

SHALE GAS

The background of the cover is a photograph showing the silhouettes of a large bull and a cowboy on a horse. The bull is in the foreground, facing left, with its horns curved upwards. The cowboy is on the horse to the right, wearing a wide-brimmed hat and holding a large wreath. The scene is set against a clear, bright blue sky. The overall mood is one of traditional Western culture.

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Worth a Closer Look

Who would have guessed that shale-gas plays throughout the U.S. would have generated so much interest in recent years? Thanks to the amazing success operators have enjoyed in the prolific Barnett in the Fort Worth Basin, shales are the most attractive plays around.

With high-profile Barnett asset sales of more than \$1 billion and gross production topping 1 billion cubic feet per day (Bcf)—and even the Fort Worth City Council willing to lease city land for drilling—no one needs to be convinced that shale plays are valuable, highly prospective and worth a closer look.

The Barnett is like the prettiest girl at the dance—everyone wants to be her partner—joked Tom Price of Chesapeake Energy in a recent interview with the *Fort Worth Star-Telegram*.

Other shales plays, however, are not wallflowers, for they too are seeing increased leasing activity and commanding higher prices per acre. Operators are looking in West Texas, for example, hoping to repeat at least a portion of the Barnett's production success.

Total shale-gas resources in the U.S. have been estimated between 500- and 600 trillion cubic feet (Tcf). According to the National Petroleum Council Committee on Unconventional Gas Sources, the New Albany Shale in the Illinois Basin alone could contain as much as 86 Tcf.

There are more than 35,000 producing shale-gas wells in the U.S., with cumulative production of about 600 Bcf per year, according to a press release from College Oak Investments LLC, which recently formed a new joint

venture and funded 10 wells to pursue the New Albany Shale.

In this special report, the editors bring you some updated information on the Barnett, the Fayetteville Shale in Arkansas and several other shale plays throughout the country. Enjoy the dance!

—Leslie Haines, Editor in Chief, *Oil and Gas Investor*



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On the Cover: A sculpture of Texas longhorns marks the entrance of the Ponderosa Estates subdivision in Denton County, Texas. Drilling rigs mix with upper-end housing in this part of the Barnett Shale play. (Photo by Lowell Georgia)

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THE SHALE SHAKER

From private firms to small caps to supermajors, interest in U.S. shale-gas plays is broad.

By John White, U.S. Exploration and Production Analyst, Natexis Bleichroeder Inc.

In an analysis of major U.S. shale-gas plays, Natexis Bleichroeder identified 23 companies involved in eight shale-gas plays, from the supermajor Royal Dutch Shell to the micro-caps Contango Oil & Gas Co. and Infinity Inc.

Based on disclosed holdings and Natexis Bleichroeder estimates, Chesapeake Energy Corp., Southwestern Energy Co. and EnCana Corp. are in a three-way tie for the top spot in terms of total U.S. shale-gas acreage as of September 30—each has about 900,000 net acres. EOG Resources Inc. (628,000), Devon Energy Corp. (620,000) and Quicksilver Resources Inc. (551,000) round out the top six.

Using undeveloped acreage to gauge potential impact has limitations:

- undeveloped acreage will not, in all cases, translate into production and reserve growth;
- some sub-plays within larger shale plays demonstrate stronger economics; and
- many of these shale plays are early in the development process.

Following is a review of U.S. gas-shale activity by company, as of the quarter ending September 30.

Burlington Resources Inc.—Burlington has been in the Barnett/Fort Worth Basin for several years, with 28,000 net acres in the core area. Southwest of the core area, the company has a 22,000-net-acre position in Palo Pinto County and plans an exploration program on that acreage.

Directly south of the core area, Burlington has established a 70,000-net-acre position in Parker, Hood and Johnson counties, where it has drilled three horizontal wells. The company's Barnett production has not been disclosed.

In the Barnett/Woodford play in West Texas, Burlington has acquired some 350,000 net acres. To date, it has completed the re-entry of an old wellbore, the Kirk well in Reeves County, and was completing a second exploration well in the play at press time.

The industry is excited about this new Barnett/Woodford play. This and the Barnett near Fort Worth, Texas, show significant similarities in reservoir thickness and pressure, organic content and thermal maturity.

Carrizo Oil & Gas Inc.—Carrizo expects to soon have Barnett/Fort Worth Basin production from two wells to reach about 2.7 million equivalent per day, bringing its Barnett/Fort Worth Basin production to about 10 million equivalent per day. The company is adding acreage in northern Hill, northern Bosque, southern Parker and southeastern Tarrant counties, and a minor amount in Erath County.

In the Barnett/Woodford of West Texas, Carrizo has begun initial leasing and drilled two wells—one vertical and one horizontal—and reports it is too early to make a determination.

Chesapeake Energy Corp.—In the Barnett/Fort Worth Basin, Chesapeake holds about 50,000 acres and recently expanded into Johnson County through the Hallwood Energy acquisition.

In the Fayetteville, Chesapeake has about 600,000 net acres. By Natexis Bleichroeder's estimates, this probably ranks it as No. 2 acreage-holder in the play following Southwestern Energy.

In the Caney/Woodford, the company has a 250,000-net-acre position. In the Devonian/Ohio, Chesapeake recently closed its \$2.95-billion acquisition of Columbia Natural Resources LLC. The company plans to leverage the experience it has gained from the Barnett/Fort Worth Basin, Caney/Woodford and Fayetteville plays in the Appalachian shales.

Contango Oil & Gas Co.—In the Fayetteville Shale, Contango owns some 15,000 net acres, a considerable amount relative to its company-wide net undeveloped acreage of 100,387 as of June 30. Contango hopes to hold 40,000 more Fayetteville acres and plans to spud six horizontal wells by the middle of this year.

Denbury Resources Inc.—Denbury is involved in the southern portion of the Barnett/Fort Worth Basin play with 50,000 net acres, generally in Hill, Hood and Erath counties. Last year, through early December, the company drilled 18 horizontal wells with initial rates between 1- and 3 million equivalent per day, and production was some 15 million equivalent per day in third-quarter last year.

Devon Energy Corp.—During the third quarter, this kingpin of the gas shales drilled its 2,000th Barnett/Fort Worth Basin producer. Of the 18 rigs running, eight are outside the core Barnett area of Tarrant, Parker and Wise counties. Of these eight, five are drilling in Johnson County.

In the Caney/Woodford in eastern Oklahoma, Devon reports encouraging results based on early production outcomes from three horizontal wells. The company has assembled 70,000 net acres with working interests ranging between 50% and 80%.

As for other shales, Devon was questioned in a recent conference call about whether it has picked up noncore Barnett/Fort Worth Basin acreage in Erath County and/or acreage in the Barnett/Woodford in West Texas. The company reported it added some 250,000 acres last year in various onshore regions and implied that some was in new shale plays.

Edge Petroleum Corp.—In the Floyd in the Black Warrior Basin that straddles the northern Alabama-Mississippi border, Edge has 27,000 net acres. It plans one test well for this year, subject to rig availability. The Floyd is an incipient attempt to establish shale-gas production in the Black Warrior Basin.

SHALE PLAYERS: AN OVERVIEW

In the Fayetteville, Edge has about 6,000 acres and plans one or two test wells this year.

EnCana Corp.—EnCana is a well-established participant in the Barnett/Fort Worth Basin, with 190,000 net acres, of which 58,000 are in the core area. Production there for EnCana is about 65- to 70 million equivalent per day.

In the Barnett/Woodford in West Texas, EnCana is estimated to be the No. 1 leasehold-owner: 670,000 acres.

Encore Acquisition Co.—Encore has small exposure in the Barnett/Fort Worth Basin relative to its size, with about 2,000 to 4,000 acres and one rig running in third-quarter last year.

EOG Resources Inc.—The Johnson County portion of EOG's Barnett/Fort Worth Basin play is working better than expected, the company reports. In eastern Johnson County, there is a Viola seal rock, which prevents severe water encroachment by keeping the frac job from penetrating the Ellenberger formation. This is different from that encountered in the western and eastern portions of Johnson County.

