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Natural Gas Shortage Can Be Avoided by Investing in New Technologies

Are we on the verge of a supply crisis? Depends on whom you ask. But developing new methods to find and produce natural gas will help meet demand.

On June 26, Department of Energy Secretary Spencer Abraham held a Natural Gas Summit in conjunction with the National Petroleum Council to discuss a looming natural gas crisis. Reports issuing from that conference paint a rather gloomy picture, but some constructive ideas were presented.

Daniel Yergin, chairman of Cambridge Energy Research Associates and author of *The Prize,* warned of plant shutdowns, job losses and the export of production capacity if the problem is not rapidly addressed.

"In some ways, this is similar to what happened in the early 1970s in the oil market, when the U.S. went from importing a little oil to importing a lot of oil," Yergin said. "But this time it is with a different set of suppliers and supply arrangements, and without the geopolitical overlay."

He added that these types of crises, whether the Arab oil embargo of the '70s or the California "brown-out" crisis of a couple of years ago, highlight the same lessons.

"One of the most important [lessons] is to identify in advance the measures that can promote flexibility and reduce rigidities, and be prepared to act on them if necessary – rather than having to scramble and coordinate in the midst of turbulence, animosity and suspicion. Understanding what is in the toolkit is one of the prime needs," Yergin said.

He pointed to "disappointing geological experience over the past few years plus restrictions on exploration," along with a

shift to new uses of gas, as being the crux of the problem.

The American Petroleum Institute (API), meanwhile, is urging greater access to government lands for natural gas exploration. While calling for more imports and greater conservation efforts, the organization also contended that without new domestic drilling, consumer prices could move well beyond the current high levels because of a fundamental shortfall in U.S. supplies, according to an article in *Gas Processors Report's Midstream Sector Update.*

But John F. Riordan, president and chief executive officer of the Gas Technology Institute (GTI), maintained that the United States is not running out of natural gas.

"We have 1,400 Tcf of technically recoverable gas reserves, which is a 60-year supply at current consumption rates," Riordan said. The problem, he continued, is that "we have cherry-picked the inexpensive gas, and now we need new ways to affordably meet demand."

While Riordan agreed with the API that imports such as liquefied natural gas would help the situation, as will access to more real estate, he said that the most important step is increased funding in continued development of new technology for finding and producing gas.

Let's hope that call is heeded. In these pages, we continue to bring you updates about that new technology, and the benefits are quantifiable. Riordan told the Natural Gas Summit audience that a Bureau of Economic Geology study found that GTI-sponsored projects have substantially accelerated the pace of unconventional gas production.

"This technology development was not serendipitous," Riordan said. "It was a result of government and industry collaboration – a focused research effort combined with critical production incentives.

"Investing in developing the technologies we need to affordably produce our domestic gas resources in environmentally sound ways is critical, it is possible, and it has been proven effective time and time again."

If you have any questions or comments, please contact managing editor Rhonda Duey at *rduey@chemweek.com*. ✧

The Editors

GTI Staff Report

GTI Catoosa Test Facility: The Oil Field Proving Ground

Catoosa, Okla., is the birthplace of one of America's great folk heros. It sits at the head of a 445-mile interstate waterway that sees billions of dollars of goods pass by each year. Historic Route 66 runs through it, and it is where the future of the oil and gas industry is tested and fine-tuned.

Most people, however, would have trouble finding it on a map. Catoosa, Okla., sits on a hill (*Catoosa* is Cherokee for *hill*) overlooking its more well-known neighbor, Tulsa, 18 miles to the southwest. Will Rogers, the famous Hollywood cowboy humorist and philosopher, was born in Rogers County, Okla., which claims half of Catoosa – the other half is in Tulsa County. The Port of Catoosa launches barges onto the McClellan-Kerr Navigational System, which connects with the Mississippi River and ultimately the world.

But to many in the oil and gas service industry, Catoosa is synonymous with high-tech, state-of-the-art testing of tools and techniques to increase productivity and profitability.

Amoco built the Catoosa Test Facility in the mid-1980s as a proprietary testing ground for downhole tools and equipment. When BP purchased Amoco in the late 1990s, it divested the test site, and it is now a part of the Gas Technology Institute (GTI). Part of Amoco's decision to base the test facility in rural northeastern Oklahoma had to do with the type of rock underfoot.

"The geology at Catoosa allows companies to test tools that can be used in formations virtually worldwide," said Scott Randolph, operations manager for GTI Catoosa. "The variety found here in relatively shallow depths allows testing to be done more cost effectively."

Variety and knowledge of the subsurface

The data acquisition unit for **Rig 11** *uses the Sperry-Sun Drilling Services' Integrated System for Information Technology and Engineering (INSITE™), which allows for real-time data that can be viewed from the rig or GTI Catoosa's data acquisition room.*

All photos in this article courtesy of GTI Catoosa.

A rig floor hand monitors equipment on Rig 11.

as well as the shallow depth makes the geology at Catoosa unique.

“The first 1,250ft is a mixture of reservoir-quality sandstone with shale and limestone sequences. From 1,250ft to 1,600ft is a very dense and high compressive-strength formation. And from 1,600ft to 3,000ft is a thick limestone section,” Randolph said.

The varied geology and relatively shallow depths make GTI Catoosa ideal for cost-effective testing of drilling applications, including downhole tools, formation evaluation and drill bits. The shale and sandstone sections from the surface to 1,250ft are good for testing tools and polycrystalline diamond compact (PDC) bits in transition from soft to hard and then back to soft rock.

Extensive geophysical and petrophysical rock information has been taken off the subsurface formations at Catoosa and is available to the customer as a data baseline. Numerous electric, acoustic and radioactive logs have been run during the years as well, and the reservoir rocks in the Lower Skinner, Bartlesville and Misener Sands were analyzed for permeability, porosity, mineralogy and other characteristics. Additionally, a continuous core sample was taken from the surface to a depth of 2,500ft and is available for evaluation. Tool readings can be compared with the actual rock.

Testing, evaluating and calibrating tools in a realistic environment are vital in exploration and production.

Workers run tubing on Rig 2.

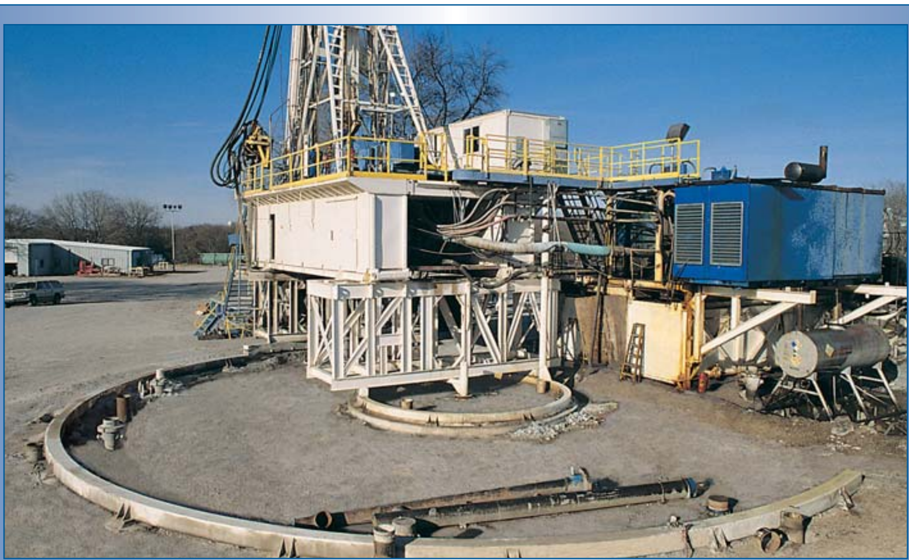
“The tool development process is more complex than ever before,” Randolph said. “Firmware, software, hardware, electronics and measurement issues, and the integration of these, can be very complicated.”

However, the pressure to take a tool from concept to field deployment can be overwhelming. Compared with developing tools in other industries, like space and military, research and development and testing budgets in the oil business are miniscule.

But according to Randolph, this route has dire consequences.

“The temptation to bypass the testing phase does present itself. But the costs of taking a tool direct-to-field can be high – very high,” he said. “A failure at that point costs the toolmaker, the producer and the consumer, but most importantly, it costs time. Knowledge of failures gives naysayers evidence for keeping the status quo and not trying new tools and techniques. That is why accurate testing and proper procedures to apply the tool are so important. Especially in today’s economy.”

Unlike the computer industry, where “early adopter” consumers will purchase the latest device, then give feedback allowing the manufacturer to fine-tune the product for the general market, the oil and gas industry is more conservative. Companies do not want to invest in tools that have not been extensively tested. Using live wells for such tests is risky. A failure interrupts normal operations or the flow potential of a well, and the bad news will travel fast. To paraphrase Winston Churchill, bad news can travel around the world before good news can even get its pants on. “When a technology is being developed, it usually takes two or three iterations and can take as long as 10 years before the technology is perfected and adopted by field personnel, and it becomes most effective. Many times multiple technologies have to emerge and



A well template on **Rig 11** *has slots for 12 wells.*

converge for a particular technology to make a significant impact," Randolph said.

This has been the case in virtually all the emerged technologies used extensively in the oil business – measurement-while-drilling (MWD), logging-while-drilling (LWD), PDC bits, slimhole technology, horizontal drilling, coil tubing operations and rotary steerable systems, among others.

Field tests conducted at GTI Catoosa do not interfere with normal oil and gas field operations and do not require shutting down productive wells. Confidentiality of tests and their results are paramount at GTI Catoosa.

"The results of tests and types of tests conducted, as well as the specific tools tested, are held in the highest confidence," Randolph said. "GTI Catoosa provides the equipment, facilities and personnel, but the service companies actually conduct the tests."

GTI Catoosa is no longer just a drilling research site. The facility is used extensively for formation evaluation tools, downhole data acquisition and completion tools testing. It is an excellent location for testing new geophysical methods and techniques.

In addition, a variety of tools and technologies have been successfully tested and evaluated at GTI Catoosa, which was instrumental in the advancement of PDC bits in the late 1980s and early 1990s, with hundreds of bit tests being conducted at the site. Their customer list includes the who's who of oil field service companies as well as some not so well-known companies.

Types of technology tested at GTI Catoosa:

- MWD and LWD tool verification and calibration;
- horizontal drilling;
- multilateral drilling;
- short radius drilling;
- drill bits;
- slimhole drilling;
- rotary steerable systems;
- coil tubing;
- expandable tubular systems;
- coring systems;
- data transmission systems; and
- well-control simulations.

Additional technology that can be tested at GTI Catoosa includes seismic, borehole gravimeters, electromagnetic tools and cement evaluation tools. Also available on-site is the ability to test wireline logging in open and cased holes. Environmental research can also be conducted. Drilling mud systems and their environmental acceptance can be evaluated as well as the testing and calibrating of new environmental monitoring devices, such as leak detection equipment, ground-penetrating radar and laser-based subsidence systems.

The facility has numerous wellbore configurations available to accommodate various customer needs. Straight, directional and horizontal wells with casing sizes of 22-in., 13 3/8-in., 9 5/8-in., 7-in. and 5-in. and open-hole sizes of 12 1/4-in., 8 1/2-in., 6-in. and others are available. For up-to-date details of the wellbore configurations and schedule, please visit *www.gticatoosa.com*.

The rig equipment and supporting infrastructure are designed to maximize testing time at GTI Catoosa. Drilling ***Rig 11*** is a top-drive rig with a pivot system to reduce move and set-up time to less than 2 hours. It features several drill strings, including 4 1/2-in. steel and aluminum drill pipe, as well as 2 7/8-in. steel drill pipe; a 107-ft double mast derrick; a Skytop Brewster 1100B mud pump capable of 650 gal/min; and a Venturetech VK-150 power hydraulic swivel with up to 12,000 ft/lb of rotary torque. The National T-20 hydraulic drawworks system is able to handle drilling loads up to 200,000 lb.

Rig 2 is a trailer-mounted, Chicago-Pneumatic workover rig with a Gardner Denver pump. It is used to evaluate slimhole drilling tools and techniques, drilling holes from 3 7/8-in. to 6 1/8-in. It can also provide short-radius (30ft to 90ft – 9.15m to 27.45m) wells and is capable of horizontal drilling. ***Rig No. 2*** is rated to 20,000 lb and is rotary steerable.

Supporting power equipment includes a logging unit, HT 400 and HT 150 high-pressure pumps, slickline unit, a crane, a forklift and a tank truck.

The data acquisition unit for ***Rig 11*** uses the Sperry-Sun Drilling Services' Integrated System for Information Technology and Engineering (INSITE™), which allows for real-time data that can be viewed from the rig or GTI Catoosa's data acquisition room. Clients can gather data such as hook load, weight-on-bit, rotary speed, rotary torque, hoist position, bit depth, penetration rate, pump pressure, mud flow rate and drillstring axial acceleration.

Quality data on all aspects of the drilling operation are gathered during testing at GTI Catoosa. Computers monitor the sensors on ***Rig 11***, with the information then made available to the client. Data gathered during testing are generated and displayed time-based and depth-based.

Another unique feature of GTI Catoosa is the full-service machine shop. Tool modification and repair can be done on-site, allowing uninterrupted testing.

GTI Catoosa features commercial power, land-line phone service, a water well and high-speed Internet connectivity. Offices and a conference/training room also are available on-site.

As impressive as the facilities are at GTI Catoosa, they would simply be high-tech decorations without the personnel to support their use. Facilities manager Ron Bray and operations manager Randolph each have numerous years of experience in operator and supplier fields. They oversee a staff that includes a data acquisition technician, driller, assistant driller, derrick man, roughneck, motorman and a machine shop fabricator.

"Our men have significant experience in field as well as research operations," Randolph said. "They have extensive experience on the Catoosa rigs, which allows tests to run very smoothly. And most importantly, they have maintained 8 years of no lost-time accidents, and we intend to do all we can to keep a safe working environment for our customers and our employees."

The employees take pride in the contributions they have made to developing technology in the oil and natural gas business.

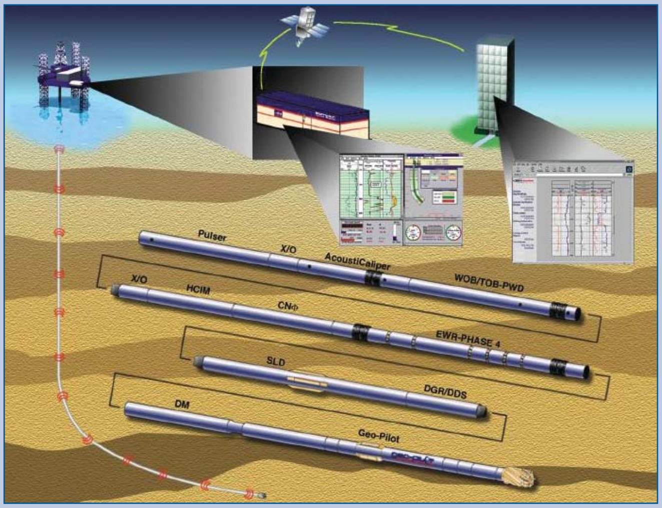
GTI Catoosa's goal is to help its customers cut the time and cost of developing tools and implementing them in the industry. The development and acceptance of new technology can take too long. This proves costly to the producer and, ultimately, to the consumer.

