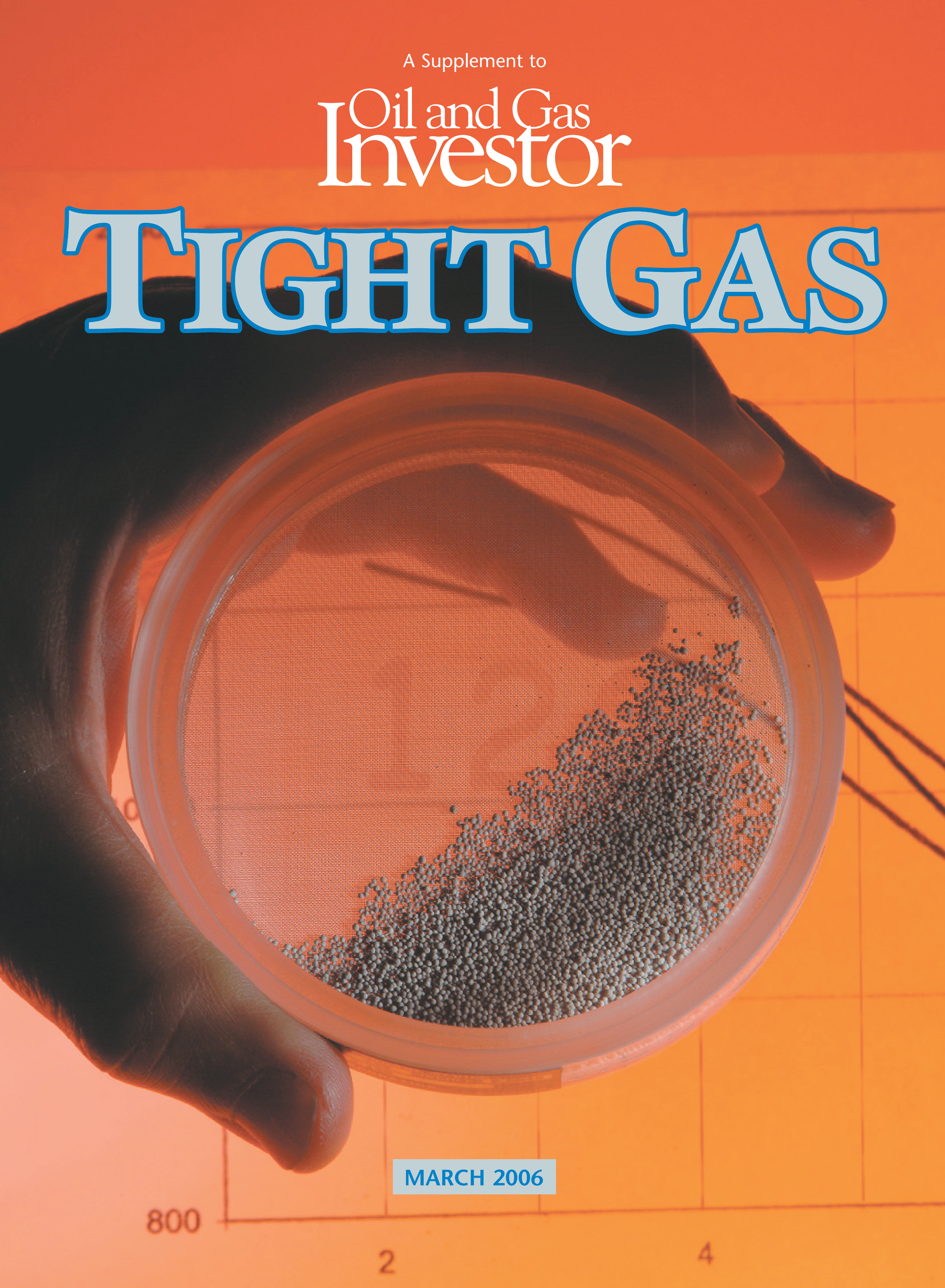
A Supplement to

Oil and Gas Investor

TIGHT GAS



MARCH 2006

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ABOUT THE COVER: Photo courtesy of Carbo Ceramics, Inc.

Greatest Production for Tight-Gas Reservoirs in Rockies

In 2005 the U.S. was dealt a solid blow from two hurricanes, causing natural gas production from the Gulf of Mexico to be temporarily knocked off line. Some production is still not back to pre-storm levels.

This test of supply reliability reminded us all that diversity of gas supply is important. But onshore, producers are now able to increase production from a diverse number of basins with tight-gas reservoirs, thanks to better frac technology and regulators who are open to increased well density (downspacing) in certain plays.

Tight-gas sands and shales in the U.S. may contain as much as 460 trillion cubic feet (Tcf) of gas, according to the U.S. Geological Survey (USGS). If some 135 Tcf of that is economically recoverable, as the USGS estimates, then that spells plenty of supply and opportunity for years to come.

It is clear that the market will demand more of that gas be produced, and it is clear that independent producers know it. Chesapeake Energy's $2.2-billion acquisition of Columbia Natural Resources last year, giving it a major presence in a tight-gas region, the Appalachian Basin, is just one strong market signal that access to more tight-gas drilling locations is the way to the future for companies' growth and consumers' needs.

Tight-gas sands now account for about 15% of U.S. gas production. The gas comes from most basins, including Rocky Mountains plays in the Piceance and Uinta basins, the Pinedale Anticline in Wyoming, the Cotton Valley of East Texas, and the South Texas Lobo play. As operators drill deeper, those wells tend to tap tighter formations.

From 2003 to 2025, the greatest production growth from tight-gas reservoirs is forecast to occur in the Rockies, particularly in the Greater Green River, Uinta and Piceance basins.

This report brings you information on several of the key areas where burgeoning tight-gas production will make an impact.

—Leslie Haines
Editor-in-Chief

Contents

Frequently Asked Questions

Tight-gas reservoirs are responsible for more than 15% of U.S. natural gas production. Here are answers to some common questions about this burgeoning resource.

