Tight-gas myths, realities have strong implications for resource estimation, policymaking, operating strategies

Keith W. Shanley
John Robinson
Consulting Geologists
Littleton, Colo.

Robert M. Cluff
Discovery Group Inc.
Denver

Natural gas demand in the US is expected to grow from 23 tcf/year now to 30-34 tcf/year by the year 2025.

Most gas producing regions are expected to decline, but gas production from unconventional sources, most notably tight-gas sandstones, are expected to provide a large proportion of this future gas supply.

These forecasts are based on historical work suggesting that unconventional, tight gas is a very large, widespread resource with limited geological risk in which the critical technologies are more related to resource extraction and optimization than resource definition.

Recent work suggests, however, that these unconventional gas resources are not continuous, or basin-centered, as was previously suggested, but rather are distributed in a manner similar to conventional oil and gas fields, and have far greater geological risk than is generally appreciated.

As a result, it is likely that resource volumes are substantially overestimated, while the risks associated with finding and recovering those resources have almost certainly been underestimated. This has strong implications for resource estimation, the development of prudent energy policy measures, as well as exploration, production, and acquisition strategies.

Introduction

Natural gas is a critical source of energy that permeates virtually every sector of the economy accounting for some 25% of all US energy use.[1] Projections of North American natural gas supply and demand by the Energy Information Administration[2,3] and the National Petroleum Council[1] suggest that natural gas demand in the US is likely to increase from 23 tcf/ year to in excess of 30-34 tcf/year by the year 2025.

At present, the variability in scenarios put forth by these and other organizations revolves around differences in economic growth rates, degrees of technology implementation, and regulatory climate, etc. Regardless, overall demand for natural gas is expected to increase by 40%.

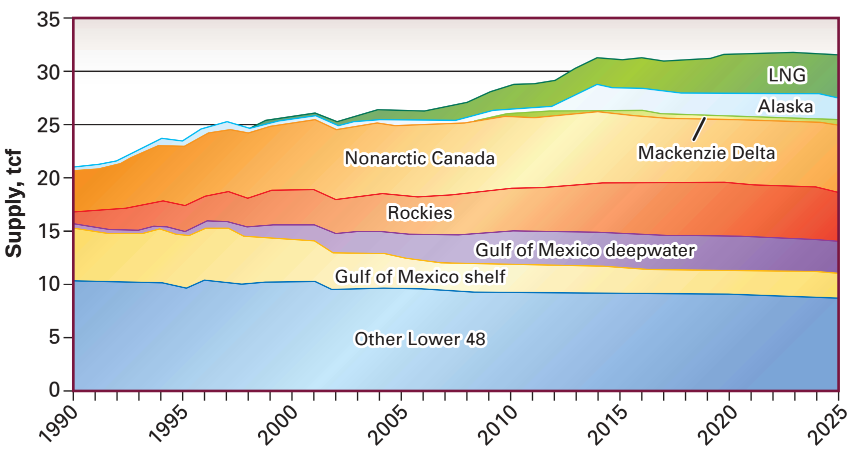
To help meet this increased demand, US natural gas production is expected to rise from 19.5 tcf/year in 2004 to more than 25 tcf/year by the year 2020; natural gas imports are expected to make up any shortfall between production and demand. Production trends within traditional supply regions suggest that most producing regions will experience substantial decline over this period; however, two key areas, the deepwater Gulf of Mexico and the Rocky Mountain region, are expected to substantially increase their natural gas production (Fig. 1).

By virtually all accounts, the largest potential source of natural gas capable of impacting supply on a national scale is thought to exist within unconventional gas sources (Fig. 2).

Recent studies by the EIA for example[2,3] suggest that there is an unproven, yet technically recoverable resource base of 445-475 tcf of natural gas in unconventional gas sources. Almost 70% of this resource is thought to reside in tight-gas reservoirs (low-permeability sandstones) (Fig. 2) with the remaining unconventional gas occur-

NORTH AMERICAN GAS SUPPLY PROJECTIONS

Fig. 1



Source: From National Petroleum Council, 2003, Fig. 2.

