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Technology Developments in Natural Gas Exploration, Production and Processing

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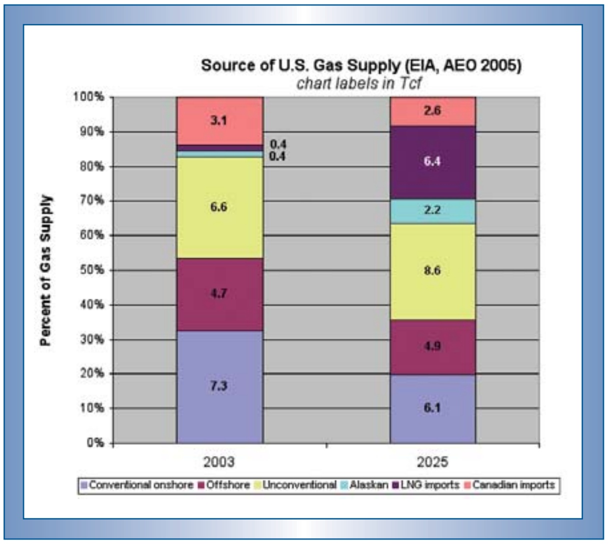
Commentary

Importance of Unconventional Gas and LNG Expected to Grow

The Energy Information Administration (EIA) recently published its 2005 Annual Energy Outlook. One of the biggest changes compared with last year's report is in the expectation for long-term (2025) domestic natural gas production. The EIA now believes production will increase from 19.1 Tcf in 2003 to only 21.8 Tcf in 2025, rather than the 24.0 Tcf projected last year. The lower number is a result of revised expectations for reserve growth (slower), discoveries (fewer), and exploration and development costs (higher). The EIA expects the lower 48 states' onshore natural gas production to increase from 13.9 Tcf in 2003 to a peak of 15.7 Tcf in 2012 before falling to 14.7 Tcf in 2025. The offshore gas production for those states is projected to increase in the near term from 4.7 Tcf in 2003 to 5.3 Tcf by 2014, because of the development of some large deepwater fields, and then decline to 4.9 Tcf in 2025.



Meeting the growing U.S. demand for gas supply will depend primarily on additional unconventional domestic production, imports of liquefied natural gas (LNG) and a new Alaskan pipeline. Unconventional natural gas production is now projected to grow from 6.6 Tcf in 2003 to 8.6 Tcf in 2025. Total net LNG imports are projected to increase from 0.4 Tcf in 2003 to 6.4 Tcf in 2025, about one-third more than last year's EIA projection of 4.8 Tcf. Completion of an Alaskan natural gas pipeline within the next decade could add about 2 Tcf to the lower 48 states' supply by 2025.

These projections reveal that incremental contributions (by source) toward meeting 2025 U.S. gas demand likely will be distributed unevenly: offshore (2%), unconventional (20%), LNG (60%) and Alaska (18%). While negotiations recently have begun to determine just how the risks related to building an Alaskan gas pipeline might be distributed among public and private entities, if barriers to construction lead to delays, the shift toward unconventional gas resources and LNG imports will increase.

Fortunately, these two sources continue to remain important areas of focus for research at the National Energy Technology Laboratory (NETL) and the Gas Technology Institute (GTI). In this issue of ***GasTIPS***, we highlight several examples.

An article from Ticora Geosciences wraps up a three-part series on unconventional gas reservoir property analysis. This project assessed the geology and production potential of a number of frontier play areas, and this article targets the Western Interior Coal Region of the North America (eastern Kansas and Oklahoma, and western Missouri) in particular.

A second article describes a collection of new products designed to help operators manage produced water, particularly in many of the unconventional gas development areas of the Rocky Mountains. *The Produced Water Atlas* collects and displays information useful in developing water management plans. *The Produced Water Decision Tree Model* provides a tool for streamlining water management decisions using basin level data on costs, regulatory issues and disposal practices.

Two more contributions to this issue of ***GasTIPS*** focus on LNG. One describes three modeling tools, developed with GTI's assistance, that can help LNG terminal developers and others understand potential fire and explosion hazards resulting from accidental releases at specific sites. The second is a summary of the research needs identified at the U.S. Department of Energy's (DOE) LNG Roadmap workshop in Houston last November. The strategies outlined at this meeting will provide the framework for new DOE research efforts related to LNG facility siting and the safe and effective use of LNG within the existing gas delivery infrastructure.

Delivering natural gas to the U.S. consumer during the next 20 years, at a reasonable price, will require new supply sources. Continued efforts to develop and expand the technologies that enable these sources are an important aspect of the NETL research portfolio. Past program successes in bringing unconventional gas resources, like coalbed methane and tight sands, into commercial production highlight the benefits of DOE's programs. ✧

The Editors

Note: The EIA's Annual Energy Outlook 2005 is available for download at www.eia.doe.gov/oiaf/aeo/index.html/

Advanced Simulation Technology for Combined Percussion and Rotary Drilling and Cuttings Transport

By Michael Bruno, Gang Han
and Claudia Honeger,
Terralog Technologies USA, Inc.

Basic research is required to advance simulation technology and help industry more economically recover vast untapped gas resources contained in deep, hard rock environments.

Development of more efficient and lower cost drilling technology will significantly increase gas production by allowing economic exploitation of difficult formations, such as deep, hard rock reservoirs. The estimated yearly cost to drill hard rock in the United States exceeds $1 billion. Potential savings of $200 million to $600 million are possible if the penetration rate in hard rock can be doubled while maintaining bit life, according to Tibbitts et al.

There is evidence the combination of percussion and rotary drilling techniques can potentially provide significant improvement in rate of penetration in hard rock environments (see review by Samuel, 1996). In addition to faster penetration, other benefits include the ability to use lower weight on bit, less contact time with rock and therefore less abrasion and longer bit life, improved hole deviation control and generation of larger cuttings allowing improved geologic interpretation. These potential and theoretical advantages for combined percussion and rotary drilling, however, have not been consistently demonstrated in the field.

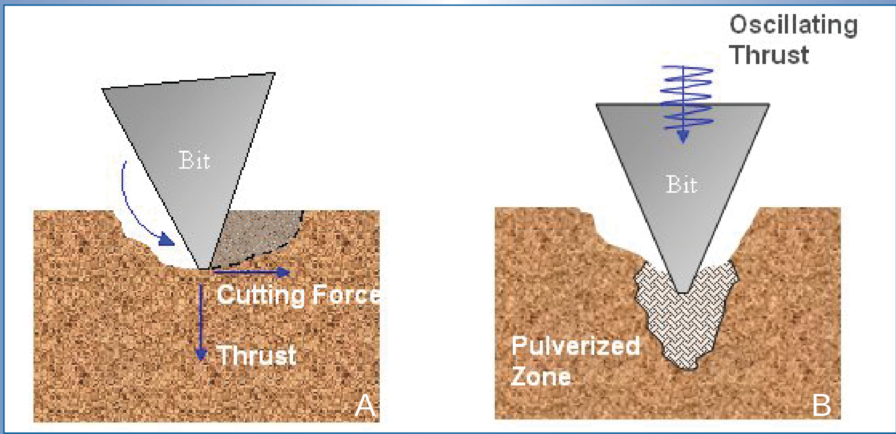


Figure 1. Rock damage process for rotary (a) and percussion drilling (b).

The fundamental rock mechanics processes associated with combined percussion and rotary drilling have not been fully defined and adequately modeled, and there are no practical simulation tools available to help design and optimize drilling operations. This has led to cost and reliability concerns, limiting the widespread application of percussion drilling by industry. Terralog Technologies, with partial funding provided by the U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL), is pursuing a comprehensive research program to significantly advance fundamental understanding of the physical mechanisms involved in combined percussion and rotary drilling. The project team, headed by Terralog Technologies and supported by TerraTek, has extensive and unique experience and capabilities in fundamental rock mechanics, geomechanical simulation, and full-scale rock mechanics and drilling experiments. The research program includes three primary efforts:

- analytical investigations to develop an improved understanding of the fundamental rock mechanics processes involved in percussion drilling;
- development of advanced simulation technology for the drilling process taking into account coupled structural, particle and fluid flow mechanics; and
- investigation and validation of these improved characterization and modeling approaches with full-scale laboratory experiments.

Background

In rotary drilling (Figure 1a), the bit rotation produces impact and shearing forces. The thrust on drag bits provides a penetrating force normal to the direction of movement that breaks the bond holding the rock particles together. The stress (energy) is built up until relieved by the formation of tension or shear fractures along the direction of thrust. While the impact creates compression, a cutting force perpendicular to the penetrating

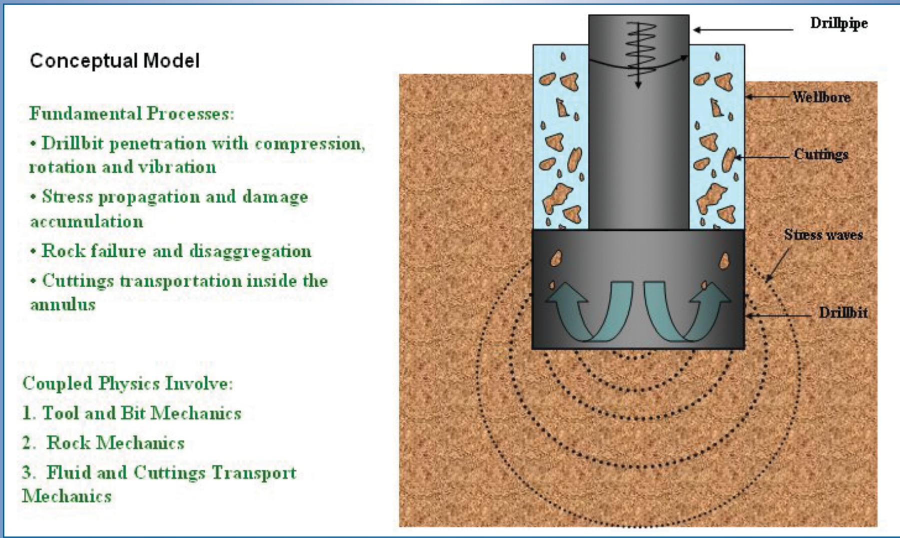


Figure 2. Conceptual drilling model and physical processes.

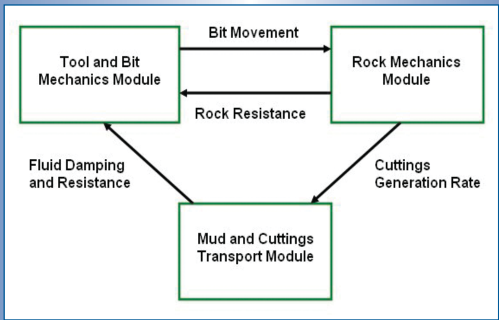


Figure 3. Coupled simulation software.

direction may cause tensile fractures that extend from the bit tip to the rock surface at about 80°. Chip formation occurs discontinuously ahead of the drag bit, and the penetrating and cutting forces oscillate during cutting.

In percussion drilling (Figure 1b), the bit and cutter oscillate axially to impact the rock, imparting compression loads. Developed by the Chinese more than 4,000 years ago, percussion drilling first involved the raising and dropping of heavy piercing tools to cut and loosen earth materials. In 1859 at Titusville, Pa., Col. F. L. Drake completed the first oil well using a cable tool percussion-type machine. One of the earliest reports of percussion drilling technique was documented in 1949. Since then, different terms have been used, such as downhole hammer, percussion hammer, percussive drill and percussive-rotary drill.

Percussion drilling with and without rotation has been shown to improve rate of penetration in some hard formations, such as siliceous granite, sandstone, limestone and dolomite. In addition to a faster penetration, other benefits include the ability to use lower weight on bit, less contact time with rock and therefore less abrasion and longer bit life, improved hole deviation control and generation of larger cuttings to allow for improved geologic interpretation.

But the potential and theoretical improvements in drilling efficiency using combined percussion and rotary drilling have proved difficult to achieve consistently in the field. The project's objective is to significantly advance the fundamental understanding of the physical mechanisms involved in combined percussion and rotary drilling, and thereby facilitate more efficient and lower cost drilling and exploitation of hard rock reservoirs.

A conceptual model of the drilling process is illustrated in Figure 2. We attempt to better characterize and simulate for fundamental processes during drilling:

- drillbit penetration with compression, rotation and vibration;
- stress propagation and damage accumulation;
- rock failure and disaggregation; and
- cuttings transport away from the bit face and up the wellbore annulus.

These are coupled physical processes, with different physics related to the tool and bit mechanics, rock mechanics, and fluid and cuttings transport mechanics. A coupled simulation system is illustrated schematically in Figure 3. The tool hits the rock face, imparting an impact and shearing load. The rock provides resistance to the tool motion. As the rock becomes damaged and fails, the solid material becomes crushed and disaggregated and adds cuttings to the mudflow stream. The mud system also may influence the tool and bit movement through damping and pressure resistance.

Tool and bit mechanics

The tool and bit motion can be described through the fundamental structural dynamics equations relating force (F) to the combined influences of mass (M) times acceleration (d^2U/dz), damping (C) times velocity (dU/dz) and stiffness (K) times displacement (U).

$$F_z = M_z\, d^2U_z/dz + C_z\, dU_z/dz + K_zU_z \qquad (1)$$

$$F_\theta = M_\theta\, d^2U_\theta/dz + C_\theta\, dU_\theta/dz + K_\theta U_\theta \qquad (2)$$

There is one structural dynamics equation to define the axial motion, with the subscript z shown in equation (1), and one structural dynamics equation to define the rotational motion, with the subscript Θ given in equation (2). In our coupled model simulation process, we solve the equations for a given time increment and impose displacements onto the rock interface.

Rock mechanics

The rock mechanics system (Figure 4) reacts to that imposed deformation during the given time increment. The elements in the rock system deform and may become damaged or fail during that time period, while at the same time, the rock provides resistance to the tool

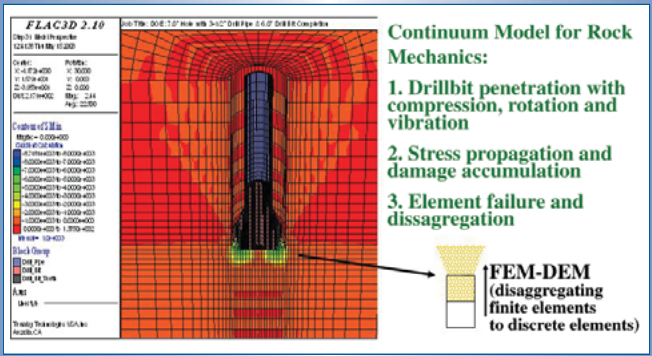


Figure 4. Continuum model for rock mechanics.

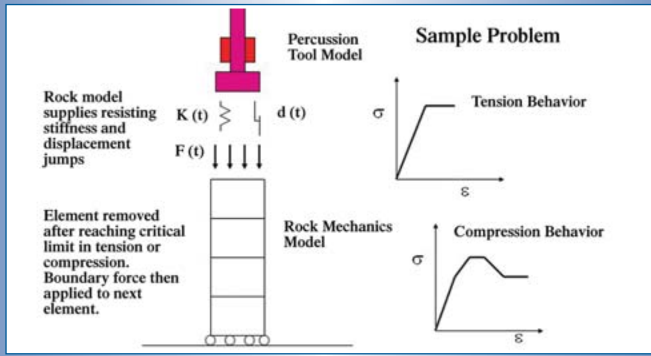


Figure 5. Conceptual for bit and rock interaction and penetration.

advance (through a resisting stiffness). In our geomechanical simulation, we apply a continuum model for the rock system, using the FLAC3D software from Itasca.

