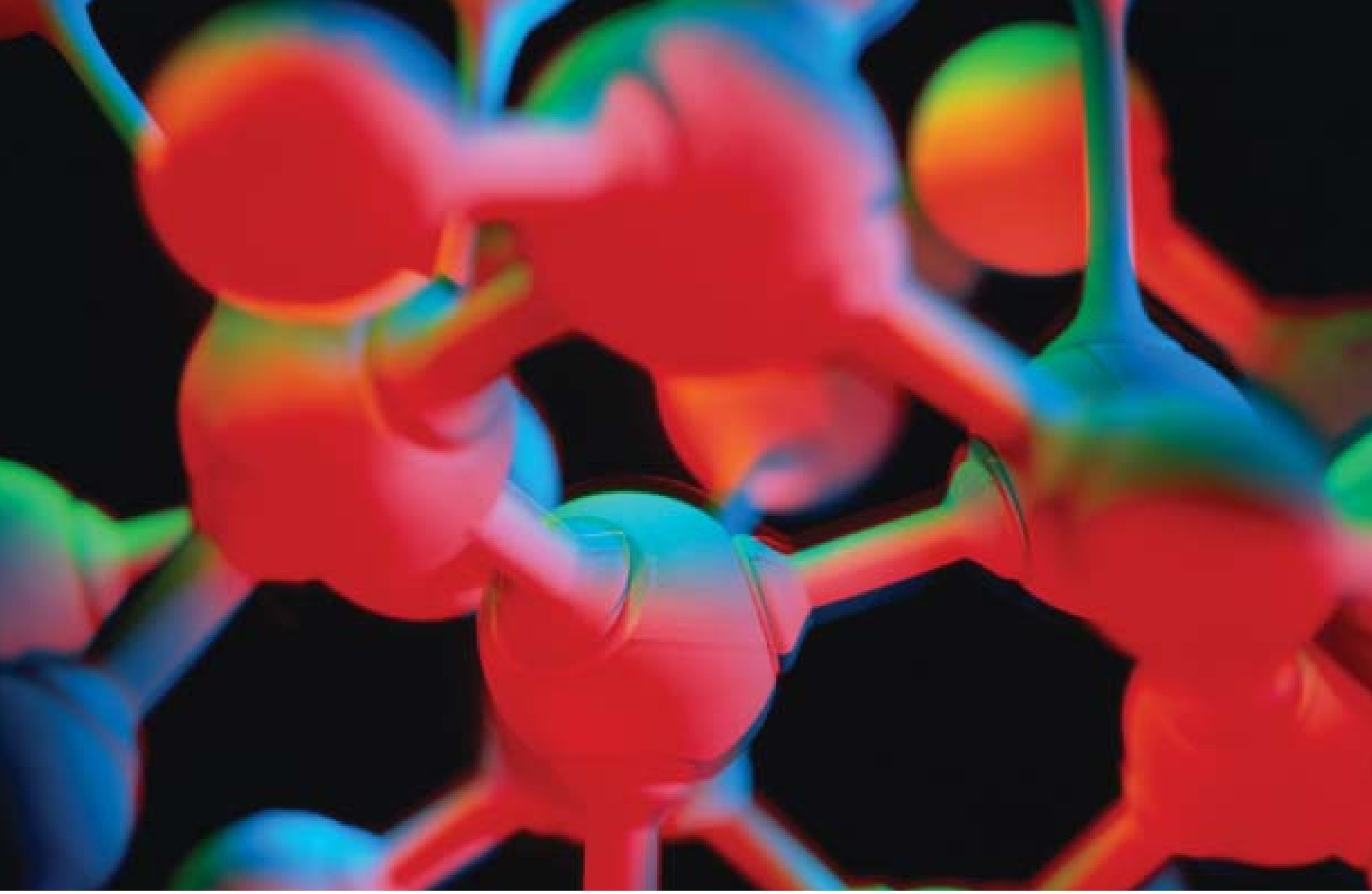
GasTIPS®

Spring 2004 • Volume 10 • Number 2

TECHNOLOGY DEVELOPMENTS IN NATURAL GAS EXPLORATION, PRODUCTION AND PROCESSING

A Publication of Gas Technology Institute, the U.S. Department of Energy and Hart Energy Publishing, LP

GTI-04/0045



Did you leave any hydrocarbons behind?

Pinpoint stimulation technologies help you reach more zones.

The goal: economically stimulating the pockets of oil and gas you used to bypass. The means: Halliburton's family of pinpoint stimulation technologies.

The key is different systems for different applications. Because each well type has its special challenges—new wells and old wells, vertical and horizontal. But one common theme: if there's a zone of interest, Halliburton can help you stimulate it with pinpoint accuracy and great operational efficiency.

To learn more about Halliburton's pinpoint stimulation technologies, contact your representative or visit myHalliburton.com.

THINK RED

HALLIBURTON

Stimulation

GasTIPS®

CONTENTS

GasTIPS® (ISSN 1078-3954), published four times a year by Hart Energy Publishing, LP, reports on research supported by Gas Technology Institute, the U.S. Department of Energy, and others in the area of natural gas exploration, formation evaluation, drilling and completion, stimulation, production and gas processing.

Subscriptions to ***GasTIPS*** are free of charge to qualified individuals in the domestic natural gas industry and others within the western hemisphere. Other international subscriptions are available for $149. Domestic subscriptions for parties outside the natural gas industry are available for $99. Back issues are $25. Send address changes and requests for back issues to Subscriber Services at Hart Energy Publishing, LP, 4545 Post Oak Place, Suite 210, Houston, TX 77027, Fax: (713) 840-0923. Comments and suggestions should be directed to Rhonda Duey, ***GasTIPS*** Editor, at the same address.

Publication Office
Hart Energy Publishing, LP
4545 Post Oak Place, Suite 210
Houston, TX 77027
(713) 993-9320 • FAX:(713) 840-0923

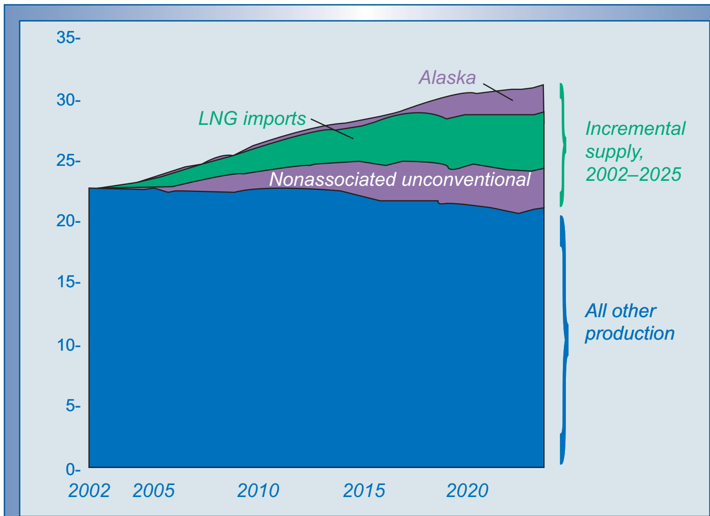
POSTMASTER: Please send address changes to ***GasTIPS***, c/o Hart Energy Publishing, LP 4545 Post Oak Place, Suite 210, Houston, TX 77027.

Commentary

Weathering the Perfect Storm

If the right confluence of situations doesn't happen, meeting demand for natural gas will be a bumpy ride.

Four years ago a film titled "The Perfect Storm" debuted about a storm stronger than any in recorded history that struck off the coast of Massachusetts in 1991. Meteorologically, the storm was formed from the remnants of a hurricane (Grace), winds coming across New York from the Great Lakes and a storm front that was already in the area. The combined energy from these three meteorological events created a situation where fishing boats encountered 100-ft waves; a tragedy subsequently detailed in a book and, eventually, the film.



Major sources of incremental gas supply (Tcf), 2002-2025

Early this year, the Energy Information Administration (EIA) was asked to predict what might happen if three events do not occur, leading to another sort of perfect storm. The task was to estimate the impact on natural gas prices if: (a) a pipeline bringing gas from Alaska is not constructed, (b) unconventional gas production (largely from Rocky Mountain basins) does not meet expectations, and (c) the liquefied natural gas (LNG) terminal capacity needed to allow expanded imports is not built. The EIA recently had published its Annual Energy Outlook for 2004, wherein it had estimated that Alaskan gas, unconventional gas (primarily from tight sands and coal seams) and LNG would supply 14.8%, 10.3% and 7.3%, respectively, of the 31.3 Tcf expected to be demanded by U.S. consumers in 2025. The EIA estimated wellhead prices in 2025 would average \$4.40/Mcf (in 2002 dollars).

The results of this exercise in weather forecasting showed that if any one of the three did not occur, the result would be an addition of between \$0.20 and \$0.45 to the gas price in 2025. If all three sources of natural gas were to fall short, however, the 2025 price jumps by \$1.21 (27%) to \$5.61/Mcf.

The Annual Energy Outlook 2004 also included projections of gas prices based on variation in the speed at which oil and natural gas exploration and production technology is adopted and applied. In the "slow technology" case, natural gas development costs are higher, wellhead prices are higher and natural gas consumption is reduced. The rapid technology case assumes 50% faster technology progress, resulting in lower development costs, lower wellhead prices and increased consumption of natural gas.

The important point here is that technology advancements that help bring more unconventional (or conventional) gas online at a lower cost can help offset the impact that delays in the expansion of LNG facilities or the construction of an Alaskan gas pipeline might create, while technology delays will exacerbate them. Accelerating technologies that can improve the likelihood of expanding LNG imports can accomplish the same thing. Efforts by the U. S. Departments of Energy's National Energy Technology Laboratory (NETL) and Gas Technology Institute (GTI) are targeting these goals.

The last issue of *GasTIPS* (Winter 2004) included a story on GTI's push to continue development of LNG safety models used to help set design standards for new LNG terminals. NETL is developing a novel LNG regasification/storage technology (the Bishop process) that could substantially lower costs and minimize safety and security concerns. NETL also is implementing the U.S. Department of Energy/National Association of Regulatory Utility Commissioners LNG partnership focused on providing state regulators and other stakeholders with science-based information to facilitate productive dialog about LNG siting decisions. NETL also has a suite of research projects with the goal of advancing technologies related to drilling for deep gas, finding and producing low permeability gas resources and lowering the costs of producing gas from coal seams. The goal of all of these programs is a secure, reasonably priced supply of natural gas for the U.S. consumer – whatever the weather may be.

The Editors

Benchmarking Deep Drilling and Completion Technologies

by John D. Rogers, *U.S. DOE/NETL*; Stephen W. Lambert, *Schlumberger DCS*; and Steve Wolhart, *Pinnacle Technologies*

The U.S. Department of Energy has undertaken two concurrent studies to establish a baseline of information related to the costs of drilling deep wells and the technologies currently employed in the process. This information will help determine the industry's most important drivers and where research and development efforts should be focused.

Deep formations (defined here as depths greater than 15,000ft) are one of the sources of natural gas that will play an important role in meeting the growing need for natural gas in the United States. The Energy Information Agency estimated 7% of U.S. gas production came from deep formations in 1999. This contribution is expected to increase to 14% by 2010. Much of this deep gas production will come from the Rocky Mountain, Gulf Coast and Gulf of Mexico (GOM) sedimentary basins (Figure 1).

The challenges of drilling and completing deep gas wells are significant. The limits of conventional well construction technology are tested and costs increase below 15,000ft. At these depths, the last 10% of a well's depth can account for 50% of its total cost. As depth increases, the rock is typically less permeable (tight), hot, hard, abrasive and highly pressured. These conditions of pressure and heat exacerbate the corrosive nature of any fluids produced. Control of wellbore trajectory and placement of casing and cement that are relatively easy at shallower depths can become significant challenges. And the number of rigs capable of drilling deep wells is limited, a factor that also adds to the drilling costs.

To help facilitate the economic development of deep reservoirs, the U.S. Department of Energy (DOE) initiated the Deep Trek Program, which was designed to develop technologies that improve the economic feasibility of drilling to and producing from deep oil and gas resources. As part

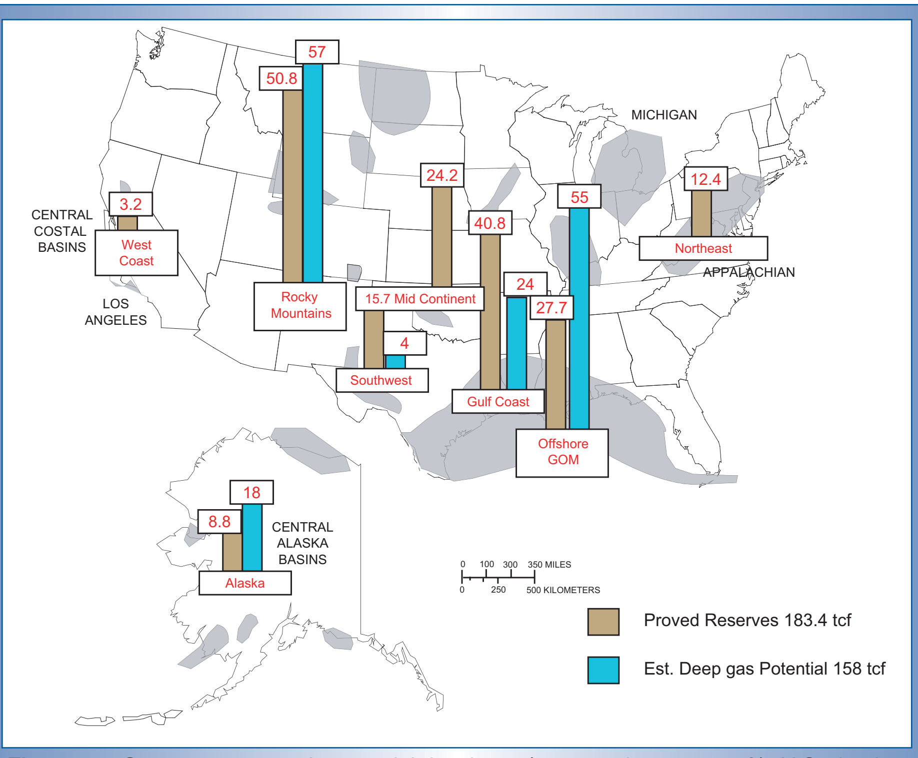


Figure 1. *Gas reserves and potential in deep (greater than 15,000ft) U.S. basins. (Source: Strategic Center for Natural Gas)*

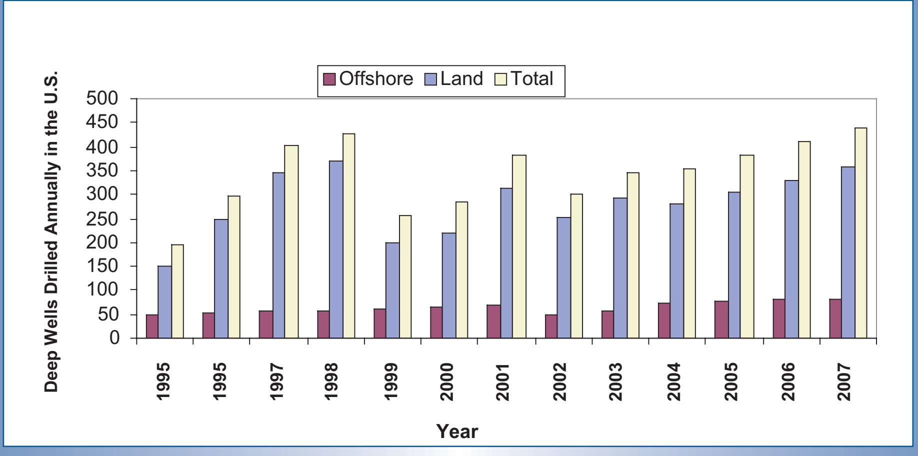


Figure 2. *Deep drilling historical data and forecast for greater than 15,000ft.*

of the Deep Trek Program, the DOE is supporting two studies: one to benchmark current deep drilling costs and technologies (Schlumberger Data Systems), and the other to specifically evaluate current deep gas well completion technologies (Pinnacle Technologies). The first of these was designed to provide current drilling technology and cost benchmarks as reference points in evaluating future cost improvements from technology advancements.

For the purposes of these studies, the DOE defined "deep" as greater than 15,000ft (true vertical depth – TVD). Data related to shallower wells were also included, provided the wells were located in high temperature/high pressure (greater than 350°F and greater than 10,000psi) environments and drilled within the past 5 years to 7 years.

As part of this effort, the DOE licensed the IHS database to create a database of deep wells categorized by TVD, targeted formation, geographic location, completion technique and operator. Information also was collected from operators on drilling and completion technologies currently being used, data monitoring and management techniques, well control planning and tubular designs (casing, drillpipe and tubing). Information gathered from interviewing operator and drilling company contacts has been compiled into a condensed format that does not identify specific companies or individuals.

The IHS database was used to identify 3,015 deep well locations. By selecting only operators that have significant experience in drilling deep wells in a specific geographical area, the number of operators included in this study was confined to 140, representing 78% of the IHS deep well population. About 50 of these operators drilling in selected geographical areas were contacted by phone and in writing and invited to share information for this project. In all, about 12 responded with information, producing a total of 22 usable data sets.

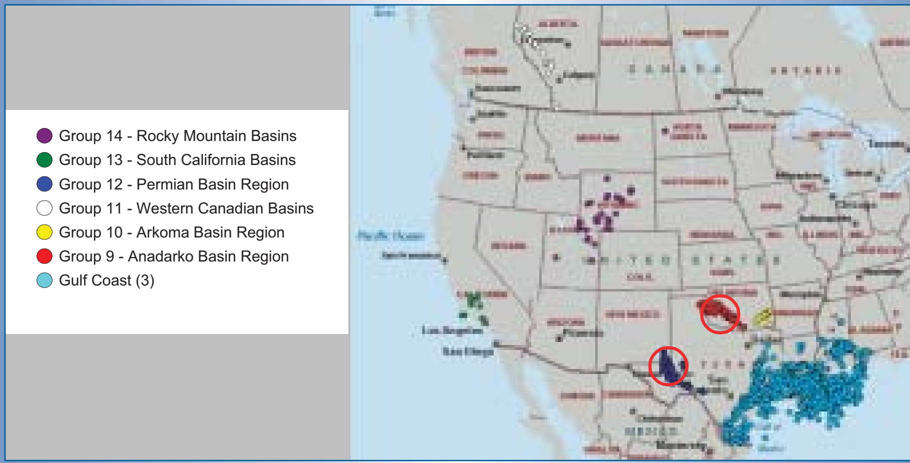


Figure 3: *U.S. and Canada Deep Drilling Locations 1997–2001*

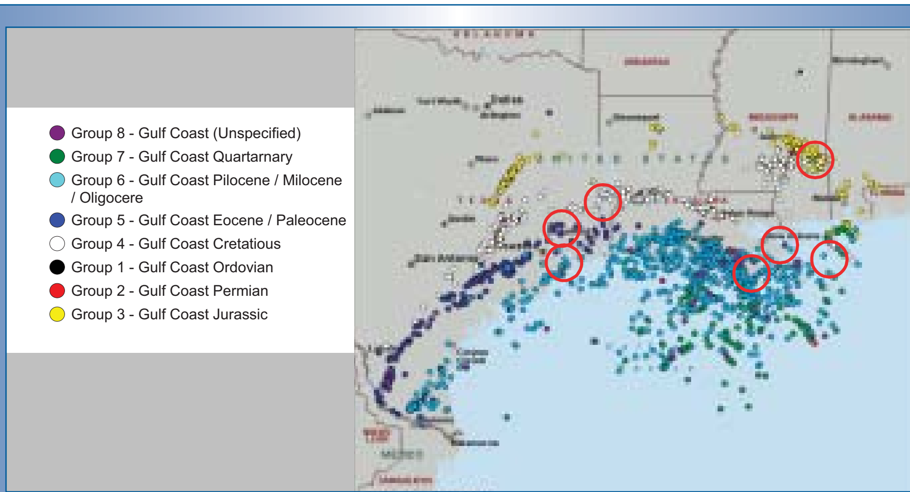


Figure 4: *Gulf of Mexico Deep Drilling Locations 1997–2001*

Recent historical perspective

There are relatively few deep wells being drilled. Of the estimated 29,000 wells (oil, gas and dry holes) drilled in the United States in 2002, about 300 were deep wells. Deep drilling peaked at 425 wells in 1998 and fell to 250 wells in 1999 as part of an overall industry downturn. Because of the cyclic nature of the industry, it is difficult to project future drilling trends, but the overall trend of deep drilling activity appears to be increasing through the industry cycles, according to one DOE forecast (Figure 2).

