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Technology Developments in Natural Gas Exploration, Production and Processing

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CONTENTS

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Collaboration Important to E&P Research

The energy industry, on both individual and corporate levels, is continuing to find new ways to collaborate in the face of continued pressure to lower costs and improve performance. Recently, the Society of Petroleum Engineers, the American Association of Petroleum Geologists and the Society of Exploration Geophysicists—organizations where the average age of the membership has been increasing yearly—have begun offering automatic, Associate Member status to members of each of the other groups. (Engineers joining AAPG will be required to wear plaid shirts and hiking boots instead of a shirt and tie, every other Tuesday.) Major producers that once guarded their research programs as jealously as their well logs, are joining with their competitors and service suppliers to leverage the research funds they still choose to spend.

Research consortiums are not new. The DeepStar project, a consortium of 15 oil companies and 48 service-supply companies, has sponsored research related to deepwater production technologies since 1991. But such consortiums are providing an increasingly larger share of the industry's overall E&P research investment as producing company R&D spending continues to decline. According to the Energy Information Agency, E&P company R&D expenditures in 2000 were less than half of what they were in 1990 and only a third of their 1982 peak. Often, consortia are catalyzed with government dollars. For example, a group made up of *Shell, Statoil, Halliburton,* and *Petrotech* recently began researching a downhole testing method that could eliminate the need for flaring, with financial aid from the Research Council of Norway. The number and relative contribution of groups such as these will only increase.

Two of the stories in this issue of *GasTIPS* deal with examples of such collaboration. The first provides an update on an effort by the Department of Energy's (DOE) Strategic Center for Natural Gas to broaden and deepen our understanding of methane hydrate. One portion of that effort involves a Joint Industry Project (JIP) among producers and service companies to learn more about methane hydrate accumulations in the Gulf of Mexico.

The second describes a consortium of industry partners that jointly identify technologies that can benefit stripper oil and gas wells. The Stripper Well Consortium then implements DOE cost-shared research to develop those technologies.

In the first example, high tech tools are being used to characterize what could become a prime source of natural gas for economies of the future. In the second case, relatively low-tech solutions are being used to coax the last bit of hydrocarbons out of the wells of the past. In both cases, companies are teaming with each other and government to maximize the results of their R&D investments.

Three other articles in this issue cover a wide range of topics, from research efforts that target tight gas sands in the Rocky Mountains, to the results of laser drilling, to liquefied natural gas (LNG). One topic that has not been dealt with before in *GasTIPS* is LNG. Here we present a summary of the outlook for LNG in the United States by Dr. Colleen Taylor Sen, a well known expert on the topic who has edited the annual *Gas Technology Institute World LNG Source Book* for a number of years and more recently, *A Review of the Global LNG Shipping Industry 2002.* While imported LNG still accounts for a relatively small portion of the domestic gas supply, its role is clearly growing.

We trust you'll find this issue of *GasTIPS* informative. Please contact the individuals listed at the end of each article to obtain more information on specific topics. If you have any other questions or comments, please contact the Editor, Karl Lang, at klang@chemweek.com/.

The Editors

Laser Drilling: Understanding Laser/Rock Interaction Fundamentals

By Brian C. Gahan
Gas Technology Institute

The task of researchers is often to re-evaluate our fundamental assumptions. Is mechanically breaking rock the best way to drill a hole? Lasers may provide an alternative.

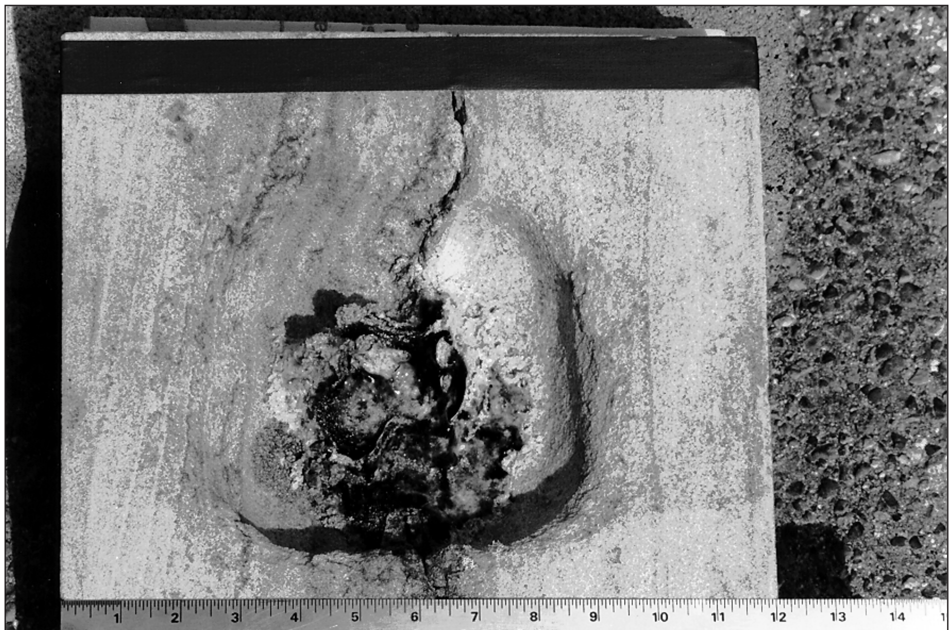


Figure 1: A Berea Sandstone Target after a 4.5 Second Burst From a 900kW MIRACL Laser

Laser technology is everywhere today, from the checkout line at the grocery store (laser scanners), to the doctor's office (laser surgery), to the dashboard of your car (CD players). While these examples of lower power lasers are well recognized, higher power versions (such as carbon dioxide lasers) are finding industrial applications where there is a need to cut steel and other materials cleanly and quickly. The appeal of a method for quickly cutting through hard things has not been lost on drillers. It can cost a half-million dollars to drill a new gas well on land using rotary systems, and more than $4 million for an offshore well. A laser drilling technology that could cut these costs significantly, by increasing the rate of penetration or reducing the time spent tripping pipe or retrieving information, could translate into increased reserves, increased cost-savings, and increased profitability. Laser technology could also conceivably play an important role in horizontal drilling, clearing debris from wellbores, and perforating casing.

Driven by this vision, laser drilling research carried out over the last five years has begun to build a basic understanding of how rocks react to lasing. Work currently underway is adding to that, while an effort is concurrently being mounted to develop a consortium of industry partners for further research and development.

Initial Research Helped Formulate Basic Questions

From 1997 to 1999, the Gas Research Institute (one of GTI's predecessor companies), teamed with the Colorado School of Mines, the U.S. Department of Energy (DOE), the US Army, the US Air Force, and three subcontractors to pursue fundamental research on the laser drilling concept (see *GasTIPS*, Winter 1998/1999 issue).

The team tested three military laser systems on more than 200 samples of shale, limestone, and sandstone, finding that these state-of-the-art lasers have enough power to cut rock perhaps 10 to 100 times faster than rotary drills. In one "brute force" test, a six-inch laser beam removed six pounds of sandstone in four seconds (Figure 1).

Based on the positive results of that fundamental work, GTI, the DOE's

National Energy Technology Laboratory (NETL), *Petroleos de Venezuela-INTEVEP SA, Halliburton Energy Services,* Colorado School of Mines, and DOE's Argonne National Laboratory conducted more research during 2000 and 2001. This work explored some key issues:

- How much energy is needed to remove a volume of rock?
- Does pulsing the laser increase the rate of penetration?
- Can a laser beam operate in the presence of drilling fluids or will too much laser energy be wasted vaporizing mud, rather than penetrating rock?

The answers were encouraging enough to proceed to the next phase of research, launched in March 2002 and scheduled to run through February 2003. During this time frame, GTI and its partners are determining how lasers and rocks behave under simulated downhole conditions, evaluating more precisely how various factors affect the amount of energy needed to break the rock, and developing a model of the laser drilling process to guide future technology development.

In parallel, GTI is seeking industry partners for a consortium that will begin designing a "concept" system and address specific issues. For example, significant effort will likely be needed to devise the most efficient and effective energy transmission system to carry the laser beam down into the wellbore and focus and control the beam at the point where it strikes the rock face.

Types of Lasers

HF(DF) Laser – Hydrogen fluoride (HF) and deuterium fluoride (DF) lasers operate at wavelengths between 2.6 and 4.2 m. The U.S. Army's Mid-Infrared Advanced Chemical Laser, MIRACL, was used for the first series of tests on reservoir rocks in this research project. This laser was the first megawatt-class, continuous wave chemical laser outside of the Former Soviet Union.

COIL Laser – The U.S. Air Force Research Lab's Chemical Oxygen Iodine Laser operates at a wavelength of 1.315 m. Initially developed in 1977, this high power continuous wave laser has evolved to a sophisticated level for military and now industrial applications. It has gained notoriety for its Airborne Laser (ABL) tactical capability to track and destroy missiles.

CO_2 Laser – The carbon dioxide laser operates at a wavelength 10.6 m in either continuous or pulse modes. Its average power is up to 1 MW. When operating in pulse mode, its pulse length can vary between 1 and 30 s. The significant advantage of the CO_2 laser is its durability and reliability. CO_2 lasers emit energy in the far-infrared, and are used for cutting hard materials. One of its problems is that because of its large wavelength, it is greatly attenuated through fiber optics.

CO Laser – The carbon monoxide laser operates at a wavelength of 5 to 6 m. Like the CO_2 laser, it can operate in either mode. Its average achievable power is 200 kW and pulse length can vary between 1 and 1000 s.

FEL Laser – The Free Electron Laser operates on high energy electrons that lack discrete energy levels and therefore can be tuned to virtually any wavelength in continuous wave mode. Some scientists consider it to be the high power laser of the future.

Nd:YAG Laser – The neodymium yttrium aluminum garnet laser operates at a wavelength of 1.06 m. Currently only 4 kW industrial lasers are commercially available. R&D trends indicate the feasibility of output powers of 10 kW and higher.

KrF (excimer) Laser – Excimer lasers (the name is derived from the terms excited and dimers) use reactive gases, such as chlorine and fluorine, mixed with inert gases such as argon, krypton or xenon. When electrically stimulated, a pseudo molecule (dimer) is produced. When lased, the dimer produces light in the ultraviolet range. The krypton fluoride excimer laser operates at a wavelength 0.248 m. Because the component atoms krypton and fluoride in this diatomic molecule are bound in the excited state, but not in the ground state, this laser operates in the pulsating mode. The maximum average power is 10 kW with a pulse length of 0.1 s.

Diode Laser – Unlike the Nd:YAG laser, which is a solid state laser (lasing material distributed in a solid matrix), the diode lasers or semiconductor lasers are generally very small and use low power. They may be built into larger arrays, such as the writing source in some laser printers or CD players. These lasers typically emit a red beam of light that has a wavelength between 0.630 m and 0.680 m.

Specific Energy: What Does It Take to Lase Rock?

During the 2000-2001 phase of the study, tests were carried out to measure the amount of energy required to remove material under various laser conditions. The focus was on trying to minimize the secondary effects that absorb much of the laser's power and to establish a specific energy (SE) for each sample. Specific energy is defined as the amount of energy required to remove a given volume of rock in kilojoules per cubic centimeter (kJ/cc). Similar evaluations have been carried out for conventional drilling

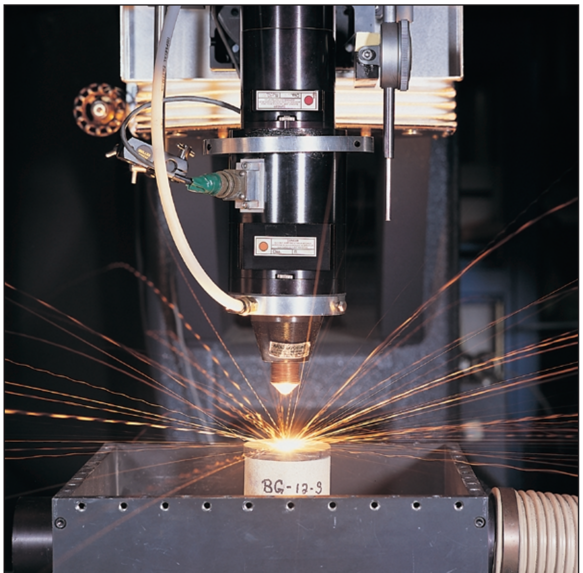


Figure 2: Experimental Set-Up Showing Nd:YAG Laser Interacting With Rock

technologies. To this end, laser parameters such as duration and power were controlled such that the lased hole diameters were larger than the depths. This, combined with a gas purging system to particles so that the laser beam was continuously hitting newly exposed rock surface, provided what was felt for a reasonably good measure of SE for each sample.

A series of initial tests to determine sample SE using the CO_2 laser at Argonne National Laboratory under continuous wave conditions, revealed that the CO_2 laser went from merely scorching the rock to melting it as power was increased. In order to measure the SE, the laser needed to be operated at a level between these two extremes where thermal spallation takes place. Lasers remove rock through thermal spalling (chipping of rock material through temperature and pressure fluctuation), melting, or vaporizing. Thermal spallation is the most efficient rock removal mechanism in that it exhibits the lowest specific energy. Based on these preliminary tests, the experiments were modified to focus on the pulsing capabilities of a 1.6 kilowatt neodymium yttrium aluminum garnet (ND:YAG) laser (Figure 2). A series of linear tests were performed on sandstone, shale and limestone samples (Figure 3). For each combination of peak power, pulse width and repetition rate, a spalling-only zone was clearly visible. The power density of that zone was used as the boundary of the test matrix developed to determine the SE for each lithology.

The laser beam power density required for producing thermal spallation zones were determined to be around 920 watts per square centimeter (W/cm^2) for Berea Grey sandstone and 784 W/cm^2 for shale. In limestone it appears that the hole is made by thermal dissociation ($CaCO_3$ to CaO and CO_2) instead of the breaking of bonds between grains or within mineral crystals as is seen in sands and shales, so there are fewer opportunities for secondary effects to cloud the results. Secondary energy absorbing mechanisms (melting, vaporization and dissociation, and fracturing caused by thermal expansion) divert beam energy from directly removing rock and preclude an accurate measurement of SE. As laser power is increased, two rock removal zones, spallation and melting, can be identified. In the shale sample data, for example, the lowest SE occurred at the point just prior to melting (Figure 4).

Studies of the effects of various Nd:YAG laser parameters on the

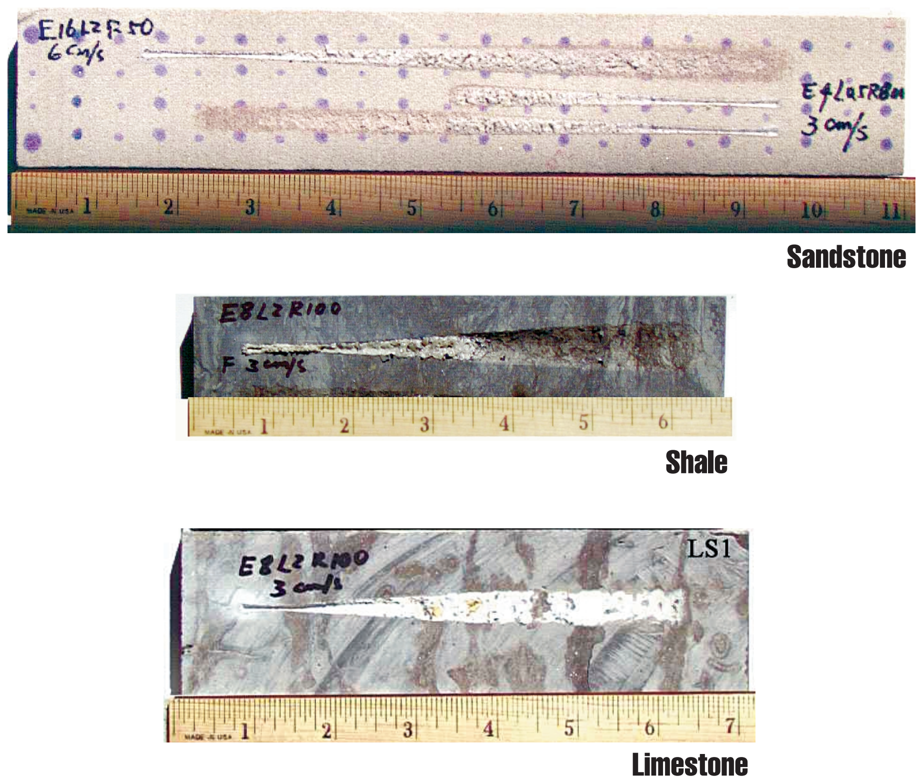


Figure 3: Test Tracks Showing Laser-Rock Reaction Zones Across a Range of Calculated Power Densities

specific energy for samples of shale, limestone, and sandstone revealed:

- Measured SE increases very quickly with beam exposure time indicating the effects of energy consuming secondary processes.
- Shale samples recorded the lowest specific energy values as compared with limestone and sandstone.
- As both laser pulse repetition rate and pulse width increase, the specific energy decreases, however, pulse width is a more dominant mechanism for reducing the specific energy than the pulse repetition rate.
- Each rock type has a set of optimal laser parameters to minimize SE.
- Rates of heat diffusion in rocks are easily and quickly overrun by absorbed energy transfer rates from the laser beam to the rock. As absorbed energy outpaces heat diffusion, temperatures rise to the minerals' melting points and beyond, quickly elevating SE values.
- Sandstones saturated with water cut faster. More rock can be removed before melting commences.
- A laser is able to spall and melt rock through water.