Some customers not only develop their tools, but also their service personnel at GTI Catoosa. This value of training and developing the service personnel in the intricacies of running their specific downhole tools is only now beginning to be realized. Many other industries value and spend time and money practicing their craft – sports teams, musicians, military units, automobile racing and space exploration, to name a few. Typically, however, this is not done in the oil and natural gas business.

Running procedures and equipment lists, as well as the detailed operations, diagnostics and maintenance procedures, are perfected at the site. Some customers practice at Catoosa and go directly to the field.

GTI Catoosa has a foundation of past success and is building on this to provide for the future. The facility is expanding its capabilities to include fracture diagnostics and environmental projects. Yet the mission remains stable: help customers develop tools and techniques in a low-risk, cost-effective and confidential environment.

What does the future hold for GTI Catoosa? Words like lasers, robotics and nanotechnology are beginning to be heard. As wells get deeper, hotter and go in more inhospitable places, the requirements for tools and testing them will become more prevalent. ✧



Since 1998, Halliburton Sperry-Sun has successfully tested two Geo-Pilot™ Rotary Steerable System sizes along with the Geo-Span™ Downlink Telemetry System at the GTI Catoosa test facility. Tool sizes have been for 8½-in. and 12¼-in. hole families. The usefulness of using the GTI Catoosa facility was invaluable to the product development of this important technology for Halliburton Sperry-Sun. Since this first test, the company has tested several improvements to the system, including GTI Catoosa's downlink telemetry system and field replaceable battery version.

Status Report: Operation of the Morphysorb® Process at a Canadian Gas-Treating Plant

by Raj Palla,
Dennis Leppin
and Aqil Jamal,
GTI

In 10 months of continuous operation, the Morphysorb Process has worked successfully, encountering no solvent-related problems and exceeding performance targets.

Morphysorb is a physical solvent-based process used for the bulk removal of carbon dioxide (CO_2) and/or hydrogen sulfide (H_2S) from natural gas and other gaseous streams. The solvent consists of N-Formylmorpholine and other morpholine derivatives. This process is particularly effective for high-pressure and high acid-gas applications and offers substantial savings in investment and operating cost compared with competitive physical solvent-based processes.

The Gas Technology Institute (GTI) and Duke Energy Gas Transmission Co. (DEGTC) entered into an agreement in 2002 to test the Morphysorb process at the DEGTC Kwoen Gas-Treating Plant in northern British Columbia. Details on the Morphysorb technology and the project background were published in the Winter 2003 issue of ***GasTIPS*** (p. 28-32). This article will update the process performance after 300 days of continuous operation.

The process is operating successfully without any solvent-related problems and has exceeded performance targets set forth in the demonstration agreement between DEGTC and GTI. As of June 2003, about 49 Bcf of sour gas was processed. Of this volume, about 4 Bcf of acid gas (containing mainly H_2S and CO_2) was injected back into the depleted reservoir, and 45 Bcf was sent for further processing at DEGTC's Pine River Plant. The weekly averages of the feed, product, recycle and acid gas flows are displayed in Figure 1. As the figure shows, the plant has been operating at close to its full capacity (300 MMcf/d) for the past 4 months.

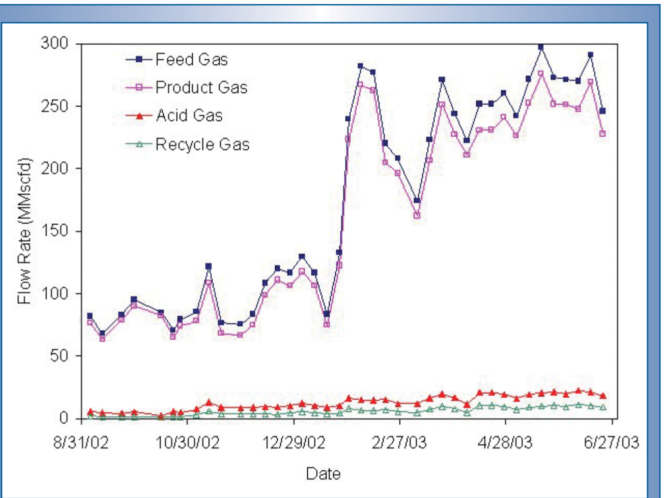


Figure 1. Weekly averages of feed, product, recycle and acid gas flows since the Kwoen Plant commissioning.

GTI continues to monitor the Kwoen plant performance and collect crucial design data for future commercial applications of the Morphysorb Process. These data will be helpful in ensuring the smooth running of the plant and avoiding potential operational problems associated with corrosion, foaming, off-spec gas and reduced performance. GTI collects Morphysorb solvent samples from the Kwoen plant once a month and analyzes them to monitor solvent composition, water content and degradation products. Thus far, GTI has collected and analyzed six solvent samples from the plant since its startup in August 2002. GTI will continue to collect these samples until mid-2004.

Solvent thermal and chemical stability

Solvent analysis at GTI indicates the Morphysorb solvent is stable after 10 months of operation. No solvent degradation has been observed, and the solvent composition is similar to the initial startup value. Total makeup solvent added to date is less than predicted initially. The total solvent loss will be further verified by analyzing product gas and acid gas samples after the plant has operated at full capacity for some time.

NFM and NAM are the products of reaction of morpholine with formic and acetic acid, respectively. The solvent samples were analyzed for thermal and chemical degradation products such as formate, acetate, sulfate, oxalate and chloride. The concentrations of anions have been constant during the past several months, and there has not been a significant change since plant startup.

Accumulation of higher hydrocarbons

GTI's analysis shows the concentration of higher hydrocarbons in the solvent has increased during time. This phenomenon is common in any gas-treating plant using physical solvents. The accumulation of heavies in the solvent and their effect on solvent performance should continue to be monitored closely. GTI plans to track the accumulation of heavies in the solvent samples collected monthly to see whether a steady concentration is reached. Various procedures can be implemented if the concentration of heavies increases beyond an acceptable limit.

Accumulation of iron in solvent

GTI has observed the iron (Fe) content in the solvent is increasing during time, but this is expected to level off in the near future. The slow increase in Fe concentration in the solvent from startup to the present is likely the result of a typical passivation process at the carbon steel surface.

Solvent foaming

So far, no foaming incidents or process-related upsets have occurred. As indicated earlier, about 49 Bcf of gas has been processed so far, and no antifoam agent has been used.

Total hydrocarbon losses in acid gas stream

The methane content in the acid gas is continuously monitored using an online analyzer. The total methane losses are in the range of 0.95 mole % to 1.2 mole %. This is one of the strongest advantages of this process. By GTI's calculations, methane losses are three to four times lower than competing physical solvent process.

Overall solvent performance

DEGTC assesses the Morphysorb performance according to five metrics: acid gas pickup; recycle gas flow; total hydrocarbon loss in the acid gas stream; Morphysorb solvent losses; and foaming-related problems. Plant data during a period of 10 months show the Morphysorb solvent has performed well in four out of five of these categories. Morphysorb solvent loss is being evaluated during a longer-term period for assessment purposes. However, preliminary indications based on makeup solvent used to date are that solvent losses also will be within expectations. Analysis of the solvent samples indicates the solvent is stable and did not show any sign of degradation. The operability of the solvent is good, and no foaming-related problems have been encountered. According to plant operators, the Morphysorb unit runs smoothly and requires no special attention. ✧

For more information about application of the Morphysorb Process, contact Dennis Leppin, Associate Director, GTI Gas Processing Program; (847) 768-0521; E-mail: dennis.leppin@gastechnology.org

Figure 2. Recycle gas compressor at the Kwoen Gas Plant.

Figure 3. A view from the absorber tower showing sections of the plant.

Behind-Outcrop Well in Deep Sandstones in the Lewis Shale, Wyoming

By Neil F. Hurley,
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A newly released CD provides a wealth of information concerning sedimentology, stratigraphy and petrophysical properties of an important gas-producing sandstone in the eastern Green River Basin of south-central Wyoming.

The Greater Green River basin is a major gas-producing province within the Rocky Mountain region. Specifically, the Lewis Shale (Upper Cretaceous) has been estimated to have 10.7 Tcf of potential gas resource (Doelger and Barlow, 1997). The Lewis has only produced a little more than 1 Tcf. Rising gas demand and the development of pipeline infra-structure have created more interest in the exploitation of this valuable resource.

In addition to the formation's economic importance, outcrops of deepwater deposits of the Lewis Shale provide analogs to other turbidite reservoirs. Outcrop analogs extend to deepwater depositional sequences, such as those in the Gulf of Mexico, North Sea, offshore west Africa, offshore Brazil, Indonesia and West Texas.

The purpose of this study is to bridge the gap between 1-D borehole data and 3-D outcrop data. The objective has been accomplished by linking geometry, stacking patterns and sedimentologic features observed in outcrop to similar features observed in core, borehole images and other wireline logs acquired in a behind-outcrop well. Through correlation and comparison of the outcrop to the subsurface, lateral continuity of sandstone packages can be determined away from the wellbore. The full report, which includes core descriptions and extensive petrophysical analyses, is documented in a CD published by the Gas Technology Institute (Hurley et al., 2002). This data set should be of interest to exploration and development geoscientists and petroleum geology teachers.

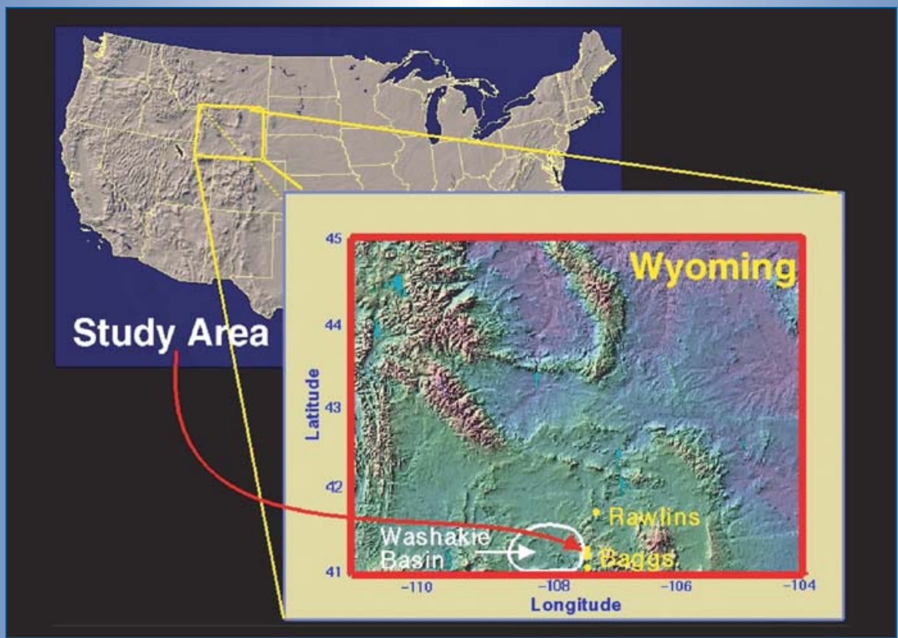

Figure 1. The Lewis Shale intermittently crops out along about 60 miles of the eastern edge of the Great Divide and Washakie basins and the western edge of the Sierra Madre uplift.

Background

The Lewis Shale consists of 2,200ft to 2,600ft of interbedded shales, siltstones and sandstones that primarily were deposited in a deepwater submarine fan environment. The Lewis Shale intermittently crops out for about 60 miles along the eastern edge of the Great Divide and Washakie basins and the western edge of the Sierra Madre uplift (Figures 1 and 2).

Witton (1999) first described the outcrops pertinent to this study. Her closely spaced measured sections documented the degree of lateral continuity of offset-stacked channel-fill and sheet-sand deposits. Depositional facies range from amalgamated, unconfined turbidite sheet sandstones at the base of the section to confined slope-fan channel-fill sandstones and associated thin-bedded turbidites at the top of the section. In order to view a correlative interval using typical subsurface data, a 1,723-ft behind-outcrop research well was drilled from which well logs and about 600ft of core were collected. This well, the **CSM Stratigraphic Test No. 61,** was drilled in September 1999. Baker Atlas logged the well with electrical borehole images (STAR), nuclear magnetic resonance (MRIL), full waveform sonic (XMAC) and conventional logging tools. Subsequent studies by Maglio-Johnson (2001), VanDyke (2003) and Goolsby (Ph.D. dissertation, in progress) have built upon Witton's interpretations and constructed a detailed geologic and petrophysical model using core and well log information. Hurley et al. (2000, 2002) summarized these and other related Lewis Shale studies.

Outcrop description

The study area is in Carbon County, south-central Wyoming, 20 miles north of Baggs and 65 miles southwest of Rawlins (Figure 2). The studied outcrop exposure is in Sections 24 and 25 of T16N-R92W.

There are four general lithofacies types in the outcrop area. These are: laterally continuous turbidite sheet sandstones; laterally discontinuous channel-fill sandstones composed of turbidity current and debris flow deposits; shingled turbidites of variable continuity; and fine-grained sediments composed of suspension and traction deposits.

The lower to middle portions of the exposed Dad Sandstone member are laterally continuous sandstones deposited in an unconfined environment near the toe of the slope and proximal basin floor. The upper portion of the exposed Dad Sandstone member consists of laterally discontinuous channel-fill sandstones of turbidity current and debris flow origin. Fine-grained deposits of variable lithology separate channel-fill and sheet sandstones. Undisturbed laminated mudstones with lesser amounts of siltstone, thin bentonite layers and occasional sandstone stringers separate sheet sands and are incised by channel-fill sands. These beds are interpreted to be relatively unburrowed suspension deposits. Laminated siltstones with interbedded sandstones up to 6-in. thick overlie channel-fill sandstones. Sandstones appear to be graded and are occasionally ripple-laminated. This facies type is intepreted to represent late-stage spill events associated with the filling of underlying channels.

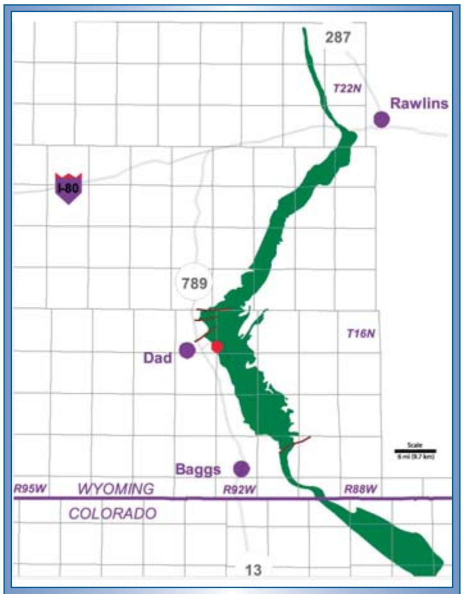

Figure 2. The general location of the CSM Stratigraphic Test No. 61 research well is 20 miles north of Baggs and 65 miles southwest of Rawlins in Carbon County, Wyo. The red circle represents the approximate well location. The green shaded area represents the Lewis Shale outcrop belt.