Stresses and strains are propagated dynamically through the rock based on fundamental continuum mechanics equations. Application of the continuum of the momentum principle yields Cauchy's equation of motion:

$$\sigma_{ij},_j + \rho b_i = \rho \frac{dv_i}{dt} \tag{3}$$

where ρ is the mass per unit volume, *b* is the body force per unit mass, *v* is rock velocity related to rock displacement (u_i) through $v_i = {du_i}/{dt}$, and the subscripts *i* and *j* are coordinate system indices. The usual summation convention is implied. The rock total strain increment is a sum of elastic strain increment $\Delta\varepsilon^e$, shear plastic strain increment $\Delta\varepsilon^{ps}$ and tensile plastic strain increment $\Delta\varepsilon^{pt}$:

$$\Delta\varepsilon = \Delta\varepsilon^e + \Delta\varepsilon^{ps} + \Delta\varepsilon^{pt} \tag{4}$$

Rock is modeled as a Mohr-Coulomb type of elastoplastic material with strain hardening and softening:

$$\vec{f} = f(\sigma_{ij}, \varepsilon_{ij}{}^p, \kappa) \tag{5}$$

The yield surface *(f)* where rock starts to behave plastically is defined by dynamic stresses (σ_{ij}) calculated from equation (3), plastic strain ($\varepsilon^p = \Delta\varepsilon^{ps} + \Delta\varepsilon^{pt}$) if the stresses exceed the yield surface and a hardening parameter (κ) that describes rock strength behavior with plastic deformation.

Stresses are related to strains through rock properties, and these change during time as material becomes damaged. When a finite rock element becomes sufficiently damaged so as to lose its inherent strength, it will disaggregate into discrete particles. Generally, this occurs across the entire bit face during a given time interval, and the tool and bit penetrates to the next level of elements.

A conceptual one-dimensional model to illustrate this process is shown in Figure 5. The percussion tool oscillates, rotates and impacts the top of the rock column, which resists the movement by supplying a return stiffness. Rock elements may reach their critical strain limit and fail in tension, compression or shear. The element disintegrates into cuttings and induces a small displacement jump in the tool motion as the bit assembly penetrates deeper into the hole.

Coupled simulation

To simulate cuttings transport mechanics, Terralog has developed a coupled fluid dynamics and particle mechanics model that captures not only macroscopic fluid behavior, but also the effect of solid particles on mudflow and interactions among these particles. A particle suspended in a fluid is subjected to a number of hydrodynamic forces. The momentum of a solid particle moving with a fluid can be described as:

$$\rho_p V_p \frac{d\vec{v}_p}{dt} = -\rho_{fl} V_p g + \int_S T \cdot \vec{n} dS \tag{6}$$

where V_p is particle volume, ρ_p is its density, $\vec{v}_p$ is the particle velocity vector, and *T*, representing all forces between fluid and particle, is the instantaneous stress tensor that must satisfy the Navier-Stokes equations. A set of constitutive models are developed to calculate various forces from fluid-particle interactions, such as drag forces because of fluid viscosity and pressure difference across a particle, buoyancy forces and particle collisions. The influence of pipe rotation on fluid transportation is considered through a solution of the circumferential velocity for the Taylor Couette experiment. Analytical solutions are available for laminar, Newtonian flow (with patterns shown in Figure 6), while numerical solutions with the help of computational fluid dynamics solvers are required for turbulent and non-Newtonian flow conditions.

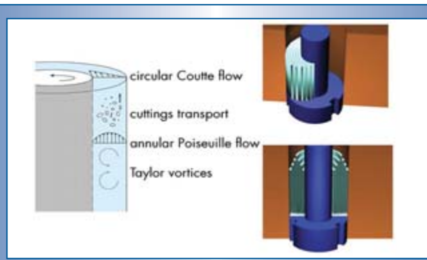


Figure 6. Radial and axial flow and cuttings transport in well annulus.

Particles generated through rock damage are modeled as individual spheres or clumps of particles to simulate irregular blocks and plates. They are introduced into the drillbit slots and then flow along the annulus. Figures 7 and 8 illustrate two sample simulations showing cuttings transport in vertical and horizontal wells for varying bit penetration and mudflow conditions.

Cuttings transport mechanics

The combined models defining the tool and bit mechanics, the rock mechanics and the cuttings transport mechanics are coupled to simulate the complete drilling process.

First, the tool model generates an impact velocity applied to the rock model. The rock model then calculates loading stresses and determines whether rock failure occurs, and if so, how much. The rock properties, including rock stiffness resisting further bit penetration, are then updated based on damage accumulations. The bit model recalculates bit velocity, which is in turn used by the rock model again. This cycle continues until bit velocity is reduced to zero, which indicates the beginning of bit retreat after impact.

The rock model calculates how much volume of rock will fail based on the implemented failure criteria. This will trigger the cuttings transport model to discretize the failed rock into a number of spheres or clumps, which influences fluid viscosity and therefore its velocity, and which also loads the fluid system with additional cuttings particles. Simulations from the cuttings model are used to determine whether failed rock can be efficiently carried away from the bit-rock impact surface.

Efforts and discussion

The next phase of this project will include laboratory testing and validation studies. We will first simulate and test single cutter assemblies, followed by full-scale mud hammer tools for a variety of loading conditions. TerraTek Corp. in Salt Lake City, Utah, will perform full-scale laboratory testing under simulated downhole conditions at its drilling simulation facility. At least six drilling tests would be completed using two rock types. During each drilling test, parameters such as borehole pressure, rotation, axial load, weight on bit, rotary speed, hammer frequency and amplitude will be measured. During each test, we will measure the rate of penetration for varying rotation, hammer frequency and amplitude.

The fundamental rock mechanics processes associated with percussion drilling have never been fully defined and combined into a comprehensive treatise. Critical processes include dynamic load and energy transfer from the reciprocating and rotating drillbit to the rock, geomechanical processes of dynamic damage and fracture at the bit face, and coupled fluid and cuttings particle flow around and away from the bit. This project will advance the state-of-the-art in each of these areas, providing industry with fundamental algorithms to better characterize the drilling process, a revolutionary new type of simulation technology and new laboratory experimental data. ✧

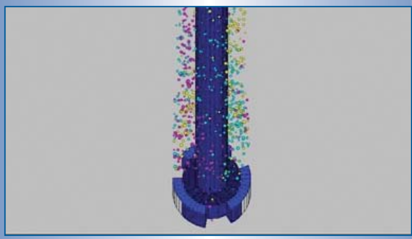


Figure 7. A sample simulation of cuttings transport with high viscosity and high flowrate in a vertical well.

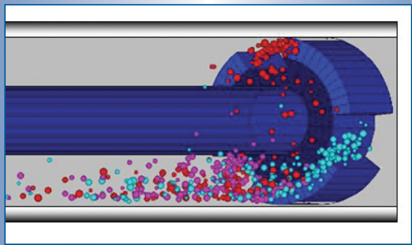


Figure 8. A sample simulation of cuttings transport with low viscosity and low flowrate in a horizontal well.

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Coal Gas Reservoir Assessment — WIC Region

By David P. Young
and Timothy J. Pratt,
TICORA Geosciences, Inc.

TICORA Geosciences, Inc. wraps up a multi-year cooperative research evaluation of the Western Interior Coal Region.

TICORA Geosciences, Inc. (TICORA), with the assistance of Tesseract Corp., have concluded a study of domestic unconventional gas reservoirs titled *Frontier Plays Coalbed and Shale Gas Resource and Production Assessment.* Funded by the Gas Research Institute (GRI) and industry research partners, this project assessed the geology of frontier play areas, advanced unconventional gas reservoir characterization technology and transferred research results to the energy industry. Specific accomplishments included:

- refinement of isotherm technology;
- reservoir characterization and gas-in-place assessment surrounding coreholes drilled by cooperative industry participants (20 wells in nine basins);
- geologic assessment of the Western Interior Coal Region (WIC) of the North American mid-continent (literature research and log interpretation); and
- modeling of possible production scenarios from WIC reservoirs.

This article is a summary of TICORA's research work in the WIC, where in recent years about 3,500 wells have been drilled and completed targeting coal gas, of which about 2,300 are producing, according to T.J. Pratt, et al. The research summarized includes a regional geologic assessment, the experimental results from research coreholes and some examples of production modeling for the WIC reservoirs. The article concludes with lessons learned from the project. The article is drawn from TICORA's topical report *Geologic Assessment of Natural Gas from Coal Seams in the Western Interior Coal Region, USA* and from the Reservoir Property Analysis Reports for individual research coreholes. The reports are available on the company's Web site at *www.ticora.com*.

Geologic overview

The WIC Region is an 85,000-sq-mile, north-northeast elongate tectonic trough in the North American mid-continent in which upper Paleozoic sedimentary rocks were deposited and preserved. It is an area of interest to the unconventional gas industry for the coal gas potential of its Carboniferous coal seams. It is divided into the Forest City, Cherokee and Arkoma basins on the basis of regional variations in depositional history and basement structures described below. Figure 1 illustrates the location of the WIC, the structural features that define it, and the distribution of the Forest City, Cherokee and Arkoma basins.

The basins of the WIC developed in latest Mississippian and Pennsylvanian time when increasing tectonic activity created uplifts and down warped areas across what had been a stable epicontinental marine platform. The Nemaha Uplift primarily defines the western margin of the WIC. It formed a significant escarpment and depositional barrier during most of the WIC depositional history. To the east of the WIC are the Mississippi Arch and Ozark Uplift, platforms elevated during and after the formation of the WIC basins. Pennsylvanian strata thinned across these uplifts and have commonly since been removed, obscuring the original eastern extent of the WIC basins. In the south, the Arkoma basin is bounded by uplifts, which were more active during and after the basin's development, as is reflected in its complex structure and depositional history relative to the rest of the WIC.

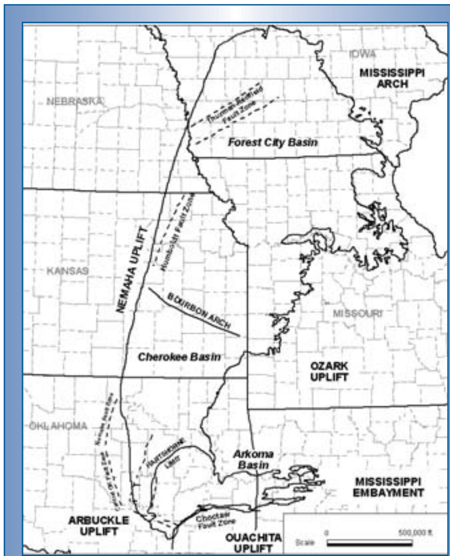

Figure 1. Western Interior Coal Region location and major structural features.

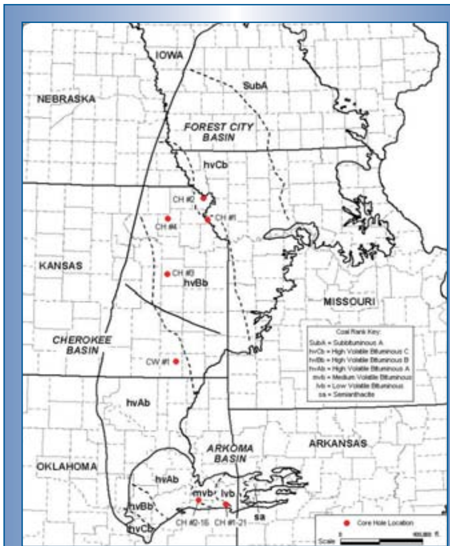

Figure 2. Western Interior Coal Region thermal maturity with research corehole locations.

The Arkoma basin formed earliest, and its northern limit is defined by the pinch-out of its Pennsylvanian Harthshorne formation

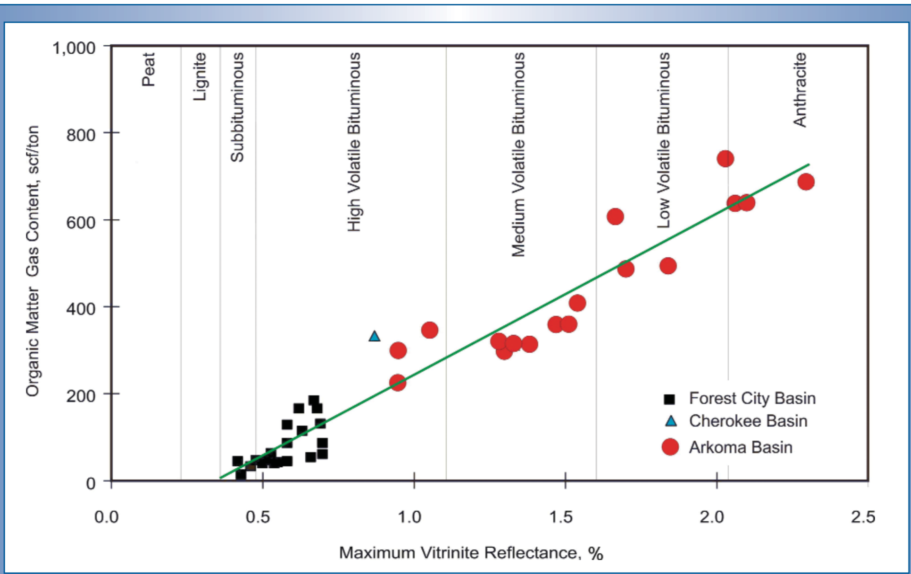

Figure 3. Dry, ash-free gas content vs. coal rank.

(Figure 1). Conversely, much of the younger stratigraphic section of the Forest City and Cherokee basins is absent in the Arkoma basin, having either not been deposited further south, or having been subsequently eroded. The Bourbon Arch, a subtle anticlinal feature, separates the Forest City and Cherokee basins. During their early depositional history, the Bourbon Arch physically separated the two basins. Erosion later breached the arch, and the basins were connected.

The major coal gas targets of the WIC are found in the middle Pennsylvanian Marmaton and Cherokee Groups (Desmoinesian Series). The Marmaton Group conformably overlies the more important Cherokee Group and is mostly comprised of marine shale, limestone and sandstone. The Cherokee Group is comprised of sandstone and shale, with minor limestone and coal. The lower Cherokee Group is terrestrial and sand-dominated in character, and its coalbeds are discontinuous. The upper Cherokee Group contains increasing amounts of laterally continuous marine shale and limestone, and the contained coalbeds also are more laterally continuous. Stratigraphic terminology varies across the region. The Upper and Lower Cherokee Group are known as the Cabaniss and Krebs Subgroups in Oklahoma. In the Arkoma Basin, the important coal gas targets are in the lower Cherokee Group, McAlester and Harthshorne Formations.

The Cherokee Group varies in thickness from less than 100ft at basin margins to more than 800ft in northern Kansas. It hosts at least 57 recognized coalbeds and many more that are thin, discontinuous and unnamed. Coalbeds are typically 2ft to 6ft thick, and generally do not exceed 10ft. Refer to Pratt et al. for gross coal thickness, isopach and other structural maps of the Cherokee group, and further details of WIC structure and stratigraphy.

Thermal maturity (coal rank) is important in coal gas plays. Figure 2 illustrates the generalized coal rank of Cherokee Group coalbeds across the WIC, as well as the locations of research coreholes drilled by El Paso Production Co. and Colt Energy, Inc. in cooperation with this study. These coal rank distributions primarily were determined through a literature survey supported by TICORA's analytical results. Coal rank generally increases from northeast to southwest across the Forest City and Cherokee basins, ranging from relatively immature sub-bituminous A to high volatile bituminous A. Coal rank increases from west to east across the Arkoma basin, reaching a rank of semi-anthracite in Arkansas. Coal rank is locally variable, but generally increases with depth. Elevated geothermal gradients appear to be recorded by coal rank in some areas of the WIC, in that there are higher ranks than can be accounted for by depth of burial alone.

