Chaveroo and Tomahawk Oilfields, New Mexico (Murphy Operating Corp. and LANL), which was designed to overcome premature water breakthrough by using microseismic monitoring to determine the location and prevalent orientation of fractures.

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- Development of a Multi-Station Borehole Seismic Receiver (OYO Geospace and Sandia), which called for designing, developing, and field-testing a multi-station, three-component borehole seismic receiver for improved crosswell seismic surveying.
- Imaging the Faults in the McKittrick Oilfield (Texaco USA, Chevron Oil Field Research Co., and LANL), which focused on evaluating crosswell surveying technology for delineating saturation boundaries and complex faults controlling production in a large producing sand in central California.

NGOTP evolves

The ORTP later spread its focus to concentrate on three general areas: Drilling and Production, Oil Recovery, and Crosswell Seismic.

Drilling and Production evolved into Drilling and Completion Technology. Then the Drilling, Completion, and Stimulation (DCS) area was added to the partnership in 1992. DCS currently focuses on developing and demonstrating innovative drilling, perforating, and fracturing processes; subsurface instrumentation; and advanced software.

Crosswell Seismic was renamed Borehole Seismic Technology, which eventually begat Diagnostic and Imaging Technology. Research in this area strives to improve exploration and reservoir characterization through advances in borehole geophysics and seismic processing and imaging.

In 1994, Oil Recovery gave way to Oil and Gas Recovery, as the partnership's scope was expanded to include natural gas exploration and production research. That effort also prompted a switch to the partnership's current name. In the same year, Lawrence Berkeley (LBNL) and Lawrence Livermore national laboratories joined NGOTP.

The following year saw saw the addition of Argonne, Brookhaven, Idaho (INL), Pacific Northwest, and Oak Ridge national laboratories to the partnership.

Computational Technology became the fourth technology area of the partnership in 1995, although that proved short-lived, as the computational technologies projects later were folded into the three main technology areas.

NGOTP subsequently added Upstream and Downstream Environmental technology areas in 1997-98 and organized a Natural Gas Technology area in 2002 with two subtopic areas: Gas Storage and DCS (which focused on gas drilling, completion, and production success in harsh-reservoir environments).

Today, NGOTP is the home for more than 50 active projects. Any natural gas or oil producer, refiner, or service company is eligible to participate in the partnership, provided the participant teams with a national lab. Universities and other research institutions also may join project teams. The program is entirely industry-driven, in that it establishes active industry interfaces through review panels and forums that define industry needs, provide annual project reviews, and determine the priority of new proposals and ongoing projects.

Partnership perspective

Borns, who succeeded Hanold and Northrop in 1998, said NGOTP always has been viewed as an expanding, multi-year program.

"The rationale was to devevelop a fast, flexible, and simple program that was industry-focused," he said.

There also were areas where the various labs' strengths would dovetail to the benefit of the research. Borns cited a $1 million-per-year project in which an independent requested that several of the labs work together on a project involving single-borehole seismic technology: LANL and Sandia had experience in seismic technology, LBNL specialized in microinstrumentation, and INL had developed a high-broadband capability, he said.

Apart from the synergies and complementary strengths of the national labs working together on critical technology needs that industry wasn't otherwise undertaking, the partnership helped DOE simplify its oil and gas research programs.

"Instead of all of the national labs lining up to DOE and pleading for funding, [NGOTP] was a way to prioritize their [oil and gas] research needs to DOE," Borns said.

"It also got people to work together" because of funding limits, he noted. "A single lab project could be funded at only $350,000. If you wanted more for your project, you had to work with another lab."

About 5% of partnership funding went to the national labs for overhead expenses—including running the industry committees—related to NGOTP projects, he noted.

NGOTP successes

On balance, however, Borns points proudly to the partnership's research successes overshadowing the few bumps in the road. He cited important technology advances made in the areas of 3-D seismic, polycrystalline diamond compact bits, characterizing diatomaceous oilfields in California, drill cuttings injection, tiltmeter technology for monitoring hydraulic fractures, early microhole efforts, and optimizing algorithms for massively parallel computing in oil and gas applications.

