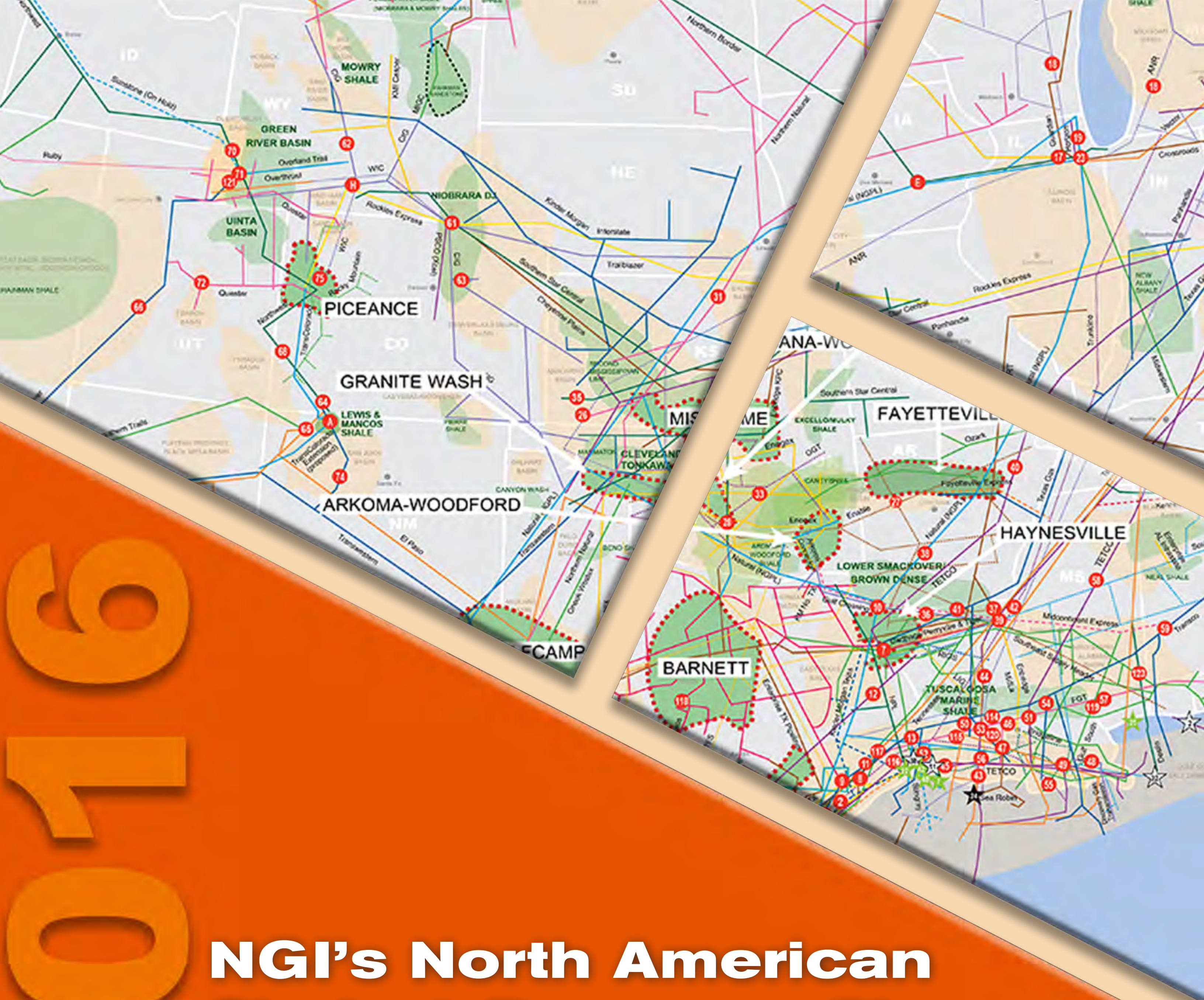

2016

NGI's North American Shale & Resource Plays FACTBOOK

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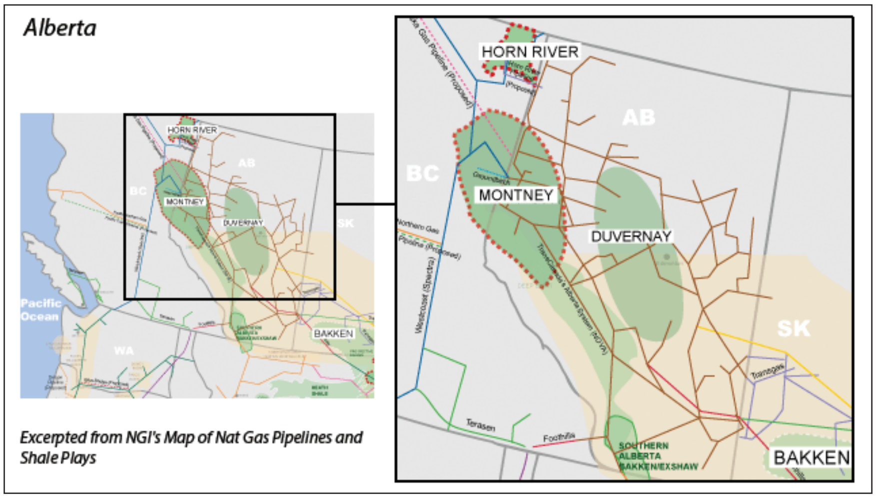
DUVERNAY SHALE

Background Information

The Duvernay Shale is an emerging oil and liquids-rich gas formation in the Western Canada Sedimentary Basin that is thought to hold 443 Tcf of natural gas, 11.3 billion bbls of NGLs, and 61.7 billion bbls of oil, according to a report released in November 2012 by the Alberta Geological Survey.