What is tight gas?

"Tight gas" refers to natural gas produced from reservoirs that have very low porosities and permeabilities. Reservoirs are usually sandstone, although carbonate rocks can also be tight-gas producers. The standard industry definition for a tight-gas reservoir is a rock with matrix porosity of 10% or less and permeability of 0.1 millidarcy or less, exclusive of fracture permeability.

How prevalent are tight-gas reservoirs?

Tight-gas reservoirs are found throughout the world and occur in most of the common types of reservoir rocks. Although the resource has been known for many decades, commercial development didn't kick off until the 1970s when demand for natural gas increased, prices rose, and drilling and completion technologies improved. At present, almost all commercial tight-gas development is in the U.S. and Canada.

How important is tight gas to U.S. natural gas production?

Tight-gas reservoirs supply more than 15% of U.S. natural gas production. By themselves, tight-gas reservoirs produce volumes nearly equal to the combined production from the other major sources of unconventional gas, including coalbed-methane, shale and deepwater reservoirs. In 2003, the U.S. Energy Information Administration predicted that tight-gas production would surge from 3.3 trillion cubic feet (Tcf) in 2001 to 6.8 Tcf in 2025. Estimates of the volume of recoverable gas in tight reservoirs in the U.S. range from 200- to 550 Tcf.

Where are tight-gas plays found in the U.S.?

Major tight-gas plays in the U.S. include the Cotton Valley in East Texas; the Mesaverde in New Mexico's San Juan Basin; the Canyon sands in the Permian Basin of West Texas; the Wasatch in Utah's Uinta Basin; the Wilcox/Lobo in South Texas; and the Lance, Dakota and Frontier formations in Wyoming's Green River Basin. About half of the nation's tight-gas proved reserves are in the Rocky Mountain region, and all areas of the country hold significant resources, with the exception of the West Coast.

How do companies explore for tight-gas deposits?

While tight-gas plays tend to cover broad areas and support hundreds if not thousands of wells, the successful explorer does not drill random locations. Reservoir thickness and distribution, structural position, reservoir pressures, water production and natural fractures are just a few of the geological factors that must be weighed. Effective development of tight-sand resources requires a thorough understanding of the subsurface.

What is the most critical technology for tight-gas wells?

Hydraulic fracturing is the key technology in tight-gas development. Most tight reservoirs have to be fractured before they will flow gas at commercial rates. In the 1980s, thick, cross-linked polymer fluids that carried tremendous volumes of sand were popular for tight-sand reservoirs, but the high cost of these treatments rendered many plays uneconomic. In the 1990s, slick-water fracturing techniques were developed that used high volumes of water and low concentrations of proppant. These jobs were much less expensive and opened some new areas to commercial development. Multi-stage fracturing was another advance, allowing several stages to be treated in quick succession. At present, operators use a variety of techniques, the choice depending on the particular characteristics of a reservoir. ■

The Grande Dame Of Tight Gas

Long-established tight-gas plays still yield drilling opportunities in the gas-rich Appalachian Basin, while an emerging resource play offers intriguing new possibilities.

BY PEGGY WILLIAMS, Senior Exploration Editor

The Appalachian Basin is the matriarch of the oil patch. More than a million wells have been drilled into its Paleozoic sediments, which have yielded more than 70 trillion cubic feet (Tcf) of gas equivalent. Despite its old-line pedigree, the Appalachians remain an essential player in the nation's gas supply and a home where independent operators can thrive because of favorable finding costs, sturdy rates of return and low-risk drilling.

The first commercial attempt to drill for natural gas was in 1821, when entrepreneur William Hart drilled a well to the depth of 70 feet in the Devonian Dunkirk Shale in Fredonia, New York. Gas discoveries followed in 1860 in Pennsylvania, 1861 in Ohio and 1863 in Kentucky.

In the decades since, through manifold booms and busts, people have been drilling wells in Appalachia, the largest onshore basin in the U.S. Today, more than 147,000 active wells are producing 680 billion cubic feet (Bcf) of gas a year.

While the Appalachian Basin spans an immense area with myriad geologic plays, tight-gas reservoirs are an integral part of its remaining resource base. From the top down, major tight-gas plays occur in Mississippian sandstones and carbonates in Ohio, West Virginia and Kentucky; Upper Devonian sandstones and shales in Pennsylvania, West Virginia and Kentucky; and Silurian sandstones in New York, Pennsylvania and Ohio.

Mississippian reservoirs

The youngest tight-gas reservoirs in Appalachia are found in the Mississippian section, divided among sandstones and carbonates.

A major Mississippian reservoir is Ohio and West Virginia's Berea sandstone. In the Buckeye State, more than 12,400 wells have been drilled into the Berea, which consists of shallow marine sands found at depths down to 6,000 feet. A typical well can recover up to 400 million cubic feet of gas.

The Federal Energy Regulatory Commission has declared the Berea tight throughout much of eastern Ohio. The heyday of Berea drilling was in the early 1980s, when 700 to 800 wells a year were drilled in the state. That level has dropped as the play has matured, and fewer than 120 Berea wells were drilled in the five years between 2000 and 2004, according to Ohio's Division of Mineral Resources Management.

The Berea play also extends into West Virginia, but that state took a different approach to tight-gas designations. It applied for county by county, and by formations or plays within each county or group of counties, says Katherine Lee Avary, with the West Virginia Geological Survey. West Virginia's tight-gas designations cover several Mississippian reservoirs.

In addition to the Berea, sands in the Mauch Chunk formation, such as the Ravencliff and Maxton, are included, as are the Mississippian Big Lime carbonate, and Big Injun, Squaw and Weir reservoirs.

Kentucky's designations include the Berea in Pike and Lawrence counties, and the Big Lime in Harlan County. In Tennessee, the Mississippian Monteagle formation has been designated tight. Gary Pinkerton of the Tennessee Geological Survey says Scott, Morgan, Fentress and Anderson counties in north-central Tennessee are known to produce from Monteagle.