WIC Reservoir Characterization

To increase the scope of publicly available data on coal gas resources, GRI accepted TICORA's proposal to conduct detailed reservoir characterization and assessment in the WIC. El Paso Production Co. and Colt Energy, Inc. became research participants, drilling and allowing access to the seven coreholes listed in Table 1 and shown on Figure 2.

From these coreholes, 197 core samples were collected. Lithologies ranged from coal to carbonaceous shale, intending to provide a sample suite spanning the range of potential reservoir types. The samples were first sealed in desorption canisters for sorbed gas content determination (desorption testing). After desorption, the samples were subjected to an array of other tests TICORA designed to provide the critical data required for comprehensive reservoir assessment.

Table 1. Cooperative Research Coreholes.

Corehole	Basin	County	State	Section, Township, Range	Operator
FCB CH #1	Forest City	Platte	Missouri	S 26, T 54 N, R 37 W	El Paso
FCB CH #2		Doniphan	Kansas	S 6, T 3 S, R 21 E	El Paso
FCB CH #3		Osage	Kansas	S 35, T 15 S, R 14 E	El Paso
FCB CH #4		Jackson	Kansas	S 34, T 6 S, R 14 E	El Paso
Hinthorn #CW 1	Cherokee	Montgomery	Kansas	S 14, T 32 S, R 16 E	Colt
CH #2-16	Arkoma	Haskell	Oklahoma	S 16, T 6 N, R 25 E	El Paso
CH #1-21		LeFlore	Oklahoma	S 21, T 17 N, R 20 E	El Paso

The scope of reservoir characterization included:

- sorbed phase gas analysis (sorbed gas volume, composition and diffusion rate);
- adsorption isotherm analysis (gas storage capacity and initial sorbed phase gas saturation);
- reservoir bulk properties (core lithology, proximate/ultimate analyses, maceral composition, true density and moisture holding capacity);
- coal rank (gross calorific value, fixed carbon content and maximum vitrinite reflectance); and
- gas-in-place resource assessment (seam thickness/density determination and seam-specific, *in-situ* gas content calculation for standardized drainage areas).

All laboratory procedures conformed to “best practices protocols” developed by TICORA. The body of results from the characterization exercise is extensive, and best summarized in Pratt, et al’s article.

Comparing the corehole results from numerous reservoirs and across all three basins illustrates some interesting relationships, especially the influence of coal rank on gas content, storage capacity and sorption time.

Figure 3 illustrates the correlation between dry, ash-free gas content and coal rank. Coal rank is determined through gross caloric value, fixed carbon content or maximum vitrinite reflectance, depending on coal rank. For comparative purposes, Figure 3 classifies coal rank using only vitrinite reflectance, which is a petrographic technique that measures the reflectance of light from organic particles, which increases with thermal maturity. Gas content is determined through desorption testing. The results show a progressive increase of gas content with increasing coal rank. The highest gas contents were returned from Arkoma Basin anthracite samples. While the trend of increasing gas content with increasing coal rank is important, note that for any given coal rank, there is a range of measured gas contents. Comparing dry, ash-free basis coal properties effectively removes the effect of dilution by inorganic material, allowing for better direct comparisons.

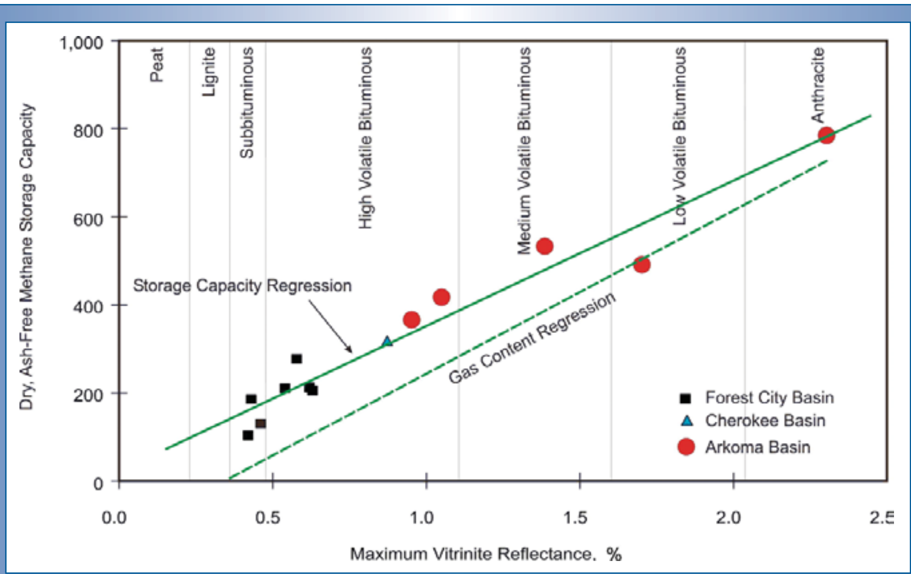

Figure 4. Dry, ash-free methane storage capacity vs. coal rank.

Figure 4 illustrates a positive correlation between increasing coal rank and increasing dry, ash-free methane storage capacity. The highest storage capacities were returned from Arkoma Basin anthracite samples.

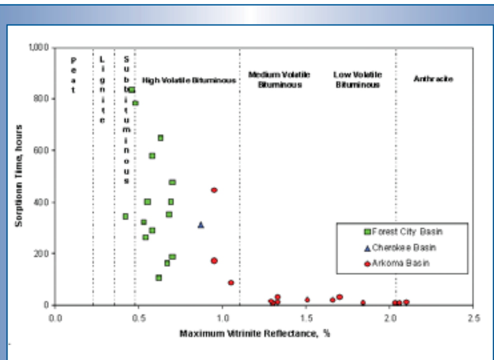

Figure 5. Sorption time vs. coal rank.

Storage capacity, derived from the results of volumetric adsorption isotherm testing, is a measure of the amount of gas that a material can sorb and increases with increasing pressure. Storage capacity calculated for reservoir pressure is compared to measured gas content to determine reservoir initial saturation. Isotherm results also are used to calculate abandonment volume and are a crucial input for production modeling. In this study, storage capacity was completed for an assumed reservoir pressure gradient of 0.4 psi/ft, which may overestimate the true reservoir pressure and therefore overestimate the storage capacity.

In Figure 4, the solid trend line shows the methane storage capacity. The dashed trend line shows gas content results from Figure 3. As expected, the coals are undersaturated (storage capacity exceeds the gas content). Note however that as rank increases, the gas content approaches the storage capacity (initial saturation increases). This is important because the greater the initial saturation, the lesser the pressure reduction required to initiate gas production.

Figure 5 illustrates a negative correlation between increasing coal rank and sorption time, and shows a distinct break between the high volatile bituminous and medium volatile bituminous ranks. Sorption time is defined as the time required to desorb 63.2% of total gas content and is inversely related to diffusivity. Longer sorption time might equate to lower production rates.

Utilizing the study’s analytical results, TICORA estimated gas-in-place volumes surrounding each corehole (Figure 6). These

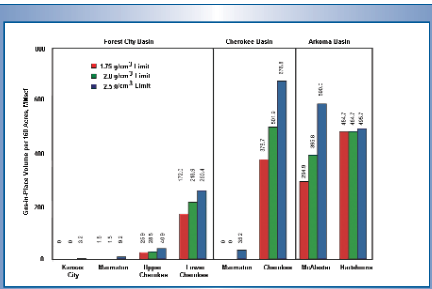

Figure 6. WIC gas-in-place volume comparison (MMscf/160 acres).

volume estimates are specific to the corehole locations, and caution should be used when extrapolating these results to surrounding areas. The degree to which the corehole locations are representative of surrounding areas is unknown.

Gas-in-place volume was calculated using the following formula:

$$G=1{,}359{,}7Ah\rho G_c$$

where:

G = gas-in-place volume, scf

A = reservoir area, acres

h = reservoir thickness, feet

ρ = average in-situ rock density at the average in-situ rock composition, g/cm^3

G_c = average *in-situ* gas content at the average *in-situ* rock composition, scf/ton.

Typically, laboratory results, such as gas content as a function of sample density, from a statistically valid number of core samples are combined with bulk density and reservoir thickness interpreted from high-resolution geophysical logs for the calculation of gas-in-place. Reservoir thickness is based on a chosen density cut-off value, above which it is assumed that gas contribution will be minimal (gas content generally decreases with increasing sample density). Gas-in-place calculations also require the specification of a drainage area. This can be chosen on the basis of reservoir permeability, anticipated well spacing or arbitrarily. The results in Figure 6 are calculated for an assumed 160-acre drainage area. This study was atypical in that entire reservoir intervals were collected for testing, eliminating the need of log interpretation.

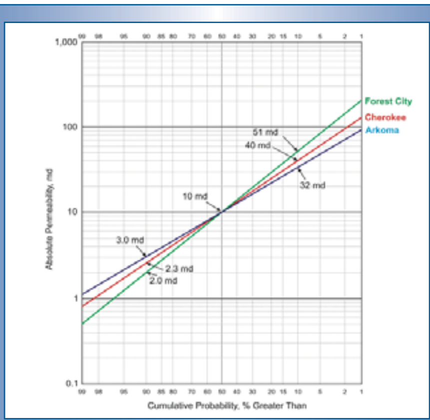

Figure 7. Mid-continent region possible absolute permeability distributions.

Figure 6 illustrates the gas-in-place volumes from Forest City Basin coreholes are relatively low. Furthermore, as shown in Table 2, the Figure 6 volumes are the summation of the volumes from numerous, thin seams (average of 14 seams per corehole). Cherokee Basin and Arkoma Basin gas-in-place volumes are greater. Again though, the Cherokee Basin Cherokee Group gas-in-place volume is the summation of 11 narrow coal seams spread over a stratigraphic interval of more than 400ft. In contrast, the Arkoma Basin Hartshorne Formation gas-in-place volume is from one or at most two seams, with the thicker seam ranging from 3ft to 5ft in thickness.

Figure 6 also illustrates the importance of recognizing the contribution of gas from higher density reservoir intervals for the purpose of gas-in-place calculations. While coal is commonly identified in open-hole log data as rock with a density equal to or less than 1.75 g/cm^3, there can be a substantial volume of gas contained in the organic component of carbonaceous shale having densities as high as 2.5 g/cm^3. The graphic contrasts gas-in-place volume estimates using density cut-offs of 1.75 g/cm^3, 2 g/cm^3 and 2.5 g/cm^3.

Potential gas productivity modeling

Ideally, productivity modeling utilizes permeability data measured from well test and laboratory studies. Unfortunately, no permeability data were collected as part of this project. As a substitute, lognormal permeability distributions were estimated for each basin on the basis of past experience with coal permeability ranges, primarily from the Cherokee Basin. Figure 7 illustrates the estimated cumulative probability that absolute permeability might exceed a given value. The permeability values are expressed in millidarcies (md), a standard unit of measure for permeability.

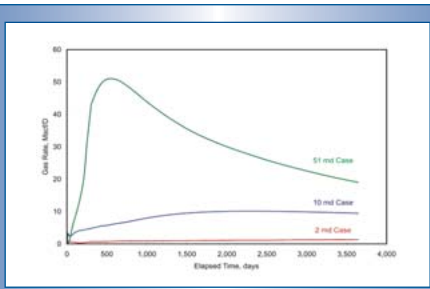

Figure 8. Arkoma Basin CH No. 2-16 Hartshorne potential gas productivity.

Potential gas productivity for vertical wells was modeled using the corehole analytical results and the estimated permeability distributions described above. Figure 8 demonstrates a simulation that forecasts gas productivity from an Arkoma Basin Hartshorne Formation vertical well as a function of time. The three gas productivity cases illustrated correspond to the 90%, 50% and 10% probable permeability values from Figure 7. Gas production rates are given in thousands of standard cubic feet per day (Mscf/d). Productivity modeling demonstrated in Pratt, et al's article addresses a variety of WIC reservoirs and production scenarios for vertical wells, including enhanced gas recovery and carbon dioxide sequestration scenarios.

Conclusions and lessons learned

This research study demonstrates the types and usefulness of reservoir properties that can be determined from the analysis of core samples. It is possible to contrast the areas represented by the research coreholes and demonstrate clear differences. While it should not be expected that the results from such a limited number of research coreholes are representative of entire basins, the regional trends suggested are generally valid.

Experimental results from the research coreholes studies demonstrate the following for coal gas systems in the WIC:

- increasing gas content with increasing coal rank;
- increasing gas storage capacity with increasing coal rank; and
- decreasing sorption time (i.e., faster rate of diffusion) with increasing coal rank.

In addition, a trend of increasing gas saturation with increasing coal rank is suggested, but this trend is less certain owing to the wide ranges of gas content and gas saturation possible for any given coal rank.

The corehole experimental results generally agree with the results of TICORA's literature-based geologic assessment in defining regional variations in coal rank. Rank increases to the southwest in the Forest City and Cherokee basins and to the east in the Arkoma Basin, with the highest observed rank (semianthracite) found in the Arkoma Basin. Storage capacity, gas content and sorption time results all point to Arkoma Basin coals as having the most favorable properties for commercial gas production.

Relative to other WIC reservoirs tested in the research coreholes, the Arkoma Basin Hartshorne seam is also an attractive coal gas target in that it is comprised of a single, 3-ft to 5-ft thick seam, or at most two seams, simplifying drilling and completion logistics in comparison with the combinations of thinner, stratigraphically separated seams typical of the Forest City and Cherokee basins. The Hartshorne seam geometry may be especially favorable for horizontal drilling completions rather than vertical completions. As an example of the potential of this reservoir, Lexington Resource recently announced an initial production rate of 500 Mcf/d to 600 Mcf/d from a 2,000-ft vertical completion in the Hartshorne, and this rate is expected to incline with further dewatering. The Hartshorne seam is being aggressively developed and may be one of the most successful horizontal completion plays in North America.

Table 2. Numbers and Thicknesses of Seams Included in GIP Calculation

Basin	Forest City	Cherokee	Arkoma
No. of Coreholes	4	1	2
Average Number. of Seams Included in GIP Calculation	14	11	7
Seam Thicknesses (ft)	0.1 – 3	0.1 – 2.5	1 – 5

The gas productivity modeling performed for the research coreholes was compromised by a lack of measured permeability and reservoir pressure data. These data are now readily available from well testing, and TICORA's newly developed *PermLab*[sm] is an example of a modern, reliable, accurate and cost-effective water injection-falloff well test system. These systems are able to operate in reservoirs ranging from very high to very low permeability and across a wide range of reservoir pressure. Utilizing properly measured coal property data, such as *in-situ* gas content, density and storage capacity, as were determined from TICORA's research, in combination with accurate well test data (reservoir pressure and permeability), modern software is able to simulate fluid deliverability with a high level of sophistication. The company is engaged in modeling the expected results of vertical vs. horizontal completions and other production scenarios for the Hartshorne and other reservoirs.

If a reservoir's gas content can be reasonably established, even qualitatively, then it may be prudent to measure reservoir permeability, pressure and gas storage capacity early in the assessment of a coal gas play. Productivity potential could then be utilized as a screening tool, in advance of over-investing in core analysis or blindly over-drilling a non-productive area. Through the collection of the proper data at the proper stage of coal gas exploration and development, operators are provided cost effective ways to greatly minimize their risk. ✧

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Gas Hydrate Storage Process for Natural Gas

By R.E. Rogers,
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and Yu Zhong, R. Arunkumar, J.A. Etheridge, L.E. Pearson, J. McCown and K. Hogancamp, *Diagnostic Instrumentation & Analysis Laboratory, Mississippi State University*

A Department of Energy-sponsored laboratory project had as an objective the development of a process to safely store natural gas aboveground primarily as a peak-load fuel for electrical power plants. The study led to a conceptual process for economically storing natural gas in gas hydrates for industrial use.