Success has marked the program from the beginning. Borns noted that Heyco was able to double production from the Shoestring sands of the Delaware Basin in West Texas as a result of NGOTP research.

He also pointed to BP USA's kudos for NGOTP's Gulf of Mexico wellbore stability research, to which the company attributed savings of more than $30 million in its deepwater Gulf of Mexico oil and gas development program.

Borns sees continuing value in collaboration on oil and gas research: "Our focus shouldn't be as competitors on technology. There is still a lot of [collaborative] research that can be done that's of value to the oil and gas industry,"

He cited deepwater oil and gas, deep gas, and oil shale as prospective areas for new and continuing collaborative research among the national labs.

The longtime advocate of NGOTP acknowledges his continuing role with the partnership has evolved into a "part-time, gratis" role versus his earlier years with it, when "for a while, it took over my career.

"There's still a role for the labs to play [in oil and gas research], and not just to compete with each other," Borns added. "That's why I've held on—I'm a zealot."

Revolutionary 'smart' drill pipe creates 'downhole Internet'

A U.S. Department of Energy-funded technology has been commercialized that establishes a "downhole Internet" for drilling oil and natural gas wells.

The technology turns ordinary drill pipe into a two-way highway for transmitting drilling and formation data at blazing speed from bottomhole to the surface and vice-versa. Potential benefits include decreased costs, improved safety, and reduced environmental impacts of drilling.

Grant Prideco, a leading drill pipe manufacturer, announced the commercial launch of its IntelliServ® Network and related Intellipipe® technology at a press conference in Houston, TX, in February. Contract talks already are underway with several major oil and gas operators. The announcement caps 5 years of research under a project sponsored by DOE and managed by DOE's National Energy Technology Laboratory.

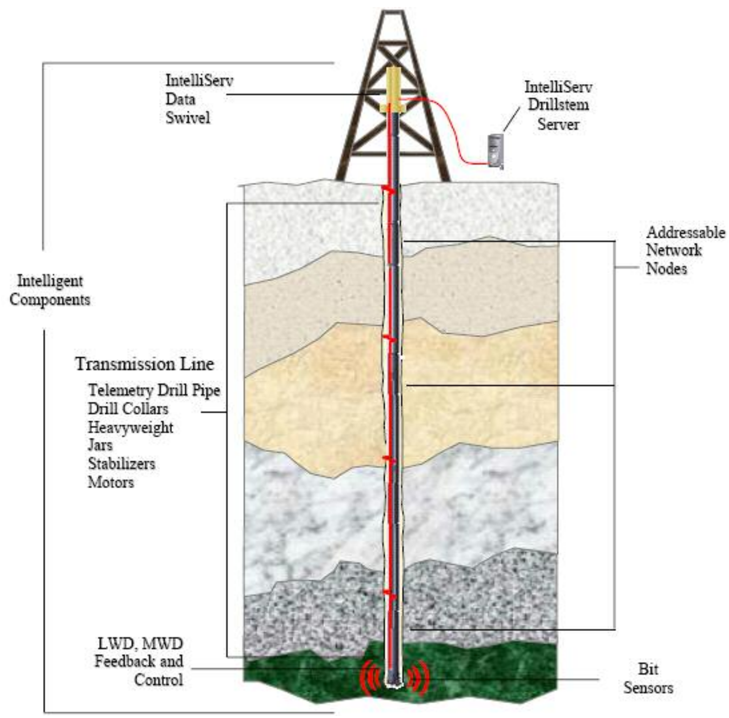
For decades, the "Holy Grail" of drilling has been the ability to "look ahead" of the drillbit: gathering a wide range of downhole data—pressure, temperature, well position, formation characteristics, etc.—in as close to "real" time as possible.

Until now, no method of hard-wiring pipe with electrical wire connections to transmit these data has proven reliable. The couplings that connect the jointed drill pipe were a barrier; manipulating the drill pipe downhole usually broke the electrical connection.