Upper Devonian

When Col. Drake drilled his historic well in 1859 in Venango County, Pennsylvania, he hit oil in an Upper Devonian sandstone. His discovery opened a prolific oil and gas play that stretched across western Pennsylvania and northern West Virginia. According to the U.S. Geological Survey (USGS), about 800 oil and gas fields have been discovered in this slice of Devonian sediments.

A series of sandstones in the Venango, Bradford and Elk groups produce stratigraphic traps, and more than 30 prospective sand lenses come and go within the encasing shale.

Reservoirs are often stacked and are found at depths ranging from 1,200 to 5,500 feet. A typical Upper Devonian well costs between $150,000 and $170,000, depending on depth, and recovers up to 300 million cubic feet of gas.

Although the Upper Devonian play is heavily drilled, infill work continues. The reservoirs on the eastern edge of the play, in Jefferson, Indiana, Westmoreland, Fayette, Cambria and Clearfield counties, have tight formation status.

"Essentially, all of the Upper Devonian sandstones from the Allegheny and Monongahela rivers east to the Allegheny Mountains are considered tight here," says John Harper of the Pennsylvania Geological Survey. Excepted are the oil fields and certain sweet spots where the porosities and permeabilities are high enough for gas to flow naturally.

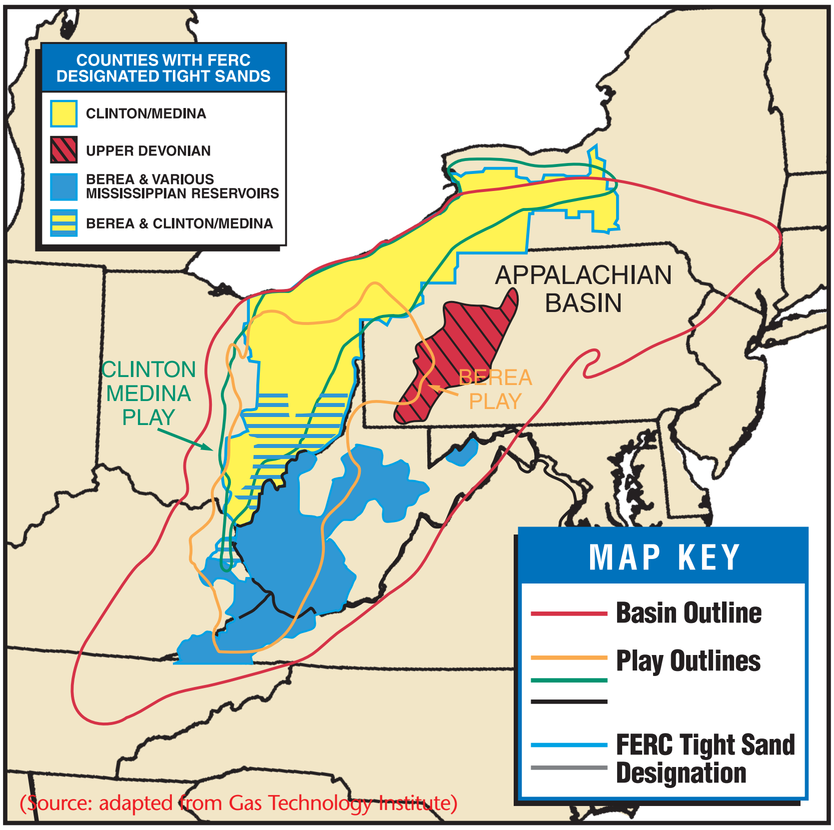
In addition to the sandstone lenses, in Kentucky the Devonian black shales are classified as tight-gas formations. These shales have been producing commercial quantities of natural gas since 1892.

One small public firm has recently acquired a tight-gas project in Clay County, Kentucky. Energas Resources, based in Oklahoma City, says its Parkway property is prospective from Mississippian Big Lime and Waverly and Devonian Shale.

To date, Energas has bought 23 shut-in wells in a rural corner of Clay County. The wells, ranging in depth from 1,800 to 3,700 feet, had been drilled for oil in the 1950s and 1960s. Some crude was found and produced, but the gas reservoirs that were also encountered had been shut in for decades and basically forgotten.

Energas thought the wells had potential for rejuvenation, but there was no pipeline into the property. The company flowed nine of the wells on a half-day test and was sufficiently encouraged by the pressure readings to build a line. The six-inch, 3.5-mile pipeline to connect the wells to sales is nearly complete, says Scott Shaw, executive vice president. "We expect the pipeline to be finished first-quarter 2006."

The next step will be to tie the wells into sales and see how they perform, he says. The company is interested in recompletions and perhaps new drilling. The wells were apparently not treated with modern stimulations, or logged with modern logging tools.



Appalachia's extensive tight-gas plays occur in Silurian, Devonian and Mississippian sandstone and carbonate reservoirs.

"The tests were encouraging, and we're excited about the area," says Shaw. "What was not economic years ago can be very economic at today's gas prices and with today's technologies."

Silurian sandstones

Lower Silurian Clinton/Medina sandstones are prospective in a 17,000-square-mile arc that stretches from southern New York through northwest Pennsylvania and into eastern Ohio and Kentucky. The USGS has estimated that several tens of Tcfs of recoverable gas still remain in the extensive Clinton and Medina reservoirs.

Large-scale development of Clinton fields started in the early 1900s along the updip edge of the play in east-central Ohio, where oil was a target. Drilling gradually moved eastward, marching deeper into the basin and encountering more gas-prone areas.

In eastern Ohio, the red, white and stray Clinton sands are found at depths between 4,000 and 6,500 feet. A typical well might encounter a prospective section between 100 and 200 feet thick, with about 25 feet of net pay. Recoveries per well range from 80- to 275 million cubic feet. More than 77,000 Clinton wells have been drilled in Ohio since 1887, when a 1,957-foot well in North Berne Field in Fairfax County established first production from the reservoir.

