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Technology Developments in Natural Gas Exploration, Production and Processing

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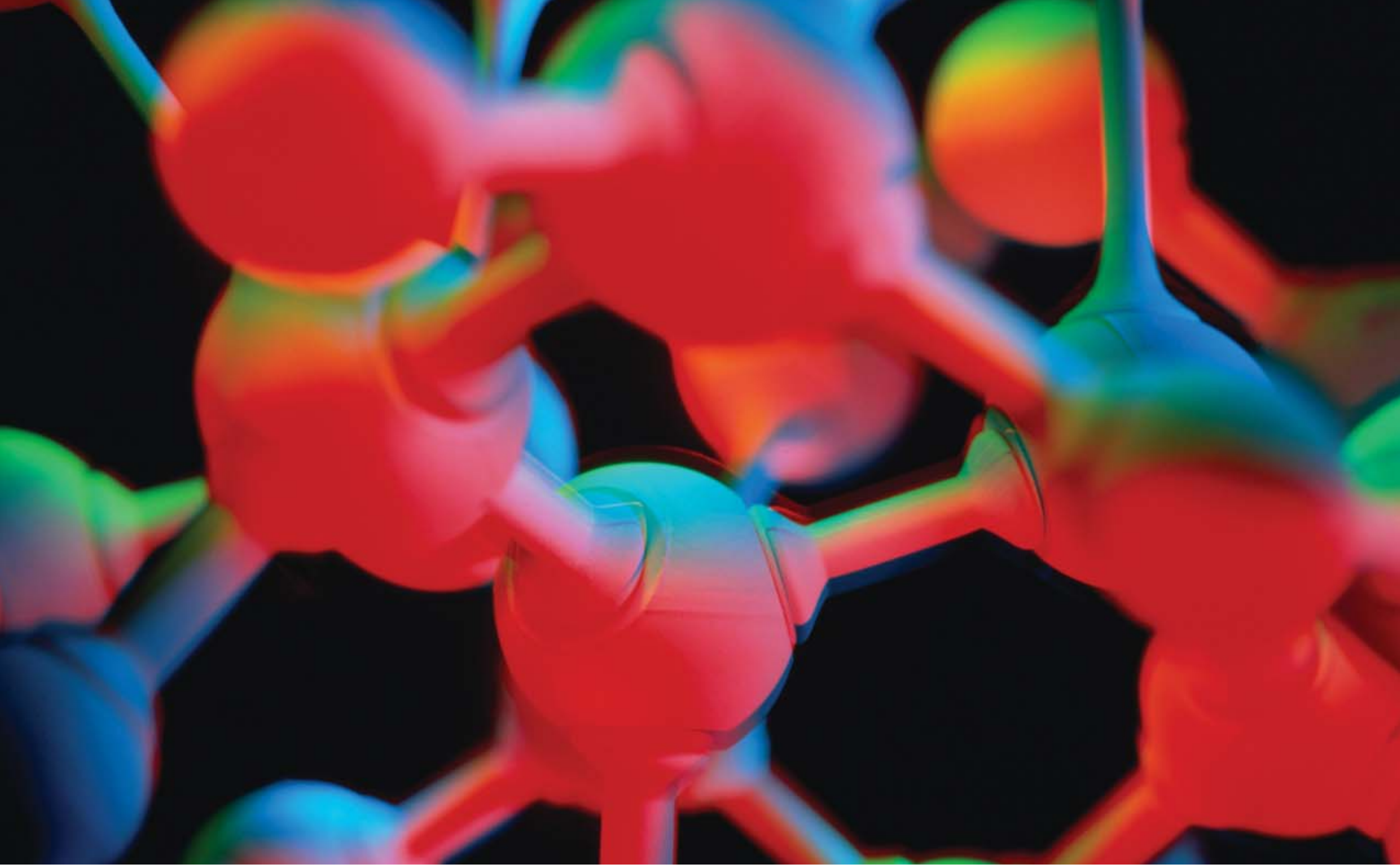

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CONTENTS

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Developing Deep Gas Resources Key to Meeting Energy Demand

As this issue of *GasTIPS* goes to press, the U.S. Senate is beginning work on an Energy Bill passed by the U.S. House of Representatives. Two elements of this bill would encourage the development of "deep" gas: an Onshore Deep Gas Production Incentive that would provide federal royalty incentives for onshore deep gas production; and Incentives for Natural Gas Production from Deep Wells in Shallow Water in the Gulf of Mexico, which would provide for royalty incentives for natural gas at depths greater than 18,000ft below the ocean floor. These incentives speak to the fact that demand for natural gas is increasing, as are the costs of developing new reserves, particularly those at greater depths.

The oil and gas industry spent 36% more in 2003 to drill and equip gas wells than it did in 2002, according to the 2003 Joint Association Survey on Drilling Costs released last month by the American Petroleum Institute (API). The survey also shows that 2003 was the 16th consecutive year the industry spent more drilling for natural gas than for oil. Every metric was up compared with the previous year's gas well drilling: average depth (3.2%), median cost per well (14.2%) and average cost per foot (8.1%).

A deep gas well is defined as any well that produces from a depth below 15,000ft. According to the Potential Gas Committee's (PGC) report published in 2003, there are more than 2,500 active well completions below that depth in the lower 48 states, producing from more than 180 separate reservoirs. These deep gas reservoirs are primarily found in the onshore and offshore basins of the Louisiana and Texas Gulf Coast, in the Anadarko and Permian basins of the mid-continent and in a number of Rocky Mountain basins.

The PGC reported in 2003 that the average recoverable reserve for a deep gas well varies from 6 Bcf to nearly 34 Bcf, depending on the basin. While only half of 1% of the gas well completions in the lower 48 states qualify as deep completions, together they historically produced 55 Tcf (6%) of the natural gas cumulatively produced through 2002.

In addition, a significant volume of deep gas remains to be discovered. The committee's 2003 estimate of technically recoverable gas remaining to be discovered at depths between 15,000ft and 30,00ft was 133 Tcf, or about 29% of the nation's potential gas resource. More than half this potential lies beneath the onshore and offshore areas of the Gulf of Mexico region. The industry is spending increasing amounts of money to develop deep gas, and a rising percentage of this money is being spent in the Gulf of Mexico region.

These reserves are not easily captured. Deep gas wells are more than twice as expensive on a cost per foot basis as a typical gas well. According to the API survey*, the cost to drill and equip the median gas well in 2003 was about $289,000. The average deep, non-deviated, onshore well drilled in 2003 (307 deep wells averaged 16,936ft) cost $6.82 million. The average cost per foot for onshore, non-deviated deep gas wells was $403/ft compared with $190/ft for the average U.S. gas well. Offshore in the Gulf of Mexico, deep gas well costs run to $1377/ft. It is extremely important that these costs are reduced.

The U.S. Department of Energy (DOE) has been sponsoring the Deep Trek Program to help develop the high-tech drilling technology the industry needs to economically develop this deep resource. Two of the articles in this issue of *GasTIPS* detail some of these efforts.

The first is an update on National Energy Technology Laboratory (NETL) efforts to extend the capabilities and reliability of logging tools – including logging-while-drilling and measurement-while-drilling tools – and other "smart" well equipment. Key to this extension is the production of electronic components that can operate at temperatures up to 600°F. The NETL has formed a joint industry project with electronics manufacturers and oilfield end-users to achieve this goal.

A second article provides an update on efforts to develop laser technology for use downhole as a perforating mechanism. Achieving effective perforations in the hard rocks found at great depths is not an easy task. Gas Technology Institute (GTI) has been evaluating the possibility that lasers might some day be configured to accomplish this feat and provides an update of this research in this issue.

Together with these two articles focusing on deep gas technologies, are a number of others that provide insights on other NETL and GTI research efforts related to the geochemistry of gas from fractured shale, produced water management, cost-benefit analysis of royalty incentives and marine transport of compressed natural gas. We hope you find this issue informative. ✧

The Editors

** The 2003 Joint Association Survey (JAS) on Drilling Costs is available electronically and in hard copy from the American Petroleum Institute, Statistics Department, by calling (202) 682-8508. The cost for non-members is $6,500. JAS statistics provided above courtesy of Jeff Obermiller.*

Enhancing Microbial Gas from Unconventional Reservoirs

By Anna M. Martini,
Amherst College; and
Klaus Nüsslein and Steven T. Petsch, *University of Massachusetts Amherst*

Amherst College and the University of Massachusetts Amherst have formed a research partnership to examine methanogenesis in sedimentary basins. Funding from the National Science Foundation, the Gas Technology Institute/RPSEA and industry partners has allowed this group to develop a multifaceted study on gas from the Michigan Basin and Forest City Basin, drawing from tools common to aqueous, isotope and organic geochemistry as well as environmental and molecular microbiology.

With demand for natural gas on a steady rise (about a 30% increase during the past 15 years), unconventional gas deposits such as those produced from coalbeds and shales are receiving attention from small independent operators and major energy companies. In unconventional plays, knowing the origin of the gas is fundamental for assessing reservoirs and guiding exploration strategies. Basin margins generally exhibit low organic matter maturity and active hydrologic flow systems, while deeper sections are more mature. Thus, exploration for gas of thermogenic origin would target mature sections of a basin, while exploration in unconventional gas plays of predominantly microbial origin may instead more successfully target basin margins. Given the extensive occurrence and abundance of fractured black shales and coalbeds throughout U.S. sedimentary basins (Figure 1), there is a significant economic incentive to evaluate potential microbial origins of gas plays. Methanogenesis, or microbial methane generation, may be a significant and sustainable source of natural gas in many unconventional gas reserves.

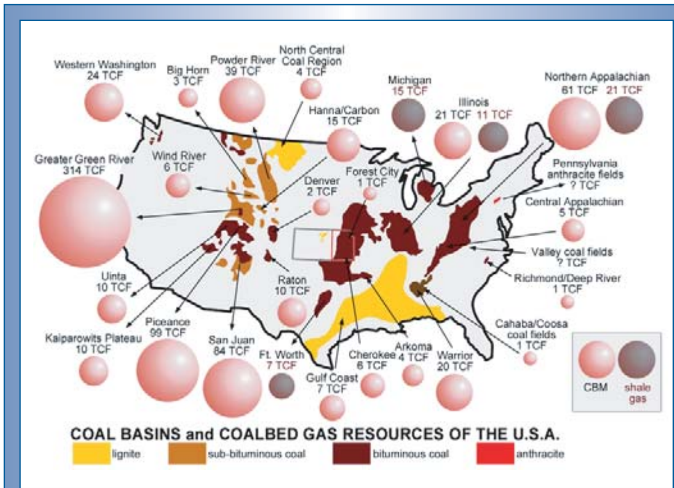

Figure 1. Distribution of U.S. coalbed and shale gas resources (Newell et al. 2004). Many of these basins include a mix of thermogenic and microbial gas.

The organic-rich shales of the eastern United States have a long history of gas production, accounting for nearly 2% of current domestic natural gas production. Since 1988, U.S. shale gas production has increased by more than 60%, primarily because of a single new black shale play – the Antrim Shale in the Michigan Basin. Given its importance, the Antrim Shale provides a model setting to study microbial methanogenesis and modification of thermogenic gas. Development in the Forest City Basin (Iowa-Missouri-Kansas-Nebraska) has revealed this play as another potential source of microbial gas.

Antrim Shale wells from the northern margin exhibit the highest natural gas production rates in the basin, strongest geochemical and isotopic indicators of microbial activity and sharpest chemical gradients in formation water composition. Production histories of wells in the region suggest active and sustained methane generation, rather than relict methane generated in the geologic past. Living organisms are detected in a number of productive well waters, with genetic signatures suggesting high relatedness to other known forms of methane-generating microorganisms. Similar geochemical and microbiological indicators are observed in Forest City Basin waters suggesting this play too may derive from active subsurface methanogenesis.

One key geochemical indicator of microbial activity in subsurface formation waters is the concentration of dissolved inorganic carbon (DIC), also known as carbonate alkalinity. In most formation waters, alkalinity is held buffered at low concentrations through equilibrium with carbonate minerals in the rock. Accordingly, groundwaters in the overlying glacial drift and deep central Antrim brines measure about 0-5 meq/L DIC (Figure 2a). However, when other processes, such as organic matter degradation, contribute alkalinity to formation waters, DIC concentrations rise. Antrim waters collected along the N, W and S

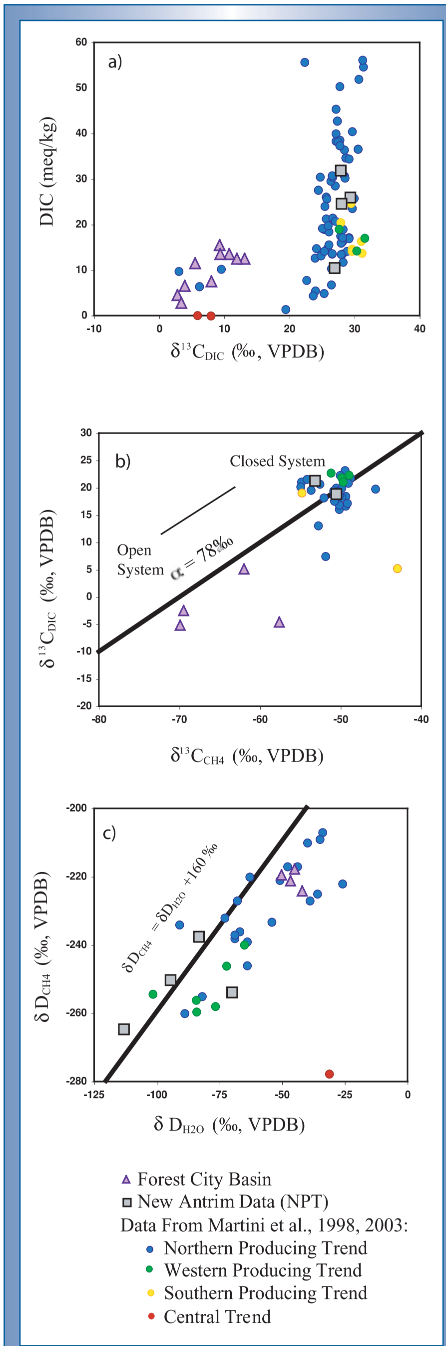

Figure 2. New data from the Forest City Basin and Antrim Shale plotted with previously published data.

Margins all exhibit DIC concentrations >>10 meq/L, and Forest City Basin waters are similarly high in alkalinity. This indicates extensive organic matter (OM) oxidation within the Antrim Shale and Forest City coals localized along basin margins.

Stable carbon isotope ratios also provide a measure of microbial activity within shale formation waters. The ratio of ^{13}C to ^{12}C in DIC reflects a balance between sources of DIC, equilibration with carbonate minerals and processes that remove DIC from the water. By convention, differences in $^{13}C/^{12}C$ ratios are expressed as per mill deviations off a standard on the $\delta^{13}C$ scale. In most formation waters, carbonate mineral equilibration dominates, generating carbon isotope ratios ($\delta^{13}C$ values) similar to carbonate in the rock. This is seen in $\delta^{13}C_{DIC}$ values in waters from the overlying glacial drift and deep Antrim brines, indicating little or no microbial activity in the central Michigan basin. However, microbial methane generation consumes DIC in a process strongly selective for ^{12}C, leaving behind DIC that becomes more and more enriched in ^{13}C. This form of Rayleigh isotope distillation indicates closed or nearly closed system behavior. The extremely ^{13}C-enriched $\delta^{13}C_{DIC}$ values in productive Antrim waters are some of the highest measured in natural waters anywhere, indicating extensive methanogenesis along the margins of the Michigan Basin (Figure 2a). Forest City Basin waters also exhibit elevated $\delta^{13}C_{DIC}$ values, but not as extreme as in Antrim Shale waters. This indicates a more open isotopic system operating in the Forest City play.

Stable carbon isotopic ratios of natural gas provide an effective tool to distinguish thermogenic from microbial gas. Thermogenic methane forms by abiotic cracking of kerogen, generating methane slightly depleted in ^{13}C relative to bulk organic matter. More importantly, however, thermogenic $\delta^{13}C_{CH4}$ values will exhibit no relationship with formation water $\delta^{13}C_{DIC}$ values. In contrast, microbial gas generation is intimately linked with DIC geochemistry. Methane $\delta^{13}C$ values are systematically offset from $\delta^{13}C_{DIC}$ values by about 78‰. Early researchers identified gas in the Antrim as thermogenic because $\delta^{13}C_{DIC}$ was not measured and assumed to be near 0‰. $\delta^{13}C_{CH4}$ values of about -50‰ seemed to more closely resemble kerogen $\delta^{13}C$. However, measurement of a single isotopic parameter, $\delta^{13}C_{CH4}$ values, is not sufficient to uniquely identify methanogenesis. When coupled to measurement of the extremely ^{13}C-enriched pool of DIC, Antrim methane is clearly shown to obey a tight relationship between $\delta^{13}C_{CH4}$ and $\delta^{13}C_{DIC}$ values offset by 78 ‰ (Figure 2b). Once again, the Forest City Basin samples plot nearer to open system fractionation.

During methanogenesis, there also is a direct link between hydrogen isotopic ratios (D/H) of H_2O and microbial CH_4. This relationship is not observed in thermogenic gas. A strong regional H-isotope gradient in Antrim waters (δD from -25‰ to -100‰) permits chemical tracing of H_2 derived from H_2O[4]. For the Forest City Basin and most of the W, N and S margins of the Antrim Shale, the $\delta D_{CH4-H2O}$ relationship $\delta D_{CH4} = \delta D_{H2O} + 160$ (± 10‰) (Figure 2c) indicates a strong imprint of microbial methane generation. In contrast, CH_4 from the central Michigan Basin has δD values consistent with a thermogenic origin and little evidence of equilibration with associated waters.