Gas hydrates are clathrates where the guest gas molecules are occluded in a lattice of host water molecules. With all cavities of Type I structure occupied by methane molecules, the volume ratio of gas (at standard temperature and pressure) to water can be as high as 185. In 1942, M.E. Benesh first proposed using this unique hydrate property to store natural gas. Conceptual investigations have been carried out during the past five decades to do this in gas hydrates. Even though the investigations proved the concept of storing natural gas in hydrates technically feasible, applications stayed in the laboratory stage because of complexities of the process, slow hydrate formation rates and costs.

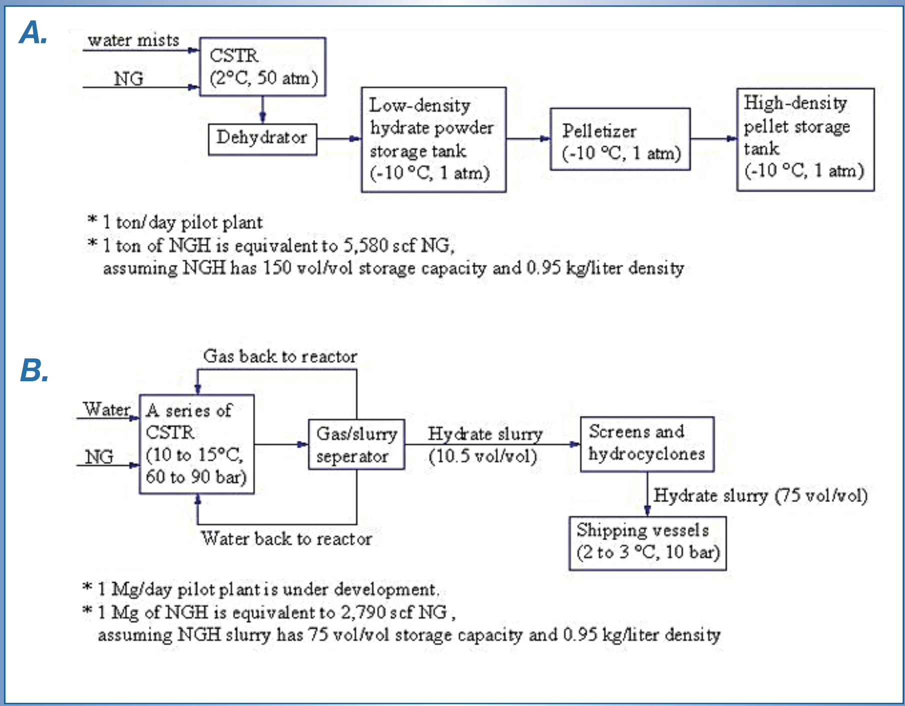

Figure 1. A – Japanese Hydrate production process (MES, 2002) and B – BG slurry hydrate production process (Fitzgerald, 2001).

Study at Mississippi State University

Mississippi State University (MSU) has been conducting investigations into storing natural gas in gas hydrates since 1991 with the goal to develop this technology on a practical and economical basis. In the patent of R.E. Rogers and G.Y Yevi, natural gas was proposed to be stored on vehicles in gas hydrate form as an alternative fuel for gasoline or diesel. Their work also stressed the practicality of key issues to be solved for gas hydrate storage.

In 1997, the U.S. Department of Energy (DOE)/National Energy Technology Laboratory awarded a grant to the hydrate research laboratory at MSU to determine the feasibility of storing natural gas in gas hydrates for electric power plant use at peak loads. The successful laboratory feasibility study then led to a second DOE-sponsored project to demonstrate and test the process at a proof-of-concept scale of 5,000-scf natural gas storage.

Storing and transporting associated gas

In addition to the project at MSU, storage and transportation of natural gas in hydrate form recently have been investigated, primarily in Japan, Norway and England.

Japan seeks commercialization of a natural gas hydrate process to compete with liquefied natural gas (LNG) in transportation. Pilot plants capable of generating 600 kg to 1,000 kg of gas hydrates per day are under construction or testing in these countries. Figures 1 and 2 show diagrams of the different processes.

The Japanese process and Norwegian

dry process have the following common characteristics:

- a hydrate slurry is formed in a high-pressure, continuous stirred tank reactor;
- a series of treatments pack the low-energy-density slurry into high-energy-density dry hydrate; and
- natural gas hydrates are stored and transported at atmospheric pressure and temperature of 1°F or lower.

British Gas Group (BG) keeps the gas hydrates in slurry state throughout the formation, storage and transportation process. Because of the hydrate slurry's lower energy density than LNG, multiple tankers would be necessary to compete with a single LNG tanker.

The Japanese, British and Norwegian processes are designed primarily to transport natural gas in competition with LNG.

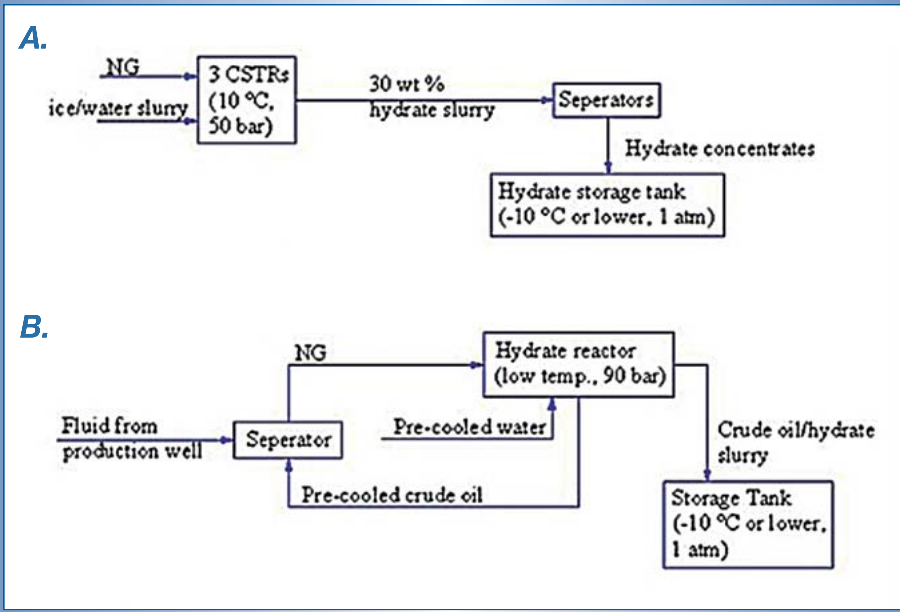

Figure 2. A – Norwegian dry hydrate process (Gudmundsson and Hveding, 1995) and B – Norwegian crude/hydrate slurry process (Gudmundsson and Mork, 2001).

Experimental

Equipment, MSU Laboratory Feasibility Study—The laboratory equipment was designed to study the feasibility of a non-stirred system to occlude natural gas in gas hydrates with a minimum of labor. A simple hydrate formation/storage/decomposition tank without any moving parts was preferred to reduce maintenance, labor and capital costs. Ordinarily, it could take days with distilled water to initiate the nucleation of hydrates and achieve appreciable growth in a non-stirred system. Even after hydrate nucleation is initiated in a quiescent system, a thin solid film forms across the gas/liquid interface that separates the gas and liquid phase, thus significantly slowing hydrate formation. Also, when gas hydrate crystals mature, as much as 80% to 90% of interstitial waters of the crystals may remain unreacted.

The result was a 3,800-ml, 304 stainless steel, laboratory hydrate test cell of 4-in. diameter with a removable top blind flange sealed with a Teflon gasket. The laboratory cell has the following basic capabilities:

- warm or cool pressurized cell contents upon demand;
- monitor pressure and temperatures in cell;
- view contents and video record when desired, as process proceeds;
- collect data continuously and store on computer; and
- maintain constant pressure while measuring inlet gas flow.

Stainless steel cooling coils of three-eighths-in. diameter surround the test cell. A separate set of coils protrudes into the bottom half of the cell. Water-glycol solution circulates through the coils from two independent, constant-temperature baths that can be alternately cooled or heated. The refrigerated baths maintain ± 0.01 K of the set point to as low as 253 K. Insulation encloses the test cell and exterior cooling coils. A transducer and resistance temperature detector (RTD) probes monitor pressure and temperatures. A Tescom Corp. model 26-1026 constant-pressure regulator maintains a desired pressure in the test cell as gas occludes into hydrates; the regulator can maintain a pressure within ± 6.9 kPa. Flow rate of gas into the test cell during hydrate formation is monitored with an Omega Engineering model FMA-8508 mass gas flow meter that has a capability of 0 sccm to 5,000 sccm, at an accuracy within 1% of full scale and a repeatability of within 0.25% of flow rate.

An Omega Engineering data acquisition system records the outputs from mass flow meter, RTDs and pressure transducers on a computer.

A model AG 204 Mettler analytical balance is used to weigh surfactant. Powdered sodium dodecyl sulfate (SDS) purchased from Strem Chemicals Inc. was used in the tests; the 98%+ pure SDS (with no alcohols in the residuals) has a molecular weight of 288.4 g/mol. Double-distilled water was used in the surfactant solutions.

A representative natural gas purchased from Matheson contained 90.01% methane, 5.99% ethane and 4.00% propane, as analyzed by a model 6890 Hewlett-Packard gas chromatograph using a HPPLOT-Q column and a flame ionization detector. Ethane of 99.6% purity from Matheson Gas Products was used in some preliminary experiments to establish procedure at less stringent test conditions prior to verification with natural gas.

Procedure, MSU Laboratory Feasibility Study—Initially, surfactant-water solution

Figure 3. Typical hydrates formed in a chilled test cell during a 5-day to 10-day period.

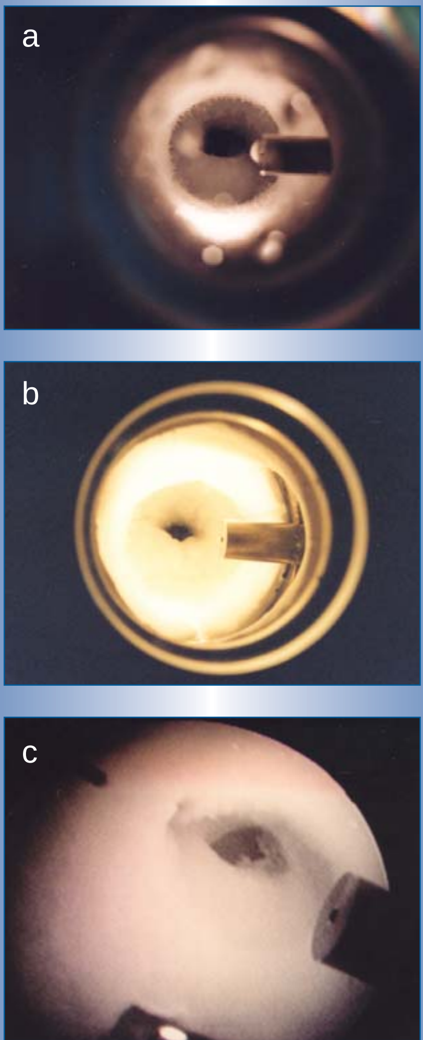

Figure 4. These images show the symmetrical pattern of hydrate accumulation and a reduction in time of hydrate formation by adding sodium dodecyl sulfate.

was pumped into the empty cell to displace all gases. The hydrocarbon gas was then injected to displace water to a predetermined water level. For example, this level could be selected to be along the line of sight of a camera probe. Liquid completely covered the internal cooling coils. The system was cooled to 275 K to 278 K under a pressure too low for hydrates to form. Pressure was then raised to the operating pressure during a 2 minute to 3 minute span by flowing pre-cooled gas into the cell; measurement of gas mass admitted was made with a flow meter. Hydrate formation was tracked through monitored temperatures, pressures and mass flows continuously displayed and recorded on the computer. During the experimental run, cell interior was observed on a TV monitor, and the video was recorded with commentary on videotape.

Results

Results from the successful laboratory feasibility study were used to design a scaled-up proof-of-concept process. Three major achievements as a consequence of using surfactant solutions led to the scale-up:

- gas hydrate formation rates in the non-stirred system were increased by orders of magnitude;
- hydrate particles were self-packed as they formed in the formation vessel; and
- interstitial water of the hydrate mass was reacted to near completion.

Gas-hydrate formation rates—If a gas hydrate storage process is to be practical for industrial applications, then natural gas must be occluded in gas hydrates at a rapid rate. This property coupled with the economic requirement of a non-stirred system, creates a particularly difficult problem because a pressurized and chilled quiescent water/natural-gas system develops a thin hydrate film at the water-gas interface that acts as a barrier to mass transport. Figure 3 illustrates hydrates typically formed in a chilled test cell during a 5-day to 10-day period in which a hydrocarbon gas pressurizes a distilled water phase. A slow, random growth of hydrate crystals is evident.

R.E. Rogers and Y. Zhong found that by adding about 284 ppm of SDS, the rate of formation could be increased by a factor greater than about 700.

Physical properties, such as surface tension, of water-surfactant solutions change abruptly at the critical micellar concentration (CMC) where surfactant molecules organize and orient their hydrophilic heads and hydrophobic tails. However, the concentration of 284 ppm SDS used effectively in the experiments was well below the CMC measured to be about 2,700 ppm at ambient conditions. It was found by repeating pressure, temperature and surface area in the test cell while varying SDS concentration that hydrate induction time decreased rapidly with SDS concentration until a threshold concentration was reached at hydrate-forming conditions, whereupon no further decrease occurred with added surfactant. This threshold concentration at hydrate conditions was found to be about 242 ppm. It is thought that increased solubility of hydrocarbon gases in the water at hydrate-forming conditions may increase SDS solubility at these low temperatures and enhance micelle formation to the lower 242 ppm.

Self-packing of gas hydrates—The photographs in Figure 4 show a reduced time of hydrate formation and symmetrical pattern of hydrate accumulation by adding SDS to the water in a concentration above that of a critical threshold at hydrate-forming conditions – they show sequential hydrate buildup in the test cell. SDS facilitated the filling of the test cell with hydrates of natural gas in about a two to three-hour period, and the hydrates accumulated symmetrically on the metal cell walls.

Reaction of interstitial water—Ordinarily, unreacted interstitial water adsorbed on hydrate particles can occupy as much as 80% to 90% of the total volume of the hydrate mass – an important consideration when economics dictates that volume of storage be minimized. However, when water of the SDS solution goes into the hydrate molecular structure, surfactant is excluded into interstitial water where it promotes hydrate formation of that interstitial water. Hydrates are promoted in the interstitial water because surfactant solution concentrated in the interstices continues to help solubilize natural gas, and the surface areas of the surrounding hydrate particles provide large interfacial areas for further reaction.

The reaction of the interstitial water became evident by draining free water from the test cell after hydrates had accumulated and noting the continued fast formation of gas hydrates. This happened because the hydrates formed from surfactant solutions accumulate as a porous mass of orderly-packed small particles through which natural gas can permeate and contact unreacted interstitial water.

Scaled-up process design—The performance of the laboratory process indicated a scaled-up process could be designed to incorporate notable process attributes enhancing economics of gas hydrate storage of natural gas. These attributes suggest a simple process that minimizes labor (Figure 5).