CSM Stratigraphic Test No. 61 Well

The test well is in the NW-NE-NW quarter of Section 25, T16N-R92W. Accessibility to service vehicles and the existence of a large (greater than 1 acre), level site were important considerations in the site selection. The Federal Bureau of Land Management (BLM) and various governmental agencies in Wyoming permitted the well.

The pre-drill criteria called for a 6.5-in. borehole diameter, drilled to a depth of 1,700ft with the ability to core 600ft of section. Himes Drilling, based in Grand Junction, Colo., was the chosen contractor. This company uses an air and foam drilling technique. As a general rule, an air/foam fluid system is more expensive because of the increase in compressor capacity required to overcome hydrostatic pressure at depth. However, the process does less formation damage than a mud system. The Lewis Shale in this region is known for bentonitic, expansive shale layers sensitive to fresh water. Therefore, air drilling is the ideal method.

Coring points were selected before drilling began by using adjacent well logs, outcrop correlation and extrapolated lines of section from the cross sections of Witton (1999). The closest adjacent wells are more than 3 miles away, which introduced some error because of laterally discontinuous sandstones and significant faulting. The first core point occurred close to the surface at 150ft. Other core points were selected with the aid of a Geolograph™ and correlations of the rate of penetration (ROP) log to the gamma ray log in an offset well.

The research well was spudded Sept. 7, 1999. The contractor began by drilling a $9^7/_8$-in. hole to accommodate $7^5/_8$-in. surface casing. Surface casing, which was not permanently cemented in place, was needed during the drilling operation to prevent cave-in. The driller alternated between coring with a 6-in. core barrel and reaming or drilling with a $6^1/_4$-in. bit to prevent tool-sticking problems. Figure 3 shows photos of the coring operation.

The drilling operation was deemed a success because the core recovery from the two turbidite facies (channel and sheet sand) was almost 100%. High-quality electrical borehole images were obtained for the entire well. Other data obtained were conventional gamma ray, resistivity and neutron/density/sonic porosity

Figure 3. Core is drilled out in 20-ft increments using a core catcher sub (top). Pieces of core were caught out of the bottom of the core catcher and placed into the tray (bottom).

logs; specialty thin-bed resistivity, NMR and dipole sonic logs; and drilling data such as ROP logs, rock cuttings and the driller's lithology interpretation.

Core description

Lithofacies identification is accomplished through the use of wellbore data and detailed core description, which identifies the bedding characteristics and sedimentary structures of each lithologic interval. These characteristics are used to interpret depositional environments and the stacking patterns of each interval.

In general, the same lithofacies are recognized in outcrop and core. Additional lithofacies detected in the subsurface include amalgamated channel and sheet sands. Distinctive signatures occur on electrical borehole images for each identified lithofacies. Seven major lithofacies have been recognized in the CSM Stratigraphic Test No. 61 well, which include several lithofacies previously described by Witton (1999).

To facilitate the comparison of the core description depths to the well log depths, a core-to-log depth shift was necessary. The gamma ray signature from the STAR tool was compared with the core description and a core gamma ray log. Using this correlation, a "single point" or "bulk" depth shift of −3.8ft was applied to the upper cored interval (0ft to 600ft), and another bulk depth shift of −5.7ft was applied to the lower cored interval (850ft to 900ft). The single point shift eliminates expansion and compression of the data, which might skew interpretations.

Study of the No. 61 well indicates that borehole image logs have sufficient resolution to identify each major lithofacies encountered in the well. To determine whether the lithofacies could be interpreted from the image logs, detailed correlation was made between the core description and the STAR log. Photographs of the slabbed core were also used to confirm the interpretation of the image log. This work showed that an adequate number of critical bedding features and sedimentary structures can be identified on the image log to distinguish each of the major lithofacies in the well. Figure 4 shows a typical comparison of core and borehole image logs in this well.

Figure 5 is a plot of the conventional openhole logs from the No. 61 well, with the following intervals dominated by major lithofacies groups:

Slope apron facies—Channel and overbank deposits are the major lithofacies present in the interval dominated by slope apron facies. The log depth is 0ft to 300ft. Outcrop studies by Witton (1999), Pyles (2000) and Bracklein (2001) have demonstrated sandstone reservoirs within this interval have limited widths in a depositional strike direction. Witton (1999) measured channel widths of only a few hundred feet. She demonstrated the channels are relatively small and isolated and do not show vertical or lateral amalgamation. Bracklein (2001) examined other channels in the Lewis Shale, just 2.5 miles east of the No. 61 well. He also found relatively small isolated channels. For this reason, individual sandstones in this interval would be expected to be discontinuous and not correlate even with relatively close well spacing. Because of this, the reservoirs probably have limited drainage areas.

Basinal or toe-of-slope sheet sandstones—Sheet sands are the predominant facies found within the interval dominated by basinal or toe-of-slope sheet sandstones. The log depth range is 300ft to 1,160ft. The reservoir characteristics of rocks within this interval should be excellent for hydrocarbon production. Individual sheet sandstones have been traced for more than 2 miles in the area of the No. 61 well (Pyles, personal communication, 2000). Reservoir continuity is therefore high within these sandstones.

Basinal shales—This interval, which occurs from log depth 1,160ft to 1,723ft, is dominated by basinal shales and has little conventional reservoir potential. The dominant lithology is laminated shale, with rare interbeds and laminations of thin-bedded siltstone and sandstone. These beds are probably not extensive enough to provide sufficient reservoir storage for commercial production. The basinal shales do have source rock potential.

Stratigraphic correlation between core and outcrop

The CSM Stratigraphic Test No. 61 well was placed in such a position that it would penetrate a complex of discontinuous, offset-stacked channels that previously had been mapped in outcrop by Witton (1999). Sandstones in this channel complex have resisted erosion, and a topographic "spine" (Spine 1) has developed along the outcrop belt at the location of the stacked channels. The No. 61 well was on top of Spine 1, and the intent was to core the channel complex.

Correlation of the logs from the No. 61 well with the outcrop measured sections (Figure 6) demonstrates the well was successful in coring the channel complex. However, the lowermost channel sand, which makes the most prominent outcrop, had pinched out by the time the equivalent horizon was reached in the wellbore. VanDyke (2003) measured 121 stratigraphic sections from the nine channel sandstones that comprise Spine 1. This work, coupled with 3-D ground penetrating radar (Young et al., 2004) and electro-magnetic induction (Stepler et al., in press) studies, has shown the reason the same channel sandstones occurred in the outcrop were not penetrated by the No. 61 well is because the sandstones are sinuous and meander within the third dimension within the outcrop.

As illustrated in the cross section (Figure 6), the sheet sand known as Marker Bed A, mapped by Witton (1999), correlates to the sandstone encountered at a log depth of 350ft to 365ft in the wellbore. The sheet sand known as Marker Bed B, mapped by Witton (1999), correlates to the sandstone encountered at a log depth of 295ft to 310ft.

Petrophysical analysis of core

Maglio-Johnson (2001) presented conventional core analyses, minipermeameter data and capillary pressure results from the CSM Stratigraphic Test No. 61 core. She used neural network software to predict permeability in uncored intervals, then defined flow units using cumulative storage capacity (øh) and cumulative flow capacity (kh) plots. Her results and data are provided in Hurley et al. (2002). Stolz (2003) performed reservoir simulations using various approaches to define flow units in this well.

Porosity and permeability measurements were recorded from 150 core plugs. Minipermeameter readings were taken every 6-in. along the cored interval. These results were calibrated to conventional core permeabilities. From the core and minipermeameter measurements, synthetic permeability was modeled for the entire well using a neural network approach.

To better characterize the pore-throat size distribution, Maglio-Johnson (2001) measured mercury injection capillary pressure on 17 core plugs. This analysis produced R35 values, which measure pore throat radius at 35% mercury saturation. The R35 values for the well were successfully predicted using the Modified Winland Equation, which relates porosity and permeability to R35.

The next step was to define hydraulic flow units for the research well. A flow unit is defined as a group of reservoir rocks that

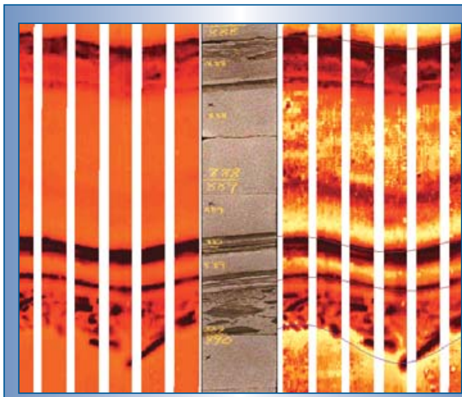

Figure 4. Comparison of core and borehole image logs. Note shale clasts. Vertical scale is 1.5ft. Borehole images on the right and left are static (unenhanced) and dynamic (contrast enhanced) images, respectively. (graphic courtesy of Gerald Keucher, Baker Atlas)

have similar rock properties that affect fluid flow. The primary method used here to define flow units is the Stratigraphic Modified Lorenz Plot, which uses plots of øh vs. kh. Inflection points on this plot indicate flow unit boundaries.

Conclusions

The major objective of this study was to link geometry, stacking patterns and sedimentologic features observed in outcrop to similar features observed on borehole images and other wireline logs. This correlation allows for the interpretation of small-scale sedimentologic features and bedding styles, which are directly related to the lateral continuity of sandstones. The establishment of criteria to distinguish laterally continuous from laterally discontinuous sandstones allows for interpretation of sandstone continuity when only borehole data are available.

Outcrops of the upper portion of the Dad Sandstone Member and the Upper Shale Member exposed north of Baggs, Wyo., were studied in order to understand depositional patterns and features of Lewis Shale deposits. Fifteen stratigraphic sections were measured through the upper Dad Sandstone, the Upper Shale Member, the Fox Hills Formation and the basal Lance Formation to construct

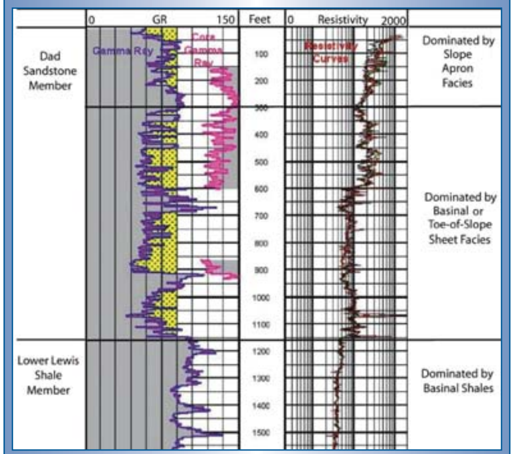

Figure 5. *A plot of the conventional openhole logs from the CSM Stratigraphic Test No. 61 well shows intervals dominated by certain facies.*

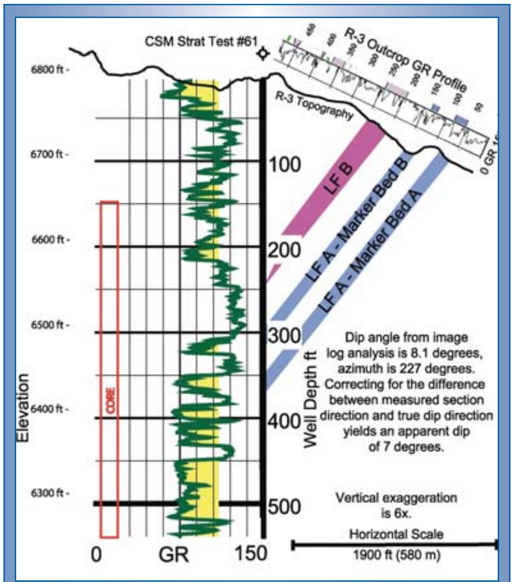

Figure 6. *A stratigraphic correlation between core and outcrop is indicated.*

the geometric and depositional framework for this portion of the Lewis Shale.

Core was described and borehole images were analyzed in a behind-outcrop well, the CSM Stratigraphic Test No. 61. This well was drilled, cored and logged through correlative Lewis Shale strata. In summary, the well contains three primary lithofacies associations – channel complexes and debris flows near the top of the section (log depth 0ft to 300ft), sheet sandstones and channels (log depth 300ft to 1,160ft), and basinal shales (log depth 1,160ft to 1,723ft).

The primary purpose of petrophysical research was to develop an improved flow unit definition methodology and apply it to the CSM Stratigraphic Test No. 61 well. Petrophysical analysis involved conventional core analysis, capillary pressure tests, minipermeameter data and neural network modeling of permeability. The flow unit zonation was accomplished using plots of øh vs. kh. ✧

Acknowledgements

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'Deep Trek' Seeks Deeper, Smarter Drilling Technology

Compiled by Rhonda Duey,
Managing Editor,
GasTIPS

The U.S. Department of Energy hopes to develop a "smart" drilling system tough enough to withstand the extreme conditions of deep reservoirs, yet economical enough to make gas affordable to produce.

In the 1960s cult hit *Star Trek,* Capt. Kirk and his crew set forth "to boldly go where no man has gone before."

In the 21st century, the U.S. Department of Energy (DOE) has set itself a similar goal – only it's looking down, not up.

Already, more than 70% of gas produced in the continental United States comes from wells deeper than 5,000ft. But as gas demand grows in the United States, shallow targets are disappearing, and the big reserves lurk several miles beneath the Earth's surface.

Drilling for these reserves is no walk in the park. High pressures and high temperatures make for an environment hostile to downhole tools and dangerous to the personnel on the surface. But the prize is substantial – the DOE estimates gas resources below 15,000ft at about 125 Tcf, equivalent to about 5 years of total U.S. gas consumption.

To help develop the high-tech drilling tools the industry will need to tackle these deeper deposits, the DOE's Office of Fossil Energy is kicking off the "Deep Trek" program.

The DOE has an aggressive goal to help the industry deploy new deep drilling systems by the year 2010.

Tapping into deep gas resources is currently daunting and expensive. In fact, in the few deep wells being drilled, as much as 50% of the drilling cost is spent on drilling the last 10% to 25% of the wells, where rock formations are harder and temperatures are higher.

Today's sensors, drillbits and materials are ineffective when exposed to the extreme conditions found in deep formations. To help remedy this situation, technologies pursued in the Deep Trek program include low-friction,

Nabors Rig ***No. 196*** *drills toward targets in the ultra-deep Hunton At Chesapeake Energy Corp.'s No. 1-Plunk in western Oklahoma's Beckham County. Projected depth at the time of this photo was 25,100ft.*

(Photo courtesy of Lowell Georgia, Oil and Gas Investor)

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. New tools developed under the Deep Trek program are to operate in extreme temperatures (more than 347°F) and pressures (greater than 10,000psi).