Initial production flow rates from selected wells in eastern and western Johnson County are slightly higher than 5 million equivalent per day, and based on results so far, the 35,000 acres in eastern Johnson County could be the single-best piece of acreage it owns in the Barnett.

On the western side of the play, EOG has drilled wells in Jack, Hood and Erath counties, where per-well reserves will be about 1- to 1.4 billion equivalent. In these western counties, the Barnett is thinner, leading to lower reserves, but it is also shallower, resulting in lower completed well costs as compared with Johnson County or the core counties. Meanwhile, EOG owns acreage but has yet to drill any wells in Palo Pinto, Hill or Somerville counties.

As for the Barnett/Woodford, EOG has not disclosed whether it owns acreage in this play. The company often refers to a "stealth shale play" in Texas, that it holds 125,000 acres and is leasing more. Industry sources believe the undisclosed play is the Barnett/Woodford. Meanwhile, EOG reports that, in this undisclosed shale play, it has drilled one well, pulled a core sample and had the core analyzed. EOG says the core looks reasonably similar to the Barnett Play near Fort Worth.

Infinity Inc.—This small-cap operates in the far southwestern Barnett/Fort Worth Basin play, with about 61,000 net acres including 31,000 net in Comanche County and 30,000 net in Erath and Hamilton counties. Infinity has one rig running in Erath County, where the company plans to drill 18 to 20 wells this year.

Marathon Oil Co.—The company has an acreage position in the Barnett/Fort Worth Basin and drilling plans, but zero production at press time.

Murphy Oil Corp.—Murphy finished drilling one of the initial Floyd/Black Warrior Basin test wells, Murphy No. 1 Exum Trust 6-16, in third-quarter last year; has commenced drilling a second test, Murphy No. 1 O'Bryant 6-15; and has filed a permit for a third. According to industry sources, Murphy obtained a core sample in the initial well and continues to acquire leases.

Noble Energy Corp.—Noble Energy has also drilled a Floyd/Black Warrior Basin well. The shale effort at Noble is being led in large part by the technical team obtained from the acquisition of Patina Oil. The Patina team developed a significant amount of expertise in exploiting tight-gas reservoirs in the Wattenberg Field in Colorado.

Newfield Exploration Co.—Newfield is not a newcomer to the Caney/Woodford, having been active in southeastern Oklahoma since early 2004. Newfield has amassed a 73,000-acre position in the Arkoma Basin and grown production from a standing start in 2004 to the current 17 million equivalent per day.

Newfield refers to this area as its Waccawh play, a lengthy acronym representing the productive formations in the area: the Wapanucka (limestone), Cromwell (sandstone), Caney (shale) and Woodford (shale).

The Woodford is the deepest of the zones; Newfield drills through and sees logs on the Wapanucka, Cromwell and Caney. If the Woodford is unproductive, these up-hole zones can be serendipitous secondary targets. Further, when the Woodford is depleted, completions can be attempted on these zones up-hole.

Shale-Gas Acreage/Market Capitalization

	Percentage of Shale-Gas- Play Acreage	Market Cap (\$Million)	Enterprise Value (\$Million)
EnCana Corp.	6%	39,029	47,327
Burlington Resources	2%	27,461	28,538
Devon Energy	3%	27,191	32,163
Marathon Oil	NA	22,080	25,788
Talisman Energy	NA	17,724	19,960
EOG Resources	13%	17,478	18,279
XTO Energy	53%	15,182	18,392
Chesapeake Energy	45%	10,392	15,563
Murphy Oil	NA	9,095	8,355
Noble Energy	NA	6,756	8,749
Southwestern Energy	71%	6,281	6,130
Newfield Exploration	3%	5,821	6,588
Range Resources	6%	3,253	3,879
Quicksilver Resources	36%	2,952	3,471
Denbury Resources	40%	2,706	2,919
Penn Virginia	NA	1,092	1,738
Petrohawk Energy	40%	907	1,364
Carrizo Oil & Gas	26%	619	719
Parallel Petroleum	2%	545	607
Edge Petroleum	53%	442	458
Contango Oil & Gas	13%	155	127
Infinity Inc.	31%	96	113

Source: Natexis Bleichroeder Inc., with Bloomberg

In acreage versus market cap, publicly held companies with the highest exposure to their U.S. shale-gas programs are Southwestern, XTO and Edge Petroleum.

Parallel Petroleum Corp.—The Barnett/Fort Worth Basin is a new addition to the Parallel portfolio and already accounted for about 10% of total-company, third-quarter production last year. The company has about 3,000 to 4,000 net acres (10,000 gross) in the play. Through early December, Parallel’s five wells in the play were producing a total of some 16 million equivalent per day.

Penn Virginia Corp.—The company has acreage in the New Albany play in the Illinois Basin, and expects to drill two vertical wells and gather some reservoir formation, where it owns some 28,000 acres.

The company also owns a large acreage position in Virginia and West Virginia that provides exposure to the Devonian/Ohio shale.

Petrohawk Energy Corp.—Petrohawk has significant exposure to the Caney/Woodford shale-gas play through its interest in 15,000 gross (14,000 net) acres in the Pine Hollow South area, just south of its Hichita prospect in MacIntosh County, Oklahoma, in the Arkoma Basin. The Caney/Woodford is the same geologic age as the Barnett in northeast Texas and the Fayetteville in western Arkansas.

Questar Corp.—This diversified gas company has had strong early success with its Baxter play in the Vermillion Basin of northern Colorado and southern Wyoming. The shale is of Cretaceous-age and found between 10,000 and 13,000 feet with thickness ranging from 2,500 to 3,500 feet with pressures between 6,000 and 11,800 psi. Questar holds some 143,000 acres in the play. The company had three wells

online as of November 21. The first well averaged about 4 million equivalent per day and has been assigned estimated reserves of 4- to 5 billion cubic feet equivalent.

As for the Hilliard play, Questar recently tested this shale and reported inconclusive results. The Hilliard is deep, at 19,500 feet, and underlies the Lance pool on the Pinedale Anticline.

Quicksilver Resources Inc.—Quicksilver drilled 25 wells in third-quarter last year in the Barnett/Fort Worth Basin, where it holds 251,000 net acres, with 19 completed and connected to the pipeline. Current net Barnett production is 15 million equivalent per day.

The drilling effort has been spread across the acreage, with wells 28 miles apart in the north-south direction and 14 miles apart east-west. Quicksilver’s acreage is in the southern part of the shale play, south of Johnson County in Hill, Bosque, Somerville and Hood counties.

Quicksilver also has a large exposure in the Barnett/Woodford, with 300,000 net, contiguous acres. It plans several vertical wells to obtain cores this year. The company believes it is pursuing a portion of the basin where the shale is shallower than some of the other areas of the play.

In the Antrim/New Albany, Quicksilver has drilled 50 net wells in Michigan and Indiana. It had positive results in a re-entry horizontal drilling program in the Michigan Antrim, which is the company’s original shale effort and the foundation of the reserve base. Quicksilver has implied that overall well results are not as positive as expected, but it believes the play still holds promise.

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Reichmann Petroleum Corp. has burned plenty of midnight oil ensuring 95% of its leases are drilled on or before expiration. As a result, drilling in the Barnett Shale has increased threefold, with over 70 wells scheduled for drilling in Texas in 2006 alone.

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SHALE PLAYERS: AN OVERVIEW

Royal Dutch Shell—RDS owns about 35,000 net acres in the Barnett/Fort Worth Basin, where sources say it is looking to expand its position.

Range Resources Corp.—Range is particularly excited about its Devonian/Ohio play in Pennsylvania. The company drilled its first vertical well and put a large slickwater frac on it. Results were encouraging and followed with three more vertical wells. One encountered a strong, sustained open flow of 1.6 million per day from a shallow zone.

The company continues to lease in this play and has about 100,000 acres. It reports that the Pennsylvania shale compares well with the Barnett in terms of thickness and total organic content.