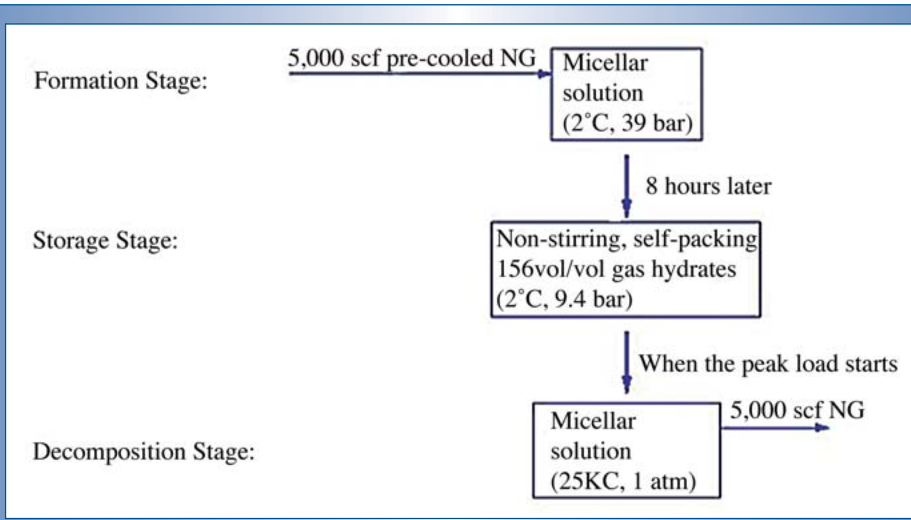

Figure 5. This three-stage design incorporates attributes enhancing gas hydrate storage economics that minimize labor.

Consequently, a proof-of-concept hydrate gas storage process was designed to form, store and decompose 5,000 scf of natural gas in gas hydrates. In this proof-of-concept process, hydrates form with no stirring at 35°F (1.6°C) and 550psi from a water solution containing surfactant above its critical threshold concentration at hydrate-forming conditions. As hydrates form, the mass accumulates on cold, solid surfaces placed at the liquid-gas interface. These metal surfaces serve to transfer heat in formation and decomposition steps, but they also adsorb and collect hydrates during formation. The process was designed so hydrates attach to the solid interfaces and, as the water level drops, the solid hydrate particles grow radially from those surfaces until the vessel is filled.

Stainless steel 304L comprises the pressure vessel, and its shell is 34.5-in. inside diameter and 36-in. outside diameter. The working length of the pressure vessel, which will be used in the vertical position, is 72-in. The top ellipsoidal dome is Teflon-coated on the inside to prevent hydrate buildup from blocking exit ports.

The jacket surrounding the pressure vessel is made of one-eighth-in. thick 304L stainless steel. Baffles direct the flow of circulating water-glycol solution through the jacket. The gap between jacket and pressure vessel is 1-in.

Thirty finned heat exchanger tubes, which are symmetrical, extend into the pressure vessel – 15 tubes for entering fluid and 15 for exiting fluid. The 30 tubes are brought into three concentric doughnut-shaped ring headers; 12 outlet tubes exit the ring headers and extend through the top dome of the pressure vessel. Hydrates also build symmetrically upon the heat-exchanger tubes and fins. At the end of the process, hydrates from adjacent heat-exchanger tubes/fins should touch but leave flow paths to the exit ports at the top of the vessel.

The heat exchanger tubes are designed to withstand a maximum external pressure of 650 psig; the minimum internal pressure is 45 psig for the circulating glycol solution. The design temperature is 20°F to 110°F (-6.7°C to 43.3°C) to accommodate heating or cooling in forming or decomposing hydrates.

The fins increase hydrate formation rate in two ways. Formation rate is directly proportional to the interfacial surface area and is dependent on heat transfer rate, a parameter dependent on surface area.

The pressure vessel and internal heat exchanger are fabricated to American Society of Mechanical Engineers (ASME) standards as given by the 2001 edition of *ASME Boiler and Pressure Vessel Code,* Section VIII, Division 1.

Hebeler Corp. (headquartered in Tonawanda, NY) constructed the formation tank at their facility in Vicksburg, Miss.

The installation of the proof-of-concept system at MSU is shown in Figure 6. The hydrate formation vessel is shown in the foreground. Seen in the background is the chiller capable of circulating glycol-water solution at the required flow rate and temperature. The chiller of 12-ton refrigeration was purchased from Drake Inc. Glycol-water solution will be circulated from the chiller through the heat exchanger/adsorber inside the formation tank; the solution will flow in parallel through the formation tank's exterior jacket.

Out of the line of sight to the right of the formation vessel is the surge tank for decomposition gases. Not shown in the photograph are the deionized water supply and boiler to burn off-gases.

After having purged the vessel of air, the procedure is to fill it about two-thirds full with water/surfactant solution, cool the system and establish 550 psig with natural gas. Thereafter, a constant-pressure regulator admits makeup gas to maintain 550 psig as hydrates form, self-pack on the heat exchanger fins and drop the water level. No further labor is needed until the vessel is full of gas hydrates that contain 5,000 scf. By altering the procedure slightly, action in the formation vessel may be visualized with some data plots. In Figure 7, plots of feed-gas flow rates and vessel pressures vs. time are given when gas was admitted manually. The downward spikes in the figure represent rates of batches of gas manually input; superposed are the corresponding pressure spikes to about 550+ psig in the vessel. Immediately after each batch gas input, hydrates form and drop the pressure, signifying the formation and collection of hydrates on the fins.

Conclusion

Formidable problems (forming hydrates rapidly, collecting and packing hydrates, and reacting interstitial water) to make natural gas storage in gas hydrates an economically viable process are overcome by forming the hydrates from a surfactant solution. In the feasibility study, a non-stirred laboratory test cell could be filled with hydrates in less than 3 hours with a capacity of 156 vol/vol. The important attributes of the laboratory process are incorporated in the design for a proof-of-concept scale-up. Simplicity and minimum labor requirements are stressed in the design. The process is designed to store 5,000 scf of natural gas in gas

Figure 6. The methane hydrate formation vessel (foreground) and chiller (background) at Mississippi State University.

hydrates to be formed from surfactant solutions at 550 psig and 35°F. A finned-tube heat exchanger accommodates latent-heat transfer during hydrate formation and decomposition, but the exchanger also serves to collect by adsorption and symmetrically pack hydrate particles as they form.

The proof-of-concept facility is based on experimental results of the laboratory feasibility study; the facility has been constructed, installed and full-scale tests are proceeding. ✧

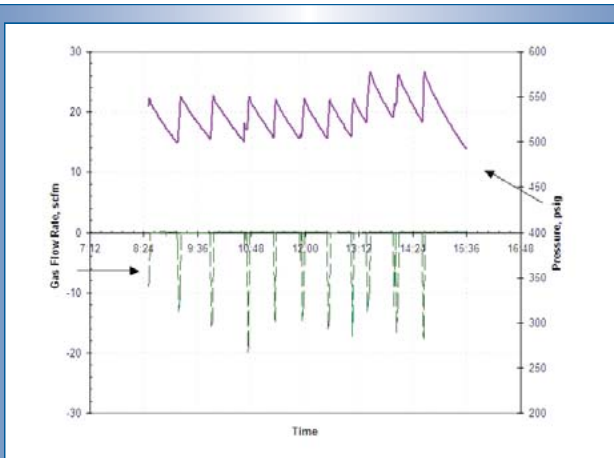

Figure 7. The above chart results are based on manually-admitted gas.

Acknowledgments

The authors would like to acknowledge the support of the DOE/NETL through the grants DE-AC26-97FT33203 and DE-FC26-01NT41297. Especially appreciated is the supportive role of National Energy Technology Laboratory management and Project Manager Gary Sames in helping make the research and development successful.

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A New Tool for Long-Range Visual Inspection of Live Gas Mains

By Richard Baker and Dr. Daniel Driscoll,
U.S. Department of Energy/ National Energy Technology Laboratory;
Dr. George Vradis,
Polytechnic University and NYSEARCH/ Northeast Gas Association;
and Dr. Hagen Schempf,
Carnegie Mellon University Robotics Institute

Inspection of natural gas distribution mains can provide gas utilities with valuable information about the condition of the infrastructure and determine the proper remedial action to rehabilitate or replace certain pieces of pipe.

An increasingly larger segment of the nation's distribution network needs to be inspected because of its age. As a result, during the past 15 years, a number of tools have been developed to provide such a capability. Such tools include video cameras that are inserted in a main, typically under live conditions, and pushed in either direction providing relatively high quality images of the pipe's interior. Other systems provide additional features, such as rehabilitation of cast iron joints or non-destructive evaluation of the pipe and subsequent rehabilitation using a repair patch. While these tools have enhanced the ability to inspect distribution mains, their use has been limited by the high cost of deployment. The systems are costly because they are tethered and as a result have a limited range (no more than 250ft – 61m – from the insertion point). When a longer length of pipe needs to be inspected, multiple excavations and hot-tappings of the main have to be undertaken. The associated cost makes the use of these technologies uneconomical in most instances. The operating company in these cases has to make a decision whether to spot or section repair a leaking main, reline it or replace it based on *in-situ* evidentiary data, such as maps, historical repairs, leak surveys and corrosion data, rather than detailed knowledge of the pipe's condition.


Figure 1. The EXPLORER's robotic architecture is symmetric with a seven-element articulated body.

The overall assessment and repair process can be costly without the ability to judge the most cost-effective repair approach. In the United States alone, more than $650 million/year is spent to repair leaks. Thus, giving the utilities the tools needed to make the decisions for cost-effective repair-method selection would have a drastic impact on their operations. Possible savings are hard to estimate, but if one assumes up to 50% of the section-replaced/relined mains could have been repaired with the next "cheapest" repair method, savings may be about 25% to 30% over conventional replacement techniques, saving the gas industry tens of millions of dollars annually.

In early 1999, the Robotics Institute at Carnegie Mellon University presented NYSEARCH, the research, development and demonstration organization within the Northeast Gas Association, with a proposal to develop a robotics system for the visual inspection of 6-in. and 8-in. distribution mains under live conditions that carries no tether of any kind. Through the use of on-board batteries and wireless communication between robot and operator, this robot would be able to travel in a main for thousands of feet and negotiate bends, tees and any inclined or vertical segments of pipe encountered. In addition, through the design of a special launcher able to be installed on the main through commercially available fittings, the robot would be launchable under live conditions. The realization of such an untethered inspection system was expected to radically improve gas line inspection and repair procedures. NYSEARCH, with co-funding from the National Aeronautics and Space Administration, and participation by the Jet Propulsion Laboratory and the Johnson Space Center, decided to co-fund a 1-year feasibility study to determine whether such a system was viable. At the end of the study, it was shown that existing state-of-the-art technologies in locomotion, electronics, controls and wireless communications, if properly integrated, could provide for the development of the desired tetherless visual inspection robotic platform. NYSEARCH and the U.S. Department of Energy (DOE), through the National Energy Technology Laboratory (NETL), decided to fund such an effort, which was initiated in early 2001. It was concluded in late 2004 with the

Figure 2. IPSCO fitting and launching tube.

successful demonstration of the developed robot named EXPLORER™ in live gas pipelines of three gas utilities in New York State.

The availability of such a long-range and easily deployable tool will greatly enhance the diagnostic and maintenance capabilities of gas operators, such as a job-planning tool, with the potential to result in substantial savings in terms of providing the data to make decisions about which repair/replacement method (spot/local/complete-line replacement/relining) to utilize. In addition, such a system also could be used as an emergency maintenance tool, by assisting in:

- the location of water infiltration into a low pressure gas main (thus eliminating or reducing the duration of costly main outages);
- the location of cracked cast-iron gas mains and damaged steel mains; and
- the location of water pools and obstructions because of foreign material in the pipe.

Since the system is insensitive to the metallic material of which the pipe is made, it is actually applicable to 100% of the ferrous pipeline market, in sizes bigger than 4-in. Finally, because of the robot's modular design, additional corrosion-detection and corrosion-loss measurement sensors could be added to give a more detailed picture of pipe condition.

EXPLORER description

The robot's architecture is symmetric (Figure 1). A seven-element articulated-body design houses a mirror image arrangement of locomotor/camera modules, battery-carrying modules and locomotor support modules, with a computing and electronics module in the middle. The robot's computer and electronics are protected in purged and pressurized housings. Articulated joints connect each module, which are connected to their adjoining ones with pitch-roll joints, while the others are connected via pitch-only ones. These specially designed joints allow orientation and turning of the robot in any direction needed within the pipe. The locomotor module houses a mini fish-eye camera, and its corresponding lens and lighting elements. The camera has a 190° field of view and provides high-resolution color images of the pipe's interior. The locomotor module also houses the dual-drive actuators, designed for the deployment/retraction of a set of three legs, equipped with custom-molded driving wheels. The robot can sustain speeds up to 4-in./sec. However, inspection speeds are typically lower than that for the operator to obtain an image that can be processed. Given each locomotor has its own camera, the system provides views at either end, allowing travel in both directions. The image management system allows the operator to observe either of the two views or both simultaneously on his/her screen. The camera image can be dewarped and mosaiqued for better image analysis and storage.

What People Say About the New Tool

"EXPLORER represents a new generation of pipeline inspection technology. Our vision is that future EXPLORERs will be autonomous and actually live inside the natural gas infrastructure, constantly roaming through the pipes and searching for anomalies. These EXPLORERs will substantially improve the reliability and safety of natural gas pipelines and represent the first-line of response to any emergency situation, reducing risks to both operators and emergency response personnel."

– Rodney Anderson, DOE-NETL Technology Manager—Gas Delivery, Storage and LNG

"The investment being made by NYSEARCH/NGA and NETL/DOE for the development of EXPLORER and other related robotic devices for the inspection of gas mains promises to provide quantum leap advances in the ability of natural gas distribution system operators to operate their systems in the most efficient, economic and safe manner allowed by state-of-the-art technologies."

– Daphne D'Zurko, Vice President, Research, Development & Demonstrations, NYSEARCH, Northeast Gas Association

Batteries have been sized for a "typical" 8-hour mission and can be of various types (chemistry) depending on cost and recharging characteristics. The support modules are primarily used to help center the robot in the pipe for launching and imaging purposes. The wheels at the end of the three extendable legs are passive and used for accurate displacement encoding. The computer module at the center of the robot contains the custom-packaged 32-bit low-power (less than 1 W) processor. It also includes support hardware for robot control and communication between robot and operator, which is accomplished via wireless radio frequency technology, using the pipe as a waveguide for long-range communications. The range of the robot can be extended by *in-situ* recharging and/or by inserting additional antennas via keyholes.

Two different systems are used for robot launching into a live pipe. Both systems consist of a custom-made launch tube and commercially available fitting to which the launch tube is attached. The fitting, in both cases, is installed using commercially available tapping and drilling equipment. In the case of low-pressure applications (cast iron mains at inches of water pressure), a commercially available fitting by IPSCO is used. Figure 2 shows the IPSCO fitting and launching tube. In the case of medium- and high-pressure applications, a commercially available fitting by the Mueller Co. is used.

Figure 3. EXPLORER's second field test was last summer in a low-pressure cast iron main in a residential area.

Operational experience

EXPLORER was designed and constructed with extensive input from end-users to ensure its features and operational characteristics would meet the demands and needs of the gas industry. Once the prototype was ready, it underwent an extensive 1-year testing program in a laboratory-testing loop to troubleshoot all mechanical, electronic and software components for optimum performance. Testing was then moved to an outdoor, above-surface piping network specifically constructed for the purpose of testing EXPLORER. The network consists of 6-in. and 8-in. steel pipe featuring cast iron joints, 45° and 90° bends and tees, as well as inclined and vertical pieces. The robot was endurance tested for more than 3 months.