The Silurian play continues into northwestern Pennsylvania's Erie, Crawford, Mercer, Warren and Venango counties, where the sands are called Medina. A typical well in this area reaches about 6,000 feet.

In western New York, the Silurian Medina and Whirlpool sands are shallower, found between 1,000 and 4,000 feet deep. Erie and Chautauqua counties were the sites of tremendous drilling programs mounted by small independents in the 1980s; some 1,200 wells still produce from Medina in those counties.

Kentucky also has tight-gas production from Silurian reservoirs. Brandon Nuttall of the Kentucky Geological Survey says the Clinton and Big Six sands are designated tight-gas reservoirs in Lawrence and Johnson counties, as is the Silurian/Devonian Corniferous.

Although the Silurian Clinton/Medina sandstones have been intensively drilled, the tight reservoirs remain rewarding. One firm that holds thousands of locations is Range Resources, based in Fort Worth, Texas.

Range, which traces its roots to Appalachia, holds 1.9 million net acres and produces 96 million net cubic feet per day from the basin. Tight-gas drilling is one of four major initiatives it pursues in Appalachia, in concert with deep exploration, coalbed-methane and shale-gas programs. This year, Range has budgeted $197 million for its activities in the region.

The company holds an impressive stock of 2,310 proven tight-gas locations and more than 1,000 locations that are unbooked.

"We've got a big inventory, and we are continuing to ramp up our pace of drilling in the basin," says Jeff Ventura, chief operating officer. "This drilling is very low risk: our success rate is 99 %."

The company's tight-gas locations lie in three major areas: Cooperstown/Cramerven Field in northwest Pennsylvania's Medina sands; the Canton area in eastern Ohio's Clinton; and an Upper Devonian play in western Pennsylvania. The majority of the locations are in the Silurian sands, in which a 5,500-foot well costs in the range of $270,000, and recovers between 150- and 250 million cubic feet of gas.

"We're doing both infill drilling and field expansion drilling. It's surprising, because of the age of the area, but we have a lot more locations to drill," he says.

An emerging shale play

In addition to its traditional tight-gas sand play, Range is pursuing an exploratory plan in Pennsylvania's Devonian shales. According to the Potential Gas Committee, the Devonian Ohio Shale in the Appalachian Basin holds some 225- to 248 Tcf of gas in place, with estimated recoverable gas resources between 14.5- and 27.5 Tcf.

"We like the potential of the shale in Pennsylvania, and we have leased 150,000 acres just in the shale play, and we are still leasing," says Ventura. The company completed its first well in the play at the end of 2004, in an area where the shale occurs at about 6,000 feet. It tested the well for several months. "It looked very encouraging, so we followed up last summer with three additional wells."

Two of those tests intersected the shale and deeper tight-sand reservoirs, and were completed in the tight zones at openflow rates of 1.2- and 2.1 million cubic feet per day. The third hit a strong gas flow of 1.6 million cubic feet per day from a shallow zone at a depth of about 1,000 feet. "Not only do we have an attractive shale play, we're also in a stacked pay area," says Ventura.

At present, Range has two rigs working in the area. "We're drilling our first horizontal shale well, and we'll drill two or three more," he says. The other rig is drilling vertical wells in the area. This year, the company plans to drill at least three horizontal and 10 vertical wells in the play. Range expects fracture stimulations will be required in this area, either big fracs in vertical wells or multiple fracs in horizontal wells, to make commercial rates.

"Based on initial information, we think we are in a good area, and we are encouraged," says Ventura.

That's a sentiment that sums up today's Appalachian Basin. Although it's unquestionably an aging province, it still offers operators solid, and sometimes surprising, opportunities.

East Texas Thrives

One of the world's most heavily drilled regions thrives as unconventional gas plays take off.

BY GARY CLOUSER AND DAVID WAGMAN, Contributing Editors

In East Texas, credited as the birthplace of the modern oil industry, prolific, shallow, conventional wells have long made oil the king of the region. But, as drilling has gone deeper, exploration has allowed producers to tap the so-called unconventional or tight-gas zones, long-trapped in deep, low-porosity sands.

High natural gas prices and advanced technology, particularly fracturing techniques, have spurred drilling activity and turned a once-marginal economic venture into a lucrative pursuit.

The production numbers are impressive. "The East Texas Basin is one of the most dynamic in the U.S.," says Porter Bennett, president and chief executive of Bentek Energy, a Denver-based natural gas information and consulting firm.

Compressor header for gas-gathering in the Freestone Trend. *(Photo courtesy of XTO Energy Inc.)*

Bennett estimates that last year, the basin produced about 1.3 trillion cubic feet (Tcf), or 3.6 billion cubic feet (Bcf) a day, representing a 10.7% increase over 2004 production levels. That rate of increase means East Texas had the third-highest growth rate among major U.S. production sites, trailing only the Uinta-Piceance Basin straddling Colorado and Utah (also an unconventional gas play, with a growth rate of 18.2%) and the Fort Worth Basin (driven by Barnett Shale production, with a growth rate of 13.7%).