Pathways and constraints on microbial methane generation

There remains a key unresolved question regarding sedimentary basin methanogenesis: what fuels these subsurface microorganisms to generate such significant amounts of methane? Active microbial populations are recognized in a variety of subsurface sedimentary environments, including OM-poor marine sediments, gas hydrate-rich sediments, sedimentary rocks, petroleum-contaminated aquifers, unconsolidated sediments and petroleum reservoirs. Only one group of microorganisms (Archaea) is capable of generating methane, and only through a limited number of metabolic reactions (Table 1). These organisms are strict anaerobes that die in the presence of oxygen and are easily outcompeted by other forms of microorganisms. None of the chemical precursors for methanogenesis (H_2, single-carbon compounds and acetate) are abundant in biologically inactive sedimentary basins. Thus microbial methane generation in the Antrim and Forest City Basin must be coupled to anaerobic biodegradation of shale OM (kerogen, bitumens or aqueous dissolution products) to generate the necessary substrates for active methanogenesis. Thus the question becomes not "What fuels methanogenesis?" but rather "What fuels production of the precursors that drive methanogenesis?"

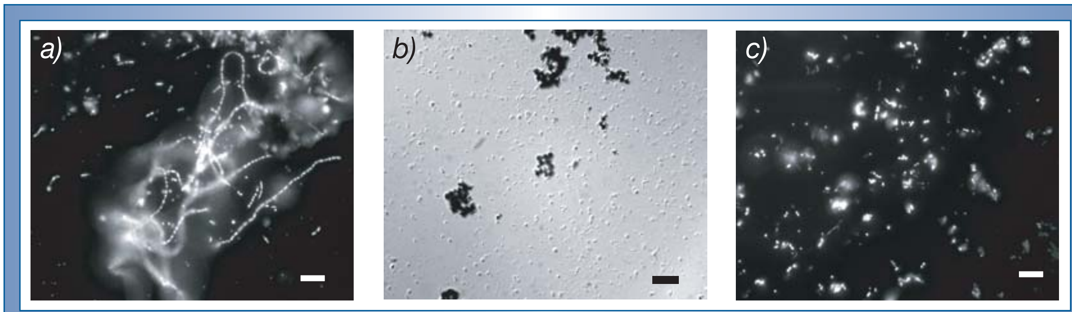

Figure 3. All photomicrographs are of enrichments from a single producing well. a) Epifluorescent photomicrograph of DAPI-stained methanogenic enrichment culture. b) Plain light photomicrograph of ferric iron-reducing enrichment culture. Black precipitate is iron sulfide. c) Epifluorescent photomicrograph of DAPI-stained sulfate-reducing enrichment culture. Scale bar is ~25 µm.

Methanogenesis by itself requires no external supply of e-acceptors, only H_2, CO_2 and acetate. An intriguing source of H_2 and acetate in environments where competition from anaerobic respiration cannot occur is decomposition of hydrocarbons leading to methanogenesis. Zengler and colleagues showed that hexadecane decomposition to acetate and H_2 can proceed (i.e. is energetically favored) if coupled with removal of acetate and H_2 through the activity of methanogens. These three microbial reactions (Table 2) can operate in syntrophy, decomposing hydrocarbons into methane and CO_2 in a set of reactions thermodynamically favored only when combined. Although initial reports suggested this reaction is sluggish and revealed concerns about co-metabolism with sulfate-reducers, subsequent study has indicated this process is fairly rapid in subsurface sediments and in the absence of sulfate.

Microscopic evidence of active microbial populations in the Antrim

Freshly collected waters from the main Antrim gas-producing trend reveal an active, and in some cases motile, population of organisms when examined under the microscope. This stands in strong contrast to saline waters in the center of the basin (where cells are absent) and glacial drift waters (in which cells are sparse). Microbial incubation experiments using Antrim formation waters are also instructive models of subsurface microbial activity in the Michigan Basin. No detectable growth is observed under aerobic or nitrate-reducing conditions. Growth is detected under sulfate- and iron-reducing conditions, and strong growth is observed under conditions supporting fermentation and methanogenesis. Importantly, when waters collected from outside the main gas-producing zone were used (e.g. from the southernmost, highly saline well), no growth in any of the enrichment media was observed. Only limited growth (nitrate reduction, fermentation) was detected in waters collected from the glacial drift recharge well. Methane-producing enrichment cultures inoculated with waters from the Antrim Shale main gas-producing trend revealed an abundant array of cells, with two dominant morphologies: single or paired rod-shaped cells and long filaments of cells linked in single rows end-to-end (Figure 3a). In contrast, sulfate- and ferric iron-reducing enrichments exhibit a distinctly different morphology of principally single (Fe-reducing, Figure 3b) or paired cells (SO_4-reducing, Figure 3c).

Community analyses based on DNA

Attempts to culture microorganisms in the laboratory generally are of limited success; less than 0.1% of microorganisms can be grown in the laboratory on media. Thus identification of microbial communities relies heavily on culture-independent techniques employing sequences of DNA isolated from environmental samples. These techniques have been applied to waters collected from productive and non-productive Antrim wells and overlying glacial drift waters. Our research compares sequences among species-indicating marker genes to identify community members and functional, protein-coding marker genes to evaluate genetic diversity among the methanogens present.

Table 1. Selected methane-generating pathways

$4\ H_2 + CO_2 \rightarrow CH_4 + 2\ H_2O$

$CH_3COO^- + H^+ \rightarrow CH_4 + CO_2$

$4\ CH_3OH \rightarrow 3\ CH_4 + CO_2 + 2\ H_2O$

$CH_3OH + H_2 \rightarrow CH_4 + H_2O$

$4\ CO + 2\ H_2O \rightarrow CH_4 + 3\ CO_2$

Other known substrates: formate, amines, thiols

Table 2. Syntrophic anaerobic decomposition of hydrocarbons

(1) hexadecane ($C_{16}H_{34}$) $+ 16\ H_2O \rightarrow 8\ CH_3COO^- + 8\ H^+ + 17\ H_2$

(2) $CH_3COO^- + H^+ \rightarrow CH_4 + CO_2$

(3) $4\ H_2 + CO_2 \rightarrow CH_4 + 2\ H_2O$

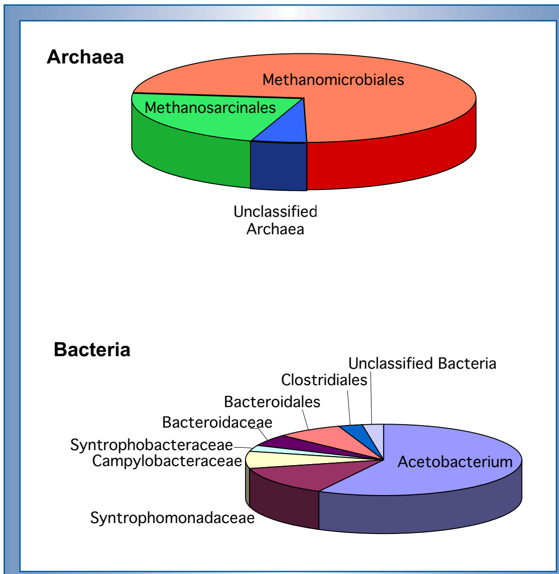

Figure 4. Diversity and relative abundance of Archaea (top) and Bacteria (bottom) from culture-independent molecular studies of a gas-producing well in the Antrim Shale. Note that methanogens comprise almost the entire Archaea diversity. For the Bacteria, note the dominance of Acetobacterium relatives and the absence of sequences related to sulfate- or metal-reducing bacteria.

DNA extracted from wells within the producing trend exhibits rich diversity among Archaea. In particular, the species that dominate these communities are directly or indirectly implicated in methanogenesis, such as acetate producers, syntrophs and methanogens. This description of community composition is based on marker gene analysis (16S rRNA) for presence of Archaea and analysis of a functional gene (mcrA) specific to methanogens. The methanogenic community is particularly rich in species members (Figure 4). Numerous novel genetic sequences were found, clustering within groups of methanogens such as Methanomicrobiales, Methanosarcinales and Methanobacteriales. Bacteria diversity is much more limited, mainly to acetate-producing members of the Acetobacteria, Syntrophomonadaceae and Syntrophobac-teraceae. Surprisingly, no DNA or enrichment culture evidence for sulfate- or metal-reducing bacteria is detected in Antrim waters.

Microcosm methane generation

This research also includes microcosm experiments in which Antrim and Forest City formation waters are returned to our laboratories in Amherst, Mass., under O_2-free conditions. These waters are then used to establish microcosms of microbial activity representative of ambient environmental conditions in the subsurface. Methane concentrations were measured in the headspace of microcosm experiments inoculated with formation waters from wells in the Forest City Basin and from the main gas-producing trend of the Antrim Shale. Control and sterile blank experiments show no methane generation, while increased methane concentrations up to 20 micromoles/L are measured in the headspace of microcosms containing methanogenic enrichment media. Dilution and transfer of methanogenic enrichment cultures into new enrichment media initiates renewed methane generation after increases in methane concentration had leveled off. Similarly, methane generation was achieved in unamended formation waters in dilution stimulation experiments where relatively dilute formation waters from the main gas-producing trend in the Antrim were mixed with poorly producing waters from the highly saline center of the basin. While methane concentrations in these mixed experiments do not match those observed in the highly producing trend, the concentrations achieved are much greater than measured in methane-poor waters prior to amendment.

Conclusions and recommendations

Geochemical analyses confirmed microbial methanogenesis as the dominant methane source in Antrim formation waters and revealed significant microbial methane generation in Forest City Basin formation waters. Active (rather than relict or ancient) methane generation was confirmed in enrichment as well as microcosm experiments using waters from both reservoirs, a finding that has significant implications for gas production prediction. Genetic information obtained from DNA isolated from Antrim formation waters indicates a microbial community comprised of acetogenic bacteria acting in syntrophy with acetate-utilizing and CO_2-reducing methanogenic Archaea. Thus, active microbial methanogenesis in sedimentary basins may not depend on an external supply of electron acceptors (e.g. sulfate, ferric iron), but instead reflects internal control limited by formation water hydrology, geochemistry and organic matter composition.

The results of this seed project involving microbial community analysis in shale gas plays strongly indicate microbial methane generation in sedimentary basins is an active process, with a high potential for stimulation and extension of projected well production histories. Application of these results has a direct relationship with potential targets of exploration and gas production in other sedimentary basins where methanogenesis may occur or, in the future, be stimulated. Thus, this research may contribute toward development of technologies to enhance methane production in shale gas plays and help secure natural gas resources from the extensive occurrence of fractured black shales and coal beds found throughout the United States.

Further investigations are necessary to understand microbial methane generation to develop strategies to target or deploy naturally occurring microorganisms for conversion of domestic hydrocarbon resources to natural gas. In addition, geologically distinct regions should be examined for fingerprints of biogenic gas production, both geochemical and biological. Through strategic analysis of more gas-producing sites, we will identify and characterize the full range of anaerobic microbial consortia capable of producing methane.

This research demonstrates a direct path toward stimulating and enhancing gas generation in unconventional resources, crucial for securing U.S. domestic energy resources. These highly promising preliminary results exhibit the synergy of combined geochemical, isotopic and microbiological efforts to investigate the activity of economically important microbial processes in the subsurface. ✧

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ANAEROBIC RESPIRATION

Anaerobic respiration is the oxidation of organic matter using electron acceptors (e-acceptors) other than oxygen, such as ferric iron minerals or dissolved sulfate. The products of respiration can be coupled to microbial fermentation reactions to yield H_2 and acetate. Common anaerobic respiration pathways detected in subsurface environments include iron- and sulfate-reduction. Provided that e-acceptors can be supplied in sufficient, sustained quantities, anaerobic respiration as the initiator of fermentation and methanogenesis might be predicted as a common feature of sedimentary basins. A strong limitation to respiration is imposed by extremely slow migration of fluids resupplying potential terminal e-acceptors. Oxidized iron minerals are not abundant in black shales, and sulfate resupply requires constant recharge from either seawater or evaporites. Unless a mechanism can be established that maintains a sustained supply of e-acceptors to the Antrim or Forest City Basin, anaerobic respiration is unlikely to be an important means of providing substrates for fermentation and methanogenesis. Our geochemical analyses support this conclusion; sulfate concentrations are below detection limit in all wells with significant microbial gas contributions.

High Temperature Electronics—One Key to Deep Gas Resources

By John D. Rogers, Ph.D., PMP, P.E., *U.S. Department of Energy/National Energy Technology Laboratory*; Randy Normann, *Sandia National Laboratory*; and Ed Mallison and Bruce Ohme, *Honeywell*

Large resources of unconventional gas are locked up in tight-gas sands, shales and coalbed methane throughout the Gulf of Mexico, Rocky Mountains, Texas, Oklahoma and Appalachian Basin, but to obtain this resource, there are a number of hurdles to overcome.

There are a number of challenges from cost and technological improvement before significant quantities of gas can be categorized as a potential resource to technically and economically recoverable reserves (Figure 1). A considerable amount of this gas is in deep (greater than 15,000ft) sources. Recently, a major oil company announced plans to drill more than 30,000ft below the mudline on the Gulf of Mexico Continental Shelf. Current indications show environments at these depths will be high pressure (HP – approaching 30,000psi) and high temperature (HT – greater than 600°F).

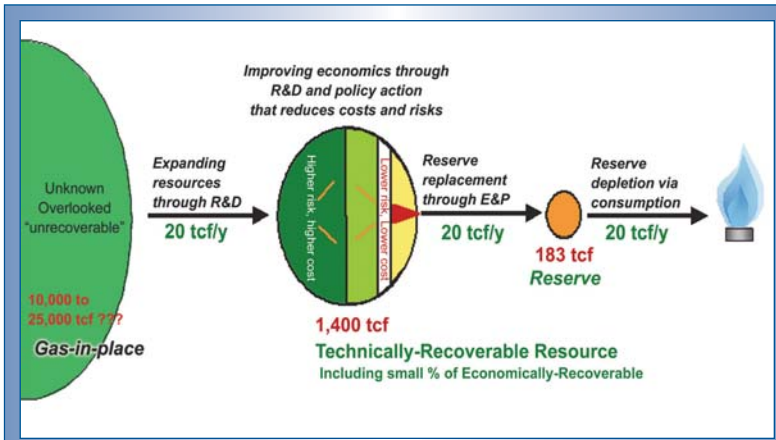

Figure 1. An expanded view of natural gas resource base.

Efforts to extend the capabilities and reliability of logging tools – including logging-while-drilling (LWD) and measurement-while-drilling (MWD) – and other "smart well" tools to these HT and HP have been underway for some time. In the late 1990s, prior to the current Deep Trek program, the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL), Maurer Engineering Inc., Halliburton's Sperry-Sun Drilling Services and Halliburton Energy Services recognized the future need for HT drilling and geological measurement technology. Two partnership projects were to enhance the capabilities of HT LWD and MWD tools. The LWD project was to extend the capability of such tools (from 284°F to 347°F with survivability to 392°F). The MWD project objective was to extend the temperature of the suite of tools from 347°F to 383°F.

Although a complete suite of MWD tools was not developed during that project, the MWD project did advance the knowledge base with significant lessons learned and provided important direction to additional research for MWD and LWD tool development. Changes made as a direct result of work performed under these projects have resulted in improved life and a more robust MWD tool at the previous temperature rating of 346°F, as well as limited use at higher temperatures. The LWD project also benefited from lessons learned in the MWD project.

These two studies and other industry information showed current electronics are not capable of providing the building blocks to develop the tools necessary to characterize the reservoirs and drill the complex wells at these HT/HP environments. As a result, the DOE's Office of Fossil Energy (FE)/NETL has taken a leadership role, partnering with the industry to encourage the development of HT electronic component building blocks. Thus the electronics industry should be able to provide the infrastructure the oil and gas industry needs to develop the necessary advanced electronic tools to explore at deep HT/HP depths in the near future.

The oil and gas industry is not the only one in need of elevated temperature electronics. Other industries will need the HT components for improved safety, reliability and maintainability at lower cost. Some of these other industrial applications include automobiles with longer life and higher fuel efficiency, chemical processes with ultra-precise control and minimal waste, and commercial and military aircrafts that can fly at greater than twice the speed of sound. Even with all the other industries, the market for HT electronics is not sufficient to sustain the research and development, and process development to manufacture the HT electronics components or building blocks of the LWD, MWD logging and other downhole electronic tools to drill and produce at elevated temperature environments.

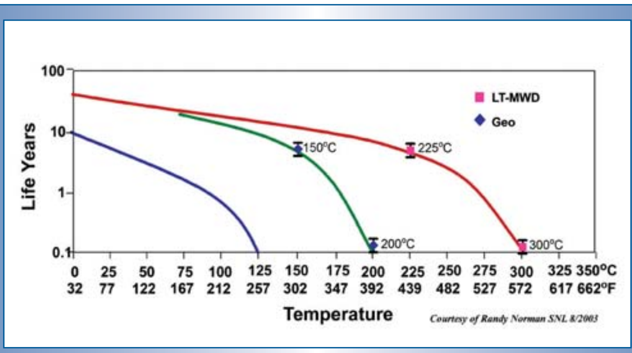

Figure 2. A qualitative comparison of electronic component operating life.

Historical perspective on electronics

Historically, electronic devices such as televisions, radios and even the first computers of the modern age used vacuum tubes, which operated well even at elevated temperatures. In fact, they needed a warm-up period to function properly. As the solid-state (SS) or semiconductor industry emerged, semiconductors and integrated chips (ICs) replaced these effective but inefficient vacuum tubes, and the age of microelectronics and miniaturization was born.