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

Consulting firm Wood Mackenzie Ltd. also highlighted the potential of the play in a report it issued only several weeks before the release of the Alberta Geological Survey study. "It has the potential to be as big as the Eagle Ford, but it's a much different play," said Wood Mackenzie analyst John Dunn. "It's further on in life," in terms of the shale's formative life, but based on early well results, "it certainly has the potential." In fact, many in the industry believe the Duvernay is the closest analog to the Eagle Ford, since they are both over-pressured reservoirs, and both formations feature volatile oil, condensate, wet gas, and dry gas windows that are all believed to be productive.

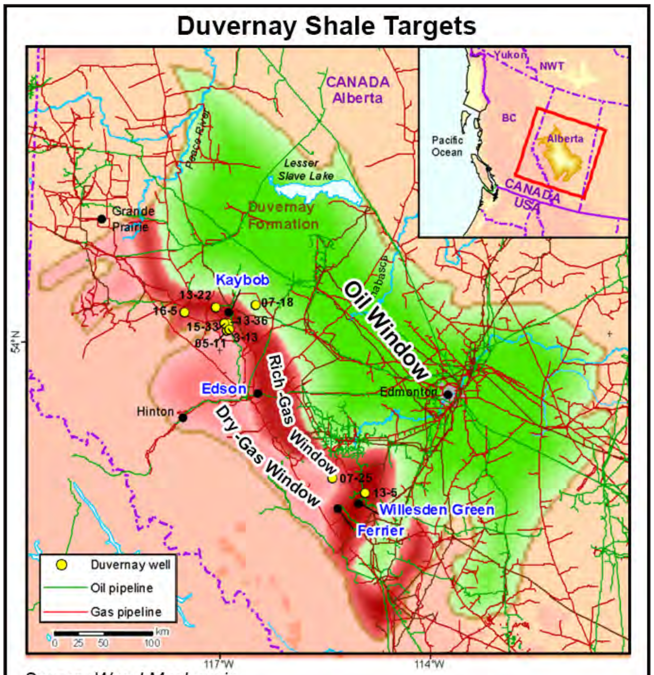
In a separate report in July 2015, Wood Mackenzie estimated that liquids production in the Duvernay would grow from 27,000 b/d in 2015 to more than 320,000 b/d in 2025. But the firm also noted that takeaway capacity in the play is constrained (see *Shale Daily*, June 24, 2015).

Macquarie Research noted that prospective operators spent C$1.4 billion to purchase more than 1 million acres in Alberta with Duvernay potential between late 2009 and August 2011, and Wood Mackenzie reported the industry had drilled roughly 80 Duvernay wells as of October 2012. Most of the activity has been centered in Kaybob in the northwest, which appears to be an early sweet spot. Drilling is expected to pick up south of Kaybob in Edson, Rimbey, Willesden Green and Ferrier as acreage is high graded, according to Andy McConn of Wood Mackenzie.

Even though the Duvernay has long been known to hold a lot of unconventional reserves, one thing that has inhibited full development until now is its remote location. But a lack of infrastructure isn't a hindrance, at least not yet.

"It comes with development, and that is in early stages," McConn told *NGI's Shale Daily*. "What it would look like, in terms of pipelines, midstream operations, is the same thing that's happened all across North America, which wasn't prepared for the huge surge in production," he said. "The Duvernay is subject to some of the same issues occurring in different plays, like the Bakken. In differentials, we're not seeing quite the prices because it's so early in the play's life, but as development ramps up, we will see where the shortfalls are. But today infrastructure is not viewed as an inhibitor."

Although the Duvernay Shale certainly has the potential to be a highly productive and economic play, its development has been very slow thus far, at least relative to other North American resource plays. For example, as of October 2014, there had not been much multi-well pad drilling in the region, an activity which is a hallmark of accelerated or "development mode" production. We



Source: Wood Mackenzie

Duvernay Shale (continued)

believe there are several reasons for the slow pace of development in the Duvernay thus far:

1. Much of the acreage in the Duvernay is held by a block of large companies (see acreage table), and these entities either tend to focus on limiting production growth in order to maximize free cash flow over the long-term, or they are faster growers who have a number of other compelling properties in their portfolios that are competing for the same capital.

2. We believe the mineral rights to the Duvernay by and large are held by the Crown, and the Canadian government tends to issue less restrictive leases than those in the United States. Operators in the Duvernay have up to nine years to drill the formation in order to hold it by production, as opposed to the three years or so that is more typical in the U.S. As a result, Canadian operators have much more time to be selective in choosing which properties to drill.

3. The Duvernay is something of a deeper play, so that adds to drilling costs in the formation. Wood Mackenzie opined that the Duvernay "is home to some of the most expensive wells onshore" in North America, noting that total estimated costs to drill a well in late 2012 were US$12-14 million, versus most U.S. unconventional wells that were below $10 million at the time. Wood Mackenzie believes those costs will come down as producers use pad drilling, retain long-term hydraulic fracturing crews, have better water sourcing, and optimize completion techniques. In fact, several Canadian operators at an industry conference held in New York in October 2014 agreed that the ultimate goal is to get Duvernay drilling and completion costs down to US$10 million.