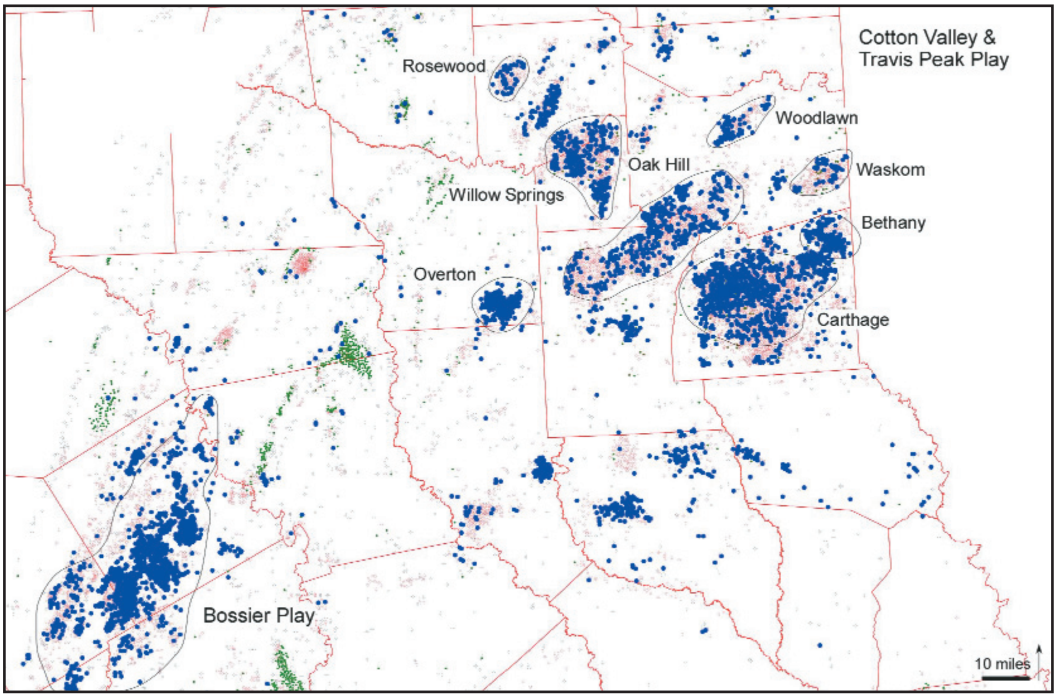
Last year, about 67% of total production in East Texas was derived from conventional formations. However, since 2000, production from the unconventional zones has grown the fastest, by 12.5%, while conventional production increased at an annual rate of about 5.5%, Bennett says.

One factor causing gas production to grow in this basin is operators' enthusiastic pursuit of tight-gas or unconventional plays. Through December 20, these plays showed cumulative production of 8.7 TCF of gas, and 61.2 million barrels of oil, says David Reimers, senior data specialist for Houston-based IHS Energy, an E&P data and consulting firm. Monthly gas production was 47.7 Bcf and daily output was 1.6 Bcf.

At year-end, some 66 operators were active in East Texas and there were 7,684 producing wells.

In East Texas (and nearby North Louisiana, which is geologically related), tight-gas sands include four individual pays: Travis Peak, Cotton Valley, Bossier (found between 12,000 and 14,000 feet), and Deep Bossier (at 15,000 feet and deeper), says Vello Kuuskraa, president, Advanced Resources International (ARI), an E&P technology development and consulting firm based in Arlington, Va., which specializes in unconventional resources.

So far, Travis Peak and Deep Bossier development has been limited to East Texas. Excluding these two plays, ARI's estimate for the Cotton Valley/Bossier plays in East Texas and North Louisiana is an ultimate resource potential of about 39 Tcf, with 20 Tcf of undeveloped resource, assuming wide-scale infill development with density of 80 acres per well. Closer well spacing would substantially increase the resource estimate.



East Texas drilling activity 2000-2005. *(Map provided by Matador Resources, Dallas)*

"The really exciting new play in East Texas is the Deep Bossier tight-gas play, which is just starting," Kuuskraa says.

The Cotton Valley formation is found throughout East Texas. This gas-bearing sandstone is found in the Overton Field in Gregg, Rusk and Smith counties, and in the Carthage Field of Panola County. The Bossier Sand of East Texas also is a continuous play of multiple fields and pay zones. Current drilling activity centers on Freestone, Henderson and Anderson counties. New development also is occurring in the Travis Peak formation in the Joaquin Field of Shelby County, and in some areas of the Freestone Trend in Freestone, Limestone and Robertson counties. A single well can find multiple pay zones of Cotton Valley, Bossier and other sand formations.

By the end of last year, a cumulative total of 9,506 wells had been drilled in Cotton Valley and 1,730 drilled in Bossier for a total of 11,276, Reimers says, with most of those occurring within the past five years.

Production from East Texas tight-gas sands (excluding the recent Deep Bossier wells) varies. Although the average well produces 1.5- to 2 Bcf over its productive life, the top 10% of the wells will produce an average of 5- to 6 Bcf, Kuuskraa says. The best wells will produce up to 8 Bcf and the lowest-quality wells will produce less than 1 Bcf. Recent higher gas prices now enable the lower-quality portions of this gas play to be economically developed, he adds.

The various Travis Peak formations are the most prolific unconventional sands in the East Texas Basin. In 2004 (the last year in which composite statistics are available), wells in the Travis Peak formation accounted for 37% of total unconventional production. The Cotton Valley Limestone and Sandstone formations accounted for 24% and 21% respectively, meaning the three groups of formations accounted for more than 80% of the total unconventional production in the basin, Bennett says.

Leading producers

East Texas production is relatively concentrated. In 2004, the top 10 producers accounted for about 77% of the basin's total production. XTO Energy was the largest operator, producing 210 Bcf, or 17% of the total. Anadarko Petroleum and Devon Energy were the second and third largest producers, respectively, in the region.

XTO also took honors as the largest unconventional gas producer, accounting for 22% of that production. Hunt Petroleum, Devon, Southwestern Energy and Marathon were the second through fifth largest unconventional gas producers, respectively, each accounting for between 6% and 9% of total unconventional production. Anadarko, XTO and Devon were the three largest operators of conventional wells; respectively they produced 18%, 16% and 10% of total conventional production, Bennett says.

Through the third quarter last year, the largest East Texas producers, combining conventional and unconventional production, were XTO, Anadarko, Devon, Samson Lone Star, Hunt Petroleum, ExxonMobil, BP Energy, Valence, Chevron and Marathon, respectively.

Southwestern Energy's East Texas production through third quarter last year was 100% from unconventional gas wells, and Marathon's production was 93% unconventional, according to the Bentek database.

XTO Energy is the largest East Texas gas producer, producing about 500 million cubic feet per day from the Freestone Trend alone. About 65% of XTO's total corporate production comes from tight-gas sands, with about 45% of it from East Texas. XTO estimates its East Texas reserve potential could be up to 2.6 Bcf a day.