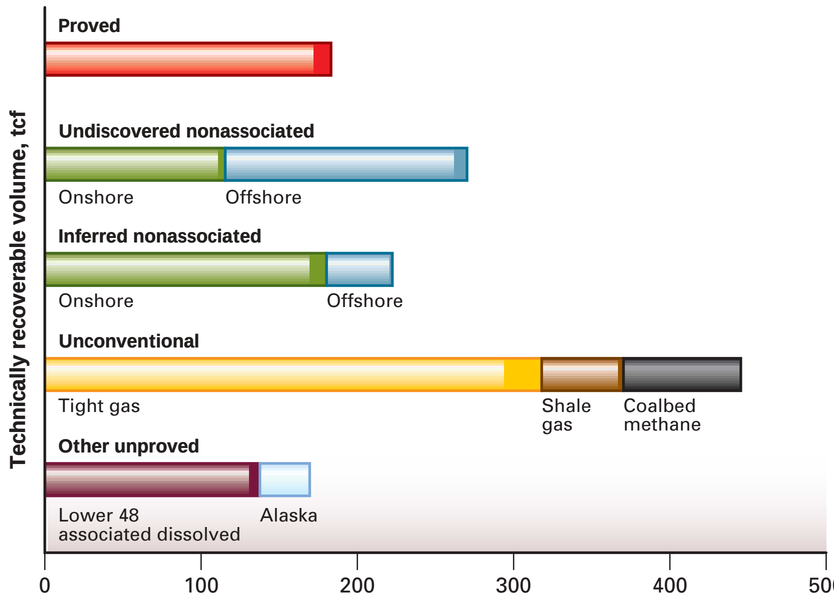
ring in coalbed methane and shale gas.

When viewed geographically, the lion's share (more than 70%) of these resources is thought to be located in the Rocky Mountain region. As a result, expansion of unconventional gas production from the Rocky Mountain region is critical to the future gas supply of the nation and figures prominently in all scenarios (e.g., Fig. 3).

The Rocky Mountain region already accounts for 18% of domestic gas production; however, it is anticipated that the region will further increase its gas production, on a sustained basis, by 2.7 tcf/year by 2020-25, the vast majority of which is anticipated to come from low permeability gas supplies. In fact, some forecasts[3] suggest that gas production from the Rocky Mountain region may account for as much as 39% of total domestic production by 2025, the vast majority of which will come from unconventional, low-permeability sandstone reservoirs.

TECHNICALLY RECOVERABLE US GAS RESOURCES

Fig. 2



Source: Energy Information Administration, Annual Energy Outlook 2003, Fig. 10. Data as of Jan. 1, 2002.

Because gas production from unconventional sources figures so prominently in virtually all scenarios of gas supply, it is critical that the nature of the resource and the attendant risks be well understood. By understanding the resource and the associated risks prudent financial decisions can be made by industry and thoughtful policy can be developed.

In the remainder of this article we discuss the nature of these tight-gas resources and how a new paradigm concerning their occurrence may have significant implications for resource assessment, risk analysis, and the construction of scenarios for both industry and policymakers.

Prevailing paradigms

Unconventional gas resources generally comprise coalbed methane, shale gas, and 'tight-gas' (gas hosted in low permeability sandstones). Of the 445-475 tcf of technically recoverable gas resources thought to occur, 315-340 tcf are proposed for tight-gas resources.[2]

These resources are predominantly concentrated in the Rocky Mountain region where they are thought to occur in the central, deeper portions of sedimentary basins. These resources have been widely characterized as 'basin-centered gas,' 'deep-basin gas,' 'continuous-type gas accumulations,' etc. Although many of these terms are well engrained in both the technical and nontechnical literature, we find the terms to be misleading and refer to these either as 'tight gas' or as 'gas resources in low permeability reservoirs.'

Unconventional tight-gas resources are generally perceived to be large accumulations of natural gas hosted in very low permeability sandstones. Gas fields located in these regions are thought to lack well-defined gas-water contacts, and wells drilled in these areas often record gas shows while drilling, produce only modest volumes of water, and are commonly abnormally pressured.