The SEs measured were highest for limestone at 20-50 kilojoules per cubic centimeter (kJ/cc), 10 to 20 kJ/cc for sandstone, and lowest for shale at 0.5 to 2 kJ/cc. To put this in context, a specific energy of 10 kJ/cc means the energy required to lase away, under ideal conditions, the equivalent of a 10,000 foot, 7 inch diameter hole of this material, is equal to the energy in 222 barrels of diesel fuel.

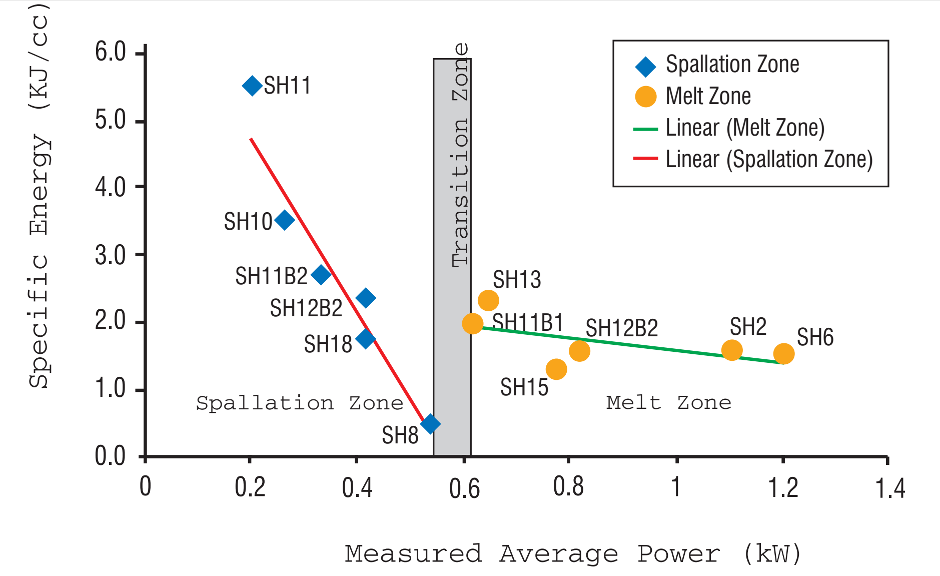


Figure 4: Plot of Specific Energy as a Function of Average Power for a 0.5 Sec Exposure

Current Efforts Build On Results

During 2002 and early 2003, a number of areas will be investigated in more detail. First, a more detailed determination of the spallation/melting zone interfaces will be identified in sandstone, shale and limestone samples, to better determine their respective minimum SE values. The existence of such a boundary was demonstrated but its position needs to be determined with more accuracy. Melting/vaporization zone interfaces will also be explored.

There is a strong indication that the rock immediately around the lased hole exhibits increased permeability due to the formation of micro-fractures and the destruction of grain-grain contacts. A follow-up analysis is being conducted to determine the effect of laser/rock interaction on permeability.

The SE for shale is not only about an order of magnitude lower than that for sandstone and limestone, but shows the clearest division between the spalling and melting zones. This significant result needs to be extended to other types of shale samples, since shale characteristics can vary widely and a relatively large volume of shale is drilled in most wells.

One possible approach for the application of this work to the drilling of wells is to alternate the lasing of multiple spots to create a hole of the desired size. In order to estimate the number of spots required for a given hole, the amount of overlap necessary to create a smooth work face has to be determined. The amount of "relaxation" time needed to cool a given spot and prevent the accumulation of melted material also needs to be determined.

Phase 2 of the DOE study also includes the development of a suitable pressure vessel that will simulate down hole confining stresses and pore pressures. Experiments will start using water as the fluid, and then progress to one or more common drilling fluids.

Empirical results from both the original GRI study and the initial phase of the DOE project have resulted in a huge body of data. In order to understand and make the best use of this data, a theoretical understanding must be developed of the physical processes underway during the lasing of rock. In Phase 2, computer models will be developed to assist in creating a theoretical framework for the data.

Conceptual Development of a Laser Drilling System

Of course, the ultimate goal of this effort is to be able to actually use a laser to drill wells more cost effectively. This will require a design for a laser drilling system that reflects the unique character of the mechanisms at work and takes full advantage of possible benefits. Some of the basic design elements that need to be developed for a prototype include the following.

Cutting Schemes – Several possible designs for bottom hole assemblies have been discussed by the research team. Most involve using optical fiber to bring the energy to the bottom of the hole, but whether the energy should be combined into one beam or applied as a number of smaller beams is yet to be determined.

Laser System – The specific laser to be used for a prototype must be determined. Candidates at this time include the Nd:YAG, the COIL, a diode laser and possibly the free electron laser (see sidebar).

Energy Delivery – Optical fibers seem to have the characteristics necessary for sending large amounts of power down a hole. However, a diode laser head is small enough that, properly reconfigured, it may be possible to locate the laser in the hole. A literature review and summary of optical fibers will be performed as a preliminary step towards making a determination in this area.

Drill String and Bottom Hole Assembly – Laser drilling will differ from current technology in that no weight on bit is necessary, therefore there is no need for the tensile and compressive strength of steel in the drill string. Also, if optical fiber is used to send the energy down hole, sectional tubing would complicate deployment. A composite coiled tubing system seems to be a reasonable option, as long as pressure differentials do not exceed collapse strength. Since there will be a minimum of abrasive activity around the drill head containing the fiber end effectors and fluid nozzles, there is no need for a heavy steel "bit," and a composite matrix, easily millable bit is one possible option. Engineering design work will be carried out to shorten the list of design options in this area.

Drilling Fluid and Solids Control Systems – It is most likely these systems will remain much the same as conventional systems. Some adaptation will be needed for use in composite tubing. At some time, a pressure control system will have to be adopted for deeper wells, but for the purposes of a prototype, will not be needed.

Next Steps

A final report on Phase One research will be available from GTI and NETL in June of 2002. Phase 2 activities are currently underway at GTI and at DOE's Argonne National Laboratory with final results expected in early 2003. Concurrently, GTI is actively searching for industry partners to join a laser perforation consortium that will consider the potential for developing a laser perforating tool that can be commercialized much more quickly than a laser drilling system. The consortium will demonstrate and compare th performance of different lasers in different rock types under a variety of laboratory and in situ conditions. Such a tool, while providing valuable benefits in terms of perforating performance, would also provide an ideal way to gather information on the ability of lasers to operate under down hole conditions. The first meeting of the consortium was held May 14, but interested parties can still contact GTI regarding membership. ■

Contact Brian C. Gahan, GTI Principal Project Manager at 847/768-0931 or brian.gahan@gastechnology.org for more information on the work described above or to become involved in the consortium.

Methane Hydrate Research Effort Accelerates

By Brad Tomer
NETL Strategic Center for Natural Gas

Government, academic and industry partners are ratcheting up their efforts to better understand this energy mineral's potential as a climate change agent, a subsea hazard, and a natural gas resource.

Clean fuels, energy independence, and global climate change are three issues of concern to many US citizens and policymakers. One place where these issues clearly intersect is on the topic of methane hydrate (also called natural gas hydrate). Methane hydrate could potentially provide an enormous domestic supply of clean-burning natural gas. Improving our understanding of methane hydrate not only can provide the tools for eventually converting it into gas reserves, but also may provide missing pieces to the global climate change puzzle. Also, improving our ability to identify subsea hydrate and predict its behavior, improves our ability to safely tap the conventional deepwater gas resources we increasingly rely on to provide clean energy.

Development of DOE's Hydrate Program

During the 1980s the DOE invested a relatively modest $8 million dollars in acquiring basic knowledge about the distribution and nature of naturally-occurring methane hydrate. During the 1990s, with priorities shifting to other R&D issues, work continued on a much smaller scale. Starting in 1997 however, research results in the U.S. and overseas indicated that the issues surrounding methane hydrate justified increased Federal attention. These issues included the acceleration of oil and gas development in the deeper areas of the Gulf of Mexico where methane hydrate occurs, the recognition of hydrate as a potential future resource of clean-burning natural gas, and policymakers' need to better understand the relationship between methane hydrate and global climate change. Foreign research efforts have also increased in countries like Japan, Germany, India, Korea, and others. Consequently, the DOE initiated planning for a multi-agency national methane hydrate R&D program. Two workshops conducted in 1998 resulted

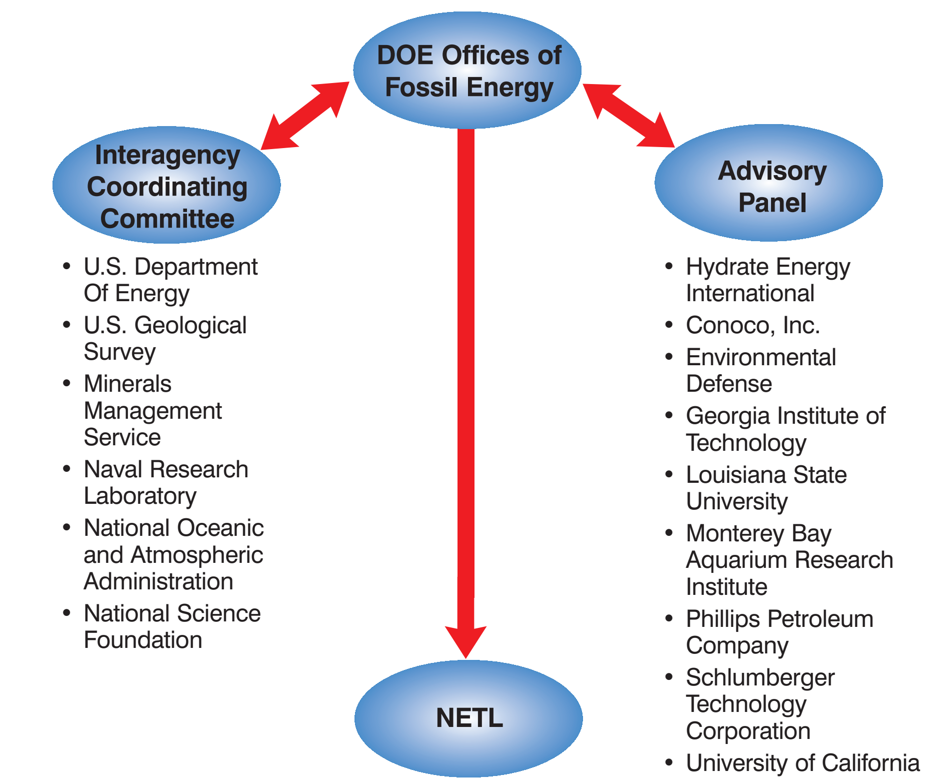
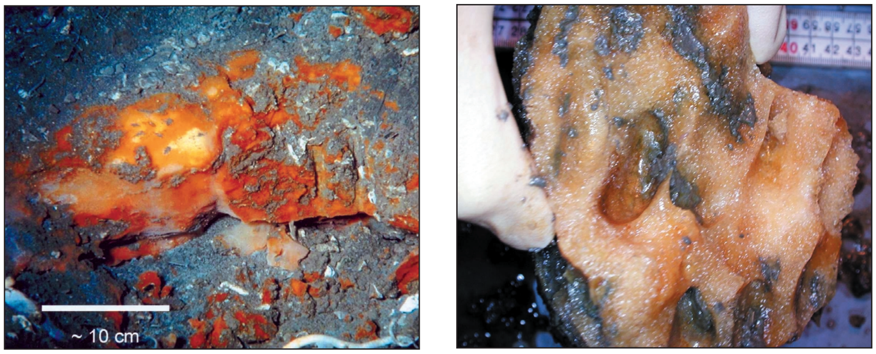


Figure 1: Organization of the DOE Methane Hydrate Program



A. B.

Figure 2: (A) Subsea Photo of Methane Hydrate Outcrop at a Gulf of Mexico Location (courtesy Roger Sassen) and (B) Collected Sample (MacDonald, 2002).

A. B.

Figure 3: Methane Hydrate (A) Surrounding Coarse Gravel in Onshore Core Sample (Collett, 2002) and (B) As Veins in Offshore Core Sample (Jones, 2002).

in the publication of "A Strategy for Methane Hydrate Research and Development," followed by the "National Methane Hydrate Multi-year R&D Program Plan."

Recognizing that no single institution had the resources to resolve the technical challenges surrounding the study of methane hydrate, and that a series of duplicative efforts would delay results and leave questions unaddressed, the Federal Government implemented a nationally-coordinated, collaborative research program after the signing of the "Methane Hydrate Research and Development Act of 2000." The DOE office of Fossil Energy implements this program through the National Energy Technology Laboratory (NETL), with input from two important sources, an Interagency Coordinating Committee and an Industry Advisory Panel (Figure 1). With this input, NETL supports four types of projects: Interagency Projects, Industry/University Projects, National Lab Projects, and NETL Onsite R&D.

The National Methane Hydrate R&D Program has defined goals for the near-term, mid-term, and long-term periods. Near-term (by 2005) goals include:

- Conducting laboratory and field studies of physical and chemical properties of hydrate and hydrate-bearing sediments.
- Conducting investigations into the relationship between natural methane hydrate, the global carbon cycle and climate.
- Providing improved assessments of the distribution and volume of methane hydrate.
- Providing practical means to avoid or mitigate the potential hazards of overlying hydrate deposits to conventional oil and gas production in the Gulf of Mexico.
- Developing improved seismic and other geophysical tools for hydrate identification and characterization.
- Developing pressure/temperature-controlled devices for the sampling and preservation of samples in low-temperature, high-pressure environments.

By 2010, the program expects to have developed and tested engineering concepts for production of gas from hydrate deposits. Goals for 2015 include the enabling of commercial production of methane from hydrate.

An increase in funding has driven this coordinated effort among national labs, universities and industry partners. In FY1999, the U.S. Department of Energy (DOE) spent half a million dollars on methane hydrate research. During FY 2001 a total of $17 million was invested; $10 million by DOE and another $7 million by other government members of the Coordinating Committee [The National Oceanic and Atmospheric Administration (NOAA), Minerals Management Service (MMS), United States Geological Survey (USGS), Naval Research Lab (NRL), and the National Science Foundation (NSF)]. Although coordinated by the Strategic Center for Natural Gas (SCNG) at NETL, the research program now involves thirteen government labs or agencies, ten

Figure 4: Worldwide Locations of Gas Hydrate Occurences (Holbrook after Kvenvolden and Lorenson, 2001).

universities, and at least seven E&P-related private companies.

Character of Methane Hydrate

Methane hydrate is a form of energy mineral found in onshore sediments in polar regions and in offshore sediments under certain conditions of seafloor temperature, pressure, and hydrocarbon composition. Methane hydrate consists of water molecule cages that surround and trap hydrocarbon molecules in a lattice network. With a structure and appearance similar to ice, one cubic foot of solid hydrate contains between 150 and 180 cubic feet of natural gas at standard conditions. Hydrate crystalline architecture follows three basic forms, depending on the amounts of heavier hydrocarbons present. Within sediments, depending on the geothermal gradient and the depth of water or permafrost, there can be a region of several thousand feet where hydrate exists as a stable solid. Deeper depths and the subsequent increased temperature precludes hydrate formation.

Methane hydrate can perhaps be more accurately thought of as a vein-filling mineral deposit than a pore-filling alternative to conventional natural gas. Samples of hydrate collected from seafloor accumulations are quite hard and can appear as dirty white bands within cores (Figures 2 and 3).

Occurrences of methane hydrate have been recorded worldwide along the continental margins and in Arctic Alaska, Canada and Siberia (Figure 4). Onshore, hydrate has been observed or inferred in a number of areas, more recently in the Alaskan North Slope and in the Mackenzie Delta of Canada's Northwest Territories. Significant known offshore occurrences include the Nankai Trough southeast of Japan, Hydrate Ridge off the coast of the U.S. Pacific Northwest, Blake Ridge off the coast of the Carolinas, and a wide deepwater area in the northwestern Gulf of Mexico.

Research has shown that offshore accumulations of methane hydrate can be categorized as structural, stratigraphic, or combinations of the two. Structural accumulations can be associated with a fault system, where gas migrates from depth along faults to the surface. Such accumulations often exhibit hydrate mounds on the seafloor, chemosynthetic communities of sea life surrounding these mounds, and gas plumes escaping into the water column (Figure 5). Gas hydrate features associated with faults have been observed in the Gulf of Mexico.

How Much is There?