Current business interest in deep gas targets on the shallow water GOM shelf and natural gas market pressures in the United States could help revitalize deep gas drilling activity. The U.S. Minerals Management Service has indicated more than 15 recent new deep gas discoveries in shallow GOM waters. One company operating in the shallow GOM has revealed plans to drill at least six deep (greater than 25,000ft) exploratory wells this year. Another Outer Continental Shelf operator has reported it plans to drill or participate in four deep gas wells.

Though, the average success rate for deep gas discoveries in the Gulf Coast area is 50% to 60%. Increases in deep gas drilling will not be sustainable unless sustained higher gas prices overcome costs or costs can be reduced through technology.

Deep drilling—1997–2001

As part of the ongoing deep drilling benchmark study, a data set of all deep wells within the United States and Canada drilled from Jan. 1, 1997, through Dec. 31, 2001, was extracted from the IHS well database. Selecting only the wells that met the criteria of depth and location (greater than 15,000ft TVD) resulted in a total of 3,015 wells.

These wells were subdivided into seven groups based on major geologic or geographic play regions (Figures 3 and 4 and Table 1). The largest region, the Gulf Coast, was further divided into a series of subgroups based on the geologic age of the deepest formation drilled. Fourteen area groupings were recognized and operator data sets were obtained from seven of these fourteen areas.

Group Number	Description	Number of Wells	Operators	Minimum TVD (ft)	Maximum TVD (ft)	Well Type			Prod Type	
						Vertical	Deviated	Horizontal	Gas	Oil
1	Gulf Coast - Ordovician	8	6	15,000	17,950	5	3	0	8	0
2	Gulf Coast - Permian	11	9	15,000	28,008	6	5	0	1	7
3	Gulf Coast - Jurassic	232	84	15,000	23,505	114	102	7	98	34
4	Gulf Coast - Cretaceous	541	76	15,000	23,472	81	80	355	232	198
5	Gulf Coast - Eocene / Paleocene	303	98	15,000	20,928	198	90	13	125	53
6	Gulf Coast - Pliocene / Miocene / Oligocene	1032	218	15,000	29,680	419	507	9	522	79
7	Gulf Coast - Quaternary	143	45	15,105	29,229	34	80	0	23	17
8	Gulf Coast - Unknown (see map)	41	35	15,000	28,665	25	12	0	13	4
9	Anadarko Basin Region	372	73	15,000	26,566	187	67	4	305	19
10	Arkoma Basin Region	32	12	15,047	17,638	3	26	1	22	0
11	W. Canadian Basins	24	13	15,025	18,291	0	0	0	12	0
12	Permian Basin Region	177	77	15,000	28,666	136	20	21	34	31
13	S. California Basins	20	10	15,000	21,769	6	14	0	1	11
14	S. Rocky Mountain Basins	79	36	15,000	25,830	42	26	5	43	11

Table 1: *U.S. and Canada Deep Drilling Well Data 1997-2001*

Benchmarking deep drilling costs

Because each company participating in this project provided its own form of authorization for expenditure (AFE), the first major challenge to examining and comparing deep well costs was to establish a data management system that would categorize costs in a consistent manner across companies. In order to accomplish this, a standard set of cost categories was established and each AFE line item was analyzed to determine in which category it belonged. Costs could then be grouped into the larger components, such as drilling costs, and subcomponents, such as tangible completion-packer and downhole equipment. This system also allowed individual AFE cost components to be associated with particular technology areas.

Once AFE costs were standardized, relevant deep well scenarios could be established, where significant operator data sets were available and average cost values could be established for each scenario. These costs could then be examined by category. Unfortunately, because some operators provided more information than others, the sum total well costs do not provide an accurate estimate of total deep well costs for every individual group. However, they do provide a credible picture of the average costs of many of the major technology areas benchmarked in the study. For example, Figure 5 shows average cost data for 11 cost categories across seven drilling scenarios.

Quantifying the impact of technology advancements

Benchmarking costs of deep wells is important to enable the industry and the DOE to identify areas where new technologies can make the most impact and measure how much improvement can be attributed to particular technology advancements.

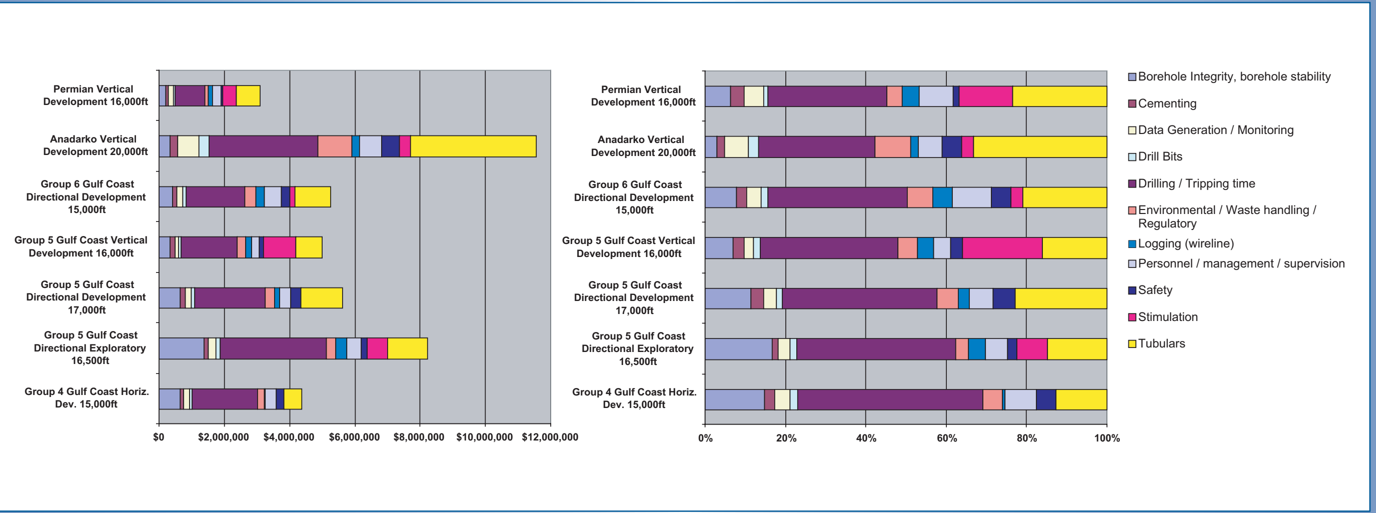


Figure 5: *Category cost data for selected scenarios in dollars and as percentage of total*

Technology advances have a significant impact in the reduction of drilling time and costs. This can be illustrated by comparing the depth-time plots of two deep East Texas wells drilled in the same area to the same target, one in 1985 and one in 2002 (Figure 6). Drilling time in 2002 has been reduced to less than one-third of the time required 17 years earlier (58 days to completion point in 2002 compared with 185 days in 1985). This improvement is attributed to advancements in bits, downhole tools, directional drilling capability, fluids and hydraulics, safety systems, as well as to the effective application of lessons learned in this particular area.

Bit and downhole motor and turbine technology have improved significantly during the past several years, leading to faster rates of penetration (ROP) for deep wells. Polycrystalline diamond cutter bit technology is one of the most significant technology improvements in the drilling industry during the past 20 years. However, bit vibration is one aspect of deep, hard rock drilling that continues to give drillers problems, as it reduces ROP and damages bits and bottomhole assemblies.

Modern drilling rigs are designed to be more mobile and modular. The use of high-pressure rotating heads, top drives, rotary steerable systems, and more efficient hydraulics and fluid delivery systems (bigger surface pumps and larger-diameter drill pipe) have helped increase drilling efficiency and reduce the costs of drilling during the past couple of decades. However, continued reduction in costs will be necessary if deep gas drilling is to realize its full potential.

Current and proposed well construction methodologies that should continue to reduce costs of drilling deep and extended reach wells include solid expandable tubulars and the concept of "casing drilling" or "liner drilling," where the bit/motor assembly is attached below the casing shoe and a dual-rotary system rotates the casing independently while drilling. However, these novel concepts are still evolving.

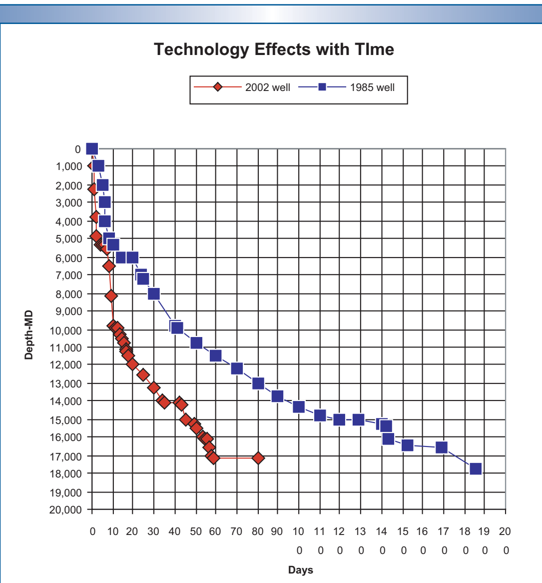


Figure 6: *A comparison of depth-time plot for two wells drilled to the same depth in the same area, 17 years apart, shows the impact of technology advancements.*

As these and other new technologies are employed in the drilling of deep wells, efforts can be made to identify the degree to which costs have dropped relative to earlier benchmarks.

Further analysis

The cost data accumulated in these two studies will be compared and correlated with information developed from a review of current technologies and practices employed by operators.

A preliminary assessment of the data indicates a number of findings, some not unexpected and others that merit further scrutiny.

A complete analysis may require some additional information to be gathered for areas where the data is sparse. One challenge in this regard is the variable degree of interest in participation on the part of operators. ✧

Close Tolerance Liner Drilling and Liner Requirements for Deepwater Applications

by Ken Smith, *ConocoPhillips*; Bruce Houtchens, *Tesco Corp.;* George Givens, *Baker Hughes Inc.;* Greg Bailey, *Grant Prideco, Inc.;* and Doyle Reeves, *Hunting Energy Service LP*

Lessons learned from onshore casing drilling might pay offshore benefits.

An extremely tight operating window between fracture pressure and formation pressure characterizes Gulf of Mexico deepwater drilling operations. The consequence is that eight or more casings may be needed to reach deep drilling objectives. Industry has become adept at managing the balance of mud weight, equivalent circulating density, trip margins, lost circulation material (LCM) treatments and other aspects of the operation to try and push the casing points. However, this balance is difficult and problems frequently occur.

These wells are inherently expensive and typically are budgeted for $40 million to $50 million. However, when problems occur, they can be extensive, and cost overruns commonly approach at least 50%. A few wells in the Gulf of Mexico have exceeded $100 million in cost.

Toward the other end of the drilling cost spectrum, ConocoPhillips operations in South Texas are frequently characterized by massive lost circulation and many wells have been lost as a consequence.

Tesco Corp.'s Casing Drilling™ operations were introduced in 2001, and the lost circulation, stuck pipe and well control issues have all but disappeared on those wells. This was an unexpected benefit, but clearly one that has tremendous potential in the deepwater environment.

Accordingly, in early 2003, ConocoPhillips, Tesco Corp. and Baker Hughes Inc. jointly embarked on extending the onshore Casing Drilling technology offshore to deepwater.

Deepwater liner drilling design basis and candidate selection:

A typical deepwater casing program for a 25,000ft to 30,000ft measured depth (MD) well might be:

- 36-in. conductor;
- 22-in. surface casing (with high pressure wellhead);
- 18-in. liner;
- 16-in. liner;
- 13 ⅝-in. intermediate casing;
- 11 ¾-in. intermediate liner;
- 9 ⅝-in. solid expandable liner;
- 9 ⅜-in. liner; and
- total depth (TD) with 8 ½-in. hole.

Each hole interval has its own challenges, and most can benefit from some form of Casing Drilling technology. Generally, the hole intervals through 13 ⅝-in. do not experience many problems. The goals are usually associated with reducing drilling times. The deeper hole intervals tend to be more problematic, especially if the well is drilled through a massive salt section. The primary goal in these intervals is risk reduction.

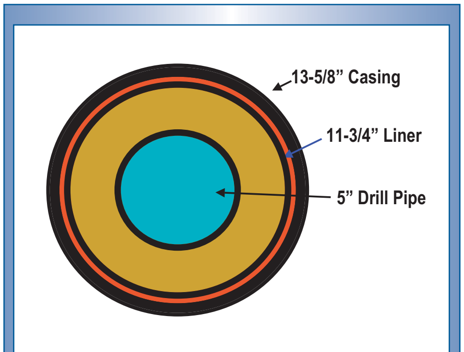


Figure 1. *Casing clearances in offshore drilling are often too tight to allow for the circulation of cuttings and mud up the annulus between the casings.*

The interval immediately below salt has caused ConocoPhillips the most significant cost overruns. This interval is where the 11 ¾-in. liner is set, so this string became the initial candidate for the Close Tolerance Liner Drilling (CTLD) operation.

For this application, the design basis for CTLD was agreed upon and would provide for:

- 11 ¾-in., 65 pounds per foot (ppf), Q-125 liner with flush or near-flush joint connections;
- set inside of 13 ⅝-in., 86 ppf casing (12.25-in. drift inner diameter or ID);
- 5,000ft long;
- set from 19,000ft to 24,000ft MD/true vertical depth (TVD);
- drilled interval = 5,000ft;
- directional drilling possible;
- typical formation evaluation tools run while drilling;
- 13 ½-in. open hole; and
- synthetic-based mud with density of 14.5 parts per gallon (ppg) to 15.5 ppg.

Overview of CTLD operations

After agreeing on the specific liner that would be targeted and the environment in which it would be set, it was necessary to agree generally how the drilling and cementing operations would be done. Several operational scenarios were discussed, each with its consequential impact on the complexity of the CTLD system.

It was ultimately agreed a two-trip system would be developed. This met the objectives of quickly getting the well cased off and keeping the complexity of the tools to a minimum. An outline of this plan is:

Trip 1:

- drill the hole interval;
- hang the liner;
- set the liner top packer; and
- pull out of the hole.

Trip 2:

- run in the hole with a cement retainer;
- close blowout preventers, and test the liner top packer and cement retainer;
- squeeze cement; and
- pull out of the hole.

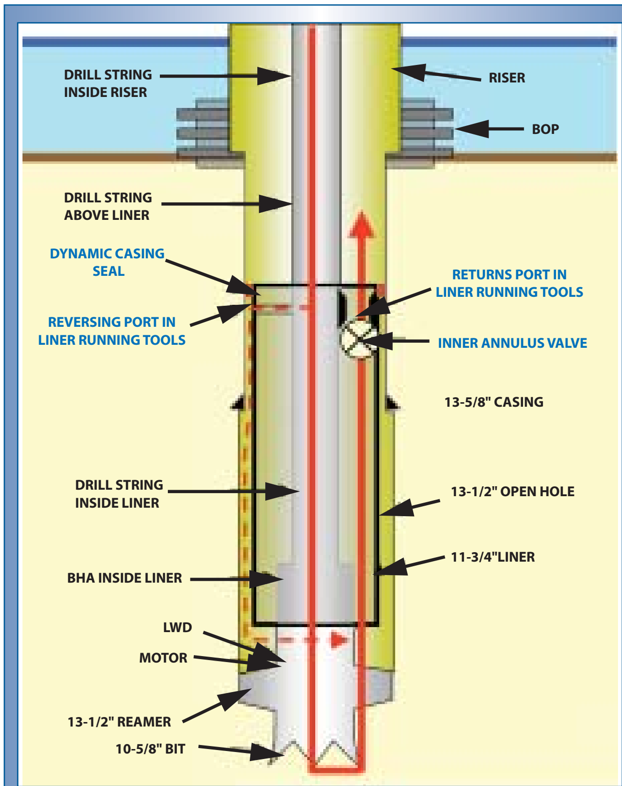


Figure 2. *A Close Tolerance Liner Drilling configuration.*

CTLD configuration

There are significant differences between onshore casing drilling operations and subsea liner drilling. In onshore operations, casing is in the rotary table. The bottomhole assembly (BHA), consisting primarily of an underreamer and a pilot bit, latches into the bottom joint of casing and extends below it. The casing is used as the "drillstring," and returns are taken up the annulus of the casing and open hole.

In subsea drilling operations, all casing is at or below the mudline, and drill pipe is in the rotary table. Therefore, all casings are effectively "liners," and drill pipe will extend to at least the top of it. Because of the clearances between the casings in the deepwater Gulf of Mexico wells, it is impossible to circulate drilling mud and cuttings up the annulus between two casings (Figure 1).

Instead, the drillstring and BHA must extend through and out the end of the liner so mud and cuttings can be circulated up the inside of the liner between it and the drilling assembly.

This unique circulation path is shown in Figure 2. The mud is pumped down the drillstring, through the BHA and then up through the ID of the liner and out the top through a bypass area built into the liner hanger running tool. At the top of the liner, a small portion is diverted down the backside of it through a reversing port. This ensures the open hole stays flushed of any cuttings or well fluids. The friction pressures down the liner and casing overlap interval are quite high, so a Dynamic Casing Seal™ (DCS) element had to be developed for the top of the liner to ensure the fluid went down the backside rather than up into the casing above it.

There is one low-risk yet high-consequence safety issue that had to be addressed in the tool design. There is a slight possibility that a kick will be detected when the liner, along with the encased drillstring, is across the blowout preventer (BOP). Because the mud return flow bypass area goes through the inside of the liner, any influx would go directly into the drilling riser above the BOP. Most BOPs are not capable of shearing the liner and the drillstring, so an inner annulus valve (IAV) was needed that could shut off this internal flow after the BOP was closed around the liner.

This configuration leads to several realizations, all of which impact system design and operational considerations:

- the liner is in full tension and only experiences the torque associated with rotational drag;
- the inertia of the liner rotation is a force that, if stopped quickly, may back the liner out at a connection, so rotation will be relatively slow. Therefore, all drilling is planned to be done by a mud motor;

Figure 3. *This image shows a closer view of the Dynamic Casing Seal.*

- all formation evaluation tools will be run below the liner; and
- the concentric reamer must be retrieved through the liner. It must be capable of opening a hole to about 30% greater than its body outer diameter (OD).

System component descriptions and testing

The CTLD system consists of several components that had to be designed in an integrated manner. Each component needed to be tested in the shop environment and then as a system in an onshore test well before it could be confidently deployed offshore.