The products that used these ICs needed to be run at cooler temperatures. The first semiconductors ran so hot they destroyed themselves. Thus, the SS devices needed coolers or heat sinks instead of "heaters" like the vacuum tubes. This is not a problem for typical consumer devices operating at normal temperatures. However, it does limit the ability to apply electronic systems where there is critical need for operations at elevated temperatures. The current need in the oil and gas industry is to provide the sensors and devices to effectively explore, drill, and produce oil and gas at elevated temperatures above 350°F without coolers and thermal shields.

Typically, ICs are designed to perform reliably at temperatures up to 158°F for commercial grade electronics, 185°F for industrial grade electronics and 257°F for military grade. Above those design limits, the characteristics for semiconductors change sufficiently so the circuit parameters will not be met, or permanent changes may occur that cause the circuit to fail.

Figure 2 shows a qualitative analysis of the effect of temperature on the life of semiconductor components:

- the blue line is an attempt to relate expected operating life of commercial/industrial grade electronics and is based on "standard" metallization practices of commercial/industrial electronic components. Unfortunately, there is no operating life requirement on commercial or industrial grade electronics;
- the green plot is for commercial/industrial components being re-qualified and/or repackaged. This is based on some known proprietary data. The curve is generous as it gives a life expectancy of 1,000 hours at 392°F and 5 years at 302°F, but it could actually be lower (i.e. 400 hours at 391°F and 3 years at 302°F); and
- the red curve is an estimate of silicon-on-insulator (SOI) technology. There has been some demonstration with the limited SOI available (Honeywell components) that has established significant life expectancy even at HTs.

Two strong and evident observations are that temperature has a dramatic effect on SS devices, and SOI can increase longevity and reliability significantly at lower temperature.

Most oil and gas wells drilled today are below the 302°F limit of a typical semiconductor. However, drilling to deeper depths will need a different paradigm. HT electronics are necessary if LWD and MWD tools, logging tools and even smart well applications are to be used to any reliability.

Silicon-on-insulator technology

Transistor density and speed define the performance and cost of a digital device. A metal-oxide semiconductor (MOS) transistor is an electronic switch and consists of three basic elements: the source, the gate and the drain. Figure 3 is a simplified sketch of a MOS transistor.

The source and drain are regions of silicon that have been implanted with a small percentage of dopant atoms (such as boron or phosphorous) that change the conducting properties of the silicon. The silicon region between the source and drain is doped with a species different from that used to dope the source and drain. Doping adjacent regions of silicon with different dopant species creates a "junction" that has an inherent electrostatic barrier to conduction.

The gate is between the source and drain on top of a thin insulating (non-conducting) layer of silicon dioxide. When sufficient charge or voltage is applied to the gate (referred to as the "threshold" voltage, V_T) the electrostatic conduction barrier is overcome, and a conducting channel is established in the silicon region directly beneath the gate. In this case, current can flow from the source to the drain through the silicon substrate when a charge or voltage is applied to the gate. Basically, when the gate-voltage is below the threshold voltage the silicon substrate acts as a barrier to conduction. When the gate voltage is above the threshold voltage, the substrate acts as a conductor allowing current to flow. However, a small amount of current can leak into the substrate (even at conventional temperatures) across the boundary between the source/drain and the substrate, which occurs regardless of the gate voltage. As temperatures increase, the leakage currents rise dramatically.

Finally, it should be noted that the threshold voltage itself varies with temperature. Depending on the processing details (such as the thickness of the insulator under the gate and the doping levels in the substrate) the threshold voltage may go to zero at HT, making it difficult to use the gate terminal as a means to control conduction.

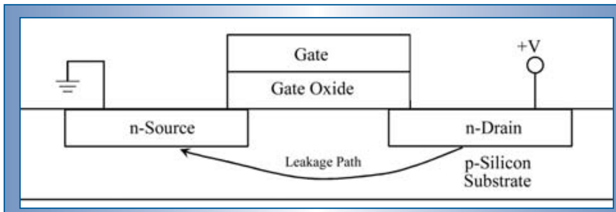

Figure 3. A cross-section of typical metal-oxide-semiconductor transistors on silicon substrate showing leakage path that could occur at high temperature.

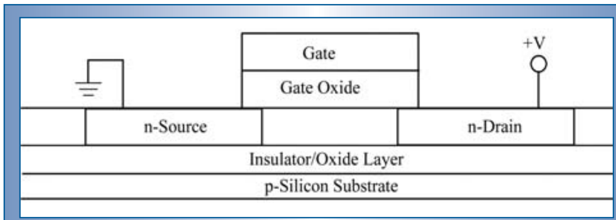

Figure 4. Cross-section of a metal-oxide-semiconductor transistor in a silicon-on-insulator technology.

Six typical basic effects occur in material as temperature increases:

- electrical resistance of interconnection materials and contacts increases;
- electrical resistance of insulating materials decreases and charge leakage increases;
- thermal conduction decreases for good conductors;
- thermal conduction increases for poor conductors;
- thermal expansion coefficients increase; and
- chemical and metallurgical activity and interactions within and between materials increase.

Controlling these effects is essential for ICs in devices needed to operate at HTs. Additionally, operating life and dependability can be critical. Temperature is commonly associated with faster aging, shorter lifetimes and degraded reliability.

The junction current leakage between the source or drain and the substrate is greatly reduced by using SOI technologies. The MOS transistors are isolated by a silicon dioxide dielectric layer (Figure 4). SOI limits appear at about 572°F where junction leakage currents become prohibitive, though operations up to 752°F have been reported.

Conventional semiconductor processes employed for commercial electronics are not capable to produce components that operate at HT or are reliable at HT. The upper limit of operation for conventional silicon devices is about 392°F, and even at these temperatures the operating life may be very short (measured in weeks). Operation at higher temperatures (such as the 600°F current projected temperatures of deep gas resources) require different materials such as SOI, silicon on sapphire (SOS), silicon carbide (SiC), gallium arsenic (GaAs), gallium nitride (GaN), diamond and so on.

GaN and diamond does not have the technological maturity that silicon does and is difficult to work with. GaAs offers only a slight temperature advantage over SOI while lacking the design flexibility of SOI. SOS technology is limited by the cost of growing a layer of silicon on a single crystal of sapphire substrate. SiC is useful for power electronics and has the ability to handle high voltage, high currents and high temperatures. Power transistors became commercially available in 2004.

The other materials have not had sufficient market draw or commercial devices developed to justify process development. The material selected depends on the temperature range and needed bandwidth. Even for HT SOI technology, the manufacturing of the integrated chips or ICs is difficult, and only a few companies have the "foundry" capable of making the high-quality HT SOI devices. This technology, though not highly employed, is well understood and can produce well functioning devices to 572°F.

SOI and SiC are complementary technologies. SOI can be seen as the brains; taking measurements, processing data and then making decisions. While SiC provides the power to turn the motor or open the valve.

SOI devices can be reliable, even at HTs. The major factors limiting the life of IC conductors and contacts operating at elevated temperatures are electromigration – the transport of material caused by the gradual movement of the ions caused by current flow, time and temperature – and corrosion accelerated by the HTs.

Deep Trek HT electronics initiative

To develop highly reliabile HT electronic products and technology that will enable smart drilling at depths of 20,000ft and temperatures more than 392°F, the DOE through its gas program at NETL initiated a project to develop SOI technology for the oil and gas industry. Honeywell International Inc. Solid State Electronics Center in Plymouth, Minn., formed a joint-industry-project (JIP) to direct and provide the necessary cost share for the HT electronics project. The JIP will ensure this project addresses the most relevant set of system specifications and functionality primarily for the oil and gas industry to develop the deep HT tools.

Three major service companies – Baker Hughes, Halliburton Energy Services and Schlumberger – two smaller technology developers/service companies – Quartzdyne and NOVATEK – one major oil and gas operator (BP), and a large aerospace company (Goodrich Corp. – Aerospace Engine Systems) co-fund the JIP with the DOE.

The DOE provides about $6 million and the JIP members and Honeywell provide a cost share of about $2.5 million. The project began in October 2003 and will continue through December 2006. The project has changed significantly since the initial proposal to DOE through the guidance of the JIP members to develop technically relevant and purposeful products. More than 24 components initially were considered and prioritized with five fitting within the allocated budget:

- programmable memory electrically erasable programmable read only memory (EEPROM);
- pre-programmable (volatile) field programmable gate array (FPGA);
- precision amplifier;
- Sigma-Delta analog to digital converter (18-bit); and
- an electronic designer's tool kit for creating custom "system-on-a-chip" SOI ICs.

A state-of-the-art microprocessor was considered, but the cost of intellectual property rights and subsequent upgrading to SOI technology made it prohibitively expensive for the current project. The system-on-a-chip capability allows engineers to mix analog and digital circuits in one SOI IC. Although this process is expensive (between \$250, 000 and \$350,000), the result is a small and powerful application specific device.

Most notable in the above list is the placement of a user-programmable non-volatile (holds data or program if power is interrupted) memory product. The JIP partners have placed a high value on this component. A non-volatile user-programmable memory is required in a system that contains the FPGA. User-programmable memory also is important to a system that uses a microprocessor where non-volatile memory is commonly used to store application-specific instruction code. Finally, this type of memory is useful in any type of data-acquisition system where sensors are characterized and sensor-specific calibration coefficients are stored and employed to improve system accuracy.

Developing the programmable memory significantly affected the program. Non-volatile memory required integrating new steps and features into the wafer fabrication process. A substantial effort is required for device optimization, characterization and verification of HT performance, and reliability devices operated in fundamentally different ways than envisioned by the original project. These changes involve cycles of wafer processing to characterize and optimize the wafer fabrication flow. Finally, the EEPROM product should represent a relatively large portion of the integrated circuit design and development within the project. To include the programmable memory required that other tasks be revised and/or discontinued. In particular, the microprocessor development is not affordable and is discontinued. The cost of the state-of-the-art HT SOI microprocessor development could be as much as one-third the total project budget (more than \$2 million).

Another major change is that the FPGA, which was originally proposed for implementation in 0.35-micron process, will instead be implemented in the 0.8-micron process. The major impact of this change is a trade-off between nonrecurring development cost (which is decreased) and production cost (which is increased). The development cost is decreased because this program does not fund wafer process development to render Honeywell's 0.35 micron process capable for HT use. The production cost is increased because the 0.8 micron process is less dense than the 0.35 micron process, and therefore the resulting die will be larger and (presumably) more costly to produce. Using the 0.8-micron process also means the maximum operating speed (or clock rate) for the FPGA will be lower than it would have been otherwise. A further change (also for the sake of including the programmable memory) is the elimination of the hardware demonstration task. A major motivation of this task was to demonstrate the application of the microprocessor, without which, the loss of this task is less significant than it otherwise would have been.

Because the program requires a significant number of wafers be built to characterize and optimize the process flow for EEPROM development, the number of wafers devoted to running final product designs is reduced. This means less material will be available to the JIP members than would have been the case without the EEPROM development. The FPGA in particular is impacted because in a 0.8-micron flow, the die will be larger, and therefore the number of die per wafer will be less to begin with. The quantity of FPGA die produced is not expected to exceed 150. More die could be provided for an additional cost.

Finally, adding the programmable memory to the scope of this project represents a significant new area of development risk. Offsetting this risk is the added reward that successful development of this capability represents. The HT SOI EEPROM memory chip has been identified by the JIP partners as an enabling technology. In recognition of the changed risk profile, Honeywell has established that the program shall include several key "decision gates" at which time progress will be assessed and, if necessary, a determination may be made to adjust remaining program scope and direction.

The project is currently within acceptable schedule and within budget.

The components will have higher reliability at lower temperatures because the HT SOI's designed for 5 years of life at 437°F. This long life provides reuse of tools and reconfigurations lower cost per tool. Members of the joint industry project have exclusive market access until late 2007.

Related Deep Trek HT Electronics Projects

There are three additional projects currently funded by DOE/FE/NETL/ONG to develop HT downhole tools:

- wireless electromagnetic telemetry with E-Spectrum;
- research a 436°F MWD using SOI technology; and
- a commercial innovative HT/HP MWD tool with Schlumberger technology. ✧

For more information, contact John Rogers, NETL project manager for natural gas supply drilling, completion and stimulation projects at (304) 285-4880 or via email at john.rogers@netl.doe.gov

Enhanced Wellbore Stabilization and Reservoir Productivity with Aphron Drilling Fluid Technology

By Fred Growcock,
MASI Technologies LLC

Laboratory research is required to provide understanding and validation of aphron drilling fluid technology as a viable and cost-effective alternative to underbalanced drilling of depleted oil and gas reservoirs.

Many oil and gas reservoirs in the United States are mature and becoming increasingly depleted of hydrocarbons, which makes for more costly drilling. While the formations above and below these producing zones typically have much higher pore pressures and require high fluid density to stabilize them, exposure of a depleted zone to this high-density fluid can result in significant loss of drilling fluid and differential sticking. Uncontrollable drilling fluid losses are at times unavoidable in the often-large fractures characteristic of these formations. Furthermore, pressured shales often are found interbedded with depleted sands, thus requiring stabilization of multiple pressure sequences with a single drilling fluid. Drilling such zones safely and inexpensively is difficult with conventional rig equipment. Preventive measures with normal- or high-density fluids generally entail use of a low concentration of a plugging agent in the circulating system or remediation when the rate of loss of drilling fluid exceeds some threshold level. The latter requires injection downhole of a pill – a 50-bbl to 100-bbl slug of fluid – that contains a high concentration of a plugging agent or a settable/cross-linkable fluid. None of these measures is completely satisfactory.

An increasingly popular alternative for drilling depleted or multiple pressure zones is the use of a fluid that has a density low enough to balance the pore pressure in the lowest-pressure zone. However, this results in drilling the zones above and below the depleted zone "underbalanced," a condition that risks wellbore collapse and blowouts. A new drilling fluid technology was developed recently that does not entail drilling underbalanced, yet is designed to mitigate loss of fluid and differential sticking. This novel

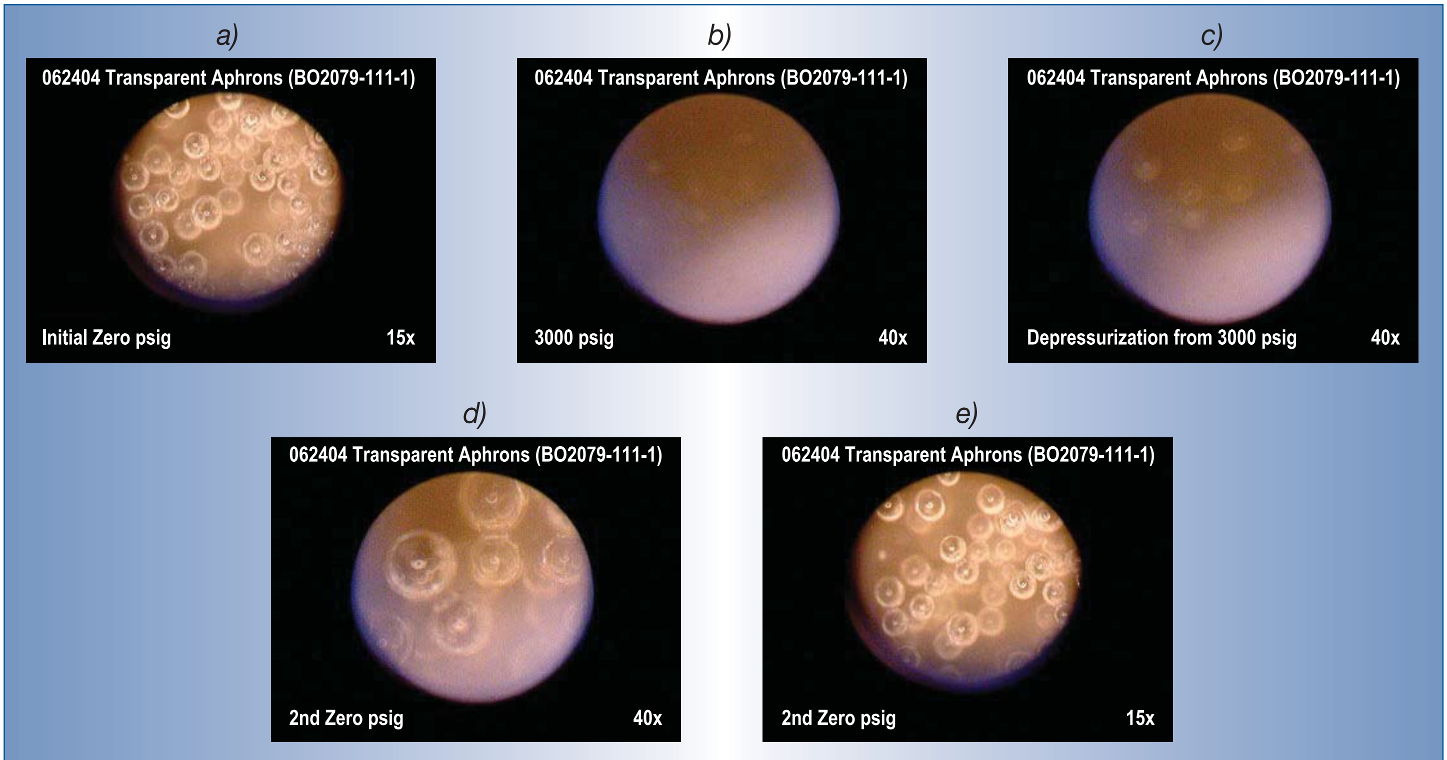

Figure 1. Aphrons can survive pressurization to at least 3,000 psig. Note that images b through d are magnified to 40x.

technology is based, in part, on the use of uniquely structured micro-bubbles of air called "aphrons."