DOE-funded technology provided a partial answer 30 years ago, with the invention of mud-pulse telemetry. But the pace of this data transmission method is glacial at 3-10 bits per second, which typically yields poor-quality data and hobbles a driller's ability to make crucial decisions quickly.

Intellipipe® accelerates that transmission rate exponentially—to 57,000 bits per second. An IntelliServ® network upgrade would boost that to a staggering 1 million bits per second. Not only can a driller receive crucial downhole information quickly with Intellipipe®, he can immediately "tell" a drilling tool what to do thousands of feet below the surface.

Having this real-time capability reduces economic and safety risk in drilling wells while it minimizes the number of wells needed to produce oil or gas from a reservoir. It also cuts down on the number of unplanned trips downhole to resolve drilling problems and eliminates the associated non-productive time and well costs.



Intelliserv® system.

Here's how it works: Intellipipe® features high-speed, high-strength data cable embedded in the inside wall of the drill pipe. These cables carry data to small induction coils that are installed in protective grooves machined into the couplers. When two sections of Intellipipe® are joined, the induction coils are placed close together, and a low-energy data signal can transmit passively between them without a dedicated power source—from one pipe section to another, along a string of tens of thousands of feet of drill pipe. There is no physical connection to break.

The system already has proven remarkably reliable in extensive U.S. and Canadian field trials. Since 2004, Intelliserv® drill strings of 14,000 feet in Oklahoma and 10,000 feet in Alberta have drilled 18 wells, accumulating more than 6,000 hours of operation while drilling 180,000 feet.

In addition, measurement-while-drilling and logging-while-drilling tools were deployed in these field trials, demonstrating the Intelliserv® network's ability to transmit high-volume data continuously from a wide variety of tools. Such a high-speed network also serves as an enabling technology for even more sophisticated diagnostic tools not yet on the market.

At the same time, being able to deploy a real-time downhole data transmission network lets drillers process more of the well and formation data at the surface rather than downhole; this allows them to use much lower-cost, more-rugged downhole sensors. The upshot: a dramatic cost reduction for oil and gas companies tackling the increasingly difficult and harsh drilling environments of today.

Novatek Engineering, Provo, UT, developed the Intellipipe® technology under a DOE-funded project. Grant Prideco, Houston, TX, subsequently formed a joint venture with Novatek to market the revolutionary drill pipe; Grant Prideco now owns the Intelliserv® Network 100%.

The first commercial deployment of the technology is expected to occur in the North Sea, with an application that could break extended-reach drilling records. That would put it at about 5 miles—beyond the current capability of mud-pulse technology to gather data and control wells.

In its final report to DOE after wrapping up its research project, Novatek commended the agency's participation as being essential to the development of Intellipipe® technology.

"Particularly in the early stages of the development effort, the risk was very high, and industry motivation to invest in such a giant leap forward was low," the report stated. "DOE vision and willingness to be involved in this technology has provided Novatek with the needed resources to get past the early stages and to develop the necessary technology."

DOE project breathes new life into aging California giant

A U.S. Department of Energy-funded research and technology development project has breathed new life into one of America's biggest mature producing oilfields.

The project is expected to add ultimately 13 million barrels of incremental oil production in a small portion of Wilmington oilfield, a 73-year-old giant in the heart of Long Beach, CA. If the new technology and innovative techniques developed under the project are applied field-wide, it could result in boosting Wilmington's ultimate oil recovery by 525 million barrels of oil. Achieving that jump in a single oilfield equates to a 2.5% increase in total U.S. proved oil reserves. An aggressive effort to transfer this technology could boost reserves in similar fields along the California coast by 1.4 billion barrels of oil.

Giant's history

Wilmington, discovered in 1932 and the third largest oilfield in the contiguous United States, has ultimate recoverable reserves estimated at 3 billion barrels of oil and cumulative production to date of 2.5 billion barrels. Expansion field-wide of technology and techniques developed under the DOE project could more than double Wilmington's remaining proved reserves.