The real advantage of a smart system is its ability to report key measurements, such as temperature, pressure, moisture and geology, as a well is drilled, pinpointing potential trouble spots on a real-time basis. This allows operators to make adjustments as drilling continues, avoiding costly work stoppages.

The Energy Department's National Energy Technology Laboratory, the research arm of the department's fossil energy program, began asking industry to propose Deep Trek development efforts in 2002, initially funding the initiative at $10.4 million.

Proposers had two opportunities to respond. The first was April 11, 2002, when the department asked prospective proposers to submit a pre-application – a mini-proposal no longer than seven pages. After the pre-applications were reviewed, applicants were advised as to whether they should submit a more detailed, comprehensive application May 30, 2002.

The second opportunity came in November 2002, when another set of pre-applications was due, and comprehensive applications were requested by Feb. 27, 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 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 4 years.

Private partners are contributing a minimum of 20% for Phase I projects, 35% for Phase II and 50% for Phase III.

The importance of deeper drilling technologies was underscored in the 1999 report of the National Petroleum Council, titled *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand.* In the report, the Council stated, "Deep drilling is increasing. Production from depths deeper than 10,000ft is expected to increase from 35% in 2000 to 41% by 2010. It is important to note, however, that industry's ability to achieve production from deeper horizons will be dependent on adequate deep drilling infrastructure and the continued evolution of technology."

The Council predicted that by 2010, 12% of all U.S. gas produced will have to come from deep formations – those 15,000ft and deeper. During this same time frame, production from gas wells less than 10,000ft deep is expected to decline as these reservoirs begin to deplete.

Deep Trek projects

The first set of projects selected for the program includes:

APS Technology Inc.—Drilling Vibration Monitoring & Control System. This project plans to develop a two-component system that monitors and controls drilling vibrations in smart drilling technologies.

The drilling environment, and especially deep hard rock drilling, induces severe vibrations into the drillstring. The result of drillstring vibration is premature failure of the equipment and reduced rate of penetration (ROP). The only means of controlling vibration for a given bottomhole assembly with current monitoring technology is to change the rotary speed or the weight on bit (WOB). Changes of the rotary speed and/or WOB to reduce vibration are often achieved at the expense of drilling efficiency.

APS Technology proposes to develop a unique system (DVMCS) to monitor and control drilling vibrations in a smart drilling system. This system has two primary elements: the first is a unique, multi-axis active vibration damper to minimize harmful axial, lateral and torsional vibrations and thereby increase ROP and bit life as well as the life of other drillstring components. The hydraulic impedance (hardness) of this damper will be continuously adjusted using unique technology that is robust, fast-acting and reliable.

The second component is a real-time system to monitor three-axis drillstring vibration and related parameters, including WOB, torque-on-bit and temperature. This monitor will determine the current vibration environment and adjust the damper accordingly. In some configurations, it may also send diagnostic information to the surface via real-time telemetry.

The ability to actively monitor and control the drilling vibration results in the following benefits:

- increased ROP by keeping the bit in contact with the cutting surface;
- increased bit life by eliminating shock and vibration damage;
- increased downhole sensor life; and
- reduced number of trips needed to complete a well.

The above combine to provide reduced drilling costs and time to complete the well.

The broader benefits of extensive use of the DVMCS flow from its role in improving the economics of deep drilling for oil and gas. As known reserves are developed, new sources are sought. These are generally either in remote geographic locations, at greater depths or both.

The primary determining factor in the choice of developing one of these new prospects vs. others overseas is economic. By reducing the financial investment and risk of developing deep domestic reserves, this technology will contribute to a reduced dependence on imported sources, thereby increasing national security.

E-Spectrum Technologies Inc.—EM Telemetry Tool for Deep Well Drilling Applications.

E-Spectrum Technologies proposes to develop a wireless, electro-magnetic (EM) telemetry system for use in deep natural gas and other high-temperature drilling beyond 20,000ft and up to 392°F. Reliable uphole communications would allow vital measurement-while-drilling (MWD), logging-while-drilling and seismic-while-drilling data to be retrieved, analyzed and used to improve the drilling process and, consequently, the wellbore quality. Unprecedented downhole communications would allow direct control of adjustable downhole tools such as kick-off subs, shock subs and drillstring stabilizers from the rig floor.

These capabilities would help to significantly reduce drilling costs, enhance wellbore productivity and improve the safety of drilling for deep natural gas.

The proposed system would use high-sensitivity receivers and sophisticated noise-rejection algorithms to recover the EM signal and maximize the system's depth capability.

The system would consist of four basic functional elements:

- a surface-unit receiver/transmitter;
- a downhole data-acquisition module;
- a downhole repeater module; and
- a downhole receiver/transmitter module.

The downhole elements of this system will be designed as stand-alone modules, using ruggedized mechanical packaging that will fit inside 1.25-in. outer-diameter pressure enclosures built within the drillstring. Modules subjected to temperatures as high as 392°F will use high-temperature components and packaging techniques designed for continuous, unshielded operation at those temperatures.

The project consists of three phases: Feasibility Assessment, Prototype Development, and Field Testing and Commercialization. The 3-year cooperative effort will develop and commercialize a product, which is expected to have immediate and significant market demand.

The Pennsylvania State University—Improved Economics in Deep Well Drilling.

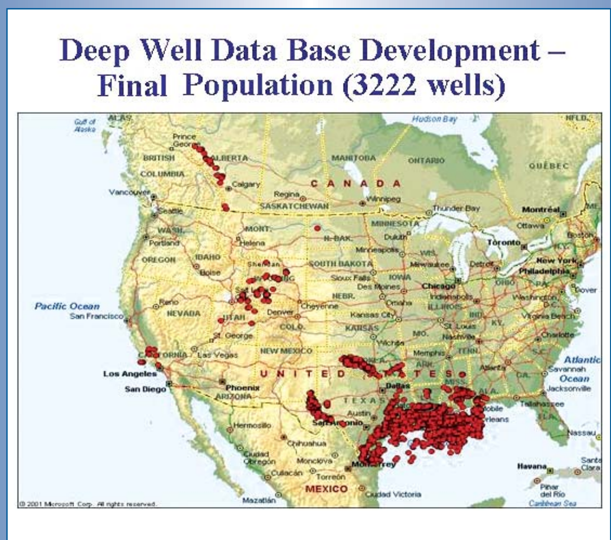
New developments (and innovative ideas) in the area of materials processing could have the most profound and wide-ranging impact on the demand for better performing and cheaper products. This is especially true today as industry and government are focusing on new joint goals:

- better (improved overall performance);
- faster (improvement in process cycle time);
- cheaper; and
- greener (environmentally friendly).

One emerging technology for meeting these goals is high-temperature microwave technology for the sintering of materials, especially the metallic materials. This project aims to exploit the recent developments in microwave technology for producing certain components of a deep trekking system used for oil and gas exploration so the well/hole can be made deeper and cheaper.

The limits of conventional methods for deep well construction for oil and natural gas have been well recognized. One of the components of a drilling system and also proposed for high-pressure jet drilling systems is drill pipe for vertical drilling operations or coiled tubing for horizontal or directional drilling operations. It carries the drillbit assembly underground and functions as the transport path for the mud and drilling fluids, housing a number of components, including sensors. However, at high pressures the conventionally made welded drill pipes tend to fail because of erosion and leaks caused by abrasive drill mud. It is important that the drill pipe and/or coiled tubing remain mechanically stable and chemically inert while in a hostile environment underground so a deeper well or hole can be penetrated and also allowing the time at the bottom of the hole to be extended. In order to accomplish this, an improved material/process for drillpipe/coiled tubing is sought. Penn State's concept for improving performance of drillpipe/coiled tubing is based on newly emerging technology utilizing microwave energy for processing of steel powders.

The main objective of the research project is to improve the ROP in deep hostile environments by improving the life cycle and performance of coiled tubing and/or drill pipe. This will be accomplished by developing an efficient and economically viable continuous microwave process to sinter formed/extruded steel powder for the manufacture of seamless coiled tubing and drillpipe. The goals of the project are to manufacture economically coiled tubing with improved performance under hostile underground and marine conditions.



The majority of wells below 15,000ft have been drilled along the Gulf Coast.

The project will be carried out in three phase involving:

- a feasibility study;
- building a prototype microwave continuous sintering and extrusion system;
- determination of optimum sintering conditions;
- plan for the commercialization of the technology; and
- cost analysis of the new technology and economic viability with respect to the existing technology. It is expected that the performance of coiled tubing and drill pipe made by the microwave process will have superior quality and performance to the standard product.

Participating in the project with The Pennsylvania State University are Dennis Tool Co. and Quality Tubing Inc.

Pinnacle Technologies Inc.—Stimulation Technology for Deep Well Completions. This project is focused on the second objective of the Deep Trek program, "Improved Economics in Deep Well Completions." The deep reservoirs that will be exploited in the future will typically be low permeability, high temperature and pressure, perhaps abnormally pressured, and contain contaminants including carbon dioxide and hydrogen sulfide. The high cost of drilling and completing these wells will require maximum effort be made to enhance production and recovery in order that these wells are economic. Therefore, these wells will require some type of stimulation, probably hydraulic fracturing, in order to be economic.

The objective of the project is to review current and past stimulation activity, and research results for deep well completions and develop information for industry that will help reduce uncertainty and increase success in frontier and emerging deep formation plays. The project will provide industry with an assessment of:

- what is currently working in deep formation stimulation;
- what is currently not working in deep formation stimulation; and
- what needs improvement in deep formation stimulation.

The project focuses on three major areas. First, it will evaluate the current state of the art in stimulation technology and identify key stimulation issues for deep gas wells. This will be accomplished through a comprehensive literature review and interviews with operators, service companies and consultants. Second, it will evaluate rock mechanic and fracture growth behavior in deep formations. The nature of deep reservoirs can result in complex hydraulic fracture growth and production behavior because of the complex stress regimes and large component of stress initially supported by the high reservoir pressure. Third, it will evaluate in detail the performance of stimulation techniques in three to five deep gas plays.

Drilling, completion, stimulation, production and geological data will be obtained from operators, and comprehensive assessment of current and past stimulation practices will be conducted. The results of the project will be documented in a comprehensive report and transferred to industry through publications and workshops.

Terra Tek Inc.—Optimization of Deep Drilling Performance; Development and Benchmark Testing of Advanced Diamond Product Drill Bits and HP/HT Fluids to Significantly Improve Rates of Penetration.

The 3-year project addresses improvements in deep well drilling performance through rigorous proof-of-concept testing of new drilling components at high borehole pressures (22,000-ft to 26,000-ft simulated depth). The work focuses on the development of novel drillbit technologies and advances in high pressure/high temperature (HP/HT) fluids for various deep, slow drilling applications. A phased approach to developing and commercializing "smart drilling bit fluid systems" combines the features of new concept bit technologies and fluids specifically benchmarked and proven for high-pressure applications. TerraTek will benchmark tool performance at conditions not possible in other laboratory environments and not practical in expensive field trials.

For domestic operations involving hard rock and deep oil and gas plays, improvements in penetration rates are an opportunity to reduce well costs and make viable certain field developments.

An estimate of North American hard rock drilling costs is in excess of $1.2 billion. Thus, potential savings of $200 million to $600 million are possible if penetration rates are doubled (and assuming bit life is reasonable). The net result for operators is improved profit margin as well as an improved position on reserves.

TerraTek has assembled a team of industry and academic contributors who are recognized leaders in:

- hostile environment drilling operations;
- engineering development and large-scale testing;
- downhole tool engineering and supply;
- mechanics and rock cutting characterization;
- rig-site pump equipment developments;
- commercial experience.

Objectives of the project include:

- ***Characterization of applications:*** Determine the specific performance issues with roller cone, impregnated and/or PDC bits in the operators' areas of interest and conduct engineering evaluations of promising concepts.
- ***Benchmark performance of emerging products:*** Full-scale drilling tests would be performed in TerraTek's Drilling and Completions Laboratory. In the wellbore simulator, drilling tests at high pressures in hard rock and others as appropriate will reveal deficiencies and design features required for a next level of performance.
- With the industry team, develop and supply new aggressive impregnated and

PDC bit prototypes and HP/HT drilling fluids addressing ROP challenges. Higher ROPs in a variety of rock types is the goal for these deep applications. TerraTek will test, evaluate and document the performance of these innovative diamond products and drilling fluids.

Participants include TerraTek (contractor), University of Tulsa, Hughes Christensen, BP America, ConocoPhillips, INTEQ Drilling Fluids, Marathon Oil Company, ExxonMobil and National Oilwell.

Additional projects awarded in May 2003 include:

Honeywell International, to identify and develop a suite of high-temperature electronic components that can be used for instrumentation in deep gas drilling systems.

Drilling for natural gas below 15,000ft has presented the electronics industry with a challenging environment. Locating an instrument for pressure or flow measurement at the end of 3 miles of pipe poses problems for electronics, including withstanding temperatures ranging from 250°F to 437°F for prolonged periods of time. Honeywell hopes to combine and upgrade some of its existing electronics technology to perform in the harsh deep reservoir environment.

Honeywell will conduct the project though its Solid State Electronics Center for Excellence and will form a joint industry participation group to develop system specifications prior to product development.

Schlumberger Technology Corp., to design and commercialize a high-temperature (approaching 400°F), high-pressure MWD tool that provides direction, inclination, and toolface and gamma ray measurements continuously in real time to improve drilling decisions on the rig. The tool also will be fully retrievable while the drillstring is downhole, eliminating the need to remove the entire drillstring assembly to retrieve directional equipment.

*Chesapeake's **No. 1-12** in Caddo County, Okla., is being drilled by Nomac Drilling's Rig **No. 3** to a projected total depth of 15,700ft.*
(Photo courtesy of Lowell Georgia, Oil and Gas Investor)

High-temperature and high-pressure are two of the challenges in deep horizontal wells, and operation in these environments often limits the effectiveness and life of MWD tools. Failures are costly if drilling must stop to remove the pipe and replace a tool. Schlumberger's MWD tool, if successful, will improve the economics for deep well drilling by reducing downtime, boosting the overall ROP in deep hostile environments.

Cementing Solutions, Inc. (Watters Engineering), in a combined effort with Argonne National Laboratory and other industry partners to develop "supercement" capable of sealing drill pipe annuli (the space between the drill pipe and the surrounding rock formation) at high temperatures and pressures. The supercement will possess superior pipe- and formation-bonding capabilities to ensure a tight annular seal at depths exceeding 15,000ft.

Industry authorities estimate that repairing failed cement jobs in deep, hot wells costs industry more than $100 million each year. Many failures occur because the Portland cement systems used today cannot stand up to the extreme temperatures, pressures and corrosive gases found in deep reservoirs. The team's supercement will have the tensile strength, permeability, compressive strength and expansive properties required for long-term durability, minimizing the potential for mechanical failures at high temperature (exceeding 350°F) and pressure.