CMU developed a launching procedure with input and approval from operations personnel of NYSEARCH member companies to warranty the robot's safe deployment. Different procedures have been developed for the low- and high-pressure applications to ensure the highest levels of operational safety.

EXPLORER's first field deployment was at a Keyspan facility in Long Island, NY, in May 2004. The robot was successfully tested for the first time in a pressurized natural gas environment. The system was loaded into a natural gas-filled pipe section that could be flooded with nitrogen and natural gas to varying pressures. The robot was proven to be capable of operating under these conditions, including operation, such as driving and communicating, at pressures up to 55 psig (limit of test-loop – notice an earlier test with compressed air showed the robot is able to operate in pressures of at least 124 psig).

The second field deployment was held in a live 8-in., low-pressure cast iron main in Yonkers, NY, in the service territory of Consolidated Edison in June 2004. The field trial site was in a residential area, the launching point being in the middle of an 800-ft (244-m) segment of an 8-in. cast iron main (Figure 3), bounded by a 90° tee on one end and a replacement plastic section at the other end. The low-pressure IPSCO fitting and associated launcher was used in this first demonstration. The launcher was attached to the IPSCO fitting, which was installed prior to the demonstration. The 2-day field trial involved the launching and retrieval of the robot four times, traveling more than 2,500ft (762.5m) of straight pipe and making six turns through the 90° tee. No problems were experienced during the launching, operation and retrieval of the robot, which was launched into and removed from the pipe following the established pro-


Figure 4. EXPLORER's final field test took place on the State University of New York campus, where a 1979-vintage 8-in. main was to be inspected.

cedures. The pipe inspected was clean with some debris encountered at the points where service tees had been connected to the main. The robot operated flawlessly during the 2 days of operation and demonstrated the versatility anticipated. The launching and retrieval procedures were tested in the field and met all safety standards the utility imposed.

The third field deployment of EXPLORER was held on a live 8-in. high-pressure main in the State University of New York campus in Brockport in the service territory of Rochester Gas & Electric, where a 1979-vintage 8-in. 60 psig main was to be inspected (Figure 4). The main ran straight westward from the point where the launcher was installed for more than half-a-mile, while in the other directions about 75ft (22.9m) away there were two back-to-back elbows (one 90° and one 70°) followed by a long straight segment. The field trial lasted 4 days, during which four launching and four retrieval procedures were performed. The robot covered a total distance in excess of 6,000ft (1,830m). During its travel in the pipe, it performed eight successful elbow turns, and it traveled more than one-half mile in one direction from a single hole in one run, leaving ample battery-power. A number of mapped and unmapped features (Ts and an unmapped main connection) were verified. The high-pressure fitting and launcher were successfully used.

Launching and recovery took 30 minutes each, including all safety steps. Installation of the launcher and antenna was proven to take 30 minutes and 15 minutes, respectively. The operator interface was shown to be user-friendly and a remote display for monitoring and evaluation also was determined to be a viable option.

The initial development and demonstration phase of this project has been successfully completed. EXPLORER has demonstrated the ability to provide long distance visual inspection of low- and high-pressure distribution mains, in an efficient and safe manner. The robot will be transferred to the commercialization partner selected by NYSEARCH. In the early phase of this effort, EXPLORER will be further tested under extreme operational conditions to ruggedize the system and prepare it for routine commercial deployment. The robot is expected to be available as a commercial service late next year.

Looking forward

EXPLORER's future only becomes brighter. The Northeast Gas Association and DOE's NETL have teamed up to develop an advanced version of the robotic inspection platform, EXPLORER II. This version will include the capability to incorporate a suite of novel inspection sensors that can, in addition to the robot's visual inspection capabilities, effectively evaluate the integrity of the pipeline walls through the use of advanced evaluation techniques. Inspection technologies under evaluation include Remote Field Eddy Current, Electromagnetic Acoustic Transducers and other acoustic sensor-based systems. This new system is targeted toward the evaluation of pipelines not currently inspectable using available technologies. The schedule for development aims for live natural gas pipeline demonstrations of the EXPLORER II robot with the integrated advanced sensor technologies within the next 3 years. One can only imagine a future where independent, autonomous inspection robots will live within the natural gas pipeline infrastructure providing continuous evaluation, and possibly repair, of the delivery network. This technology holds the potential to provide a significant advance in maintaining the integrity and operational reliability of the nation's natural gas pipeline delivery system and helps ensure the safe, efficient and reliable delivery of natural gas to America's homes and businesses. ✧

Decision Tools for Natural Gas Industry Planners: Part 2—Produced Water Atlas Series and Decision Tree Model

By Tom Hayes,
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and John Boysen,
BC Technologies, Ltd.

Gas Technology Institute and BC Technologies, Ltd. have created several informational products to help energy planners, regulators and producers develop effective and economical strategies for treating and managing produced waters. Second of a two-part series.

Produced water management is playing a progressively more important role in determining the economic feasibility of oil and gas field development. Increasingly, the planning involved in the development of natural gas reserves, including coalbed natural gas, requires a considerable familiarity with the practices, stakeholders, environmental requirements and regulations associated with water management. These decisions are driven by specific issues that include location, environmental sensitivity, and the quality and quantity of water streams (produced water and receiving water). To support these decisions, energy planners need access to many types of information that are location-specific, especially information pertaining to produced water and environmental management.

These requirements point to the need for rapid access to accurate and up-to-date information about key agencies, permits, tribal jurisdictions, regional best practices for produced water management, beneficial-use water guidelines, and interwoven rules that affect land use and water rights. the Gas Technology Institute (GTI), in collaboration with BC Technologies, Ltd. (BCT), has developed three informational products that can help governmental and energy industry planners in their efforts to obtain the right information regarding produced water management required for energy development:

- Produced Water Management Handbook;
- Produced Water Atlas Series; and
- Produced Water Decision Tree Model.

The first of the above products was discussed in Part 1 of this series (Fall 2004, *GasTIPS*) and describes the Produced Water Atlas Series and Produced Water Decision Tree Model for produced water management.

Table 1. Summary of states and basins included in the Produced Water Atlas Series.

State	Basins Selected for Further Analysis
Colorado	Denver Basin, Hugoton Embayment, Las Animas Arch, North Park Basin, Paradox Basin, Piceance Basin, Raton Basin, San Juan Basin, Sand Wash Basin
Illinois	Illinois Basin
Kansas	Anadarko Basin
Louisiana	Arkla Basin, Gulf Coast Basin
Michigan	Antrim Shale Formation
Montana	Big Horn Basin, Central Montana Uplift, Powder River Basin, Sweetgrass Arch, Williston Basin
New Mexico	San Juan Basin, Permian Basin, Raton Basin, Sierra Grande Uplift
Oklahoma	Anadarko Basin, Arkoma Basin
Utah	Central Western Overthrust, Greater Green River Basin, Paradox Basin, Uinta Basin
Wyoming	Big Horn Basin, Central Western Overthrust, Greater Green River Basin, Powder River Basin, Wind River Basin

Produced Water Atlas Series

This was developed to graphically depict how produced water is managed across the United States. Data presented was primarily collected from state regulatory agencies as well as oil and gas producers and has been arranged in a format that lends itself to the development of water management plans.

Conducted between 1997 and 2002, the study that formed the basis for the atlas examined a variety of elements relevant to water management planning and decision making. Ten states were identified for inclusion in the series: Colorado, Illinois, Kansas, Louisiana,

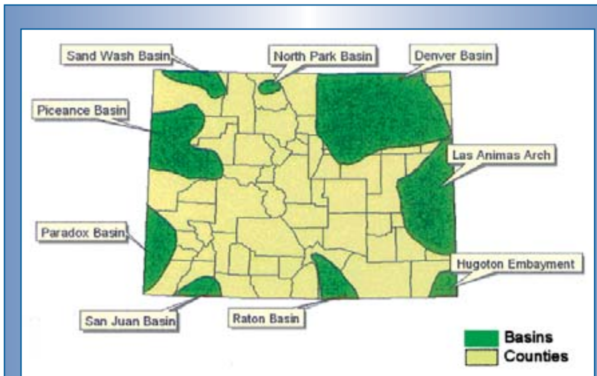


Figure 1. Oil and gas producing basins in Colorado.

Michigan, Montana, New Mexico, Oklahoma, Utah and Wyoming. Oil and gas basins within each state were identified using production statistics furnished primarily by state agencies. Basins reporting high volumes of oil and/or gas as well as high volumes of produced water were selected for inclusion in the study (Table 1). Oil, gas and water production volumes were stored in a database BCT designed specifically for this study. Additional analysis identified oil and/or gas fields within each basin that reported high volumes of oil, gas and water production – and linked that information with the operators who managed those resources. During the project, more than 250 producers were interviewed by telephone and asked to provide information about how they managed produced water at their leases in the targeted fields and oil and gas basins. They were also asked to provide economic data pertaining to handling, treatment, disposal or reuse costs. That information also is represented in the atlases.

The atlas series contains features designed to allow energy planners and stakeholders rapid access to geographical information that can assist in energy planning and produced water management decision making. The following sections describe those features.

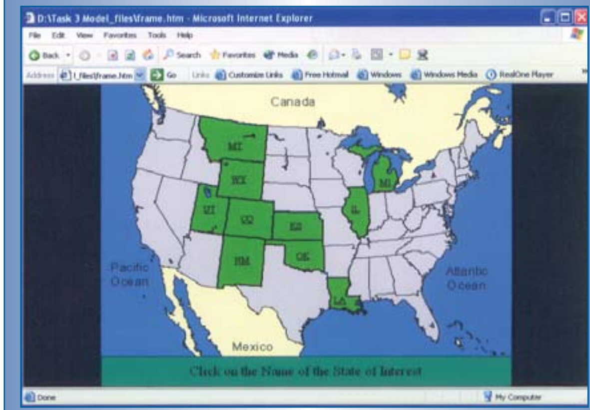


Figure 2. The main map page shows the states included in the Decision Tree model.

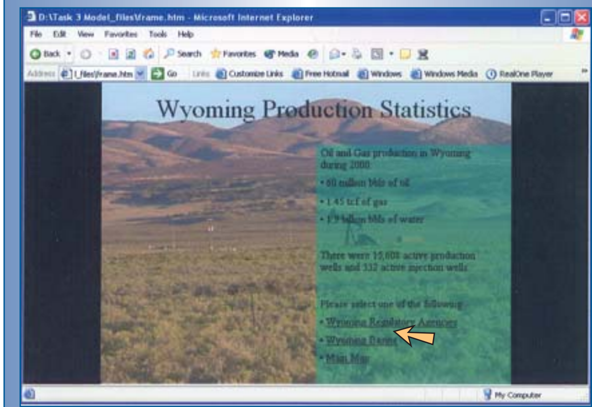


Figure 3. Wyoming Production Statistics page.

Basin profiles

Each atlas offers a profile of the oil and gas basins included in the study. Within each of the states, one or more oil- and gas-producing basin was selected for inclusion in the study and researched. Each one selected is identified on a map (Figure 1), which shows the location of each basin in the state and further identifies the production activity. Oil, gas and water production volumes for the basin are reported for the year 2000. In states where water production volumes were not reported, water injection volumes were substituted. States are clearly identified where this substitution is made. Tables that identify the top gas-producing wells in the basin are provided. Each table reports the well's American Petroleum Institute number, location and oil, gas and water production statistics.

The field that reported the most production activity in a particular basin was showcased. That field is on a map and its oil, gas and water production statistics are provided. Gas/water ratios and oil/water ratios also are provided for selected fields. The top five gas producing wells and the top five water producing wells are identified at each of the selected fields. The major gas producers are identified at the showcased fields in each basin. Legal descriptions of key fields and wells in the basin are provided. Geographic information system maps locate fields in relationship to cities, main roads, rivers, other wells and counties in the state. Charts are provided that show oil/water ratios and gas/water ratios for key fields in each basin.

All atlases in the series include a review of state environmental regulations that apply to water management planning and decision making, and they identify the state authority that has the jurisdiction to enforce them. Most of these regulations are available on the Internet on state agency Web sites. Clarification for particular regulations was obtained during interviews conducted with state agency personnel between 1999 and 2001. Regulations that were reviewed examine permittable strategies for:

- subsurface disposal, such as through the use of injection wells, simultaneous injection and dual-completion wells;
- surface disposal, such as evaporation pits and ponds and surface discharge with an NPDES permit; and
- beneficial use, such as for enhanced recovery projects, land application (irrigation, dust control) and drilling mix. When applicable, permits for water management on public lands and/or tribal lands are examined, as are all other state permits that may be required. Actual permitting forms and applications related to water management strategies are provided for many of the states.

Location-specific produced water management practices and disposal economics

One exceptional outcome of the study was the collection of location-specific water management strategies, and the identification of localized costs and cost factors for each basin in the study. Producers were questioned about how they managed produced water at specific fields in each basin and how much they paid for water handling, treatment and disposal at specific fields. All atlases describe the water management practices identified by producers as those they use in each of the basins.

Internet resources

Each atlas includes a listing of Internet resources and addresses. These resources, such as state agencies, educational institutions that offer oil and gas statistics and producer associations, can help a producer locate a variety of information, such as:

- current environmental regulations pertaining to produced water management;
- production statistics for oil, gas and water; and
- other useful resources such as maps and environmental handbooks.

Decision Tree Model

Since 1997, GTI and BCT have conducted technical assessments with the goal of understanding the nature and economic impact of natural gas produced water management (PWM) issues and practices. This effort has led to the creation of a decision tree model that summarizes produced water disposal practices and regulatory issues at a local (basin) level; this product, called the PWM Decision Tree Model (DTM) is available in a user-friendly package that provides essential information in a point-and-click format.

The DTM product contains information from 30 selected natural gas-producing basins in Colorado, Illinois, Kansas, Louisiana, Michigan, Montana, New Mexico, Oklahoma, Utah and Wyoming. Completion and production data from more than 150,000 production and injection wells were included in the database that forms the basis for the DTM product. Permitting requirements for PWM options allowed in each state were investigated for commercial and owner-operated facilities. Information also was obtained from more than 250 oil and gas production personnel who responded to a telephone survey providing details of their respective produced water management practices.

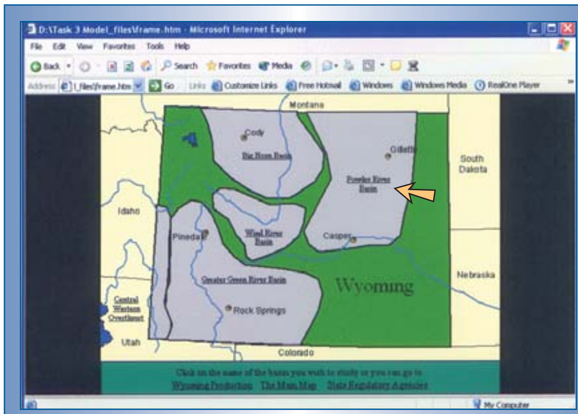


Figure 4. This screen capture shows a map of the Wyoming production basins.

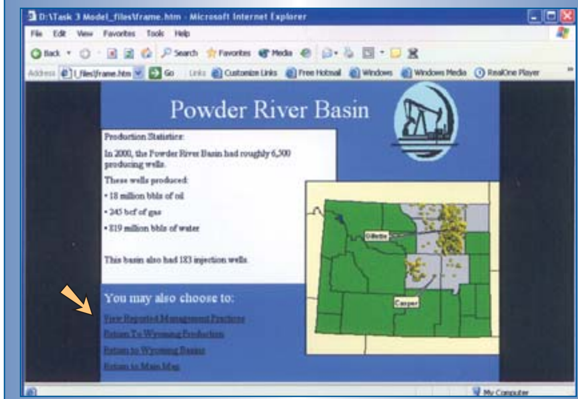


Figure 5. The production statistics screen for the Powder River Basin.