Gas production from the Duvernay could one day be liquefied and exported to Asian markets by any of the multiple liquefied natural gas export projects proposed for western Canada. The economics of Duvernay wells could also be helped because it is relatively close to Canadian oil sands (bitumen) production. The Duvernay is liquids rich, and the condensate it produces can be used as a diluent to help get the bitumen to market. Because of this, condensate prices out of the Duvernay actually have exceeded crude oil prices in the region many times in the recent past. Encana Corp. estimated on its 3Q2015 earnings call that the Duvernay earned rates of return in excess of 30% at $50/bbl crude oil.

In 2014, Encana built two eight-well pads in the Duvernay Shale between January and March (see *Shale Daily*, May 13, 2014). The company also secured two separate deals to process rich natural gas from the play. Under the first agreement, with joint venture partner Brion Duvernay Gas (formerly Phoenix Duvernay Gas), Encana agreed to process up to 195 MMcf/d for over five years, through 2020. The gas would be transported via the Alliance Pipeline to a plant in Channahon, IL owned by Aux Sable Liquids Products LP. The second agreement, also between Encana and Brion, calls for processing up to 180 MMcf/d and connecting with a receipt zone with Alliance in Alberta from November 2017 through 2020 (see *Shale Daily*, Nov. 24, 2014). Encana planned to spend $250-350 million on capital expenditures (capex) in the Duvernay in 2015, with accelerated development in the Simonette area (see *Shale Daily*, Dec. 16, 2014). Three to five rigs were to drill 15-25 net wells. Net liquids production from the Duvernay was expected to average 6,000-7,000 b/d.

Last February, in the wake of low commodity prices, Apache Corp. slashed its capex budget by $2 billion and streamlined its capital program, electing to work on efficiency improvements, downspacing and other testing to delineate its holdings in the Duvernay, among other plays (see *Shale Daily*, Feb. 12, 2015). The company placed its first Duvernay pad, consisting of 7 wells, online in October 2015. Those pad wells came in at roughly $11.6 million each, down from the $18.1 million per well the company spent drilling one off wells in the play in 2014. Also last February, Encana said it would focus on the Duvernay and three other plays in 2015, with its development program in the Duvernay targeting the Kaybob and Simonette areas (see *Shale Daily*, Feb. 26, 2015). Encana said it planned to average two or three rigs there, to drill approximately 15 net wells, and would spend nearly $230 million, mostly for completions. Encana reported that during 2Q2015, its wells in the Duvernay had production rates of up to 2,000 b/d of condensate and 11.5 MMcf/d of natural gas after 27 days on production (see *Shale Daily*, July 24, 2015). Meanwhile, Royal Dutch Shell plc indicated that it would keep its assets in the Duvernay idle until commodity prices recover (see *Daily GPI*, July 30, 2015).

Chevron noted on its 3Q2015 earnings call that they are coming down the cost curve in the Duvernay, and have learned where the sweet spots of the play are located through its delineation drilling. The company just recently embarked on a horizontal drilling program.Pembina Pipeline Corp. announced in November 2015 that it would begin construction of its third natural gas processing plant (see *Shale Daily*, Nov. 10, 2015). The plant, which would cost C$125 million (US$94 million) and be called the Duvernay 1, is forecast to start stripping up to 5,500 bbl out of 100 MMcf/d in 2017. The plant will be built at a site 260 kilometers (160 miles) northwest of Edmonton. Pembina has two new plants farther west, near the Alberta-British Columbia boundary: Musreau II, where construction was recently finished, and Musreau III with a completion target of 2016. Pipeline additions are also under way.

Other players in the Duvernay include Spain's Repsol SA, Chevron Corp. and a unit of Kuwait Petroleum Corp. Repsol acquired part of its Duvernay portfolio through its takeover of Talisman Energy Inc. in late 2014 (see *Shale Daily*, Dec. 16, 2014). Meanwhile, Chevron

Duvernay Shale (continued)

sold a 30% stake in its Duvernay position to KUFPEC Canada Ltd. for $1.5 billion in the fall of 2014 (see *Shale Daily*, Oct. 6, 2014).

Provinces

Alberta

DUVERNAY SHALE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Canadian Natural Resources	480,000	Enerplus	66,000
Shell	400,000	Husky Energy	54,000
Encana	335,000	Sonde Resources	44,021
Respol (Talisman)	323,000	Black Swan Energy	42,240
Seven Generations Energy	289,549	Yangarra Resources*	39,040
Chevron	228,000	Paramount Resources	34,305
Canadian International Oil Corp.	224,000	Mako Energy	33,362
PetroChina	222,055	Abraxas Petroleum	29,440
NAL Energy	212,135	RMP Energy	19,680
Vermilion Energy*	202,880	Yoho Resources*	13,811
Athabasca Oil Sands Corp.	197,000	Canadian Pan Ocean	N/A
Apache Corp.	177,600	Delphi Energy	N/A
Trilogy Energy*	128,000	Long Run Exploration	N/A
ConocoPhillips	120,000	Sinopec Daylight Energy	N/A
ExxonMobil	104,000	Sirius Energy	N/A
KUFPEC Canada Ltd.	97,500	TAQA	N/A
Lightstream Resources*	83,840	Wellstar Energy	N/A
Bellatrix Exploration*	82,560		