Gas hydrate researchers agree that the global volume of methane contained in hydrate is huge and that although

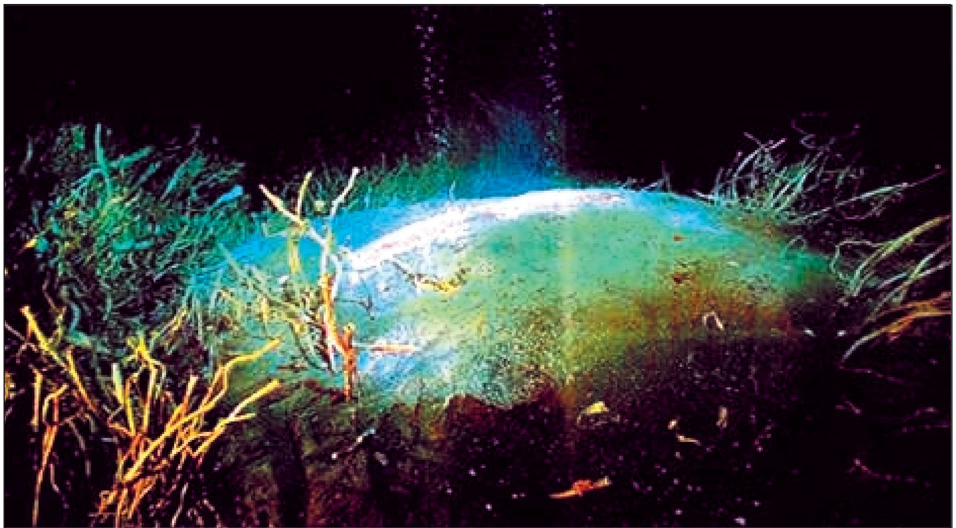


Figure 5: Chemosynthetic Communities Surrounding a Hydrate Mound in the Gulf of Mexico

significant amounts are found onshore in arctic areas, most gas hydrate is to be found in deep marine environments. However, estimates vary across a large range, due to sparse and widely distributed field data.

Early estimates were as high as 270,000,000 Tcf. More recent data have begun to narrow the spread to a more realistic range of from 100,000 to 1,000,000 Tcf. In the United States, a 1995 appraisal conducted by the USGS allocated 320,000 Tcf to nine offshore hydrate plays and one in Alaska. The USGS assessed both the probability of hydrate presence in each region and the range of likely values for the parameters controlling hydrate volume. Subsequent to that work, core samples taken on the Blake Ridge prompted a revised, as-yet unofficial, estimate of 200,000 Tcf. As sites are studied in detail, new data will certainly lead to further refinement of this number.

Assuming for the moment that this volume is reasonably accurate, it amounts to more than seven times the United States' total original gas-in-place for all non-hydrate methane. If even only 1 percent of it were technically recoverable, it would more than double the current estimate of technically recoverable natural gas in the US. Structurally focused hydrate accumulations in the Gulf of Mexico, which are apparently the more concentrated type, are estimated to contain about 280 to 390 Tcf (Milkov *et al*, 2001). If 50 percent of the gas in these locations alone was determined to be recoverable, it could double existing, readily recoverable US gas reserves. This prospect is one of the reasons behind the level of interest in methane hydrate.

In the following sections, we highlight several of the geographic locations where research projects are underway to refine our understanding of this potential resource.

Arctic Region Hydrate

Methane hydrate is known to occur both within and below permafrost in polar areas. Three provinces in North America and four in Russia show potential for hydrate accumulations. The North American areas include northern Alaska, the Mackenzie Delta-Beaufort Sea region, and the Sverdrup basin of Canada.

Direct evidence for the existence of methane hydrate in the Arctic comes from cores that recovered hydrate in wells of the Prudhoe Bay area on the North Slope of Alaska and in the

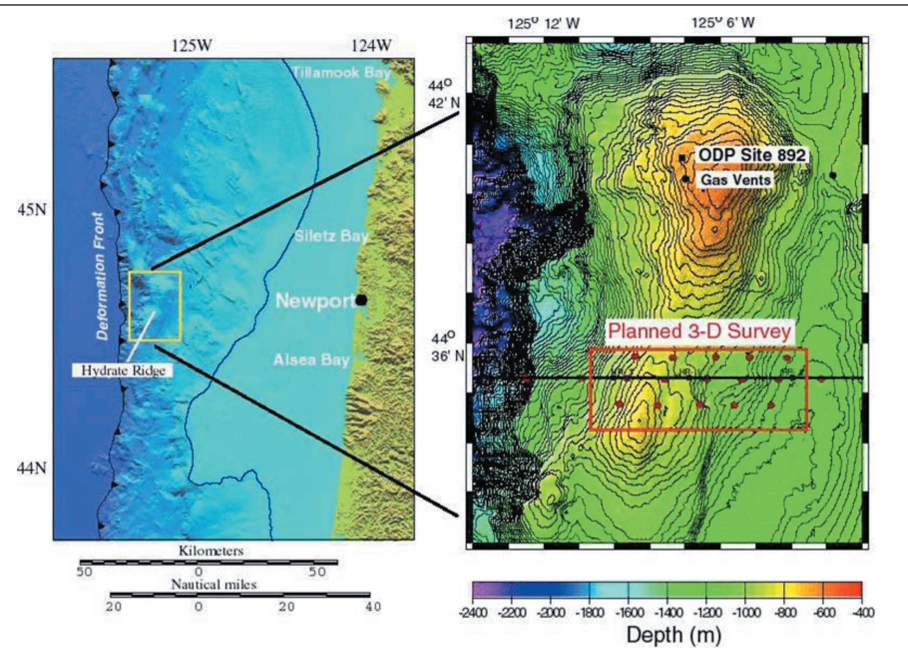


Figure 6: Schematic of Hydrate Ridge Area Showing Seismic Acquisition Area (Rack, 2002).

Mackenzie Delta region of Canada's Northwest Territories. Indirect evidence has been observed from well logs, drill-stem tests, bottom-hole surveys, gas chromatographic data, and water samples.

The Mallik Field site in the Mackenzie Delta exhibits geology and gas hydrate reservoir conditions similar to many offshore deposits, making it an ideal, easily accessible laboratory. About 20 percent of wells drilled there in the 1970s and 1980s found evidence of hydrate. In 1998, Japan, Canada and the US (through USGS and DOE) drilled the Mallik 2L-38 Well with the purpose of obtaining core of hydrate-containing sediments. In the winter of 2001/2002 a second consortium, which included India and Germany as well as the original members, drilled three more research wells. Objectives included open/cased hole logging, surface geophysics, coring through gas hydrate zones and beneath, formation testing and production flow testing. Two observation wells were drilled to conduct cross hole seismic tomography and monitor temperature response of the formation to production. This project successfully obtained a large amount of information, including 48 lengths of core. The first thermal stimulation (use of warm fluid to dissociate hydrate downhole) production testing of a gas hydrate zone was also carried out. The data from this well is scheduled for public release in 2004.

The DOE is also involved in a second effort to determine the potential volume and production capacity of Arctic hydrate. This three-year, $7.7 million project is jointly funded by DOE, Anadarko Petroleum, Noble Drilling, and Maurer Technology. Noble plans to drill and core a dedicated hydrate well on Anadarko leases during FY 2003. The data from the well, along with seismic data, will be used to develop a geologic model of the geographic extent and concentration of hydrate in and beneath the permafrost. This model, coupled with core analyses, logs, and well tests, will be used to estimate natural gas reserves. Additional wells, well tests and reservoir modeling will also be carried out to help predict the production potential of Arctic hydrate. The project team will employ an on-site laboratory to perform core analyses. Experts from universities, industry, national labs, Alaskan state agencies, and the USGS, will provide input as part of an Advisory Council. Phase I of the project, which has begun, will attempt to identify geophysical and petrophysical parameters indicative of hydrate formation, select surface locations, model the phase behavior of hydrate during coring, design and test coring techniques, and construct a mobile core laboratory. A potential drilling site has been identified just south of the Kuparuk Field and east

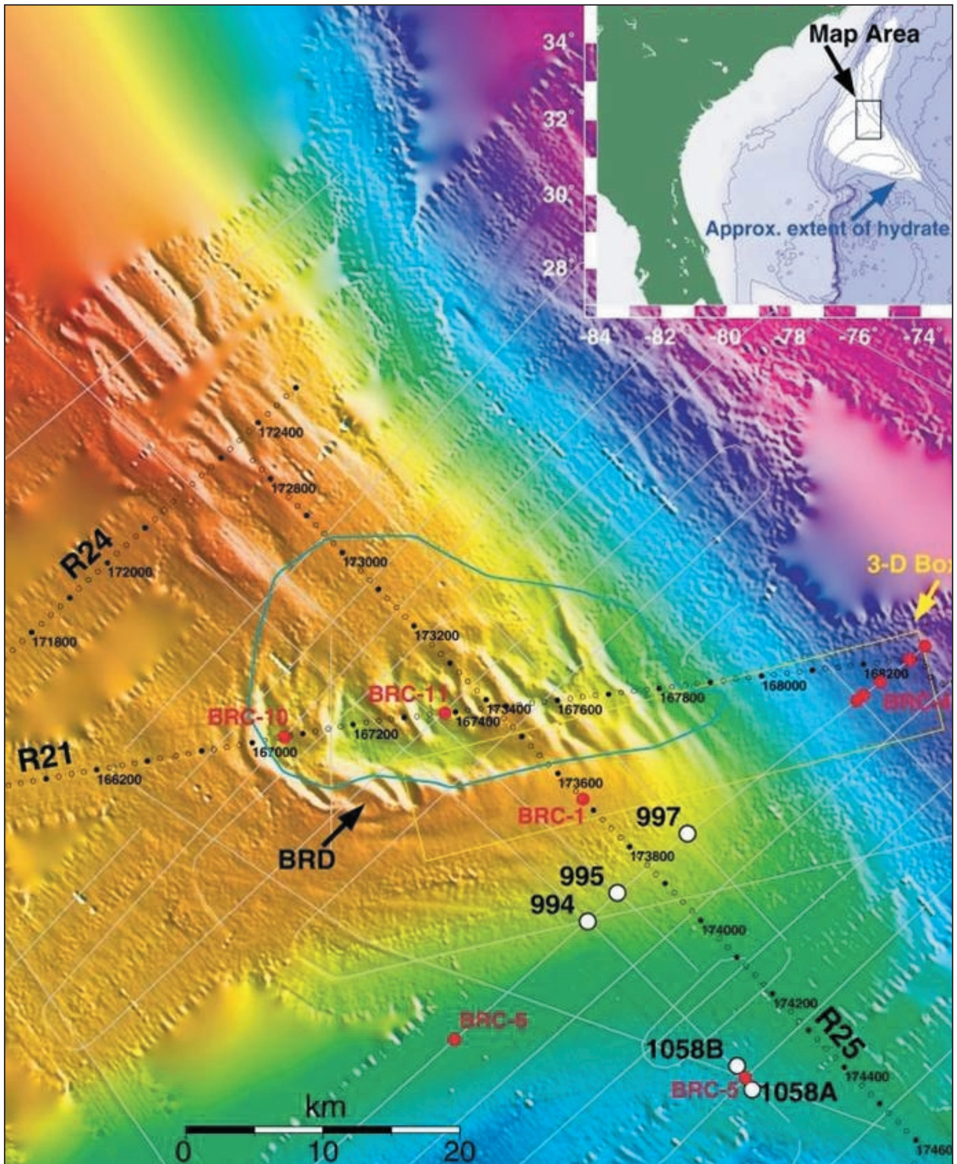


Figure 7: Blake Ridge Area with Seismic Acquisition Area Outlined (Holbrook, 2001).

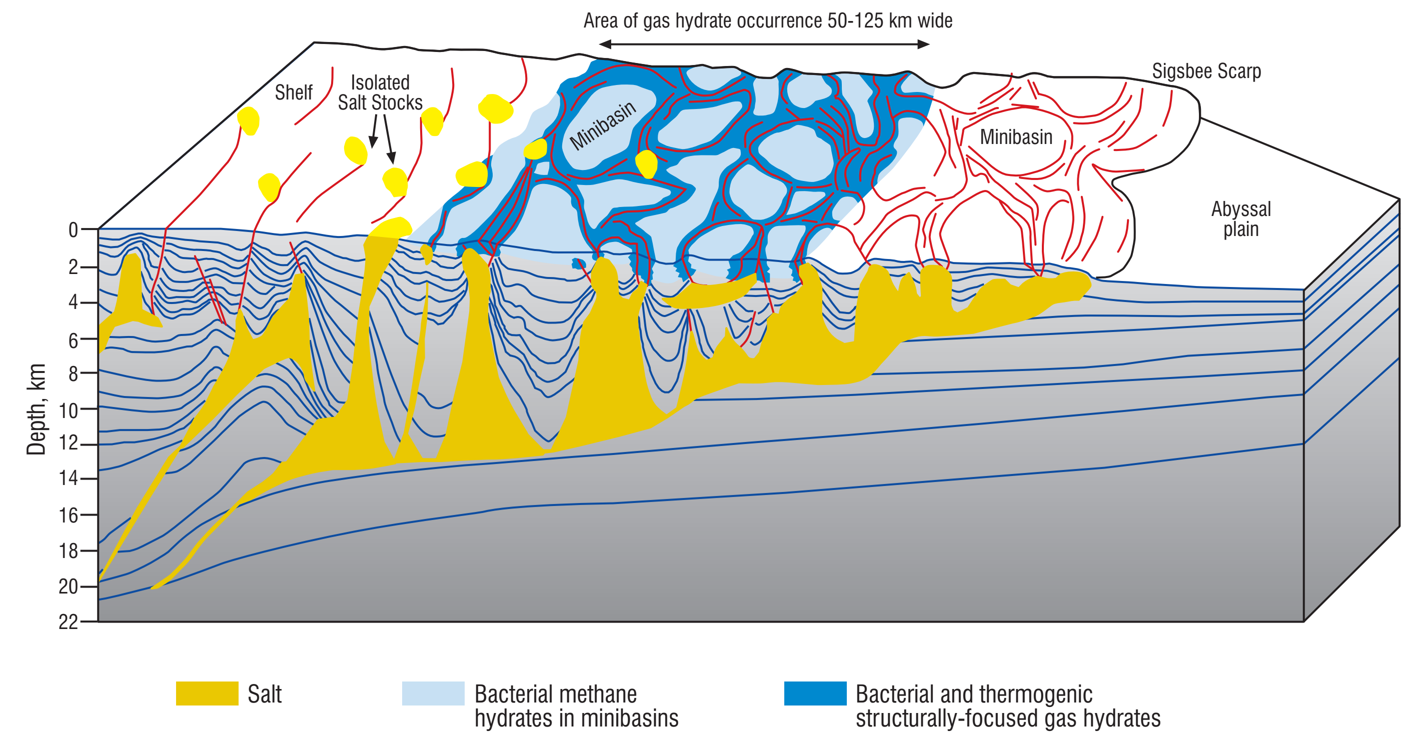


Figure 8: Schematic of Methane Hydrate Occurences in the Gulf of Mexico (after Milkov and Sassen, 2001).

of the Tarn Field. At this location the hydrate stability zone is over 2000 feet thick.

Another project, currently underway with BP Exploration Inc. in the lead position, is focused on characterizing and quantifying the hydrate and associated free gas accumulations in the Tarn and Eileen Trend areas adjacent to the Kuparuk Field, Alaska. This project, also cofunded by DOE, includes plans for the eventual drilling of wells for production testing during the 2005-2006 time frame.

West Coast Hydrate

Hydrate Ridge, a subsea topographic feature with two adjacent summits about 100 km off the Pacific coast due west of Newport, Oregon (Figure 6), is a known hydrate accumulation. The Ocean Drilling Program (ODP) Leg 146 in the late 1980s established the presence of hydrate near the seafloor at Site 892. This was followed by discovery of massive hydrate at the southern summit in 1996. During July – September 2002, the D/V JOIDES Resolution will undertake Leg 204 of the ODP. On this leg, several holes will be drilled on the southern summit of Hydrate Ridge. Goals of this project include: gathering data to calibrate seismic-based estimates of hydrate and underlying free gas concentrations, determining the porosity and shear strength of hydrate-bearing and underlying sediments, and quantifying the distribution of bacteria in the sediments in order to evaluate their contribution to hydrate formation and destruction. A number of coring, sampling and diagnostic tools will be modified or upgraded as part of this project.