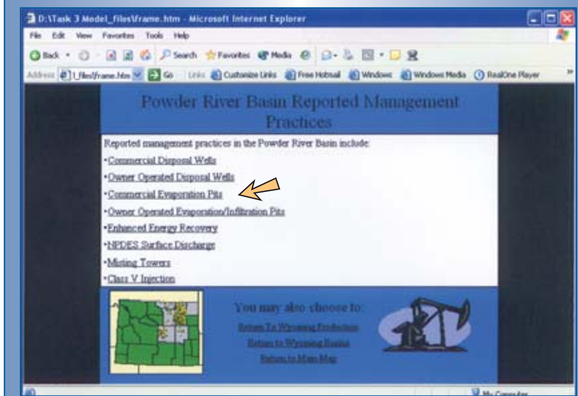


Figure 6. The management practices screen for the Powder River Basin.

Detailed information contained in the DTM was provided by gas, oil and water production statistics producers reported to state agencies, information provided by state regulatory agencies, and information provided by local oil and gas producers in a telephone survey conducted as a part of this project. The DTM provides oil, gas and water production statistics along with Internet links to the appropriate regulatory agencies for each state considered.

Basin level detail

In addition to state demographics, detailed information also is made available on a basin-to-basin basis. The oil and gas-producing basins selected for consideration are illustrated for each state. At the next level of the DTM, basin oil, gas and water production statistics are provided along with PWM technologies reported by the survey respondents. Cost data associated with specific water management strategies and comments made by the survey respondents are summarized for each PWM technology reportedly used in the basin. The final level of the DTM provides general information describing each reported PWM technology, and the pros and cons of owner-operated and commercial technology application.

Water end and beneficial use considerations

An increasingly important factor in PWM is the potential opportunity for processing produced water for beneficial use purposes. Many areas in the Western United States where natural gas is produced are arid. In addition, population growth in these regions has been substantial. Further pressure on municipal water supplies in these arid regions has resulted from drought conditions during the past few years. The potential for utilizing produced water as a supplemental source for community water supply or as a water stream that can be used for irrigation, livestock or industry purposes has stimulated discussion among the public, environmental protection groups and governmental agencies on the best practices for PWM aimed at beneficial use. In the midst of this dialogue, it is important for the concerned public, participants of energy development, governmental agencies and other stakeholders to be current with PWM options and costs. The DTM product is designed to facilitate a comparative analysis of PWM alternatives available for each basin and offers links to Web sites that can provide updates on water utilization options as well.

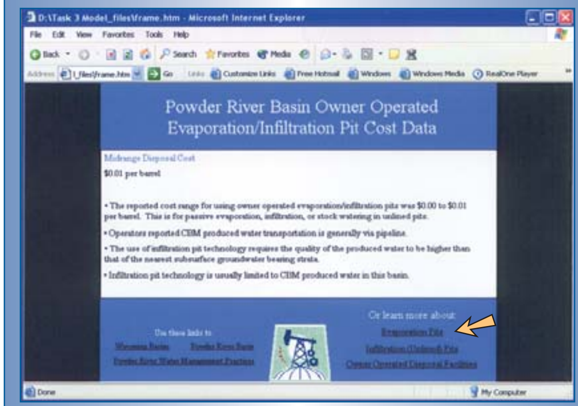


Figure 7. The above graphic shows the cost information screen for the owner-operated evaporation/infiltration pit option.

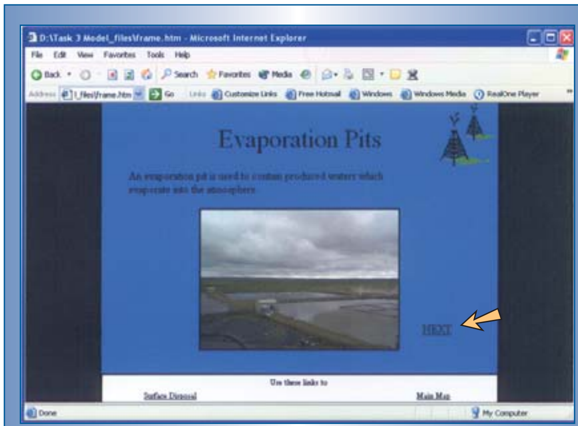


Figure 8. This is the initial screen of a slide series describing evaporation pit deployment in the Powder River Basin.

A walk through the software

To facilitate ease of use and access to continually updated information on the Internet, the Produced Water Management DTM was created in PowerPoint 2000 and published as a Web page to run in an HTML format. This version can run on Internet Explorer or Netscape and uses all Web page capabilities. The following section gives a number of examples of how easy it is to use the PWM DTM software for obtaining information regarding PWM practices in a selected oil- and gas-producing basin.

The DTM is run off of a CD. Just place the PWM DTM CD into the CD drive of the computer and open the MS Windows® program "My Computer." Double click on the CD drive in which the CD is placed, and the contents of the CD are displayed. Double click on the Internet Explorer or Netscape icon and the software opens and begins on the first page. The user can move throughout the software by clicking on the underlined text or using the Web browser buttons.

Following the introductory credits and disclaimer pages, there are a few pages of general information provided regarding the program. Next, a U.S. map illustrating the states selected for consideration in this research project (Figure 2).

Select a state by clicking on its abbreviation. This will take the user to the general production statistics information page regarding the state production and gives the option to go to state regulatory agencies, the basins map or to return to the main map (Figure 3).

Choose the basins map and a map of the basins is displayed (Figure 4). Select a basin, such as the Powder River. This will take the user to general information about basin production with user options of selecting basin-reported management practices, the state production page, the basins map or returning to the main map (Figure 5).

Click on the option for "Reported Management Practices" for a particular basin and the decision software takes the user to the screen listing the major management options available and practiced. Specifically, this gives the user a list of management practices reported in this particular basin by the respondents of the survey (Figure 6). The user can then choose a management practice for more detailed information. If, for example, the user chooses the evaporation pit option, the model takes the user to a screen that provides cost information on this alternative (Figure 7). At this point, the user has the option of drilling even deeper for information. The "Learn More About" list allows the user to access a series of information slides on each detailed aspect of the option. For example, if the evaporation pit item were selected from the list, the user would be presented with a number of screens that provide facts and visual depictions of the technology as applied to the specific basin (Figure 8).

Choose a reported management practice. This will take the user to the reported capital and operating expenses, transportation issues and regulatory issues for this practice in this particular basin.

Other types of information that can be accessed include:

- guidance on the major governmental and non-governmental organizations that influence produced water practices;
- beneficial use water management policy for each state and basin, including key Web site links; and
- critical analysis of produced water management technologies and alternatives.

The Produced Water Atlas Series and the DTM are available from the GTI Web site at *www.gastechnology.org*. For more information about these and other GTI produced water products (such as the *Produced Water Management Handbook*), contact Tom Hayes, GTI's associate director of environmental engineering, via phone at (847) 768-0722 or e-mail at *tom.hayes@gastechnology.org* ✧

Siting and Safe Operation of Liquefied Natural Gas Facilities

by Dr. Erwin T. Prater,
Trinity Consultants

Safety is a prime consideration in the placement and design of liquefied natural gas facilities.

Regulations require facilities to use computer simulations to model potential fire and explosion hazards from accidental liquefied natural gas (LNG) releases. This has required the run of several separate computer models and manual transfer of data among the models, which is a time-consuming process prone to errors.

The Code of Federal Regulations (49 CFR 193) defines safety standards for LNG facilities covered by federal pipeline safety laws. It addresses protection in the vicinity of LNG storage and transfer systems by specifying the models used to calculate exclusion zones for thermal and vapor hazards. The models specified are LNGFIRE3 for thermal radiation protection and DEGADIS for air dispersion calculations. The Gas Technology Institute (GTI) sponsored development of the LNGFIRE3 model as well as the LNG-specific SOURCE5 model that predicts the spread and vaporization rate of LNG spills. Output from the SOURCE5 model is compatible with DEGADIS, making the combination of the two models useful for ensuring compliance with 49 CFR 193. SOURCE5, DEGADIS and LNGFIRE3 can be run on typical personal computers.

SOURCE5

In developing SOURCE5, GTI examined field and laboratory experiments and selected the best-in-class model that simulated LNG spread and vaporization rates for each of the following release types:

- instantaneous confined spills on land;
- continuous confined spills on land;
- instantaneous unconfined land spills;
- continuous unconfined water spills; and
- instantaneous unconfined water spills.

SOURCE5 allows the user to specify the size and shape of fuel impoundment basins, material properties of the impoundment structure (dike) and LNG chemical properties. The main outputs from SOURCE5 are the LNG vaporization and spread rates, and a comparison of the volume of a specified impoundment basin with volumes as specified in 49 CFR 193 (Figure 1, Table 1).

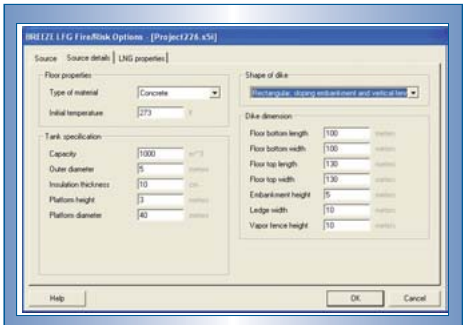


Figure 1. SOURCE5 input screen.

DEGADIS

49 CFR 193 specifies DEGADIS as an acceptable model for determining the downwind distances to flammability limits. The program originally was developed for the U.S. Coast Guard and GTI with the primary objective of simulating dispersion of cryogenic flammable gases. DEGADIS has been used for a number of years in industry and is widely accepted. When modeling air dispersion from LNG releases, DEGADIS can accept predicted vaporization and spreading rates, such as those produced by SOURCE5 (Figure 2).

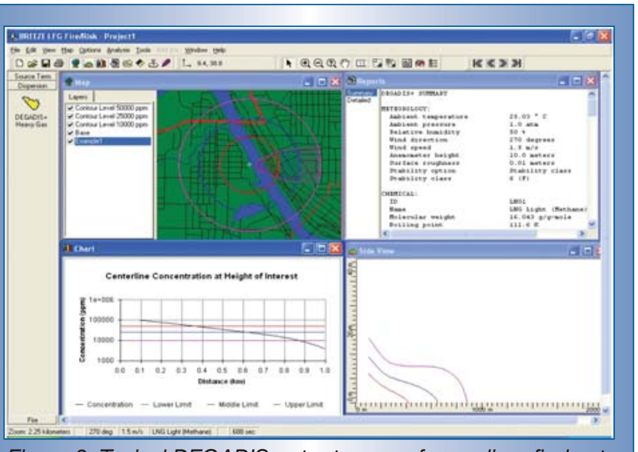


Figure 2. Typical DEGADIS output screen from a liquefied natural gas release scenario.

LNGFIRE3

49 CFR 193 specifies LNGFIRE3 as an acceptable model for determining thermal exclusion areas surrounding LNG fires. LNGFIRE3 is a set of three fire models that calculates the thermal exclusion distances for

Table 1. Key SOURCE5 Input and Output Parameters.

Input Parameters	*Output Parameters*
Type of LNG release (5)	*Construction material of impoundment basin*
Release duration	*DEGADIS-compatible LNG vaporization and spreading rates*
Release amount	*LNG chemical properties*
Size, shape of impoundment basin	*Comparison of impoundment basin volume with specifications in CFR 49 193*

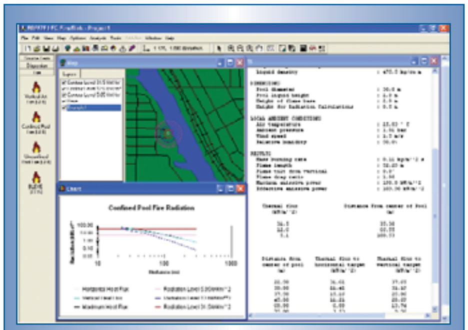


Figure 3. LNGFIRE3 output screen.

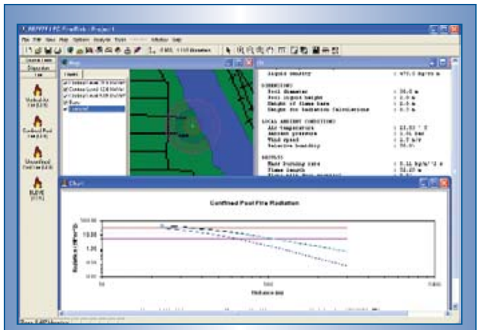


Figure 4. Results from LFG Fire/Risk featuring a plot of thermal exclusion distances and thermal flux.

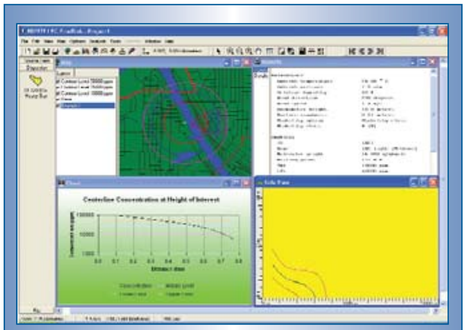


Figure 5. LFG Fire/Risk output screen.

unconfined pool fires, confined pool fires and jet fires (Figure 3). It calculates radiant flux levels at user-defined points downwind of an LNG fire. Meteorological information, including wind speed, wind direction and humidity as well as parameters that describe the LNG release are specified through a series of input screens. The model for pool fires simulates flame as a cylinder or a parallelepiped, depending upon the geometry of the impoundment areas. Wind-induced flame drag and tilt also are accounted for in the models.

An integrated approach

The commercial product BREEZE LFG Fire/Risk from Trinity Consultants combines SOURCE5, DEGADIS and LNGFIRE3 into one package, allowing the analyst to efficiently simulate a broad set of potential hazards associated with LNG process operations (Table 2). The product also contains an additional U.S. Environmental Protection Agency-approved model for simulating the exclusion distance for boiling liquid expanding vapor explosions. Input parameters are shared among the programs, eliminating redundant data entry while saving time and increasing efficiency. Output is available in tabular and graphical forms, giving the user several different ways to display and analyze results. Output also can be imported into other programs, such as Microsoft Word, Excel and PowerPoint, aiding preparation of reports and presentations. For more information, visit *www.breeze-software.com*

Scenario analysis

LFG Fire/Risk recently was used to determine exclusion distances for various accidental release scenarios for an LNG terminal. These hazards included releases from tanker grounding, LNG transfer, LNG off-loading, re-gasification, and failure of tanks and piping. One scenario involved an LNG storage tank dike fire that occurred when a tank was damaged and its contents were released into a circular containment structure. Figure 4 features a plot of thermal exclusion distances and a graph of thermal flux as a function of distance, which are useful for determining the proper siting for an LNG facility.

Another scenario involved the release of LNG from a 1.64-ft (0.5-m) diameter hole in an LNG tanker resulting from its accidental grounding. This is an unlikely scenario given the procedures and technology used to guide tankers during docking and unloading. Figure 5 shows the results from running SOURCE5 and DEGADIS from within LFG Fire/Risk. The vapor exclusion distances were calculated to 2.5% methane concentration.

As economic conditions continue to make LNG import, processing and storage more attractive, robust analytical capabilities associated with potential hazards are becoming more important. Integrated, productivity-enhancing software that facilitates these analyses will make project planning for LNG operations easier.

For more information about hazardous release analysis, contact Dr. Erwin Prater, senior product specialist for Trinity Consultants, at (972) 661-8881 or *eprater@trinityconsultants.com*

Reference documents are GRI-92/0534 for SOURCE5; GTI-04/0049 for DEGADIS and GTI-04/0032 for LNGFIRE3; and are available on GTI's Web site at *www.gastechnology.org* ✧

Table 2. Features in BREEZE LFG/Fire Risk.