**Estimate based on reported net sections multiplied by 640*

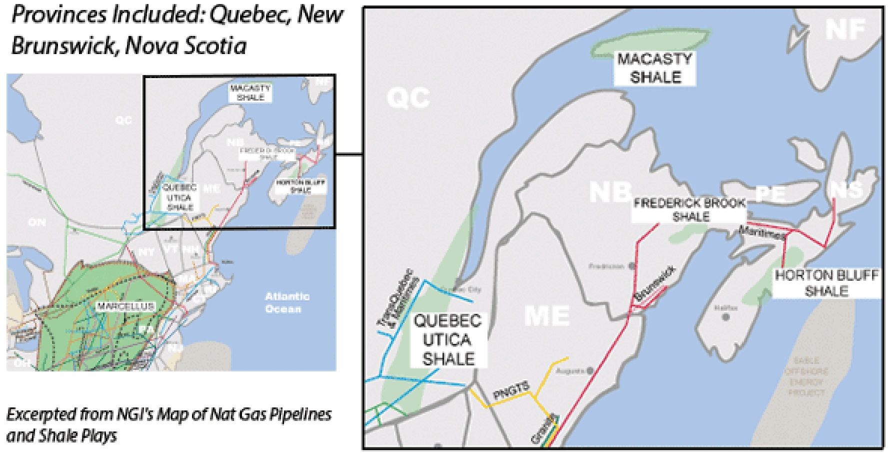
Source: Compiled by NGI from company documents

EASTERN CANADIAN PLAYS

Background Information

Although Alberta and British Columbia dominate oil and gas production in Canada, the eastern half of the country is not without its prospects, particularly on the unconventional front. The Quebec-Utica, Frederick Brook, Horton Bluff, and Macasty shales have all sparked at least some cursory interest in recent years. The main question, though, is will these properties ever reach full scale development? Eastern Canada faces several challenges that may prevent this from happening, including, but not limited to: 1) bans on hydraulic fracturing (fracking) in portions of Quebec and all of Nova Scotia; 2) decreasing natural gas exports to the U.S. Northeast because of rapidly growing production from the Marcellus and Ohio-Utica shales; 3.) the emergence of the Canaport LNG import facility in 2009, and 4) the potential future development of properties off the shores of Nova Scotia from large operators such as BP plc and Royal Dutch Shell plc.

Provinces Included: Quebec, New Brunswick, Nova Scotia



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

On the other hand, a downward revised estimate of reserves in the Deep Panuke field off the coast of Nova Scotia in February 2015 by Encana Corp. from 400 Bcf to 200 Bcf (see *Daily GPI*, Feb. 26, 2015) downgrades the long-term prospects for that facility. Encana put the long-awaited field into service in August 2013, but it was shut down from May through October 2015 because of underground water flow, and Encana now intends to bring it on only during the winter months to capture higher prices (see *Daily GPI*, Nov. 12, 2015). In addition, a proposed reversal of Canaport to an export facility, along with the proposed Goldboro and Bear Head LNG export facilities and one proposed on the St. Lawrence River by GNL Quebec Inc. – a 25-year export license to load up to 1.55 Bcf/d into tankers at a planned terminal in Saguenay, 210 Kilometers (130 miles) east of Quebec City – would provide potential new markets for Eastern Canadian natural gas production, if these projects are ever completed.

Annual Monthly Average Marketed Eastern vs. Western Canadian Marketed Natural Gas Production 2000-2014 ($10^3m^3/d$)

Year	Nova Scotia	New Brunswick	Ontario	Total Eastern Canada	% of Total	Y/Y % Chg	Total Western Canada	% of Total	Y/Y % Chg	Total Canada
2000	9409.8	0.0	1585.9	10995.7	2.3%	N/A	462493.1	97.7%	N/A	473488.8
2001	13925.0	0.0	971.2	14896.2	3.0%	35.5%	479953.6	97.0%	3.8%	494849.8
2002	14277.1	0.0	1012.5	15289.5	3.1%	2.6%	475346.1	96.9%	-1.0%	490635.6
2003	12238.4	32.2	810.2	13080.8	2.8%	-14.4%	460638.9	97.2%	-3.1%	473719.7
2004	11409.8	51.9	745.7	12207.4	2.5%	-6.7%	469653.0	97.5%	2.0%	481860.4
2005	10974.5	49.6	697.3	11721.4	2.4%	-4.0%	470468.5	97.6%	0.2%	482189.9
2006	9873.3	47.0	710.7	10631.0	2.2%	-9.3%	473947.6	97.8%	0.7%	484578.6
2007	11246.8	428.3	583.2	12258.2	2.6%	15.3%	464501.2	97.4%	-2.0%	476759.4
2008	11719.8	753.4	533.1	13006.3	2.8%	6.1%	444189.9	97.2%	-4.4%	457196.1
2009	9210.0	653.6	495.2	10358.8	2.4%	-20.4%	418299.8	97.6%	-5.8%	428658.6
2010	8364.0	483.1	466.3	9313.4	2.3%	-10.1%	404023.5	97.7%	-3.4%	413336.9
2011	7172.3	446.5	431.8	8050.6	1.9%	-13.6%	405018.1	98.1%	0.2%	413068.7
2012	5427.8	341.5	400.3	6169.6	1.6%	-23.4%	386694.8	98.4%	-4.5%	392864.3
2013	4855.0	306.3	348.1	5509.5	1.4%	-10.7%	392301.9	98.6%	1.5%	397811.3
2014	9117.6	264.2	295.6	9677.5	2.3%	75.7%	406011.6	97.7%	3.5%	415689.1