Because of concerns about corrosion and well control, drillers generally discourage entrainment of air in drilling fluids; indeed, they often go to substantial lengths to eliminate air altogether from drilling fluids. Consequently, the purposeful incorporation of air, as in aphron drilling fluids, is looked on with some apprehension. Furthermore, there are no controlled studies that have been able to shed much light on the mechanism or the effectiveness of the aphrons at downhole pressures. This project was developed to provide the much-needed validation data that would put such issues to rest, thereby leading to greater application of aphron drilling fluid technology. With wider use of aphron technology, clients will reduce their drilling costs significantly and be able to pass some of those savings on to American consumers.

MASI Technologies, funded in part by the U. S. Department of Energy's Office of Fossil Energy, is carrying out a study with three objectives: develop a comprehensive understanding of how aphrons behave at elevated pressures and temperatures; measure the ability of aphron drilling fluids to seal permeable and fractured formations under simulated downhole conditions and establish how the fluids control fluid invasion with minimal formation damage; and determine the role played by each component of the drilling fluid.

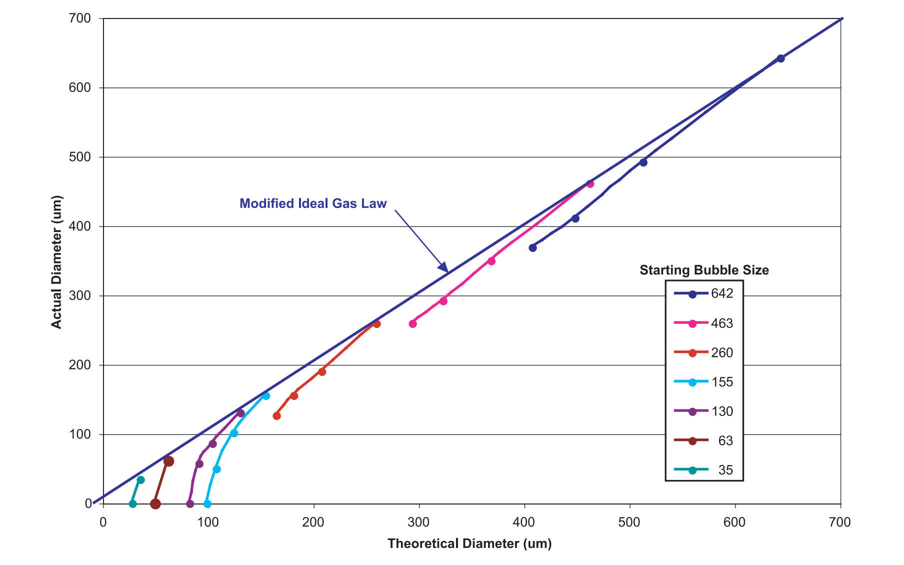

Figure 2. Large aphrons survive pressurization from 500 psig to 2,000 psig, but smaller aphrons (50 µm to 100 µm) do not.

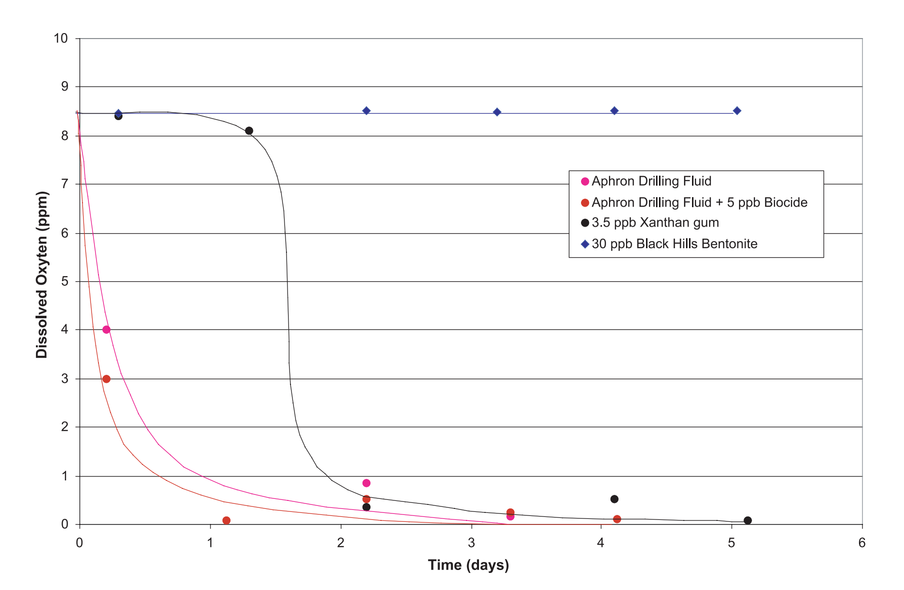

Figure 3. Oxygen in aphron drilling fluids depletes rapidly.

Background

Aphron drilling fluids have been used successfully to drill depleted reservoirs and other low-pressure formations in a large number of wells, particularly in North and South America. These novel fluids have two chief attributes that serve to minimize fluid invasion and damage of producing formations. First, the base fluid is very shear thinning and exhibits an extraordinarily high low-shear-rate viscosity; the unique viscosity profile is thought to reduce the flow rate of the fluid dramatically upon entering a loss zone. Second, very tough and flexible micro-bubbles are incorporated into the bulk fluid with conventional drilling fluid mixing equipment. These highly stabilized bubbles or aphrons are essential to sealing the problem area and are thought to form a seal within the permeable or fractured formation.

Aphrons are made of a spherical gas core and a protective outer shell. Contrasting with a conventional air bubble, which is stabilized by a surfactant monolayer, the outer shell of the aphron is thought to consist of a much more robust surfactant tri-layer. This tri-layer is envisioned as consisting of an inner surfactant film enveloped by a viscous water layer; overlaying this is a bi-layer of surfactants that provides rigidity and low permeability to the structure while imparting some hydrophilic character to it. Under quiescent conditions, the structure is compatible with the aqueous bulk fluid; however, it is thought that when enough shear or compression is applied to the aphron, for example, when bridging a pore network, the aphron may shed its outermost shell layer, rendering the bubble hydrophobic.

Aphrons are claimed to act as a unique bridging material, forming a micro-environment in a pore network or fracture that appears to behave in some ways like foam and in other ways like a solid, yet flexible, bridging material. As is the case with any bridging material, concentration and size of the aphrons are critical to the drilling fluid's ability to seal thief zones. Drilling fluid aphrons have cores of air and are constructed by entraining air in the bulk fluid with standard drilling fluid mixing equipment; this reduces the safety concerns and costs associated with high-pressure hoses and compressors commonly utilized in underbalanced air or foam drilling. Although each application is customized to the individual operator's needs, the drilling fluid system is generally designed to contain between 12 vol % and 15 vol % air at the surface (ambiant temperature and pressure), and the aphrons generated are thought to be sized or polished at the drillbit to less than 200 µm diameter, which is typical of many bridging materials.

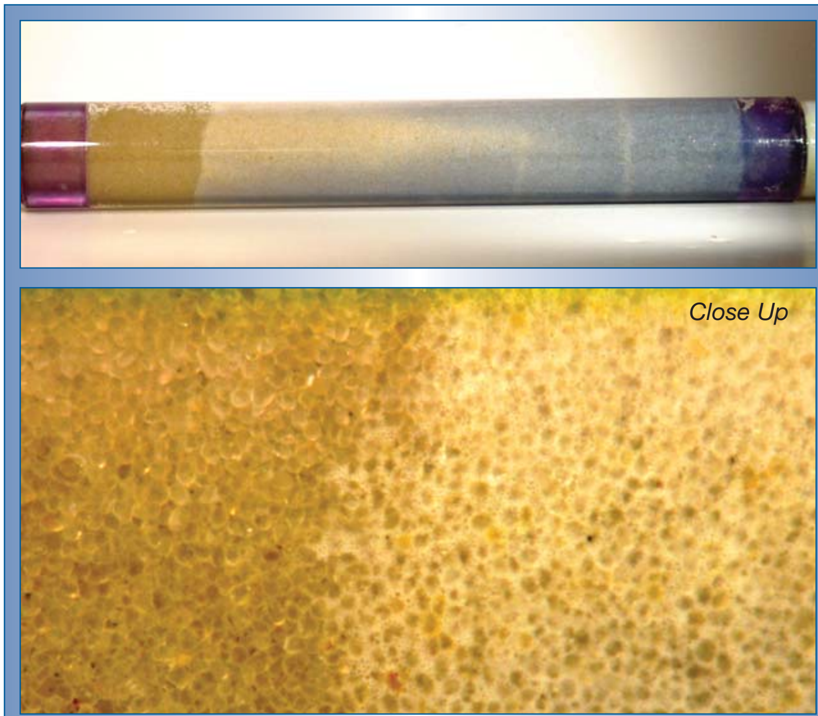

Figure 4. Aphrons undergo bubbly flow during displacement of water from 20/40 sand pack by an aphron drilling fluid. Note that the fluid front (at the fluid/water interface) is predominantly aphrons (white).

The project is divided into two phases. Phase I (year 1) dealt with developing evidence for the ways in which aphrons behave differently from ordinary surfactant-stabilized bubbles, particularly how they seal permeable and micro-fractured formations during drilling operations. Various methods were evaluated for characterizing the properties of aphrons, including acoustic bubble spectrometry, optical and electronic micro-imaging and interfacial tension. Key properties investigated included the effects of pressure on bubble size, the influence of environmental parameters on aphron stability, the affinity of aphrons for each other and the mineral surfaces in rock pores and micro-fractures, and the nature of aphron seals in permeable and micro-fractured rock. Initial sealing and formation damage tests were carried out, using lab-scale apparati designed to simulate permeable and micro-fractured environments. Phase II (year 2) is focusing on optimization of the structure of aphrons and composition of aphron drilling fluids, quantifying the flow properties of the fluids (radial vs. linear flow, shear and extensional viscosity effects and bubbly flow phenomena), and understanding formation sealing and damage under simulated downhole conditions (including scale-up tests), so as to furnish irrefutable evidence for this technology and provide field-usable data.

Much of the scenario described above about the role of aphrons in reducing fluid losses downhole is conjecture that has not been confirmed under stringent laboratory conditions. Furthermore, the overall manner in which the drilling fluid is able to reduce fluid losses downhole has been brought into question. As a result, there has been considerable resistance in some places to acceptance of the technology.

Aphron properties

In contrast to conventional bubbles, which do not survive long past a few hundred psi, aphrons have been found to survive compression to at least 27.3 MPa (4,000 psig) for significant periods of time. When a fluid containing bubbles is subjected to a sudden increase in pressure above a few hundred psi, the bubbles initially shrink in accordance with the modified Ideal Gas Law. Aphrons are no exception. However, conventional bubbles begin to lose air rapidly via diffusion through the bubble membrane, and the air dissolves in the surrounding aqueous medium. Aphrons also lose air, but they do so very slowly, shrinking at a rate that depends on fluid composition, bubble size, and rate of pressurization and depressurization.

Compression will reduce a bubble of 200-µm diameter at atmospheric pressure to 76 µm when subjected to a pressure of 250 psig,

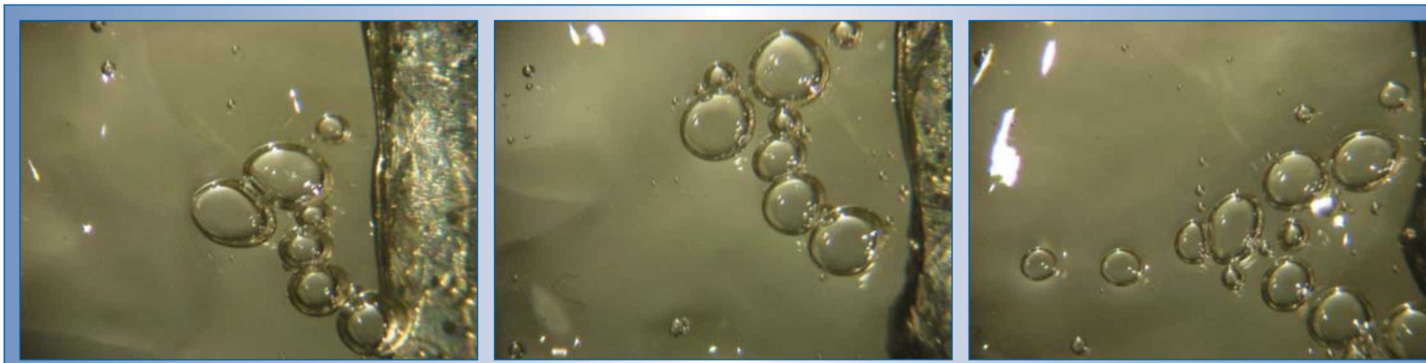

Figure 5. In time, conjoined aphrons separate and show little affinity for each other.

and 36 µm at 2,500 psig. But the biggest effect of pressure by far on the fate of a bubble is increased gas solubility. Henry's Law states that the solubility of a gas is roughly proportional to the pressure. When a fluid containing 15% v/v entrained air at ambient pressure is compressed to just 250 psig, all of the air becomes soluble. If the stabilizing membrane surrounding the bubble is permeable, the air will diffuse into the surrounding medium and go into solution. This is what happens with ordinary bubbles, and it occurs within a matter of seconds after compression. Aphrons have a much less permeable membrane, so they do not lose their air as readily; indeed, when subjected to a pressure of 250 psig, air is prevented almost indefinitely from diffusing out of the aphrons and into the aqueous medium.

Aphrons will survive compression and decompression for short periods of time. As shown in Figure 1, rapid compression of an aphron drilling fluid from 0 psig to 3,000 psig followed by decompression back to 0 psig results in essentially full regeneration of the aphrons. Large aphrons appear to be able to survive better than small aphrons. Figure 2 shows the effect of the size of an aphron on its survivability. Aphrons of different sizes are pressurized from 500 psig to 2,000 psig in steps of 500psi every 10 seconds. Aphrons larger than 200 µm diameter decrease in size with increasing pressure as expected by Boyle's Law (modified Ideal Gas Law); the small deviation from Boyle's Law is because of loss of air via slow diffusion into the surrounding fluid. When aphrons reach a critical minimum size (50 µm to 100 µm diameter), they undergo a structural change that leads to their rapid demise, with the expelled air again dissolving in the surrounding fluid. Upon decompression to a pressure sufficiently low for the aqueous medium to become supersaturated with air, the air is released; most of the air goes into existing aphrons, though it may also create new aphrons.

Another important finding is that the oxygen in aphrons – even the oxygen dissolved in the base fluid – is lost via chemical reaction with various components in the fluid, a process that usually takes minutes and results in nitrogen-filled aphrons. Thus, corrosion of tubulars and other hardware by aphrons is negligible. Figure 3 shows that even at ambient temperature and pressure, the oxygen in solution in an aphron drilling fluid disappears within hours after preparing the fluid. By contrast, in a typical clay-based or polymer-based fluid, the concentration of oxygen in solution remains relatively constant.

Fluid dynamics

The base fluid in aphron drilling fluids yields a significantly larger pressure loss (or, for a fixed pressure drop, lower flow rate) in long conduits than any conventional high-viscosity drilling fluid. Similarly, if flow is restricted or stopped, aphron drilling fluids (at a fixed wellbore pressure) generate significantly lower downstream pressures than do other drilling fluids. In permeable sands, the same phenomena are evident. In addition, in permeable sands of moderate permeability (up to at least 8 Darcy) and low pressures, aphrons themselves slow the rate of fluid invasion and increase the pressure drop across the sands. Lastly, and most importantly, aphrons move more rapidly through the sands than the base fluid. Figure 4 shows a transparent version of an aphron drilling fluid (dyed blue) displacing water from a bed of 20/40 sand under the influence of a 100-psi pressure gradient. The drilling fluid front is populated with a high concentration of bubbles that turn the fluid nearly white. This phenomenon, called "bubbly flow," appears to follow conventional Navier-Stokes theory. High-density particles such as barite (a densifying material) or drilled cuttings tend to be left behind the base fluid. Low-density internal phases, such as bubbles, flow more rapidly than the base fluid. For a rigid sphere in a fluid under the influence of a one-dimensional pressure gradient, $\Delta P/L$, the relative velocity of the bubble in an infinitely wide conduit is:

$$V = 0.23\ r^2/\eta * \Delta P/L$$

where r is the bubble radius and η is the fluid viscosity. For flow through permeable media, the expression is modified to incorporate Darcy flow.

Wettability tests indicate aphrons have very little affinity for each other or for the mineral surfaces in rock formations encountered during drilling. This is demonstrated in Figure 5, which shows bubbles purposely joined by creating them via air injection. The bond between the bubbles is thought to be the result of imperfect development of the aphron shell. Within a few seconds, the bubbles separate from each other, rather than coalesce. This lack of affinity of bubbles for one another and for silica and limestone surfaces does not result from shedding surfactant layers, as was thought before, but is an intrinsic characteristic of the whole aphron structure. Thus, aphrons resist agglomeration and coalescence and are expected to be pushed back out of a permeable formation easily by reversing the pressure differential, thus minimizing formation damage and cleanup.

Finally, leak-off tests demonstrate that aphron drilling fluids are capable of sealing rock as permeable as 80 Darcy. Figure 6 shows test results in synthetic Aloxite cores of 0.75 Darcy to 10 Darcy permeability. The base fluid in aphron drilling fluids is primarily responsible for slowing or stopping the invasion, but properly designed aphrons can reduce these losses even further.