The company's Freestone Trend production will increase to an estimated 730 million a day during the next three to five years, says Gary Simpson, senior vice president of investor relations and finance.

"There is not that much risk," says Keith Hutton, president. Tight-gas plays in East Texas posted 30% returns back when gas was at $2, he says. "There are already 700 wells drilled there, so we know it's going to work."

XTO currently has 20 rigs operating in East Texas. It drilled about 200 Freestone wells last year and expects to drill 250 this year. At an estimated cost of about $2 million per well, that represents an expenditure of $500 million. Through last year, the company drilled about 670 Freestone wells with plans to drill about 1,100 more within the next few years.

"The Freestone wells are prolific and fit the company's mission of low-risk, high-margin projects. XTO's Freestone wells would remain profitable even if natural gas prices dipped to about $4 per thousand cubic feet," Simpson says. With 85% of total company production coming from non-conventional plays, XTO claims to have its best low-risk drilling inventory in its history. (XTO is also the second-largest producer from the Barnett Shale.)

M&A deals capture tight gas

The announced $35.6-billion sale of Burlington Resources to ConocoPhillips signifies the return of a major integrated producer to East Texas. Burlington had made East Texas one of its core plays and had commented that discoveries there were among the largest onshore wells in the lower 48 states.

Burlington produces about 200 million cubic feet a day from its Deep Bossier play there. Before the sale was announced, the Houston company had been in an acquisition mode, most notably in the Bossier and Cotton Valley plays. In November, it paid $460 million to acquire the assets of an undisclosed private company that had been a co-owner with Burlington in the prolific Savell Field in the Bossier. Production from that 26,870 net-acre acquisition is about 50 million cubic feet a day.

ConocoPhillips' acquisition of Burlington grabbed most of the patch's end-of-year headlines as Burlington's conventional and unconventional assets would propel ConocoPhillips to number one in total North American gas production. But, that was not the only M&A deal to impact East Texas.

Oklahoma City-based Chesapeake Energy entered the play in November through a deal with Houston-based Gastar Exploration Ltd., an active producer and newly listed American Stock Exchange company with significant acreage in East Texas.

Chesapeake acquired 19.9% of Gastar's outstanding stock and 33% interests in its Hilltop Prospect area. The two companies formed a 13-county area of mutual interest agreement through an integrated three-part transaction. The Hilltop Prospect area in Leon and Robertson counties is about midway between Dallas and Houston. The primary play is the Deep Bossier sands, where Gastar and its partners have about 54,000 gross acres under lease.

"We believe that entering into this transaction with Chesapeake creates significant value for Gastar through Chesapeake's contribution of expertise, capital and access to drilling rigs and services," says J. Russell Porter, Gastar's president and chief executive. "With Chesapeake's involvement, we will be able to accelerate exploration and development drilling of the Hilltop area resulting in the creation of that value sooner, and hopefully in greater amounts, than had Gastar continued exploration and development of the Hilltop area independently."

Prior to its deal with Chesapeake, Gastar had drilled seven Deep Bossier wells in the Hilltop play. At the end of last year, Gastar was producing from four East Texas wells at a rate of about 7.5 million a day exclusively from the Deep Bossier. Just after year-end, Gastar announced the successful confirmation of a Knowles limestone discovery in the same area as its Deep Bossier activities.

The deal represents Chesapeake's initial foray into the Deep Bossier, although it is active in other nearby formations, says Tom Price Jr., Chesapeake's senior vice president, corporate development.

"This is a play that we have been looking at for a long time and have been involved in through a number of our acquisitions, though most of it in shallower formations, " he says.

Chesapeake believes the deeper, higher-pressured formations between 16,000 and 20,000 feet included in the joint venture are "likely to have greater reserves than the other plays that we've seen over the last few years," Price says.

Throughout its acreage in the Bossier, "We're expecting an average rate of 8- to 10 million cubic feet per day," Porter says. That makes the play "certainly economic at today's prices" and likely to remain economic should prices fall as low as $4 to $5 per thousand cubic feet of gas. The cost to drill and complete a well to 17,500 feet is about $9 million. Drilling and completions for prospects as deep as 21,000 feet can cost as much as $12 million.

Anadarko Petroleum has been operating in the greater Bossier Trend, which stretches across East Texas and North Louisiana, since the mid-1990s, and has discovered nearly 3 Tcf of gas there. The company holds interests in about 478,000 acres in the Bossier play.

The Bossier is a core foundation asset, says David Larson, vice president of investor relations. Anadarko plans to operate a steady five-rig program to maintain existing levels, which in third-quarter last year averaged 271 million cubic feet of gas a day. The primary area of activity is in Robertson and Leon counties.

In East Texas, Anadarko also operates a gas-gathering system that runs through the heart of the Bossier properties, as well as the Bethel gas-treating plant, which is capable of handling as much as 500 million cubic feet a day.

Canadian-based EnCana has been an active East Texas producer, targeting the Bossier and Cotton Valley zones, since 2004 through its acquisition of assets from formerly Denver-based Tom Brown Inc. EnCana has also upped its position in the play through a joint venture with privately held Houston-based Leor Energy LP.

EnCana's East Texas production last year was a little more than 90 million cubic feet per day, compared with 2004 production of 50 million a day. This year's projection calls for East Texas production of 105- to 115 million a day, says Roger Biemans, EnCana's executive vice president and president of EnCana Oil & Gas USA. EnCana spent about $220 million in East Texas last year and this year expects to spend more than $260 million.

Other producers of note

Lafayette, La.-based PetroQuest Energy, which in 2003 expanded out of the Gulf Coast region to East Texas via a

50% interest in 42,000 acres in the Carthage gas field, is currently producing about 11 million cubic feet a day from its South Carthage Field, says Todd Zehnder, vice president, corporate communications. At the time of the acquisition, the company booked reserve additions at 28 Bcf. The company identified 100 locations in Carthage and drilled about 15 wells last year, with plans to drill another 20 this year.