Note: 2014 estimates are from the National Energy Board of Canada

Source: National Energy Board of Canada data, NGI's Shale Daily calculations

Eastern Canadian Plays (continued)

Annual Net NatGas Imports From Canada Into the U.S. Northeast 2008-2015YTD* (MMcf/d)

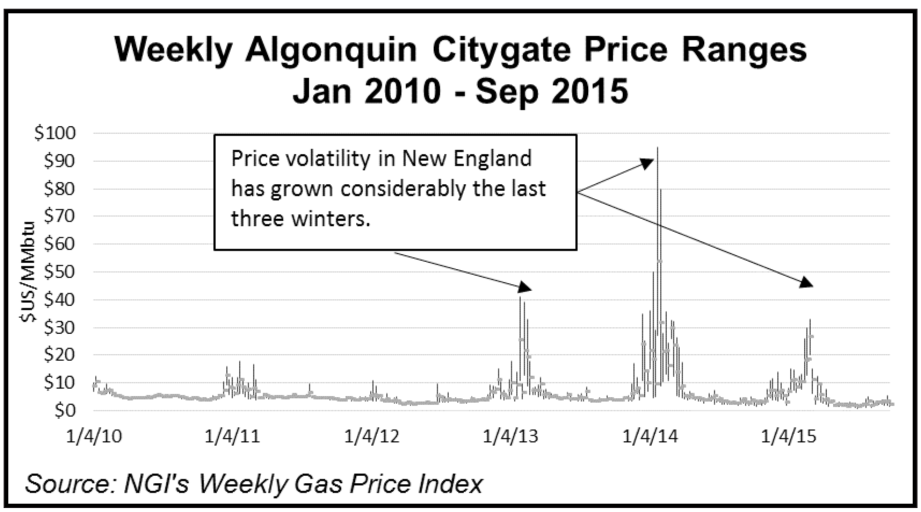
Imports - Point of Entry	2008	2009	2010	2011	2012	2013	2014	2015YTD
Calais, ME	331.4	312.6	359.0	410.2	209.1	151.4	218.1	167.1
Pittsburg, NH	107.8	73.3	50.1	54.3	129.6	173.8	142.9	216.2
Champlain, NY	49.1	38.3	25.1	22.7	18.5	19.8	13.5	13.3
Grand Island, NY	168.4	224.4	174.1	130.5	62.8	15.8	3.9	23.1
Massena, NY	18.0	15.7	15.3	10.9	10.9	11.4	10.5	10.2
Niagara Falls, NY	816.7	516.5	243.8	89.8	8.6	4.5	8.1	5.4
Waddington, NY	1,081.3	958.8	732.1	635.2	659.9	588.1	512.9	534.2
Highgate Springs, VT	22.1	25.5	24.4	28.3	22.5	26.8	28.9	35.5
Total U.S. Northeast Imports	***2,594.8***	***2,165.2***	***1,624.0***	***1,381.8***	***1,122.0***	***991.6***	***938.7***	***1,005.0***

Exports - Point of Exit	2008	2009	2010	2011	2012	2013	2014	2015YTD
Calais, ME	0.0	5.8	1.2	2.8	19.0	36.8	7.4	31.7
Pittsburg, NH	0.2	0.0	0.0	0.9	0.5	0.3	1.0	2.4
Champlain, NY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grand Island, NY	0.0	0.0	0.0	4.2	16.9	2.3	0.5	5.6
Massena, NY	0.0	0.0	0.0	0.0	1.3	0.0	0.0	0.0
Niagara Falls, NY	0.0	0.0	0.0	17.9	63.9	433.2	444.7	388.1
Waddington, NY	0.0	0.0	0.0	84.2	106.0	68.8	107.4	20.5
Highgate Springs, VT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total U.S. Northeast Exports	***0.2***	***5.8***	***1.2***	***110.0***	***207.6***	***541.3***	***561.0***	***448.2***

NET U.S. NORTHEAST IMPORTS	2,594.6	2,159.3	1,622.7	1,271.8	914.4	450.2	377.8	556.8
Y/Y % Chg	*N/A*	*-16.8%*	*-24.8%*	*-21.6%*	*-28.1%*	*-50.8%*	*-16.1%*	*47.4%*

*2015YTD data are through July

Source: EIA, NGI's Shale Daily calculations



Source: NGI's Weekly Gas Price Index

Consumers in New England would love to access more Eastern Canadian natural gas production, especially during the extremely volatile winter months. But that would require more pipeline capacity from Canada, and pipeline construction has been a contentious issue in the U.S. Northeast. However, we do believe that electric generators in New England are making an effort to burn more natural gas, and that would likely require a coordinated effort to increase pipeline capacity in the region.

In October 2015, the National Energy Board of Canada (NEB) estimated that crude oil and equivalent production from Eastern Canada would average 182,920 boe/d in 2015, or 5% of the national total (3.64 million b/d).

We describe each of Eastern Canada's unconventional plays in a bit more detail below.