The team's work will begin with laboratory analysis of various Portland and non-Portland materials and mixtures to identify compositions that provide the optimum mechanical properties for withstanding extreme downhole temperatures and pressures. Upscale testing will be done to determine the cement's performance in larger quantities. Finally, a demonstration of the cement's performance will be conducted in three to six field applications in hot, deep wells. ✧

For more information about Deep Trek, contact Gary Covatch, National Energy Technology Laboratory, (304) 285-4589, e-mail: gary.covatch@netl.doe.gov; *or Brad Tomer, National Energy Technology Laboratory, (304) 285-4692, e-mail:* brad.tomer@netl.doe.gov.

Coalbed Natural Gas Resources and Produced Water Management

by Dan Arthur and
Bruce Langhus,
ALL Consulting
and
Viola Rawn-Schatzinger,
RMC Consultants

As coalbed methane becomes a primary objective for natural gas drillers, concerns about produced water are coming to the forefront. ***First of three-part series.***

Private and government emphasis in recent years has stressed the growing importance of natural gas as a prime source of energy for industrial, power and residential heating needs in the United States. Natural gas was a top priority at a June 2003 meeting of the National Petroleum Council in Washington, D.C. The chairman of the Independent Petroleum Association of America, Diemer True, spoke of development of coalbed natural gas supplies in the western United States.

"The Inter-Mountain West holds a vast promise for America's future natural gas supply," True said.

Western coalbeds with softer bituminous coals contain abundant coalbed natural gas but produce large quantities of water during extraction processes. The U.S. Department of Energy (DOE), in cooperation with the Bureau of Land Management (BLM) and the Ground Water Protection Research Foundation, sponsored a comprehensive guide to coalbed natural gas-produced water. Data from the United States Geological Survey (USGS) displays in map form the coal producing basins in the Rocky Mountain region showing the complex federal and state land ownership, which affects mineral leases, coalbed natural gas production, and environmental regulations for produced water (Figure 1).

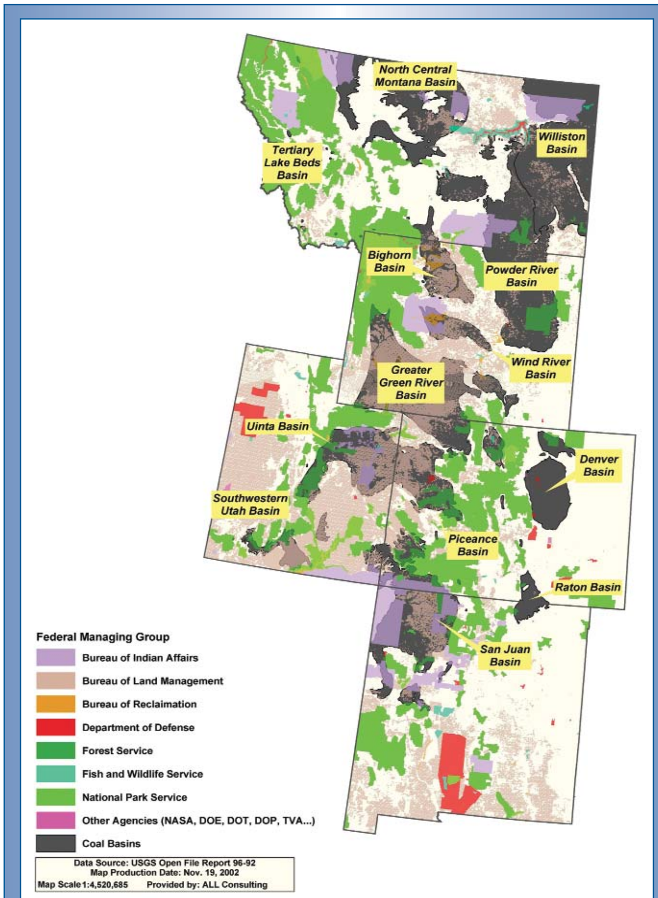


Figure 1. *This map shows coal basins within the study area as well as land ownership distribution. (Source: USGS Open File Report No. 96-92; produced by ALL Consulting)*

Introduction

The purpose of the *Handbook on CoalBed Methane Produced Water: Management and Beneficial Use Alternatives,* prepared by ALL Consulting of Tulsa, Okla., is to summarize existing knowledge on the geological and environmental constraints of producing coalbed natural gas and to explore alternative treatments and beneficial uses for the large quantities of produced water. Formerly termed coalbed methane and still commonly referred to as CBM, the governmental terminology is coalbed natural gas. The USGS, the BLM and the various state geological surveys provided volumes of produced water and CBM production estimates of coalbed natural gas recoverable reserves. Extensive documentation is included in the handbook, soon to be available from the DOE in Tulsa.

This article is the first in a three-part series summarizing the CBM Handbook to appear in future issues of *GasTIPS*. Water problems related to coalbed natural gas production include withdrawal of groundwater from the coal seams, the potential of wasting high-quality water and environmental concerns on disposal of the produced water. The guidebook addresses these concerns, beginning with an overview of coalbed natural gas production scenarios and including a basin-by-basin assessment of CBM resources across the United States, water rights, produced water treatment methods and beneficial uses. Emphasis is on the beneficial uses for the produced water in the Rocky Mountains, with special attention to the Powder River and San Juan basins. The San Juan Basin is the oldest coalbed natural gas region in the United States and along with the Powder River Basin has reached a mature stage in CBM development.

Coalbed natural gas is produced in the Illinois Basin, the Appalachian region, the Black Warrior Basin in Alabama, the Gulf Coast and

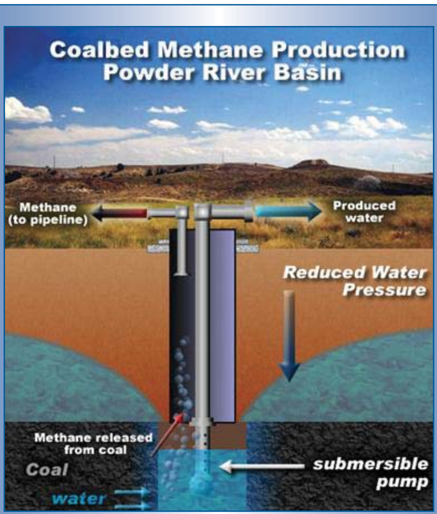


Figure 2. The hydrostatic pressure drops by producing water from a coalbed methane well.

the mid-continent (Kansas, Oklahoma, Arkansas) region; however, produced waters from these areas have higher concentrations of chlorides and dissolved solids than produced water from most western basins, which preclude them from most beneficial uses of CBM produced water.

Coalbed natural gas management and resources

To produce coalbed natural gas from coal seams, a series of wells are drilled to pump groundwater to the surface to reduce the hydrostatic pressure in the coalbeds. Figure 2 shows a simplified schematic of the production process. Once the fluid pressure in the coalbed is released, natural gas or methane is released. The produced water is high volume early in CBM development, but the volume of water is reduced dramatically during the life of the well. Produced water quality varies from meeting federal drinking water standards up to concentrations of 180,000 ppm total dissolved solids (TDS).

Coalbed natural gas contains nearly 100% methane and is typically produced from coal seam reservoirs at shallow depths. The coal deposits underlie 13% of the United States. Coals are ranked by hardness, with most of the hard coals found in eastern basins. Eastern hard coals have less water, which is normally of low quality and unsuitable for drinking or agricultural use. In addition, many eastern coals do not have enough water to be removed from the coals to initiate methane or natural gas production. Coals in the western United States are younger in age and typically softer, producing significantly more water of higher quality. Coal seams in the western United States are often the aquifers for drinking water. Coal basins in the western United States are generally in dry to very arid climates, and water availability for CBM development and produced water disposal are more critical concerns than in the temperate eastern United States.

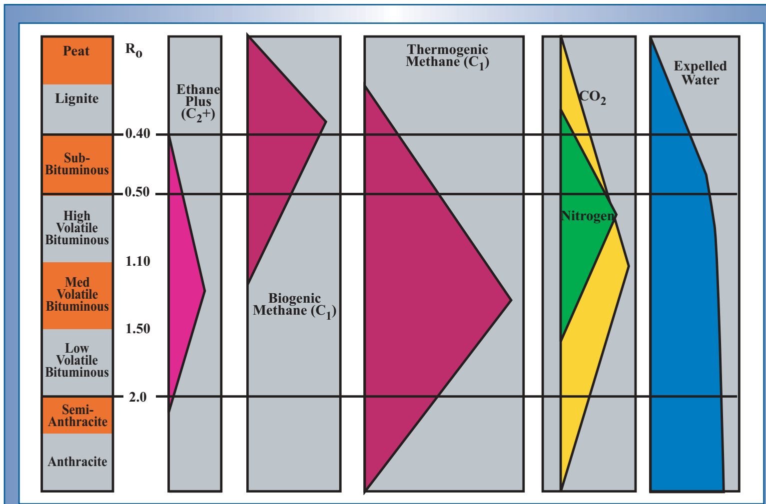


Figure 3. Maturation of coals from soft plant and woody debris is a lengthy geologic process caused by heat and pressure from the overlying rock layers. These thermogenic and biogenic processes produce several by-products, including methane.

A number of factors control coalbed natural gas production and the associated produced water, including permeability, fractures, gas migration, coal maturation, coal distribution, geologic structure and basin tectonics. Natural fracturing is primarily related to geologic structure and coal maturation or ranking. Maturation of coals from soft plant and woody debris is a lengthy geologic process caused by heat and pressure from the overlying rock layers. Older coals are typically in the harder anthracite and semi-anthracite range. Younger, soft coals range through several levels of bituminous coal to lignite and peat (Figure 3).

As a rock, coal has low permeability, so that fluids produced from coal seams migrate through secondary permeability zones such as fractures. In mining and coalbed natural gas production, the network of natural fractures is termed cleat. The cleat provides the surface area and the pathway for coalbed natural gas desorbsion from the coal. Cleat formation, orientation and spacing result from variations in regional stresses, bed thickness, coal rank, vegetative content and ash content. As water is produced through the wellbore, the hydrostatic pressure within the coal seam decreases, and gas is desorbed and flows into the cleat network migrating toward the production well. As coal matures to anthracite, less methane/natural gas is generated, and little porosity or water remains in the matrix. Coalbed natural gas from most western states is produced from sub-bituminous and bituminous coals. The softer western coals with more abundant water have the potential to produce vast quantities of coalbed natural gas, but produced water volumes also are significant.

Coalbed natural gas/methane completion methods

Because sub-bituminous coals are softer and less competent, they are typically completed using vertical wellbores. The wellbore and coal face are completed using formation water to flush the cleat or natural fractures. Submersible pumps are commonly used to pump the water from the coal seams in order to desorb or release the natural gas. If the cleat is not fully developed, the coal may be artificially fractured using low-pressure stimulation techniques. Both water flushes and

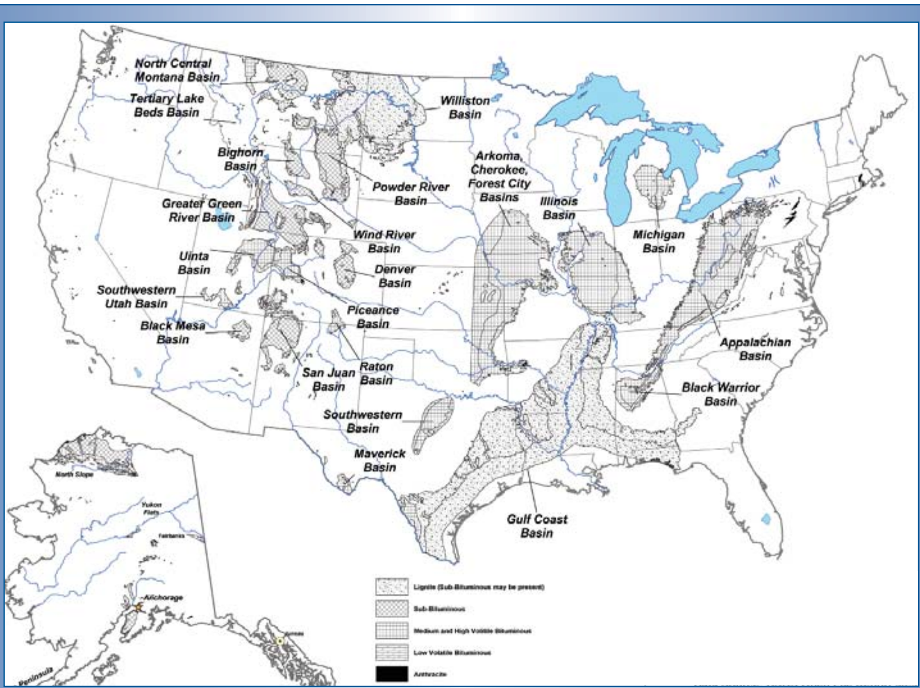


Figure 4. *The coal ranking is an indication of coalbed natural gas potential.*

stimulation require large volumes of water to produce the coalbed natural gas, and as a consequence large volumes of produced water are brought to the surface.

Eastern hard coals, which contain less water, are often developed using multiple horizontal drains from a single borehole. Horizontal wells have a drawback for CBM production in most western states in that they work best when limited to a single coal seam per well, which would make horizontal drilling prohibitively expensive in the multi-level western basin coal seams. Attempts at multi-laterals into more than one reservoir often fail because it is not possible to lower the water level in individual coals independent of each other. However, horizontal wellbores have been successfully used to produce coalbed natural gas from bituminous coal seams in the San Juan Basin of New Mexico. Eastern coals tend to require more fracturing to produce coalbed natural gas than the more highly naturally fractured western coals.

CBM development and resources by region

Water problems associated with coalbed natural gas production are significantly higher in the western United States than in the east. The necessary water to pump out of CBM wells to desorb the natural gas involves water right issues, which will be addressed in the second article of the series. The potential for wasting usable groundwater and the disposal costs of produced water are serious environmental concerns in western states. In the arid West, usable water must be conserved for beneficial uses. In general, groundwater quality in the West is higher than in eastern basins. Produced water from the Appalachians, Gulf Coast and central United States typically contains more than 10,000 ppm TDS and is not suitable for beneficial uses. In the West, coalbed natural gas production raises two concerns – depleting ground water and lowering local water tables, which could cause residential and agricultural wells to go dry. Figure 4 is a map of coal distribution across the United States showing the coal ranking, which is an indication of coalbed natural gas potential.

CBM developers are expected to manage ground water production, find beneficial uses for produced water and at the same time minimize or remediate any negative impacts produced water may have on the environment. To understand the potential effects and uses of coalbed natural gas produced water, it is essential to review the resources of CBM producing areas, both for historical production and future potential.

Alaska—Alaska is new to coalbed natural gas production (first well in 1994) but has potential for development, and production would benefit remote rural communities as well as larger cities and towns. Reserve estimates for Alaska are as high as 1 quadrillion cf of coalbed natural gas. Coals identified in 13 basins in Alaska are in the bituminous to lignite range with abundant water. Three of the basins – the western North Slope, the Alaskan Peninsula (southwest Alaska) and the Yukon Flats basin in central Alaska – contain the highest resources. Water supply is not a problem in Alaska because of high annual precipitation; however, produced water disposal is a concern. Surface discharge is not a viable means because during the winter streams experience low flow rates. Water quality data from Alaska is limited, so studies would be required in most basins prior to CBM development.