East Coast Hydrate

Blake Ridge, about 200 km off the Carolina coast in the Atlantic, is a methane hydrate province that has been the target of both Ocean Drilling Program (ODP) and Deep Sea Drilling Project (DSDP) voyages and seismic data gathering during the last six years. The only seafloor seepage of gas is associated with the Blake Ridge diaper, where gas migrates along a fault and vents into the water column, creating a pockmarked seafloor and associated chemosynthetic communities. Blake Ridge has been sampled at nineteen different sites during various voyages. Methane hydrate has been recovered in four cases at depths between 0 and 1100 feet sub-bottom. Indirect seismic evidence of methane hydrate (BSRs) has been used to extrapolate their lateral and vertical distribution within the sediments. These seismic indicators together with the core information have been used to estimate that more than 1000 Tcf of methane could be dispersed across the area. The low concentration, however, would appear to be a

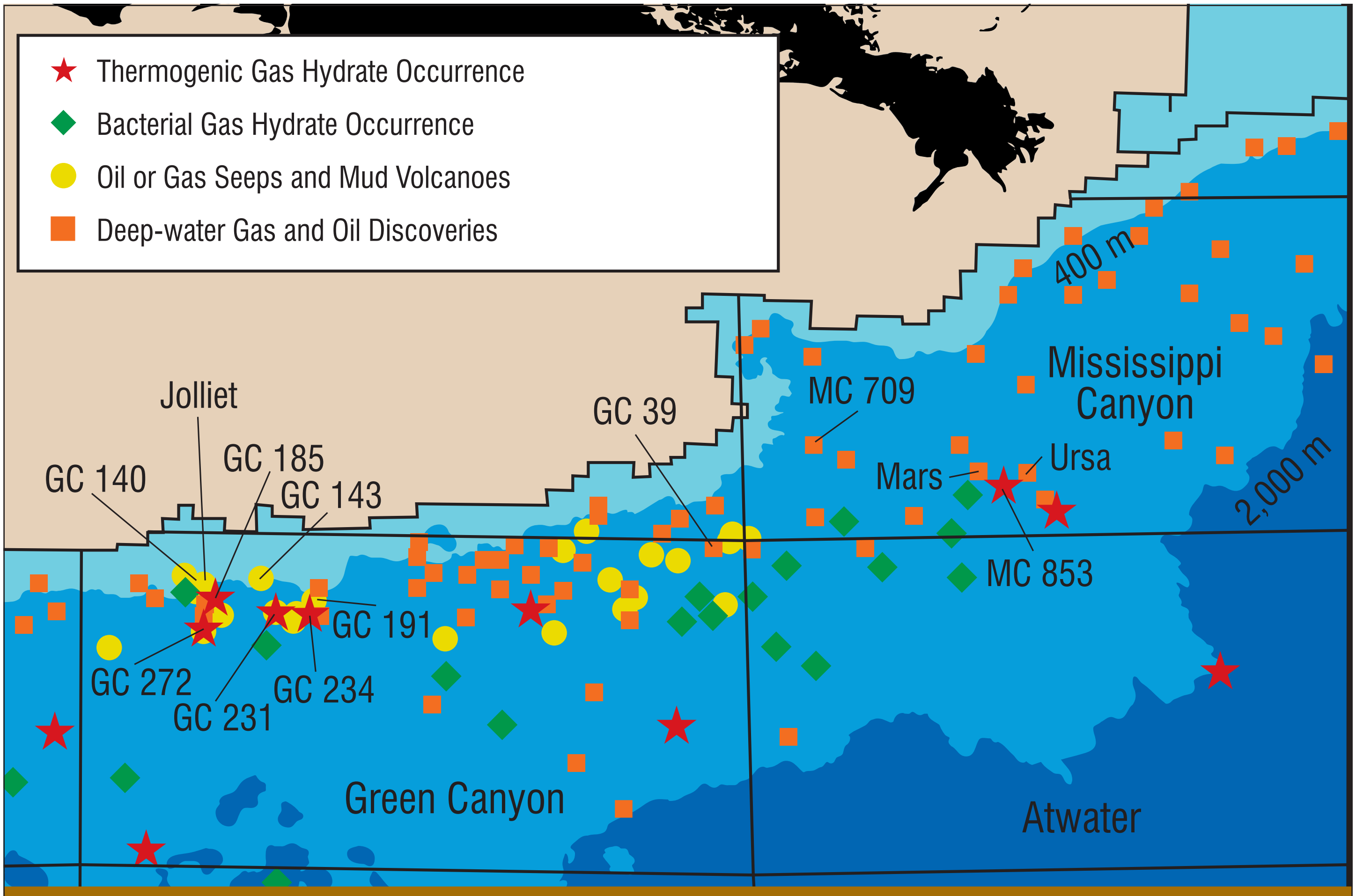


Figure 9: Locations of Methane Hydrate in Gulf of Mexico (after R. Sassen, et al, 2001).

significant barrier to recovery.

NETL and the National Science Foundation (NSF) are co-funding work by the University of Wyoming and the University of Texas to collect new 3-D multi-component seismic data and use these data to map the distribution of hydrate and associated free gas (Figure 7). This approach takes advantage of the uniform geologic character of Blake Ridge sediments to isolate the seismic response of hydrate zones. Early results from this effort show the unique sedimentary structures and details of the dynamic nature of the hydrate/free gas interaction that has not been observed previously.

Gulf of Mexico Hydrate

In the Gulf of Mexico, most hydrate is focused along structures formed by ongoing salt deformation and active faulting. Venting of thermogenic gas along faults leads to hydrate concentrations of 20-30% of the sediment volume in some places, and cores showing 100% gas hydrate intervals have been observed. Biogenic (bacterial) methane hydrate is also formed in the mini-basins between the salt-induced ridges (Figure 8). This type of hydrate, crystallized in sediments from methane generated in situ or migrated from depth over a long time, exhibits lower concentrations in the range of 1-2% of sediment volume.

Gulf of Mexico gas hydrate accumulations have been located across an area encompassing more than 20,000 square miles at water depths from 1450 to 7900 feet. Thousands of piston cores have been retrieved and methane hydrate samples have been recovered from such cores or from submersibles at more than 53 different sites (Figure 9). Most hydrate is found within the first 20 feet of sediment and can often be observed outcropping on the seafloor. Well studied localities include the Bush Hill hydrate mound at Green Canyon 184/185 (near the Jolliet platform), a location at Mississippi Canyon 852/853 (between the Mars and Ursa developments), and sites at Green Canyon 234 and Atwater 425.

In July 2002 a research cruise, organized and co-funded by DOE and the USGS, will collect several series of giant piston cores (160 feet long) to determine the lateral distribution of gas

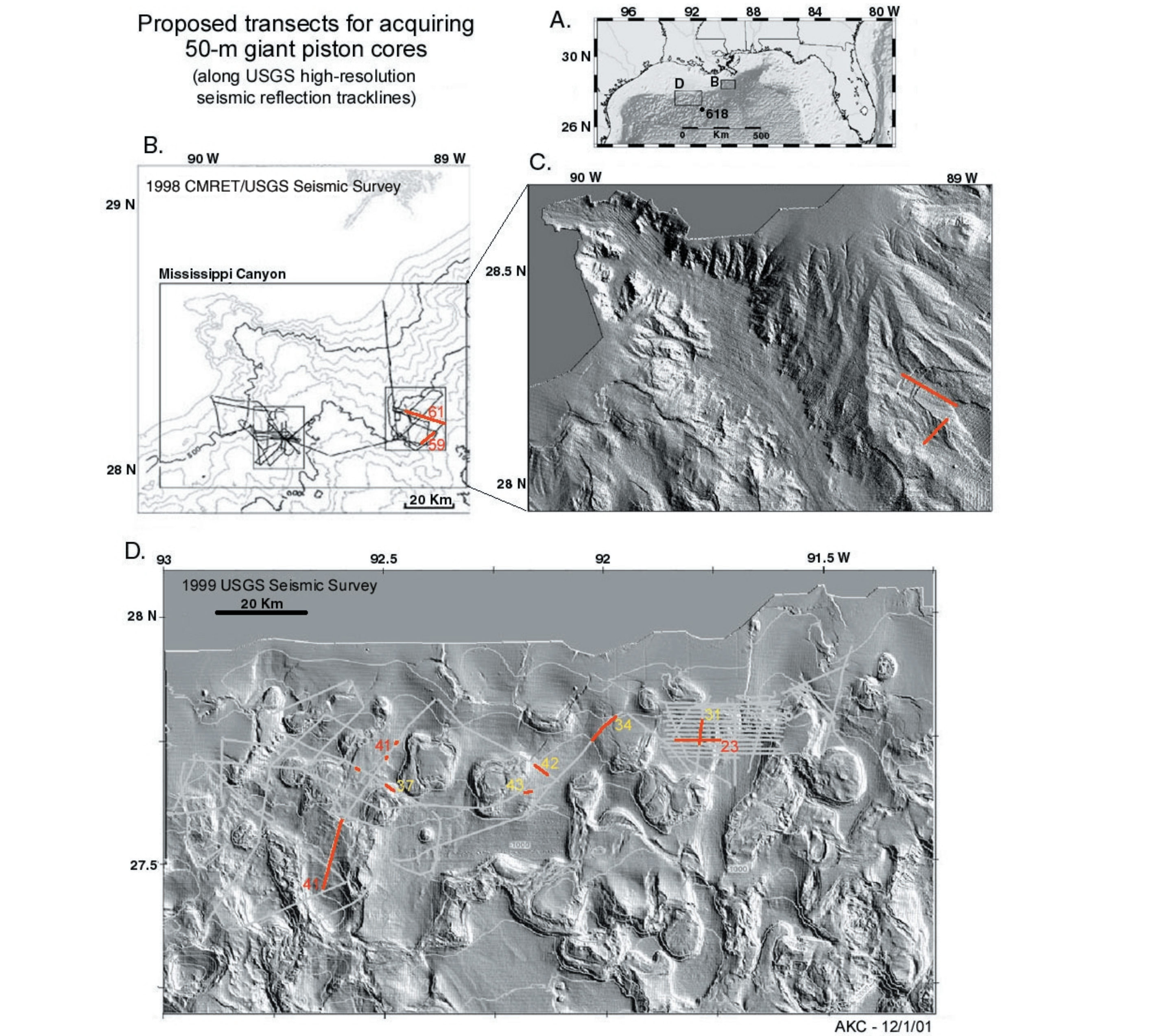


Figure 10: Locations of Proposed Sites (In Red) for Piston Core Samplings (Lorenson, 2002).

and gas hydrate in sediments near known hydrate accumulations. The information obtained in this sampling cruise will be used to help guide drilling in 2003 and 2004 to obtain more information about these accumulations.

Five sites have been tentatively chosen (Figure 10). The first is east of the Ursa platform in Mississippi Canyon 810/854. The second is an area with some seismic indication of hydrate in Garden Banks 423/554, southwest of the Auger platform. Third is a feature north of the Cooper development in Garden Banks 344/345. The fourth is a mid-basin test in the Garden Banks 301/302/345 area. And the final site is north of the Baldpate platform, at Garden Banks 215/216/239. The drilling site to be chosen based on data obtained by these cores will provide the first opportunity to calibrate geophysical data with hydrate occurrence in the Gulf of Mexico. Hopefully, there will also be an opportunity to obtain and study core from a massive hydrate accumulation.

Drilling a test well into a hydrate accumulation is a goal of a joint industry-government project, the Gulf of Mexico Gas Hydrates JIP. The JIP team, which presently includes ChevronTexaco, Schlumberger, Phillips Petroleum, Halliburton, Conoco and the MMS, all in collaboration with NETL/DOE, is investigating naturally occurring gas hydrate in the Gulf of Mexico. The primary goals of the JIP include: (1) characterization of sediments containing hydrate, (2) understanding potential safety hazards associated with drilling and pipeline laying through sediments containing gas hydrate, (3) developing a database of existing seismic, core, log, thermo-physical and biogeochemical data to identify current hydrate containing sites in deepwater GOM, (4) implementing a drilling and sample collection program to collect data and obtain cores, and (5) developing wellbore and seafloor stability models pertinent to hydrate-containing sediments.

Phase I of this multi-phase, multi-year project will be devoted to data collection, analysis, model development, and generating protocols to detect and characterize hydrate containing sediments. The results of Phase I will be used to plan and execute the drilling, sampling, and data collection field program to be conducted in Phase II.

NOTE: Hydrate formation can also reduce or block the flow of natural gas in pipelines, especially in cold, deepwater environments. The next issue of GasTIPS will include an article about the efforts of Gas Technology Institute to help resolve methane hydrate formation problems at deepwater production locations, including a description of GTI's state-of-the-art laboratory for studying hydrates.

Website Serves as Focal Point for Research Program

Any program incorporating such a large number of collaborating organizations will be challenged to simply maintain good communication of research progress and results. To help in this effort, the Strategic Center for Natural Gas at NETL has established a Methane Hydrate website at http://www.netl.doe.gov/scng/hydrate/. This site serves as a single reference point for updating and informing project participants, industry, and the public.

Other hydrate-related sites that are somewhat more specific have been set up by various parties; a site dedicated to the ChevronTexaco Gulf of Mexico Gas Hydrates JIP and sites for the two Mallik well programs in Canada are examples.

Laboratory Work Progressing Concurrently

This article has briefly described research that is ongoing or planned at field locations in four hydrate provinces. At the same time, laboratory efforts to characterize the physical behavior of methane hydrate and computer modeling efforts to predict its dynamic behavior are underway, utilizing the data that has been collected during past field projects. This work is being carried out at National Labs, at various universities, and at Westport Technology Center and Gas Technology Institute (see related article in this issue). As new information becomes available, our understanding of the methane hydrate resource and its potential as a future source of clean fuel will become clearer. ■

For more information on the DOE Methane Hydrate Program contact the author at (304) 285-4692 or via e-mail at btomer@netl.doe.gov/.

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Tight Gas Technologies for the Rocky Mountains

By James Ammer
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Current research is focusing on three ways to help producers tap the vast tight sand gas resource of the Western U.S. — finding fractures, avoiding water, and optimizing production.

No matter whose forecast you read, the Energy Information Agency's, the American Gas Association's, or the National Petroleum Council's, natural gas is expected to play a major role in fueling the future U.S. economy (EIA, 2001; AGA, 2000; NPC, 1999). Developing resources at depths greater than 15,000 feet, in water depths beyond 4,000 feet, and in unconventional reservoirs, will be key to meeting future domestic demand for natural gas. Two regions in particular – the deepwater Gulf of Mexico and the Rocky Mountains – will be called on to contribute significantly to new supplies.

As new discoveries from conventional supplies decline, future supplies of natural gas will increasingly have to come from unconventional reservoirs – and several Rocky Mountain basins (Greater Green River, Piceance, Wind River, and Uinta) contain significant volumes of such resources (tight gas sands and coal seams in particular). In their most recent study, the NPC concludes that unconventional production in the Rocky Mountain region will increase by 1 Tcf per year by 2010 and by as much as 1.5 Tcf per year by 2015. The EIA's Annual Energy Outlook 2002 projects that total natural gas production from the Rocky Mountains will increase from 3.1 Tcf in 2000 to 5.75 Tcf in 2020.

One unconventional resource, tight gas, is deliberately being targeted by some companies pursuing long-term growth strategies and now accounts for roughly 16 percent of U.S. production (*GasTIPS*, 2001). However, to realize the full potential for natural gas use in the U.S. (the question is not *if* gas demand will reach 30 Tcf per year, but *when*), the NPC recognizes that significant challenges must be met by industry that will require substantial support on key issues by the government. Significant increases in production will be required to meet this demand.

The U.S. DOE/NETL has been conducting research on low permeability (tight) gas reservoirs for over 30 years. Major field experiments like the multiwell experiment and the multi-site experiment at Rifle, Colorado, have provided tremendous insight into the characterization of low permeability gas sands, associated natural fracture networks, and the implications of hydraulic fracturing (Figure 1). Since the early 1990s, the DOE has focused its research efforts on developing technologies and methodologies to detect and characterize natural fractures in the subsurface and on demonstrating methods for enhancing production.

Resource Assessment

During the past 12 years, NETL has worked closely with the United States Geological Survey (USGS) to assess the potential of low-permeability sandstones in key basins. This work included exhaustive resource studies for the key basins of the Rocky Mountain region including the Piceance (Johnson, *et al,* 1987), Greater Green River (Law, *et al,* 1989), Wind River (Johnson, *et al,* 1996), and Bighorn (Johnson, *et al,* 1999) basins. These studies estimate that a staggering total of 6,800 trillion cubic feet (Tcf) of natural gas resource may be present in these four basins.

NETL's work in bringing basin-centered gas into the "light of day" has not only served to highlight the concept and importance of basin-centered gas, but has provided industry with a sound rationale for off-structure exploration and development. One major effort at the Strategic Center for Natural Gas has been focused on reassessing the in-place resource of major, untapped, domestic gas basins. This effort will produce detailed gas-in-place resource assessments for selected marginal gas plays (i.e., tight sands and deep plays), identify the technological advances required to accelerate entry of portions of this gas into the nation's gas reserve, and document the amount of gas that is located beneath federal lands where drilling is currently prohibited or restricted. The Greater Green River and Wind River basins are the first to be evaluated.

In the case of the Greater Green River Basin, a series of stratigraphic cross-sections and sandstone isopach maps will illustrate the regional distribution of gas-bearing sandstones in the Lewis, Upper Mesaverde (Almond/Erickson), Lower Mesaverde, Frontier, Dakota, and Madison plays. Plays characterized in the Wind River basin will include the Fort Union, Lance, Mesaverde, Frontier, Dakota, Nuggett, Tensleep and Madison.

This reassessment of the Greater Green River and Wind River basins is expected to be completed by June 2002. A topical report providing details of the study (e.g., in-place resources by play, results of the advanced technology runs, impact of land use restrictions); will be posted on the SCNG web site. A CD-ROM that preserves relevant isopach maps, stratigraphic cross-sections, etc., will be made available to the gas industry. The second set of basins to be reassessed will more than likely be the Anadarko and Uinta basins.

Figure 1: Multiwell Site Near Rifle, Colorado

Fracture-Finding Exploration Technologies

Over the last several years, independents surveyed by *The American Oil and Gas Reporter* and the Petroleum Technology Transfer Council (PTTC) have indicated that “seismic/ geophysical” technologies have been some of the most beneficial to their operations. In their efforts to develop more efficient methods for locating and developing tight sand gas, operators in the Rocky Mountains have identified two key goals: finding zones of high natural fracture density and avoiding water. NETL currently manages more than 10 projects (Table 1) designed to help industry improve its ability to achieve these goals. A number of these projects are close to completion and are described below. The key results will be featured in upcoming issues of *GasTIPS*.