At the top of the CTLD system is the DCS element (Figure 3). Below that is the Hy-Flow™ running tool and the liner hanger. This makes up both into the liner and drillstring running through the liner.

DCS—One critical component of the system is the DCS element that is positioned above the liner and hanger. This element must seal the small annular space between the 11 3⁄4-in. liner and 13 5⁄8-in. string, yet allow the drillstring to extend through the middle while carrying the full hook load. In addition, it must slide, rotate and seal while tripping and drilling. The return fluid circulation path is up the inner annulus between the drill pipe and the ID of the liner. The seal also must be able to contain the pressure of circulating a low rate down the backside of the 11 3⁄4-in. liner with up to 5,000ft of overlap with the 13 5⁄8-in. casing.

Additional design objectives for this tool required it to survive the trip in the hole prior to drilling (about 10,000ft) and rotate and drill for an interval of up to 5,000ft, which includes about 300,000 revolutions of the drill pipe and liner assembly. Mud properties were planned to match recent drilling experiences in the Gulf. This interval requires a weighted, synthetic-based system, medium temperature with minimal LCM as a background concentration with occasional pill additions as required.

The tool concept, when finalized, incorporated a pilot seal, main seal and rotational elements that were subsequently separated to simplify testing and isolate the critical components. Translating or sliding of the DCS element required a design that did not wear out and yet held pressure while tripping and drilling. A bearing assembly allowed rotation, and a filter system kept the solids in the drilling fluid from damaging the seal or bearing assembly.

Shop testing began on a scale version of the translating seal assembly tripped for 19,000ft while under pressure. Results led to alternative designs in the pilot seal, but the main seal functioned well. A second translating test was run for 12,000ft and indicated additional design modifications to be implemented on the prototype tool.

Rotational testing was accomplished with a full-scale model run under high pressure with weighted synthetic-based mud and elevated temperatures. Rotation speeds varied from 30 rpm to 90 rpm, pressures were as high as 3,000psi, and mud temperature topped out at 250°F.

Testing was halted at 300,000 revolutions (equal to a week of rotation). No sealing material degradation was noted from this exposure. Results of the rotational testing proved the durability of the bearing assembly. Attempted plugging of the device with LCM was the final test for this tool. Results exceeded expectations, as the tool tolerated extremely high concentrations of LCM without detrimental effects.

These tests proved all DCS components met all design criteria. Key learnings from the tests were incorporated into the prototype tool used for the subsequent full-scale CTLD system tests.

The DCS element is mated to the Baker Hughes Hy-Flow liner hanger running tool with a common thread that locks it in rotation. Again, the load path is through the inner drill pipe string passing through the ID of the DCS element.

Liner hanger and running tool—The liner hanger, running tool and DCS are all integrated into one assembly. The liner hanger is a field proven Inline™ hanger/packer modified for vigorous rotation. It is attached to the running tool assembly so all rotation at the surface is transferred through the running tool into the liner hanger and liner.

Setting of the hanger is accomplished with hydraulic pressure isolated from the hanger until the time of setting.

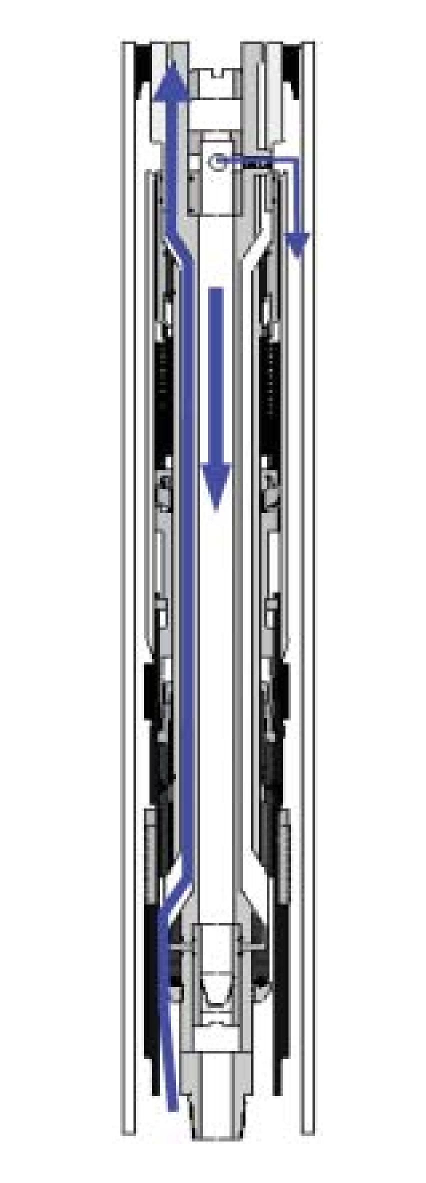


Figure 4. *Flow paths in the Close Tolerance Liner Drilling system.*

Figure 5. *Cyclic fatigue testing was done on selected liner connections.*

The running tool assembly provides critical functions essential to the success of CTLD operations. The integrated assembly allows fluid flow to be directed through the tool and BHA in a conventional manner while diverting a small portion of flow to the annulus above the liner hanger system (Figure 4). Fluid flow diverted to the annulus continues down the open-hole annulus and commingles with the fluid exiting the BHA. Returns are taken up the inner annulus between the liner and the drill pipe inner string. The path of return fluid through the running tool is achieved with a concentric flow area internal to the tool, isolating critical mechanisms from fluid flow. The inner annulus flow area can be selectively closed and opened by the IAV. A second valve is integrated into the design to control the fluid that is diverted or "reversed" to the annulus. The IAV and reverse circulating valve remain open during drilling operations.

Sequential closing of the valves is accomplished with left-hand pipe manipulation and can be cycled repeatedly as required.

Releasing the running tool from the hanger is accomplished with hydraulic pressure mechanically isolated from the running tool until time of release. An extrudable ball seat placed in the tool ID allows the use of either a ball or drill pipe dart to pressure against for hanger and running tool activation. Once activated, the ball or plug is pumped through the extrudable seat and circulation is re-established.

After releasing from the liner hanger, the running tool is picked up a few feet, freeing some dogs to allow setting down on the liner and compressing the ZXP liner top packer. At this point, the well is mechanically cased off, and the drill pipe and BHA are tripped out of the well. The cement retainer is then tripped in and the well is cemented.

Specific design features were incorporated to address anticipated drilling dynamics not normally associated with standard liner systems. Significant redundancy is designed into the system to allow for multiple activation methods. There are hydraulic and mechanical means for releasing the running tool from the liner. The extrudable ball seat can be functioned twice and a standard blanking plug can be run in on wireline to pressure against. The reverse circulating port can be cycled open and closed with drill pipe manipulation or a wireline-shifting tool as a contingency.

Lab testing of the components and new mechanism designs was extensive. Valve mechanisms have been cycled repeatedly to assure functionality. Critical components subject to fluid erosion were placed in a flow loop and subjected to 14.5 ppg mud flow for 170 hours at 12 bbl per minute.

Intermediate drilling liner 11 3⁄4-in.—Because of the tight clearances with the 13 5⁄8-in. casing ID, the 11 3⁄4-in. intermediate drilling liner will have an integral flush or near-flush connection. Additional application requirements for the 11 3⁄4-in. 65 lb HC Q-125 include:

- alternating stresses equal to the tension inflicted by a 5° per 100-ft build rate;
- 300,000 cycle service life;
- 40,000ft/lb torsional capacity;
- 15,000ft/lb retained torque;
- gall resistant for contingency tripping;
- 5,000psi internal pressure;
- 2,500psi external pressure;
- fluid sealing;
- 325,000 lb tension load equivalent to 5,000ft of pipe; and
- connector OD restricted to 12-in.

Flush and near-flush joint casing suffers from the stigma of being relatively weak, so there was concern about its ability to endure the loads encountered during drilling operations. However, design tools such as finite element analysis, more sophisticated test equipment and improvements in metallurgy have played a major role in improving connection performance and removing this stigma of equating flush and near-flush connections with flimsy and weak.

Two connections were tested: one from GrantPrideco (DWC/DS-A) and one from Hunting (SLSF). These connections have design attributes that were felt to be favorable in the CTLD application.

Connectors integral to the pipe improve the economics compared with threaded and coupled connectors. Using one connector per joint reduces the leak and fatigue points compared with threaded and coupled as well. These connections have axial ratings less than the pipe body, but tensile capabilities of both connectors exceed the expected tension range with safety factors above four.

The connectors feature negative load flank thread forms to enhance their tensile capacity and assembled rigidity by means of mechanical advantage using torque to pull mating members together vs. pushing them apart. Interference at the thread pitch promotes retention of torque independent of axial loading. Torque shoulders allow preloading of connector cross-sections for fatigue resistance. Proper use of preload and control of stresses during make-up can result in useful service life for dynamic applications.

Bi-directional sealing systems provide integrity from internal or external pressure. Tapered threads with coarser pitches allow deep stabbing and decrease operational deployment time.

Fatigue from extended rotation was the primary concern. With improved chemistries, quality control and heat treatment methods, casing materials have been enhanced. The result is increased toughness and through-wall consistency, which decreases notch sensitivity reflected in improved fatigue performance.

Product verification was still needed, so cyclic fatigue testing was performed to determine endurance limits for an alternating stress equivalent to a 5° per 10-ft build rate (Figure 5). Both liner connections tested exhibited a high resistance to rotational bending fatigue, exceeding the required 300,000 cycles without failure. This testing was performed with a nominal pressure of 250psi to detect a through-wall crack. They also broke out at values near or above make-up levels.

Previous static load tests conducted by the thread companies also were considered in the evaluation. Internal and external pressure capacity as required for the drilling and installed conditions were verified in laboratory environments to pipe capacities, and they exceed the application requirements. In addition, laboratory make/breaks and torque-to-failure tests were conducted. Anaerobic thread lubricants and conventional Teflon-based "green" dopes were tested and found to be suitable for CTLD applications.

In short, both liner connectors appeared suitable for the CTLD application.

Concentric reamer design—The last component that needed evolution was the concentric reamer, which was Smith's Rhino Reamer. This reamer regularly opens a hole to about 20% more than the body OD, yet to drill the 13 1/2-in. hole, a 30% enlargement was needed. Smith engineers redesigned their existing reamer in a 10 3/8-in. OD body and extended the reaming blocks the additional length needed. At the time of this writing, these tools have been delivered and successfully run in two deepwater wells. In both cases, they were run to enlarge a previously drilled 12 1/4-in. hole. This is an inherently unstable configuration and is tough on the tools; however, they performed well.

Onshore system testing

After successfully passing all the laboratory and shop testing, the full-scale DCS and liner hanger and running tool were assembled and delivered to Tesco's test well in Houston. This test well has 13 3/8-in., 54.5 ppf casing set to 2,214ft in a deviated wellbore.

The test had several objectives:

- to understand the hydraulics with the system. Surge and swab pressures will be unique with the reverse circulating port and the two downward flow paths;
- to determine whether rotational dynamics between the liner and the 13 3/8-in. casing are an issue;
- to subject the system to about 10,000ft of tripping, simulating an offshore well;
- to subject the system to the equivalent of about 3,000ft of drilling rotational wear; and
- to drill an open hole.

Clearly, after performing these tests, the liner hanger still had to set, and the liner packer still needed to be able to be set and seal.

The testing plan consisted of two parts. The first was a cased-hole test that targets the first four objectives. The second is an open-hole test that targets the last objective of drilling open hole. The cased-hole test was successfully completed in mid-February. The cased-hole test utilized about 1,000ft of 11 3/4-in. liner. Within the liner was a 5-in. drillstring and BHA, which included a drilling dynamics sub and an annular pressure-recording sub. This liner and BHA assembly was run on 5-in. drill pipe to about 2,000ft. The mud in the casing was a 14.5 ppg water-based fluid.

Figure 6. *The liner hanger and drill pipe stringer are lowered through the liner below the false rotary table.*

The initial tests involved extensive tripping at various speeds with the reversing valve opened and closed, with rotations of 0 rpm to 90 rpm, and with and without pumping. After the various tripping tests, the assembly was physically tripped into and out of the test well for 10,000 cumulative ft, simulating the initial trip into a deepwater well prior to commencement of drilling. After this was done, the assembly was rotated and reamed for 100,000 revolutions, equivalent to about 2,500ft of drilling.

Afterward, the assembly was tripped out, returned to the shop and investigated for function, damage and wear.

Onshore test findings

The initial cased hole-testing program yielded promising results on all fronts.

The pressure information collected is being used to help modify a widely used industry drilling hydraulics, surge and swab model to accommodate the unique flow paths of this system. The drilling mechanics package clearly demonstrated that vibrations because of rotation at moderate rpms were well within acceptable limits. This was a crit-

Figure 7. *After 10,000ft of tripping and 100,000 revolutions, the Dynamic Casing Seal system showed no damage.*

ical positive finding. The internal setting mechanisms of the Hy-Flow setting tool were found to be well isolated from the drilling fluids. Their integrity was proven when the liner hanger was returned to the shop, where the setting ball was dropped into the setting tool, the setting tool was pressured up, and the liner hanger was set. After a full teardown of the DCS, minor damage had been sustained by the leading edge of the pilot seal, but the seal was still functioning (Figure 6). The main seal displayed acceptable wear and functioned as designed. Of note was the observation that the test well casing (13 3/8-in.) appeared to be rougher than would be expected on a deepwater well where the casing would have been set a few days or weeks earlier.

The rotational components of the seal showed minimal wear in the 100,000 revolutions, and there was no evidence of plugging in any of the internal passages (Figure 7). Modifications to the pilot seal have been implemented, and the tool is being prepared for the second phase of testing.

Tripping is an unplanned event, and most tripping offshore will not involve laying down the liner. However, the liner connectors need to be robust enough to accommodate a trip and retain the make-up torque throughout subsequent drilling operations. The testing thus far has required two round trips of the liner. Torque monitoring was used on all make-ups and breakout torque was recorded. No breakout torque degradation was noted between two trips. The liner was inspected for damage after each trip. Most of the damage found was field-repairable, which was done before running the liner back into the well. A few joints required complete re-cut in the shop.

This suggests that in an offshore setting, a connector representative needs to be on location during the running of the liner. If it is necessary to lay it down, it needs to be inspected by personnel qualified to make minor field repairs. Further, some excess liner should be on hand to replace any excessively damaged pipe.

In conclusion, the application is not limited by thread technology. Existing casing product lines, as well as those designed envisioning such applications, met project requirements.

Conclusions

The work done so far on CTLD operations leads to several conclusions.

- the components necessary for this system have now been designed, built and tested in a full-scale test well onshore. The testing simulates most aspects of an offshore well;
- the DCS element is robust and fully meets the design requirements;
- the liner hanger has been demonstrated to be robust. It was successfully set after the testing operations were completed;
- the 11 3/4-in. liner connections are not limiting. They fully meet the needs of the liner drilling;
- operational adjustments are needed to implement CTLD, but they are not significant; and
- well control and safety are fully addressed with the design and operation of the system.

The one remaining test objective is to drill open hole. The test is scheduled for late April/early May.

CTLD operations may soon become an available alternative to fighting formation problems in deepwater. There appear to be no show-stoppers at this time. ✧

Acknowledgements

The authors gratefully acknowledge the support of the parent companies, ConocoPhillips, Tesco Corp., Baker Hughes Inc., GrantPrideco and Hunting Energy Services LP, for their continued support in this project, their belief in this project team and their support in publishing this paper. Additionally, the authors extend thanks to the U.S. Department of Energy's National Energy Technology Laboratory for its financial and enthusiastic technical support of this work. The DOE is a vital, supportive partner to the industry.

This article was presented at the 2004 *World Oil* Casing while Drilling Technical Conference on March 31. It has been reprinted with the permission of Gulf Publishing Co.

Mechanism of Hydrogen Generation in Coalbed Methane Desorption Canisters: Causes and Remedies

by Basim Faraj and Anna Hatch, with contributions from Derek Krivak and Paul Smolarchuk, all of *GTI E&P Services Canada*

The presence of hydrogen gas is a serious problem in coalbed methane desorption. Gas Technology Institute conducted a research program to understand the formation of hydrogen gas in desorption canisters to try to eliminate the underlying causes of this problem.

During routine gas chromatography (GC) analysis of desorbed gases from coalbed methane desorption canisters, hydrogen gas (H_2) was noted in variable amounts (values range between about 0.1% and 82-mole % of the total volume of the desorbed gases) along with methane in several canisters.

The presence of H_2 with methane is a serious problem that impacts the measured gas content values as well as the economic evaluations of coalbed methane plays. If the H_2 were not detected and assumed to be coal-desorbed methane, erroneous methane content could result. It was also noted that the proportion of H_2 increases significantly in comparison to methane with increased time of the desorption test. It was ultimately determined that H_2 gas was forming in the canisters during the desorption experiments.

High-resolution scanning electron microscopy confirmed the presence of bacteria (≈ 2μm in size) as being most responsible for H_2 generation. Hydrogen gas is formed because of fermentation reactions of anaerobic bacteria within the canisters during desorption of coal samples. The H_2 is generated within the canisters in the presence of coal, water and reducing headspace gases (mostly methane). Although the canisters used in this study were made of aluminum or anodized aluminum, it is unlikely that the make-up of canisters *per se* have any bearing on the H_2 generation capacity of the bacteria.

The most likely sources of introduction of the bacteria communities into the canisters are:

- water used as headspace filler in the canisters;
- water used to make the drilling mud. Drilling mud would invade and permeate coal samples, fractures or cleats and other porosity types during drilling and coring; and
- cross-contamination between canisters, as these are not usually sterilized between desorption experiments.

The anaerobic bacteria would thrive in a reducing atmosphere provided by methane and other reducing gases within the canisters. The fermentation reactions that produce H_2 are kept under disequilibria conditions (open system) each time the gases are vented for desorbed gas measurements.

To overcome the problem of H_2 (and other biogenic gases) being produced in canisters, it is strongly recommended to:

- add a biocide such as Tetrakis (hydroxymethyl) phosphonium sulfate ($[(CH_2OH)_4P]2SO_4$ — commercial name Tolcide, manufactured by Rhodia Inc.) to the water used in the canisters, at a rate of 150 mg/L; and
- sterilize the canisters before and after each use. Ultraviolet radiation or autoclave can be used for this purpose.

During routine coalbed methane desorption testing being performed by Gas Technology Institute (GTI) E&P Services Canada Inc., technical personnel detected the presence of H_2 among the desorbed gases through routine GC analysis. Since the objective of the testing is to determine the accurate volume of methane contained in a sample, this serious finding required further steps to be taken to correct for the presence

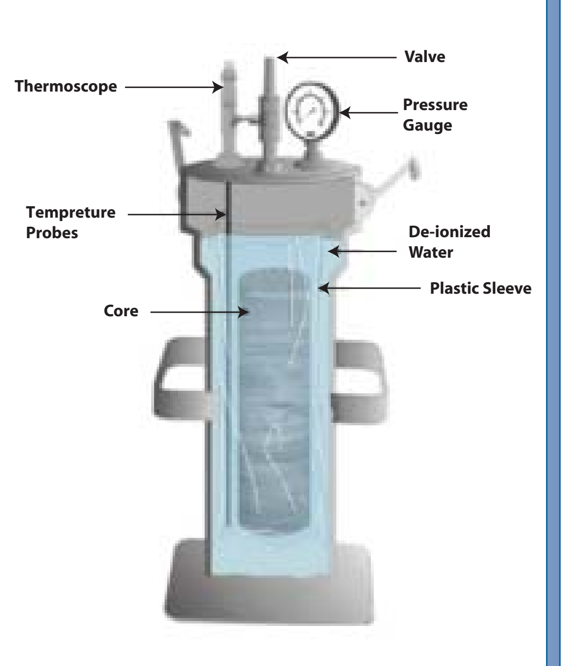


Figure 1. *The above schematic illustrates the placement of core, water and plastic sleeve within a canister (and other details).*

of H_2 in the total desorbed gas content values. Thereafter, GTI embarked on a research program to determine and understand the mechanism(s) of formation of H_2 gas in the desorption canisters to try to eliminate/modify the underlying causes of this problem. This summary outlines the findings, results and recommendations of the research undertaken thus far.