Black Warrior Basin—The Black Warrior Basin in Alabama is one of the oldest CBM plays in the United States. Coal degasification projects in the early 1980s led to a rapid expansion of coalbed natural gas production. CBM reserves are estimated at 20 Tcf with about 20% considered recoverable. As of 2002, there were 3,250 active CBM wells in the Black Warrior Basin. Because of the type of hard coals and the number of years water has been withdrawn from the coal reservoirs, the volume of produced water is low, averaging 58 b/d per well. Produced water quality is typically low, with TDS in excess of 30,000 ppm in portions of the basin. Produced water is discharged into surface water such as the Black Warrior River, which has a very large surface flow and a large assimilative capacity to dilute CBM water.

Gulf Coast—The large Gulf Coast region extending west from the Mississippi Embayment across Alabama, Mississippi, Louisiana, Arkansas and Texas into northern Mexico contains a number of coal-bearing formations. Coals are mainly Eocene- and Cretaceous-age sediments. The USGS estimates CBM reserves from the Gulf Coast at 4 Tcf to 8 Tcf. Groundwater quality across this area is highly variable. In south Texas, the water is brackish with high TDS content. Although test wells have been drilled in Louisiana and Texas, CBM production in the region is minimal at this time.

Illinois Basin—The Illinois Basin contains the largest deposits of coal in the United States, primarily of Pennsylvanian age. Coal beds are shallow, most at less than 650ft deep. Test wells have been drilled in Illinois, Indiana and Kentucky, but commercial coalbed natural gas production is limited. Groundwater in the Illinois Basin is low quality, and a significant portion is contaminated because of previous coal mining activities. The TDS content is high, particularly the chlorides, making produced water unsuitable for beneficial uses.

The neighboring Michigan Basin, although similar to the Illinois Basin in many aspects of petroleum production, does not contain sufficient coal reserves to be considered for coalbed natural gas development.

Appalachian Basin—The extensive coal deposits of the Appalachian Basin range across Pennsylvania, West Virginia, Ohio, Kentucky, Maryland, Tennessee, Virginia and the Black Warrior Basin of Alabama. The coals of Pennsylvanian and Permian age have coalbed natural gas potential at depths of 500ft to 1,200ft. Coalbed natural gas is heavily commercialized in Virginia and Alabama and moderately developed in Pennsylvania, West Virginia and Kentucky. Reserve estimates for the Appalachian Basin range from 60 Tcf to 76 Tcf. The water conditions in the Appalachian Basin are highly variable, but typically produced water contains above 10,000 ppm TDS, high in metals, sulfur and arsenic. The low volumes of water are not suitable for human or livestock consumption and must be disposed of primarily through reinjection.

Arkoma-Cherokee Basins—The Cherokee Platform covers parts of southeast Kansas, southwest Missouri and northeast Oklahoma, while the Arkoma Basin extends from central Arkansas into central Oklahoma. Because of changes in the Tax Credit laws, coalbeds in this region of Pennsylvanian age formulations have been developed for coalbed natural gas production extensively during the past decade. In Kansas, CBM wells have increased from 230 in 1992 to nearly 800 by 2002. By late 2001, there were more than 550 CBM wells in the Oklahoma portion of the Arkoma Basin, with most of the wells producing less than 20 bbl of water per day. The produced water in the region is high in TDS, up to 90,000 ppm, and is normally injected into the underlying Arbuckle formation.

Figure 5. A coalbed natural gas well is shown being drilled in the Powder River Basin of Wyoming.

Powder River Basin—The Powder River Basin of Wyoming and Montana (Figure 5) has become the hottest coalbed natural gas/CBM play of the past decade, and its large volumes of produced water have caused considerable public concern and controversy. The Tertiary-age bituminous coals in the Powder River Basin produce CBM from three to five widespread coal seams in the Wyodak Anderson zone of the Tongue River member of the Fort Union formation. By early 2002, more than 9,000 CBM wells were operating in the Wyoming portion of the basin, a more than ten-fold increase in only 3 years. Production in 2002 averaged more than 25 MMcf/d in Wyoming. In the Montana part of the basin, only one field has been developed, with 200 wells by 2001. Reserves are estimated at 90 Tcf for the Montana portion of the Powder River Basin, and further development is anticipated once the BLM completes the Environmental Impact Statements (EIS). The BLM estimates that more than 60,000 CBM wells will be drilled in the Powder River Basin during the next 10 years to 20 years. One of the key factors for CBM development in the Powder River Basin is the economic management of produced water. A number of factors will be discussed in the second and third articles of this series.

The BLM estimates that coalbed natural gas wells in the Powder River Basin produce as much as 20 gallons/minute (gpm) during initial CBM production. Water rates decline as CBM production continues, with average rates of 2.5 gpm to 4 gpm estimated during the life of each well. On the margins of the Powder River Basin, produced water quality is high because of fresh water recharge into the coal seams. Produced water from the marginal areas can be used for human and livestock consumption, as well as crop irrigation. This water is in high demand from ranchers and other residents. Toward the north end of the basin, TDS rises so that water cannot be used for human consumption but can still be used for livestock. The high saline content with TDS more than 3,000 mg/L and high sodium content makes the produced water from the north end of the basin unsuitable for irrigation without proper management to prevent potential damage to some local soils. Livestock are able to adapt to the saline/sodium levels. Produced water from the Powder River Basin suggests a variety of treatment and beneficial use options.

San Juan Basin—The San Juan Basin of New Mexico and Colorado is one of the oldest CBM producing regions in the United States. Cretaceous-age Fruitland and Menefee formations contain thick coal deposits. The Fruitland coalbeds are more extensive, average 10-ft thick, and are found at depths of 4,000ft. The deeper Menefee (6,500ft) coals are thinner and more discontinuous across the San Juan Basin. Coals in the basin are bituminous and sub-bituminous. Methane gas has been an economic resource in the San Juan Basin for 100 years. Coalbed natural gas development began in the 1940s and 1950s and became extensive in the 1980s following passage of the Crude Oil Windfall Profits Tax (1980). Annual production of CBM averages 0.9 Tcf from more than 3,100 wells.

The BLM estimates that in the San Juan Basin, more than 1,000 CBM wells will be drilled in Colorado and 3,000 in New Mexico in the near future. These wells produce an average of 25 bbl water per day per well. Currently, deepwater injection is the most common means of disposal. Treatments and beneficial use options need to be expanded to meet environmental requirements for the arid San Juan Basin.

Uinta Basin and Central Utah—The coals from Utah mainly fall into the Ferron Coalbed Fairway, an 80-mile corridor of basins crossing east-central Utah. The Fairway averages 6 miles to 10 miles wide, and the BLM estimates it contains 4 Tcf to 9 Tcf of recoverable reserves. Coalbed natural gas production is primarily from the Blackhawk and Ferron formations in the Uinta Basin and the Cretaceous-age Mesaverde Group and Mancos shale further south on the western portion of the Colorado Plateau. CBM exploration began in Utah in the 1980s and expanded significantly in the mid-to-late 1990s. Utah Geological Survey data shows that CBM production provides 28% of all Utah's natural gas. Development is expected to increase when new EISs are completed by the BLM. Coalbed natural gas resources are estimated at 10 Tcf for the state of Utah. Water production from CBM operations in Utah averages 215 bbl water per day per well, a significant volume of water for disposal or beneficial use. TDS content ranges from 6,000 mg/L to 43,000 mg/L. In the Uinta Basin, 98% of all water used is from surface runoff from the Wasatch Mountains. The arid basin dewaters the river system during dry summers, and new water sources would be highly beneficial. Proper management of CBM produced water could favorably impact the agriculture of the region.

Colorado Plateau Basins—The Colorado Plateau contains a number of basins in Wyoming and Colorado resulting from Laramide tectonics and deposition in the Cretaceous Western Interior Seaway. The best known basins are the Wind River, Green River, Hanna, Denver, Raton and Big Horn basins. The Western Interior Seaway and the Laramide Orogeny also formed the Powder River Basin.

Coalbed natural gas reserves for the Wind River Basin in west-central Wyoming are estimated at 2.2 Tcf to 6 Tcf. The five sub-basins making up the Green River Basin in south-central Wyoming and north-central Colorado have more than 200 exploratory CBM wells into bituminous coal seams. The BLM estimates an additional 4,000 CBM well will be drilled in the Wyoming portion of the basin in the future. The Hanna and Denver basins have been extensively exploited for surface and shallow coals for decades, but little coalbed natural gas has been developed. CBM development of the Raton Basin of southeast Colorado and northeast New Mexico has increased in the late 1990s to several hundred wells. Water appropriation for CBM operations is a major consideration in the Raton Basin. No CBM development has occurred in the Bighorn Basin of northern Wyoming because of insufficient laterally extensive coalbeds.

Western Washington—Coalbed natural gas development in Washington has been tested in three basins west of the Cascade Mountains. Coalbed natural gas potential from Washington is estimated at 24 Tcf (recoverable percent unestimated). Three Washington basins resulting from volcanism and glaciation provide the best opportunity for CBM development – Bellingham Basin, Western Cascade Mountains and Southern Puget Lowlands. Limited testing but no commercial CBM development has occurred in these areas. Groundwater provides 65% of Washington's drinking water, and 25% of all commercial, industrial and agricultural water, so water management for coalbed natural gas development will be a prime concern.

Williston Basin—The Williston Basin of northeast Montana, North and South Dakota, and Saskatchewan and Manitoba, Canada, is one of the newest regions for coalbed natural gas evaluation and development. The coals of the Williston Basin are similar in age and deposition to those of the Powder River Basin to the southwest. However, surveys for CBM potential by the North Dakota Geological Survey indicate the Williston Basin does not have the same potential as the Powder River Basin. There is no CBM development in the Williston Basin, although some potential is seen in lignite plays in the southern part of the basin. Almost 95% of North Dakota's communities depend on groundwater. Water quality from shallow aquifers is high, but water from deeper formations has higher saline content and would require proper water management if produced.

Conclusions

Coalbed natural gas will supply a significant portion of natural gas from the western United States in the next 20 years. Expansion and continued development will depend on planning and proper water management to meet the requirements set out in EISs. Several states are waiting for the new EIS being prepared by the BLM. New technologies to treat produced water and new evaluations for beneficial uses will form an important part of the development of coalbed natural gas in the future. The DOE, the BLM, the Ground Water Protection Council, and various state geological surveys and universities are actively involved in solving the problems of produced water so coalbed natural gas development can continue to supply valuable natural gas to the U.S. economy while maintaining the environmental quality of the land. ✧

Future articles

Water Appropriation and Treatment Methods for Produced Water.

Beneficial Uses for CBM Produced Water.

Natural Gas Storage in Basalt Aquifers of the Columbia Basin: A Guide to Site Characterization

by Stephen P. Reidel,
Vernon G. Johnson and
Frank A. Spane,
Pacific Northwest National Laboratory

Thick layers of basalt in the Pacific Northwest offer the potential for storage.

Increasing domestic and commercial demand for natural gas in the Pacific Northwest requires development of adequate storage facilities. Geologic storage is one economically attractive option, provided adequate storage capacity and containment requirements can be met in favorable locations.

Extensive areas of thick layers of basalt within central Washington State represent a large geologic province that is relatively unexplored for subsurface gas storage. Existing gas transmission pipelines cross this area, and certain basalt structures have been found capable of containing natural gas. The challenge is to identify specific locations suitable for natural gas storage and near existing pipelines.

To assess the potential of developing natural gas storage in basalt aquifers of the Columbia Basin, the U.S. Department of Energy (DOE) National Energy Technology Laboratory asked Pacific Northwest National Laboratory (PNNL) to compile existing information pertaining to permeable, groundwater-producing zones within the Columbia River Basalt Group (CRBG). These zones would be the focus of natural gas storage. This compilation, along with the authors' combined experience in basalt studies, provides the basis of a report that can be used as a guide to explore the feasibility of establishing natural gas storage reservoirs within the CRBG in the Columbia Basin. The report is designed to provide a detailed framework for the design and conduct of exploration characterization activities to companies interested in natural gas storage within basalts.

This article is an excerpt from that report and provides a preliminary screening assessment and a compilation of information and methods needed to select and characterize suitable locations for subsurface gas storage.

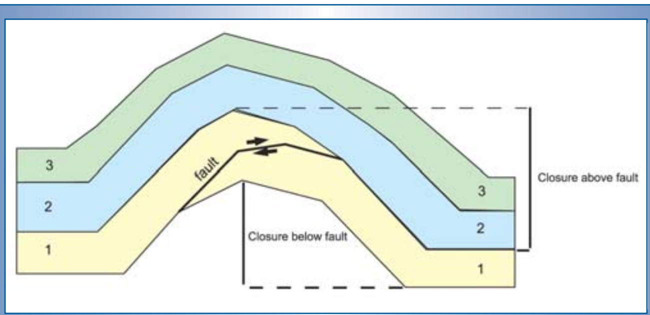


Figure 1. Internal features of a Columbia River Basalt Group lava flow.

Natural gas reservoir considerations

There were 413 underground natural gas storage sites in the United States in 1999 with 76 Bcf/d of withdrawal capability and 3,933 Bcf of working gas capacity. Most of these existing storage sites are in porous sedimentary formations associated with depleted hydrocarbon reservoirs and/or salt dome structures.

CRBG lava flows differ from the more uniformly porous media used in conventional natural gas storage facilities, primarily because only a portion of each lava flow (i.e., the top and bottom of the flow, the interflow zone, Figure 1) is capable of storing gas. A significant portion of the dense interior of an individual lava flow forms a barrier or confining caprock to the vertical movement of gas. Thus, development of an economically feasible gas storage zone requires sufficient effective porosity in the interflow zone(s) to allow injection, storage and withdrawal of gas at a rate that will meet system demands.

Technical issues

The primary technical issues that need to be addressed to determine whether an interflow zone in the CRBG lavas can function as a natural gas storage zone are grouped as follows:

- are there zones within the basalt flows that have sufficient size (lateral extent, thickness, continuity) to store natural gas;
- do the storage zone(s) have favorable properties, such as sufficient porosity and permeability, for efficient natural gas storage and retrievability;
- is there sufficient closure at depth to keep the gas from migrating away from the site;
- are there good caprocks that will prevent the stored natural gas from leaking from the storage horizon; and
- is the water quality favorable (non-potable and devoid of hydrogen sulfide).

Lava flow size

Collectively, the CRBG covers an extensive area with individual lava flows covering many tens of thousands of square miles. Depending on the characteristics of flow at the time of eruption – volume; paleotopography, which is the topography at the time of flow emplacement – an individual CRBG flow can range from a few tens of feet to 300ft thick. Generally, basalt flows of the Grande Ronde Basalt, particularly within the south-central region of the Columbia Basin, are thicker than counterparts within the overlying Wanapum Basalt and Saddle Mountains Basalt.