In addition to the Pennsylvania play, Range has acquired about 20,000 acres in the Barnett/Woodford. The company believes there is also potential in the deeper conventional zones, the Fusselman and Wolfcamp. Meanwhile, Range has also announced a “stealth shale” play somewhere in Texas.

Southwestern Energy Co.—In 2004, this company discovered a Fayetteville gas shale that, based on initial drilling and production results and the sheer magnitude of the aerial extent of the play, has all the elements to potentially become as active as the Barnett/Fort Worth Basin.

Since September 2004, Southwestern has drilled 67 wells in 10 different pilot areas across five counties—Franklin,

Conway, Van Buren, Cleburne and Faulkner. As of September 30, Southwestern held some 724,000 net acres in the Fayetteville area and an additional 125,000 net developed acres in the traditional fairway area of the Arkoma Basin, totaling a truly staggering 849,000.

In the Barnett/Woodford, Southwestern has leased more than 48,000 net acres and plans re-entry of an existing wellbore during this quarter.

Talisman Energy Inc.—This company has a large acreage position in the Appalachian Basin, operating primarily through its Fortuna Energy Inc. subsidiary. As of December 31, 2004, Talisman held about 1.2 million net undeveloped acres, a large portion being in the Appalachian Basin. This acreage position provides exposure to the Devonian/Ohio play.

XTO Energy Inc.—XTO is a large participant in the Barnett/Fort Worth Basin, where its third-quarter production last year averaged some 190 million equivalent per day and it holds some 150,000 net acres—some 50% of this in the core area. The company is active in drilling test wells in the noncore and is running about 19 rigs in the play overall. ■

This article is excerpted from the author's extensive report on U.S. shale-gas activity. He can be reached at (713) 751-1638.

Publicly Held U.S. Shale-Gas Players

	Barnett	Fayetteville	Caney/ Woodford	Devonian/ Ohio	Barnett/ Woodford	Floyd	Baxter	Antrim
Burlington Resources	X				X			
Carrizo Oil & Gas	X				X	X		
Chesapeake Energy	X	X	X	X				
Chevron Corp.					X			
Contango Oil & Gas		X						
Denbury Resources	X							
Devon Energy	X		X		X		X	
Dominion Resources				X				X
Edge Petroleum		X				X		
EnCana Corp.	X				X			
Encore Acquisition	X							
EOG Resources	X				X			
Infinity Inc.	X							
Marathon Oil	X							
Murphy Oil						X		
Newfield Exploration			X					
Noble Energy		X				X		
Parallel Petroleum	X							
Penn Virginia				X				
Petrohawk Energy			X					
Questar Corp.							X	
Quicksilver Resources	X				X			X
Range Resources				X	X			
Royal Dutch Shell	X							
Southwestern Energy		X			X			
St. Mary Land & Exploration			X					
Talisman Energy				X				
XTO Energy	X	X						

Note: The table is not an exhaustive list.

Source: Natexis Bleichroeder Inc.

Chesapeake Energy Corp. and Devon Energy Corp. appear in four of the eight U.S. shale-gas plays that were reviewed.



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THE BOOMING BARNETT SHALE

Frenetic activity quickens the pace in the Barnett Shale amid projections it may be the largest domestic gas play ever.

By Gary Clouser, Contributing Editor

The Barnett Shale in the Fort Worth Basin in North Texas has grown from a sub-economic, unconventional natural gas play to the largest onshore U.S. gas producing area—with predictions that it may become the most prolific domestic, onshore play.

Production from the play now exceeds 1.2 billion cubic feet (Bcf) a day. An estimated 1.5 trillion cubic feet (Tcf) of gas has been commercially produced from the Barnett Shale. More than 100 companies have drilled a total of about 4,000 successful wells in the field.

The U.S. Geological Survey, in a study now more than two years old, had estimated the Barnett Shale at 26.2 Tcf, which is far below what many geologists now working in the play think.

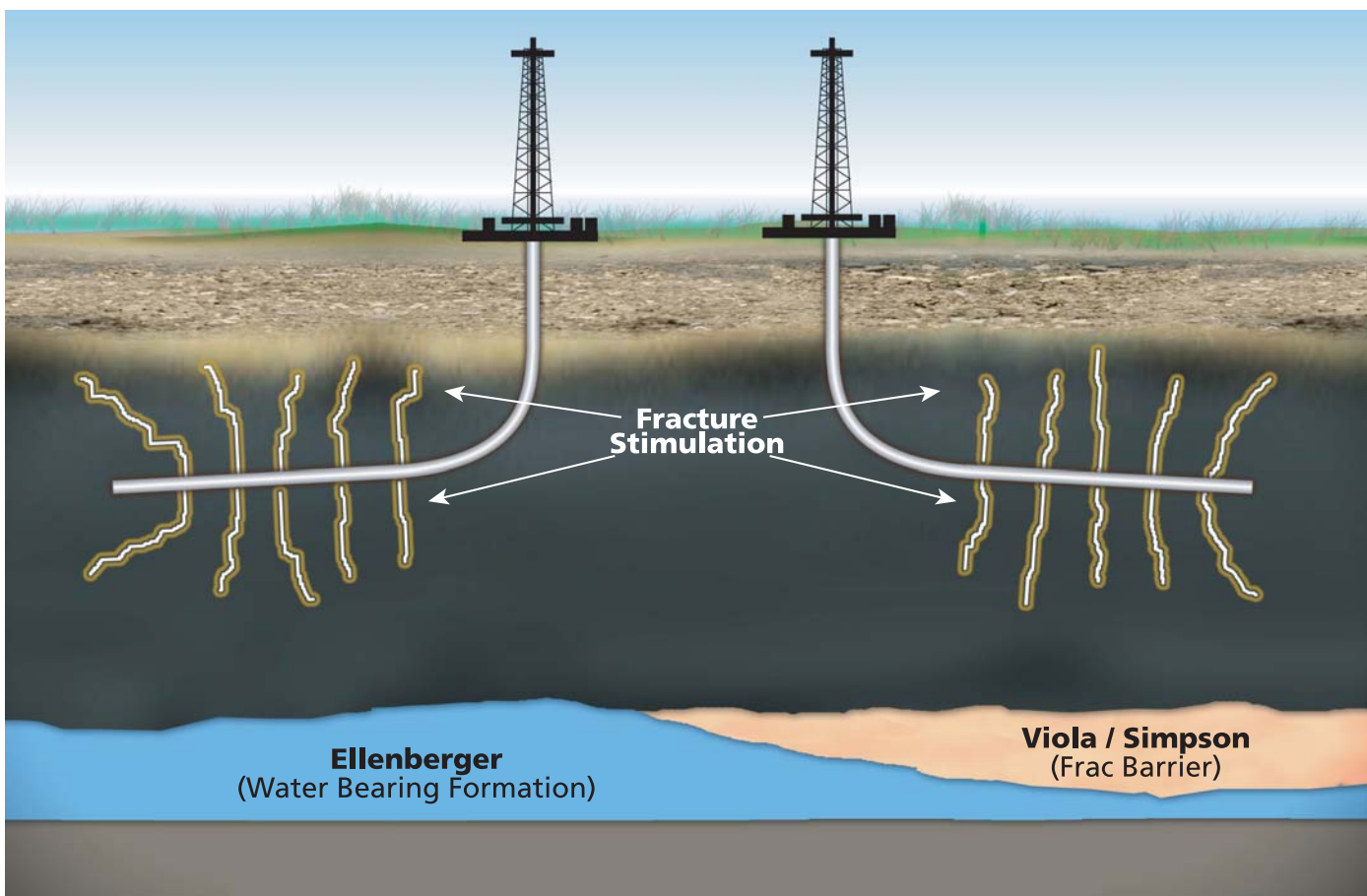
Kent A. Bowker, an independent geologist and consultant, notes that the government estimates pre-date the geo-

graphic expansion of the play and important additional discoveries. He predicts the reserves will be north of 30 Tcf. Bowker, a former geologist of Mitchell Energy, the company credited as the pioneer of the field, says he has been wrong several times about Barnett Shale, always underestimating it.