Research procedure

The research procedure began with complementary analytical techniques for characterizing the desorbed gases, water and coal samples within desorption canisters. Stable isotopes analysis of four H_2 gas samples showed an extraordinary depletion of the stable isotope deuterium, with dD H_2 values ranging between -706.5 and -749.3 (mean value of -733).

This strongly depleted H_2 indicates a biogenic origin of hydrogen. Stable isotopes of carbon and H_2 of the associated methane (CH_4) show a very different composition (d13CCH_4 between -44.75 and -52.61 and dD CH_4 between -260.3 and -276.1). These values indicate a mixed origin of the desorbed methane of geological biogenic/thermogenic mixtures. The dD CH_4 is heavier (more enriched in deuterium) than that of dDH_2. This big difference in hydrogen/deuterium (H/D) ratios points to a different origin for the H_2 atoms in methane and H_2 gas. Accordingly, the author's data show only H_2 gas and not CH_4 was generated in the canisters.

Table 1 shows the molar percentages and ratios of H_2 to methane in desorbed gases from a number of coalbed methane desorption canisters, along with other details of the experiment.

Rigorous GC testing showed H_2 gas was present in various proportions in the desorbed gases from a large number of canisters used by GTI E&P
Services Canada Inc. in Calgary. Hydrogen gas was detected in 43% (a total of 261 canisters) of previously used aluminum canisters and in 12% of new (first time used) anodized canisters (a total of 168 canisters).

The desorbed coal samples were from the Western Canadian Sedimentary Basin. However, the samples were from different coal seams as well as different coal measures, rank and depth range. Desorption temperatures also were variable and reflect the estimated or measured reservoir temperatures (ranged between 48.9˚F and 102.9˚F).

The time range for the first occurrence of H_2 identified in this study is the variable and found to occur at any time between 5 days and 100 days from the start of the desorption experiments. Trace amounts of H_2 may have been generated earlier than 5 days. However, no GC analysis was performed for periods less than 5 days, making this impossible to confirm.

In particular, if H_2 is not detected, it is assumed to be coal-desorbed methane.

As a result of these findings, GTI took the following actions:

- informed the clients if their samples showed H_2 in the desorbed gases. In the absence of critical knowledge of how and why H_2 was present within the desorbed gases, steps were taken to correct for the presence of H_2, using the shape of the cumulative desorption curves as well as quantitative gas chromatography results. The clients then were supplied with normalized gas content values (without the effect of H_2) with the knowledge that this method is only an approximation and not very precise; and
- embarked on a research program to understand the mechanisms of H_2 generation in the coalbed methane desorption canisters to eliminate/modify the underlying causes of this serious problem.

Desorption Protocols Utilized by GTI E&P Services Canada Inc.

Coal samples are collected at the well site and placed in aluminum or anodized aluminum canisters. Each canister is 37 cm long and 14 cm in diameter, with an internal volume of about 2,400 cm^3 (Figure 1). Once the core barrel has been retrieved and the core released from the shoe, the overall length of the core is measured. As dictated by the sampling prognosis, a representative sample(s) is designated and a measurement from the top of the core is used as a reference for the sampling depth. A 30-cm-long sample is cut and placed inside a plastic sleeve, which is then placed inside a canister. Each canister is then filled with deionized water, which has been purged with argon and heated to the estimated reservoir temperature. The canister lid is secured and the vent valve is put into the closed position to seal the sample and desorbed gases within the canister prior to beginning the measured portion of the total gas content.

While still onsite (inside the field desorption trailer), stabilization of canisters (at the estimated reservoir temperature) is carried out by placing the canisters in temperature-controlled water baths. The canisters are read (vented) as often as possible, maintaining a constant time interval between readings, to maximize the number of data points for the linear lost-gas back extrapolation, while keeping analytical variables such as time and temperature as constant as possible. The volume of gas desorbed per unit time determines the frequency of gas venting and recording.

A typical timeframe for lost-gas data collection is between 2 hours and 6 hours. After such time, the gas venting frequency will decrease according to:

- decreasing volume of gas at each reading;
- field demand and number of canisters used;
- availability of technical staff on-site; and
- gas pressure level that can be safely stored within the canister before being vented (about 25psi).

Prior to sample transportation, desorbed gas volume(s) are measured for each canister in a final field reading, and the canister is cooled (to about 30.9˚F) with the intent to minimize further desorption during transportation. The canisters then are transported (under ice) to a laboratory in Calgary.

Upon arrival at the laboratory, the internal temperature of each canister is recorded (typically at 30.9°F) and the canisters are placed on shelves in specially designed temperature-controlled rooms. Desorption measurements of the canisters commence at less regimented time intervals once the internal canister temperature is at or near the estimated reservoir temperature. The samples are read at least once (and up to three times) per day, depending on the volume of gas being desorbed from individual samples (as stated earlier).

The frequency of readings will gradually decrease until the sample is ready to be removed for residual gas measurements and other third-party analysis such as organic petrography, proximate and ultimate analyses, and cleat measurements.

Depending on its gas desorption characteristics, each sample is allowed to desorb for longer periods of time, usually between 3 months and 8 months. During these desorption experiments, a number of gas samples are collected from each canister for GC analysis. Typically, three to six gas samples are collected from each canister.

From the results shown in this work, the H_2 found in the desorption canisters is biological in origin and was formed within the desorption canisters. Various types of bacteria were found in the water samples and on the surfaces of the coal samples using high-resolution electron microscopy (Figure 2). The H_2 is generated within the canisters in the presence of coal, water and reducing head-space gases (mostly methane).

The production of H_2 gas by anaerobic bacteria is a widely known and well-documented phenomenon. It is well known that biogenic produced gases such as methane and H_2 are depleted in the heavy isotope (deuterium) as the microbes use (fractionate) the lighter isotopes (C_{12} in preference to C_{13}, and H instead of D) as these lighter atoms require less energy to utilize than their heav-

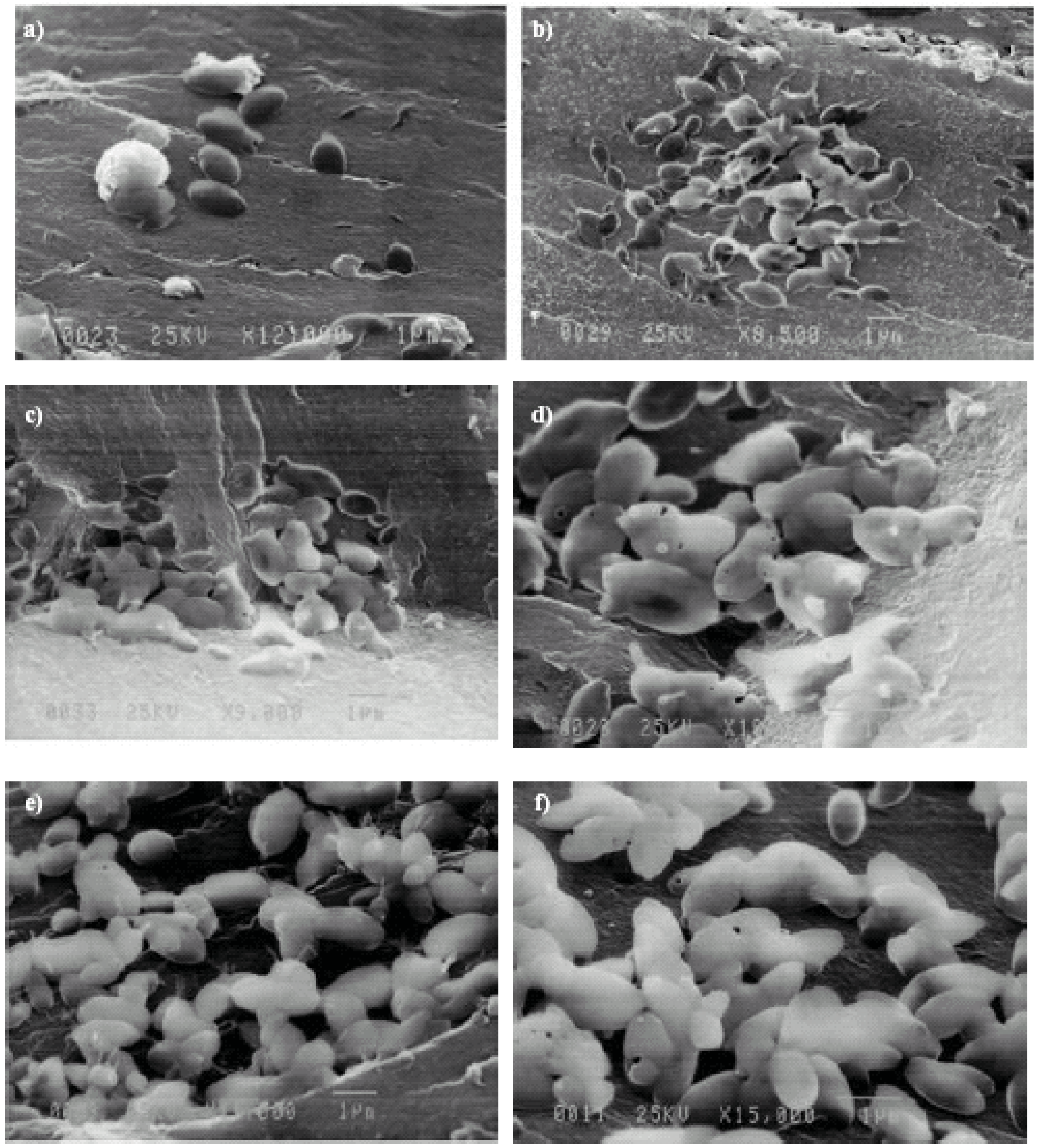


Figure 2. *An SEM photomicrograph showing the various types of bacteria found on the surfaces of several coal samples from desorption canisters.*

ier counterparts. These heavier isotopes impart slight physical and chemical properties that result in their fractionation.

The reducing conditions within the canisters, because of the presence of the desorbed methane, promoted the growth of various anaerobic bacteria. The presence of water and coal must have promoted the growth of various types of bacteria with the hydrogen-generative type dominant. The authors do not know what steps took place that resulted in the dominance of this type of bacteria community over another. This is a complex process that was not addressed in this study because of time constraints. The bacteria are ubiquitous and appear to have been introduced into the canisters through one or more major sources (or a combination thereof):

- bacteria introduced into the canisters through drilling-mud contamination. Water used to make the drilling mud is usually taken from nearby local sources (such small ponds) close to the well site. These water sources may contain bacteria associated within the suspended mud;
- water used as headspace filler. Although deionized water is usually used, water analysis shows that even this water was contaminated with bacteria; and
- previously used canisters that had undergone H_2 exposure from previous use. The bacteria are able to survive and may have spores that revive once the conditions are suitable in the next desorption experiment using the same canisters.

The various analyses of the coal samples confirmed they are ordinary with no migrated hydrocarbons or extraordinary minerals. The combination of reducing environment, coal and water, along with the long time involved in desorption, may combine to promote the generation of H_2 gas within the canisters.

To overcome the production of H_2 (and other biogenic gases) in canisters, it is strongly recommended to add a biocide to the water used in the canisters and to sterilize

Table 1. *Hydrogen gas and CH_4 mole % values from desorption experiments in coal samples from Alberta, Canada.*

Sample No.	Total Desorbed H_2 Volume (cm_3)	Total Desorbed CH_4 Volume 8(cm^3)	Experiment Duration	Mole% of H_2 to Total Gas Desorbed	Corrected Gas Content (Scf/ton)	Air-dry Sample Weight (gm)
1	2,079.8	2,753.8	71.0	43%	47.4	1,861
2	4,430.4	950.4	70.6	82%	14.2	2,145
3	1,041.9	1,373.1	242.5	43%	50.3	--
4	14.8	7,885.2	172.9	0.2%	1,153.0	--
5	1,789.4	5,553.6	254.2	24%	116.2	--
6	1,887.2	2,635.9	71.1	42%	50.5	1,670
7	117.6	5,337.1	172.7	2.2%	79.6	2,145
8	165.7	542.3	245.3	23.4%	12.7	--
9	1,537.5	2,816.5	250.1	35.3%	91.1	--
10	1,280.6	2,563.4	337.9	33.3%	64.9	1,264.3
11	0.01	2,799.0	337.9	0.01%	61.0	1,468.1
12	963.9	5,733.1	337.3	14.4%	88.8	2,067.2
13	464.2	864.8	236.6	35%	36.5	1,165.8
14	1,713.8	1,949.2	236.4	47%	36.9	1,689.3
15	142.1	6,240.4	260.5	1.9%	92.9	--
16	7.9	9,089.2	260.4	0.1%	132.5	--
17	55.2	3,000.5	258.4	1.8%	54.3	1,768
18	692.8	2,832.0	253.5	19.7%	42.7	2,121
19	141.9	3,945.1	272.7	3.5%	82.0	--
20	1,030.4	2,285.6	272.1	31.1%	67.9	--

canisters before and after each use.

The various analyses carried out in this study showed the coal samples analyzed do not contain migrated hydrocarbons or other contaminants that might be responsible for the bacteria to produce this H_2. Rather, it appears the combination of coal samples, water, time and moderate temperature under reducing environment (provided by the desorbed methane) is providing the necessary conditions capable of producing H_2. It is expected that this phenomenon will be widespread in the industry if the conditions that produce this gas are common.

From the morphological studies, it is possible the bacterial species found in the Canadian samples are from the *Vitreoscilla* species. Other species of bacteria known to produce H_2 include *Xanthobacter*. Further molecular biological analysis would allow for a precise identification of the bacteria in the coal samples. However, cost and time constraints prevented this work from being done as part of this study.

Conclusions and recommendation

- Hydrogen gas was probably misidentified as helium in routine GC analysis. This may be one of the reasons for the lack of reported H_2 by many analytical facilities. The H_2 was probably mistaken for helium because their elusion time is very close.
- Stable isotopes of H_2 confirmed the biogenic origin of the hydrogen. The H_2 was highly depleted in deuterium.
- GTI E&P Services developed a method by which correction of H_2 contamination is carried out by a combination of desorption curve shape and gas chromatography analysis.
- After considering many possibilities, a likely cause for the observations noted is the presence of a thermophilic bacterium such as *Thermotoga neapolitana*. This type is an anaerobic bacterium that uses certain organic carbon compounds as a food source and produces H_2 as a by-product. It is likely this type of bacteria is present in the canisters utilized.
- High resolution SEM (~15Å) examination of the coal samples confirmed the presence of bacteria on the surfaces of the samples.
- Whole oil GC, GC/mass spectroscopy of extractable organic matter from the coal samples, and other petrographic and mineralogical analyses show the coal samples to be ordinary, containing no migrated hydrocarbons.
- It is recommended to use a biocide as well as sterilization of canisters between each desorption experiment to prevent introduction or activity of bacteria.

To learn more about this research and the study's results, please visit *www.gastechnology.org*. *[Mechanism of Hydrogen (H_2) Gas Generation in Coalbed Methane Desorption Canisters: Causes and Remedies*; GRI-03/0076.] For more information, contact Kent Perry, executive director, Exploration and Production Research Center, GTI: *kent.perry@gastechnology.org*. ✧

References

1. Castanier, S., Le Metayer-Levrel, G., Perthuisot, J-P. (1999) *Ca-carbonates Precipitation and Limestone Genesis—The Microbiologist Point of View*. Sedimentary Geology, Vol. 126, pp. 9–23.
2. Estep, M.L.F. (1984) *Carbon and Hydrogen Isotopic Compositions of Algae and Bacteria from Hydrothermal Environments, Yellowstone National Park.* Geochimica et Cosmochimica Acta, Vol. 48, pp. 591–599.
3. Lavorto, Nick (2002) Personal communications.
4. Lee, J.A., Faraj, B., McKinstry, B.W., and Sloan, G.R. (2002) *Drilling Program Planning and Field Operations Protocols for Coalbed Methane and Shale Gas Reservoirs in Canada*. Gas Technology Institute Report No. GRI-02/0153. GTI E&P Services Canada, Inc., Calgary, Alberta, Canada. Variously paginated.
5. Nealson, K.H. and Stahl, D.A. (1997) *Microorganisms and Biogeochemical Cycles: What can we Learn from Layered Microbial Communities?* Chapter 1 in Ribbe., P.H. (series editor), Banfield, J.F. and Nealson, K.H. (editors) *Geomicrobiology: Interactions Between Microbes and Minerals.* Reviews in Mineralogy Vol. 35. Mineralogical Society of America, Washington, D.C. pp. 5–34.
6. Schoell, M. (1983) *Genetic Characterization of Natural Gases*. AAPG Bulletin, Vol. 67, pp. 2225–2238.
7. Sung, S., Raskin, L., Duangmanee, T., Padmasiri, S., and Simmons, J.J. (2002) *Hydrogen Production by Anaerobic Microbial Communities Exposed to Repeated Heat Treatments*. Proceedings of the 2002 U.S. DOE Hydrogen Program Review, NREL/CP-610-32405, pp. 1–17.
8. Tissot, B.P. and Welte, D.H. (1984) *Petroleum Formation and Occurrence.* Second revised and enlarged edition. Springer-Verlag, Tokyo. 699 p.
9. Ueno, Y., Haruta, S., Ishii, M. and Igarashi, Y. (2001) *Microbial Community in Anaerobic Hydrogen-Producing Microflora Enriched from Sludge Compost*. Applied Microbial Biotechnol., Vol. 57, pp. 555–562.
10. Van Ginkel, S., Sung, S., Li, L. and Lay, J. (2001) *Role of Initial Sucrose and pH Levels on Natural, Hydrogen-Producing, Anaerobe Germination*. Proceedings of the 2001 DOE Hydrogen Program Review. Document number NREL/CP-570-30535. 14 p.
11. Van Ooteghem, S.A., Beer, S.K. and Yue, P.C. (2001) *Hydrogen Production by the Thermophilic Bacterium Thermotoga Neapolitana*. Proceedings of the 2001 DOE Hydrogen Program Review. Document No. NREL/CP-570-30535. 12 p.
12. Wilson, J. and Ingram, G. (2002) Personal communications.

Optimization of Infill Drilling in Naturally-Fractured Low-Permeability Gas Sandstone Reservoirs

by Lawrence W. Teufel,
Petroleum and Natural Gas Engineering Department, New Mexico Institute of Mining and Technology

Studies demonstrate the importance of natural fractures and the associated reservoir permeability and permeability anisotropy for infill well potential. This is the second in a three-part series.

Natural fractures are important in the economical production of low-permeability (tight) gas reservoirs throughout the Rocky Mountain region, as they not only enhance the overall permeability of these reservoirs, but also can create significant permeability anisotropy.

Permeability anisotropy causes the drainage area around the wells to be elliptical. Elongated drainage can create more production interference and drainage overlap between adjacent wells and may leave large areas of the reservoir undrained. Evaluation of infill well potential in these reservoirs requires knowledge of the magnitude and orientation of reservoir permeability anisotropy to determine the optimal number and location of new wells.