Future efforts

Phase II of this project is continuing with a study of the effects of individual components in the fluid on the properties of aphrons; a detailed investigation of the surface chemistry involved in the interactions of the drilling fluid with reservoir rock and produced fluids; visualization of the flow of aphron drilling fluids in a wellbore/reservoir simulator; and extension of the fluid flow model to include bubbly flow. ✧

Acknowledgements

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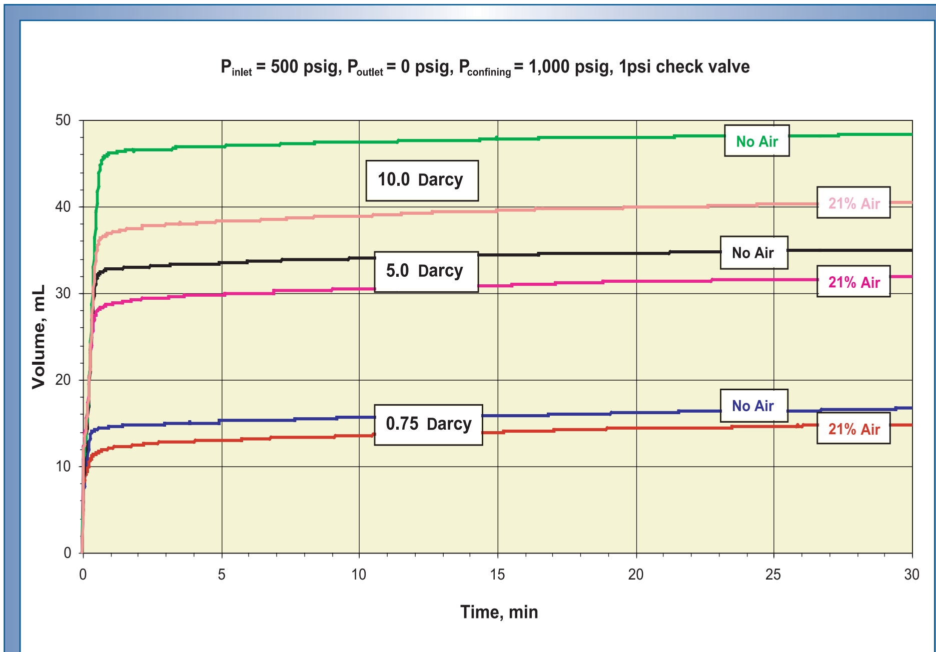

Figure 6. Static linear leak-off tests of aphron drilling fluids in permeable Aloxite cores demonstrate the sealing performance of the fluids and the role played by aphrons (air).

Fiber Laser Offers Fast Track to Clean Perforations

By Brian C. Gahan, P. E.,
Gas Technology Institute

Traditional methods of completing a cased hole include perforating with explosives, creating a tunnel to allow production of reservoir fluids to the surface. Although methods have been devised throughout the years to optimize this completion process, significant damage to the reservoir is typically created with a corresponding restriction to fluid flow. In addition to this damage are concerns of safety and security.

For the past 8 years, Gas Technology Institute (GTI) and its research partners have investigated the application of high-power laser energy for well construction and completion. Initial investigations were performed with larger military lasers to qualitatively demonstrate their feasibility for well construction. Additional work followed with less powerful, yet more practical and commercially available industrial lasers to determine rock-breaking energy requirements. In its most recent research, GTI advanced its downhole application research focusing on perforations using the most recent evolution of high-power lasers – a 5.34-kW ytterbium-doped multiclad fiber laser. The investigation has produced promising application results as well as an extensive testing of the most likely laser device to be deployed at a well site.

Early thoughts on laser applications

Since the earliest practical demonstration of lasers, the petroleum industry has recognized them as a potential alternative to, or means to assist, conventional mechanical methods of reaching and producing petroleum reserves. Many logical designs and methods were conceived and patented for subsurface laser applications that might offer revolutionary improvements in penetration rates and efficiency.

Laser technology, however, proved inadequate and impractical when first demonstrated. Lasers at the time were expensive and had limited practical applications, located primarily in academic and military settings. The lasers of the time had excessive power requirements, were large in size, and experienced poor reliability and frequent maintenance. Although technical progress and applications were expanding, limited energy transmission to subsurface targets and overall energy conversion inefficiencies tabled any real thoughts for applications in the petroleum industry.

By the late 1990s, laser technology had matured considerably when GTI and its partners investigated military and industrial lasers applications, only to dispel many of the oil and gas industry's previously held beliefs. With more technically advanced laser systems and the ability to better control beam application, it was shown that lasers were capable of breaking any lithology. Efficient rock removal methods of spallation and calcination were investigated, while avoiding more energy intensive methods of melting and vaporization.

Examination of post-lased rock properties yielded additional observations that supported laser application methods, particularly as part of a non-explosive perforations procedure. It was found that the transfer of thermal energy to the rock produced stimulation effects to fluid flow characteristics while rock was being removed. In Berea sandstone applications, porosity increased between 50% and 150%, and permeability increased 22% in the rock tunnel and surrounding areas. In addition, thermal energy weakened the overall strength of the rock in and around the excavated tunnel.

Key technical breakthrough in design

Historically, low-power versions of fiber lasers were used as optical signal amplifiers in the telecommunications industry. High-power configurations theoretically were achievable and only commercially realized in 2001. Since the design was scalable, fiber lasers were available with output powers nearing 10 kW within a year.

The principle behind the fiber laser is an internalization of the process that creates photonic emissions. In a fiber laser, photonic emissions are created in a doped silica "active" fiber using individually connected diodes, resulting in an efficient, compact laser source with exceptional beam quality. In other lasers, this process takes place in a separate resonance chamber energized by flash lamps or diodes. Laser emissions must then be channeled from the resonance chamber into an optical fiber or directly applied. Most industrial lasers are fiber connectable, although carbon dioxide (CO_2) laser emissions must be applied in a direct line of sight or through reflective optical tubes.

The unique design of the fiber laser allows a number of significant advantages over other industrial lasers. Together, these advantages have accelerated the practical application of high-power lasers for remote applications, including well perforations and other well construction and completion methods. Notable improvements include: energy conversion, or wall plug efficiencies about 20%; the footprint of the 5.34-kW ytterbium fiber laser is 5.4 sq ft; and mean time to failure in excess of 50,000 hours of continuous operations.

The high wall plug efficiency of the fiber laser significantly reduces the required input energy compared with other industrial lasers generating the same output power. Assuming identical application conditions, a typical lamp-pumped Nd:YAG laser would require as much as 200 kW of electrical power compared with about 25 kW for an ytterbium fiber laser to send 4 kW of laser energy to a target (Figure 1). This represents 87.5% less input energy for the fiber laser to achieve the same output power. Less input energy results in a reduction of on-site electrical generation equipment and a reduction in cooling requirements for energy lost through thermal dissipation.

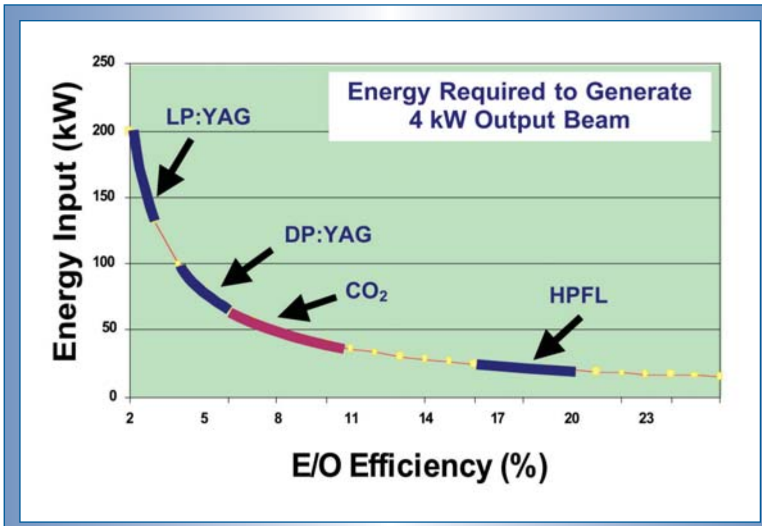

Figure 1. Comparison of required energy required of lamp-pumped Nd:YAG (LP:YAG), diode-pumped Nd:YAG (DP:YAG), carbon dioxide (CO_2) and high-power fiber laser (HPFL) to generate a 4-kW beam.

Perforating with fiber lasers

Given the advantages of fiber lasers over other high-power lasers, and the observed improvements they create in the fluid flow characteristics of rock, GTI performed a demonstration to further explore the practical application of fiber lasers for wellbore perforations.

Many of the previous experiments were performed using high-power lasers on Berea sandstone as it is well described in the literature as clean and relatively homogeneous in its physical properties with good fluid flow characteristics. Berea sandstone also has become the accepted standard for laboratory investigations of porous, permeable rock. A 1-ft cube of Berea sandstone was chosen to determine the ability of the fiber laser beam to tunnel through the block, the resulting energy requirement and resulting changes to rock properties. Since the influence of thermal energy on Berea previously was documented, we examined only permeability as an indicator of the extent of any changes in physical properties.

Previous laboratory experiments have observed laser/rock interactions of single or multiple beam bursts of several laser types on various lithologies with up to 4-in. x 6-in. length cylindrical core samples. The deepest penetrations recorded to date for a Berea sandstone was a 1-in. x 3¼-in. deep hole, created by a 6-kW CO_2 laser with a defocused, conical beam shape.

Specific energy (SE) was used to quantify the energy required to remove a unit amount of rock (kJ/cc). In previous experiments, optimal SE observations in Berea were determined using half-second beam exposures. The lowest recorded observations of SE in Berea under these controlled, optimized single shot conditions ranged from 4.3 kJ/cc to 5.2 kJ/cc. Later tests involving multiple shots were designed to layer single shots upon one another resulting in larger, deeper holes in Berea samples (about 1-in. in diameter and 1-in. deep) with SE values ranging from 9.2 kJ/cc to 13 kJ/cc.

The low values of SE were achieved by avoiding secondary effects, defined as processes that consume laser energy for purposes other than breaking the rock. Most of the secondary effects that occur in laser/rock interactions, including mineral melt, were avoided through limiting temperature accumulation in the exposed tunnel matrix and cuttings. As quartz is the dominate mineral in Berea (about 85%), melting occurs at temperatures greater than 2,700°F. Once mineral melt occurs, any additional energy the beam applies to the rock serves to increase the temperature of the melt rather than spallating the rock.

Altering the rate of energy transferred to the rock face while simultaneously reducing beam exposure to the cuttings as they exit the hole can control temperature accumulation in the rock. Energy transfer rates can be controlled easily through methods that include altering the average measured power applied, changing the power density (power/area) of the application or limiting the exposure time on a given area. Optimal beam power level and density were independently determined for fiber laser applications to Berea.

Cuttings removal is important in avoiding thermal accumulation. This becomes more apparent the deeper a hole is drilled. Experimental observations identified methods of creating a hole with a diameter larger than that of the applied beam. This was accomplished by moving the beam in a repetitive geometric pattern that allowed a greater percentage of cuttings to exit the hole with limited or no exposure to the beam.

Tunneling through the target

The laser used for this demonstration was a 5.34-kW ytterbium-doped multiclad fiber laser with an emission wavelength of 1.07 microns (Figure 2), capable of generating continuous or pulsed beams. Although larger fiber lasers have been built, this is the largest available for research in the United States. Other major elements of the laser system included a tri-axial robotic arm mounted on a vibration free optical table, a gas purge nozzle, a fume extractor and beam dump. In addition, a beam collimator mounted on the robotic arm was used to convert the raw laser beam from the fiber into a collimated beam 1-in. in diameter. The robotic arm was programmed to move the beam in a circular motion 2-in. in diameter at 22.6 rpm.

A purge gas consisting of compressed air at 75 psig was directed through a stainless steel nozzle with a quarter-in. outlet diameter and maintained at about 1-in. from the target block by continuously moving it forward as the hole deepened.

The target block of Berea sandstone measuring 12-in. on each side was exposed to the beam for a total of 6 minutes. Permeability measurements were taken prior to beam exposure for later comparison to those taken after. Measurements were taken using a pressure-decay profile permeameter at intersections of a 1-in. grid system.

The beam was applied continuously at 1-minute intervals to avoid thermal accumulation. Laser power was maintained at an optimal level found in previous studies for this rock type (3.2 kW). When the beam penetrated half the length of the block, it was turned such that the beam could penetrate from the opposite direction and meet the existing tunnel in the block's center. This procedure was performed to reduce the influence of boundary effects and better simulate an infinite reservoir rock. Boundary effects had been observed as design artifacts of past experiments: as the beam approached rock sample edges, thermal diffusion characteristics are altered, regardless of the sample's physical dimensions.

Demonstration results

The resulting hole created in this demonstration passed through the full 12-in. length of the sample. The tunnel diameter was about 2-in. at the entry points on either face and 1.1-in. at the center of the block (Figure 3). Although a collimated beam was used and a uniform diameter hole was expected, the laser head assembly and purge nozzle were moved forward nonlinearly between laser applications.

An SE value for creating the entire tunnel was determined to be 5.5 kJ/cc. This represents one of the lowest values observed for a tunnel created by any laser source previously investigated. In addition, it was obtained while creating the deepest tunnel in Berea to date. This was achievable by limiting temperature accumulation and avoiding phase change of the rock minerals. Also notable in their contributions were the novel purging system that maximized ejection of cuttings from the hole and the applied circular motion of the beam that minimized cuttings exposure to the beam prior to ejection while limiting continuous beam exposure to the tunnel walls.

Comparisons of pre- and post-lased permeability measurements along the lased rock face perpendicular to the direction of the beam were inconclusive, as the deformation zone ext-

Figure 2. A 5.34-kW ytterbium-doped multiclad fiber laser with an emission wavelength of 1.07 microns.

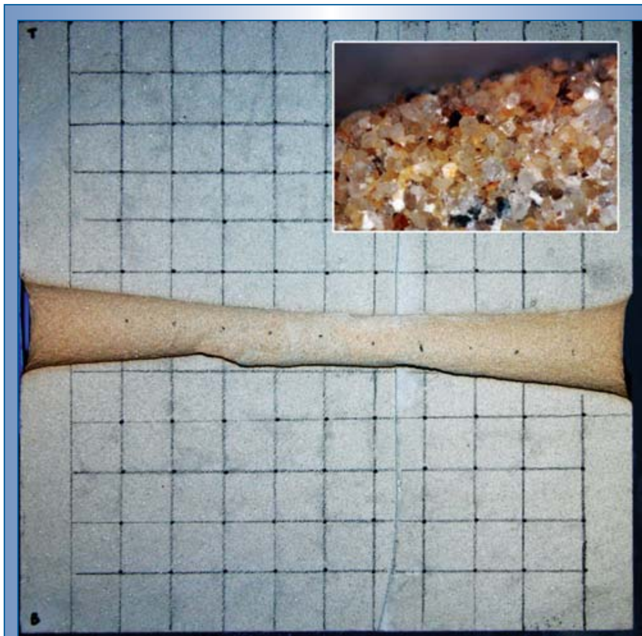

Figure 3. A cross-section of lased tunnel 12-in. across measuring 2-in. diameter on each end. The inset is a micrograph showing no evidence of melt and some discoloration.

ended only one-sixteenth-in. radially into the rock from the tunnel wall. This indicated, along with the observed SE value, that much of the energy directed at the sample was used to spallate the rock, and not to thermally alter near-tunnel rock properties. A similar comparison was made along the bisected length of the tunnel. There was no evidence of mineral melt on the tunnel wall. Post-lased permeability readings ranged from 100 mD (low) to 300 mD (high) with a pattern of highest permeability readings correlating with the tunnel. This represented permeability increases in the wellbore of between 15% and 30%. Although this enhancement is produced only within one-sixteenth-in. of the tunnel walls, we observed that the process of lasing perforation tunnels is at worst a non-damaging application (Figure 4).

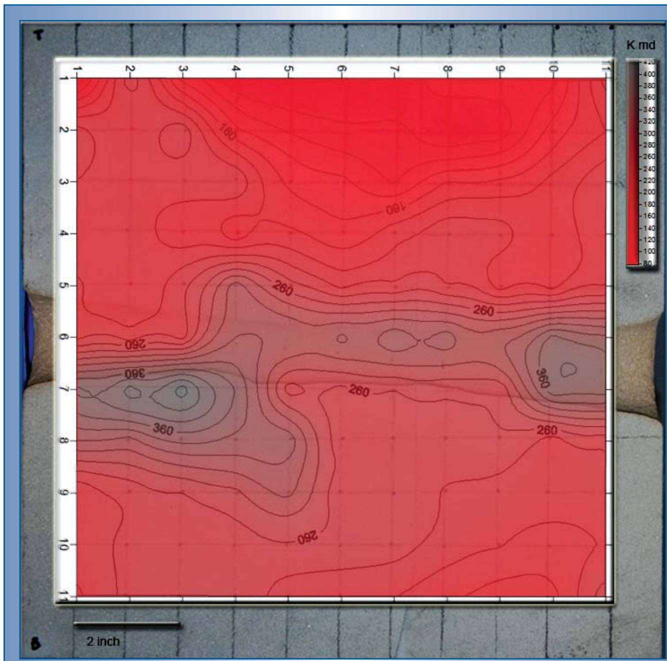

Figure 4. A two-dimension permeability map overlaying a photograph of tunnel cross-section.

Conclusions

The commercial introduction of high-power fiber lasers beginning in 2002 represented a significant step forward in realizing field-based applications of photonic energy for well construction and completion. Fiber lasers meet the multiple demands from industry regarding a field deployable system, including overall size limitations, mobile rugged on-site deployment, requisite energy delivery to target, real-time controllability and penetration of multiple materials.

From an economic perspective, the order of magnitude improvement in efficiency significantly lowers input energy and waste heat dissipation requirements. They also require minimal maintenance and repair, and are commercially available.