Fellow Mitchell Energy alum Dan Steward, now a consulting geologist for Republic Energy in Dallas, which has drilled more than 200 wells in the play, is even more optimistic. Steward predicts that Barnett Shale production eventually will exceed a total of 50 Tcf and become the largest U.S. onshore gas field.

Republic Energy, one of the first companies in the play behind Mitchell, has been successful in conducting technical evaluations, acquiring properties, drilling and then selling to others to exploit.

The Barnett Shale is a large complicated play and anyone



Horizontal wells can avoid water even when the shale is not protected by the frac barrier. Horizontal wells also are exposed to more pay zone and are able to produce more gas than vertical wells. (Graphic courtesy of Devon Energy)

planning to participate needs to understand its unique geology and engineering as some unknowledgeable producers have learned the hard way, Bowker says.

“The truth of the matter is that no one knows everything about the Barnett Shale. We are still learning,” he says.

Bowker, like Steward, credits his former boss, George Mitchell, for having the perseverance and determination to stick with the Barnett Shale field when naysayers said it was too tight to produce economically.

Technological advances have made the play successful. Water fracs caused the Barnett to take off, horizontal drilling propelled it to a new level, and a yet-unidentified technology, or combination of technologies, will propel it even further, Bowker says. Steward predicts technology will probably include dual laterals, low-pressure gathering systems and many things the industry has not yet identified.

Sweet spots

Pickering Energy Partners Inc., in a study about the Barnett released in October, reported, “Though the core area is commonly referred to as Denton, Wise and Tarrant counties, the true sweet spot has been the Newark East Field, which has been extensively drilled. Results outside Newark East have

not been as impressive. However, another sweet spot appears to be developing in Johnson County, which looks superior to much of the ‘core’ acreage beyond Newark East.”

“The Barnett Shale has come a long way over the last five to 10 years, as light sand fracs and horizontal drilling have driven an explosion of activity in the play.”

–Pickering Energy Partners Inc.

On average, the companies that were the early entrants into the play got the best acreage and have the best results, say Pickering authors Jeff Hayden and Dave Pursell.

“The Barnett Shale is thickest and deepest in the core area, which corresponds to the highest gas-in-place per section in the Barnett.”

Analysts at Petrie Parkman & Co., an investment bank, say, “The average estimated ultimate recovery per well in Johnson County is expected to be 2.4 Bcfe per location. In the higher-risk areas in outlying western counties, EUR is estimated to be 1.1 Bcfe per well in Hill, Erath and Palo Pinto counties.”

Producers are scrambling at a frenetic pace to secure acreage in surrounding areas, extending beyond that initial core. Steward says the play will extend about 6,000 to 7,000 square miles and cover parts of 18 counties.

“The Barnett Shale has come a long way over the last five to 10 years, as light sand fracs and horizontal drilling have driven an explosion of activity in the play,” say the Pickering analysts. “We believe the rig count in the play will only move higher, as many of the larger players are adding rigs...and will likely have to increase their rig count further in the future in order to hold all of their leases.”

Production results in the play have shown that horizontal wells are superior to vertical wells, they add. “Probably not a surprise given the increased industry focus on horizontal wells, but the magnitude was surprising. Using \$6 per thousand cubic feet as our benchmark gas price, the typical horizontal well generates a 100%-plus return, while the typical well generates only a 39% return.”

Since Devon Energy of Oklahoma City bought the former Mitchell Energy of Houston in 2002, it has expanded Mitchell’s initial work. Representatives of Devon said at an industry conference in November that it is producing 575 million cubic feet a day from Barnett Shale. It has drilled 2,040 wells and currently has 18 rigs operating.



Devon is the largest leaseholder and producer in the Barnett Shale, with more than half a million acres under lease for exploration and development inside and outside the core area. (Photo courtesy of Devon Energy.)

During third-quarter 2005, the company surpassed 1 Tcf of total production from the play. Most of Devon’s wells are in Wise and Denton counties, but it expanded last year into Johnson County, where five of its drilling rigs now are operating, chief executive Larry Nichols says.

Devon projected that at year-end 2005, its production would be 590 million cubic feet per day, company spokesman Chip Minty told *Oil and Gas Investor*. That compares with 2004 year-end production of 560 million a day. Projections are that by the end of this year, production will be 630 million a day. Devon’s E&P budget for the Barnett Shale last year was \$450 million, compared with \$300 million in 2004.

Thanks to its acquisition of Mitchell Energy, Devon is far and away the largest player in the Barnett Shale, both in terms of acreage and production, with about 550,000 net acres. Devon has an upside potential of about 5.8 Tcf, according to the Pickering analysts.

Devon representatives caution, however, that “the industry still does not have definitive proof of where the gas window ends, nor what the decline rates or recovery factor will be. Each of these items will meaningfully impact the play’s ultimate potential.”

Strong plans

The second-largest producer from the Barnett Shale is XTO Energy Inc., having seized that ranking from privately held Chief Oil & Gas LLC.

“Through its acquisition of Antero Resources, XTO became the second-largest producer in the Barnett, with net production of about 100 million cubic feet per day,” says the Pickering report. “The company holds about

Key Public Acreage-Holders

Company	Acreage	Upside potential (Bcf)
Devon Energy	550,000	5,800
EOG	503,000	3,500
XTO	155,000	1,500
Burlington Resources	89,000	899
EnCana Corp.	127,000	785
Chesapeake Energy	48,000	570
Denbury Resource	43,500	387
Quicksilver Resources	230,000	1,900
Carrizo Oil & Gas	65,000	693
Infinity Resources	60,700	341
Parallel Petroleum	2,300	36

Source: Pickering Energy Partners

155,000 acres in the play, located mainly in Tarrant, Johnson and Parker counties.”

The report estimates XTO’s upside potential could be about 1.5 Tcf.

EOG Resources Inc. has 503,000 acres leased and is running 11 drilling rigs; nine in Johnson County and one each in Parker and Erath counties, CEO Mark Papa told analysts in November. Its Barnett production is 82 million cubic feet per day, and it appears EOG was to end the year close to its goal of 100 million per day, “because we have recently been completing a string of monster wells.”

Papa told analysts, “The last 20 wells we’ve completed in Johnson County have averaged 2.4 net Bcf, which is 20% better than the 2.0 net Bcf we’d been modeling.”

One of the wells started production at 7.7 million cubic feet per day, a record in Johnson County.

“Every one of the last 20 Johnson County wells have generated a 100% after-tax rate of return,” Papa said.

Without divulging a timetable, EOG says it plans to drill up to 750 additional wells in Johnson County alone.

Depending on the results from its noncore areas, the company plans to drill as many as 4,000 more wells throughout its Barnett acreage.

The Pickering analysts say EOG is at the forefront of pushing the Barnett play westward into Johnson County, and into Jack, Palo Pinto and Erath counties. Pickering estimated EOG’s upside potential at about 3.5 Tcf.

Dallas-based Chief Oil & Gas has placed itself for sale. Chief, now the third-largest Barnett producer, is producing at about 125 million a day. It has drilled about 350 Barnett wells and has 230,000 acres leased, according to Tony Carvalho, vice president, geology and geophysics.

The sale of Chief would follow the earlier Barnett sales of Mitchell Energy to Devon, Antero to XTO, Hallwood Energy to Chesapeake Energy and Progress Energy’s Barnett holdings to EnCana.

Bowker predicts a rapid consolidation, with numerous independents, particularly the smaller players, putting themselves up for the sale during this period of high commodity prices in which good onshore plays sell at a premium.

Top Public Producers

Company	Daily Barnett Production (MMcf)
Devon Energy	575
XTO Energy	103
Burlington Resources	80
EOG Resources	82
EnCana Corp.	70
Chesapeake Energy	50
Denbury Resources	15
Quicksilver Resources	13
Carrizo Oil & Gas	6
Infinity Resources	2
Parallel Petroleum	nearly 2

Source: Pickering Energy Partners

Pickering Energy Partners identified 11 publicly traded E&P companies with significant exposure to the Barnett Shale play as of October. Some of them are just getting started.