Quebec-Utica Shale

Quebec's history in shale gas development began in 2008, when Denver-based Forest Oil Corp. announced that it had discovered gas from two vertical pilot wells targeting the Utica Shale on its 269,000 net acres in the province (see *Daily GPI*, April 2, 2008). By 2011, Talisman Energy Inc. had become the largest acreage holder

Eastern Canadian Plays (continued)

in Quebec's Utica with 756,000 net acres, followed by Questerre Energy Corp. with 336,440 net acres.

But the outlook for shale development in Quebec began to dim in 2011 as development became a political football. While the Liberal government outlined a new royalty regime in March 2011 (see *Shale Daily*, March 14, 2011) that would take effect once a two-year strategic environmental assessment of the oil and gas industry was complete, it also decided to restrict fracking for exploration purposes only. In September 2012, the Parti Québécois (PQ) came to power, in part on a campaign promise to shut down shale development. Five months later, the PQ enacted a moratorium on shale gas development and suspended all exploration licenses in the province (see *Shale Daily*, Feb. 8, 2013). Despite the moratorium, PQ leaders agreed to two joint ventures (JV) between the government and four oil and gas producers (see Macasty Shale) to drill wells on and offshore Anticosti Island (see *Shale Daily*, Feb. 21, 2014). The Liberals returned to power after elections in April 2014, with Phillippe Couillard as premier. Since then speculation has grown that the province may allow fracking in other parts of the province, although Couillard has been on record as saying he opposes the practice in environmentally sensitive areas. Junex Inc., a junior oil and gas explorer based in Quebec, received a permit in the summer of 2014 to drill its first horizontal well from an existing vertical wellbore near the city of Gaspé (see *Shale Daily*, July 3, 2014).

Much of the Utica Shale lies under some of French Canada's oldest communities, which are settled into traditional rural livelihoods, as well as affluent ex-urbanite colonies of families blending modern technical and professional livelihoods with country lifestyles. According to a 2014 report "Strategic Environmental Assessment on Shale Gas: Knowledge Gained and Principal Findings," or SEA by Quebec's environmental review board — the Bureau d'audiences publiques sur l'environnement (BAPE) — "shale gas is problematic because of the location of deposits."

"The shale gas development zone lies in an area of 34,672 square kilometers [13,175 square miles], composed of 30 regional county municipalities [RCM], 393 municipalities and four areas not in RCMs, the total population being 2.1 million," the SEA said.

"Nearly 75% of the region is in the permanent agricultural zone and is therefore characterized by farming activities — 43% of the land and 15,878 farm operations — together with forestry operations."

The SEA added that, unlike U.S. states where shale development thrives, Quebec follows the Canadian pattern of split land titles: private property owners only have surface rights, while underground minerals including oil and gas are public or Crown resources. As a result, no popular interest groups form as development promoters to offset opponents of industrial activity anywhere near their backyards.

The report suggested big changes will be needed to make French Canada welcoming of fracking. "Though it seems unlikely, it cannot be excluded that different economic conditions, new technologies, changes in energy supply and demand, or a change in political leadership, could shift public opinion in Quebec toward a more favorable view of the shale gas industry," (see *Shale Daily*, April 8, 2014).

Frederick Brook Shale

The Frederick Brook Shale is a natural gas-rich play in southern New Brunswick. The play, located in the Elgin sub-basin, underlies the tight sandstone rocks of the McCully Field. It also has a total thickness of up to 1,100 meters (3,609 feet) and covers approximately 120,000 acres. According to Corridor Resources Inc. — a junior E&P based in Halifax, Nova Scotia — a resource assessment conducted in 2009 by GLJ Petroleum Consultants Ltd. found that the play holds 67 Tcf of natural gas. GLJ, a Calgary-based firm of independent petroleum engineers, reconfirmed their estimate in 2014.

Corridor jumped into the Frederick Brook in 2009 when it drilled and fracked a vertical well: the Green Road G-41. In December of that year, Corridor and a subsidiary of Apache Corp. — Apache Canada Ltd. — signed a farm-out and option agreement to develop oil and gas resources in the province (see *Daily GPI*, Dec. 8, 2009). But Apache pulled out of the agreement in May 2011 after it drilled two wells with disappointing results (see *Shale Daily*, June 3, 2011). Apache backed out after Corridor announced "unexpected and perplexing" results in the Frederick Brook and Corridor has yet to find another partner (see *Shale Daily*, Dec. 7, 2010). To date, 13 wells have been drilled in the Frederick Brook. According to Corridor, the play is productive from at least six different sub-intervals, spread across a distance of 20 kilometers (12.4 miles). Four wells are currently in production. In May 2015, Corridor shut in most of its producing gas wells in the McCully Field after a dispute over natural gas prices at the Algonquin City Gates. The company resumed production five months later. Corridor said it expects production to average 10.9 MMcf/d (8.5 MMcf/d net) in November and December 2015, followed by 8.4 MMcf/d (6.6 MMcf/d net) for the first quarter of 2016.