These attributes coupled with the proximity of many subsurface reservoirs to coal-bearing strata, led early workers to develop a model in which vast portions of sedimentary basins were viewed as gas saturated and at or near irreducible water saturation.

The resource volumes commonly associated with these provinces are impressive and have been estimated to be in the tens or hundreds of trillions of cubic feet of gas for technically recoverable volumes, and thousands of trillions of cubic feet of gas for gas in place. Many of the attributes of these tight-gas provinces were not easily explained in terms associated with conventional petroleum provinces, leading to the conclusion that these were a distinct type of petroleum system with behaviors not accounted for in conventional petroleum systems.

This history is of more than just academic interest. The fundamental perception that these gas systems behave differently from conventional oil and gas systems underlies the methods used to assess resources and has led to a view that these resources have significantly less geologic risk than their conventional counterparts.

Studies of unconventional natural gas by the EIA and NPC suggest that the commercial viability of tight gas is largely a function of innovations in drilling and completion technology, gas price, and land access. The common risks that figure so prominently in conventional gas exploration, risks related to source, migration, trap, reservoir, and seal, are thought to be substantially less important in natural gas systems characterized as 'continuous type' or 'basin-centered' gas accumulations.

In point of fact, the predominant risks are perceived to have shifted from the exploration side to the 'extraction' side where innovations in drilling and completion technology are thought to be crucial to economic recovery. Scenarios for natural gas supply in effect treat these tight-gas volumes as an enormous 'natural gas bank' where withdrawals are governed by innovations in the extraction technologies, an improved regulatory climate, and associated cost-of-supply functions.

Scenarios that attempt to shed light on gas-supply functions routinely consider subtle variations in economic growth factors or the rate and nature of technology development, or changes in regulatory affairs. These scenarios do not, however, routinely consider substantial variation in either the size or uncertainty of the resource volume itself.

The very notion that these gas resources are regarded as technically recoverable implies that their location and geologic setting are reasonably well understood and that a step-function change in extraction technology is required for commercial production.

Change in paradigms

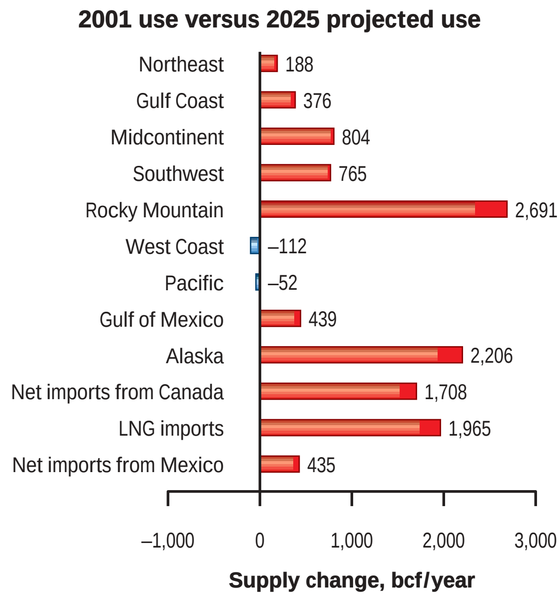
The Green River basin of southwestern Wyoming has long been viewed as a "classic basin-centered gas" province with cumulative production in excess of 11.7 tcf equivalent (as of October 2002).

We examined all fields with an expected ultimate recovery (EUR) in excess of 50 bcf gas to determine the fundamental controls on gas production.[4,5,6] These fields represent more than 92% of the total gas production from the Green River basin.

Of some 53 fields examined, 100% were found to occur in conventional structural, stratigraphic, or combination traps (Fig. 4); 38% of the fields were found to be in structural traps accounting for 50% of the basin's production, 41% were found to be stratigraphic traps accounting for 30% of the basin's production, and 21% were found to be in combination traps accounting for 20% of the basin's production.

PROJECTED CHANGES IN US GAS SUPPLY

Fig. 3



Source: Energy Information Administration, Annual Energy Outlook 2003, Fig. 84.