LNG-specific SOURCE5 model	*Extensive database of industrial chemical properties*
User-specified LNG containment basin size, shape and composition material	*Flexible and user-friendly MS-Windows interface*
Seamless integration of results from SOURCE5 into DEGADIS dense-gas air dispersion model	*LNGFIRE3 fire models*
Choice of tabular and graphical output	*Environmental Protection Agency boiling liquid expanding vapor explosions model*
Output compatibility with common MS-Office applications	*Ability to animate results from DEGADIS*
Import map images in popular formats, including DXF, BMP, and JPEG	*Ability to overlay thermal and vapor exclusion areas on maps, plots and drawings*

Liquefied Natural Gas Roadmap Workshop

By Robert Vagnetti
and Richard Baker,
U.S. Department of Energy/National Energy Technology Laboratory

*The following is an excerpt from the final report describing the US. Department of Energy/National Energy Technology Laboratory Liquified Natural Gas Roadmap workshop in Houston from Nov. 8-9, 2004.**

The United States benefits from the use of natural gas. While most of the gas we burn in our homes and factories; use to make plastics, chemicals and fertilizer; or burn to produce electricity comes from our own country's resources, a growing portion is imported into the United States as liquefied natural gas (LNG – see graphic). LNG imports currently provide about 2% of the U.S. natural gas needs. Forecasts from the Energy Information Administration (EIA Annual Energy Outlook 2004) predict steady growth in natural gas consumption with demand rising almost 40% to 31.4 Tcf by 2025. During this period, imported LNG is expected to satisfy a growing share of the gas supplied, increasing from about 0.5 Tcf in 2003 to nearly 5 Tcf. If this increase is realized, LNG will represent nearly 15% of total natural gas consumption by 2025.

Forecasts of a 10-fold increase in LNG are coupled to an era of unprecedented change in global energy markets as well as to a new awareness in national and energy security. To address these concerns, the U.S. Department of Energy (DOE) is working with other government agencies and industry stakeholders to identify major obstacles to expanding LNG imports.

Last November, the DOE hosted a roadmapping workshop in Houston. The workshop was attended by nearly 120 participants including representatives from industry, local and state government, federal agencies and academia. Four separate breakout sessions were conducted covering issues or challenges associated with safety, siting and security; public understanding; interchangeability and gas quality; and LNG technology.

The participants identified a range of policy, market and technology concerns, including the need for:

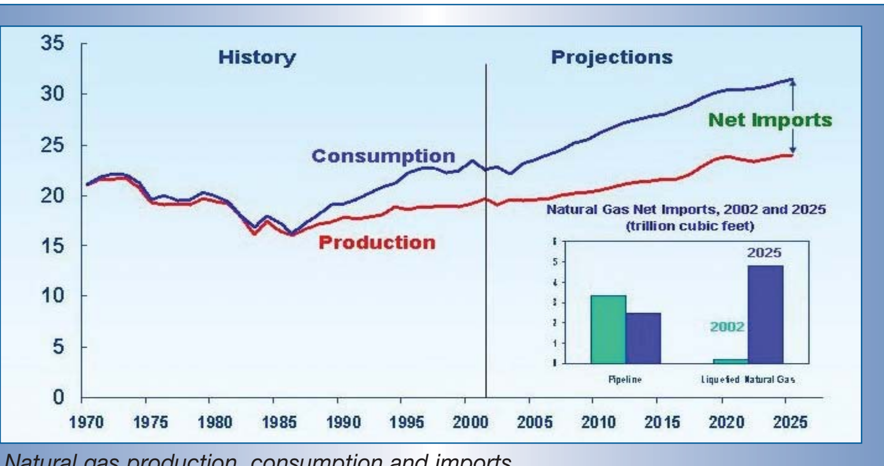
- improved public understanding regarding the benefits and risks of LNG;
- more sharing of data and improved testing programs relative to LNG safety, interchangeability and gas quality;
- more consistent and updated LNG codes, standards and regulations;
- improved market structure (i.e., spot market);
- enhancement and expansion of existing pipeline/storage infrastructure to handle expected LNG demand;
- better understanding and communication of LNG supply and security in a post-9/11 world and in the overall context of a comprehensive national energy policy; and
- improved technology to increase operational efficiency and safety, and reduce potential risks to the public and environment.

These examples are only a few of the many challenges discussed and though this effort was not exhaustive, it did, however, provide a consensus framework for the identification and planning of a collaborative implementation strategy to address high-priority concerns. Based on the workshop findings, five high-priority roadmapping strategies were identified:

- develop consistent local, state, regional and national outreach plan and communication tools;
- develop science-based models to support risk analyses, and new siting and security regulations;
- develop standardized testing program leading to national gas standards;
- assess LNG impacts on gas infrastructure leading to market efficiencies and maximized supply; and
- develop new technologies and new applications of existing technologies to improve safety and maximize supply.

This document describes these high-priority strategies and also provides the detailed findings of the workshop, including a discussion of the major challenges as well as the solutions and implementations strategies outlined by the working groups. Additional workshops focusing on targeted issues identified during this initial effort will be conducted to hone strategies for future program implementation. ✧

** The full report document will be available for review upon completion at www.netl.gov/scngo/reference%20shelf/index.html#publications*



Natural gas production, consumption and imports

FEASIBILITY STUDY OF DILUTING A WEIGHTED DRILLING FLUID WITH A LOW DENSITY LIQUID TO CREATE A RISER FLUID FOR A DUAL-DENSITY DRILLING SYSTEM

This report documents an investigation of two dual-density drilling concepts – riser dilution with a low density liquid and riser gas lift – as a potential means to implement a dual-gradient system for simpler, safer and more economic well designs. The report summarizes the experimental work performed to evaluate the feasibility of diluting high-density mud from the wellbore with a low-density liquid to create a reduced density mud in the riser.

Price: $60
Form: Computer file, 357 KB
Document No.: GRI-04/0176

Order through the Gas Technology Institute Web Site "Search" function at *www.gastechnology.org*

IMAGING DEEP GAS PROSPECTS USING MULTICOMPONENT SEISMIC TECHNOLOGY

This report investigates the value of long-offset multicomponent seismic data for studying deep-gas geology across the northern shelf of the Gulf of Mexico (GOM). Long-offset four-component ocean-bottom-cable (4-C OBC) seismic data have been analyzed to determine whether increased source-receiver offsets improve the ability to image deeper geology across the gas-producing areas. The data were processed using source-receiver offsets as large as 6.2 miles (10 km). These data represent the largest imaging offsets available for seismic reflection data and should image deeper than conventional seismic reflection data. This information sets new guidelines for deep geology across the GOM basin. The P-SV mode sometimes images to depths of 8 miles (13 km). Both modes, P-P and P-SV, provide good images of geologic conditions to depths of 5.6 miles (9 km), the present deepest depth that most operators wish to drill along the shallow-water, northern shelf of the GOM. The research findings should encourage operators in the GOM basin to integrate long-offset 4-C OBC seismic technology into their prospect evaluations.

Price: $60
Form: Computer file, 7.28 MB
Document No.: GRI-04/0186

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REAL-TIME PORE-PRESSURE PREDICTION AHEAD OF THE BIT

This project evaluates the feasibility of using a new method for predicting formation pore pressures ahead of the bit in real time while the well is being drilled. Pore pressures of formations are one of the big problems drillers face in exploration areas. The pore pressure, together with fracture gradient, determines the amount of mud weight needed. The new approach estimates the pore pressures of formations before the drillbit drills through them. Surface seismic data, in the vicinity of the well, and real-time logs and check-shot measurements as the well is being drilled, are combined to make a more reliable estimate of velocities ahead of the bit. The predicted velocities are then mapped to pore pressures using an equation or empirical relationship appropriate for the area. The study demonstrated that incorporation of check-shot and well log data significantly improves the velocity estimates ahead of a well. The field data inversion study showed that big improvements could be seen, particularly in gradual changes of velocities that are typically associated with pore-pressure variations in areas like the Gulf of Mexico.

Price: $60
Form: Computer file, 423 KB
Document No.: GRI-04/0208

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FIELD TESTING REMOTE SENSOR GAS LEAK DETECTION SYSTEMS

The U.S. Department of Energy (DOE) is funding several commercial companies and research laboratories to develop advanced ground and aerial remote sensor systems to provide high quality, cost-effective natural gas leak detection and quantification information. To aid in the development and availability of these remote detection systems, the DOE (with the U.S. Department of Transportation-Office of Pipeline Safety co-funding) conducted "real world" field testing of five of the supported remote leak detection systems. The demonstration testing was conducted at the DOE's Rocky Mountain Oilfield Testing Center (RMOTC) field site, north of Casper, Wyo., Sept. 13-17, 2004. Southwest Research Institute and RMOTC staff:

- developed a detailed and representative test plan, with input from a gas industry advisory panel and equipment providers;
- determined how best to conduct the testing at the RMOTC field site, including the development of a virtual pipeline and specific design of leak sites, rates and methods;
- designed and fabricated the equipment necessary for the field test and prepared the test site;
- coordinated and conducted the field tests, where the equipment providers collected their own data, including provision of their own data collection platform; and
- reviewed and compared equipment provider results to data for actual leak locations and sizes.

The technologies tested included ground and air-based systems and incorporated technologies such as passive infrared multi-spectral scanning, laser-based differential absorption light detection and ranging, hyperspectral imaging and tunable diode laser absorption spectroscopy.

The primary objective of this project was to provide a forum where the developers of remote, natural gas leak detection systems would be able to test or demonstrate their systems, potential commercializers could evaluate the readiness of the technologies and the ultimate end-users (the gas industry) could observe the effectiveness of the technologies in a real-world environment. Results of the project are available in a final report at the National Energy Technology Laboratory Web site: *www.netl.doe.gov/scngo/Natural%20Gas/publications/t&d/Final%20Report_RMOTC.pdf*

PIPELINE INSPECTION TECHNOLOGIES—DEMONSTRATION REPORT

For several years, the U.S. Department of Energy has funded the development of advanced in-line inspection technologies to detect mechanical damage, corrosion and other threats to pipeline integrity. Many of these efforts have matured to a stage where demonstration of their detection capability is now warranted. During the week of Sept. 13-17, 2004, the Natural Gas Delivery Reliability Program and the U.S. Department of Transportation's Office of Pipeline Safety (OPS) co-sponsored a demonstration of eight innovative technologies; five developed through SCNGO funding support and three technologies supported by OPS.

The demonstrations were conducted at Battelle's West Jefferson Pipeline Simulation Facility (PSF) near Columbus, Ohio. The pipes, and the pipe damage to be evaluated, in the demonstration were prepared by Battelle at the PSF and each was pre-calibrated to establish baseline defect measurements. Each technology performed a series of pipeline inspection runs to determine their capability to detect and quantify the damage for which their sensor was designed (mechanical damage, corrosion, or stress corrosion cracking). The final report provides a summary of the demonstration results for all equipment involved in the demonstration testing. The goal of the report is to present the results and provide data comparing each technology relative to the benchmark data. It does not include analysis of success or failure or direct comparisons of a technology's performance. The full report is available for review at the National Energy Technology Laboratory Web site: *www.netl.doe.gov/scngo/Natural%20Gas/publications/t&d/Battelle%20Inspection%20Demo%20Final%20Report_111804.pdf* ✧

▶ SOCIETY OF PETROLEUM ENGINEERS/INTERNATIONAL ASSOCIATION OF DRILLING CONTRACTORS CONFERENCE

Feb. 23-25, Amsterdam, The Netherlands
For more information, visit *www.spe.org*

▶ SPE/EPA/DOE EXPLORATION AND PRODUCTION ENVIRONMENTAL CONFERENCE

March 7-9, Galveston, Texas
For more information, visit *www.spe.org*

▶ OFFSHORE TECHNOLOGY CONFERENCE

May 2-5, Houston, Texas
For more information, visit *www.otcnet.org*

▶ SOCIETY OF PETROLEUM ENGINEERS CONFERENCE

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

▶ SPRING 2005 STRIPPER WELL CONSORTIUM PROPOSAL MEETING

March 8-9, 2005, San Antonio, Texas
For more information, visit *www.energy.psu.edu/swc/*

▶ 5TH INTERNATIONAL CONFERENCE ON GAS HYDRATES

June 13-16, 2005 Trondheim, Norway
For more information, visit *www.icgh.org/* ✧

▶ NEW RESEARCH AND DEVELOPMENT SOLICITATIONS

The National Energy Technology Laboratory is planning four solicitations with a release date close to the end of January 2005. Research and development (R&D) proposals will be requested in the following natural gas areas: Gas Hydrates—to increase the understanding of their role in the environment and the potential of methane hydrates as a future energy resource; Advanced Diagnostic and Imaging Systems—to develop new exploration and development tools and technologies; Drilling, Completion and Stimulation—to drill into unconventional, more complex, deeper, harsher and lower-quality reservoirs; and Liquefied Natural Gas—to address anticipated issues as liquefied natural gas importation and use increases in the future. Stay abreast of the announcements by visiting *www.netl.doe.gov/business/solicit/*

▶ CO_2 FLOODING ADVANCMENTS

Technology advances, economic improvements and environmental needs have aligned to create a growth opportunity for a proven method for enhancing oil recovery (EOR) in the United States: carbon dioxide (CO_2) flooding. A watershed project in Kansas seeks to demonstrate that this technology's time has come, while leveraging energy security, energy efficiency and environmental benefits in a number of ways. The payoff could be hundreds of millions of barrels of oil in Kansas that otherwise might never be produced.

The Kansas project takes a different approach, capitalizing on the benefits of a unique, scalable model for linked energy systems. The project is recovering CO_2 that is a by-product of the fermentation process involved in corn ethanol production and using it for a CO_2 EOR flood in the Hall-Gurney field in central Kansas.

The Hall-Gurney flood represents a couple of firsts: the first CO_2 flood in Kansas and the first time waste CO_2 from an ethanol plant has been used for EOR. The Kansas project is managed by the National Energy Technology Laboratory in partnership with the Kansas Geological Survey at the University of Kansas in Lawrence, Kinder Morgan CO_2 Co. LP (Houston), Murfin Drilling Co. (Wichita, Kan.), MV Energy (Princeton, NJ), ICM Inc. (Colwich, Kan.) and the Kansas Department of Commerce. For more information visit: *www.netl.doe.gov/publications/press/2005/tl_kansas_co2.html*

▶ NEW ADVANCED DIAGNOSTIC AND IMAGING PROJECTS

The U.S. Department of Energy (DOE) Office of Fossil Energy recently kicked-off five new cost-shared research projects to develop advanced diagnostic tools and technologies to remotely identify gas reservoirs and reservoir properties in deep exploration settings. The projects will be managed by the National Energy Technology Laboratory, with about $4.2 million in DOE funding support. The new projects are: Ultra-deep Wave-equation Imaging and Illumination, 3DGeo Development, Inc.; Imaging Super Deep Gas Plays across the Gulf of Mexico Shelf with Multi-component Seismic Technology, The University of Texas at Austin, Bureau of Economic Geology; Advanced Seismic While Drilling System, Technology International, Inc.; Novel Use of P-wave and S-wave Seismic Attenuation for Deep Natural Gas Exploration and Development, RDSP I, L.P. d/b/a Rock Solid Images; A Robust MEMS Based Multi-component Sensor For 3D Borehole Seismic Arrays, Paulsson Geophysical Services, Inc. For more information, visit *www.netl.doe.gov/scngo/main.html* ✧

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