The application of GTI's 5.34-kW fiber laser to a 1-ft cubic block of Berea sandstone successfully demonstrated the most recent breakthrough in industrial laser technology. The demonstration provided a minimal value of SE when compared with previous laser/rock interaction tests, and yet was achieved while creating the deepest tunnel to date. This was made possible, in part, by effectively removing cuttings to avoid energy losses through thermal accumulations in the matrix and the cuttings. Additionally, boundary effects were minimized by using a target with a greater mass than found in cylindrical cores, and by opening the tunnel from both sides to meet in the center.

Evaluation of changes to rock properties proved that low power applications will create a narrower thermal deformation zone than megawatt military lasers. The deformation zone extends from the tunnel face radially into the rock; however the resulting impact on fluid flow enhancement is undetermined.

The importance of removing rock cuttings was again demonstrated, by means of creating tunnel diameters larger than beam diameters, and continually pushing gas purge lines into the deepening hole.

During the past 2 years, commercially available fiber lasers have increased in power from several watts to kilowatts. They are now capable of efficiently delivering requisite power via fiber optics to targets downhole, and have rapidly evolved into the leading candidate for on-site applications in well construction and completion. Their use as an alternative method to conventional explosive charges could reduce or eliminate perforation damage and significantly boost production rates, cumulative production and overall economic returns. ✧

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Safety Net Royalty Relief Analysis of Natural Gas and Oil Production and Revenues

By Betty Felber, *National Energy Technology Laboratory, U.S. Department of Energy*

The U. S Department of Energy's National Energy Technology Laboratory has completed work on behalf of the Bureau of Land Management that evaluates potential impacts of tax and royalty incentives and the trade-offs of these incentives on future production from federal and Native American gas and oil leases during the next 20 years.

The incentives costs and benefits were measured in terms of changes in natural gas and oil production, and direct federal and state revenues. A decline curve analysis and economic evaluation was conducted on 16,515 federal properties containing more than 62,000 producing wells on leases managed by the Bureau of Land Management (BLM). The analyses were based on monthly historical production from 1990 to 2003.

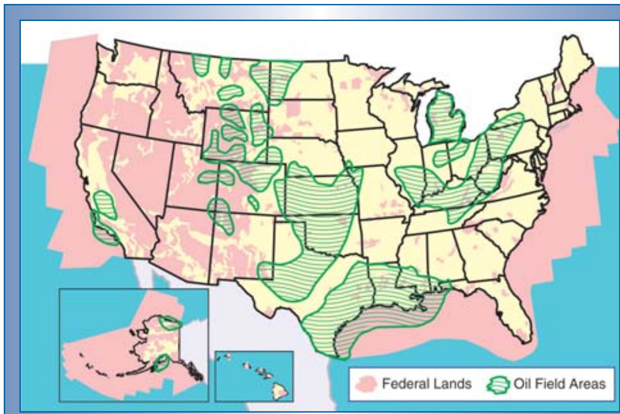

Figure 1. Federal lands locations

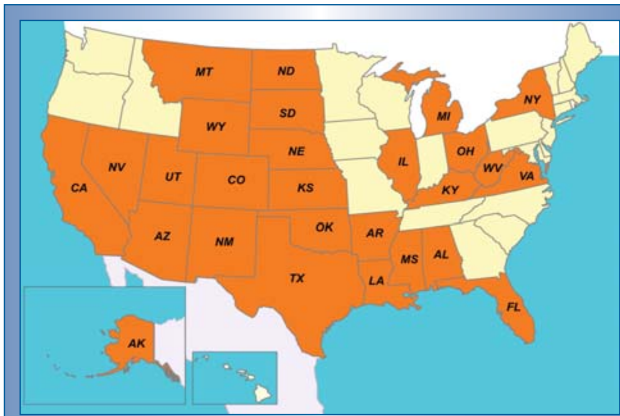

Figure 2. States included in the studies

In 2002, the BLM formed the BLM incentives team to conduct a review of existing incentives for natural gas and oil production, and recommend changes or new incentives that would promote federal lands production at a reasonable cost to the federal treasury. The incentives team membership included: BLM representation from headquarters and field offices; the U.S. Minerals Management Service (MMS); the Department of Energy's (DOE) Office of Fossil Energy and the National Energy Technology Laboratory (NETL); and representatives from New Mexico, Wyoming and Oklahoma.

The NETL Strategic Center for Natural Gas and Oil maintains, operates and utilizes a reservoir level analytical system for evaluation of programmatic and policy decisions in support of its gas and oil programs. The system is used to set research and development priorities; evaluate technology feasibility; justify program elements; and estimate benefits of various policies, environmental, and other regulatory initiatives for the DOE and other agencies.

Evaluating incentives

The team initially considered more than 20 different incentives. The incentives reported here target existing production and extending reservoir life – the so-called "safety net study." The incentives team determined that any safety net system would have a production rate and price requirement.

Incentive goals—One goal was to create a safety net to avoid premature producing well abandonment during low product prices. The incentive is to be used when necessary to keep wells on production. The incentive rules also must be simple to administer for royalty relief reduction or increase.

Design considerations—Several considerations were given to the safety net incentive design. The primary focus was to balance two often-competing goals:

- incentive must be targeted so it is only provided to producing properties that need it to remain on production; and
- incentive must be reasonable for the BLM, the MMS and industry to administer.

It was decided that low prices and low production rates are required to trigger the incentive. This avoids granting the incentive to a property during a low production rate period and then having the production rate increase significantly with the incentive still active. If the

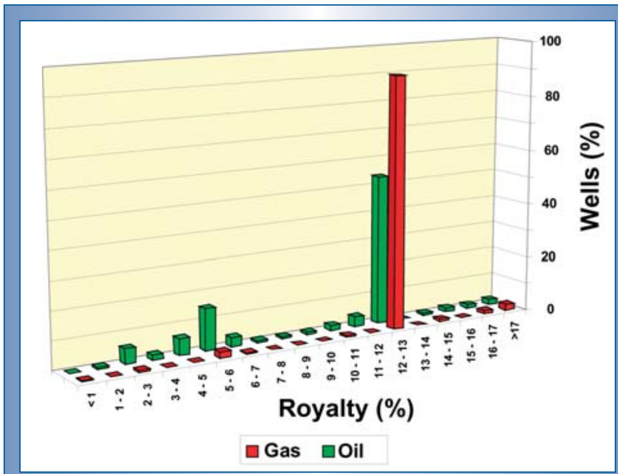

Figure 3. Current royalty rates

production rate or price trigger is exceeded, the incentive will not be allowed for that property.

Incentive starting criteria—The product prices where royalty relief incentives are initiated were identified. These incentives were tied to published prices of West Texas Intermediate (WTI) crude for oil and Henry Hub natural gas prices. There also is a time requirement to make the incentive effective, which is when the average monthly WTI price falls below a threshold for three consecutive months (four consecutive months in the Energy Bill case) or when the average monthly Henry Hub price falls below a threshold price for the same period.

Either price condition can be met for this incentive to be effective. It is possible to have the incentive effective for oil, natural gas or both. There is also a rate qualification – 15 boe/d – or each property. This rate follows a similar qualification time period.

Incentive removal criteria—Once the incentive has been granted, there must be clearly defined price, production and time parameters required to remove the incentive. These match the starting criteria of price and rate qualification. The incentive will be removed when the average monthly WTI or Henry Hub price is greater than the threshold price for three consecutive months. The barrel-of-oil-equivalent rate qualification will follow the same pattern. Three months of high rate will remove the property from the incentive. If the incentive is the Energy Bill, the time period is 4 months instead of 3. When the incentive is removed (because of rate or prices) the incentive starting criteria must again be met to reinstate the incentive. In these analyses, threshold prices were not adjusted for inflation.

Importance of analyses

Federal lands produce one-third of the nation's gas and one-fifth of its oil. The federal lands locations are shown in Figure 1, and the states included are shown in Figure 2.

Data—Data was derived from a variety of sources including, the MMS-Mineral Revenues Division, the BLM and the state of Wyoming. The primary data source was the MMS Oil and Gas Operations Report (OGOR) data system. The MMS Mineral Revenue Division provided monthly detailed OGOR data on a well-by-well basis for all onshore federal and Native American lands from January 1990 to December 2003. This data was used to populate the database required to run the analytical model.

Data processing—The data processed included the lease and agreement number, gas and oil production, depth, primary product, state and county, lease well counts, days on production, water injection or steam injection, BTU content, American Petroleum Institute gravity, number of completions per well, percent of federal lease, percent of private lease and effective royalty. All 16,515 leases were tagged for current stripper, heavy oil and multi-rate royalty relief configurations. The production for each well was accumulated to the lease level.

The gas and oil operating costs were updated through December 2002. The data used was the annual operating cost ($/well). The data provided consists of regional parameters needed to define equations for certain depth dependent gas and oil fixed operating cost equations. Also included are regional values for variable operating costs (based on volume of production) and regional values for G & A costs. The operating costs also took into account the number of completions in each wellbore. Multiple completions had differing operating costs from single ones. For oil leases, these costs also included the primary production operating cost plus the pump operating cost or secondary operating cost for waterflood or steamflood leases.

Figure 4. Example analysis conducted

Oil Price ($/bbl)	Gas Price ($/Mcf)	Constant 12.5% Royalty	Current Royalty Structure	Energy Bill	Energy Bill with Injection
35.00	4.67	✓	✓		
20.00	2.67	✓	✓	✓	✓
18.00	2.40	✓	✓	✓	✓
16.00	2.13	✓	✓	✓	✓
15.00	2.00	✓	✓	✓	✓
13.00	1.73	✓	✓	✓	✓
11.00	1.47	✓	✓	✓	✓

Safety net royalty relief modeling system

The system used to model the proposed safety net royalty relief scenarios consists of two FORTRAN modules designed specifically for this application. The first model performs a hyperbolic decline on historical production for the major product (gas or oil) of the lease/agreement being evaluated and produces a 20-year monthly production prediction. The second model performs a cash flow analysis to determine the economic limit under various price and cost structures. This model has coded into it the series of different royalty relief scenarios proposed by the BLM incentives team as well as the current royalty rates by product. Figure 3 shows the distribution of current royalty rates as of 2003.

For each lease/agreement the economic evaluation model does a monthly cash flow analysis. Included in this analysis are calculating gross revenue, royalty payments based on the royalty structure, state production taxes based on individual state rates and net revenue. The monthly operating cost based on the product, number and depth of wells, fluid production and region in which the lease exists also is calculated. Operating costs are subtracted to calculate income, which determines whether the lease economic limit has been reached. This calculation determines when the lease will be shut-in and when it will be abandoned. As part of determining the economic limit, the model calculates royalty payments and severance taxes paid. This allows comparison between production and royalty payments for differing assumptions of future product prices, operating costs and royalty schemes. A separate model run must be made for each price, cost or royalty scenario. The system is designed to model all the onshore federal lands in the Lower 48 and Alaska.

The results track 20 years of monthly production (gas, oil and water), well count, along with federal and state royalties and severance tax projections. Production and royalty collection is broken up into its federal, Native American and private components. They are aggregated at the lease, state and total U.S. levels, and presented as monthly volumes as well as 20-year summaries.

The secondary product is estimated by multiplying the primary product by the gas-oil ratio or yield derived from historical data analysis. Future water production is estimated by multiplying the primary product rate by the water-oil ratio or the water-gas ratio, also derived from historical data analysis. These results are provided by individual lease, state totals and U.S. totals. A monthly complete cash flow at the individual lease/agreement level is also provided.

Two assumptions made were that the future royalty rate did not change and that distribution between federal and Native American land remained unchanged. The results were then compared to determine the change in gas and oil produced with the change in royalty collected. In effect, the "cost" to the federal and state treasuries of incremental product produced as a direct result of the proposed incentive. Thus the programs traced production and the economic factors on a lease basis.

Two base runs were defined to help analyze the incentives. A current royalty case was run to model the current property royalty status. The royalty rate included existing incentives received, for example, the Stripper Well Incentive and/or the Heavy Oil Incentive.

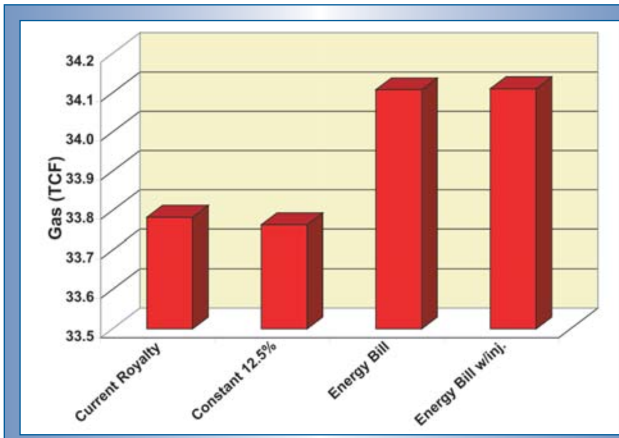

Figure 5. 20-year cumulative gas production

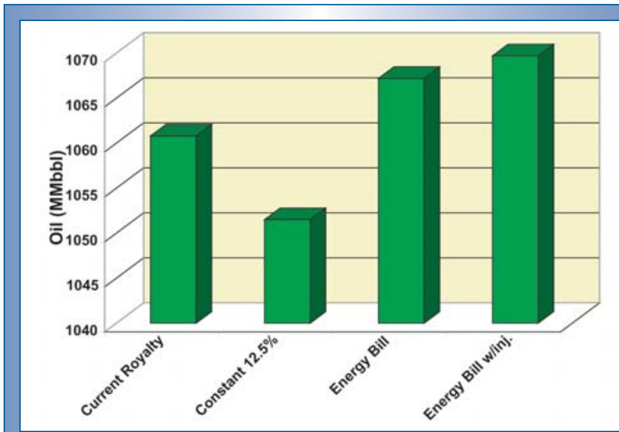

Figure 6. 20-year cumulative oil production

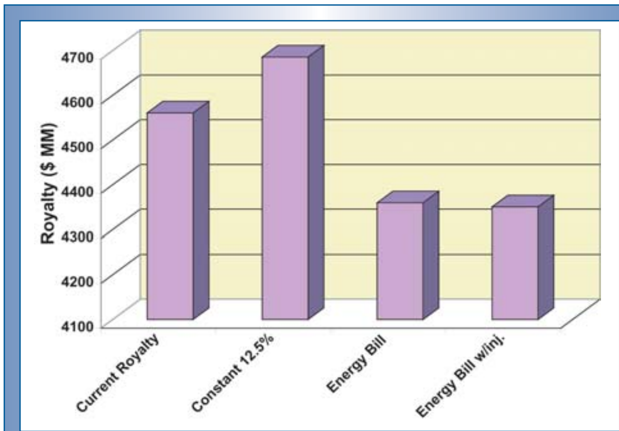

Figure 7. 20-year royalty collections

The second base case assumed that no existing royalty incentives were available. All properties have a constant 12.5% royalty. For comparison, the constant 12.5% royalty case was assumed as a base case and compared to the current royalty case and the two defined incentives cases, the Energy Bill and the Energy Bill with water or steam injection wells days on line used to calculate daily production rates.

The BLM safety net royalty relief analysis results

Overview of Analysis—The set of analyses consisted of 26 model runs. Figure 4 provides a matrix of the model runs performed for the analysis.

The four royalty cases were run using seven constant monthly price tracks. The ratio between oil and gas prices was maintained at 7.5 for each price track. This ratio is derived from the $15.00 and $2.00 price thresholds proposed in the Energy Bill. No runs were made for the proposed Energy Bill cases using the $35 to $4.67 price track since it was not conceived that the threshold oil price for royalty relief would be above $20/bbl or $2.67/Mcf levels.

Incremental comparison of summary results—There is an implicit assumption when analyzing a royalty relief proposal that there will be a benefit defined by production increases. There also is a cost – a loss in public sector revenue because a smaller production percentage goes toward royalty payments. The goal is that there is a scenario where the outcome is "revenue positive," meaning that so much incremental production is stimulated that the amount of royalty collected is greater than it would have been even though the percentage collected per barrel equivalent produced is less.

Three royalty structures at a range of product prices are compared. The three royalty scenarios are the Energy Bill, Energy Bill with injection and the current royalty structure in place today. To evaluate the cost/benefit ratios in a consistent manner, the 20-year summary results are compared to the results of the constant 12.5% royalty case.

All of the scenarios studied were "revenue negative," meaning there was less revenue generated for the federal and state treasury than there would be under a standard 12.5% royalty. Please note that the 12.5% royalty is not the current royalty on many of the leases studied. There is always going to be a cost associated with producing incremental oil by the safety net royalty relief programs being considered. Figures 5, 6 and 7 show the cumulative production of gas and oil as well as the royalty collections at a gas price of $1.47 and an oil price of $11.

Incremental federal and state revenue royalty collected provides the incentive cost. State revenue collected is calculated by adding the state royalty to the state severance tax. Some lost state revenue is offset by the increased severance tax collection. The cost to the federal and state treasury is then provided in a cost per incremental barrel of oil equivalent produced. This is calculated by dividing the incremental federal royalty and the incremental state revenue by the incremental barrel of oil equivalent generated. Finally, the federal cost and state cost are combined to get the total cost per incremental barrel of oil equivalent produced.