The project, managed by DOE's National Energy Technology Laboratory, originally had envisioned an increase in production in that targeted portion of Wilmington field from 8,000 barrels per day of "heavy," or highly viscous, oil in 2005 to 9,600 barrels per day in 2010. A drilling program based on lessons learned from the DOE research already has hiked oil production in the target area from 6,100 barrels per day in 2002 to an average 8,793 barrels per day in November 2005—a level researchers didn't expect to achieve before late 2007. Expectations now are that the project will reach almost 10,000 barrels per day by the end of this year.

A small, independent producer, Long Beach-based Tidelands Oil Production Co., operates the western portion of the field as a subcontractor to the field owner, the City of Long Beach. Wilmington has been one of Southern California's mainstay producers for decades, currently producing 46,000 barrels of oil per day from 1,550 wells. The field lies in a 13-mile-long geologic structure that extends from the onshore community of San Pedro along Los Angeles Harbor across Long Beach to offshore Seal Beach in the Long Beach Harbor area. Of special concern are ecological sensitivities in a heavily populated coastal area of a state widely regarded by industry as having the world's most stringent environmental regulatory regime.

Since 1932, more than 3,400 land-based wells have been drilled in the western portion of Wilmington oilfield. By the 1950s, that portion of the field had been completely developed under primary recovery, and waterflooding was started in order to increase recovery and control subsidence. These efforts were followed by a long program of steamflooding.

Steamflooding, typically an expensive process, had been economic in Wilmington field even when oil prices were low, because the operators had access to a low-cost source of steam from a nearby power plant. However, inexpensive steam isn't expected to be available to Wilmington operations in years to come, as the power plant has shut down. Future expansion of thermal recovery to other parts of Wilmington field depends on improving the efficiency and economics of heavy oil recovery apart from the steam source.

DOE project details

Tidelands' project called for using advanced reservoir characterization and thermal production technologies together with horizontal drilling to improve the efficiency of a deep, heavy oil steamflood in Wilmington field. The main producing horizon at Wilmington is a reservoir characterized as slope-and-basin clastic (SBC).

The DOE-funded project addressed several producibility problems in two large portions of Tidelands' operating area that are common to SBC reservoirs. Difficulties with oil recovery arose frequently because the targeted Wilmington formations are relatively deep, high-pressured, and heterogeneous compared with those found in thermal EOR projects elsewhere in the state.

Among many other innovations, Tidelands developed:

- An advanced computer model to simulate the Wilmington reservoir, which it used to optimize steam, hot water, and water injection with oil production efforts without causing surface subsidence—a perennial problem in the field.
- A series of operational changes based on

Location of Wilmington oilfield.

the new reservoir model to improve heat efficiency, reduce costs, and expand steamflood operations.
- New horizontal steamflood pilots, with the aid of new 3-dimensional computer models.
- A novel alkaline-steam well completion technique that controls excessive production of sand in the wellbore, cutting capital costs by 25%.
- New ways to reduce the formation of scale minerals in the producing wellbores, further trimming well costs.
- A new, commercial technology to scrub out deadly hydrogen sulfide gases created in the steamflood at a 50% cost reduction.
- A new steam generator that can burn a variety of low-quality waste gases created by the thermal EOR operations.