For example, under one contract, *Geospectrum Inc.* of Midland, Texas is developing a methodology for identifying areas of high natural fracture density in the San Juan Basin using seismic attributes gleaned from multi-azimuth seismic data. The company analyzed petrophysical data, borehole image data, and production data for fractured plays in the Lower Dakota sandstone and found that certain seismic attributes track high production. Specifically, areas of high seismic lineament density, favorable AVO anomalies, a phase difference that correlates with low clay content, and seismically-mapped paleo-channels, correspond to those areas with the best producing wells and best natural fracture networks. Using these relationships, *Geospectrum* has proposed a Lower Dakota well site and the test has been approved by their industry partner, *Burlington Resources.* The results of this test of the methodology should be available soon.

Advanced Resources International (*ARI*) has demonstrated the application of geomechanical modeling to identify areas of open natural fracture networks. Their first study, in the Rulison field (Piceance Basin), showed that wells located within a stress envelope indicating open fractures had estimated ultimate recoveries (EURs) that were

Table 1: Current NETL Projects Focused on Exploration and Production Technologies for Rocky Mountain Tight Sand Reservoirs

TECHNOLOGY	BASIN(S)	CONTRACTOR
Seismic Attribute Analysis – Statistical analyses of seismic attributes combined with borehole image data and petrophysical data are used to identify fractures in prospective commercial gas reservoirs.	San Juan	GeoSpectrum Inc.
Geomechanical Modeling – Provide exploration-setting demonstrations of geomechanical, natural fracture detection technology to predict areas of dense, open, natural fractures in low-perm reservoirs.	GGRB, Wind River, Anadarko	Advanced Resources International
Rock Physics/Attributes – Optimize seismic capabilities for seeing fractures, quantify their size and orientation using rock physics models, and relate them to well data and the geologic environment.	East Texas	Stanford University
Integrated Methodology – Demonstrate a methodology for integrating data from structural geology studies, remote sensing, 2D seismic, and soil gas surveys to identify regional fracture intensification domains that are associated with sweet spots.	Appalachian	State University of New York at Buffalo
400-Level Seismic Array – Develop and test a downhole receiver array and advanced elements of a companion multi-component seismic data processing package for high resolution imaging of gas reservoirs.	TBD	Paulsson Geophysics Services, Inc.
Surface/Borehole Integration – Develop a new strategy for improved production through combined 3D surface and high-resolution downhole seismic, and new processing and interpretive techniques integrated with reservoir engineering.	San Juan	Lawrence Berkeley National Laboratory
S-Wave Processing – Combine a new shear-wave imaging concept for 3D seismic with a new microfracture-based analysis technique of oriented sidewall cores to create a next-generation technology for detecting and characterizing subsurface fractures.	Various	Bureau of Economic Geology, University of Texas
RTM Basin Model – A reaction-transport-mechanical (RTM) basin simulator will be enhanced and integrated with seismic inversion techniques to improve the prediction of natural fractures and their characteristics.	Austin Chalk	Indiana University
Seismic/Reservoir Modeling – A software interface package will be developed to integrate seismic software, fracture network generation models, and reservoir simulations for improved prediction of reservoir performance.	GGRB	Advanced Resources International
Water Identification – Identify and model the sources and flow paths of produced water in basin-centered formations and field test options for avoiding or mitigating the problems caused by high water production.	GGRB/ Wind River	Advanced Resources International
Basin Modeling – Construct a basinwide 3D model of the rock/fluid system for the Tertiary and Mesozoic units in the Wind River Basin to specifically identify pressure compartment boundaries, gas and water content, microfracture swarms, and faults.	Wind River	Innovative Discovery Technologies

higher by 1.5 to 2 Bcf than wells located outside of the envelope. The model was subsequently used in a step-out mode to verify the proposed location of a horizontal well in the Frontier Formation in the GGRB. That well intercepted over 400 open natural fractures. More recently, a second test well site has been selected in the Anadarko Basin and the industry partner, *Burlington Resources,* has approved the site for drilling. This well should provide further validation of the model's applicability.

In another project, Stanford University is using the principles of rock physics to quantitatively link seismic, geologic, and log data, in a study of fractured carbonate reservoirs in the James Limestone of the East Texas Neuville Field. In analyzing a VSP (vertical seismic profile) dataset, they have found that interval velocities are diminished and p-to-p wave reflections lose amplitude in areas of high fracture density. Also, travel time is delayed while scattering attenuation increases for seismic waves traveling orthogonal to oriented fracture sets. By combining these seismic attributes, they can distinguish between fractured and unfractured zones of the reservoir, and also predict the strike and dip of oriented fractures. In the third phase of the project, now ongoing, they will apply this newly developed approach to a full 3D seismic dataset to extend its utility to a larger geographic area. Their industry partner, Marathon Oil Company, is continuing to provide critical support for the project.

Energy Research at DOE – Was It Worth It?

In response to the National Resource Council's assessment of past DOE projects (NRC, 2001), NETL conducted a review of its Tight Gas Sands Program and determined that the program has contributed over $2.2 billion in realized benefits by bringing an important source of natural gas into the national supply stream earlier and at less expense than would otherwise have occurred. At the start of the program in the mid-1970s, tight gas in the Rocky Mountain Foreland basins was a poorly understood and largely uneconomic resource. The $180 million in R&D investment (1978 to 1999) by DOE in tight gas sands built an impressive base of new knowledge and technology that spurred development of this resource. The information, insights, tools and methodologies enabled industry to commercially produce the geologically complex tight gas resource in the Rocky Mountain gas basins. Through 2000, an additional 1.8 trillion cubic feet of gas production has been attributed to DOE's program.

DOE's major contributions have come through:

- Resource assessments that for the first time showed the vast amount of tight gas resource and established the importance of basin-centered gas plays.
- Specialized equipment and techniques designed to fully characterize reservoir properties under *in situ* stress and water saturation conditions that are now routinely used for low-permeability core testing.
- Surface and downhole tiltmeters and microseismic monitoring technologies that allow mapping of hydraulic fracture treatments. Developed, significantly enhanced or validated with DOE support, these technologies are now a commercial service offered by *Pinnacle Technologies*.
- New insights on hydraulic fracturing provided by field observations of fracture growth and properties obtained through mine-backs and coring.
- Over three thousand feet of vertical and horizontal core, along with detailed single-well and interference testing, that allowed for a unique evaluation of *in situ* natural fracture systems, the importance of anisotropy, and the first quantitative information on natural fracture spacing in the subsurface.
- The most comprehensive stress test program ever carried out and the first comprehensive comparison of the various stress testing techniques with an assessment of their accuracy and reliability.

Avoiding Water Production

The presence of mobile water and high water production rates continue to plague certain producing areas in the Rocky Mountains. For example, *Union Pacific Resources* (now *Anadarko Petroleum Corporation*) drilled a 2,300 foot lateral section, with over 1,600 feet in the Frontier Formation, at 15,000 feet in the GGRB near Table Rock Field (Rock Island 4H well). The well has produced 6.4 Bcf of gas in just under 3 years and is currently making nearly 4 million cubic feet per day, supporting the potential benefits of drilling horizontal wells to intersect natural fractures. However, the well has produced a significant amount of water, at times over 1,000 barrels per day, and the high rate of water production has affected gas recovery. Portions of the Mesaverde Formation in the Wamsutter area of the GGRB are also known to produce water, and in the Wind River Basin, significant water problems in hot

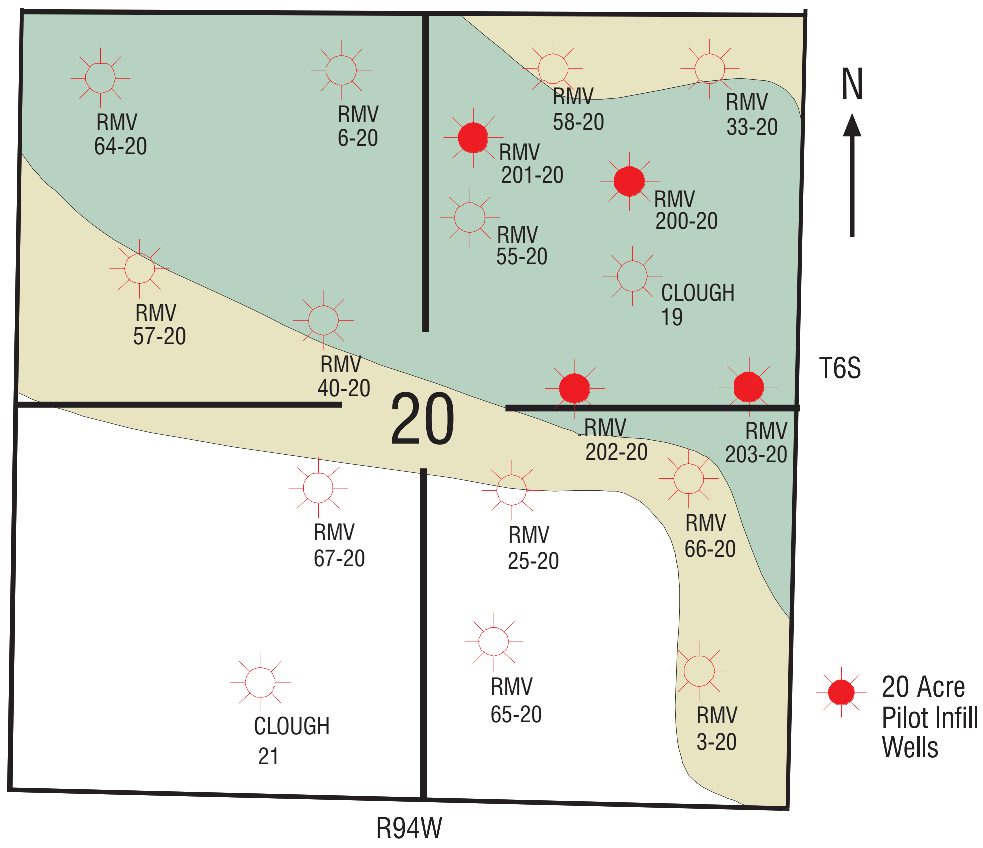

Figure 2: Intensive Field Development Pilot, Sec. 20, Rulison Field, Colorado

plays like Cave Culch are beginning to make operators apprehensive. But just where is this water coming from and how can it be avoided? Two new projects initiated by SCNG will begin to address these issues.

Researchers at *Innovative Discovery Technologies* (IDT) will remove some of the risks and uncertainty of drilling tight gas wells by developing a basin-wide, 3-dimensional model of the Wind River Basin that will provide detailed information about the reservoir before drilling begins. The model will map water and gas content, enhanced porosity and permeability areas (sweet spots), and characterize pressure boundaries. As a result, gas companies can avoid excessive water production by designing optimum drilling and completion programs.

Concurrently, *ARI* is assembling a high quality, regional water composition database for the Greater Green River and Wind River Basins by classifying water compositions and modes of occurrence. Regional water storage and flow models will be built and verified by field tests using the Waltman/Cave Gulch Field complex in the eastern Wind River Basin, Wyoming as the field test site. These models will provide options for avoiding or mitigating the problems caused by high water production.

Production Optimization Technologies

But questions also remain in tight sand fields even after they are discovered. For example: how close is close? In the Piceance Basin of Colorado, well spacing in the Rulison field is now set at 20 acres. In the San Juan Basin, spacing for Mesaverde formation wells has been reduced to 80 acres statewide. How can operators and state regulatory agencies know what the optimum well spacing and pattern is? NETL is providing assistance to help answer these questions.

Two pilot area studies have shown that optimal in-fill drilling can add an additional 26 to 44 percent to gas recovery. These studies provided a preliminary estimate of potential reserve additions in the Mesaverde formation of nearly 8 Tcf of gas across the San Juan Basin. The R&D program at Rulison provided the essential insights and reservoir data for the intensive infill development that is taking place in the Mesaverde. DOE's sponsorship of a series of closely-spaced test wells and the subsequent horizontal core well provided detailed depositional and sand continuity information showing the very limited reservoir drainage being accomplished with standard 160 acre well spacings.

Using this information, *Barrett Resources* (now *Williams Production*) launched a methodical program of downspacing, first to 80 acres per well, next to 40 acres per well and finally to the current 20 acres per well. Each of these steps was accompanied by reservoir analysis and well testing, drawing on the geological and reservoir models developed at DOE's research site.

Independent analysis by *ARI* of 30 closely-spaced wells drilled in Section

20, T6S R94W of the Rulison Field (Figure 2), shows that each of these downspacings added significant reserves (59 Bcf in Sec. 20 alone), without any significant depletion of reserves or reservoir pressure in the previously drilled wells. *Williams* has now begun to pilot test a series of 10 acre per well spacings to better understand reservoir flow and optimum spacing patterns for these tight, massively stacked basin-center sands. Using the type curves and data collected during these studies, researchers at the New Mexico Institute of Mining and Technology (NMT) have developed a simple and robust Infill Well Locator Calculator (IWLC) program to predict infill well performance.

Advanced Technologies Key to Meeting Demand

Gas supply from the tight reservoirs of the Rocky Mountain basins will continue to play a major role in meeting future demand. NETL is committed to helping producers develop the advanced technologies needed to convert this resource to reserves. Past performance has shown the value of DOE's research program and ongoing projects are expected to continue this performance trend. ■

For more information on the status of any of the projects described above, check out the Projects page at www.fetc.doe.gov/scng/index.html or contact James Ammer, NETL Project Manager for Natural Gas Supply and Storage, at 304-285-4383 or at james.ammer@nelt.doe.gov/.

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LNG in the Atlantic Basin: Where It Is, Where It's Going

By Colleen Taylor Sen
Gas Technology Institute

The growth of LNG as a source of imported natural gas has grown dramatically around the world and the U.S. is poised for a surge in LNG imports.

The U.S. Department of Energy (DOE) has projected that U.S. gas consumption will increase 59 percent to 35 trillion cubic feet (Tcf) in 2020. Domestic production is forecast to rise 2 percent per year to 28 Tcf by 2020. However, existing production is declining faster than expected, with some analysts suggesting it could fall between 3 and 7 percent in 2002 alone. Meeting demand will require not only the aggressive development of conventional, unconventional and frontier resources, but also the expansion of another important component of the supply solution: imported liquefied natural gas (LNG). Gas Technology Institute (GTI) reports that LNG's share of global natural gas imports and exports could grow from 21 percent to around 30 percent by 2010 and even higher by 2020. In the U.S., LNG could make an important contribution to gas supplies, provided that price and regulatory issues can be settled.

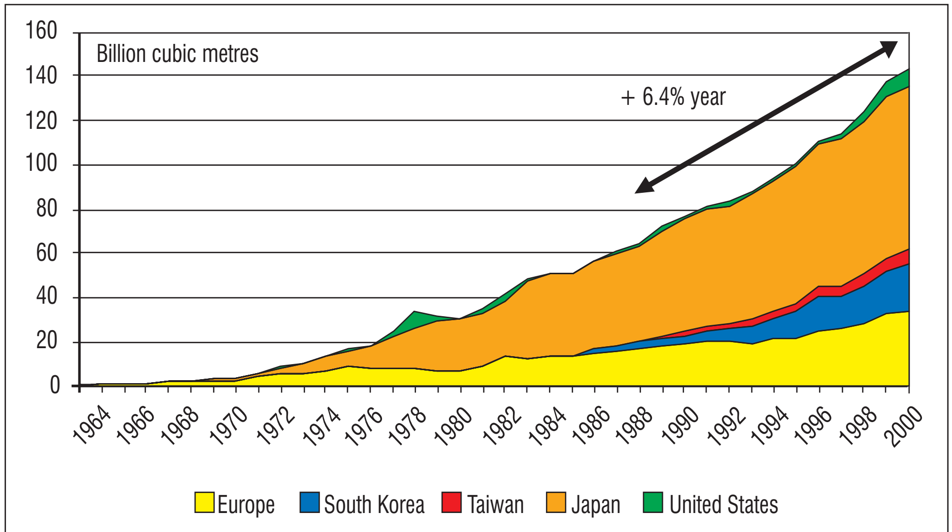

Figure 1: Growth of the World LNG Trade, 1964-2001

LNG Growth Worldwide

The transportation of natural gas as LNG has become one of the world's most rapidly growing energy delivery alternatives. Exports of LNG from gas producing countries, which have grown 6.4 percent per year since the mid 1980s (Figure 1), rose 4.2 percent in 2001 to an estimated 143 billion cubic meters (Bcm, equivalent to 5.05 Tcf of natural gas or 104 million metric tonnes of LNG). This compares with only a 1.5 percent increase in total marketed world gas production (2521 Bcm or 89.03 Tcf in 2001) and a 3.3 percent rise in volumes traded via pipeline (537 Bcm or 18.96 Tcf in 2001). LNG accounted for 21 percent of all international gas flows in 2001.

An important feature of LNG markets over the past decade has been the emergence and growth of short-term contracts and spot trading, which accounted for 5.5 percent of total LNG production in 2000. The U.S. accounted for nearly 50 percent of the worldwide short-term cargoes in that year; the rest was shared by Asia and Europe. Spot/short cargoes accounted for nearly two-thirds of U.S. LNG imports in 2001. The development of a spot market in LNG will have an affect on how new LNG projects are designed and financed.