We also examined the nature of water production from the Green River basin and found that water production is both common and widespread[6] despite the prevailing notion that the basin is at or near irreducible water saturation. Within the Green River basin, although produced volumes are not prodigious on a per-well basis, 70% of the gas wells produce significant amounts of formation water.

These wells account for almost 50% of the gas production from the basin. The lack of unequivocal gas-water contacts similar to those found in conventional provinces is not due to large portions of the basin being at irreducible water saturation, as had been previously suggested, but instead results from the relative permeability properties of these very low-permeability reservoirs.

Low-permeability reservoirs have such low effective permeability to gas that conventional models of multiphase fluid flow must be reconsidered. The lack of well-defined gas-water contacts, the low overall volumes of produced water, and the common occurrence of gas shows neither require nor imply a basin that is gas saturated or at irreducible water saturation. In fact, the data clearly support a basin in which reservoirs are charged by buoyancy-driven processes and where an understanding of trap geometry and seals as well as low-permeability petrophysics is critical.

Implications

This change in perspective regarding the controls on gas production from what was once a 'classic basin-centered gas' province has profound implications at a number of levels.

The paradigm of a continuous resource largely dependent on improvements in extraction technology has thoroughly permeated virtually all aspects of the natural gas industry from resource assessments to policy, from exploration philosophy to production, from research emphasis to financial decision making. In the following we discuss how a change in paradigms may have impact.

Resource assessment

Resource estimates attempt to quantify the state of knowledge regarding resource distribution in a meaningful manner such that informed decisions can be made by policymakers, government research organizations, the investment community, and industry.

Because technology changes with time, periodic reassessments are necessary and assessed volumes change with time, perspective, and technology. To date, resource estimates of tight gas have had embedded a fundamental perspective that (1) buoyancy is not a dominant process, and (2) that large areas of a basin are gas saturated and at or near irreducible water saturation.

These embedded assumptions have a direct impact on the assessment process and, in our opinion, bias assessments towards very large resource estimates. Within the US three groups have conducted resource estimates in these low-permeability gas provinces with each group using a different approach.

The US Geological Survey conducts perhaps the most rigorous resource assessment of the three groups. Based on an analysis of available data, a decision is made as to whether a petroleum system contains a 'continuous gas' accumulation.

If a 'continuous accumulation' is thought to be present then the analysis takes on a more statistical view in which cells are aggregated and integrated with concepts related to production rate, drilling success, drainage area, and the likelihood that a sweet spot will occur to produce a probabilistic estimate of the technically-recoverable gas resource.[7]

Although Charpentier[8] suggests that a single evaluation methodology can be used for 'conventional' and 'continuous' gas accumulations, recent assessments by the USGS treat 'conventional' and 'continuous' type assessments very differently. Recent assessments of the Green River basin by the USGS suggest that 80.6 tcf gas and 2,500 million bbl of natural gas liquids (NGL) are present (P50 estimate) in low-permeability, 'continuous gas' accumulations.[9]

The Department of Energy (DOE) and its' National Energy Technology Laboratory (NETL) conduct resource assessments with a view to assessing which technologies are likely to impact future gas supply. Because the notion of a technically recoverable gas resource already carries with it some idea about appropriate technologies, DOE/NETL attempts to describe the gas-in-place (GIP) preferring to evaluate which technologies might be appropriate as a separate step.

The GIP calculation is based on conventional hydrocarbon pore-volume calculations integrated with perceptions regarding technology development and extraction costs.[10 11] Recent assessments of gas-in-place for the Green River basin using this approach are in excess of 3,000 tcf of gas. Boswell[11] suggests that much of this gas is currently uneconomic; however, he goes on to suggest that with 'foreseeable technology' dramatic changes in recovery are possible, reinforcing the idea of a very large 'natural gas bank.'

The third approach to resource estimation is to have a team of experts consider the geology, production history, trends in technology, the nature of analog deposits, etc., to develop a resource estimate. This approach is the essence of the technique used by the Potential Gas Committee (PGC). Recent estimates by the PGC for the Green River basin suggest a most-likely resource of 18.4 tcf gas.[12] Although the PGC does not specifically address low-permeability resources, the majority of gas in the Green River basin is in this resource category.