Project benefits

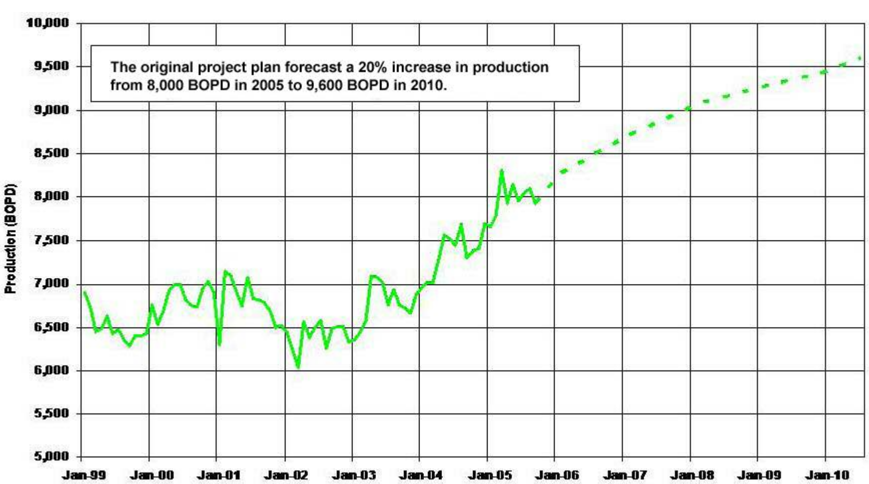
As a result of these innovations, Tidelands in 2003-2005 enjoyed the most successful round of drilling in the Wilmington onshore field area in 20 years. The company attributes these successes to technologies transferred from earlier DOE reservoir-class research. Several of these technologies have since been commercialized by service companies, been adopted or further researched by other oil companies, or used by Tidelands in other operating areas. The company said it expects some of its innovations to spread to other operators in the Los Angeles Basin, one of the Nation's most prolific—yet high-cost and environmentally sensitive—producing areas.

The project, entering its final phase, started up in 1995 and is slated to end early in 2007. DOE funding is expected to account for 40% of the project's estimated total cost of more than $20 million.

NETL project manager Jim Barnes, based in Tulsa, OK, noted that two significant companies have started up as a result of the project: Dynamic Graphics, Inc. (DGI), Alameda, CA, and Geomechanics International, Inc. (GMI), Houston, TX.

"DGI started expansion in the mid-1990s after they realized the effectiveness of 3-D modeling in describing a complex reservoir and oilfield such as Wilmington; since then, they have become a 3-D modeling provider of choice to small and mid-size California independent operators who have seen the value of this technology for complex reservoirs," Barnes said. "Tidelands teamed with Stanford and the University of Southern California during many of their investigative efforts; GMI was a company during this time that came out of Stanford researchers, who developed dipole acoustic/sonic [well] logs calibrated to accurately measure porosity and oil saturation through acoustic wave technology."

A pumpjack working in giant Wilmington oilfield in the Long Beach, CA, area. The large, wrapped pipeline in the foreground is a steamline.



Wilmington project area daily production history and forecast.

Tidelands' Wilmington project is one of a number that DOE supported in its Reservoir Class Oil Field Recovery program. Begun in 1991, the program targeted geologic classes of U.S. oilfields that were on the verge of being prematurely abandoned. With federal matching funds allowing higher-risk technologies to be tried, many operators have been able to keep oil flowing from these fields long after conventional wisdom labeled them "depleted."

There are many other large, mature SBC reservoirs in the U.S., notably elsewhere in California and in the Gulf of Mexico. With the new technologies and innovative techniques emerging from Tidelands' ambitious project at Wilmington, other venerable U.S. oilfield giants can win a new lease on life as well.

Crucial well slated to test Alaska methane hydrate resource

A DOE-funded research project has taken another important step toward determining the technical and economic viability of Alaska's methane hydrate resource.

Success in this project could help lay the groundwork for unlocking a resource that could be an important contributor to future energy demand.

BP Exploration Alaska Inc. has filed with state authorities a plan of operations for drilling a stratigraphic test well to probe a large hydrate resource on the Alaskan North Slope (ANS). BP is studying possible gravel pad sites for the summer, with an eye to spudding the well during the 2006-2007 winter drilling season.

The stratigraphic well—and the data it acquires—is the critical next step in a 5-year, nearly $25 million research project to gauge the potential for ANS methane hydrate to become part of the Nation's energy supply portfolio.

The ultimate payoff could be huge. The U.S. Geological Survey (USGS) has postulated that 44-100 TCF of methane hydrate in-place underlies the North Slope oilfield infrastructure in the Eileen and Tarn trends (see map). The overall North Slope hydrate resource is pegged at 590 TCF.