"The average well will have an initial production rate between 1 million and 2 million cubic feet equivalent per day and it has a hyperbolic decline curve, meaning most of the decline will be in the first six to 24 months. We book about 1- to 1.5 [billion cubic feet equivalent] per well.

"We use all types of fracs depending on what zone we are completing (in Travis Peak, we primarily use nitrogen foam fracs and in the Cotton Valley, we typically use a hybrid of slick water and gel fracs," Zehnder says.

"We have been getting long-term contracts on rigs in this area, and we line up service ahead of time to minimize downtime," he adds.

GMX Resources told investors in December that largely based on the positive results of its East Texas wells, it would more than double its capital-spending budget this year to $70 million compared with $32 million last year.

The Oklahoma-City based E&P company said it had finished drilling its 53rd Cotton Valley well in the North Carthage extension. The company's total daily production at the end of last year was about 10 million cubic feet of gas. GMX also announced it had acquired a drilling rig it had under contract in East Texas and plans to use it to continue Cotton Valley wells.

"The company expects this purchase to increase development in our North Carthage Field and to help us control the costs of our drilling," says Ken L. Kenworthy Sr., executive vice president. GMX and Penn Virginia Oil & Gas, a subsidiary of Penn Virginia Corp., formed a joint venture in December 2003 to exploit East Texas tight-gas sands.

Houston-based Southwestern Energy, whose East Texas operations are primarily in the Overton Field in Smith County, seeks to expand its position through additional development. Its Overton Field development has been a standout success. Tight-gas production, which was only 2 million cubic feet a day in March 2001, rose 10-fold to 22.2 Bcf in 2004. And, by mid-December, the production rate was about 107 million a day. This year, the company plans to invest about $196 million in East Texas.

Detailed background on these tight-gas plays is available in previous issues of *Oil and Gas Investor*. See "The East Texas Basin," February 2004; "North Louisiana," March 2004; "East Texas Gas Manufacturing (Overton Field)," August 2003; and "The Bossier," December 2000. ■

Tight Gas Is Hitting Its Stride

Despite problems with land access and rig availability, many E&P companies are devoting their attention to tight-gas sands.

BY DAVID WAGMAN, Contributing Editor

Natural gas produced from tight-sand formations is close to hitting its stride, thanks to advances in fracturing technology and strong commodity prices. Both factors help make tight-gas plays economical to develop and profitable to produce.

Some of the largest such gas reserves are in Utah's Uinta Basin and Colorado's Piceance Basin. There, companies like XTO Energy and Gasco Energy plan aggressive drilling programs for 2006.

In the Rockies, tight-gas resources appear plentiful, but getting them out of the ground poses a problem for some. Two stumbling blocks are access to federal land and a chronic shortage of drilling rigs.

Pecking order

"We're at the lower end of the food chain," says Carter Mathies, chief executive of newly formed, Denver-based Slate River Resources LLC. "We don't have the balance sheet to make long-term rig commitments."

The company shelved plans to add a second rig in January because none was available. Mathies says Slate River will make do with one rig for now and hopes to add a second later this year.

Restricted access to federal land remains an issue, but may be solvable, says Jeff Eppink, vice president of Advanced Resources International (ARI).

In the tight-gas basins of the West, more than half of the resource is on federal lands, managed principally by the U.S. Bureau of Land Management (BLM) and the U.S. Forest Service. The land's multi-use nature results in lease stipulations that place "tremendous control over access to the resource," says Eppink. Many E&P companies argue those restrictions are too stringent.

ARI completed a study for the U.S. Department of Energy suggesting a 10% improvement in permitting, wildlife mapping, drilling exceptions and length of drilling season could increase the available natural gas resource by about 14 trillion cubic feet (Tcf).

"With marginal improvements in access, you can make large amounts of natural gas available," much of it tight gas, he says. "This is not a case where the environment has to be destroyed."

In an effort to speed up its own permitting process, Denver-based Gasco Energy has completed two environmental assessments and is finishing work on an environmental impact statement, says Michael Decker, chief operating officer and executive vice president.

"We keep exploring the next layer of the onion" in Utah's Uinta Basin, Decker says. The company began with the 5,500 to 9,000-foot-deep Wasatch formation, moved to the 9,000 to 11,800-foot-deep

Denver-based Gasco Energy is drilling for natural gas in the 12,500 to 13,300-foot-deep Blackhawk formation in Utah's Uinta Basin. *(Photo courtesy of Gasco Energy)*

Mesa Verde and most recently has been drilling in the 12,500 to 13,300-foot-deep Blackhawk formation.

Three-quarters of Gasco's 124,000 gross acres in Utah are on federal land, but Decker says Gasco plans to drill half its wells on state and fee acreage, in part because of permitting backlogs at the Vernal, Utah, office of the BLM. Gasco's acreage lies west of the Greater Green River basin, a location the company began working five years ago. Lack of a river crossing made the Green River a geographical barrier splitting the basin in two. Trucks had to drive as much as 100 miles to reach Gasco's acreage.

Gasco has been investing considerable effort in completion engineering, which holds special challenges for tight gas.

Artful completions

During the 1980s it was common to drill a well, fracture the formation, then shut the well in until it could be connected to a sales pipeline, says Decker. Keeping frac fluids in the tight-sand formation for any length of time can hurt the well's productivity. As a result, Gasco now waits to fracture a well until it is connected to a pipeline.

Gasco has its own gas gathering affiliate—River Bend Gas—which allows it to better control its resource development. River Bend operates a 50-mile gathering system with three compressor stations.