Pickering's Hayden agrees.

"We expect M&A in the Barnett to continue and wouldn't be surprised to see some of the other private, or even public, E&P companies, get bought over the next year," he says.

New players

Independent E&P companies have dominated Barnett Shale exploration so far. With production figures soaring and projections even higher, it has attracted the attention of major producers such as Shell, long-time investors and several newcomers as well.

Legendary Texas oilman and investor T. Boone Pickens, through a joint venture with turnkey contractor Sundance Resources, has gotten involved in the play. Jay Petroleum, a subsidiary of Isramco Inc., has acquired working interests in the Barnett through a joint venture with Ness Petroleum International. Dune Energy is buying 95% of Voyager Partner's interests in Barnett properties. Wynn-Crosby Partners and Kerogen Resources have taken a combined 25% interest in 6,200 acres of Reichmann Petroleum's Barnett play. In total, Reichmann has various interests in more than 70,000 acres in the Barnett Shale.

Westside Energy, which formed a joint venture with EBS Oil and Gas Partners last year, says it now has 68,084 acres leased and has drilled eight Barnett wells. Terax Energy, an E&P company formed exclusively to focus on Barnett Shale, says it has more than 31,000 acres leased, and has completed the vertical section of its initial well and has selected four addi-

tional well locations in Erath County.

Infrastructure players have taken note of the rapidly increasing production that needs an outlet. Crosstex Energy says construction of its 122-mile, 24-inch pipeline, which will have the capacity to transport 250 million cubic feet per day of gas, will be operational early next year. The \$98-million pipeline will extend from just north of Fort Worth to interconnect with Natural Gas Pipeline Co. of America and the Houston Pipeline Co. in Lamar County, Texas.

Crosstex already is planning an additional 11-mile extension of gathering pipelines to interconnect supply from Tarrant County.

Independent E&P companies have dominated Barnett Shale...

Barnett look-a-likes?

Without revealing the location, EOG says it has 125,000 acres leased on a "Barnett look-a-like elsewhere in Texas" where the company is flow-testing its first well.

"We expect to have results from our initial two wells during our year-end earnings call which will be in early February. We also have several other domestic shale-gas

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plays where we're acquiring acreage based on our Barnett knowledge. We'll disclose these later in 2006 after we firm up our acreage positions," Papa says.

There is speculation that some of the hard lessons learned could be applied to the Permian Basin. While gas-shale-related seminars and symposiums have become commonplace in the Fort Worth area, there is increased interest in addressing the question of shale production potential in the Permian Basin and other shale plays. More than 200 oil and gas producers attended a symposium in November held at Midland College in Odessa, in the heart of the Permian Basin. That symposium was sponsored by the Society of Petroleum Engineers of the Permian Basin.

The Barnett Shale may be centered in the Fort Worth

Basin, but there are those who believe it has potential in the Permian Basin, says W. Hoxie Smith, director of Midland College's Petroleum Professional Development Center.

"Many people are talking about its potential out here and there has been some drilling, though the results are being kept quiet," Smith says.

Not only does the Permian Basin hold potential for a similar play, but a number of Midland operators are active in the Fort Worth Basin.

Although lessons learned from the Barnett Shale could speed the learning curve, veteran industry observers caution that betting on a shale play is not for the faint-hearted or those with shallow pockets, noting that it took the Barnett Shale 17 years to become an "overnight success." ■

BARNETT M&A FEVER

The amalgamation process has begun in the Barnett Shale of North Texas, says a prominent investment banker.

"After the next two or three deals, the basin will be locked up and it will be very hard to be in the top three," says Greg Pipkin, managing director, Lehman Brothers' global energy group, based in Houston.

In mid-November, Devon Energy still led the play based on its production rate of 575 million cubic feet a day. XTO ranked second and privately held Chief Oil & Gas was third—although in November, the latter formally announced it is for sale, confirming rumors. The price tag was expected to be well north of \$1 billion.

Chief produced 33.2 billion cubic feet (Bcf) of natural gas from Tarrant, Denton and Parker counties in 2004 and an additional 25.8 Bcf in 2005 through August, according to the *Fort Worth Star-Telegram*, citing data from the Texas Railroad Commission.

Chesapeake Energy was in fourth place and thought to be in the hunt for more Barnett assets such as from Chief.

In 2005, the true market value of the Barnett Shale was exposed thanks to several high-profile sales. In April, XTO acquired Antero Resources for \$1 billion, the largest shale-gas-related transaction yet. It included 165 wells, 60,000 acres of leases, 440 Bcf of proved reserves and some mid-stream assets, with the reserves going for about \$2 per thousand cubic feet.

Lehman Brothers financed Chesapeake's \$277-million acquisition of the Barnett assets of privately held Hallwood Energy in 2004 as well. The deal included 42 wells and 18,000 leased acres in Johnson County.

Now, Lehman Brothers is handling the sale of Chief.

Bidders were expected to be other large firms focusing on so-called resource plays or unconventional gas: Burlington Resources, Williams, Devon Energy, Chesapeake and Shell. Pipkin says they all are fighting to end up among the top three producers in this play by the time it shakes out.

In August, Shell came into the fray by taking 25,000 leased acres in Parker County and entering a joint venture

with Sundance Resources of Rio Vista. Another key player, EOG Resources, has insisted it intends to grow via leasing and drilling, not acquisitions.

Devon chairman Larry Nichols told Bloomberg News that "we're likely to bid on it," referring to Chief's announcement.

Lehman is also handling the sale of assets, mostly in Johnson County, owned by David H. Arrington, a private company whose drilling in the Barnett is funded in part by a joint venture with Lehman. Bids were due December 1 with a closing expected in the first quarter.

"People are paying \$12,000 to \$14,000 per flowing, thousand cubic feet of production, and \$3,000 to \$5,000 per net undeveloped acre. If midstream assets are included in a Barnett deal, then they go for 10 times cash flow," Pipkin says. "These prices are higher than what is being paid in other tight-gas basins because the drilling results have been so impressive. There is a lot of interest."

Meanwhile, in December, Point Comfort-based Gulf Coast producer Neumin Production Co., a wholly owned subsidiary of Formosa Plastics Corp. USA, acquired a 25% stake in eight wells and 6,200 undeveloped acres in the Barnett Shale held (and operated) by Reichmann Petroleum. It joins other partners—Wynn-Crosby and Kerogen Resources—in the development project. Neumin expects to participate in drilling more than 20 new wells in the Barnett Shale next year.

Although Neumin has historically focused its exploration efforts along the Texas and Louisiana Gulf Coast, the company recently closed on a joint-venture program with Navidad Resources in Tyler, Texas, with plans of expanding its exploration efforts into the East Texas Basin.

In addition, Neumin is kicking off operated drilling programs in Texas and Louisiana, which were derived from its own proprietary 3-D seismic programs shot in 2004.

Neumin says it plans to continue to make an aggressive effort to acquire additional properties in the Gulf Coast and East Texas and, as applicable, to look at unconventional gas opportunities.

Neumin has opened a Houston office, says land manager Jim Gilstrap.

— Leslie Haines

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SHALE PLAYS SHOW GROWTH PROSPECTS

Oil shale exploration is heating up in Texas' Palo-Duro while robust gas prices are benefiting producers in Midwestern legacy fields

By David Wagman, Contributing Editor

It's still the early days of exploring shale potential in the Palo-Duro in the south Texas Panhandle, but exploration companies on the ground point to similarities they say the basin shares with the prolific Barnett Shale, 260 miles east. Suspicions are strong that the Palo-Duro may be as big as the Barnett. The Palo-Duro's Bend Shale tests as thermally mature and reaches gross thicknesses between 500 and 1,000 feet at depths from 7,000 to 10,500 feet.