The research project delineated more than a dozen drillable hydrate prospects containing more than 600 billion cubic feet of gas within the North Slope's Milne Point Unit (MPU) alone. Extending these findings throughout the greater Prudhoe Bay area yields an estimated 33 TCF of original-gas-in-place in the Eileen Trend. Reserve modeling indicates commercially viable production is possible, with as much as 12 TCF in the greater Prudhoe Bay area technically recoverable with tailored applications of mostly existing extraction technologies.

That number may not seem large in light of a remaining technically recoverable U.S. natural gas resource estimated at 1,400 TCF. However, with a total U.S. in-place hydrate resource of 200,000 TCF, even a 2.5% recovery rate puts the postulated recoverable domestic hydrate resource base at 5,000 TCF. That's more than double the combined cumulative production and remaining technically recoverable resource of domestic natural gas. America's remaining proved gas reserves total 190 TCF.

The knowledge obtained in the BP strat test could be one of the critical first steps to unlock that massive potential contribution to America's gas supply.

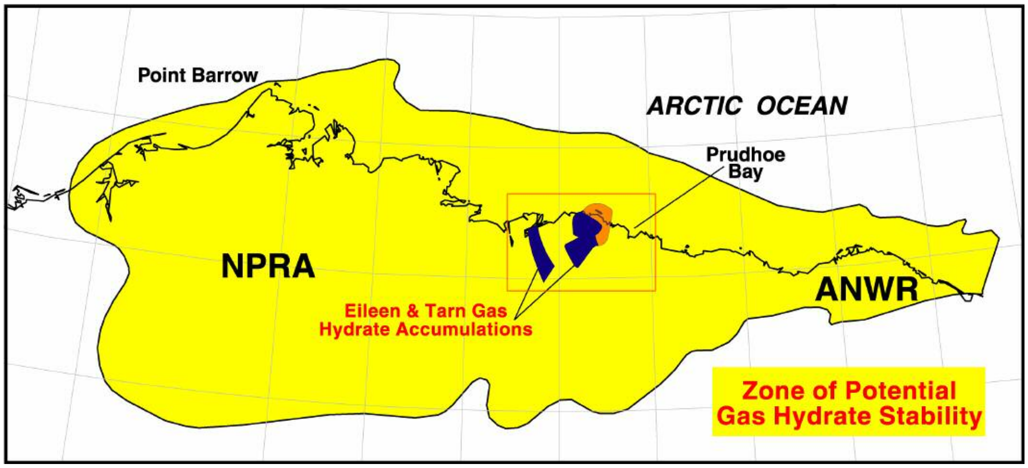
Background

In 2000, BP proposed donating a state-of-the-art 3-D seismic survey over its MPU production area. This was to provide a starting point for fully evaluating the feasibility of commercial production from arctic hydrates.

The project's first phases were designed to integrate detailed geophysical interpretation and modeling, regional geologic characterization of the prospective hydrate-bearing units, and advanced reservoir and economic modeling to choose a site for drilling, coring, and production testing.

The near-term goal is to test the science—the tools and techniques—of delineating hydrate prospects, and then to model their potential productivity and commerciality. If the project proceeds through all four proposed phases, the end result will be the world's first extended production test of a gas hydrate reservoir. The idea is to glean insights into the relative merits of various production and stimulation approaches that have been considered for this vast but elusive resource.

DOE participated in two other important North American Arctic wells that have contributed to industry's body of knowledge on hydrates. The Mallik hydrate drilling program, undertaken in 2002 on the Mackenzie Delta in Canada's Northwest Territories, conducted several brief experiments that confirmed that producing gas from hydrates is technically feasible. The Hot Ice No. 1 well, drilled in 2003-04 in the Kuparuk River oilfield area, failed to encounter hydrates but yielded a wealth of information for researchers.



Alaska North Slope methane hydrate estimated in-place resource totals 590 trillion cubic feet.
Source: U.S. Geological Survey

Project details

Having completed the first two phases of the project, BP launched Phase 3 in October 2005.