The volume and extent of CRBG lava flows sets them apart from typical small-size lava flows and provide attractive targets for gas storage reservoirs. Even though only the interflow zone sections are usable for natural gas storage, the large flows put them on equal footing with the sedimentary formations within the United States being used for gas storage.

The most important tool for recognizing a CRBG lava flow in the subsurface, and thus its areal extent, is its chemical composition. The chemical signature of each lava flow allows mapping of its lateral extent. This is particularly true for lava flows of the Saddle Mountains Basalt and Wanapum Basalt that have unique chemical compositions allowing them to be easily recognized. In contrast, Grande Ronde Basalt flows, which were erupted rapidly in time, have more subtle compositional variations. Although the compositional variations for Grande Ronde Basalt flows are subtle, their chemical signatures are nevertheless distinguishable. Based on these chemical variations, Reidel et al, 1989 have recognized 17 chemical compositional groups for the Grande Ronde Basalt. Because of the depth required for natural gas storage, it would probably be the most likely target for site characterization.

Rock properties of potential storage zones

Columbia River Basalt Group lava flows typically consist of a permeable, rubbly flow top and bottom and a dense, relatively impermeable flow interior section (Figure 2). The collective contact section between two successive basalt flows is referred to as an interflow zone (vesicular flow tops, brecciated flow tops, basal pillow complexes and basal breccia zones) and form the primary aquifers within the Columbia Basin for agricultural, municipal and domestic use. Sedimentary interbeds of the Ellensburg Formation that occur between successive flows occur most frequently within the Saddle Mountains Basalt and Wanapum Basalt and generally possess sufficient permeability to support domestic water supply needs. In the central region of the Columbia Basin, however, sedimentary interbeds commonly have fine-grained (tuffaceous sediments, clays) facies within their sections, which together with dense flow interior sections of basalt act as local and regional confining/caprock layers.

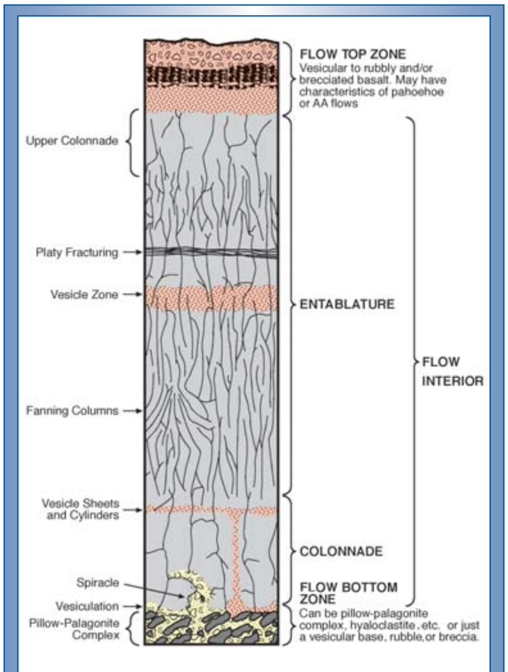


Figure 2. Example of natural gas storage in a Columbia River Basalt Group anticline.

The ability of selected interflow zones to produce groundwater throughout the region and the **Rattlesnake Hills** gas field demonstrate their potential for natural gas storage. The relatively low permeability afforded by basalt flow interiors also suggests they can act as potential confining/caprock layers for the containment of natural gas that would be stored within underlying basalt interflow zones.

Lateral continuity of reservoir zones

Two factors can affect the lateral continuity of CRBG internal lava flow features: initial variations imposed on the lava flows when they were erupted and emplaced, and post-emplacement structural effects.

Internal flow features form while the lava flow is being emplaced and/or after it has stopped and begins to solidify. The internal jointing that produces the colonnade and entablature sections of a basalt flow are a function of the solidification process, and it develops after the flow has stopped moving and begins solidifying. The joints usually follow the solidification thermal front as it moves from the top and bottom through the flow. Rubbly zones associated with basalt flow tops and pillow-palagonite complexes commonly occur near the flow base and form during flow emplacement. Discontinuous internal vesicular sheets and pipes typically form after the flow has stopped moving and begins to solidify.

Flow tops form as the lava flow loses heat to the atmosphere by convection and begins to solidify. A number of factors contribute to the thickness and extent of a flow top development. Gas content is particularly important for the development of primary porosity in the formation of vesicles as the lava degasses. Although vesicles are an important contributor to primary porosity, the degree of vesicle interconnectivity is important in the development of permeability as well as effective storage within the flow top zone. When the top of the lava surface solidifies while the flow is still moving, the flow top is susceptible to brecciation processes that provide enhanced areas of secondary porosity and permeability.

Flow top breccias represent some of the most porous and permeable lava flow features. The continuity of these zones, however, is difficult to predict, and the locations where they can be expected is uncertain. Pillow-palagonite complexes also are important contributors to the effective porosity of an interflow zone. Pillow zones form when lava enters surface-water features, such as river channels and lakes. A surface exposure of a well-developed pillow zone complex is visible at the base of the Ginkgo flow (Frenchman Springs Member, Wanapum Basalt) in the Vantage, Wash., area. It formed when this lava flowed into the ancestral Columbia River channel. Here, the pillow complex occupies an area of dozens of square miles.

Recognizing interflow zones and interflow structures in basalt flows can be facilitated by drilling continuous core or, more economically, by using wireline logging technology. Flow top and internal vesicular zone delineation can be easily distinguished using either sonic tool or neutron-neutron tool technology, because zones with higher porosity, such as vesicles, retard the sonic signal compared with the massive interior of the lava flow and produce an excellent response. Neutron-neutron tools respond to the water in the flow top and also produce an excellent zone definition. Both tools give a good measure of total porosity, which may not be indicative of actually interconnected storage volume, such as effective porosity. This can only be obtained by hydraulic characterization testing. Hydraulic testing can also be used to investigate the continuity of permeable/porous interflow zones and whether geologic boundaries such as faults are present that may disrupt their lateral extent.

Storage zone permeability and effective porosity

Interflow zones of the CRBG lava flows typically exhibit a range of hydraulic conductivity, ranging above 10 orders of magnitude. Detailed studies conducted on the Hanford Site indicated that interflow hydraulic conductivity generally decreases with depth, with Grande Ronde Basalt interflows having a geometric mean value two orders of magnitude lower than overlying Saddle Mountains Basalt and Wanapum Basalt counterparts (Spane, 1982; DOE, 1988). This depth dependence for interflow hydraulic conductivity is believed to be associated with decreases in fracture permeability and porosity associated with increased secondary mineralization and greater effective stress conditions. These conditions are particularly relevant for the south-central region of the Columbia Basin, where individual basalt flows tend to be thicker and Grande Ronde Basalt flows occur at greater depths.

Effective porosity refers to the interconnected void space within interflow zones that can collectively serve as the theoretical available volume for natural gas storage and retrieval. In contrast to hydraulic conductivity measurements, few field measurements of interflow zone effective porosity are available.

Laboratory core analyses for Grande Ronde Basalt flow tops reported in Loo et al. (1984) range between 0.07 and 0.30 (30%) but because of scaling effects, are likely overestimated actual *in-situ* formation conditions.

Hydrologic tests best designed for direct determination of effective porosity include various single- and multi-well tracer tests. Theoretically, effective porosity also can be determined indirectly by storativity (S) analysis results derived from hydrologic tests – constant-rate pumping tests and slug tests – as well as from well/aquifer barometric response analysis. Effective porosity estimates derived from these indirect methods, however, are subject to a wider range of uncertainty.

Structural closure

Closure is an important issue that must be addressed for assessing site viability. Without structural closure, stored gas is susceptible to offsite migration based on the prevailing groundwater flow dynamics and gas fluid potential distribution at reservoir depth.

Because of the two-phase conditions that develop within an aquifer-type of natural gas storage reservoir, phase segregation exists within the reservoir, with natural gas forming a bubble at the top of the aquifer. The Yakima folds provide an attractive target for a natural gas storage facility because the basalt has been folded into natural anticlines and domes.

Although closure can easily be estimated at the surface from topographic maps, several factors can significantly influence structural closure at depth in the subsurface. These factors include variation in flow thickness across structural highs (anticlines) and faulting at depth.

Flow thickening and thinning—From field and borehole studies, it has been shown that the Yakima folds were growing during the eruption of the CRBG lava flows (Reidel et al., 1989). This conclusion is based on studies showing thinner lava flows on the anticlinal ridge and thicker flows on the flanks and in synclines. This variation in

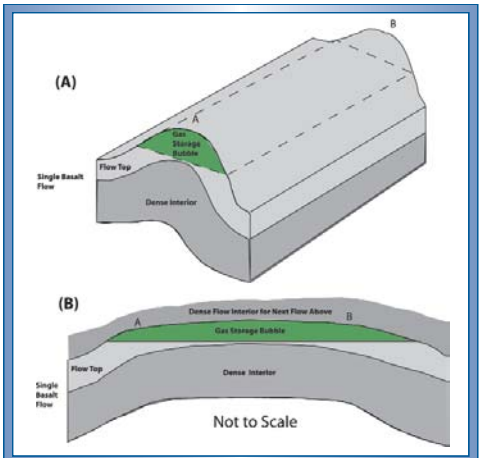


Figure 3. Example of loss of structural closure from faulting involving only a single lava flow.

flow thickness reflects the burial of the ridge during its growth by lava eruptions, which implies structural closure can be greater with depth compared with the surface closure measured from a topographic map. Closure can be evaluated at a site by drilling boreholes on the crest and flank of the structure and comparing the flow thickness or using seismic techniques.

It should be noted, however, that thinning of basalt flows in these anticlinal areas, as well as associated flow interior/caprock layers, is a factor that may be conducive for leakage and vertical communication between interflow zones. The relationships between flow thickness variations and paleotopography appears to be most significant for individual flows of the Saddle Mountains Basalt, which collectively represent the least extensive formation (by volume) within the CRBG. Correspondingly, less thickness dependence is exhibited for the more voluminous flows of the Grande Ronde Basalt.

Faulting—The Yakima Fold Belt formed within the CRBG as a direct result of compressional folding. High-angle reverse faults and thrust faults are commonly found within the fold-belt areas in the region. Normal faults are typically not present in the subsurface, but strike-slip faults can occur at near right angles to the reverse faults, often at segment boundaries along the length of the folds. Reverse and thrust faults generally have the effect of reducing closure with depth (Figure 3).

Closure occurs as a result of compression, as one block slides over another and repeats part of the subsurface stratigraphy. A repeat in the stratigraphic section produces an increase in the observed structural relief above the repeated section. Thus, in contrast to the influence of thinning, surface relief gives an overestimate of the structural relief (closure) at depth in the case depicted in Figure 3. If thrust faulting is constrained purely along flow contacts or within sedimentary interbed and does not intersect adjacent flows, no repeat in the stratigraphy will occur. In these situations, no loss in structural closure at depth would be produced compared to land surface relationships.

Because individual basalt flows can be recognized by their chemical composition, sampling and analysis of borehole chip samples can detect repeats in subsurface stratigraphy. If only one flow is involved in the faulting, it will appear as a greatly thickened flow. However, if two or more flows are involved in faulting, the repeated stratigraphy will be easily detected. This analytical tool provides the basis of assessing any potential reduction in closure occurring at depth using information obtained with a single borehole.

Strike-slip faulting can impact reservoir continuity at depth, but its detection in the subsurface is more difficult. This is because a repeat in stratigraphy typically does not occur for strike-slip faulting. A change in the geometry of an anticline expressed within surface outcrop patterns, however, probably provides one of the best indications that a buried strike-slip fault exists. Surface geophysical techniques such as seismic methods provide the best method for detection of strike-slip faults within the subsurface.

The brittle deformation of the basalt due to faulting and folding can create preferential vertical flow pathways through basalt flow interiors (tectonic fractures), enabling vertical hydrologic communication between interflow zones in areas adjacent to fault zone structures. This is the case in areas surrounding high-angle faults. The presence of faulting, and associated tectonic fracturing of confining caprock layers, therefore, should be considered a potentially adverse factor for natural gas storage.

Caprock leakage

The CRBG lava flows form a multilevel reservoir-caprock system. Confining caprock layers for natural gas storage within interflow zones are represented by flow interior sections of massively thick flows. Basalt flow interiors exhibit considerably lower hydraulic conductivities than do interflow zones. Detailed studies conducted on the Hanford Site also indicated a general decrease in permeability with depth. The reason for this depth dependence for flow interior hydraulic conductivity is believed to be the same cited for interflow zones and associated with decreases in fracture permeability and porosity because of increased secondary mineralization and greater effective stress conditions. The dense interior part of basalt flows provides a measure of interflow zone isolation and can act as a caprock for a gas storage horizon provided areas with crosscutting features (faults and stress fracturing) are avoided. Low-permeability facies (clays, tuffaceous units) within sedimentary interbeds that occur intercalated between some basalt flows can also provide effective caprocks. Sedimentary interbeds are more prevalent within the Saddle Mountains Basalt but also occur locally within the Wanapum Basalt and regionally between the Grande Ronde Basalt and Wanapum Basalt. The presence of sedimentary unit caprocks may be more prevalent within the south-central region of the Columbia Basin, where low-permeability sedimentary units occur more frequently between individual basalt flows.

A variety of direct and indirect hydrologic tests can be used to determine the permeability (hydraulic conductivity) of candidate confining/caprock zones. Direct hydrologic field tests recommended for hydraulic conductivity determination include pulse tests and constant-pressure (head) injection tests (in single- and multi-well field configurations) and various direct and indirect techniques that use constant-rate, interflow zone pumping tests (ratio method, leakage analysis methods). There are distinct advantages and disadvantages and area-of-investigation differences for each test method.

In addition to hydrologic field tests, qualitative information concerning the sealing characteristics of caprocks can be obtained through observed differences in interflow zone hydrochemistry and vertical head or fluid potential profiles. Distinct hydrochemical and isotopic compositional differences between groundwaters of the Grande Ronde Basalt, Wanapum Basalt and Saddle Mountains Basalt have been used to imply aquifer isolation, and thus, the integrity of intervening caprock units (e.g., Gephart et al., 1979; Spane, 1982; DOE, 1988). Although hydrochemical information provides valuable information concerning the separation/communication between ground-water-flow systems, such as local, intermediate and regional, the degree of isolation or leakage between individual interflow zones cannot be quantitatively determined using hydrochemical information.