Shales in the Barnett and the Palo-Duro look "more alike than different," says Paul Larkin, president of Vancouver-based Tyner Resources. His company is actively drilling in the basin.

In a research report published last year, Morgan Stanley said the Palo-Duro's Bend Shale is twice as thick as the Barnett Shale and has slightly lower organic carbon content. To Morgan Stanley, that implies gas in place roughly similar to the Barnett.

Strong commodity prices, improved completion technologies and construction of a high-pressure pipeline are drawing E&P companies to the basin. Interest resumed several years ago when Legacy Petroleum, based in Arlington, Texas, acquired a leasehold on a 1950s-vintage Granite Wash discovery in Motley County. That well had tested gas and condensate years ago but was never produced.

Legacy's arrival enticed other E&P companies. Tulsa-based Vintage Petroleum followed Legacy, buying a portion of Legacy's interests, taking over well operations and launching an aggressive leasing program.

Tyner came next, bringing Bankers Petroleum of Calgary with it. In short order, Vintage leased some 200,000 acres while Tyner leased about 13,000. Land lease prices rose from about \$10 an acre in 2004 to \$50 in early 2005, according to Morgan Stanley.

Tyner drilled the Stephen No. 1 well to a total depth of 9,500 feet last year. Log analysis confirmed penetration of about 1,000 feet of lower Bend Shale containing gas and 24 net feet of potentially hydrocarbon-bearing Granite Wash sands. Further log analysis by Schlumberger indicated potential original gas in place of 116 billion cubic feet (Bcf) per section.

"That was probably the most important piece of information," Larkin says. "It reflected the excellent potential in the basin and in our wells" and came about without fracture stimulation. Most companies working in the basin are tight-lipped about what they are finding. Tyner is something of a cheerleader, in part because it is out of the land-leasing game until 2006.

"Tyner is producing all the data from the wellbores,

while our capital is better spent on land acquisition," says Ford Nicholson, president of Bankers Petroleum U.S. Ltd.

In late October, Tyner's Broseh No. 1 well reached 9,600 feet, penetrating 600 feet of lower Bend Shale. This was expected based on data from an adjacent well drilled 40 years ago. Tyner set 5.5-inch production casing through to total depth and planned to move a completion rig from the Stephens well to the Broseh to begin frac stimulation in early last month.

Bankers began leasing land in December 2004. By November, it had leased about 260,000 net acres in Floyd and Motley counties at a cost of about \$13.6 million. The company is now in the later stages of land acquisition, picking up minority stakes to add to its portfolio of more than 400 separate lease agreements. Bankers also has received two drilling permits and recently contracted a triple drilling rig, which can drill to below 10,000 feet. The rig should be ready for work in the first quarter.

"We'll be in the thick of the learning curve..." Nicholson says.

There's a lot to learn. The Morgan Stanley report calls the Palo-Duro a technology play: "Upfront understanding of the lithology/geophysical characteristics of the shale is paramount to subsequent success."

Morgan Stanley expects a variety of well-completion techniques will be needed and that completion approaches will have to be continually refined as the play matures.

Nicholson says E&P companies combined will likely need to drill two to three dozen wells in the Bend Shale play before they will clearly understand the science and scope of the play. Companies working in the Palo-Duro have drilled about nine wells targeting the Bend Shale specifically.

Palo-Duro's Reserve Potential	
Bottom-Up Method (Generic Position)	
Net acres	100,000
Well spacing (acres/well)	100
Total unrisked wells	1,000
Net Bcfe/well	1.5
Net unrisked recoverable (Bcfe)	1,549
Net risked recovery (Bcfe)	
100% success	1,549
50% success	775
25% success	387

Source: Morgan Stanley

New Albany Shale Well Economics

Horizontal well cost	~\$750,000
Well depth	500-2,500 (feet)
Reserves/well	~0.7-1.2 (Bcf)
Peak production	~200-300 (MMcf/d)
Time to peak	6-12 months
Decline rate	~5%/year
Productive life	~30 years
Average W.I.	43%
IRR	~45% (\$5 gas)

Source: Aurora Oil and Gas Corp.

“It’s a very competitive situation,” he says.

Vintage Petroleum is quiet about its work in the Palo-Duro, in part because of competitiveness and in part because the company is being acquired by Occidental Petroleum. The deal was expected to close by the end of last year.

“We’re restricted in what we can say,” says Robert E. Phaneuf, vice president, corporate development.

In early November, the company reported in a news release that long-term testing was under way on its Echols 2 No. 1 and Burleson 60 No. 1 wells, both of which the company drilled and fracture stimulated earlier in the year. The company planned to analyze results from those wells before doing any more drilling. Vintage reported working interests ranging between 65% and 75%.

Smaller players are paying close attention to the progress being reported by other companies.

“Our goal is to sit tight and collect data,” says Ray D. Reaves, president and chief executive of Austin-based FieldPoint Petroleum Corp.

“We hope one of these other developers will show sales or consistent flow rates.”

As of mid-November, FieldPoint had filed five drilling permits in the basin, where it has a 100% working interest in about 3,200 acres. The company could begin drilling in the middle of this year, although Reaves says he can wait until later in the year to be more certain about the basin’s viability. The company has not yet set a capital budget for

Antrim Shale Well Economics

Vertical well cost	~\$300,000
Well depth	250-1,500 (feet)
Reserves/well (average)	~0.5 (Bcf)
Peak production (average)	~150 (MMcf/d)
Time to peak	6-12 months
Decline rate	~7% per year
Productive life	~40 years
Avg. W.I.	46%
IRR	~30+% (\$5 gas)

Source: Aurora Oil and Gas Corp.

this year’s drilling.

Completion technology will be a “very big factor” in determining when and if FieldPoint moves ahead with its drilling program, Reaves says.

Vancouver-based Maxim Resources said in mid-November it planned to pay Kendrick Oil & Gas \$150,000 for a 75% net revenue interest in 1,390 acres in the basin’s Pennsylvanian Sands. The property is bordered by Bankers Petroleum and Vintage Petroleum and is 1.5 miles north-east of Tyner Resource’s Stephens No. 1 well. Depending on rig availability, Maxim said it could start drilling as soon as the sale is completed.

During summer 2004, PetroGlobe Energy USA Ltd., a unit of PetroGlobe Inc., retained Easterling Acquisitions LLC of Amarillo, Texas, to act as its land broker in leasing prospective acreage in the basin. PetroGlobe’s area of interest covers Motley, Floyd, Brisco, Swisher and Hale counties.

The company first became active in the basin in 2002 when it partnered with Legacy Petroleum to drill the Cogdell Estate No. 1 and the Echols 2 No. 1. PetroGlobe has allocated capital from a private placement to acquire more acreage.

Antrim: A “great play”

The same high gas prices driving exploration in the Palo-Duro are helping already-established New Albany and Antrim shale plays in Indiana, Kentucky and Michigan. These are older plays, but in today’s market they are far from also-rans.

The Antrim Shale in Michigan is a mature producer that has been declining since 1998, says Dick Redmond, president of Traverse City, Michigan-based DTE Gas & Oil, a unit of Detroit-based DTE Energy.

“It’s been a great play for DTE; we’ve been in it over 15 years,” he says.

Antrim wells range from 400 to 2,000 feet deep, cost about \$170,000 to drill and complete, and produce 400- to 800 million cubic feet of gas during their lifetimes. Production rates after six to 12 months of dewatering are 125,000 to 200,000 cubic feet a day. Peak production is reached after two years, then the wells start to decline at about 8% a year and deliver a 20-year lifespan.

At peak production in the late 1990s, the field produced about 200 Bcf annually. In 2004, the Antrim produced about 150 Bcf and likely will produce between 140 and 150 Bcf this year, too, Redmond says. Strong commodity prices have led to an increase in drilling permits this year. Redmond says DTE drilled about 100 wells in 2004 and likely will drill 120 in 2005. With a \$40-million budget, DTE may drill as many as 130 wells this year. If past performance is any indication, 99% of them are likely to be successful.