The past few years have also seen the reemergence of the Atlantic Basin as a major growth area for LNG relative to the Asia-Pacific region, which had been the center of LNG growth for a long period ("Atlantic Basin" applies to

Table 1: LNG Trades by Country for 2001 in Billion Cubic Meters (Cedigaz, 2001)

IMPORTING ►	U.S. (incl. Puerto Rico)	Belgium	France	Greece	Italy	Spain and Portugal	Turkey	Japan	Korea	Taiwan	Total
EXPORTING											
U.S., Alaska	——	—	—	—	—	—	—	1.79	—	—	1.79
Trinidad	3.20	—	—	—	—	0.45	—	—	—	—	3.65
Western Hemisphere (Total)	**3.20**	**—**	**—**	**—**	**—**	**0.45**	**—**	**1.79**	**—**	**—**	**5.44**
Algeria	1.84	2.32	9.80	0.50	2.25	5.20	3.63	—	—	—	25.54
Libya	—	—	—	—	—	0.77	—	—	—	—	0.77
Nigeria	1.08	0.08	0.50	—	3.00	1.97	1.20	—	—	—	7.83
Africa (Total)	**2.92**	**2.40**	**10.30**	**0.50**	**5.25**	**7.94**	**4.83**	**—**	**—**	**—**	**34.14**
Abu Dhabi	—	—	—	—	—	0.02	—	6.89	0.17	—	7.08
Oman	0.39	—	—	—	—	0.91	—	0.83	5.30	—	7.43
Qatar	0.64	—	0.15	—	—	0.78	—	8.30	6.67	—	16.54
Middle East (Total)	**1.03**	**—**	**0.15**	**—**	**—**	**1.71**	**—**	**16.02**	**12.14**	**—**	**31.05**
Australia	0.07	—	—	—	—	—	—	10.05	0.08	—	10.20
Brunei	—	—	—	—	—	—	—	8.20	0.80	—	9.0
Indonesia	—	—	—	—	—	—	—	22.74	5.77	4.12	32.21
Malaysia	—	—	—	—	—	—	—	15.27	3.04	2.60	20.91
Australia-Asia (Total)	**0.07**	**—**	**—**	**—**	**—**	**—**	**—**	**56.26**	**—**	**6.72**	**72.67**
TOTAL	**7.22**	**2.40**	**10.45**	**0.50**	**5.25**	**10.10**	**4.83**	**74.07**	**21.83**	**6.72**	**142.95**

the markets on both sides of the Atlantic: the U.S., the Caribbean, and Western Europe, including Italy.) LNG has the potential to play an important role in the U.S. over the next twenty years, especially if domestic production declines at a faster than expected rate and demand continues to rise as forecast.

The first LNG production plants in 20 years to serve the Atlantic Basin were commissioned in Nigeria and Trinidad and Tobago in 1999; both are already being expanded. New export projects are planned in Egypt, the Middle East, Norway, and South America. Companies in the U.S. and Europe are expanding existing receiving terminals and planning new facilities. Cargoes of LNG are being actively traded across the Atlantic as buyers and sellers take advantage of price arbitrage opportunities.

Factors driving this growth include:

- Increased supply from new projects, expansions, and debottlenecking efforts

Table 2: Announced and Planned Expansions as of April 2001 (GTI, 2001)

Exporter	Country	Train No.	Vol. (mta)	Contractor	Startup Date	Status
ATLANTIC LNG	Trinidad	2 & 3	6.6	Bechtel	2002, 2003	Approved by govt. Construction has begun
		4 & 5	6.4			Under discussion
NIGERIA LNG	Nigeria	3	3.3	TKJS	2002	Construction has begun on 1st train
		4 & 5	8		2005, 2006	EPC contract awarded
RAS LAFFAN LNG	Qatar	3	4.7	Chiyoda, Mitsui, Snamprogetti	2004	Contract awarded
		4	4.7			Planned
QATARGAS	Qatar	4	4.8	—	2005-2006	Feasibility study
OMAN LNG	Oman	3	Up to 6.6 mta	—	2005	Markets being sought before committing
MALAYSIA LNG TIGA	Malaysia	1 & 2	Up to 7.6	Kellog Brown & Root, JGC, Sims Eng.	Late 2002, 3rd quarter 2003	—
PT BADAK NGL	Indonesia	Train I	3	—	2004	Proposed; looking for customers
NORTH WEST SHELF PROJECT	Australia	3	4.2	Kellogg Joint Venture (Halliburton Aust., Hatch-Kaiser, Clough, JGC Corp.)	2004	Letters of Intent
Total		**16 trains**	**60.4**			

- Growing demand for natural gas worldwide, especially for power generation
- Accelerated construction of tankers, which previously were in short supply
- Lower production costs: a 35-50 percent reduction over 10 years
- Competitive prices for LNG-sourced natural gas
- A projected decline in domestic natural gas production in the U.S. market
- Development of an LNG spot market as an outlet for surplus supplies
- Emergence of a trading mentality and instruments to mitigate price risks in the U.S.

While Asia remains the dominant player in the world LNG industry, both as an importer and an exporter, the share of exports from the Middle East, Africa, and Trinidad and Tobago is steadily rising (Table 1).

Imports Growing Worldwide

Ten countries currently import LNG. Japan remained the world's largest LNG importer with 52 percent of the total, followed by Korea with 15 percent and France and Spain, each with around 7 percent. U.S. imports (including Puerto Rico) accounted for around 5 percent of the world total. They rose around 6 percent in 2001, following two years of strong growth.

Six European countries (France, Italy, Belgium, Spain, Turkey, and Greece) imported 33.5 Bcm (1.18 Tcf) of LNG supplies in 2001, equivalent to nearly 8 percent of Western Europe's total gas demand. As the gap between

Table 3: Status of U.S. LNG Terminals

Location	Owner	Storage capacity (Bcf)	Peak Sendout (MMcfd)	Who Has Access to Capacity	Expansion Plans
Everett, Mass.	Tractebel N.A.	3.5	435	Tractebel (non-open access)	Adding 600 MMcfd vaporization
Lake Charles, La.	CMS Trunkline	6.3	700	BG acquired all uncommitted capacity 5.1 BCF/year	+590 MMcfd sendout + 2.5 Bcf of storage
Cove Point, Md.	Cove Point LNG Co., owned by Wiliams	5.0	1000	Shell, El Paso, and BP each have 250 million CF/day capacity	+2.8 Bcf storage 2004
Elba Island, Ga.	Southern LNG (El Paso)	4.2	675	El Paso Merchant Energy Shell has access to new capacity 2005+	+ 3.3 Bcf storage + 360 MMcfd sendout 3rd berth
Penuelas, Puerto Rico	EcoElectrica	3.5	186	EcoElectrica	Expansion considered
TOTAL		**19**	**2861**		

domestic supply and demand continues to widen, both pipeline and tanker imports will play an increasingly important role, especially in the Mediterranean countries.

As of April 2002, forty-one receiving terminals were operating in eleven countries: 24 in Japan, three in Spain, three in the U.S. plus one in Puerto Rico, two in Korea, two in France, and one each in Belgium, the Dominican Republic, Greece, Italy, Taiwan, and Turkey. They have a total sendout capacity of nearly 1 Bcm per day (equivalent to around 12.9 Tcf per year), and total storage capacity of 17.5 Bcm (0.62 Tcf) of LNG. Around half of these terminals plan to add storage and/or vaporization capacity in the next few years, including all the U.S. and Spanish terminals.

A total of at least eight new terminals are currently being built in Korea, India, Spain, Portugal, the Dominican Republic, and Turkey. In the U.S., the terminal at Cove Point, Maryland, inactive since 1980, is set to reopen early next year. Many more terminals have been announced or proposed, primarily in Europe and North America.

Exports Grow Through Expansions and New Plants

Indonesia remained the largest exporting nation, but its production fell 12 percent in 2001 because of the shutdown of one of its plants. Algeria was second, followed by Malaysia and Qatar. Production in Oman nearly tripled in 2001 as its new plant ramped up production, while Nigerian and Qatari output also increased substantially. As of March 2001 liquefaction facilities were operating in 12 countries. Together they have 64 LNG liquefaction units ("trains") and a production capacity of some 126 million tonnes per year (1 mta ≈ 1.4 Bcm per year ≈ 49.5 Bcf per year). This capacity total is approximately 20 percent higher than actual exports and the incremental difference is one of the driving forces behind the emergence of an LNG spot market.

Plans or announcements have been made for the addition of 16 trains totaling more than 60 mta of capacity at existing projects (Table 2). Particularly striking is the expected addition of 24 mta of new capacity in the Atlantic Basin: 13 mta in Trinidad and 11 mta in Nigeria. Middle East projects have announced expansions of nearly 20 mta. Qatar has revised its LNG production target for 2010 from 30 mta to 40 mta and will continue to expand its facilities.

In addition, more than twenty greenfield projects have been announced, proposed, or discussed in Angola, Australia, Bolivia, Egypt, Indonesia, Iran, Nigeria, Norway, Papua New Guinea, Peru, Russia, the U.S., Venezuela, and Yemen. Together these

Table 4: U.S. Imports of LNG in 2001 (DOE, 2001)

Importer	Country of Origin	No. of Cargoes	Volume (Bcf)	Average Price ($/million Btu)
Terminal at Lake Charles, Louisiana				
BP Energy Co.	Australia	1	2.39	3.29
BP Energy Co.	Nigeria	1	2.36	2.77
BP Energy Co.	Qatar	2	3.00	3.44
CMS Marketing	Algeria	1	2.52	4.15*
CMS Marketing	Nigeria	7	17.54	5.77*
CMS Marketing	Qatar	8	19.76	3.95*
CMS Marketing	Trinidad	2	2.88	3.22*
Duke Energy	Algeria	12	30.23	2.47*
El Paso Merchant	Algeria	2	5.41	5.90
Enron International	Trinidad	1	2.58	5.79
Enron International	Oman	6	12.05	4.74
Mirant Americas	Nigeria	5	12.87	4.58*
Sempra Energy	Trinidad	2	2.97	6.82
TotalFinaElf	Nigeria	2	5.20	4.50
Tractebel	Algeria	4	10.41	2.74
Tractebel	Trinidad	5	12.97	3.25
Terminal at Everett, Mass.				
Distrigas Corp.	Algeria	7	16.38	4.28
Distrigas Corp.	Trinidad	32	74.03	3.98
Terminal at Elba Island, Georgia				
El Paso Global	Trinidad	1	2.56	1.83
TOTAL		**101**	**238.12**	**3.97**

** Denotes tailgate price. All other imports are at "landed cost."*

projects have a potential capacity of 130-160 mta. This level of proposed capacity additions reflects both continued growth in the world's gas resource base and a desire to monetize reserves that are not adjacent to developed gas markets.

Size of reserves is not the only factor driving LNG projects. Political factors can promote or discourage project development – the reason Iran has never fulfilled its LNG exporting potential. Location is also important: Although Trinidad & Tobago's gas resources are relatively small, its proximity to markets in the U.S. and Spain has made it an important exporter. Gas quality can be a critical element. Economically valuable quantities of recoverable condensate and LPG can add 10-15 percent to project revenue and supply an early revenue stream before LNG production begins. Impurities such as CO_2 or nitrogen can entail facility costs that negatively affect economics.

The exact capacity of all these proposed projects is not as important as the general trend. There is no shortage of potential projects chasing demand. As a result, there have been delays in signing agreements for supplies from new projects and LNG producers have become more flexible in their contractual negotiations.

Status and Outlook for U.S. LNG Market

The U.S. is the only market where imported LNG competes directly with other gas supplies and is priced on a netback basis. Three receiving terminals are operating on the U.S. mainland: *CMS Energy Trunkline's* plant at Lake Charles, La.; a facility owned by *Distrigas* (now a subsidiary of *Tractebel LNG North America*) at Everett, Mass., and *Southern Energy's* Elba Island, Georgia, terminal (Table 3). All are planning expansions.

According to the U.S. Department of Energy, after increasing around 90 percent and 70 percent in 1999 and 2000 respectively, U.S. LNG imports rose 5.4 percent to 238.1 Bcf in 2001, about 10 percent less than the 250 Bcf record set in 1980 when four terminals were operating (Table 4). Another 25.6 Bcf was shipped to Puerto Rico.

Of the 238 Bcf imported by the U.S. during 2001, *Distrigas* took 90.4 Bcf, *CMS Energy* 42.7 Bcf and *Duke Energy* 30.2 Bcf. Eight other companies imported 74.8 Bcf under short-term arrangements, all into Lake Charles. U.S. LNG imports came from six countries: Algeria, Australia, Nigeria, Qatar, Trinidad, and Oman. The average price of LNG was $3.97 per Mcf, but prices per cargo ranged from less than $2 to nearly $6. The average landed price of Algerian LNG was $4.28 and the average price of LNG from Trinidad was $4.06. Spot sales accounted for nearly two-thirds of LNG imports, up from 51.4 percent in 2000.

Williams' terminal at Cove Point, which has been closed down as an import terminal since 1980, is set to start receiving cargoes in the first quarter of 2003. Its capacity has been acquired by *Shell, El Paso,* and *BP. El Paso,* which controls the capacity at the Elba Island terminal, has an agreement to buy 2.4 bcm per year (84.75 Bcf per year) of Norwegian LNG and a memorandum of understanding for the possible development of a liquefaction plant in Egypt. Following an open season, *Shell* was awarded the additional 3.3 Bcf capacity that is being built at this plant.

The energy crisis on the West coast in the winter of 2000-2001, cold weather, and prices that peaked at $10 per million Btu led to an upsurge in spot imports of LNG. Coupled with the anticipated decline in domestic gas supplies, LNG entered into the spotlight as a potentially important future source of energy. Many companies have announced plans to build LNG terminals in the U.S., Mexico, Canada, and the Caribbean (Table 5).

Table 5: Terminals Announced for the Western Hemisphere

Site	Capacity (BCF/year)	Company	Potential Source of LNG
U.S. AND CANADA			
Bahamas-Florida	200	El Paso	
Radio Island, NC	200	El Paso	
Vallejo, CA	N/A	Bechtel, Shell	
Tampa, FL	200	BP	
Gulf of Mexico, offshore	365	Texaco	
Brownsville, TX	365	Cheniere	
Freeport, TX	365	Cheniere	
Sabine Pass, TX	365	Cheniere	
Hackberry, LA	275	Dynegy	
New Brunswick, Canada	275	Irving Oil	Hibernia, Nfld.,
MEXICO			
Altamira, MX (Gulf Coast)	475	El Paso, Shell	
Ensenada, Baja California, MX	495	Shell	Shell: Australia, Timor Sea
Ensenada, Baja California, MX	365	CMS/ Sempra	Bolivia
Ensenada, Baja California, MX		Chevron Texaco	Australia
Ensenada, Baja California, MX		Marathon	Australia, Indonesia
Ensenada, Baja California, MX		El Paso/ Phillips	Australia, Indonesia

By the final quarter of 2001, prices fell to as low as $2/million Btu and spot cargoes that might otherwise have gone to the U.S. were shipped to Europe where prices were higher. This slowdown continued into the first quarter of 2002. U.S. LNG imports fell from 86 Bcf in January-March 2001 to 31 Bcf in the same period of 2002. Long-term imports, all from Trinidad into the Everett terminal, fell from 22.7 Bcf to 14.6 BCF; short-term imports plummeted from 60.6 to 11.2 Bcf. Whereas in the first quarter of 2001 six companies bought spot cargoes, in 2002 only *Distrigas* did so. This illustrates the volatility and price sensitivity of the U.S. LNG market.

A report by DOE (EIA, 2001) concluded that, provided that there is sufficient terminal capacity, LNG imports could play an important role in the US. natural gas market, especially by dampening natural gas price extremes. DOE's reference scenario sees imports

Table 6: Projected Capacity of Spanish Import Terminals, 2001-2006 (Bcm) (Cedigaz, 2002)

Terminal	Owners	2001	2002	2003	2004	2006
Barcelona	Gas Natural	9.5	10.7	10.7	14.7	24.7
Huelva	Gas Natural	3.5	3.5	7.0	7	11
Cartagena	Gas Natural	2.3	4.6	5.8	5.8	8.1
Bilbao	BP, Repsol, Iberdrola, EVE	—	—	3.1	6.2	6.2
Ferrol	Enedesa, Union Fenosa, Sonatrach, Galician govt., Spanish Co.'s	—	—	—	3.1	3.1
Sagunto	Union Fenosa, Iberdrola + BP & Gas Natural?	—	—	—	5.9	5.9
Castellon	Iberdrola, ?	—	—	—	—	3
TOTAL		**15.3**	**18.8**	**26.6**	**42.7**	**62**

growing from 160 Bcf per year in 2000 to 830 Bcf per year (around 27.4 mta) by 2020, based on increased use of existing terminals and some expansion at existing sites. However, if limits are imposed on carbon dioxide emissions, driving gas demand in the Lower 48 states upward, LNG imports could increase to 1.26 Tcf per year (26.5 mta) by 2015 and to 1.35 Tcf (28.4 mta) by 2020.

How many of the planned and announced terminals in the U.S., Mexico, and Caribbean will eventually be built depends on economics and regulatory/governmental issues. Cost reductions across the entire LNG chain have reportedly resulted in a total cost of less than $2 per Mcf for Atlantic Basin LNG. This would mean acceptable margins to upstream suppliers and downstream marketers if the Henry Hub price is in the $3-$3.50 range. As of May 2002, 12-month futures were around $4.