A U.S. Department of Energy/National Energy Technology Laboratory cooperative industry project at New Mexico Tech has recently been completed about optimization of infill drilling in naturally fractured tight-gas reservoirs. This cooperative project focused on multi-disciplinary reservoir characterization and simulation studies of the Mesaverde and Dakota sandstone formations in selected areas of the San Juan Basin in northwestern New Mexico. These studies have:

- developed geologic models from logs and 3-D seismic data, and used geostatistics to characterize reservoir heterogeneities and net thickness distributions;
- characterized natural fracture systems from surface outcrop, core, logs and seismic analyses;
- determined reservoir permeability and permeability anisotropy from well tests and production data;
- defined the shape and size of drainage area and recoverable gas for existing wells from production data and reservoir simulation; and
- determined the optimal location and number of new infill wells and forecasted the increase in gas recovery from infill drilling using reservoir simulation. Industry partners during the course of this 5-year project included BP, Burlington Resources, ConocoPhillips and Williams Petroleum.

Figure 1. *This photo shows a partially filled vertical extension fracture in Mesaverde sandstone core from the U.S. Department of Energy's Multi-Well Experiment site.*

This article will briefly summarize the influence of natural fractures on reservoir permeability, permeability anisotropy and well drainage in tight-gas sandstones. A short discussion follows on the results of four study areas in the Mesaverde that have significantly different well/reservoir productivity. These studies highlight the range of importance natural fractures and associated

This three-part series of GasTIPS *articles on tight gas sand resource development focuses on the application of advanced exploration and production technology in low-permeability sandstone reservoirs to increase domestic natural gas supplies and lower their finding and production costs. IRD is the integrated application of a series of complementary resource assessment, reservoir characterization and field development technologies designed to optimize recovery. It is particularly applicable to low-permeability reservoirs with thick but discontinuous pay zones and anisotropic flow behavior – settings where a well's drainage area is low but numerous productive intervals are penetrated.*

The suite of technologies IRD encompasses includes:

- *natural fracture identification technologies* to delineate high-productivity sections within a multi-township tight gas accumulation;
- *well logging technologies* that reliably distinguish between gas- and water-bearing sands, and can identify and quantify volumes of secondary porosity;
- *multi-zone completion technologies* that can efficiently stimulate multiple zones without damaging a formation; and
- *well testing technologies* to establish drainage volumes, well-to-well communication and anisotropic flow patterns. ●

reservoir permeability and permeability anisotropy have on drainage efficiency and infill well potential.

Natural fractures and reservoir permeability

The importance of natural fractures on reservoir permeability and productivity in tight-gas sandstone reservoirs is well documented in an extensive series of papers and reports on the U.S. Department of Energy's Multi-Well Experiment (MWX) conducted from 1980 to 1988. This field project was designed to characterize low-permeability gas reservoirs and assess stimulation technology. It consisted of three closely spaced wells in the **Rulison** field in the Piceance Basin of northwestern Colorado. The three wells were arranged in a triangle with interwell spacing varying from about 150ft to 250ft, depending on depth. The reservoirs of interest were sandstones of the Mesaverde Group, which occur between 4,000ft and 8,350ft at this site. Different depositional zones within the formation contain reservoirs of different character, varying from blanket-shaped marine sandstones to narrow, lenticular sandstones. All the sandstone reservoirs have low matrix permeability (usually less than a microdarcy), are enclosed in shale or mudstone, and are naturally fractured.

A total of 4,200ft of core was taken from the three wells for extensive rock property testing and reservoir characterization. During the 8-year program, six individual reservoir zones were isolated one at a time and each tested and characterized with extensive reservoir draw-down, build-up and interference tests, *in situ* stress measurements and stimulation experiments. Complimentary geologic studies of the core and nearby outcrops helped characterize reservoir shapes, sizes and lithologic heterogeneity as well as the distribution, intensity, interconnectivity and orientation of natural fractures.

Natural fractures in these Mesaverde sandstone reservoirs are primarily vertical regional extension fractures (Figure 1). Regional fractures occur in essentially flat-lying strata and in the absence of major structural deformation of the local strata. They form a systematic set of unidirectional fractures present over large areas of a sedimentary basin. Their distribution and intensity is a function of bed thickness and lithology. In general, fracture intensity decreases with increasing bed thickness, and fractures tend to be longer and further apart. Fracture intensity is higher in clean sandstone, and the intensity decreases with increasing shale content as the rock becomes softer and less brittle. At the MWX site, fractures occur only in sandstones and terminate at shale boundaries. The regional fracture trend is about N70°W and is aligned with the maximum horizontal *in situ* stress direction as well as the direction of hydraulic fracture propagation.

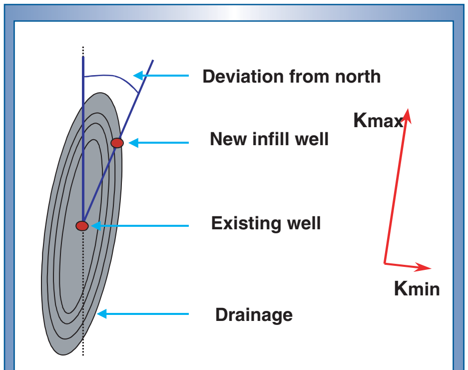


Figure 2. *These schematic diagrams show the effect of angular rotation of well alignment on drainage overlap and efficiency of a square well pattern aligned with maximum permeability direction to a square well pattern shifted 10° from the maximum permeability direction (Harstad, 1998).*

Well tests indicated the equivalent reservoir permeability was one to three orders of magnitude greater than laboratory-derived matrix-rock permeability of one microdarcy. Documented permeability anisotropy at the MWX site, because of the unidirectional fractures, ranges from 8:1 to 100:1 for the ratio of the maximum to minimum horizontal reservoir permeability. Permeability anisotropy creates elongated drainage areas along the fracture trend. Moreover, permeability anisotropy limits its lateral communication between closely spaced wells in the direction orthogonal to the fracture trend in these reservoirs with very low matrix permeability.

Subsequent to the MWX program, the slant hole completion test was conducted at the same site and designed based on the MWX findings. This Gas Technology Institute-sponsored project consisted of a deviated well, locally cored, through the Mesaverde reservoirs. The hole azimuth was normal to the trend of the subsurface regional fracture trend. This well and core confirmed vertical regional natural fractures are pervasive throughout the sandstone reservoirs and that these fractures constitute the primary permeability system in the reservoirs.

Permeability anisotropy and well drainage area

The size and shape of well drainage areas in naturally fractured reservoirs that have strong permeability anisotropy are not represented by radial flow. Instead of being circular, the drainage area is better described as being elliptical. Conceptual simulation models by Harstad (1998) demonstrate that understanding the orientation and magnitude of horizontal permeability anisotropy, as well as the size and shape of the drainage area of a producing well, has significant economic importance in optimizing the number and location of infill wells. Locating the infill well away from the maximum permeability direction reduces production interference and drainage overlap between adjacent wells, increases reservoir drainage efficiency and decreases the potential for leaving parts of the reservoir undrained (Figure 2). An example calculation of the models show a 20° angular rotation in well alignment away from maximum permeability direction increases cumulative gas production by more than 20% for a tight-gas reservoir with a permeability anisotropy ratio of 10:1.

Mesaverde study

The Mesaverde Group play in the San Juan Basin is a basin-centered gas accumulation. Cumulative gas production in these tight-gas reservoirs shows a northwest-southeast trend coincident with the depositional strike of the formations. The Mesaverde Group comprises, in ascending stratigraphic order, three commingled sandstone formations: the Point Lookout Sandstone; Menefee Formation; and Cliff House Sandstone. The Cliff House and Point Lookout are massive shoreline sand deposits that span most of the basin. The Menefee consists of discontinuous channel sands that result from estuarine, deltaic and fluvial geologic environments. Well performance in these formations varies throughout the basin because of net thickness differences, reservoir heterogeneity and natural fracture-dependent reservoir permeability. The actual contributions from each formation throughout the basin are unknown because the production is commingled.

Production from low-permeability gas sandstones of the Mesaverde Group is highly dependent on natural fractures. Natural fractures not only enhance the overall permeability, but also can create significant permeability anisotropy. Although natural fractures exist throughout the basin, their type, distribution, intensity, interconnectivity and orientations within the basin are not well known. In general, vertical regional extension fractures tend to have a north-south to northeast-southwest orientation within the basin. Fracture swarms, associated with local faulting or geologic structure that have higher rates of bed curvature, also are present in the basin. They are relatively narrow, linear zones of high-density interconnected fracturing that create "sweet spots" of much higher reservoir permeability, permeability anisotropy and productivity. Fracture swarms have been identified from 3-D seismic analysis of horizon curvature attributes and confirmed by production decline analysis.

The Blanco Mesaverde reservoir was discovered in 1927. Extensive development took place on 320-acre well spacing during the 1950s and defined areas of high initial gas potential and thick net pay. The time required to reach pressure stabilization in long-term shut-in pressure buildup tests conducted by El Paso Natural Gas Co. in the late 1950s and early 1960s indicated low permeabilities and low drainage efficiency at 320-acre spacing. These observations prompted the request for 160-acre infill well development, which was approved in 1974.

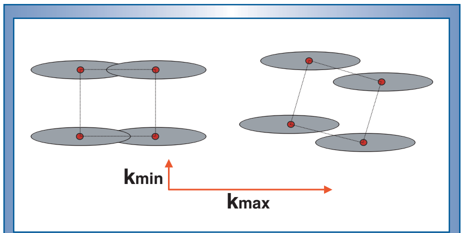


Figure 3. *This schematic diagram shows the location of an infill well relative to the elongated drainage area of an existing well with reservoir permeability anisotropy (Harstad, 1998).*

Recent work has lead to the conclusion that 160-acre infill well spacing is not sufficient to efficiently drain the Mesaverde and further infill drilling to 80-acre spacing is warranted. Pressure plots generated from the initial pressure of wells drilled in the 1950s compared with wells drilled in the 1970s indicate some areas had almost initial reservoir pressure, even after 20 years of production. Moreover, pressures from infill wells were considerably higher than those obtained from 7-day shut-in pressures of the original wells. Remaining gas reserves are based on the performance of existing wells. If these wells have high interference and low drainage efficiency, then the remaining reserves will be underestimated.

In 1997, pilot studies were conducted to determine the feasibility of reducing spacing to 80 acres. Harstad (1998) analyzed well tests and production data and performed conceptual reservoir simulation studies on two pilot areas to quantify the infill drilling potential. The results of this study demonstrated the importance of reservoir permeability anisotropy on drainage area and shape and in determining the optimal location and number of infill wells in a given area.

The two pilot areas are near the northwest-southeast trending Mesaverde fairway that has good producing wells. The reservoir net thickness, permeability and production characteristics are different for the two pilots. The first pilot is adjacent to the fairway and has moderate well/reservoir productivity in comparison to the fairway. The second pilot is farther away from the fairway and has lower well/reservoir productivity.

Pressure interference tests in the Cliff House formation in the first pilot indicate anisotropic reservoir permeability with a maximum and minimum horizontal permeability of 0.348 millidarcy (md) and 0.035 md, respectively. The observed horizontal permeability anisotropy ratio is 10:1, with the maximum horizontal permeability direction trending north-south. The calculated equivalent reservoir permeability (geometric average of the maximum and minimum permeability) from these tests is 0.110 md, which is more than an order of magnitude or greater than matrix permeability, which is less than 0.01 md. Analysis of production data from wells in both pilots indicates equivalent reservoir permeabilities that are one to two orders greater than matrix permeability. Fractures have been found in the core and are believed to control reservoir permeability, production and drainage.

The effect of permeability anisotropy on drainage is illustrated in Figure 3. Wells drilled on 160-acre spacing have a typical distance of about 2,500ft between an existing well and a new well. Initial pressure in the new well is a function of where the new well intersects the elongated drainage from the existing well. An increase in initial pressure in the new wells is observed with increasing angular deviation from north and the maximum permeability direction (Figure 4). Knowledge of the magnitude and orientation of reservoir permeability anisotropy *a priori* can clearly optimize the location of new infill wells in areas of higher-pressure potential and increase drainage efficiency.

Reservoir simulation models were developed from geologic models and production data to history-match the performance of existing wells on 160-acre spacing. Conceptual reservoir simulation models were then run to determine the number of infill wells required to effectively drain the reservoir and forecast the contribution of each well to the increased cumulative gas recovery. The infill evaluation involved using the output pressure-distribution map from the simulation to determine areas of higher pressure. Areas of higher pressure are an indication the reservoir is not sufficiently drained by the current well spacing and additional reserves can be recovered if 80-acre infill wells are drilled.

Results of the simulation models predicted 80-acre infill wells would increase recoverable gas by 23% and 46% for the two four-section pilot areas. The largest potential increase in recoverable gas was in the area with lower well/reservoir productivity. The models predicted that 80-acre infill wells would recover at least 1 Bscf per infill well. Results of the pilot tests, coupled with the reservoir simulation study, prompted the approval of 80-acre well spacing for the Mesaverde in 1998. Extrapolation of the results from these two pilots across the Mesaverde producing area provides a preliminary estimate of an additional 7.8 Tscf that could be recovered by optimal infill drilling.

Performance of 80-acre infill wells drilled in the two pilot areas was evaluated by Al-Hadrami (2000). Infill wells were drilled based on knowledge of the direction and magnitude of the reservoir permeability anisotropy, reservoir net thickness and heterogeneity, distribution of reservoir pressure, calculated drainage areas of existing wells and feasibility of surface locations. Geologic models were developed from well logs of existing and infill wells, as well as available petrophysical data using geostatistical methods. The geologic model of each pilot was incorporated into a reservoir

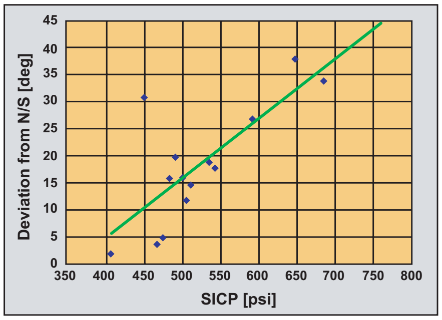


Figure 4. *The above graphic shows a plot of initial shut-in pressure of new infill wells vs. angular-well-alignment location relative to existing wells in which the direction of maximum horizontal reservoir permeability is north-south (Harstad, 1998).*

simulation model that included the observed permeability anisotropy ratio of 10:1 with the maximum horizontal permeability direction of north-south. The simulation models were verified through pressure and production history-matching of the 160-acre well spacing development. Further verification was achieved by history-matching the 80-acre well spacing development without adjusting any of the model parameters. The 30-year production forecast of the reservoir model predicted a total net increase in recoverable gas for the two four-section pilot areas of 26% and 44% over the predicted gas recovery of existing wells on 160-acre spacing (Figure 5).

The importance of considering permeability anisotropy was clearly demonstrated in this study by comparing the performance of the actual infill wells drilled away from the north-south trend of maximum horizontal reservoir permeability with hypothetical wells that had locations north-south of existing wells. The hypothetical infill well locations were the worst-case scenarios that created more drainage overlap and pressure interference between wells because of the reservoir permeability anisotropy and thus significantly reduced the potential increase in gas recovery. Simulation results for the two pilot areas show the predicted total cumulative gas production is reduced by 17% and 22% if the wells had been drilled along the north-south trend of maximum horizontal permeability from existing wells (Figure 5).

Robinson and Engler (2002) presented an integrated geologic and reservoir engineering study of a highly fractured and high equivalent permeability area within the Mesaverde. In the study area, the dominant fracture trend was N30°E as identified by seismic bed curvature analysis and confirmed by production decline analysis. Type-curve analysis resulted in an average well permeability from 0.10 md to 7.75 md. Simulations demonstrated a minimum permeability anisotropy of 13.7:1 was sufficient to match the interfering production response between wells. In contrast to the two pilot areas with much lower equivalent permeability, this area of high permeability has the potential for widespread drainage to occur. Existing wells exhibit an average drainage of about 160 acres, and only limited infill drilling was identified on the drainage maps. Knowledge of the natural fracture trend and associated permeability anisotropy is important for well location and performance. An infill well completed in the same fracture set and in-line with the maximum horizontal permeability direction as previously drilled wells has a production rate that is well below the average of wells in this area. This study demonstrated that although limited infill drilling opportunities exists, proper evaluation methods are useful in identifying the best well locations. Simulation results estimate the potential recovery for 80-acre infill wells at selected locations is 800 MMscf/well.

The potential for infill drilling was also evaluated in areas along the northeast margin of the basin. The Mesaverde formations in this area of the basin have poorer reservoir quality and much lower well productivity than the other study areas in and adjacent to the main fairway, where natural fractures have been observed and anisotropic permeability has been documented. Results of production analysis show the estimated ultimate recovery of these wells has decreased with the initial production date from a high of 1.46 Bscf/well for 320-acre well spacing to a low of 0.40 Bscf/well for the new 80-acre infill wells. This implies new well locations are partially drained by older, existing wells. Reservoir simulation modeling of the pilot area shows no significant effects of permeability anisotropy on infill well locations. Moreover, the well production history and lack of any reported measured pressure interference between wells indicates little or no influence of natural fractures on reservoir permeability or permeability anisotropy.

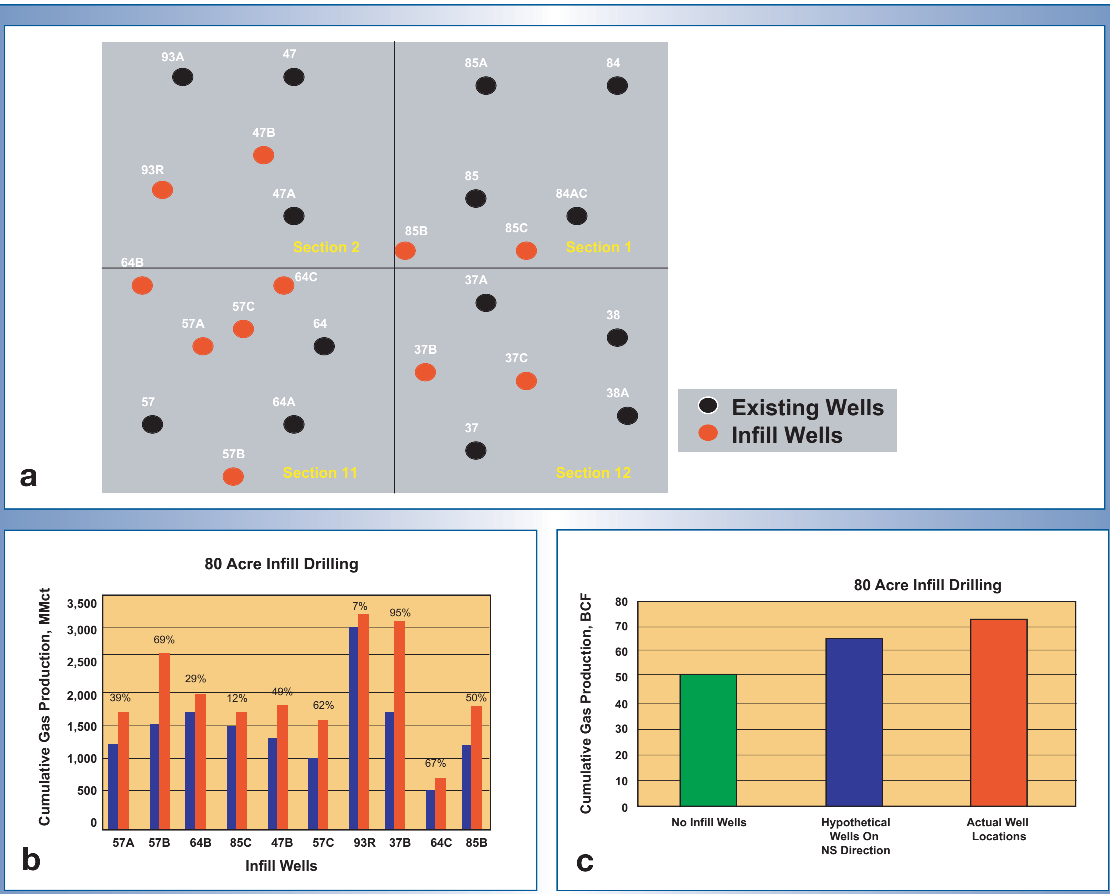


Figure 5. *The above plots compare production forecasts from simulation model of a four-section pilot in the Mesaverde reservoir for: (a) 160-acre well spacing with no infill wells, (b) hypothetical infill wells that had locations north-south of existing wells, and (c) actual infill wells drilled off the north-south trend of maximum horizontal reservoir permeability of existing wells (Al-Hadrami, 2000).*

Conclusion

In summary, tight-gas sandstone reservoirs throughout the Rocky Mountain region are economically producible because of natural fracturing. Natural fractures appear to exist in the Mesaverde sandstones of the San Juan Basin, but their distribution, intensity and orientation varies within the basin. Thus, there are areas of high and lower gas productivity, depending on the degree of fracturing.