The prospects for shale development in New Brunswick were dealt a severe setback in September 2014, after the province's voters returned the Liberal party to power and turned out the pro-shale Progressive Conservatives (see *Shale Daily*, Sept. 24, 2014). Three months later, the Liberal government enacted a moratorium on fracking, and said it would not lift it until five conditions were met — the first of which was for oil and gas companies interested in exploring the province to have "social license," a term in Canada that

Eastern Canadian Plays (continued)

essentially means the companies have earned the public's trust in keeping them safe. In September 2015, the province appointed a three-member panel to determine if fracking could be performed to its standards and solicited public comment (see *Shale Daily*, Sept. 30, 2015). The panel has until March 2016 to present its findings to Premier Brian Gallant.

Despite this, support for shale development in the province could get a boost after the NEB, in August 2015, granted import/export licenses for two liquefied natural gas (LNG) terminal projects in neighboring Nova Scotia, and one in Quebec, all of which could draw some of their natural gas supplies from onshore Canadian production (see *Daily GPI*, Aug. 17, 2015; May 26, 2015). Goldboro LNG, a project sponsored by privately-owned Pieridae Energy Ltd., received a 20-year license for its proposed 1.6 Bcf/d plant near Halifax, NS, while Bear Head LNG Corp. and Bear Head LNG (USA) LLC were given a 25-year license for a proposed 8 million tonnes per annum (mtpa) export facility on the Strait of Canso in Nova Scotia. GNL Quebec Inc. also received a 25-year export license to load up to 1.55 Bcf/d into tankers at a planned terminal on the St. Lawrence River 130 miles east of Quebec City (See *Daily GPI*, Aug. 28, 2015).

In 2010, Southwestern Energy Co. was awarded an exclusive license to conduct a three-year exploration program on 2.5 million net acres in New Brunswick by the Energy and Mines Ministry. In exchange, the Houston-based company was required to invest C$47 million in the province, with the deadline extended to March 31, 2016. During a 3Q2015 earnings call in October 2015, President Bill Way said Southwestern was marketing a package that includes its acreage in New Brunswick and other plays as it searches for a potential JV partner.

Horton Bluff Shale

The U.S Energy Information Administration, in a 2013 report on the world's shale formations, estimated that the Horton Bluff formation — part of the Windsor-Kennetcook Basin — held 3.4 Tcf of technically recoverable natural gas. In a 2014 white paper commissioned by Nova Scotia's provincial government, researchers from Cape Breton University said the extent of the Horton Bluff was "poorly understood," but said the best estimate was 520 square miles. They added that the play's thickness ranged up to about 150 meters (492 feet). But development of the Horton Bluff has been out of reach since April 2011, when Nova Scotia first enacted a ban on fracking (see *Shale Daily*, April 12, 2011). The ban has been in place ever since, with renewals in 2012 and 2014 (see *Shale Daily*, Sept. 30, 2014; April 23, 2012).

Development of Nova Scotia's shale formations began before the ban, in 2007. At that time, Denver-based Triangle Petroleum Corp. acquired an interest in the Windsor Block through a farm-in agreement with Contact Exploration Inc. Between May 2007 and March 2009, Triangle performed 2D- and 3D-seismic testing in the Windsor Block and drilled and completed five vertical test wells. The company executed a 10-year production lease with Nova Scotia in April 2009, agreeing to drill seven wells by April 15, 2014, to retain its rights to conventional oil and gas and shale gas in the area (see *Daily GPI*, April 17, 2009). Areas not drilled or evaluated after the fifth year of the agreement were subject to surrender. However, as a result of the regulatory uncertainty and bans on hydraulic fracturing, Triangle had fully impaired its more than 400,000 net acre position in Nova Scotia as of January 31, 2013.

Macasty Shale

The Macasty Shale underlies Quebec's Anticosti Island, a sparsely populated, 7,923-square kilometer (3,059-square mile) island located at the point where the Saint Lawrence River empties into the Gulf of St. Lawrence. According to Corridor, the Macasty is "a black, organic-rich shale with similar geological characteristics" to the Utica-Point Pleasant interval in Ohio. Corridor came to that conclusion after it analyzed about 900 samples it took from three test wells it drilled on the island with Pétrolia Inc. in 2012.

Despite the aforementioned moratorium on fracking in Quebec, the provincial government finalized an agreement to develop oil and gas resources on the island with Corridor, Pétrolia and a third company, Saint-Aubin E&P (Québec) Inc., in April 2014 (see *Shale Daily*, April 8, 2014). The agreement created Anticosti Hydrocarbons LP (Anticosti LP). Under the arrangement, Saint-Aubin E&P and a provincial government entity, Ressources Québec, agreed to invest $100 million in two phases for exploration efforts, with the former investing $43.3 million and the latter $56.7 million. Resources Québec was to hold a 35% interest in 38 licenses on the island, while the three remaining stakeholders were to each hold a 21.7% interest. The first phase of the project called for drilling 12 core holes between 2014 and 2015, followed by three horizontal exploration wells in the summer of 2016. Additional wells could be drilled after 2016. In 2011, consulting firm Sproule Associates Ltd. estimated that the Anticosti JV acreage held 33.9 billion boe of unrisked, undiscovered petroleum initially-in-place. The firm lowered its estimate to 30.7 billion boe in April 2015. Anticosti LP announced in October 2015 that it had completed the first phase of the project within budget, and would identify locations for the three horizontal wells within weeks. The agreement has not been without its critics; a coalition of environmental groups opposed to shale gas drilling on Anticosti Island blasted the government for not being forthcoming with the results of geologic samples taken from the island, and for taking an inconsistent stance on climate change.