A potential obstacle is public opposition to new LNG plants – the NIMBY phenomenon. Construction of a receiving terminal in California was blocked in the early 1980s by local opposition. Concerns over LNG plant safety have risen in the wake of the terrorist attacks of September 11. This is one reason companies are looking at offshore receiving terminals and terminals in Mexico, linked by pipelines to the U.S.

For example, Houston-based *El Paso Global LNG* announced in May that it will modify three LNG tankers it ordered last year to enable them to regasify LNG onboard and deliver the gas into a pipeline via an offshore mooring buoy system and subsea pipeline. *El Paso* believes the offshore solution makes better financial sense than building conventional terminals, approval of which near market centers has become much more difficult. The tankers would dock for several days, delivering gas at a rate of up to 400 MMcf per day. An empty tanker would be replaced by a full one, maintaining essentially constant delivery. The first of the converted tankers will be completed in the fourth quarter of 2004, about the same time *El Paso* hopes to have their first mooring buoy system and pipeline installed, most likely in the Gulf of Mexico. The company
plans to build additional mooring buoys and pipeline connections at locations near customer facilities or pipeline systems on the East and West Coasts. All of the technology employed in the mooring buoy, tankers, and subsea pipeline has been proven at offshore locations worldwide.

Other Atlantic Basin Markets

Mexico – Gas demand in Mexico is rapidly expanding at a time when domestic production is stagnant. The government estimates that by 2010, imports will be needed to meet 20 percent of domestic gas requirements. Several LNG plants are in the planning stage for the Gulf of Mexico and the Pacific coast, where minimal gas production and infrastructure exists. A number of fuel-oil fired power plants could also be converted to combined-cycle gas units that could become anchors for LNG import terminals. The sponsors of these terminals are developing their own supply sources.

Latin America – In the Dominican Republic, *AES* is building a terminal and a 300-MW power plant that are set to begin operation this year. The terminal has a sendout capacity of 250 MMcf per day. The Caribbean would be an excellent market for LNG with an economic method of transporting relatively small volumes of LNG to small markets. Brazil is another potential site for an LNG terminal.

Spain – Spain is poised to become Europe's largest LNG importer as its economy grows and energy consumption soars. Natural gas consumption grew 8

Table 7: Potential Supplies for the Atlantic Basin

Project & Train	Volume (mta)
Firm Expansions	
Atlantic LNG, 2&3	6.6
Nigerian LNG, 3	3.3
Ras Laffan LNG, 3	4.7
Possible Expansions	
Atlantic LNG, 4&5	6.4
Nigerian LNG, 4 & 5	7.6
Oman LNG, 3	3.5
Ras Laffan LNG, 4	4.7
Proposed New Projects	
Angola	3
Egypt, Damietta	3 - 4.5
Egypt, Union Fenosa	4 - 8
Egypt, Idku	3 - 4.5
Egypt, Shell	3.2
Iran	8 - 10
Nigeria, new plant	3 - 6
Venezuela, N. Paria	4
Venezuela, Jose	2.1
Norway, Snovhit	4

percent last year to 17.3 Bcm (611 Bcf), triple the 1990 level. Natural gas comes via pipeline from Algeria and as LNG into three receiving terminals owned by *Gas Natural* at Barcelona, Huelva, and Cartagena. All three are being expanded.

With liberalization, the government's monopoly is being divested and pipelines and terminals are being opened to other companies. Spanish electric utilities *Iberdrola, Union Fenosa, Endesa,* and *Hidrocantabrico* as well as IPPs and oil companies, especially *BP, Shell,* and *CEPSA,* have been aggressively developing markets and lining up gas supplies, sometimes by developing their own LNG projects. *Union Fenosa,* for example, is a partner in a liquefaction plant in Egypt. LNG imports are expected to reach 26 Bcm (918 Bcf) in 2005 and 31 Bcm (1095 Bcf) by 2010. Supplies will come from the new trains in Trinidad and Nigeria, new projects in Norway and Egypt; and possibly the Middle East. Plans call for the construction of four new terminals (Table 6).

Other Europe – LNG accounts for 7.8 percent of European gas supplies. The liberalization of European energy markets and opening of the gas market to competition could create new opportunities for LNG. However, pipeline supplies from Russia and Central Asia, Norway, and North Africa offer competition.

To diversify its supply, Portugal is building its first LNG terminal in Sines, 90 km south of Lisbon, that will go online in 2003. In the meantime, *Transgas* is taking delivery of 0.35 Bcm (12.36 Bcf) of Nigerian LNG through Spain's Huelva terminal.

France imports 30 percent of its gas supplies as LNG at *Gaz de France's* two receiving terminals at Fos-sur-Mer and Montoir. The LNG comes mainly from Algeria and Nigeria, but spot cargoes are imported from the Middle East. *TotalFinaElf* is planning a new terminal at Verdon on the Atlantic coast north of Bordeaux.

The terminal at Zeebrugge, Belgium is owned 41.6 percent by *Tractebel,* itself majority-owned by *Suez Lyonnaise des Eaux* of France. In 2000 *Tractebel* purchased *Cabot LNG,* owner of the terminal at Everett, MA. Zeebrugge, which is also terminus of the Interconnector pipeline, could emerge as a gas trading hub to exploit arbitrage and trading opportunities with European, UK, and North American markets.

Italy imports Algerian LNG into its sole terminal at Panigaglia, owned by *Snam,* the state gas company. *ENEL,* the state electric company, imports 3.5 Bcm (124 Bcf) from Nigeria via a swap agreement with *Gaz de France. Edison Gas* has received approval to build a 4 Bcm (141 Bcf) per year terminal near Rovigo on the northern Adriatic coast (with *ExxonMobil*) and has signed contracts for the purchase of Qatari LNG. A preliminary agreement has been signed for the purchase of additional volumes of Nigerian LNG. *Edison* and *BG* are seeking approval to build another terminal at Brindisi in southeast Italy. Several years ago, local opposition blocked construction of a terminal by *ENEL.*

Outlook for the Future

With the number of projects that could serve the Western Hemisphere and Europe under way or under consideration (Table 7), there is no shortage of potential supplies. This has been driven in part by the steady drop in the cost of producing, transporting, and regasifying LNG. Liquefaction costs alone have fallen from $350/ton of annual capacity in the 1980s to $200/ton, while the average cost of a large LNG tanker ship has fallen from more than $250 million in the early 1990s to $150-$160 million. This reflects both increased competition and economies of scale as plants and tankers become larger.

Another factor that will stimulate the global LNG trade is the expansion of total tanker capacity. At the end of 2001, 128 ships were operating, and 48 were on order, the highest figure ever recorded. Capacity is expected to grow 11 percent in 2002 and 12 percent in 2003. While traditionally, LNG ships were built for a specific trade and used on a dedicated route, in the past year several companies have ordered ships that are not assigned to a project. Japanese utilities and other buyers have been ordering their own ships. This will greatly increase the flexibility of LNG markets. Progress is also being made in international negotiations to dropping the "destination clauses" in contracts that currently preclude the resale of gas in third-party markets.

The LNG industry is experiencing unprecedented growth. Some observers even believe that LNG could ultimately become a commodity like oil. Natural gas demand is projected to grow over the next decade, with LNG growing at twice this rate. In the U.S., LNG could make an important contribution to gas supplies, provided that price and regulatory issues can be settled. ■

GTI provides a number of products and services related to international LNG activity, technology and markets. These include research, short courses, publications, conferences, and consulting. For more information on GTI's LNG products and insights, contact Dr. Colleen Taylor Sen, Associate Director of LNG Resources, at 847-768-0512 or via e-mail at colleen.sen@gastechnology.org/.

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Stripper Well Consortium Targets Low Productivity Wells

By Gary Covatch
NETL Strategic Center for Natural Gas

Stripper wells, both gas and oil, are one of our nation's least recognized sources of energy. A new research consortium helps find ways to keep them producing reliably.

Recent events have many citizens re-examining our country's dependence on imported oil. In 2000, the U.S. produced 2,130 million barrels of crude oil and imported another 3,300 million barrels. Of those imported barrels, 882 million came from Middle Eastern OPEC countries, with 227 million imported from Iraq (EIA, 2001). While that fact alone might be considered cause for concern, it is also a fact that 326 million barrels of our oil supply in 2000 was "imported" from another precarious source: U.S. stripper wells. Stripper well production, while not directly dependent on politics and world events, is increasingly dependent on technology, and access to that technology by the independent producers that are largely responsible for operating U.S. stripper wells.

As the oil and gas fields of the U.S. mature, most of the wells within these fields will at one time or another fall into the stripper well category. Stripper wells are defined as wells that produce less than 10 barrels of oil per day or less than 60 thousand cubic feet (Mcf) of gas per day. Numbers released by the Interstate Oil and Gas Compact Commission for 2000 show that there are 411,793 stripper oil wells in the U.S. producing an average of 2.16 barrels per day and 223,707 stripper gas wells producing an average of 15.4 Mcf per day (IOGCC, 2001). Such wells operate on the lower edge of profitability and because of that, when wells owned by major producers reach that level of production these companies usually sell them to small independent operators with lower overhead or more regionally specific portfolios. However, these wells are very important to the country's energy security, representing more than 15 percent of the oil and 7 percent of the gas produced in the U.S. (29 percent of the oil if we exclude Alaska, Florida and federal offshore, which have no stripper well production). With demand for oil and gas increasing each year, continued production from these wells needs to be maintained and increased if possible.

Recognizing that most stripper wells are operated by smaller independent operators who have neither the funds nor staff to develop new technologies, in 2001 the Department of Energy, through the National Energy Technology Laboratory, established a Stripper Well Consortium (SWC). This consortium offers operators across the U.S. a forum to discuss with technology developers the operating problems they face in their daily operations.

In the SWC, operators play an integral part in developing and selecting projects for funding, assuring the relevance and timeliness of the research. By pooling financial and human resources, the SWC's membership can economically develop technologies that will extend the life of the nation's stripper wells. This approach means that the success of the SWC is dependent upon the participation of the stripper well industry.

SWC Structure and Purpose

The SWC is an industry-driven consortium and as such has relied on industry input to identify three specific interest areas in which R&D projects will be funded: reservoir remediation, wellbore cleanup, and surface-system optimization. The SWC will also consider other project proposals that target well-performance issues. Membership in the consortium is open to all who have an interest in the oil and gas industry and specifically, stripper wells.

Currently the SWC has over 60 members from 14 states. The membership is comprised of natural gas and petroleum producers, service companies, industry consultants, universities, industrial trade organizations, and state agencies. Base funding for the SWC is provided by both the Strategic Center for Natural Gas and the National Petroleum Technology Office

Table 1: Projects Selected for Funding by SWC in 2002

PROJECT TOPIC	PROPOSING ORGANIZATION
Low Cost Oil/Water Separator for Stripper Wells	Pumping Solutions
Install & Test GOAL Pumps in Oil and Gas Wells	Brandywine Energy Development Company
Identification of the Effects of Corrosion on Stripper Wells	James Engineering
Test of the Vortex Unit in Flowlines	Vortex Flow
Test of the Vortex Unit in Gas Gathering Systems	Vortex Flow
Test of New Technologies for Lifting Liquids from Gas Wells	Colorado School of Mines
Using Production Pumps to Continuously Clean Wells	Pumping Solutions
Quantification of Bypassed Gas Reserves and Badly Damaged Production Zones in Gas Wells	Innovative Discovery Technologies
Velocity Tubing Strings for Liquid Lifting in Gas Wells	Advanced Resources International
Desalting Production Water	T & G Technologies
Infill and Recompletion Candidate Well Selection	Texas A&M
Injectivity Improvement of Low Permeability Reservoirs	Surtek
Reservoir Characterization of the Wileyville Oil Field	West Virginia University
Development of Vortex Unit for Downhole Applications	Vortex Flow (partially funded)

of the National Energy Technology Laboratory, along with the New York State Energy Research and Development Authority (NYSERDA).

Once a year, in the January-to-March time frame, the SWC releases to its membership a call for proposals. The first of these was released in 2001 and the second in 2002. Realizing that most members do not have the time to develop and write a typical government proposal, the SWC has set a 5-page limit, with a 1-page cost worksheet. Any proposed project requires a minimum of 30 percent cost share by the proposing organization or team. A representative of each proposing organization is required to attend the SWC Annual Meeting (held in March), give a short presentation on their proposal to the entire membership, and answer any questions. Following the meeting, the SWC Executive Council, which is comprised of elected members of the consortium, meet and select the projects to be funded. Each project is funded only on a year-by-year basis and the process must be repeated to obtain additional funding. This process ensures that the funded research continues to remain relevant to the membership's needs. The SWC maintains a web site at www.energy.psu.edu/swc.

Status of Selected Projects

The second annual meeting was held on March 12-13, 2002 in Columbus, Ohio, where 22 proposed research projects were presented and reviewed for possible SWC funding. Of these, 13 proposals were accepted for full funding and 1 proposal for partial funding (Table 1). A total of $1,338,374 was committed by the SWC for the co-funding of these 14 projects. Three of the selected projects were projects continued from those funded in 2001.

Last year, the SWC funded 13 projects, most of which will be completed by September 30, 2002. Of a total of 23 proposals reviewed, 11 proposals were selected for full funding and 2 for partial funding. The Consortium committed $921,000 for the 2001 round. Brief descriptions and preliminary results from two of last year's projects are provided here.

►***Design, Development and Testing of a Gas Operated Automatic Lift Pump*** *– Brandywine Energy and Development Company* (BEDCO) is the developer and manufacturer of the Gas Operated Automatic Lift PetroPump, also called the G.O.A.L. PetroPump, for use in improving production from stripper wells. Funded by both NYSERDA and SWC, the G.O.A.L. PetroPump is a unique free floating, automatically activated in-casing tool for the removal of downhole fluids (oil and water) utilizing only in-well pressure. The tool is 31 inches in length, weighs 42 pounds and can be installed (dropped) by a single operator (Figure1). The tool's operation is controlled by a pre-set pressure sensing control valve within the tool. The control mechanism within the tool holds the tool valve open upon entry into the casing, allowing tool descent to an equivalent pre-set depth of fluid in the well. Upon reaching the desired depth within the fluid column (equivalent to a certain volume of fluid), an on-tool sensor closes the in-tool valve. This closure prompts the sealing of the internal valve and, in conjunction with fixed sealing cups surrounding the tool, creates a complete seal with the well casing and prohibits further tool descent. As fluid and gas cannot pass through the G.O.A.L. PetroPump, downhole pressure subsequently builds behind the tool and fluid column, eventually lifting the tool and fluid to the surface process unit. Following delivery of the fluid to the surface and the subsequent production of gas and drawdown of gas pressure, the tool valve automatically reopens, allowing the G.O.A.L. PetroPump to descend into the well for another cycle.

BEDCO's G.O.A.L. PetroPump can be configured for a variety of well and fluid lift environments. The standard tool is targeted to work in the following environments:

- Cased gas or oil wells (4 inch ID)
- Down hole pressure from 100 to 600 psi
- A fluid lift of about 0.1 to 3 barrels fluid per cycle
- Casing scraped to remove scale prior to tool installation
- Well head modified to act as a tool lubricator/receiver
- Tool safety stand set above production perforations
- Casing free of obstructions, dents or separations.

The pump was field tested during the winter of 2001–2002 in two 3200 foot deep Medina sandstone gas wells with downhole pressures of 150 to 200 psi and a process unit back pressure of 50 psi.

The G.O.A.L. PetroPump completed on average 15 to 20 cycles per month, delivering 0.33 to 1.1 barrels of fluid per cycle. Results showed a gas production increase of between 60 and 300 percent. In the best case, production improved from 203 Mcf per month to more than 609 Mcf per month, while brine production averaged 8 to 12 barrels per month. The test wells previously had been using a standard casing plunger requiring 5 to 6 man-assisted runs per month resulting in somewhat less fluid production and significantly less gas production than with the G.O.A.L. PetroPump. While the standard casing plunger tool did achieve an increase over unassisted production, the new pump was clearly more effective, with less operational problems, less downtime during winter operations and less hours of well tender attention required. Welltender service declined almost to the point of merely monthly chart changes, even during severe winter operating conditions.

Figure 1: G.O.A.L. PetroPump Tools For Oil (Left) and Gas (Right) Wells

►***Advanced Decline Curve Model for Stripper Well Production Analysis (METEOR) –*** Typically, the low revenues generated by stripper wells make it difficult to justify the application of sophisticated, expensive analysis techniques. Also, a company may have thousands of strippers in its portfolio, making it nearly impossible to find the time to make a thoughtful analysis of an individual well's condition.

To help resolve this problem, *Advanced Resources International* (ARI), through funding provided by *Equitable Resources, Belden & Blake Corp.* and the SWC, is developing a computer program named *METEOR*. The program will allow quick evaluation of stripper well production data using advanced decline curve techniques coupled with material balance calculations for computation of formation permeability, hydraulic fracture half-length, drainage area and reservoir pressure. Previous GTI supported research has shown that advanced decline curve analysis can be an accurate technique for diagnosing reservoir parameters and stimulation condition for low permeability gas wells (Reeves, 2001). This easy-to-use software package will bring the power of these techniques to operators.