DTE leases about 80,000 acres of undeveloped land in the Antrim Shale, and added 19,000 acres in the last 12 months. That new acreage could add 500 well sites and 120 Bcf of new reserves. Altogether, the company leases about 290,000 acres and has 2,000 wells producing 60 million cubic feet per day. The company expects its net income from

Antrim to grow 50% to \$15 million in 2006, and triple to \$30 million by 2008. That growth is largely a function of the roll-off of legacy \$3 hedges, Redmond says. Their expiration means the company can remarket existing production at higher market prices.

Another large Antrim Shale player is Fort Worth, Texas-based Quicksilver Resources. The company started drilling wells in about 1991 and owns interests in nearly 3,000 producing Antrim wells. Quicksilver produces 65 million cubic feet per day, has more than 500 billion cubic feet equivalent of proved reserves and 200,000 acres of leases in the play.

As of early November, the company had drilled 50 net

recent third quarter. The increase, combined with higher commodity prices, helped Aurora's gas revenues rise from \$960,000 in 2004 to almost \$1.9 million through the first nine months of last year.

Aurora says it spends about \$300,000 to drill a well 250 to 1,500 feet deep in the Antrim Shale. On average, the wells produce about 150,000 cubic feet per day at their peak, which follows six to 12 months of dewatering. The wells decline at a rate of about 7% a year and have a 40-year productive life. At \$5 gas and an average working interest of 45%, the play generates more than a 30% internal rate of return, Aurora says. Finding and development costs averaged 60 cents per thousand cubic feet (Mcf).

Sizing Up the Palo-Duro

	Fort Worth Basin	Palo Duro Basin
Target resource	Gas-Barnett Shale	Gas-Bend Shale
Geologic age	Mississippian	Pennsylvanian
Depth (feet)	6,500 - 8,500	7,000 - 10,500
Gross thickness (feet)	200 - 1,000	500 - 1,000
Net pay thickness (feet)	100 - 500	300 - 600
Average TOC*	4.50%	2.50%
Average RO**	1.0 - 1.2	.8 - 1.3

*Total organic content
**Thermal maturity

Source: Bankers Petroleum

New interest in New Albany

Gas wells in the Illinois Basin drilled into the New Albany Shale trend are drilled on 160-acre spacing. Estimates made by the National Petroleum Council Committee on Unconventional Gas Sources suggest the New Albany Shale in the Illinois Basin could contain as much as 86 trillion cubic feet of gas.

The New Albany Shale has produced natural gas since the late 1850s, mostly from wells in southwestern Indiana and western Kentucky. As with many other organic shale reservoirs, the natural gas is stored as free gas in

wells in Michigan and Indiana shale projects. It also reported positive results in a re-entry horizontal drilling program in the Antrim Shale. That success, along with re-works of non-Antrim properties, kept Michigan production ahead of production for the year.

Denver-based Whiting Petroleum owns an interest in 57 multi-well gas projects in the Antrim Shale with proved producing reserves and ongoing development drilling. The company participated in drilling and completing about 50 wells in 2004 and last year.

In October, Cadence Resources acquired Aurora Energy Ltd., of Traverse City, Michigan. Aurora had been actively acquiring land in the Antrim and the New Albany Shale (in Indiana and Kentucky) for the past 10 years. Its net acreage position grew 120% between March and November, reflecting the infusion of \$18.5 million from an equity private placement early in the year and mezzanine financing of \$30 million.

Aurora's assets include more than 143,000 gross acres (65,000 net) of oil and gas leases in the Antrim Shale. Through the first nine months of 2005, Aurora drilled 54 net wells (106 gross). Of these, 20 net wells (53 gross) were producing. The remaining 34 net wells (53 gross) were awaiting infrastructure buildout, which was expected in the first quarter of this year.

Aurora has a turnkey drilling agreement that gives it preferential access to drilling rigs. Its daily gas production rose from an annual average of 492,000 cubic feet equivalent per day at the end of 2004 to 2.802 million during the most

fractures, and as absorbed gas on kerogen and clay surfaces within the shale matrix. The New Albany Shale has a continuous 100-foot-thick pay zone, capped by a thick, dense gray-green Border Shale.

Aurora says horizontal wells cost about \$750,000 to drill in the New Albany Shale and reach a depth between 500 and 2,500 feet. Peak production is between 200,000 and 300,000 cubic feet per day, and the peak follows a six- to 12-month dewatering period. Wells decline at a rate of about 5% a year and have a productive life of about 30 years. With \$5 gas and a 43% average working interest, gas from New Albany Shale produces about a 45% internal rate of return. Finding and development costs averaged 75 cents per Mcf.

In mid-November, College Oak Investments Inc. entered a joint venture with Rex Energy Operating Co., a privately held company, to acquire a working interest in leasehold acreage in the New Albany Shale in Indiana. The joint-venture partners set up a limited liability company, New Albany-Indiana LLC, which in turn agreed to pay \$10.5 million for an undivided 48.75% working interest (40.7% net revenue interest) in several oil, gas and mineral leases in the play. The seller was Aurora Energy Ltd. The deal includes all of Aurora's rights under a farmout with a third party. Closing is expected February 1, and the partners plan to drill 10 wells on the newly acquired acreage.

That's not bad for a legacy field that was already producing when Abe Lincoln left Springfield, Ill., for the White House. ■

ACTIVITY BUILDS IN WOODFORD SHALE

Some say Oklahoma's shale may hold 4 trillion cubic feet of gas.

By Leslie Haines, Editor in Chief

About the only thing more exciting than watching the impressive success of the Barnett Shale is watching another shale play begin to take off. That is the case with the Woodford Shale play currently unfolding in southeastern Oklahoma where drilling centers on Pittsburg, Coal and Hughes counties.

Like the Barnett and Fayetteville shales, the Woodford is not a new discovery. Geologists have long known this gas-saturated play existed, situated along a long fault line. High gas prices and better completion techniques are unlocking the potential. What's more, although the play is in its infancy, operators will benefit from the experience of the significant number of wells drilled in the Barnett Shale during the past 20 years.

The more active Woodford players include Devon Energy and Newfield Exploration. Since entering the Midcontinent region in 2001, Newfield has doubled its production there to 130 million cubic feet per day, hoping the company's recent entry into the Woodford shale will only accelerate that growth.

"Industry success experienced in the Barnett in Texas and the Fayetteville Shale in Arkansas has quickly elevated investor expectations for Newfield's Woodford Shale position."

—Morgan Stanley

"We think we have the assets now in place to show double-digit production growth in the Midcontinent again by 2010," says Steve Campbell, vice president, investor relations.

Originally Newfield and others were drilling in this region for Wapanucka, Caney, Cromwell, Woodford and Hunton plays, but they noticed better estimated ultimate recoveries from the Woodford, Campbell says. Combine that with the success of the Barnett, and the race was on. After exploiting the Woodford Shale, it will commingle production from the shallow zones above it, he says.

About 100 wells have been drilled to the Woodford so far, and Newfield has drilled 60% of them. Five were horizontal wells with lateral legs of 1,000 to 2,500 feet.

"We have an aggressive program there. We plan 39 wells this year in the Woodford and Caney, and up to 50 in the Woodford alone by 2007. We have four rigs running now and are moving in two more," he says.

Woodford wells are 6,000 to 11,000 feet deep and cost \$3.3 million on average to drill and complete with multiple fracs required.

The gas-bearing shale section ranges from 120 to 200 feet thick. Management estimates net unrisked potential in its acreage is between 2 trillion cubic feet equivalent on 80-acre spacing and 4 trillion on 40-acre spacing.

"We think reserves are 2- to 2.5 billion cubic feet equivalent per well," he says. Initial potential rates so far have been better than 1 million per day and sometimes as much as 3 million a day.

"The Woodford Shale compares favorably to the Barnett Shale in terms of organic content (6% to 8% versus 4.5%), per-well production rates and reserve sizes," according to a report from Morgan Stanley issued right after Newfield unveiled details of its Woodford position to analysts in October. "Industry success experienced in the Barnett in Texas and the Fayetteville Shale in Arkansas has quickly elevated investor expectations for Newfield's Woodford Shale position."