Gas threshold pressure

The creation of a natural gas storage reservoir within an aquifer imposes a multiphase condition, such as gas and water, within the subsurface. For candidate interflow zones for gas storage and overlying low-permeability caprocks, capillary forces may hold groundwater within the pore interstices, even in the presence of a pressure gradient. The pressure required to exceed the capillary forces within either an interflow zone or overlying caprock pores to displace the "held" water with injected gas is referred to as the gas entry or threshold pressure. Because of the greater permeability and porosity afforded by interflow zones, gas threshold pressure (GTP) would be expected to be considerably lower than for low-permeability/porosity flow interior caprock layers. Determination of the GTP within caprocks is particularly important from the standpoint of leakage since, if gas injection pressures within the candidate reservoir zone (interflow zone) can be held below the GTP within the caprock, the effects of capillarity will impede the vertical leakage of stored reservoir gas. The standard field test for determining the caprock GTP is the gas threshold pressure test. For sedimentary formation caprocks, gas entry pressure information also can be derived from laboratory core tests; however, statistical analysis of large numbers of core test results must be performed to effectively evaluate this parameter. Because permeabilities of basalt flow interior caprock layers is inherently low and dependent on irregular fracture connectivity, the applicability of core analysis results for these units is highly questionable and better addressed using field tests.

It also is important to know the injection gas pressure at which the overlying caprock will fracture/fail. Failure can occur when the candidate interflow zone is over-pressured during gas injection/storage operations. The injection overpressure that induces hydrofracturing of the confining/caprock layer is a function of the existing hydrostatic pressure and in-situ stress conditions. Hydrostatic pressure can be estimated from the depth to the horizon of interest and areal water-level conditions. Information pertaining to the current state of stress within the Columbia Basin comes from geodetic surveys, hydraulic fracturing tests and earthquake monitoring. The DOE have obtained direct measurements on the state of stress in the basalt from hydraulic fracturing tests on the Hanford Site. Hydraulic fracturing tests conducted at about 3,200ft depth in boreholes in the central Columbia Basin indicate that the maximum horizontal stress ranges from 7,630psi to 9,780psi, and the minimum horizontal stress ranges from 4,400psi to 5,180psi.

Calculating potential gas storage volume in basalt interflow zones

The economics of a viable natural gas storage project are variable and driven by the supplier needs pertaining to total/working storage volume requirements, recoverability and deliverability/production rates. Typical anticlinal ridge systems in the Yakima Fold Belt are 0.6 miles to 1.2 miles wide. Although the anticline serves as the trap in the transverse direction, the length of a trap system is dictated by the occurrence of end-closure points (i.e., where saddles or pinch-outs occur). A likely length where end closure can be found will vary; however, 3 miles may be taken as reasonable for purposes of estimating land requirements for a typical natural gas project. The total area of a hypothetical natural gas storage site would be 0.9 miles x 3 miles = 2.7 miles. Using multiple flows for storage also greatly increases the calculated storage volume available at a site and would reduce the size of the ridge system needed.

More detailed and exacting reservoir calculations would be needed for an actual site screening analysis; however, the preliminary scoping calculations presented here demonstrate that suitable sections within a typical basalt fold structure meet theoretical storage capacity requirements. Thousands of square kilometers of basalt ridges are theoretically available within the Yakima Fold Belt (see Figure 4 as an example of an anticlinal structure with end closure). Some of the more attractive sites may be ones suitably located in close proximity to existing pipelines and have favorable site characteristics – reasonable end closure points, non-potable water at the target depth, low seismicity and good caprock potential.

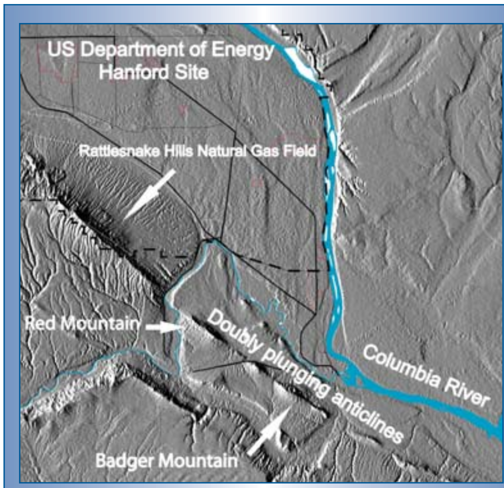


Figure 4. Map of the Pasco Basin showing examples of anticlines suitable for potential gas storage.

Summary of site selection and characterization needs

This information can be used for pre-screening and selection of candidate locations for natural gas storage. However, additional, more detailed, site-specific characterization is needed once candidate sites are selected for further investigation. The DOE's experience in drilling and testing within the Pasco Basin for nuclear repository characterization and its participation in a preliminary reconnaissance investigation for development of a commercial natural gas storage reservoir in deep basalt is useful for planning future characterization programs. For the full report, visit *www.netl.doe.gov/scng/*. ✧

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In Brief

Minority students program (GTI)

The Gas Technology Institute (GTI) has launched a program to increase minority participation in research, development and education programs related to natural gas. Twelve students from seven schools began internships this summer at GTI's headquartered campus near Chicago.

No specific preferences have been set for minority individuals or groups in this program, but the initial focus will be on attracting minority students from historically black colleges and universities as well as Hispanic-serving institutions.

In the initial phase of the program, GTI expects students will take part chiefly in cooperative research experiences or internship programs at GTI. In the longer term, a more ambitious slate of participation options is envisioned, offering activities such as:

- senior-year graduate projects;
- MS and Ph.D. thesis projects;
- energy-related academic scholarships;
- faculty development through summer internships and sabbaticals; and
- joint research projects.

GTI will provide $500,000 during 2003-2004 to fund a housing allowance, a modest hourly stipend and transportation to and from GTI for participating students.

To expand the program beyond 2004, GTI is actively soliciting support from U.S. energy companies.

In 2005 and beyond, the program will aim to place participating students and faculty with other companies as well as with GTI to broaden the variety of experiences available to participants and to give supporting companies the opportunity for direct interaction with faculty and students.

For more information, contact Michael Dugan at *michael.dugan@gastechnology.org*

DOE to hold methane hydrate research and development conference

The U.S. Department of Energy's Office of Fossil Energy/National Energy Technology Laboratory (NETL) will host a methane hydrate conference Sept. 29-Oct. 1 in Westminster, Colo. The conference will provide updates and highlights of the ongoing research supported by the national Methane Hydrate Program. Multiple government agencies and researchers will be participating. In addition to sessions on arctic and marine methane hydrate projects, the conference will include a poster session and reception.

Immediately following the conference, Sept. 30 and Oct. 1, the ChevronTexaco joint industry project (JIP) on *Characterizing Natural Gas Hydrates in the Deepwater Gulf of Mexico* will be holding its fourth workshop. This workshop will present the results of Phase I of the JIP project and will offer the plans for Phase II for discussion and critique.

The workshop will be held at the Westin Westminster Hotel in Westminster, a suburb of Denver. There will be a reception and poster session the evening of Sept. 30.

Registration is open and must be done online at *http://www.TheEnergyForum.com/NETL2003.asp* or *http://www.TheEnergyForum.com/Hydrates2003.asp*. Deadline for registration is Sept. 25. To partially offset the cost of the workshops, a registration fee of $50 for the DOE/NETL conference and $125 for the JIP Hydrates workshop will be charged to all attendees.

For more information or to arrange to display a poster, contact Wendy DiBenedetto at (281) 477-3636 or *wendy@TheEnergyForum.com*. Questions concerning the DOE conference should be addressed to Kathy Bruner at *kathy.bruner@eg.netl.doe.gov*. ✧

New Publications

Produced Water Atlases

Changing regulations and revisions in permitting processes associated with produced water disposal are raising the level of awareness of this issue among gas and oil producers. This project produced a series of atlases that document technical, regulatory and economic factors affecting produced water handling at a localized level in 10 states: Wyoming, Colorado, Utah, New Mexico, Montana, Kansas, Oklahoma, Illinois, Michigan and Louisiana. The data reflects extensive Internet research and personal interviews with producers.

Price: $850 for GTI members; $950 for nonmembers, plus shipping and handling.

Document number GRI-03/0066.

One CD-ROM. *Order by e-mail from* fillit@compuserve.com *or call (630) 406-5994.*

Lewis Shale Gas Resource and Production Potential

The Upper Cretaceous Lewis Shale of the San Juan Basin (in Colorado and New Mexico) has an enormous gas-in-place volume. This report describes formation evaluation efforts and a literature review pertaining to reservoir properties of the Lewis Shale. Data from three cooperative research wells belonging to Energen Resources Inc. and Burlington Resources Inc. are analyzed. In addition, log analysis models were developed to estimate the volume of gas stored by sorption, compression and solution. Researchers quantified gas-in-place volumes and in situ gas permeability and also estimated ranges in possible gas recovery volumes.

Price: $35 for GTI members; $60 for nonmembers, plus shipping and handling.

Document number GRI-03/0037.

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Seal Control of Hydrocarbon Migration and Its Physical and Chemical Consequences

An executive summary and five volumes document a project to (1) assemble a geochemical database in an active basin of sufficient area to capture all important processes, (2) construct models of those processes, and (3) use the models to interpret the data. Volume I presents a brief summary of the subsequent volumes. The other volumes focus on a 77.63-mile by 124.2-mile area of the offshore Louisiana Gulf of Mexico and discuss such topics as geophysics, geochemistry, gas washing of oil, hydrocarbon fluxes and inorganic alteration by the flow of brines through seals. Among the most important conclusions: hydrocarbon retention in migration conduits is low.

Price: $35 for GTI members; $60 for nonmembers, plus shipping and handling.

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A Strategic Plan to Substantially Increase the Rate and Magnitude of Converting Anomalously Pressured Gas Resources to Energy Reserves

This is a report on research designed to provide improved exploration strategies, innovative technology and diagnostic techniques that substantially reduce risk and increase profitability in the exploitation of anomalously pressured gas assets. Application of a new technology in the Washakie Basin, Wyo., resulted in improved understanding of the gas accumulation in this area and documented the tasks needed to fully develop the anomalously pressured gas resources. Research results helped to improve the economics of developing "basin-center" gas accumulations in the Rocky Mountain Laramide Basins.

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▶ GasWeek Conference & Exhibition: Incorporating Gas Supply Expo

Sept. 23-25, Houston

The GasWeek conference is a unique blend of business and technology issues that impact the industry, from production through consumption. Experts throughout the industry will address high-level strategic sessions and in-depth individual sector challenges.

Details at *www.gassupplyexpo.com*

▶ Society of Petroleum Engineers (SPE) 2003 Annual Technical Conference and Exhibition

Oct. 5-8, 2003, Denver

This event at the Colorado Convention Center will include presentations of more than 500 technical papers in 13 topic areas, on subjects ranging from drilling, well completion and well stimulation to formation evaluation, reservoir monitoring, and management and information. More than 200 exhibitors also will take part.

Details at *www.spe.org*

▶ International Petroleum Environmental Conference (IPEC)

Nov. 11-14, Houston

For more information, contact Kerry Sublette, IPEC Director at *kerry-sublette@tulsa.edu*

▶ Natural Gas Technologies II: Ingenuity and Innovation

Feb. 8-11, 2004, Phoenix

This is the second Gas Technology Institute-sponsored conference and exhibition designed to showcase new and developing natural gas technologies from across the industry. To be held at the Pointe South Mountain Resort, the conference is co-sponsored by the U.S. Department of Energy's National Energy Technology Laboratory.

Details at *www.gastechnology.org/ngt*

▶ 14th International Conference & Exhibition on Liquefied Natural Gas

March 21-24, 2004, Doha, Qatar

This triennial conference is sponsored by Gas Technology Institute, the International Gas Union and the International Institute of Refrigeration, with additional sponsorship support from many large corporations and organizations involved in the liquified natural gas industry.

Details at *www.lng14.com.qa/lng14.nsf/index2.htm*

▶ International Gas Research Conference (IGRC) 2004

Nov. 1-4, Vancouver, B.C., Canada

Held every 3 years, IGRC is recognized worldwide as the major forum devoted to the exchange of the most recent natural gas research, development, and demonstration results. This will mark the ninth presentation of the IGRC.

Details at *www.igrc2004.org* ◇

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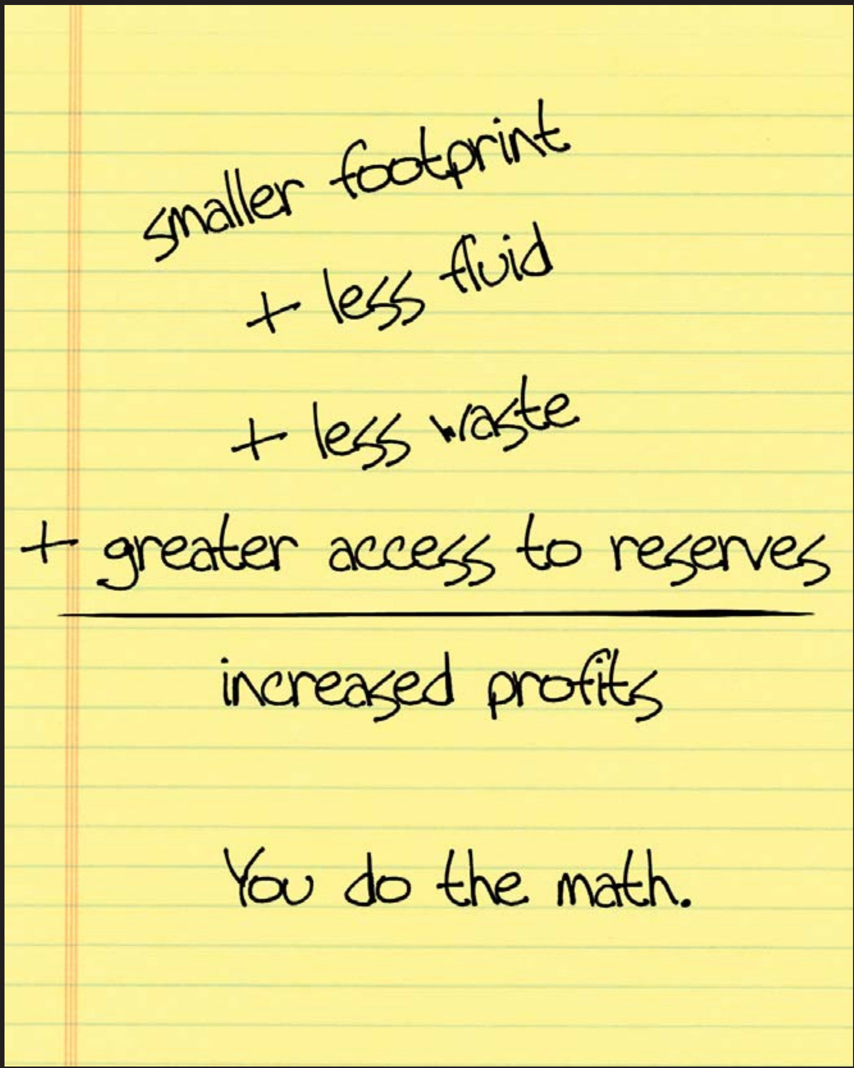

The Department of Energy is creating new opportunities. The Microhole Initiative focuses on developing low impact, lower cost microdrilling for cost-effective shallow access and VSP imaging to improve resolution of deep targets.

We are seeking oil company and service provider partners to develop shallow exploration, drilling and completion tools that significantly reduce capital expenditures.

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