This latest phase includes the drilling of one or more wells through the hydrate stability zone, with comprehensive petrophysical analyses of targeted zones. The plan of operations BP submitted to Alaska's Department of Natural Resources/Division of Oil and Gas at the end of January 2006 calls for drilling the Mt. Elbert-01 gas hydrates stratigraphic well a half-mile east of the MPU E pad, about 28 miles west of Deadhorse, AK.

This drilling will test various geophysical exploration techniques in order to select target zones and field parameters for the fourth and final phase: production testing. Moving on to Phase 4 depends on Phase 3 results and the approval of both DOE and BP.

DOE is providing about $19 million in funds for the cooperative agreement with BP and managing the project through its National Energy Technology Laboratory.

Other project partners include ASRC Energy Services, University of Alaska-Fairbanks, University of Arizona, USGS, Interpretation Services, Ryder-Scott Co., and APA Petroleum Engineering.

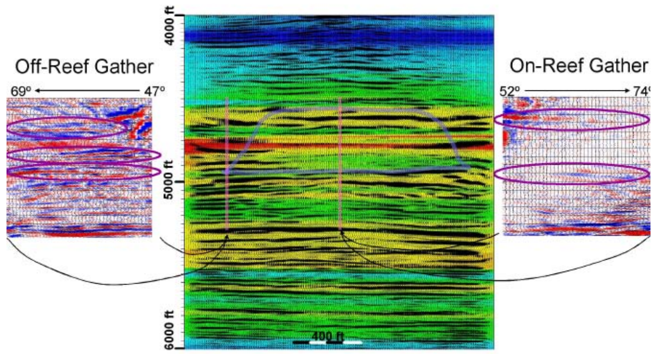
Progress reported in Michigan crosswell seismic project

A DOE research project is advancing the science of crosswell seismic—a novel technique for imaging oil and gas reservoirs in high resolution by using existing boreholes.

By lowering the seismic signal generator and receiver into the boreholes, crosswell seismic eliminates much of the subsurface interference that diffuses the signals. This technique can delineate images as small as 5 feet across, compared with about 50 feet for conventional surface seismic.

Project performer Michigan Technological University, Houghton, MI, is now processing and analyzing data it recently acquired to obtain a high-resolution crosswell image of a producing carbonate reef in northern Michigan.

If proven successful, the project results will help operators of carbonate reefs—a common reservoir type in the United States—to use their existing boreholes to image the reservoir. This has the potential to add billions of barrels to U.S. oil and gas reserves without the added environmental impact of dedicating new wellbores to seismic sensor emplacement.



The processed crosswell seismic image is shown in color, with colors representing seismic velocities, and the overlay showing the seismic reflection traces as wiggles with positive values blackened.

Michigan Tech, together with partner Z-Seis Inc., Houston, TX, bracketed the target reservoir with a seismic source in one well and a string of receivers in another. Like many other carbonate reefs, this reservoir has a low recovery rate. High-resolution imaging of the reef and thousands of others like it will enable operators to recover a much greater percentage of the original-oil-in-place, while minimizing the expense and environmental impact of added wells.

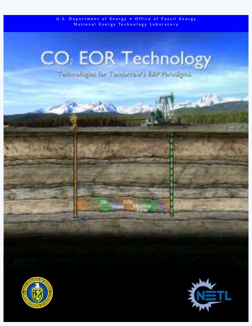
Researchers described the initial data set quality as "extraordinarily good," delineating the internal structure of the reef. The data are being interpreted in terms of amplitude-versus-angle (AVA) in order to find relationships with lithologic facies and fluid content. The high frequency content of the data requires added processing in order to "flatten" events prior to stacking. Some events are lost in stacking due to the resolution of the data exceeding the resolution of the velocity model, but these will be recovered as part of the AVA study.

Michigan Tech has begun talks to acquire a second data set in another producing field in Michigan in order to refine the technique.

DOE is funding about 80% of the $900,000, 3-year project under its Advanced Diagnostics and Imaging research area.