Morgan Stanley analyst Lloyd Byrne noted that the stock rose right after Newfield discussed for the first time its Woodford plans.

The company has about 110,000 acres and is still leasing, Campbell says. It may have as many as 1,000 locations.

"We're really working to lower costs. The name of the game is using scale—can you extrapolate what you learn from 10 wells to the next 100? Can you extrapolate what has been learned in the Barnett Shale where there are now more than 4,000 wells, to this play where only about 100 have been drilled?"

Campbell says Newfield is trying everything it can in this, the early stages of the learning curve. "We're trying water fracs, gel fracs, nitrogen foam fracs, all of them. Can we drill them a couple days quicker? We're experimenting with different bits, drilling-service companies, everything."

Last year, Newfield's Woodford production was about 9 billion cubic feet, but Campbell says the company expects to produce 20 billion this year.

"In the past when gas prices went up, the go-to place for the industry was the Gulf of Mexico," notes Campbell. "Today industry is drilling hundreds of wells onshore in these resource plays instead, to achieve the same kind of production. We are very encouraged by what we see in the Woodford shale." ■

NEW SHALE-GAS PLAY UNFOLDING

Houston-based Southwestern Energy Co. is pioneering the development of black, organic-rich Mississippian shale that is the geological equivalent to the Barnett in the Fort Worth Basin and the Caney in eastern Oklahoma.

By Peggy Williams, Senior Exploration Editor, *Oil and Gas Investor*

Found at depths between 1,500 and 6,500 feet, the Fayetteville Shale occurs below the Pennsylvanian sands that are major conventional gas reservoirs in the Arkoma Basin Fairway. The Arkansas shale compares favorably to other gas-producing shales: it is thermally mature, its total organic carbon content ranges between 4% and 9.5%, and its gas contents are between 60 and 220 standard cubic feet per ton. Gas-in-place is estimated between 58- and 65 billion cubic feet (Bcf) per section.

The Fayetteville is a genuine exploratory play, as the prime areas of thick shale do not coincide with the developed Fairway. The shale expands from a thickness of 50 feet in the Fairway to as much as 325 feet in the counties to the east.

Since early 2003, when Southwestern launched a major lease acquisition program, it has amassed 724,000 net acres in the undeveloped play area. In addition, it holds 125,000 net acres by production in the Fairway. On its undeveloped leasehold, its land costs have averaged about \$75 per acre with royalties of 12.5%.

“The part of the basin we were focusing on was a very rural area that had never had any real production, so we were able to lease without attracting wide attention,” says Harold Korell, Southwestern Energy Co. president, chairman and CEO.

The company launched its Fayetteville drilling program in 2004 in Conway County. Its first project in the undeveloped play area was in its Griffin Mountain pilot area, which it selected based on geologic parameters and its proximity to one of the two pipelines that traverse the eastern end of the Arkoma. The wells were drilled to depths near 4,400 feet and fracture-stimulated.

By year-end 2004, Southwestern had 10 vertical wells on production, making between 100,000 and 500,000 cubic feet of gas per day apiece and little to no water. The company booked total proved reserves of 7.5 Bcf from 10 wells and 10 proved undeveloped locations at year-end 2004.

As of the end of October, Southwestern had upped its total well count to 66, plus one outside-operated well, and was producing 12 million cubic feet a day from the play. The



Schlumberger crews are performing one of four stages in a nitrogen-foam fracture stimulation on Southwestern Energy's McNew No. 3-2H horizontal well in Conway County. (Photo by Lowell Georgia)

wells are sprinkled among 10 pilot areas in Conway, Faulkner, Van Buren, Franklin and Cleburne counties. The company expects to drill between 60 and 70 wells and produce about 2 billion cubic feet equivalent from the budding play for last year.

The company made horizontal drilling a big push of last year's activities. Eighteen of the 67 wells drilled to date are horizontal tests, with laterals ranging between 1,800 to 2,300 feet. At press time, a dozen of the horizontal wells were completed, two were waiting on completion, one was temporarily abandoned because of mechanical problems and three were drilling. The average initial rate for a completed horizontal is 2.5 million cubic feet per day, excluding the first well that had stimulation problems.

Based on its experiences to date in the emerging trend, Southwestern estimates ultimate recoveries for horizontal wells between 1.3- and 1.7 billion cubic feet equivalent each. Completed well costs are between \$1.4- and \$1.8 million for horizontal wells, which is down substantially from the \$2.1 million-average for the initial horizontal tests.

"We've learned rapidly on the first few horizontal wells," says Richard Lane, executive vice president. "We started out with a conservative design, and we're fine-tuning that as we gain experience."

A crucial element for the success of most shale plays is the ability to effectively fracture the reservoir, and the Fayetteville is no exception. Even horizontal Fayetteville wells must be stimulated to produce, and Southwestern has

been experimenting with several fracturing treatments, including nitrogen-foam and slick-water fracs. It also employs microseismic techniques to calibrate fracture lengths and azimuths.

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A recent notable development is the success of its No. 4-2 McNew, in the company's Gravel Hill Field. This is the first horizontal wellbore stimulated with a slick-water frac, and initial results are positive, with the well exhibiting a low



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decline rate in its first weeks on line. The company plans to perform additional slick-water treatments.

Selection of the best locations for pilots is an added issue. A defining characteristic of the Arkoma Basin is its structural complexity, from many down-to-the-basin normal faults and thrust faults. Initially, the company picked highly faulted areas for its pilots on the assumption that naturally fractured rock would yield strong gas production rates, but now it targets less disturbed areas where the fracture treatments are easier to control.

By the close of this year, it intends to have drilled an additional 35 to 40 pilots to test the bulk of its acreage. These wells will supply it with a wealth of data across its acreage holdings. One effort of particular interest is the efficacy of horizontal wells in the Fairway area, where the Fayetteville is thinner, but the company's extensive held-by-production position is laced with infrastructure.

Southwestern's plans for this year call for spending of about \$300 million and drilling between 175 and 200 wells in the play. With its immense position, Southwestern has years of activity ahead of it, and it wants to ensure rig availability doesn't hamper its programs. Toward that end, the company recently committed to buy 10 new rigs from a private manufacturer. The first rig was scheduled to be drilling at the end of last year, and by year-end, the company should have up to 15 rigs at work in the play.

"The Fayetteville Shale is a huge logistics and transportation project. This is a major manufacturing-style play in an

area with very little infrastructure. We have a lot of work to do," says Korell.

Although Southwestern launched the Fayetteville and had the shale all to itself for a while, its success has invited competition. Since news of the Fayetteville's potential broke, Oklahoma City-based Chesapeake Energy has picked up some 600,000 acres and expects to begin a drilling program shortly. It has already filed for several permits. XTO Energy, headquartered in Fort Worth, Texas, and the largest gas producer in Arkansas, holds 100,000 acres in the shale play outside of its considerable Fairway position. The company plans a pilot program in the second half of this year.

Houston independent Contango Oil & Gas Co. started leasing in March in the play, and has acquired 37,000 acres with its partners. It expects to raise that position to at least 40,000 acres and begin a six-well horizontal drilling program by mid-year. Edge Petroleum, also of Houston, has picked up acreage as well. The company has 5,000 net acres and will start a drilling program in the first half of the year.

Another new entrant is Fort Lauderdale, Fla.-based Maverick Oil & Gas Inc. The firm has leased 11,000 acres and gathered commitments for another 70,000 acres, mainly in Woodruff and St. Francis counties. Touchstone Resources USA Inc., based in Houston, and Bamco Gas LLC are partnering with Maverick in a joint venture. ■

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Southwestern Energy's McNew No. 32-H is rigged for a nitrogen-foam fracture treatment. The well, in proposed Gravel Hill Field, has a 2,310-foot lateral. (Photo by Lowell Georgia)



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