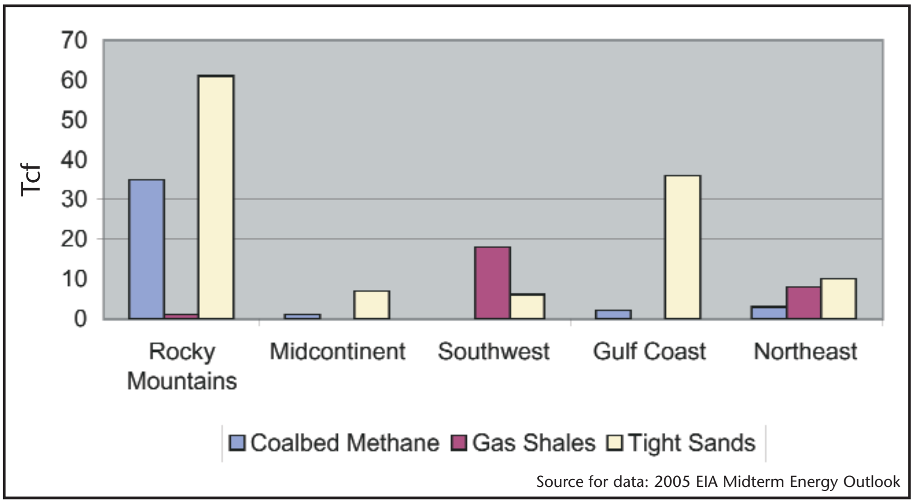
The Company's 2006 capital budget includes $4 million for seismic analysis, $13 million for pipeline gathering infrastructure, $7 million for three exploratory wells in tight-gas formations in Wyoming and $56 million for 32 wells in Utah. The company's capital budget last year was $50 million.

Gasco also has a "joint value enhancement agreement" with Schlumberger, Nabors Drilling and MI Drilling Fluids. The partners have a 70% working interest in the wellbore, while Gasco retains 30%. The partners earn on the production stream for 12 years before full ownership reverts to Gasco, and they pay 70% of the well's drilling and completion costs. The venture allows Gasco to stretch its capital budget, use cutting-edge technology and ensure ongoing rig availability, Decker says. Currently, one of the three rigs Gasco uses is covered by the agreement.

Slate River Resources is working in the Agency Draw area in the Uinta Basin, where it is drilling 7,500- to 8,500-foot-deep wells in the Mesa Verde formation on 24,000 leased acres. The company began drilling in June with a single rig and had 10 wells completed by year-end, says Mathies. Gathering facilities were slated for mid-January completion. The wells had not been flowed, so estimating their eventual production is difficult right now, he adds.

As a resource play, Slate River's Agency Draw project could offer running room for 300 to 400 wells, if it proves successful.

Slate River intentionally focused on fee land to streamline the permitting process. However, connecting the company's wells to nearby pipelines means crossing state and federal land. Obtaining the necessary permits is "taking longer than we have experienced in the past," Mathies says. "The agencies are inundated with activity in the Uinta Basin. Staff resources are constrained and the industry is operating at an all-out level." The net effect is "tremendous competition for services and supplies."



Tight gas is forecast to dominate unconventional gas production from 2003-2025.

Waiting game

KCS Energy is one of several producers with a focus on tight gas. The Houston company expects to spend between 15% and 25% more than the $260-million capital budget it had last year. Overall, about 95% of its production is tight gas.

"Out of 190 wells drilled in 2005, fewer than five did not need stimulation," says Bill Hahne, KCS Energy president.

Because E&P companies are drilling more gas wells throughout the nation, rig availability is a challenge. In South Texas, where KCS is developing a tight-gas play, the waiting time for a rig can reach between three and 12 months. "We have to build the location, then wait for an opening in the rig schedule," he says.

About two-thirds of the corporate budget is for north Louisiana development, where the company has seven rigs locked up for this year. The company's largest play is its Elm Grove project in north Louisiana, which Hahne describes as a classic stacked reservoir, tight-gas play. The Cotton Valley reservoir is between 400 and 600 feet thick, composed of "massive tight rock." Using "very large fracture stimulation," the company has achieved "robust economics on every well."

"We go into tight rock and drill wells that 10 years ago would not have been economical," Hahne says.

In 2003, KCS drilled 53 wells. It nearly doubled that in 2004 and again last year. Plans call for drilling 230 wells this year. A capital budget for the year had not been set as of mid-January.

Two factors help the Elm Grove play's economics. First, fracture stimulation costs have fallen in recent years. "Fifteen years ago, it would have cost two times as much to stimulate" a well in the play, Hahne says. High commodity prices and less costly frac technologies result in improved resource economics.

Second, the sands' nature means that massive fracturing is not necessary. Instead, KCS is using coiled tubing fracture techniques, which allow a more focused fracture to stimulate the well, Hahne says.

Many happy returns

In East Texas, XTO Energy's largest tight-sand play is on 225,000 acres in the Freestone Trend, which accounts for 35% to 40% of the company's overall production. To date, XTO has drilled around 700 wells and has at least another 1,300 to drill, a number that could grow to as many as 2,800 wells if 80-acre spacing is allowed, says president Keith Hutton.

"The key for us is we're one of the lowest-cost finders and producers," he says. "We can go to $4 or $5 gas and we still would be players."

XTO extends its approach to other tight-gas projects in basins across the west. In New Mexico's San Juan Basin, the company spends about $600,000 to drill and complete a well that produces on average 1 billion cubic feet (Bcf) and generates a 65% return. In Colorado's Piceance Basin, the company is working on a farmout from ExxonMobil. Drilling 15,000-foot wells costs $3- to $4 million and yields production of 3- to 4 Bcf. XTO considers its half interest in the 70,000-acre Piceance project to be similar to its East Texas Freestone Trend play.

Pipeline takeaway capacity is an issue in the Piceance, although by the time XTO fully develops its resource in 2008 or 2009, the infrastructure should be in place to handle the increased flow of natural gas from tight-sand formations.

"The resource is there, although there are certainly issues in developing it," says Eppink. Provided rig availability and access to federal land can be addressed, tight-sand formations in the Rockies may hit full stride as the next big source of domestic natural gas. Judging by companies' increasing budgets targeting tight-gas drilling activity, that's only a matter of time.

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