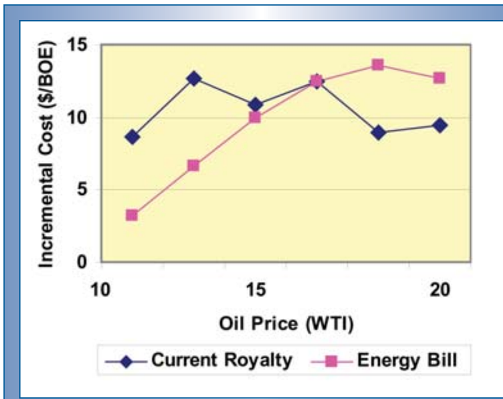

Figure 8. Cost per incremental barrel of oil equivalent vs. product price

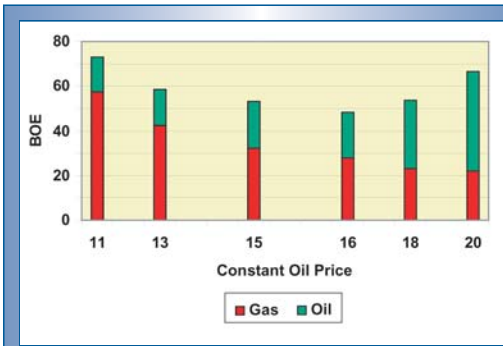

Figure 9. Constant price effect on production

Conclusions

Figure 8 shows that at prices above $15, the current royalty structure is more cost effective even though the Energy Bill scenario produces more barrels of oil equivalent. The reason for this is that the Energy Bill scenarios give royalty relief to gas production whereas the current structure does not. If the results of the Energy Bill runs are examined, the incentives are most effective for oil at higher prices and are more effective for gas as the prices become lower. This is illustrated in Figure 9, which shows the relative proportions of incremental gas and oil generated by the Energy Bill proposal at the various price tracks.

After careful interpretation of the safety net royalty relief model results, six conclusions captured the major points gleaned from this analysis:

- proposed safety net royalty relief proposals will not be revenue generators under scenarios evaluated when compared to the 12.5% royalty payments;
- small incremental production is gleaned under safety net royalty relief scenarios studied;
- gas production is not as sensitive to lower prices as oil production in the ranges considered;
- cost effective to include injection days on line for incentive to increase production;
- proposed Energy Bill incentives are more cost effective at lower prices; and
- proposed Energy Bill incentives at higher trigger prices are more expensive than current royalty structures.

The study is completed with the final report issued. The BLM has used the incentive analyses as basis to promulgate new royalty rules. ✧

Acknowledgements

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Regulatory Considerations in the Management of Produced Water—A U.S. Perspective

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There are a number of U.S. regulations of which to be aware and consider when managing produced water domestically.

The process of producing oil and natural gas generates large quantities of water produced from the same underground formations. Management of this produced water represents a significant cost component in the production of oil and gas. In the United States, about 20 billion bbl of produced water are generated per year (worldwide, the annual volume is about 70 billion bbl). Management options for produced water are to a large extent driven by applicable federal and state regulatory requirements.

Figure 1. Produced water is discharged to the surface in a coalbed methane gas field. (Photo Courtesy ALL Consulting, Tulsa, Okla.)

In 2004, Argonne National Laboratory prepared a comprehensive white paper on produced water for the U.S. Department of Energy. One chapter reviews U.S. regulatory requirements for produced water. This article offers a summary of that chapter, including a brief overview of the federal laws and regulations that govern management of produced water in the United States. States typically have similar laws and regulations but may also have more restrictive requirements in some cases. Requirements for managing produced water differ substantially throughout the world; a discussion of international produced water management requirements is beyond the scope of this article.

U.S. regulatory requirements

In 1988, the U.S. Environmental Protection Agency (EPA) exempted wastes related to oil and gas exploration and production (E&P) from the hazardous waste portions of the Resource Conservation and Recovery Act. The E&P waste exemption covers produced water. However, exempting E&P waste from the federal law governing hazardous waste management does not preclude regulation of these wastes under other federal or state laws and regulations.

Once produced water has been brought to the surface, the primary management options include discharge to surface water bodies and underground injection for enhanced recovery (pressure maintenance) or disposal. Federal laws have assigned the lead program implementation responsibility for the discharge and injection programs to the EPA. However, willing and able states can seek primacy to run the programs. The following sections describe the major regulatory programs and some of their important requirements.

Discharging produced water

In the oil and gas industry, produced water discharge volume and characteristics can vary considerably; an example of a modest produced water discharge in a Rocky Mountain state is shown in Figure 1. At the other end of the spectrum, some large offshore platforms can discharge tens of thousands of barrels per day (see Figure 2). The Clean Water Act (CWA) requires that a permit issued under the National Pollutant Discharge Elimination System (NPDES) program must authorize all discharges of pollutants to surface waters (streams, rivers, lakes, bays and oceans). The two basic types of NPDES permits issued are individual and general. Individual NPDES permits are specifically tailored to individual facilities. General NPDES permits cover multiple facilities within a certain category in a specific geographical area. General permits control most offshore oil and gas discharges.

Under the CWA, the EPA has the authority to implement the NPDES program or it may authorize states to implement all or parts of the national program. Once approved, a state gains the authority to issue permits and administer the program. However, the EPA retains oversight responsibilities, including the option to review the permits issued by the state and formally object to elements deemed in conflict with federal requirements. In cases where states have not been approved, the

Table 1 – EPA's national ELGs for produced water discharges.

ELG Subcategory	Oil and Grease Limit	Comments
Offshore	*29 mg/l average* *42 mg/l maximum*	
Coastal	*Zero discharge*	*Discharges to Cook Inlet, Alaska, are subject to the offshore limits*
Onshore	*Zero discharge*	*Applies to all onshore wells except those covered by the stripper or agricultural and wildlife subcategories*
Stripper	*No national requirements; these are left to permit writer discretion*	*Applies to wells producing less than 10 b/d of oil; no comparable section for small gas wells*
Agricultural and wildlife use	*35 mg/l maximum*	*Applies to wells west of the 98th meridian; produced water must be used for agricultural or wildlife purposes*

Figure 2. An offshore platform in the Gulf of Mexico. (Photo by J. Veil, Argonne National Laboratory)

EPA's regional offices directly implement the NPDES program. Examples of important gas-producing states that do not currently implement the NPDES program for oil and gas discharges include Texas, Oklahoma, New Mexico and Alaska.

Discharge limits—NPDES permits contain numerical effluent limits that control discharges of pollutants to receiving waters. These generally are stated as average and maximum concentration limits (in mg/l) but can be expressed as loading limits (in kg/day) depending on the circumstances. Permit writers derive effluent limits using technology-based standards and water quality-based standards. The more stringent of the two will be written into the permit.

Effluent limitations guidelines (ELG)—These are national technology-based minimum discharge requirements developed by the EPA on an industry-by-industry basis that embody the greatest pollutant reductions economically achievable for an industry sector or portion of the industry, for example, offshore oil and gas platforms. Existing facilities must meet a performance standard known as best available technology economically achievable.

The EPA has developed five subcategories of ELGs for the oil and gas industry. The terms onshore, offshore and coastal may be illustrated by drawing an imaginary line that runs along the coast of the country. The line crosses the mouth of rivers, bays and inlets. Any facility to the ocean side of the line is an offshore facility. Any facility to the land side of the line and on land is classified as an onshore facility. Any facility in or on the water or in wetlands on the land side of the line is a coastal facility. For example, a facility in a marsh or inside a river mouth or bay is a coastal facility. The EPA has codified the ELGs in the Code of Federal Regulations (CFR) at 40 CFR Part 435. The national ELG requirements for produced water are discussed in the next paragraphs. Table 1 provides a quick overview.

The ELGs for offshore wells establish limits for oil and grease of 29 mg/l average and 42 mg/l maximum. Oil and gas activities in coastal waters may not discharge produced waters, except for platforms in Cook Inlet, Alaska, which is treated in the same manner as offshore waters.

The produced water requirements for onshore wells are divided into three subcategories. As a general rule, onshore oil and gas activities may not discharge produced water. However, two subcategories provide exceptions to the onshore rule. The agricultural and wildlife water use subcategory allows those onshore facilities west of the 98th meridian (a north-south line running approximately through the center of the country) to discharge produced water that is fresh enough to be beneficially used in agriculture or wildlife propagation. These discharges must meet a maximum oil and grease limit of 35 mg/l and be used for agricultural or wildlife purposes. The second exception that allows for onshore discharges is the stripper subcategory. It applies to facilities that produce 10 b/d or less of crude oil. The EPA has published no national discharge standards for this subcategory, effectively leaving any regulatory controls to the states. The gas-producing community may be interested to note that the stripper subcategory applies only to small oil wells and not to small or marginal gas wells.

Why oil and grease —The EPA chose to limit oil and grease as an indicator of many other chemical compounds. Oil and grease is not a single chemical compound, but a measure of many different types of organic materials that respond to a particular analytical procedure. Not all produced waters contain the same constituents even if they have the same oil and grease content. Oil and grease is made up of at least three forms:

- free oil (this is in the form of large droplets are readily removable by gravity separation methods);

- dispersed oil (this is in the form of small droplets that are more difficult to remove); and
- dissolved oil (these are hydrocarbons and other similar materials dissolved in the water stream; they are often challenging to remove).

Depending on the distribution of oil and grease in a produced water type, operators must employ different types of treatment processes to meet the applicable discharge requirements.

Water quality-based limits and other permit conditions—ELGs serve as a foundation for the effluent limits included in a permit, but the ELGs are based on the performance of a technology and do not address the site-specific environmental effects of discharges. In certain instances, the technology-based controls may not be strict enough to ensure the aquatic environment will be protected against toxic quantities of substances. In these cases, the permit writer must include additional, more stringent water quality-based effluent limits and other monitoring and operational requirements in NPDES permits. The water quality-based limits may be numeric or narrative. The EPA has published numeric water quality criteria for more than 100 pollutants that can be used to calculate water quality-based limits *(http://epa.gov/waterscience/standards/wqcriteria.html)*. A narrative limitation would use language like "no toxic substances in toxic quantities." The process for establishing the limits takes into account the designated use of the water body, the variability of the pollutant in the effluent, species sensitivity (for toxicity), and, where appropriate, dilution in the receiving water (including discharge conditions and water column properties).

Four of the EPA's regional offices have issued general permits to authorize produced water discharges to ocean and coastal waters. The EPA's general NPDES permits impose additional numerical limits on toxicity and include different combinations of limits or monitoring requirements for other parameters such as metals, organics, radionuclides and nutrients. The permits also include operational, monitoring, testing and reporting requirements. Veil et al. (2004) describes the four most important general permits for oil and gas exploration, development and production operations issued for the Eastern Gulf of Mexico (Region 4), Western Gulf of Mexico (Region 6), California (Region 9) and Cook Inlet, Alaska (Region 10).

Figure 3. A Class II injection well (Photo by J. Veil, Argonne National Laboratory)

No centrally compiled information exists on the permits that have been issued under EPA's agricultural and wildlife subcategory. Veil (1997) identified the states that had issued stripper well discharge permits at that time and described the permit requirements.

Coalbed methane (CBM) discharges—CBM production activities are somewhat different from conventional gas production in that water is intentionally pumped from coal seams to lower pressure, thereby allowing production of the gas. CBM produced water may contain far lower total dissolved solids and oil and grease than produced waters from other gas or oil wells because CBM water has been in contact with coal seams rather than crude oil in the formation. The EPA did not consider CBM production when it established its oil and gas industry ELGs and has not yet revised its ELGs to include CBM discharges. In the absence of national ELGs for CBM water, some state regulatory agencies have chosen to issue NPDES permits allowing discharges of CBM water using their own best professional judgment.

The regulations that govern water discharges from CBM wells, as well as those that do not apply, are described in a 2002 report, describing the permitting procedures and limitations Alabama, Wyoming, Montana and Colorado use. Each state provides for somewhat different permitting procedures and discharge standards. In general, the states require limits or monitoring for oil and grease, salinity (such as chlorides, total dissolved solids or conductivity), pH, total suspended solids and toxicity. Similar requirements may be in place for other contaminants. In practice, the CBM producers who are currently discharging can meet the permit limits through a minimal degree of treatment. Interest in CBM discharges has intensified since 2002. The permitting agencies continue to shape new policies and permit conditions.

Injecting produced water

Most onshore produced water is injected for enhanced recovery or disposal. Injection is regulated under the Underground Injection Control (UIC) program. Injection wells related to oil and gas operations are known as Class II wells (Figure 3). The EPA has delegated UIC program authority to many states, which then regulate injection activities to ensure protection of underground sources of drinking water (USDW). Each state has somewhat different specific requirements but generally they include the following elements:

Area of review (AOR)—Applicants for new Class II injection well permits must identify within the injection well's AOR (often a one-quarter mile radius) the location of all known wells that penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within AOR penetrating formations affected by the increase in pressure.

Construction requirements—All new Class II wells must be sited to inject into a formation separated from USDW by a confining zone free of known open faults or fractures within the AOR. Class II wells must be cased and cemented to prevent fluid movement into or between USDW.

Operating requirements—The operating requirements in UIC Class II permits must specify a maximum injection pressure that will not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDW. Injection pressure must not cause the movement of fluids into USDW.

Mechanical integrity testing—Well owners or operators must demonstrate the internal and external integrity of their injection wells. This includes the absence of significant leakage in the casing, tubing, or packer of the injection wells.

Monitoring and reporting—Owners/operators must monitor the nature of injected fluids (at least once within the first year of authorization and thereafter whenever changes are made to the injection fluid); injection pressure, flow rate and cumulative volume at various frequencies specified in the regulations (weekly for disposal wells and monthly for enhanced recovery wells); mechanical integrity (at least once every 5 years); and other operational statistics. Owner/operators must submit at least an annual report of the monitoring results. In addition, well failures or other well-specific activities (including corrective action) must be reported.

Plugging and abandonment—Injection wells that have not been in operation for 2 years must be plugged and abandoned unless special precautions are taken to avoid endangerment of USDW. Prior to abandonment, Class II wells must be plugged with cement in a manner that will not allow movement of fluids into or between USDW.

Veil et al. (2004) provides a detailed description of the injection programs from several large oil- and gas-producing states (Texas, California, Alaska and Colorado), and two federal agencies that oversee activities of federal lands (onshore – Bureau of Land Management and offshore – U.S. Minerals Management Service).

Requirements relating to other management options

The previous sections described regulatory requirements for discharging or injecting produced water. Increasingly, oil and gas producers are considering ways they can reuse produced water or convert it to a commercial commodity. Some examples for reuse of produced water include livestock watering, crop irrigation, fire control, vehicle washing, cooling water and process water in a power plant and use in making drilling fluids. No national regulatory standards apply to these activities. Individual states may place restrictions on certain types of reuse options.

Research is being conducted to investigate the desalination of produced water for beneficial use for community water supplies. If that technology becomes economically viable and is used to produce drinking water, the treated water would be subject to all applicable federal and state drinking water regulations. The regulatory details are not discussed here because produced water is not currently used for human consumption. Desalination may also be used to treat produced water for reuse for irrigation or livestock. These uses are not subject to drinking water regulations but may be subject to other state or local requirements.

Summary

Most offshore produced water is discharged to the ocean under the provisions of NPDES general permits. Most onshore produced water is injected for enhanced recovery or disposal under a Class II UIC permit. The NPDES and UIC programs are administered by the EPA or through delegation by state agencies. Discharge requirements vary substantially depending on whether the well is onshore or offshore and where it is in the United States. Most states have adopted their own UIC requirements that include various operational and management provisions to protect USDW. ✧

Acknowledgements

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Volume-Optimized Compressed Natural Gas

By John P. Dunlop, P.E. and Charles N. White, P.E., *EnerSea Transport LLC*

Recent trends in the overall growth of global energy demand and the preference for natural gas within the mix of fuel supply choices has spawned a resurgence in the development of natural gas projects as well as the acceleration of new technologies to help connect stranded gas resources and consuming markets.

The maritime transport industry is engaged in a wide-ranging program for the construction of liquefied natural gas (LNG) carriers, including evolutionary designs, to support the current wave of new LNG projects. At the same time, EnerSea Transport LLC and other natural gas innovators also are leading a critical but less visible role through their development of a new generation of compressed natural gas (CNG) marine transport and storage systems that promises to establish an additional and valuable commercial means for shipping natural gas.

Figure 1. EnerSea Transport's V-800 compressed natural gas carrier.

This article will focus on the design features of EnerSea's innovative "Volume-Optimized" CNG technology and how it may be applied to improve the prospects for remote and stranded gas development. It will explain the key considerations and challenges that have been reflected in the designs and how this new gas ship concept opens a new world of remote and offshore field development opportunities (Figure 1).

CNG marine transport allows emerging, energy-hungry markets around the globe to access additional gas supplies that otherwise would continue to remain stranded. As compared with other solutions for de-stranding gas resorces, such as LNG and gas-to-liquid technologies, CNG transport offers a solution that reduces the amount of fixed-asset investment required as well as the amount of gas lost because of process energy requirements and boil off, to name a few reasons. Such value-adding features make the recent breakthrough in CNG storage and handling technologies, and the new class of ships that support CNG transport operations, attractive to gas and power players on a global scale.

Volume-optimized natural gas transport technology

Natural gas is a complex fluid that exhibits non-ideal gas properties when compressed above about 1,000 psi.The non-ideal characteristics can be accommodated by adjusting the Ideal Gas Law through the introduction of what is commonly called the compressibility factor or Z-factor. The gas industry has conducted extensive research on the phase behavior of natural gas, including predictive models to characterize the Z-factor effects in gas compression engineering. EnerSea's volume-optimized transport and storage (VOTRANS™) technology recognizes the relationship between the design requirements of containment systems and the Z-factor effect in gas storage design. By chilling gas to a suitably low temperature (usually well below 32°F), it is possible to compress great quantities of gas into tubular containers such that the ratio of the weight of the gas stored to the weight of the container is optimized, thus providing significant cost improvements over previous CNG designs.

Achieving an optimum design requires the storing of this cool gas at relatively moderate pressures – about 1,400psi to 1,800psi, depending on gas composition – which is about half that of traditional "ambient temperature" CNG designs. This critical design breakthrough means the compression horsepower requirement and its cost, along with the gas cargo container and ship hull costs, can be substantially reduced. These savings are somewhat offset by costs for refrigeration and insulation, but the net cost advantage and operational benefits demonstrate the value of volume optimization in the containment design.