One important feature of *METEOR* will be its ability to analyze commingled production to identify layered reservoir behavior. Overall performance of commingled wells can be dominated by one zone, ultimately leading to poor recovery from the other zone or zones. This is especially the case if both zones were stimulated with a single treatment. Frequently in such cases, one of the zones is not effectively stimulated, as the other zone receives most of the treatment fluid. *METEOR* will give the user the option of analyzing the commingled performance.

METEOR will be designed to quickly read user data, apply these techniques and provide reports, graphs and mapping data. The user will be able to diagnose abnormal decline due to liquid lifting problems, a need to perform a stimulation or install compression, or the differential depletion of one zone of a multi-zone well. The software will allow operators to evaluate low rate and low revenue stripper wells with minimal time and effort. This software, expected to retail in the range of $5000 to $10,000, will be made available free of charge to SWC members.

Joining the Consortium

Applying for membership in the SWC is easy and affordable. Membership is tied into the SWC's Constitution and Bylaws, which outline the governing principles of the consortium and are available on-line at **www.energy.psu.edu/swc.** Membership applications can be conveniently downloaded and mailed or faxed to Joel Morrison at Penn State University, the consortium director.

Full membership status in the SWC is reserved for companies and universities engaged in the U.S. natural gas and petroleum industries. Dues can be paid annually ($1,000/year) or at a multi-year discounted rate ($2,500 for 3 years). Only full members are eligible to submit proposals to the Consortium for funding. Affiliate membership status in the Stripper Well Consortium is reserved for trade organizations and state agencies. Affiliate member dues can be paid annually ($200/year) or at a multi-year discounted rate ($500 for 3 years). Full details on the benefits of membership and the projects currently underway are available on the web site. ■

For more information on the SWC contact Gary Covatch, National Energy Technology Laboratory's Strategic Center for Natural Gas, at 304-285-4589, or via e-mail at gcovat@netl.doe.gov.

References

Interstate Oil and Gas Compact Commission, 2001. "Marginal Oil and Gas: Fuel for Economic Growth," 2001 Edition.

Energy Information Administration, 2001. "Petroleum Supply Annual 2000," DOE/EIA-0340(00)/1, Vol. 1, June.

Reeves, S., 2001. "Insights Into Restimulation Candidate Selection," GasTIPS, Vol. 7, No. 3, Fall Issue.

New PRODUCTS, SERVICES & OPPORTUNITIES

New Mexico Tech and GTI to Collaborate on Unconventional Gas Roadmap

GTI and New Mexico Tech University (NMT) will collaborate on the creation of a detailed technology plan to guide development of unconventional onshore gas resources in the United States. The $600,000 grant with NMT specifically calls for the development of a "roadmap" for future research ventures into enhancing the industry's ability to produce natural gas from unconventional resources such as tight sands, shale, and coal beds to meet the projected future demand for natural gas.

The technology roadmap is to be completed by the end of 2002. As part of the effort, NMT will research and compile information and feedback from gas producers – both majors and independents – throughout the United States, as well as from government agencies, National Laboratories, and industry associations. Because technology needs and their relative importance for increased gas production will vary locally depending on the type of unconventional gas resources in each region, NMT will be conducting focus groups with experts and organizations in all gas-producing regions of the United States. In addition to the publication of a detailed plan, a workshop will be conducted in August 2002 to disseminate information developed through roadmapping activities.

Significant additional gas production from unconventional sources can result by adding new, marginally productive pay zones to existing wells, re-completing wells with new and more effective treatments, and infill drilling of existing fields. Researchers will investigate the potential impact on unconventional gas production of these and other technologies, including, but are not limited to:

- Three-dimensional techniques that quantify reservoir continuity and heterogeneity
- "Fuzzy logic" and neural network expert systems for integrating well and seismic data
- Well-log interpretation/petrophysical models for detection of marginal pay
- Tools and methodologies for developing integrated geologic and reservoir models
- Hydraulic fracture treatment design, application, and diagnostics
- Methods for more efficient drilling of vertical wells
- Horizontal and multi-lateral wells.

Past technology development conducted through GTI and others has increased production from unconventional gas resources from 1 trillion cubic feet (Tcf) per year in the early 1980s to 4 Tcf per year today. However, with the very bullish projections for gas demand, experts point to the need to double unconventional gas production over the next 10 to 15 years. That goal will be the "destination" of the roadmap developed under this effort.

GTI information contact:
Kent Perry, Director, E&P and Gas Processing Research,
kent.perry@gastechnology.org.

DOE Solicitation Targets Cost-Share Oil Technology Projects With Independents

The National Energy Technology Laboratory (NETL), on behalf of its National Petroleum Technology Office (NPTO), is seeking applications by independent oil producers for cost-shared (at least 50 percent) development and demonstration projects using advanced technologies in three specific areas: the shallow shelf Gulf of Mexico (< 656 feet water depth), Alaska and the Rocky Mountain Frontier. Proposed projects can either address a technical risk that affects a particular technology's full acceptance by the independents working in one of these areas or address a critical problem associated with exploration in these areas. The goal is to provide technical solutions to problems currently limiting oil exploration and production by U.S. independents, while providing the same or higher levels of environmental protection.

Proposed projects must contain a field demonstration but do not need to be limited to one area of operations. They may address exploration, drilling and completion, well stimulation, enhanced oil recovery or other operational issues, or they can involve several processes and seek to test a management process. However, projects must address identified problems in such a way that an evaluation of project success can take place and reasons for success or failure can be attributed to the technology or other identified factors.

Proposals can be submitted under

either of two areas of interest: Existing Fields or Exploration. The proposing organization must be an independent producer, although other organizations can be partners. For the purposes of this solicitation, the DOE has adopted the definition of an "Independent Producer" published by the IRS (refining capacity less than 50,000 barrels per day in any given day or retail sales less than $5 million per year). Projects related to natural gas or projects that duplicate current or completed oil program projects will not be considered. DOE will limit its contribution to any project to $1.5 million.

Interested parties should read the solicitation (Number DE-PS26-02NT 15376-00, “Advanced Technology Development by Independents for High Risk Domains”), at http://www.netl.doe.gov/business/solicit/index.html.

Deep Trek to Develop Technology to Tap Gas Supplies Below 15,000 Feet

Although most of the gas produced in the continental United States already comes from below 5,000 feet, as demand for natural gas increases tapping reservoirs at depths of 15,000 feet or more will have to become more common. To help develop the high-tech drilling tools the industry will need to tackle these deeper reservoirs, NETL has begun "Project Deep Trek" with the goal of developing a cost-effective, "smart" drilling system tough enough to withstand the extreme conditions of deep reservoirs.

The agency is initially funding the initiative at $10.4 million and is currently soliciting cost-share proposals from industry. Proposing organizations will have two opportunities to respond. Selected organizations that have already submitted a pre-application proposal (due by April 11) have been asked to submit a more detailed, comprehensive application by May 30. For organizations that missed the first deadline, a second opportunity will come before November 30, when another set of pre-applications (a mini-proposal no longer than seven pages) will be due. After review of these pre-applications, NETL will request comprehensive applications from selected applicants by January 13, 2003.

The department will fund three phases of Deep Trek research and development: feasibility and concept definition (Phase I), prototype development or research, development and testing (Phase II), and field/system demonstration and commercialization (Phase III). Technologies need not go through all three levels of development if they already have completed several years of research. For instance, technologies that are proved to be feasible may be eligible for phases II and III. Others that are more mature may bypass phases I and II and qualify for a field demonstration. No phase is planned to last longer than four years. Private partners must contribute a minimum of 20 percent for Phase I projects, 35 percent for Phase II, and 50 percent for Phase III.

Technologies likely to be pursued under the Deep Trek project include low-friction, wear-resistant materials and coatings, advanced sensors and monitoring systems, advanced drilling and completion systems, and new bit technology that could be integrated into a high-performance, "smart" system. The new system must operate in extreme temperatures (more than 347o F) and pressures (greater than 10,000 pounds per square inch). For specific information about the solicitation and the IIPS, contact Kelly McDonald, Contract Specialist, at (304) 285-4113, or via e-mail at kelly.mcdonald@netl.doe.gov. The solicitation (Number DE-PS26-02NT41434-0) can be read and downloaded at http://www.netl.doe.gov/business/solicit/index.html.

Rocky Mountain Workshop Scheduled

The National Energy Technology Laboratory (NETL) will host the “Rocky Mountain E&P Technology Transfer Workshop” the morning of August 5th in conjunction with the Natural Gas Strategy Conference. This Workshop will be an excellent primer to the Colorado Oil and Gas Association’s (COGA) current seminar scheduled for the afternoon of August 5th. Both of these sessions will focus on emerging gas plays, critical new technologies, and business practices that are boosting natural gas exploration and production in the Rockies. NETL-funded research is providing new technologies to meet the challenges of exploration and production and, by transferring technology through this workshop, will enable industry to make better decisions relative to gas exploration and production in the Rocky Mountains. Planned talks include updated in-place gas assessments of major plays in the Greater Green River and Wind River basins; seismic attribute modeling to predict drill sites in the Dakota formation in the San Juan basin; a new downhole receiver array for high resolution seismic; a newly developed and tested dual-fluid downhole-mixed reservoir stimulation technology; and methodology and tools to optimize infill drilling in naturally-fractured, tight sand reservoirs. The workshop will begin at 7:30 AM with a continental breakfast and a session start time of 8:00 AM. For more information go to www.netl.doe.gov and click on Events.

GTI Pipeline Coatings Facility Mimics Real-World Conditions

GTI's Pipeline Coatings Facility in Des Plaines, Illinois was built last year to address the pipeline industry's need for a testing facility that could compare corrosion resistance performance of a large number of commercial coatings under a wide range of conditions, consistently and objectively. In May, 2002, GTI inaugurated the facility with the launch of a multi-year project to test a variety of coatings on numerous types and sizes of pipes buried in a variety of soils, at both ambient and elevated temperatures. This work is being funded by a consortium of more than 25 pipeline companies, coating manufacturers and utilities.

The results will be compiled into a database which operators will be able to use to match an appropriate coating with known pipe size, soil type/ conditions and service temperatures. Specific information will be developed on costs per joint, time to apply a system, equipment needs and special requirements, as well as quantitative ASTM and other test data (e.g., adhesion, peel, hardness, impact resistance, abrasion resistance, etc.) According to GTI Materials Scientist Dan Ersoy, manager of the project, "No easy, scientifically sound way to determine the optimal coating for each pipe and field condition exists. This research will provide the industry with a knowledge base no one pipeline or coating company could develop on their own." In addition to a "pipe farm" where pipe joints are buried under controlled conditions, there is also a state-of-the-art testing facility for performing a wide range of both standard and specialized pipe performance and strength tests.

Other GTI laboratories nearby are involved in a wide array of gas industry research, including other pipeline-related investigations. One of these involves the testing of a capsicum-based inhibitor of microbial corrosion (capsicum is the active ingredient in chili peppers).

New PUBLICATIONS

Hydraulic Fracture Mapping Using Downhole Tiltmeters

GTI has published two summary reports related to downhole fracture mapping research: *"Hydraulic Fracture Mapping Using Downhole Tiltmeters in Treatment Wells: Theoretical Study,"* and *"Real Time Analysis of Tiltmeter Data."* The first is a 50 page report that summarizes work done for GTI by *Pinnacle Technologies, Inc.* and presents a theoretical evaluation of downhole tiltmeter responses to hydraulic fracturing in the same well where the tiltmeters are placed, as well as the results of two field tests conducted in January and March 2000 in South Belridge Field. The study presents the differences between treatment well tiltmeters and offset well tiltmeters in terms of tilt magnitude, distribution pattern, and sensitivity to fracture geometry. The second report, also by *Pinnacle,* contains details about two pieces of software developed for real time fracture mapping (*TiltTalk* and *ServXfer*) and presents results of the field test done at *Aera's* South Belridge property in Kern County at the southern end of the San Joaquin Basin. The reports (Numbers GRI-02/0007 and GRI-02/0008 respectively) are available to non-GTI members for $60 each and can be ordered from the GTI website at www.gastechnology.org.

Methane Hydrates Interagency R&D Conference Proceedings

Abstracts of the papers presented at the Methane Hydrates Interagency R&D Conference held in Washington on March 20-22, 2002, can be viewed under the heading of Publications at the NETL website (http://www.netl.doe.gov). A CD is being developed and will soon be available for ordering online.

Coalbed Methane of North America II

The Rocky Mountain Association of Geologists (RMAG) has published a third volume dealing with coalbed methane resources in the Rocky Mountain region. The volume includes results from the RMAG Coalbed Methane Symposium of June 2000, which highlighted the Powder River, Uinta and Raton basins, as well as non-conference papers. *"Coalbed Methane of North America II"* is a sequel to RMAG's 1991 guidebook, *"Coalbed Methane of Western North America."* In 1988 RMAG published *"Geology and Coal-Bed Methane Resources of the Northern San Juan Basin, Colorado and New Mexico."* RMAG has reissued both the 1988 and 1991 books on CD ROM. Organizers opted not to require presenters to submit papers for publication; however, all were invited to do so. By also soliciting contributions from other researchers, they aimed to attract papers covering more of the new North American CBM prospects and plays than could be accommodated on the conference program. The publication is available to non-members for $25 plus shipping and can be ordered online at http://www.rmag.org.

Hart Publications Launches New Magazine for Pipeline and Natural Gas Industry

Hart Publications has launched a new magazine, *Pipeline and Gas Technology,* for the worldwide pipeline construction, maintenance and rehabilitation business sectors, filling the void recently created when Gulf Publication's *Pipeline & Gas Industry* magazine suspended operations after 47 years. Publication of *Pipeline and Gas Technology* commenced with the April 2002 issue and the response from readers has been tremendous. *GasTIPS* readers with an interest in natural gas pipeline technology issues can obtain a complementary subscription by filling out and faxing in the form on the following page, or by doing the same online at www.submag.com/sub/pb.

As a subscriber to GasTIPS, you may qualify for a **FREE SUBSCRIPTION** to Hart's new magazine, Pipeline and Gas Technology. Fill out and fax in the form below, or submit a subscription form online at www.submag.com/sub/pb/.

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   - ❑ Consulting/Design Engineer
   - ❑ Other

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FAX to PipeLine and Gas Technology at 1-713-840-1449 or 1-847-647-0830

CALENDAR

Information related to workshops, short courses, and other industry meetings.

2002

June 6 - 7

CBM 2002 Conference, Camplex, Gillette, WY.
Powder River CBM Information Council and the Methane Operators Group, Phone: 307 265 5500. Email: kit@roughriderpower.com. Internet: www.wyomingcbm.com. This will be the third annual information fair and trade show held in Gillette related to coalbed methane operations in the Powder River Basin.

June 7 - 9

IPAMS Annual Meeting and Summer Conference, Sonnenalp Resort, Vail, CO.
Independent Petroleum Association of Mountain States (IPAMS), Phone: 303-623-0987. Fax: 303-893-0709. Email: ngarner@ipams.org. Internet: www.ipams.org/.

July 21 - 24

GTI Natural Gas in the Americas 6: Strategies for Developing New Markets, Republic of Trinidad and Tobago.
Gas Technology Institute (GTI), Phone: 847-768-0500; 847-768-0832. Fax: 847-768-0842. Email: education@gastechnology.org. Internet: www.igt.org or www.gastechnology.org/.

June 19

Third Annual RMAG Coalbed Methane Symposium, Denver Marriott City Center, Denver, CO.
The 2002 RMAG Coalbed Methane Symposium is a one day symposium. Lunch is included and there is a social hour afterward. For more information visit www.rmag.org or call (303) 573-8621.

August 6 - 9

COGA Annual Rocky Mountain Natural Gas Strategy Conference & Rocky Mountain Energy Investment Forum, Colorado Convention Center, Denver, CO.
Colorado Oil & Gas Association (COGA), Phone: 303-861-0362. Fax: 303-861-0373. Email: Kdrew98103@aol.com. Internet: www.coga.org/.

August 27 - 29

AAPEX - Prospect and Property Expo, Houston, TX.
American Association of Petroleum Geologists (AAPG), Phone: 800-364-2274 or 918-584-2555. Fax: 918-560-2684. Email: postmaster@aapg.org. Internet: www.aapg.org/.

September 8 - 11

AAPG Rocky Mountain Section Meeting, Laramie, WY.
American Association of Petroleum Geologists (AAPG), Phone: 800-364-2274 or 918-584-2555. Fax: 918-560-2684. Email: postmaster@aapg.org. Internet: www.aapg.org/.

September 29 - October 2

SPE Annual Technical Conference and Exhibition, San Antonio, TX.
Society of Petroleum Engineers (SPE), Phone: 972-952-9353. Fax: 972-952-9435. Email: bwright@spe.org. Internet: www.spe.org/.

September 29 - October 2

GTI Technology Transfer Conference, Wyndham Palace Resort Hotel, Orlando, FL.
Gas Technology Institute (GTI), Phone: 847-768-0500; 847-768-0832. Fax: 847-768-0501. Email: feingold@igt.org. Internet: www.igt.org or www.gastechnology.org/. New annual conference and exhibition cosponsored by the Strategic Center for Natural Gas of the U.S. Department of Energy's National Energy Technology Laboratory.

October 28-30

North American Gas Strategies Conference, Calgary, Alberta
Annual gas strategies conference sponsored by Ziff Energy Group. Contact: Paula Arnold at (403) 234-4279 or at gasconference@ziffenergy.com/.

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