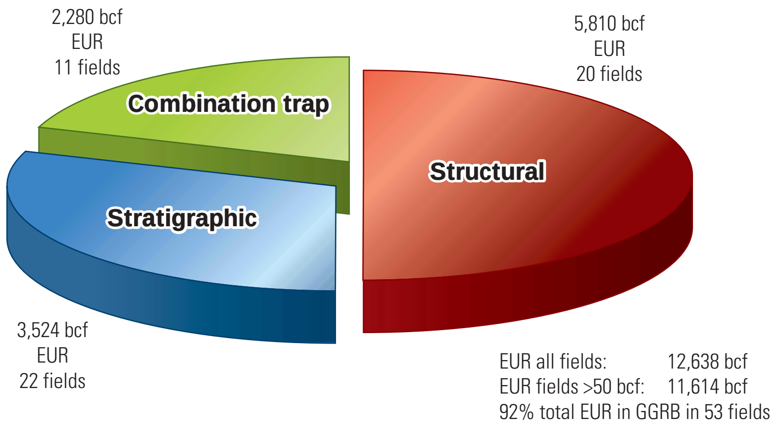
These three approaches to resource assessment are the foundation for virtually all published discussions regarding resource distribution. Other groups that develop statements and scenarios regarding natural gas resources rely on one of these three approaches to resource assessment and apply modifications based on specific goals and objectives.

Importantly, none of the groups engaged in resource estimation has undertaken a critical reexamination of the fundamental elements of the 'basin-center' or 'continuous type' gas accumulation model. Of the three groups and methods described, by far the most widely cited figures are those developed by the USGS. Its figures form the backbone of economic models and forecasts constructed by both the EIA and the NPC.

Our work[4 6 13] suggests that conventional traps dominate the Green River. Accumulations are buoyancy driven