Reservoir studies of the four study areas discussed in this article have significantly different well/reservoir productivity. These studies demonstrate the range of importance natural fractures and the associated reservoir permeability and permeability anisotropy have on drainage area and infill well potential, and that proper evaluation methods are useful in identifying the best well locations. ✧

References

1. Al-Hadrami, H.: *Influence of Permeability Anisotropy and Reservoir Heterogeneity on Optimization of Infill Drilling In Naturally Fractured Tight-Gas Mesaverde Sandstone Reservoirs*, San Juan Basin, Ph.D. Dissertation, New Mexico Institute of Mining and Technology, Socorro, NM, 2000.

2. Harstad, H.: *Drainage Patterns in Fractured Tight Gas Reservoirs*, Ph.D. Dissertation, New Mexico Institute of Mining and Technology, Socorro, NM, 1998

3. Hart, B.S., Pearson, R., Reawling, G.C., 2002: *3-D Seismic Horizon-based Approaches to Fracture-swarm Sweet Spot Definition in Tight-gas Reservoirs*, Geophysics, Vol. 66, p. 220–236.

4. Munoz, J.D., Chen, H.Y., and Teufel, L.W.: *A Type-Curve-Based Spreadsheet Program for History Matching and Forecasting Tight-Gas Production*, SPE Paper No. 71067, presented at the SPE Rocky Mountain Petroleum Technology Conference, Keystone, Colo., 21–23 May 2001.

5. Northrop, D.A. and Frohne, K.H., 1991: *Insights and Contributions from the Multiwell Experiment: A Field Laboratory in Tight Sandstone Reservoirs*, Journal of Petroleum Technology, Vol. 42, p. 772–779.

6. Robinson, R.L. and Engler, T.W.: *An Effective Technique of Estimating Drainage Shape, Magnitude and Orientation in a Low-Permeability Gas Sand*, SPE Paper No. 77742, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, Sept. 29–Oct. 2, 2002.

7. Whitehead, N.H.: *Atlas of Major Rocky Mountain Gas Reservoirs*, New Mexico Bureau of Mines and Mineral Resources, Socorro, NM, 1993.

PUMP Project: Quantifying Best Practice Analysis to Cut Costs and Boost Output

by Iraj Salehi, *Gas Technology Institute; and* Gary Walker, *U.S. Department of Energy, National Petroleum Technology Office*

Preferred upstream management practices (PUMP), a research and development project supported by the U.S. Department of Energy/National Energy Technology Laboratory, has an objective to develop a computer-assisted methodology to identify and optimize preferred management practices in upstream oil production operations.

The project was implemented in Oklahoma and included work with three independent producing companies operating in the Golden Trend area. The PUMP project was funded jointly by the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL) and Gas Technology Institute (GTI), with DOE providing 48% of the cost and GTI providing the remaining 52%. Chesapeake Energy Corp., Newfield Exploration Co., Triad Energy Corp., Oklahoma Independent Producers Association (OIPA), Intelligent Solutions Inc. and West Virginia University have partnered with DOE and GTI in the project.

Motivation

Total U.S. production from onshore and offshore – excluding Alaska but including lease condensate – is projected to decrease from 4.78 million b/d in 2001 to 4.11 million b/d in 2025, while reserves are predicted to decrease from 19.14 billion bbl to 14.98 billion bbl during the same period, according to the DOE's Energy Information Administration.

The alarming feature of these projections, which are principally in line with all previous projections, is the steady decline of the lower 48 states' reserves and production (Figures 1 and 2). This situation, with a backdrop of steadily increasing demand and driven by the incentive to achieve energy independence, has been the primary motive for the DOE to develop a two-pronged research and development program – a long-term program aiming at production from unconventional resources and a short-term program for increasing recovery from producing fields. The PUMP project relates to the second category of programs.

The primary driver behind the project is that, in general, a high percentage of the technically recoverable oil remains unproduced because of high production cost

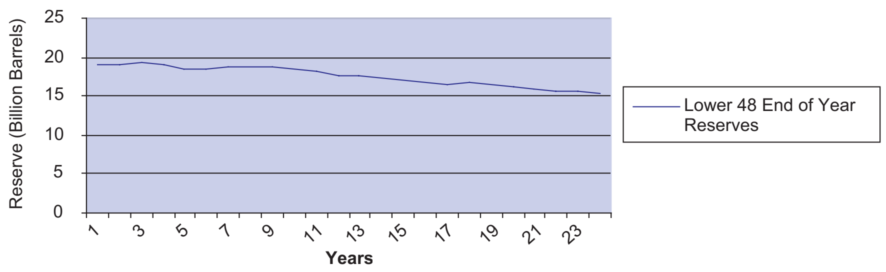


Figure 1. *Projected U.S. oil reserves from the lower 48 states from 2001 to 2025.*

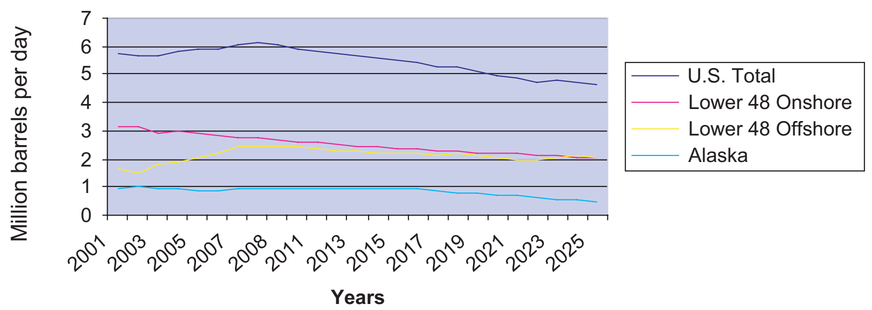


Figure 2. *Projected U.S. oil production from 2001 to 2025.*

or low production rate from application of non-optimal completion and production practices. It is therefore logical to focus on producing fields and develop techniques to improve recovery efficiency through optimization of current practices as well as develop means and methods for producing from in-field reserves, such as those left behind-pipe or entrapped in compartmented reservoirs.

The PUMP project design was based on small to mid-size independent producers in the United States drilling 85% of all oil and gas wells and producing 65% of the total gas and 40% of the total oil from onshore fields. Those technologies that address the needs of independent producers are the ones with the highest impact relative to short-term production increase and reserve replacement.

The common approach for enhancing recovery from producing fields is correlation of production data with drilling and completion parameters along with identification of the most influential parameters relative to production rate and ultimate recovery. For this reason, the foundation of the PUMP project rests on determining the effects of various completion and production parameters on production.

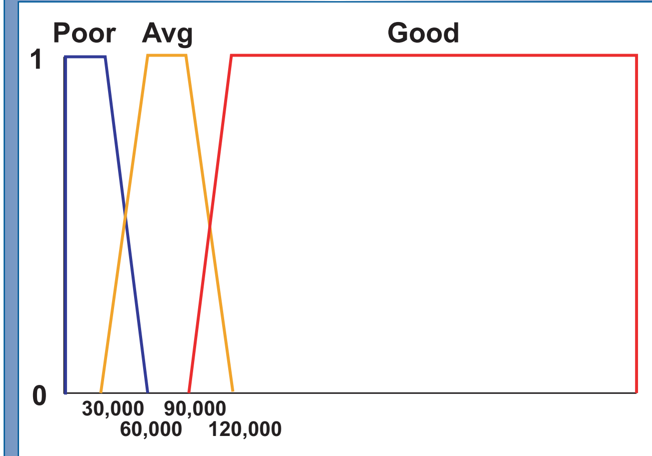


Figure 3. *The 30-year estimated ultimate recovery productivity fuzzy sets for wells in the Golden Trend field.*

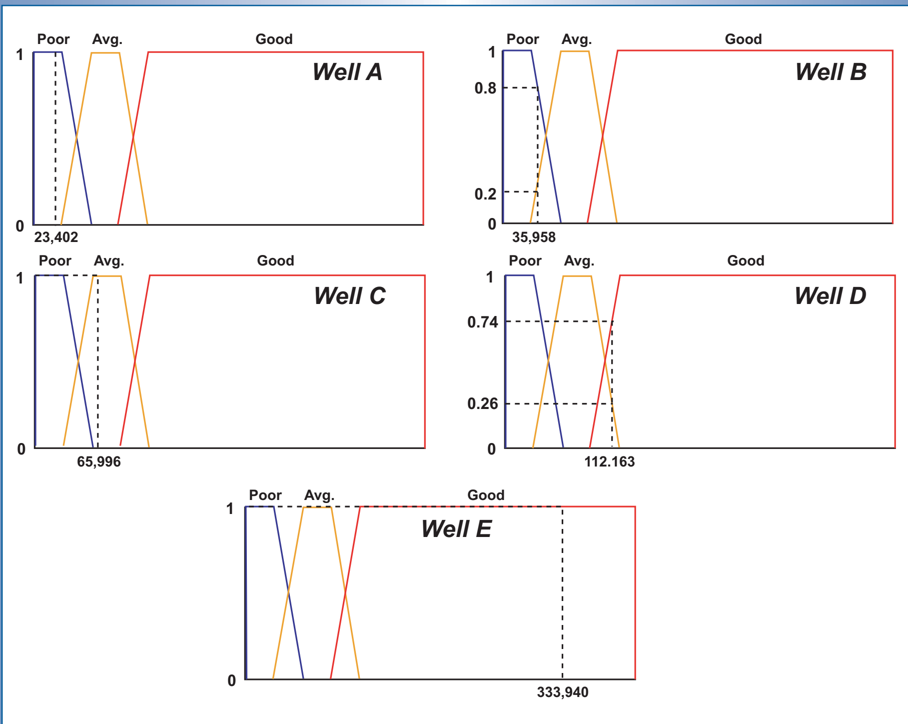


Figure 4. *Examples of fuzzy classification.*

Although petroleum engineering has become a mature scientific technology, its application to the characterization of older onshore fields in the United States, particularly those operated by small and mid-size independent producers, is usually hindered by the lack of accurate data. For several reasons, the oil field data available to small and mid-size independents have been, and will continue to be, inaccurate, imprecise and incomplete. These reasons include frequent mergers and takeovers that have diminished the corporate memory to the level of virtual non-existence and downsizing that has reduced the in-house workforce to the extent the data that might be present in company files are rarely used by busy engineers and geologists.

Under these conditions, sound engineering analyses are difficult if not impossible, and can yield unreliable and often misleading results. Aware of this situation, the industry has had to rely on the raw experience of engineers and operators and devise a method for distilling their collective experience into what is known as “best practices.” However, results from best practice analyses are qualitative by nature and do not lend themselves to reliable technical analyses and sound engineering decisions.

The primary goal of the PUMP project was to quantify best practice through the development of a computer-assisted engineering decision-support software that identifies the most influential parameters affecting overall well performance and recommends variations in these parameters for optimization of the processes. Considering the nature of oil field data, “soft” computing techniques such as fuzzy logic and neural networks, capable of handling imprecise and heterogeneous data, were the methods of choice. In practice, the project evolved to include four phases: data acquisition, soft computing data analysis, conventional seismic and production analyses, and field application.

Data acquisition

Production and completion information for 320 wells in the Golden Trend was acquired from files of the participating producing companies. The data were quite heterogeneous and inconsistent, and 90 of the total datasets were eliminated as incomplete and of questionable quality. A relational database was created and populated with the data from the remaining 230 wells.

Soft computing data analysis

Application of soft computing techniques in data analysis was by design. This was because the data were expectedly incomplete, imprecise and heterogeneous, making conventional analytical methods meaningless if not impossible. Soft computing refers to a class of computational modules that can be linked together to create an "intelligence engine" capable of handling the complex oilfield data. The modules created within the intelligence engine for the Golden Trend data included neural networks, genetic algorithms and fuzzy logic. Collectively, these applications are referred to as the "virtual intelligence" technique.

A **neural network** is a powerful data processing system whose structure resembles the interconnection of neurons in the human brain. It can mimic the brain to some degree in its ability to acquire knowledge through a learning process and handle non-linear problems.

A **genetic algorithm** is a model of machine learning that behaves in a manner similar to the selection processes seen in the evolution of living organisms. The algorithm evaluates a set of data, applies various tests of fitness and induces changes to create a next-generation data set for further evaluation.

Fuzzy logic is a multi-valued logic system that allows intermediate values between conventional yes/no, true/false or black/white determinations. It can be used to examine the degree to which the data meet certain criteria.

In general, soft computing data analysis can be described as a series of coupled descriptive and predictive analyses. Descriptive analyses lead to identification of the most influential controllable parameters, and predictive analyses estimate the expected results from variations in single or multiple parameters in the completion of new wells or re-completion of existing wells.

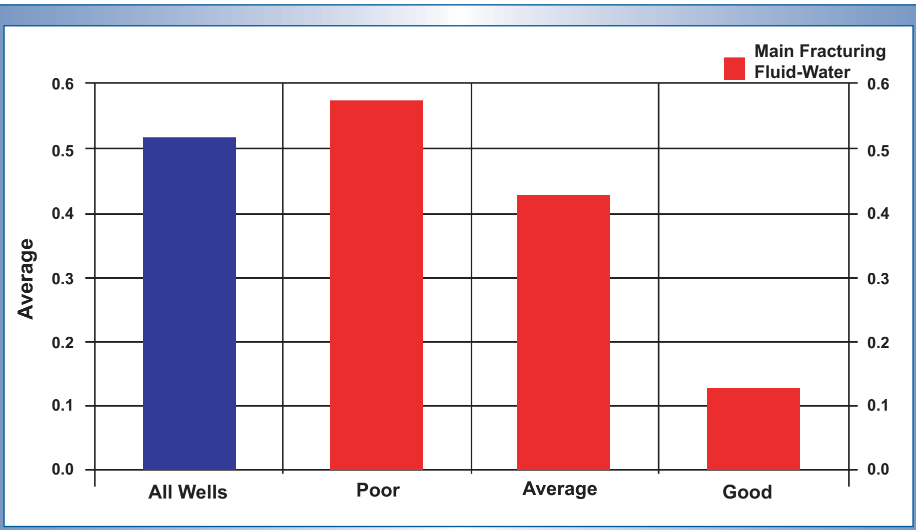


Figure 5. *The graph shows the distribution of the average value of water as the main fracturing fluid in wells of different quality.*

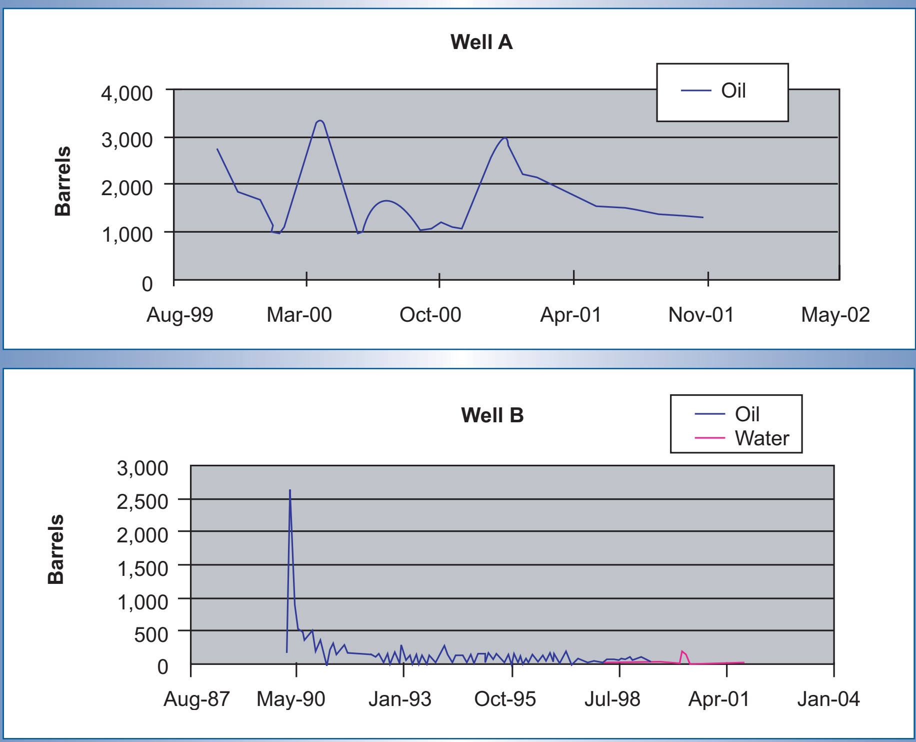


Figure 6. *An example of production difference between two neighboring wells.*

Fuzzy logic and descriptive analysis

The descriptive best practices analysis starts by identifying a parameter that would be used to partition the wells in terms of their productivity. For this project, the 30-year estimated ultimate recovery (EUR) was selected as the indicating parameter and was calculated for all wells using decline curve analysis. Conventionally, wells with EUR up to 30,000 bbl were defined as poor wells, wells with up to 60,000 bbl EUR were defined as average wells and those with more than 90,000 bbl EUR were defined as good wells.

In reality, there is little difference between a well with 30,000 bbl EUR and one with 31,000 bbl EUR. Therefore, an artificially rigid boundary between such wells should not be imposed. The use of the fuzzy set concept is more appropriate.

In a fuzzy set, everything in a category has a certain degree of belonging to that category. However, near the boundary of two sets, the subject can have one degree of belonging to the first category and another degree of belonging to the second category (Figure 3). The transition near a boundary for two categories can be better explained, for example, for Well B in Figure 4. The range between poor and average wells is from 30,000 bbl to 60,000 bbl. This well has an EUR of 35,958 bbl. As such, Well B has a membership (degree of belonging) of 0.8 to the "Poor Wells" category and membership of 0.2 to the "Average Wells" category.