E&P SNAPSHOTS

The Department of Energy has launched a solicitation to fund new research in technologies that entail injecting carbon dioxide (CO_2) to boost recovery of the Nation's oil and natural gas resources while also serving to safely store CO_2, rather than emit the greenhouse gas into the atmosphere. The DOE solicitation supports producers of oil and gas in carrying out enhanced oil and gas recovery projects to inject CO_2 in order to improve oil or gas recovery while increasing sequestration of CO_2. The projects will be managed through DOE's National Energy Technology Laboratory (NETL). Details of the solicitation and of **DOE's current portfolio of CO_2 projects are provided in a new brochure NETL has published**. It can be downloaded free at NETL's online reference shelf, under Technologies/Oil and Natural Gas Supply, at **www.netl.doe.gov**.



About 110 representatives of large and small oil and gas producers, supporting industries, and academia attended the February 22 **Pre-Proposal Workshop for the Funding Opportunity on Enhanced Oil and Natural Gas Production through Carbon Dioxide Injection**. Facilitated by the Petroleum Technology Transfer Council, the interactive meeting provided potential proposers with information contained in 10 basin-oriented, CO_2 EOR assessments developed in cooperation with NETL and on state-of-the-art technologies for resource characterization, imaging, modeling, and mobility control, as well as supply and recycle operations and monitoring. While most participants came from the Houston area where the workshop was held, almost half came from Canada and 14 other States as far as Alaska, North Dakota, and Montana. Mandated under the Energy Policy Act Section 354, the funding opportunity seeks project proposals by May 5 for the enhanced recovery of oil or natural gas in conjunction with the sequestration of CO_2.

On January 30-31, NETL's **Arctic Energy Office (AEO)**, in conjunction with University of Alaska-Fairbank's (UAF) Arctic Energy Technology Lab, had its first annual review presentation in Anchorage, AK. Twenty-three presentations on ongoing UAF and AEO projects were given, including reports on CO_2 sequestration, Cook Inlet gas demand, Beluga coal gasification, Arctic lakes, rural coalbed natural gas, low-rank coal grinding, Bristol Bay gas and oil potential, and the International Polar Year.

Calendar of Events/2006

Apr. 4-5
SPE/IcoTA, *Coiled Tubing & Well Intervention Conference & Exhibition,* The Woodlands, TX.
Contact: www.spe.org.

Apr. 9-12
AAPG, *Annual Convention*, Houston, TX.
Contact: www.aapg.org.

Apr. 22-26
SPE, Improved Oil Recovery Symposium, Tulsa, OK.
Contact: www.ior2006.org.

May 1-3
IOGCC, *Midyear Meeting,* Point Clear, AL.
Contact: www.iogcc.state.ok.us.

May 1-4
SPE, *Offshore Technology Conference,* Houston, TX.
Contact: www.otcnet.org.

May 18
IADC, *Drilling Onshore America Conference & Exhibition,* Houston, TX. Contact: www.iadc.org.

June 12-14
IPAA, *Midyear Meeting,* Naples, FL.
Contact: www.ipaa.org/meetings.

June 12-16
API, *Exploration & Production Standards Conference on Oilfield Equipment & Materials,* Atlanta, GA.
Contact: www.api.org/events.

Sept. 20-22
IADC, *Annual Meeting,* San Antonio, TX.
Contact: www.iadc.org.

Sept. 25-27
SPE, *Annual Technical Conference & Exhibition,* San Antonio, TX. Contact: www.spe.org.

Oct. 1-6
SEG, *International Exposition & Annual Meeting,* New Orleans, LA. Contact: www.seg.org.

Oct. 15-17
IOGCC, *Annual Meeting,* Austin, TX.
Contact: www.iogcc.state.ok.us.

Oct. 23-25
IPAA, *Annual Meeting,* Grapevine, TX.
Contact: www.ipaa.org/meetings.

Nov. 28-29
IADC, *Drilling Gulf of Mexico Conference & Exhibition,* Houston, TX. Contact: www.iadc.org.

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