GREATER GREEN RIVER BASIN FIELDS >50 BCF EUR

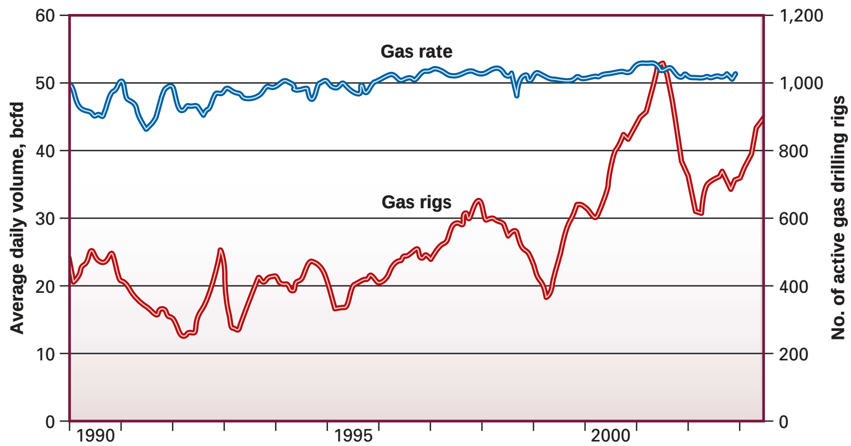
Fig. 4



Source: Data in part from Gas Research Institute 94/0363, Barlow et al., 1994

HOW RIG BOOM FAILED TO CAUSE GAS SUPPLY SPIKE

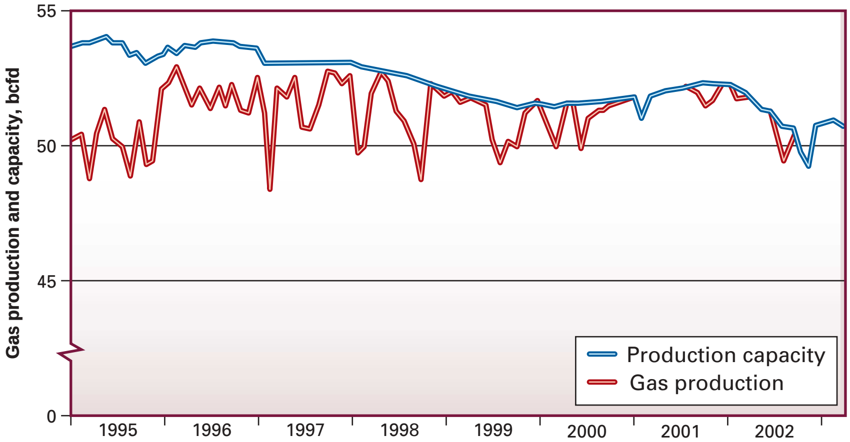
Fig. 5



Source: National Petroleum Council, 2003, Fig. 30.

HOW LOWER 48 GAS PRODUCTION CAPACITY HAS DISAPPEARED

Fig. 6



Source: National Petroleum Council, 2003, Fig. 12.

and are discretely distributed in a manner similar to that found in conventional oil and gas provinces where fields are determined by the elements of source, migration, trap, reservoir, and seal.

We see no evidence that the basin is either gas saturated or at irreducible water saturation. In addition to discretely distributed accumulations, it is likely that there is a considerable volume of gas-in-place that occurs at water saturations too high for effective flow, regardless of technology and price. It is also likely that there is a considerable volume of gas in small subeconomic traps, similar to all petroleum provinces.

We suggest that resource estimates of technically-recoverable natural gas in basins similar to the Greater Green River basin have overstated the likely volumes by a factor of at least 3 to 5 and have significantly underestimated the uncertainty associated with these natural gas resources.

Resource estimates should account for the conventional nature of gas accumulations in these tight-gas provinces, incorporate an analysis of field-size distribution, discovery-timing, etc. Scenarios that attempt to explore what future conditions might look like may wish to consider substantially greater variation in the volume of unconventional gas than has been considered thus far.

Implications for gas supply

Future gas supply models are largely predicated on having access to a very large 'bank' of unconventional gas from which withdrawals can be made as technology improvements and cost-of-supply functions warrant.

In its recent report, the NPC[1] considered industry's ability to bring on substantial volumes of unconventional gas critical to the nations' future gas supply. This viewpoint is echoed in the recent Annual Energy Outlook[3] in which unconventional gas production is expected to increase from 5.9 tcf/ year in 2003 (32% of total production) to 9.2 tcf/year (43% or total production) in 2025.

The change in our understanding of these tight-gas systems coupled with recent analysis of drilling success and production capacity indicates that these simple gas-supply models should be reexamined. The time period 1999 to 2001 was characterized by more than a doubling in drilling activity in the Lower 48. The majority of wells drilled during this time period were characterized by low initial rates and low per-well ultimate recoveries, two characteristics of many tight-gas wells.

The supply response to this near doubling in rig activity was an increase in wellhead deliverability of less than 5%.[1] This challenges the idea that substantial increases in supply can be accomplished simply by drilling much larger numbers of wells (Fig. 5).

In addition, an examination of the natural gas market in terms of productive capacity and gas production suggests that the natural gas market has experienced considerable tightening, has become increasingly efficient and has limited excess capacity. As a result, natural gas markets are less able to absorb changes in demand or supply without a significant price swing (Fig. 6). These studies[1] suggest that this dynamic will continue until additional supplies are brought to market creating increased demand flexibility.

Our work suggests greater uncertainty in the volume of natural gas and, when combined with the market forces described by the NPC[1] are likely to result in far greater upward pressure on long-term prices than downward pressure. If unconventional gas sources were unable to meet the projected supply, then further market tightening would seem inevitable providing even greater upward pressure on price.

Implications for risk analysis

In the upstream exploration sector, risk analysis attempts to quantify the uncertainties associated with an investment decision or a series of decisions.

An accurate, calibrated understanding of both technical and nontechnical risk allows an enterprise to make informed decisions, to develop strategies that are consistent with its degree of risk tolerance, and to employ its capital in an efficient manner. To the degree that risks are not fully appreciated, enterprises can destroy value by not employing resources efficiently or prudently.