In fuzzy classification, when calculating an average property for one class or category, the membership will impose a weight influence according to the following equation:

$$\frac{\sum_{i=1}^{n} x_n \mu_n}{\sum_{i=1}^{n} \mu_n}$$

where "x" represents the value of the parameter, "μ" represents the fuzzy membership function of a well in a particular fuzzy set, and "n" is the number of the wells in a particular fuzzy set.

Using the fuzzy classification, it would be possible to study the influential parameters for each category of wells in a more generalized fashion. Following this procedure, it was possible to identify the most influential parameters affecting the EUR. For example, using oil as the main fracturing fluid results in higher EURs and using water fracs result in lower production (Figure 5).

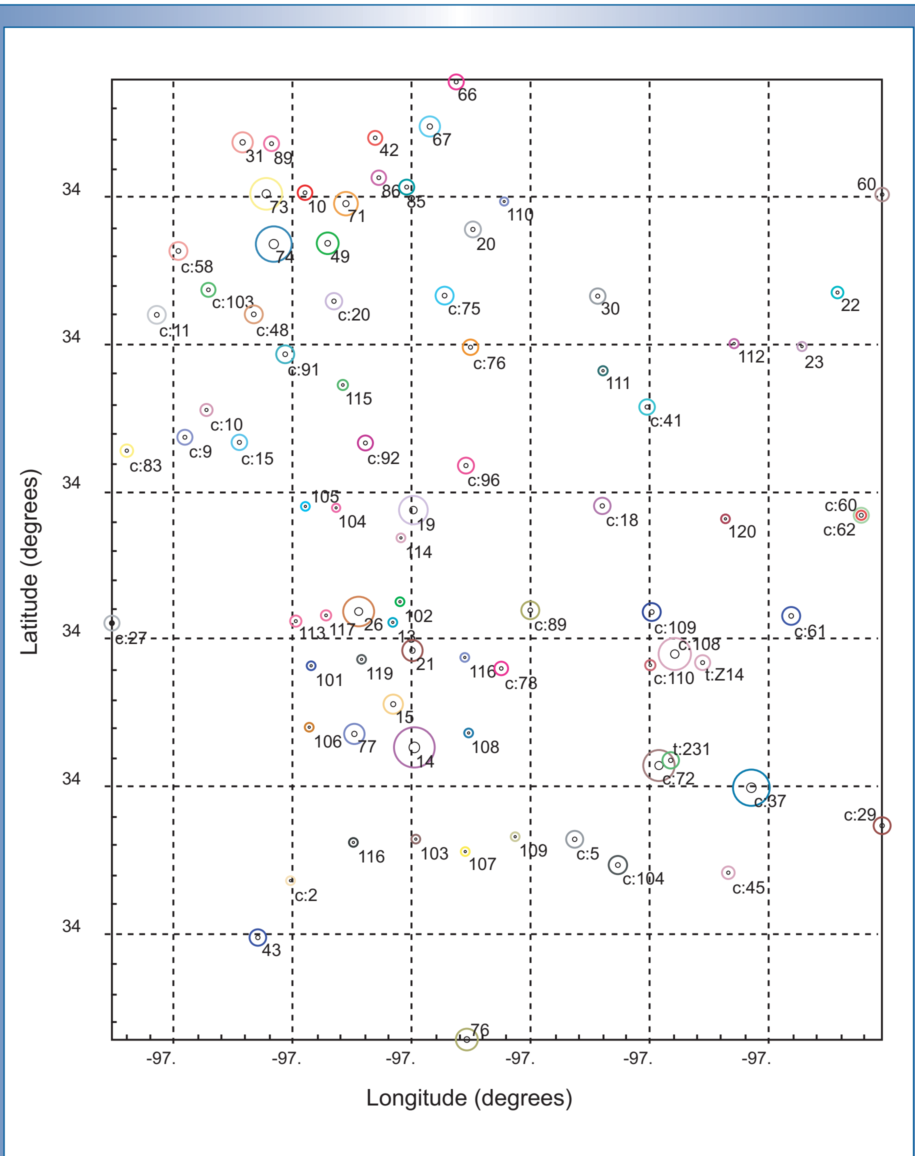


Figure 7. *Production bubble map for a field in the Oklahoma Golden Trend. Geographic coordinate values have been truncated to maintain data confidentiality. Note that some of the more productive wells, such as 73 (with larger bubble sizes), are quite close to poor wells (such as 10), indicating the presence of faults at reservoir level.*

Neural network modeling

Before performing neural network analyses, the data were quality-checked and production decline analyses were carried out for production characterizations. Fuzzy combinatorial analysis of longitude and latitude (as a proxy for geology) against 30-year EUR was conducted to define the reservoir quality indices.

Neural network models are usually used for predictions. In this work, the model was used for parameter sensitivity analysis. For example, various parameters were changed from minimum to maximum to examine the trends. To develop the neural network model, the 30-year EUR was selected as the output. The dataset was divided into three smaller sets for training, calibration and verification. The training data set included 147 records (wells), the calibration data set included 17 records (wells) and the verification data set included 18 records (wells). The training set was used to train the neural network model. The calibration data set was not used for training but served as a criterion to identify when the training process has been completed. Finally, the verification data set served to determine the goodness of the model.

Algorithm and combinatorial prediction analysis

A genetic algorithm is a powerful tool for process optimization in cases where multiple parameters are involved. In essence, each well can be viewed as living matter whose survival depends on its degree of fit to the environment. There also are multitudes of variations, or possibilities, caused through crossbreeding and mutation, and the members of the next generation that best fit the environment will survive and dominate. In this study, the measure of fitness was the expected EUR for each generation and the parameters were fracturing fluid, fracturing rate, proppant concentration and the number of perforations per foot of pay. In this work, the genetic optimization was used as a multivariable combinatorial predictive analysis.

Results from soft virtual intelligence analyses

Results from virtual intelligence analyses were produced in several forms and formats. It was recognized that hydraulic fracturing and perforation densities were the most influential controllable parameters impacting production rate and ultimate recovery. In a general sense, the data suggested oil-base fracturing fluid is more effective for oil production, while acid-fracs are more effective for gas production. In addition, lower pumping rate, higher proppant concentration and smaller number of perforation per foot of pay were shown to result in better production rate and higher ultimate recovery.

In addition to the generalized operational recommendations, several areas of high production potential were identified in the survey area. It also was observed that several wells in the high potential area have not been producing at the expected rates. Further study of these wells resulted in the identification of 23 restimulation candidate wells for oil production, 25 wells for gas production and 33 wells for combined oil and gas production.

Production and geophysical data analysis

Results from virtual intelligence analyses indicated extreme inconsistency – wells in close proximity of each other showed vastly different production history. To investigate this matter, the production data for a subset

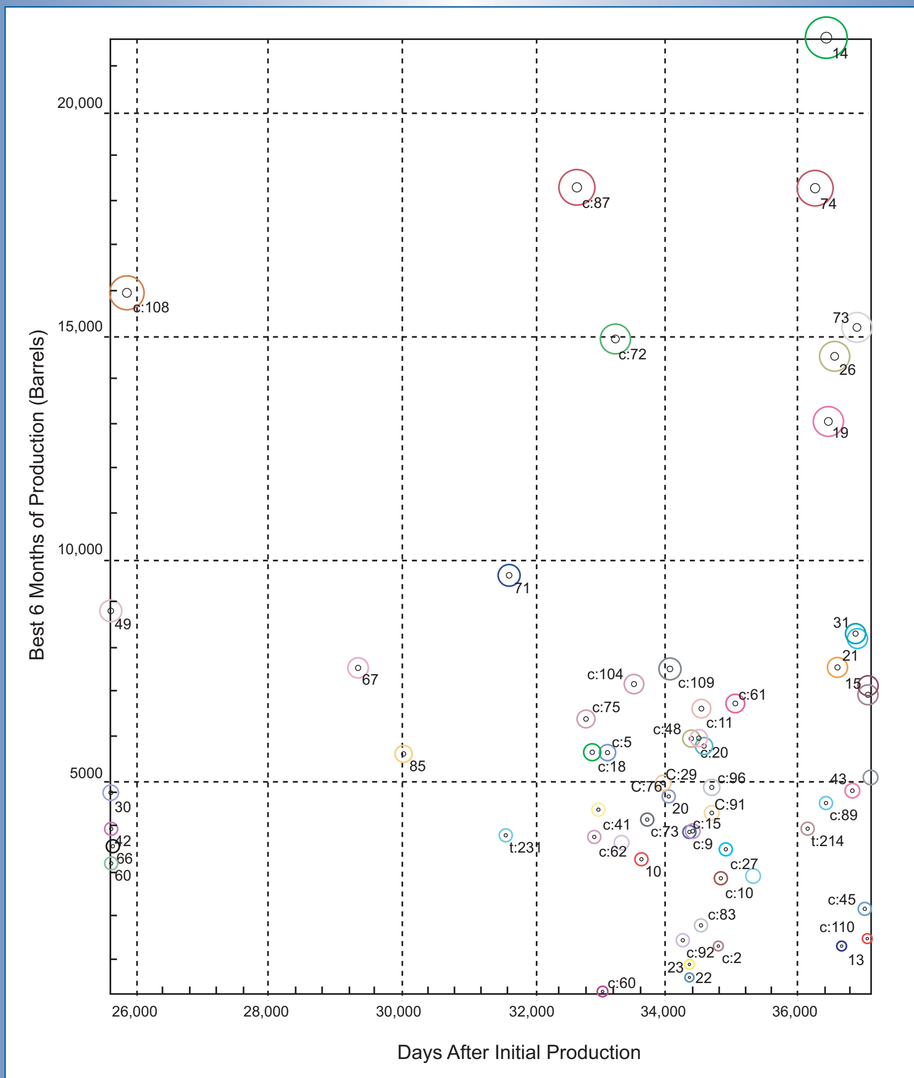


Figure 8. *Production bubble map for a field in the Oklahoma Golden Trend. Note that production from several recent wells, such as 19, 26 and 74, is higher than production from many older wells.*

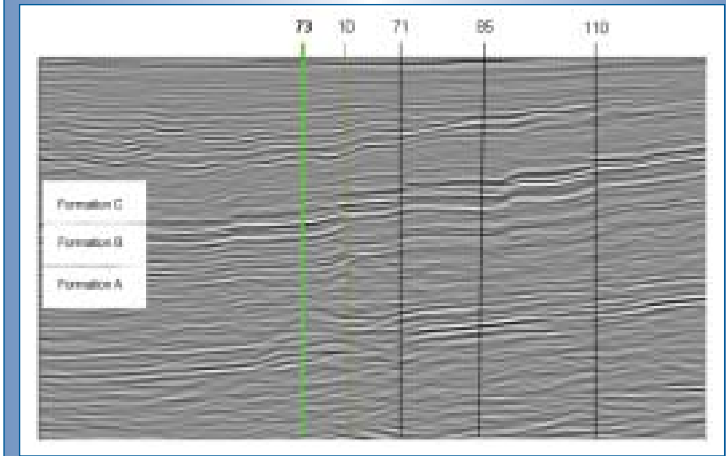


Figure 9. *Broadband seismic data corresponding to Figure 10.*

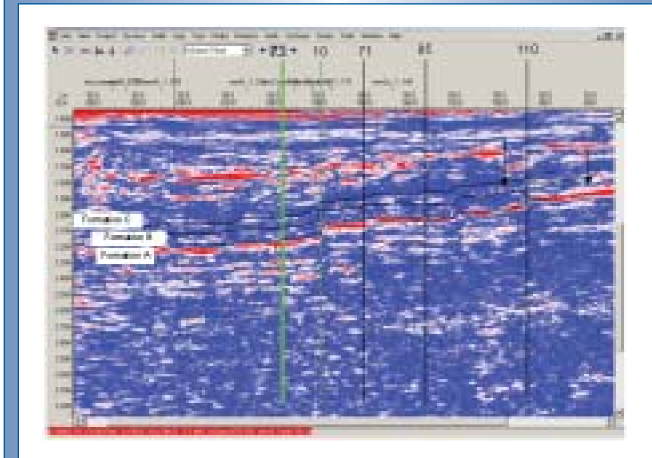


Figure 10. *Sample of spectrally decomposed seismic data.*

of the area was closely examined and general findings of the virtual intelligence work were substantiated through conventional production analyses. Elaborate conventional production analyses resulted in two major findings. First, in many cases, the wells in general proximity to one another had distinctly different production history (Figures 6 and 7); and second, some of the wells completed in recent years had higher production compared with nearby older wells (Figure 8).

These observations implied the presence of reservoir compartmentalization caused by faults or stratigraphic changes between wells. To investigate this matter, detailed seismic analyses were performed on a 3-D seismic volume belonging to one of the host companies. These studies centered on spectral decomposition of seismic traces using the InSpect[SM] seismic attribute analysis package. InSpect is a powerful spectral analysis tool that decomposes the seismic trace to its constituting frequencies using the wavelet transform methodology. In this application, the seismic traces are visualized at discrete frequency intervals, leading to recognition of subtle changes in seismic attributes and small-scale dislocations difficult to notice on broadband seismic sections. Figures 9 and 10 are samples of broadband and spectrally decomposed seismic sections from the survey area.

The resolution difference between spectrally decomposed and broadband seismic data is quite noticeable. Detailed seismic analysis and interpretation provided some explanation for difference in production from neighboring wells.

For example, the analyses showed the low production for wells 10 and 71 is most likely because of their close proximity to fault zones, while that of well 85 is because it penetrated the pay at the down-dip side of a downthrown fault block. In addition, spectrally decomposed seismic data revealed site 110, which was a drilling candidate, was located directly above a fault and should be avoided. It was recommended that moving the site to the west of the fault would place the well on the up-dip section of the fault block, offering higher production potential. It was also suggested that if surface conditions should not allow the proposed location change, the site could be moved eastward to penetrate the pay zones A, B and C at an undisturbed horizon. These suggestions and recommendations were discussed with the host company in detail and are being considered.

Project status

As of January, all analytic tasks have been completed. The virtual intelligence software, complete with detailed description of methodology and tutorial, has been submitted to the participating producing companies. The software application was explained to engineers, geoscientists and information technology staff from these companies in several in-house workshops. A list of recompletion candidate wells and suggestions for location change for two of the future wells were presented to these operators and discussed in technical meetings. The producing companies are considering these recommendations as part of their drilling and completion programs. A detailed technical description of all stages of work, including an executable version of the software package and results from field applications, will be available in the final report by the end of June.

For more information about the PUMP Project, contact Iraj Salehi, manager of exploration and production technologies, GTI at *iraj.Salehi@gastechnology.org* or (847) 768-0902, or Gary Walker, project manager, at *gary.walker@npto.doe.gov* or (918) 699-2083. ✧

References:

1. *Annual Energy Outlook 2004 with Projections to 2025*, Report No: DOE/EIA-0383-2004, January 2004.

2. *Profile of Independent Producers*, a survey conducted by the Independent Petroleum Association of America, 1996.

GTI Research on Carbon Dioxide Sequestration

By Liese Dallbauman, Ph.D.,
Gas Technology Institute

Governments, corporations and other organizations increasingly recognize the importance of stabilizing the atmospheric concentration of greenhouse gases.

Most climatologists agree a concentration increase in greenhouse gases (GHGs) contributes to global climate change and, as shown in Figure 1, carbon dioxide (CO_2) dominates these emissions.

The Global Climate Change Initiative (GCCI), launched by President George W. Bush in February 2002, commits the United States to a strategy for reducing emissions of GHGs. Since fossil fuel combustion accounts for nearly 80% of global anthropogenic carbon emissions in the form of CO_2, according to the U.S. Department of Energy (DOE), and because fossil fuels will continue to provide the majority of the world's energy for the foreseeable future, capture and sequestration of CO_2 are integral to meeting the GCCI goal of reducing baseline U.S. GHG intensity by 18% by 2012.

In 2002, U.S. CO_2 emissions totaled nearly 5.8 billion metric tons, 98% of which were "energy-related," according to the DOE. Determining the exact amount of CO_2 to be captured and sequestered is difficult because no target concentration has been specified. However, even if the aim is to maintain a CO_2 concentration 20% to 100% higher than today's 370 ppm, drastic reductions in emissions to the atmosphere will be required.

A significant portion of this reduction will need to occur through capture of CO_2 from flue gases, particularly those generated by power plants. Nearly 40% of energy-related CO_2 emissions are produced with the generation of electricity from fossil fuel power plants. The baseline capture technology is absorption in monoethanolamine. There are, however, numerous problems associated with this method, and alternatives are being researched. A few possibilities include:

- absorption using different solvents;
- adsorption onto solid materials such as activated carbon, zeolites or alkali metal carbonates/bicarbonates; and
- removal by inorganic membranes.

After CO_2 has been captured, it must be sequestered or stored. The DOE, Gas Technology Institute (GTI) and various research partners focusing on geological, terrestrial and ocean sequestration are studying a variety of approaches. The goal of geological sequestration is to inject CO_2 into subsurface formations such as coal seams, depleted oil and gas fields, and saline aquifers. Terrestrial sequestration involves maintaining or increasing the uptake of CO_2 by plant material and soils. In ocean sequestration, the goal is to increase the amount of CO_2 dissolved in seawater. One approach is to boost the CO_2 uptake by near-surface phytoplankton; another is to inject CO_2 directly into the deep ocean.

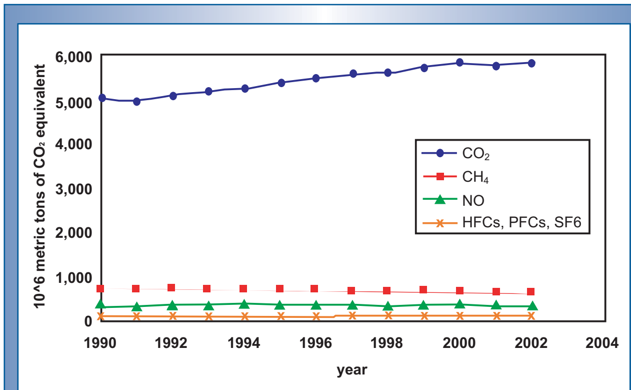


Figure 1. *U.S. greenhouse gas emissions from 1990–2002.*

Carbon sequestration research

GTI is pursuing several research programs relevant to the capture of CO_2. One project concerns a new solvent from the morpholine family, called Morphysorb®. It can remove hydrogen sulfide and CO_2 from raw natural gas and is being evaluated at a full-scale gas treatment plant in Canada. Based on test results to date, it appears Morphysorb could be adapted for use in capturing CO_2 from flue gases.

In a second project, GTI is building on its previous research on gas/liquid membrane contactor technology to evaluate its possible application to removing CO_2 from gas turbine exhaust and natural gas.

A third area of research, which GTI and the DOE proposed, is to apply evolving knowledge about gas hydrate formation mechanisms to remove CO_2 from the flue gases of fossil fuel energy systems such as boilers and turbines.

GTI also is devoting considerable effort to sequestration activities, including deep-ocean sequestration through hydrate formation, development of seismic imaging technology for monitoring CO_2 sequestration in Illinois coal seams, and application of gas storage technology to CO_2 sequestration.