Gas handling considerations

VOTRANS also employs a unique system for efficiently handling the transfer of gas cargo into and out of the cargo storage system. A patented liquid displacement system provides the ability to control pressure and temperature of the gas throughout the processes. By controlling backpressure when loading gas into the containers, temperature extremes created by auto-refrigeration and heat of compression effects in traditional CNG designs can be avoided. Using the displacement fluid as a piston to push the gas cargo out of the containers at the discharge terminal also prevents the automatic cooling of the gas and dropout of natural gas liquids.

An important feature of EnerSea's liquid displacement gas-handling technology is that this approach allows substantial transport system design and cost efficiency advantages. This capability enables the storage and transport of richer gas streams, such as gas associated with oilfield production. The low temperature compressibility characteristics of rich gas allow even more cargo to be stored, and at lower pressure in lighter and less expensive containers, than for a lean gas cargo. Because of the high-energy content of the rich gas cargo, the economics of gas transport can be attractive for transit distances up to 3,000 nautical miles.

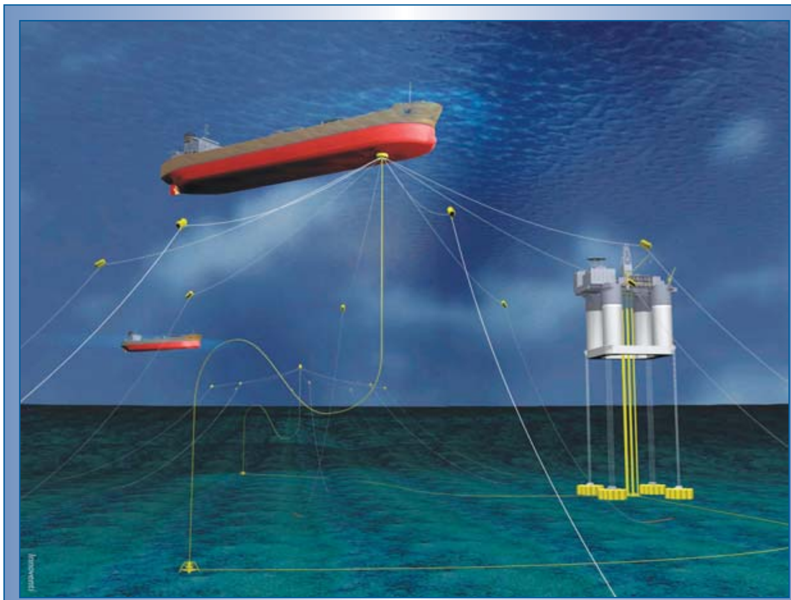

Figure 2. A schematic of Heidrun field with two submerged turret loading buoys. (Graphic courtesy of APL)

Gas cargo handling and storage

To limit the amount of time at the loading and unloading terminals, VOTRANS ships can be configured to include dynamic positioning systems for connection to an efficient bow loading or single-point mooring buoy system, or internal turret device similar to the APL shuttle loading system installed at Norway's **Heidrun** field (Figure 2). Generally, the shipboard gas-handling system design assumes the gas arrives on board at a pressure that allows the gas to be injected into the storage containers at the relatively low temperatures and pressures allowed by the volume-optimization principles noted above.

Loading is expected to take place at a rate corresponding to the production rate of the field being serviced such that the cargo containers are usually filled in 2 days to 3 days. Uninterrupted field production operations can be supported through the use of a dual-buoy loading terminal configuration.

At the gas delivery terminal, it also is desired to limit turnaround time. Therefore, the ship utilizes the liquid displacement system to dispel the gas cargo from storage in an efficient and controlled manner. Once the CNG ship is properly connected to the delivery terminal, gas is discharged through the internal turret to a flowline that ties into a subsea pipeline connection. Pumping capacity usually is designed to discharge the cargo within 24 hours. The displacement liquid is kept chilled and carried in insulated tanks with enough capacity to support a sequential, cascading displacement operation.

Container design

Vertically oriented steel cylinders ("pipe tank" bottles) are incorporated within chilled, nitrogen-inerted and insulated cargo holds for the current VOTRANS ship designs (Figure 3).

The gas cylinders are fabricated from high-strength steel pipes with end caps and nozzles produced for the specific project requirements. The pipes and heads must be made from high-strength materials that provide low temperature toughness in the as-welded condition. Current designs are based on specially developed API 5L X80 pipes at least 42-in. in diameter.

The gas cylinders may be considered to be pressure vessels and generally are designed to meet American Society of Mechanical Engineers (ASME) Section 8 Div3 under special Code Case considerations for the intended service. Det Norske Veritas (DNV) and the American Bureau of Shipping (ABS) have developed guidelines that will allow rational/probabilistic design methods to demonstrate suitability for marine service and class. Design pressure, cylinder diameter and material strength are the primary determinants of wall thickness and weight of the individual cylinders.

Ship Design and Development Status

Design evolution

A discussion of key design drivers or constraints illustrates the evolution of the current VOTRANS CNG carrier designs. These key drivers include:

- regulatory and class requirements;
- mission requirements (gas cargo characteristics and required storage capacity);

- construction and commissioning considerations; and
- operability.

Because of the status of this emerging industry, many potential beneficiaries have inquired about the ability of a marine CNG transport project to gain regulatory approval. These queries were largely answered during the successful 1st International Marine CNG Standards Forum held last June at Memorial University of Newfoundland, under the sponsorship of The Centre for Marine CNG (*www.cmcng.org*). This event gathered together a highly distinguished delegation comprised of many CNG developers, energy companies, shipping companies, leading professional organizations (such as SIGTTO and ASME) and class societies, as well as key maritime administrations and representatives from other governmental oversight agencies. The official communiqué of the forum noted that the state of guidance for classification and regulatory purposes is well advanced, and that alignment across the industry was a practical goal. The forum leadership also recognized that the CMCNG was positioned to play an important role in advancing the state of the technology toward practical standards and implementation.

The International Gas Carrier (IGC) Code provides the foundation for establishing a pathway to regulatory approval. However, because the IGC Code did not adequately anticipate large-scale marine CNG transportation projects, ABS and DNV have prepared guidelines or rules to more fully address the critical features of safety review for classification. A safety case approach, involving intense hazard identification and mitigation exercises, as well as quantitative risk assessments, complement the codes and guidelines to ensure safe designs as well as operating practices.

Having completed the initial complement of hazard identification and operability studies, the overarching consensus of the reviewers is that CNG fleets can meet, and possibly exceed, the level of safety established by the maritime LNG industry.

Inspection and maintenance considerations influence the dimensioning of, and arrangements within, the holds. Accessibility requirements are well recorded in existing Rules for Marine Vessels. In the VOTRANS system design approach, periodic visual inspection of cargo cylinders and associated piping is supplemented with a continuous integrity monitoring system based on acoustic emissions (AE) technology. All manifolds are instrumented with AE sensors such that critical areas of all tanks can be monitored throughout the service life. If indications of developing critical situations are recorded, individual manifold groups can be temporarily or permanently decommissioned. Because of the high degree of segregation and low probability of failure, there is currently no intention to remove, replace or repair any individual cylinders. Instead, a failing cylinder can be permanently isolated from a manifold tank group at the next scheduled dry-docking so the tank group may then be recommissioned into service.

Mission requirements clearly provide a competitive edge for the volume-optimized CNG design, as this technology allows for excellent flexibility relative to the design of facilities and the fleet dedicated to a specific project.

Market opportunity reviews have led EnerSea to focus on ship designs with a cargo capacity range of 500 MMscf to 1,000 MMscf. Although VOTRANS technology may be applied for horizontal or vertical pipe tank configurations, EnerSea has determined that vertically oriented tanks are appropriate for the intial target range of cargo capacities.

The VOTRANS systems are capable of accomodating a wide range of gas compositions and supply conditions with limited gas handling facilities installed on the CNG carriers. When a dry, sweet gas stream is supplied at a pressure adequate to charge the containment system (about 1,400psi for rich streams and up to 1,800psi for leaner gas when storing the gas at -22°F), onboard gas handling facilities are minimal.

Construction and commissioning

Construction and commissioning operations require early consideration when generating the ship design and project management plan. CNG carriers represent a new class of vessels that will challenge the capabilities of traditional shipyards. Only capable, progressive shipyards will be prepared to undertake the complete project to deliver a fleet of CNG carriers. If the containment system is too heavy or the hull lines are too fine, the ship cannot be completed in or ever enter a dry-dock. As an alternative, gas cargo systems may also be fabricated, installed and commissioned quayside at a specialized fabrication facility. Therefore, alternative construction scenarios have evolved that may not wholly depend on a single shipyard.

VOTRANS CNG carriers may be designed so they can be completed in dry-dock because the containers provide a low enough lightship weight to allow float out with all equipment onboard.

Ship operability

Operability targets are in many ways the most complex to address in achieving a practical implementation of a significant new technology. The overall ship dimensions were driven by a need to maintain and repair the vessel during its service life. Maximum available drafts at repair facilities around the world constrained the design draft in the repair condition (basically lightship). The maximum lightship draft is, therefore, targeted to be substantially less than 26ft, based on a worldwide survey of all major repair shipyards. This constraint drives the overall length and beam, with an associated reasonable block coefficient, to arrive at a lightship displacement within the draft limits that can be accommodated at multiple repair facilities worldwide.

Ship speed, and hence installed power, is driven by many factors including gas production rate, distance to market, economical ship speed and fleet size.

The power required for propulsion sets the minimum size of the power plant. However, depending on the offloading rate requirements, a large power load may also be allocated for cargo handling processes. This set the stage for an all-electric ship rather than a low speed diesel with separate electric power generation system. A twin-screw arrangement was chosen, in part because of the small change in draft between light ship and full load, and also to provide for additional overall vessel system redundancy.

The choice of prime mover and type of fuel was set after discussions with ship operators regarding availability of ship engineers trained in the operation of gas turbines vs. heavy fuel oil diesels. Dual fuel diesels (gas and heavy fuel oil) can also be considered but, because of the CNG cargo system's inherent capabilities, gas boil-off will not occur as it typically does in LNG tankers. To maximize delivery of the gas, heavy fuel oil prime movers may often be specified. For projects where refuelling and fuel availability are concerns or supply gas is distinctly less valuable than bunker fuel, the dual-fuel option deserves consideration.

A high degree of cargo system monitoring and automation has been incorporated into the design to minimize the size of the crew. Limited additional crew training will be required to ensure safe operation of the cargo loading and offloading systems. Most of these systems are extensions of existing marine systems though maybe somewhat larger, such as the cargo cooling system.

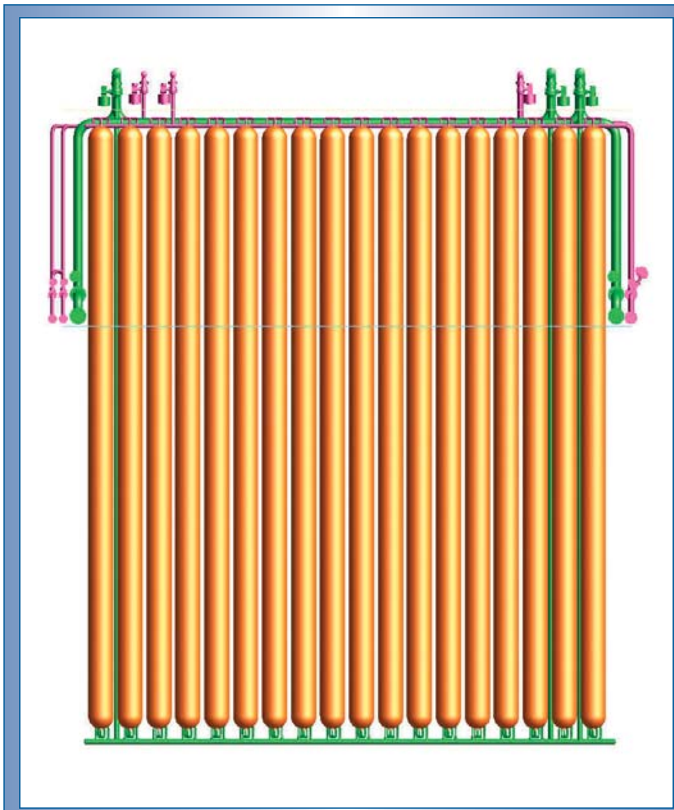

Figure 3. VOTRANS cargo module with manifold piping and valve arrangements.

CNG carrier development status

ABS granted EnerSea "Approval in Principle" for the design and operating plans for a generic V-800 VOTRANS ship in April 2003. The V-800 ships are notionally designed to carry up to 800 MMscf of rich gas. Subsequent ship design concepts being considered for new project-specific opportunities are taking onboard the lessons learned from that design exercise and the interactions with the knowledgeable review team at ABS.

EnerSea has ensured design and technology development is in line with commercial project development status. Front-end activities for a number of CNG project application opportunities were underway at the end of last year. Announced early phase project studies include Oil Search Ltd.'s Papua New Guinea-New Zealand venture, Husky Energy's White Rose gas development in offshore Newfoundland and GAIL (India) Ltd.'s gas importation project for eastern India.

Concurrently, a multi-million dollar technology validation program is moving into the final phases with participatory commitments and funding from clients and key suppliers. This validation program features both a functional testing program with the Gas Technology Institute, and a full-scale cold temperature fatigue and burst test program of the cargo cylinders. Additional special topic studies and analyses are complementing the main technical objectives with investigations into fracture/fatigue toughness and cold jet gas release thermodynamics. These strategic investigations combine to support decision-making hurdles with key clients and timely development of the foundation for possible ASME Code Case applications.

Conclusions

Large-scale marine transport of CNG is now imminent as confirmed by the announcements of a number of early stage project-engineering initiatives. Advancements on many fronts – technology, regulatory (standardization), and project opportunities – have been achieved that are bringing this new industry to realization within the near term.

The innovative features, advantages and concepts of volume-optimized CNG marine transport, as well as the progress described herein, demonstrate how this promising technology is developing a leading position in the creation of an important new gas transport solution for the upstream industry and energy-hungry markets in need of additional gas supplies. ✧

Project Selection Meeting Recap

The Stripper Well Consortium (SWC) selected 13 projects for funding in 2005 at its annual project selection meeting in San Antonio on March 8-9. The total value of the projects selected is $2,459,564, of which $1,547,192 will be funded by the SWC. The abstracts for the selected projects, as well as those for previously funded projects, can be found on the SWC Web site at *www.energy.psu.edu/swc*. Some of the projects selected include:

- "Field Application of Accurate, Low Cost Portable Production Well Testers" – Oak Resources, Inc.;
- "Interaction of Nitrogen/CO_2 Mixtures with Crude Oil" – The Pennsylvania State University;
- "Uncovering Bypassed Pay in Central Oklahoma Using Statistical Analysis and Field Tests" – Schlumberger Consulter Services;
- "Re-fit Two Stripper Wells with Existing Large Diameter or Open Hole Completions with Spoolable Non-metalic Tubing, Transition Connections, Variable Diameter Seal Cups and Modified G.O.A.L. Casing Swab to Automatically Lift Fluids and Enhance Performance" – Brandywine Energy & Development Co.;
- "Desalination of Brackish Water and Disposal into Waterflood Injection Wells" – Texas A&M University;
- "New Technology for Unloading Gas Wells" – Colorado School of Mines; and
- "Building and Testing a New Type of Vacuum Pump for Casinghead Pressure Reduction in Stripper Wells" – W & W Vacuum & Compressors Inc.

Methane Hydrate Research Cruise Underway

The semisubmersible drilling vessel *Uncle John* entered the Gulf of Mexico on April 17 for a 35-day methane hydrate research voyage. During the U.S. Department of Energy Fossil Energy supported expedition, researchers will collect drilling, logging and coring data from deep well pairs in the Keathley Canyon and Atwater Valley locations to characterize methane hydrates in the deepwater Gulf. The mission is part of the Gulf of Mexico gas hydrates joint industry project (JIP) led by ChevronTexaco in cooperation with the National Energy Technology Laboratory (NETL). The JIP is a 4-year effort to develop technologies for locating and safely drilling through or near gas hydrates. Data collected during the cruise will help researchers understand how natural gas hydrates can trap oil or gas in shallow reservoirs, affect seafloor and wellbore stability and influence climate change. The Strategic Center for Natural Gas and Oil area of the NETL Web site is providing background project information, status reports and pictures from the cruise. For more information, visit *www.netl.doe.gov/*

New Microhole Technology Projects

The U.S. Department of Energy (DOE) has marked another key milestone in its research and development initiative to develop "microhole" technologies aimed at slashing the costs and reducing the environmental impacts of drilling America's oil and gas wells. The DOE announced the award of funding for 10 projects designed to push microhole technology another step closer to commercialization and widespread adoption by the U.S. oil and gas industry. The initiative involves developing technologies associated with drilling wells smaller than 4¾-in. in diameter and related downhole micro-instrumentation. The ultimate result of industry broadly embracing this technology could be a sea change in the way the nation's oil and gas producers explore for, drill and monitor wells. *www.netl.doe.gov/scngo*

Events

5th International Conference on Gas Hydrates

June 13-16, Trondheim, Norway. For more information, visit www.icgh.org/

IPAA Mid-Year Meeting

June 15-17, San Francisco. The focus of this meeting will include the future of crude oil as it relates to global supply and demand and the role China, India and the Pacific Rim will play in the coming years; Canada's oil sand reserves and extraction challenges; the future of crude oil and exploration and production trends; and an official from Mexico's Department of Energy will address the country's outlook for supply and demand during the next decade as well as discuss opportunities South of the U.S. borders.

Society of Petroleum Engineers Conference

Oct. 9-12, Dallas. For more information, visit www.spe.org

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