The notion of vast portions of a basin being gas saturated and at or near irreducible water saturation has led to a perception that these provinces are relatively low risk, particularly from the standpoint of geologic risks associated with the petroleum system. The characterization of these very large gas volumes as 'technically recoverable' contributes to a perspective that the gas is known to exist, but getting it out of the ground is the main problem.

In effect the perceived risks have shifted from the geological domain, which captured uncertainty in the resource itself, to the engineering domain where the focus has been on improved methods of recovery and extraction.

As a result of the widely held perception that tight gas is largely an 'extraction' problem, many enterprises attempting to diversify their portfolio view tight gas as the low-risk portion of a balanced portfolio. For these enterprises tight gas becomes a play type in which geological risk is reduced, gas volumes become more certain, reserve life increases, and the focus shifts to extraction. This perspective of risk impacts decisions about how to enter and prosecute a play, the evaluation of proved and undeveloped assets, and when to acquire critical, defining-type data-sets, etc.

Our work suggests, however, that all the common geological risk elements of the conventional petroleum system exist in tight gas. In fact, it could be argued that because of additional risks related to formation evaluation and low-permeability petrophysics, the risks associated with tight gas may in some cases exceed risk levels commonly thought of in more conventional provinces.

In conventional petroleum provinces critical data, such as 3D seismic data and core data, are often acquired early in the life cycle of play development because the data can significantly reduce the risks associated with play definition. In unconventional, low-permeability gas provinces, however, the acquisition of 3D seismic data and core data are often postponed in favor of drilling wells because it is perceived that conventional traps are of limited importance and that the improvement in risk is limited.

An understanding of trap, seal, reservoir, and particularly reservoir petrophysics, is absolutely critical in the development of low-permeability gas resources. The risks associated with finding commercial tight-gas resources are substantially greater than is generally appreciated and are not simply functions of improved extraction technology.

Exploration methods, therefore, should recognize the increased risk up front and develop methods, either technical or business related, such that the risks are mitigated and in line with corporate goals. Simply amassing large acreage positions, describing them as 'basin-centered,' and focusing on extraction is in our view overly optimistic and simplistic. Failure to adequately address these elements has led to the drilling of exploration wells that had little chance of success.

By no means should our views of the resources associated with tight gas be construed to suggest that there is a lack of opportunity and potential. Many of these basins have rich source rocks that have been subjected to adequate thermal conditions, they have complex tectonic histories of burial and uplift, and they contain a myriad of reservoirs and seals.

Within this complexity lies opportunity for additional gas discoveries. These future discoveries, however, are likely to occur as a result of careful, deliberate exploration that makes full use of available technology to both define possible trends and to understand the associated risks early in a project lifecycle. Economic success is likely to come to those enterprises that can successfully marry an understanding of the subsurface with prudent risk management.

Exploration programs that approach these provinces as a 'resource play' are likely to consume value in drilling wells that have little chance of success as opposed to adding value through the discovery process. The use of concepts related to 'continuous-type' or 'basin-centered' accumulations should be restricted to certain coalbed methane deposits, certain low-permeability reservoirs that are closely juxtaposed to oil-prone source rocks, or shale-gas systems.

What it means

A change in our understanding of the controls on tight-gas production based on an examination of fundamental processes has led to the view that tight-gas production, as exemplified by the Green River basin, is far more conventional than is widely appreciated.

There is much greater uncertainty in the technically recoverable tight-gas resource base and far greater risk than is generally acknowledged. This has important implications for the development of energy policy which presently does not consider substantial variability in the size of the unconventional resource base or the associated risk within its scenarios.

Resource assessments should be critically reexamined. This work also has important implications to enterprises engaged in exploration, production, acquisition, and transportation of natural gas from provinces rich in tight-gas resources. ✦

References

1. National Petroleum Council, "Balancing Natural Gas Policy—Fueling the Demands of a Growing Economy, Vol. 1—Summary of Findings and Recommendations," Report of the National Petroleum Council, Sept. 25, 2003.

2. Energy Information Administration, Annual Energy Outlook 2003 with Projections to 2025: DOE/EIA 0383(2003) January 2003 (www.eia.doe.gov/oiaf/aeo).