Sequestration through hydrate formation—Preliminary tests at GTI's Hydrates Research Facility indicate

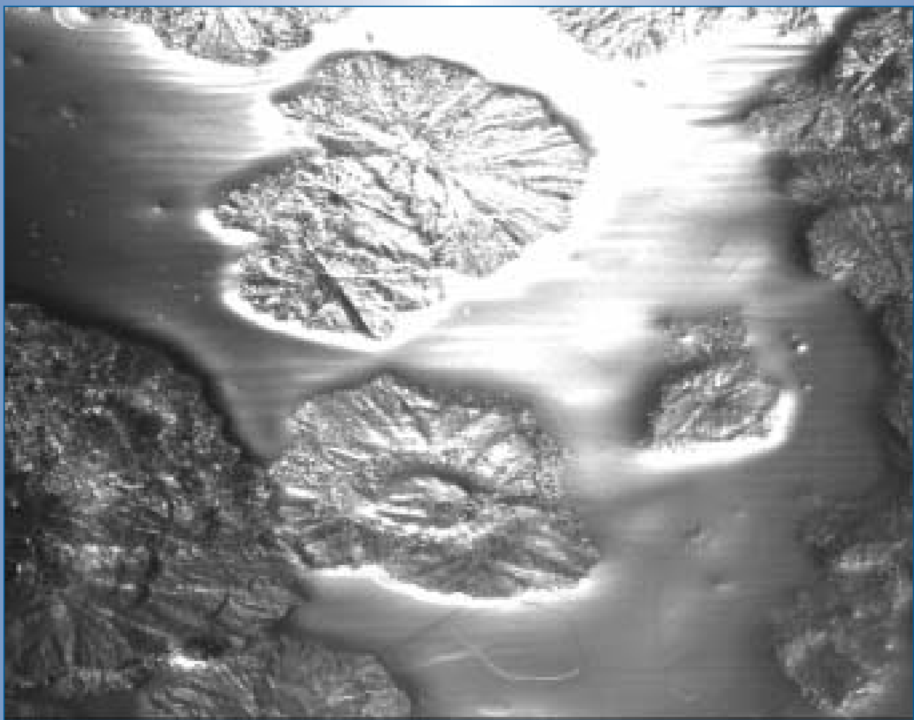


Figure 2. *Researchers at GTI's Hydrates Research Laboratory study the mechanisms of hydrate formation and dissociation.*

that injecting CO_2 into natural gas hydrate fields may simultaneously sequester the CO_2 and displace methane (CH_4). Laboratory tests (Figure 2) suggest the heat released from CO_2 hydrate formation could drive the dissociation of methane hydrates. The recovered methane may be sufficiently valuable to pay for CO_2 transportation and injection. Testing under various conditions continues.

Coal seam sequestration—Sequestration in unmineable coal seams is attracting widespread attention as researchers investigate the effects of temperature, pressure, water content, coal rank, coal composition and other variables on CO_2 adsorption. The competitive sorption of CO_2 and CH_4 is of particular interest. If CO_2 can displace CH_4 from the coal surface, commercial production will improve sequestration economics. Coal seams have the potential to serve as major CO_2 repositories; the CO_2 sequestration capacity of U.S. coalbeds has been estimated at 90 billion tons, with associated CH_4 recovery potential exceeding 150 Tcf.

Accurate mapping of host coal seams is necessary to ensure CO_2 sequestration is permanent. Candidate seams must be continuous and must extend over a wide area without encountering faults or other discontinuities that would allow injected CO_2 to escape into the water table, unintended zones or the atmosphere. GTI is adapting advanced seismic technology used to monitor gas movement in conventional natural gas reservoirs for application in a coal environment. This method will be used to select and monitor sequestration sites in unmineable coal seams in the Illinois Basin.

Natural gas storage technology—Another geological sequestration option involves natural gas storage analogs. The majority of underground storage fields in the United States are depleted fossil fuel production fields. Because these reservoirs at one time contained stores of oil or gas, their ability to trap gas has been demonstrated, and they can be expected to provide secure CO_2 storage.

Operators of CO_2 sequestration facilities will need to address issues similar to those faced by the gas storage industry, including:

- migration of injected gas over extended periods of time;
- reliable monitoring of gas location; and
- monitoring of zones above caprocks for evidence of gas leakage.

On behalf of the industry-sponsored CO_2 Capture Project, GTI recently has completed a report on the applicability of gas storage technology to CO_2 sequestration. The CO_2 Capture Project is an international effort funded by eight of the world's leading energy companies – in partnership with governments, non-governmental organizations and other stakeholders – to develop technologies to reduce the cost of CO_2 separation, capture and geologic storage from a range of combustion sources.

The GTI study reviewed the portfolio of technologies used in the underground gas storage industry and evaluated their applicability to CO_2 sequestration. Data were gathered through an extensive literature search as well as operator surveys and interviews.

The GTI study also examined the storage of natural gas in high-permeability aquifers under structural conditions that mimic naturally occurring oil and gas reservoirs (Figure 3). The technologies developed to ensure the reliability of aquifer-based gas storage also may be useful for CO_2 sequestration. In the study summary below, the term "gas" applies to either natural gas or CO_2.

Inventory verification and gas storage monitoring technologies confirm injected gas remains within the intended reservoir. Surface observations, such as evidence of crop damage, gas bubbles in wells and streams, or soil sampling, can detect disturbances caused by gas migration. Subsurface observations also are important in monitoring gas storage. For example, observation wells can be used to track water pressure within and above the storage zone or to continuously measure reservoir pressure.

Unexplained changes in reservoir pressure or water pressure may indicate gas migration or leakage.

Site selection plays a major role in preventing leakage, with particular attention to caprock integrity. Caprock leakage of stored gas is less likely from depleted fields than from aquifers, where naturally occurring oil or gas has not challenged sealing capability and integrity. It also is important to note that CO_2 storage and natural gas storage have different operational requirements. Natural gas storage requires "steep" structural closure to ensure gas deliverability, but this same feature increases the likelihood of caprock flaws. Because sequestered CO_2 is not intended to be withdrawn from storage, this type of structure offers no advantage and should be avoided.

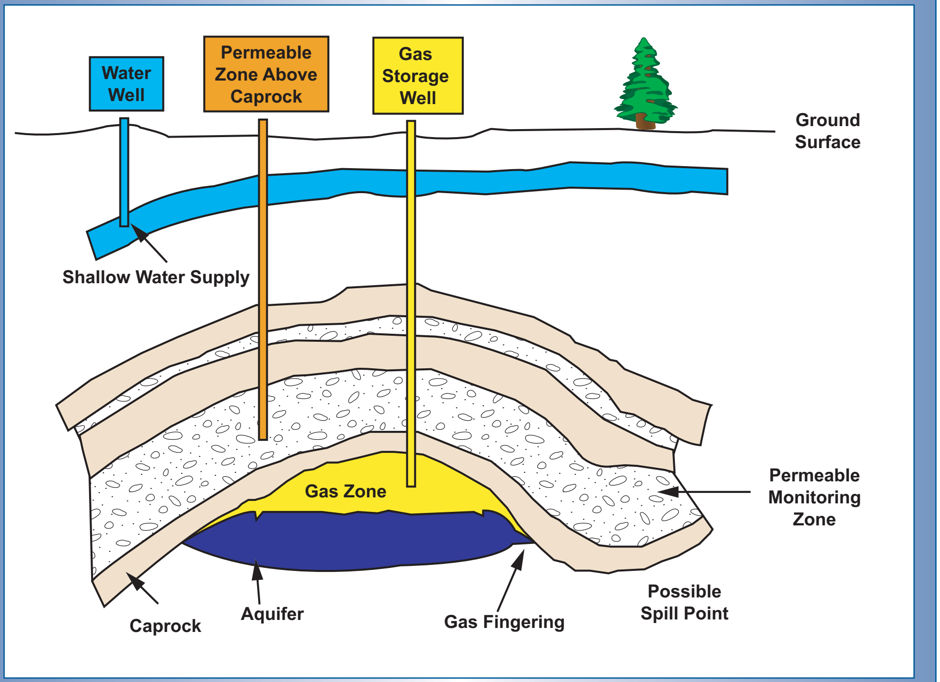


Figure 3. *Natural gas storage in high-permeability aquifers that have the same naturally ocurring oil and gas reservoirs.*

The DOE Southwest Regional Carbon Sequestration Partnership

In November 2002, Spencer Abraham, Secretary of the U.S. Department of Energy, announced plans to create a national network of public-private partnerships to determine the most suitable technologies, regulations and infrastructure needs for carbon capture, storage and sequestration in different areas of the country.

In August 2003, Abraham named seven partnerships of state agencies, universities and private companies that will form the core of this network. The partnership for the Southwest Region, led by the Western Governors' Association and the New Mexico Institute of Mining and Technology, involves more than 20 organizations in eight states. The Gas Technology Institute provides expertise to the partnership related to carbon dioxide sources, separation and capture technology.

Although the demands placed on sites intended to temporarily store natural gas differ from those meant to permanently sequester CO_2, it is clear the gas storage industry can provide valuable insights into many of the challenges associated with underground CO_2 storage.

Summary

Capture and sequestration of greenhouse gases, particularly CO_2, promises to be a topic of continuing concern and research interest. Building on its decades of expertise in developing technologies for natural gas exploration, production and processing, GTI is evaluating a range of technology options for safe and cost-effective CO_2 capture and sequestration. ✧

References

1. Battelle Memorial Institute, *Global Energy Technology Strategy: Addressing Climate Change: Initial Findings from an International Public-Private Collaboration*, (undated).

2. U.S. DOE Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2002*, DOE/EIA-0573(2002), (October 2003).

3. Kowalsky, G., Leppin, D., Palla, R., Jamal, A., and Hooper, H.M., *Morphysorb® Applied to De-Bottlenecking of Gas Treating System*, GasTIPS, 9(1), 28–32, (2003).

4. Meyer, H., Palla, R., and King, S., *Field Tests Support Reliability of Membrane Gas/Liquid Contactor Gas Dehydration System,* GasTIPS, 8(3), 37–40, (2002).

5. Palla, R., Leppin, D., and Jamal, A., *Status Report: Operation of Morphysorb® Process at a Canadian Gas-Treating Plant*, GasTIPS, 9(3), 8–9, (2003).

6. Perry, K. F., *Gas Storage Technology Applicability to CO_2 Sequestration*, prepared by GTI on behalf of the Carbon Capture Project (2003).

7. Reeves, S. R., *Assessment of CO_2 Sequestration and ECBM Potential of U. S. Coalbeds*, Topical Report (2003).

8. Sivaraman, A., *The Potential Role of Hydrate Technology in Sequestering Carbon Dioxide*, GasTIPS, 9(4), 4–7, (2003).

IN BRIEF

GTI Unveils New Laser Laboratory for Exploration and Production Research

Gas Technology Institute (GTI) recently unveiled a new research facility at its Des Plaines, Ill., headquarters campus for evaluating the use of laser energy to improve various well construction and completion processes.

Laser technology holds significant promise as a less costly and more efficient alternative to rotary drilling for constructing gas and oil wells and for related processes that prepare wells for operation.

GTI has studied several military laser systems for possible use as an alternative to rotary drilling in constructing wells. Tests from 1997 to 1999 showed that these megawatt-size lasers have more than enough power to break, melt or vaporize rock, penetrate rock more rapidly than conventional drilling and even increase the permeability of rock, which would improve gas flow from the surrounding formation into a wellbore.

However, megawatt-scale lasers were too costly for practical field use, and since 2000, GTI has focused on smaller industrial lasers, obtaining similar positive results through control of power level, beam size, beam pattern and pulsation rate for laser systems of up to 6 kW.

In 2003, GTI further refined its research focus to examine recent advances in fiber laser technology - first used in the 1980s and 1990s as low-power optical amplifiers. In a conventional laser, a mirrored cavity boosts or pumps up the energy produced by the laser energy source. But in a fiber laser, this pumping occurs within specially designed silica fibers that can perform the same function as conventional laser systems. The result is an efficient, compact laser source with excellent beam quality.

Aiming to evaluate the use of high-power (multi-kilowatt) fiber lasers for well construction, GTI turned to IPG Photonics Corp., a leading designer and manufacturer of high-performance fiber lasers and amplifiers. In 2003, GTI formed an alliance with IPG, acquiring one of the company's 5-kW fiber laser systems that forms the heart of the new GTI laser laboratory. This unit is the largest fiber laser available for research use in the United States, said Brian Gahan, GTI's manager of research on laser applications.

Alaska Well Targets Gas Hydrate, Produces Wealth of Information

Reflecting on his invention of the incandescent bulb, Thomas Edison claimed to have first discovered "a thousand ways not to make a light bulb," with each effort yielding valuable information that contributed to his eventual success. Scientists and engineers are having a similar experience as they work to unravel the secrets and potential of methane hydrate. Their latest project, the **Hot Ice No. 1** well recently drilled in Alaska, did not encounter methane hydrate as expected, but it did produce information that should help overcome the substantial technical obstacles to the eventual commercial production of this abundant energy resource.

Methane hydrate is a compound of water and methane (the major component of natural gas) that forms under pressure at cold temperatures. The amount of natural gas in methane hydrate is estimated to be far greater than all the world's conventional natural gas resources. It could potentially become a significant source of natural gas. Methane hydrate exists beneath large portions of the world's arctic permafrost as well as within deep-sea sediments. On Alaska's North Slope, the volume of hydrate-based natural gas has been estimated at several times the volume believed to exist there in conventional gas-bearing formations.

The Hot Ice No. 1 well was drilled as part of a 2-year cost-shared partnership among the U.S. Department of Energy's (DOE) Office of Fossil Energy, Anadarko Petroleum Corp., Maurer Technology Inc. and Noble Engineering and Development. The project is part of the DOE's Methane Hydrates Research and Development Program and supports the *President's National Energy Policy*, which calls for increasing domestic energy supplies. ✧

NEW PUBLICATIONS

Technology Roadmap for Unconventional Gas Resources: Idea Generation and Technology Needs

This report presents a framework of applied research required to enhance the production of domestic unconventional U.S. natural gas resources (coal seams, shales, low-permeability sandstones and carbonates, ultra-deep reservoirs, emerging plays and frontier basins). A diverse group of active petroleum personnel from industry, academia and government shared information at a series of regional workshops. A sequence of potential research programs was developed for the short term and longer term, along with recommended mechanisms to facilitate more effective research and development as well as timely gas development.

Price: $60.

Document number: GRI-03/0060

Available online or as a CD-ROM. Order through the Gas Technology Web site: *www.gastechnology.org*

Coalbed Methane in Western Canada

This report identifies regions in the Western Canadian Sedimentary Basin with high coalbed methane potential, defining the wide variability of geologic and physiographic settings in which this potential might be found.

Price: $60.

Document number: GRI-02/0157

Available online only, through the Gas Technology Web site: *www.gastechnology.org*

Gas Interchangeability Tests: Evaluating the Range of Interchangeability of Vaporized Liquefied Natural Gas and Natural Gas

This research evaluated the sensitivity of selected burners – used in residential appliances – to compositions typical of liquefied natural gas (LNG) that is rich in heavier hydrocarbons. This is important because heavier hydrocarbons can become more concentrated in LNG during handling. Using a variety of testing and modeling tools, researchers determined that, for the burners studied, expected LNG compositions are adequately interchangeable with U.S. pipeline gases if their heating value and density are suitably adjusted by dilution with air or nitrogen.

Price: $1,595.

Document number: GRI-03/0159 (April 2003)

Available only as a CD-ROM. Order through the Gas Technology Institute Web site: *www.gastechnology.org*

Upper Mannville Coals and their Equivalents - Western Canada Sedimentary Basin: CBM Play Types and Potential

This report is an assessment of the coalbed methane (CBM) potential of the Mannville Formation coals of Upper Cretaceous age within the Western Canadian Sedimentary Basin. Three CBM plays are defined: (a) one along the eastern margins of the basin at relatively shallow depths; (b) a more speculative play type within the deeper part of the basin; and (c) a play west of the deformational front on the western margins of the basin.

Price: $60.

Document number: GRI-02/0189

Available online only, through the Gas Technology Web site: *www.gastechnology.org* ✧

EVENTS

▶ Offshore Technology Conference

May 3–6, Houston

For more information, call (972) 952-9393, e-mail *spedal@spe.org* or visit *www.SPE.org*

▶ West & Central Africa Oil & Gas

May 24–26, Four Seasons Hotel, Houston

For more information, visit *www.ibcenergy.com/eq1135/?src=pre*

▶ Global Petroleum Show & Canadian International Petroleum Conference 2004

June 8–10, Calgary Stampede Park, Calgary, Alberta, Canada

For more information, call (403) 209-3562 or e-mail *gpsvisitor@ca.dmgworldmedia.com*, or visit *www.petroleumshow.com/global*

▶ Global Deepwater Strategies 2004

June 15–16, Houston Westchase & Towers, Houston

For more information, call 44 207 487 3173 or e-mail *info@glopac.com*, or visit *www.petro21.com./events*

▶ 2004 Drilling Engineering Association Workshop

June 22–23, Moody Gardens Hotel, Galveston, Texas

For more information, call (713) 292-1945 or e-mail *leesa.teel@iadc.org*

▶ Society of Petroleum Engineers Annual Meeting

Sept. 26–29, Houston

For more information, call (972) 952-9393, e-mail *spedal@spe.org* or *visit www.spe.org*

▶ Rocky Mountain Natural Gas 2004

Aug. 9–11, Colorado Convention Center, Denver

For more information, visit *www.coga.org*

▶ Offshore Northern Seas

Aug. 24–27, Stavanger, Norway

For more information, e-mail *ons@ons.no* or visit *www.ons.no*

▶ Subsea Houston 2004

Sept. 16, JW Marriott Houston, Houston

For more information, call (281) 491-5900, e-mail *sandra.gregory@questoffshore.com* or visit *www.subseahouston.com*

▶ Eighth Annual Mexican Energy Conference

Oct. 28–29, Houston

For more information, call (781) 939-2438 or e-mail *cbireg@cbinet.com*

▶ International Gas Research Conference 2004

Nov. 1–4, Vancouver, B.C., Canada

Held every 3 years, the International Gas Research Conference (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. For more information, *visit www.igrc2004.org*

▶ Developing Senior Managers in the New Century

Nov. 12–14, Edwin L. Cox School of Business, Southern Methodist University, Dallas

For more information, call (214) 758-3890 or (800) 768-6699, e-mail *execdev@mail.cox.smu.edu* or visit *http://execdev.cox.smu.edu* ✧

CONTACT INFORMATION

Gas Technology Institute (GTI)
1700 S. Mount Prospect Road
Des Plaines, IL 60018-1804
Phone: (847) 768-0500; Fax: (847) 768-0501
E-mail: *publicrelations@gastechnology.org*
Web site: *www.gastechnology.org*

GTI E&P Research Center
1700 S. Mount Prospect Road
Des Plaines, IL 60018-1804
Phone: (847) 768-0500; Fax: (847) 768-0501
E-mail: *explorationproduction@gastechnology.org*
Web site: *www.gastechnology.org*

GTI E&P Research Center (Houston)
222 Pennbright, Suite 119
Houston, TX 77090
Phone: (281) 873-5070; Fax: (281) 873-5335
E-mail: *carrie.decker@gastechnology.org*
Web site: *www.gastechnology.org*

GTI/Catoosa℠ Test Facility, Inc.
19319 N. E. 76th
Owasso, OK 74015
Phone: Toll-free (877) 477-1910
Fax: (918) 274-1914
E-mail: *srandolph@gticatoosa.org*

U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
Morgantown, WV 26507-0880
Web site: *www.netl.doe.gov/scng*

National Energy Technology Laboratory
626 Cochrans Mill Road
Pittsburgh, PA 15236-0340

National Petroleum Technology Office
One W. Third St.
Tulsa, OK 74103-3519
Web site: *www.npto.doe.gov*

Office of Fossil Energy
1000 Independence Ave., S.W.
Washington, DC 20585
Web site: *www.fe.doe.gov*

NETL gti

HART