3. Energy Information Administration, Annual Energy Outlook 2004 with Projections to 2025: DOE/EIA 0383(2004) January 2004 (www.eia.doe.gov/oiaf/aeo).

4. Shanley, K.W., Cluff, R.M., Shannon, L.T., and Robinson, J.W., "Potential of basin-centered gas," National Academy of Science, US Natural Gas Supply and Demand: A Workshop, Apr. 21, 2003.

5. Shanley, K.W., Cluff, R.C., Shannon, L.T., and Robinson, J.W., "Factors controlling prolific gas production from low-permeability sandstone reservoirs: implications for resource assessment, prospect development, and risk analysis," abs., AAPG annual meeting, Salt Lake City, 2003.

6. Shanley, K.W., Cluff, R.M., and Robinson, J.W., "Factors controlling prolific gas production from low-permeability sandstone reservoirs: implications for resource assessment, prospect development, and risk analysis," AAPG Bull., Vol. 88, No. 8, 2004, pp. 1,083-1,121.

7. Schmoker, J.W., "Resource-assessment perspectives for unconventional gas systems," AAPG Bull., Vol. 86, 2002, pp. 1,993-99.

8. Charpentier, R.R., "Conventional

and continuous oil and gas accumulations–a spectrum, not a dichotomy," abs., AAPG annual meeting, Dallas, 2004.

9. Kirschbaum, M.A., Finn, T.M., Hettinger, R.D., Johnson, E.A., Johnson, R.C., Kibler, J., Lillis, P.G., Nelson, P.H., Roberts, L.N.R., Roberts, S.B., Charapentier, R.R., Cook, T.A., Crovelli, R.A., Klett, T.R., Pollastro, R.M., and Schenk, C.J., "Assessment of undiscovered oil and gas resources of the Southwestern Wyoming, 2002," US Geological Survey, National Assessment of Oil and Gas Fact Sheet, FS-145-02, December 2002 (http://pubs.usgs.gov/fs/fs-145-02/fs-145-02.html).

10. Boswell, R.M., Douds, A.S.B., Pratt, H.R., Rose, K.K., Pancake, J.A., Bruner, K.R., Kuuskraa, V.A., and Billingsley, R.L., "Assessing technology needs of sub-economic resources: Phase 1: Greater Green River and Wind River Basins, Fall 2002," in Natural Gas Resources of the Greater Green River and Wind River Basins of Wyoming, NETL/DOE CD #2002/1176, Final Version, February 2003.

11. Boswell, R.M., "Natural gas resource assessment at DOE's National Energy Technology Laboratory," abs., AAPG annual meeting, Dallas, 2004.

12. Potential Gas Committee, "Potential supply of natural gas in the US (Dec. 31, 2002)," Potential Gas Agency, Colorado School of Mines, March 2003, 316 p.

13. Cluff, R.C., Shanley, K.W., and Byrnes, A.P., "Permeability jail and implications for "basin-centered gas" production and resource assessment," abs., AAPG Rocky Mountain Section Meeting, Denver, 2004.

The authors

Keith W. Shanley (shanleypk@msn.com) is a consulting geologist with more than 22 years' experience in exploration, development, and research. His current research interests include sequence stratigraphy and reservoir architecture, the integration of petrophysics, and risk analysis. He received a BA in geology from Rice University and an MSc and PhD in geology from the Colorado School of Mines.

Bob Cluff (bobcluff@discovery-group.com) is a geologist whose research interests include the integration of geology with petrophysics and the evaluation of nonconventional reservoirs. He has a BS in geology from the University of California-Riverside, MS from the University of Wisconsin-Madison, with additional studies elsewhere in geology, math, and physics. He founded the Discovery Group in 1987.

John W. Robinson (robinson_jw@msn.com) is a consulting geologist in Denver and has 30 years of experience in exploration and development. His research interests are in fluvial sedimentology and multidisciplinary reservoir studies. He received BS and MS degrees in geology from San Diego State University, and a PhD in geology from Colorado School of Mines.