In October 2014, Anticosti LP signed a strategic agreement in principal with Gaz Métro Limited Partnership to develop associated natural gas from Anticosti Island. Under the agreement, Gaz Métro, the largest natural gas distribution company in Quebec, will

Eastern Canadian Plays (continued)

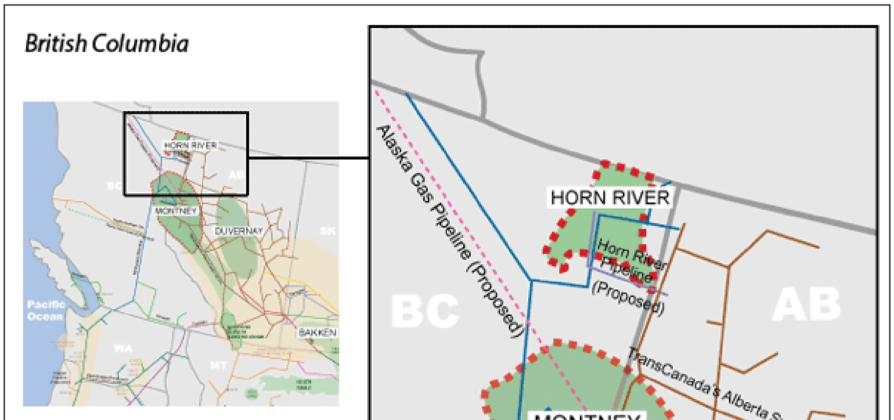
provide the partnership with technical expertise in transporting associated gas to market, should any be produced. In exchange, Anticosti LP agreed to an exclusive partnership with Gaz Métro for five years. "There are a variety of technical issues to address, including storage, transportation, and distribution of the gas," Gaz Métro said, adding that it will "have acquisition rights to any natural gas produced from wells on Anticosti Island and be able to transport or distribute it to the markets, at a price that will allow its marketing while taking into account prevailing prices."

Provinces

Quebec, New Brunswick, Nova Scotia

HORN RIVER BASIN

Background Information



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

There doesn't seem to be much question about the potential for natural gas out of the Horn River Basin (HRB), Liard Basin, and the Cordova Embayment in Northeast British Columbia (BC). The HRB alone may possess up to 650 Tcf of reserves, and one eye-opening estimate prepared by Sproule Associates in 2012 suggests these three formations may have combined resources between 809 and 2,222 Tcf. What is in question, however, is just how much these areas will be developed, and can it be done economically? Our main focus in this article is the HRB, and we will refer to that almost exclusively hereafter, since that area is farthest along in its development among these three plays (although activity in the HRB itself is still in its infancy). However, many of the issues we raise below apply to all three areas.

First, a quick description of these three plays:

Horn River Basin

According to the BC Oil and Gas Commission (OGC), the HRB is an unconventional shale play with dry gas from mid-Devonian overpressured shales, including the organic rich Muskwa-Otter Park and Evie formations. The HRB is in the northeast corner of BC, hemmed in along the west by the Bovie Lake Fault Zone and to the east and south by the Devonian Carbonate Barrier Complex. On a stratigraphic scale, the Muskwa-Otter Park and Evie shales are overlain by the Fort Simpson shales, and underlain by the Keg River platform carbonates. In a report published in February 2015, the OGC said the HRB represents 25.7% (11.1 Tcf) of BC's remaining recoverable raw gas reserves. The commission said production from the Muskwa-Otter Park and Evie formations totaled 200 Bcf in 2013, accounting for 12.7% of BC's annual production.

The OGC said an atlas of the HRB was published in June 2014, and found that the reservoir measured 1,900-3,100 meters (6,234-10,171 feet) in depth and 140-280 meters (459-919 feet) in thickness. In a separate report in October 2015, the OGC said the HRB's reporting area encompassed about 1.15 million hectares (4,440 square miles), of which 34,670 hectares (133.9 square miles) were being used for oil and gas activities.

In its February 2015 report, the OGC indicated that oil and gas drillers have been interested in the HRB since 2005, when they began deploying horizontal rigs and applying hydraulic fracturing (fracking) technology that had been successful in the Barnett Shale in Texas, which is considered an analogous shale play. But the HRB accounted for only 8% of total drilling activity in BC in 2013; the majority of drilling took place in the Montney Shale. Still, there were 376 wells (298 horizontal, 78 vertical) drilled in the HRB by 2013, according to OGC figures. Between 2012 and 2013, a typical horizontal well in the HRB had initial production of 5.6 MMcf/d. That rate declined 44% in the first year of production, and was projected to reach boundary dominated flow after more than four years, in part because of the reservoir's ultra low permeability. The OGC said 26 unconventional wells were permitted in the HRB in 2013, and added that since April 2005, a total of 522 wells had been permitted there.

But industry activity in the HRB has tapered off since the autumn of 2012, when Encana Corp., Canada's top natural gas producer, deferred plans to build its Cabin processing plant in the region. More recently, Quicksilver Resources Inc., one of HRB's top drilling rights owners, filed for bankruptcy protection in the U.S. in March 2015 (see *Shale Daily*, March 18, 2015); its Canadian assets were scheduled to be auctioned in December 2015.

Besides poor prices, the HRB suffers from natural disadvantages. The deposit is the most remote Canadian shale formation, in an uninhabited and all but roadless region along BC's boundary with the Yukon and Northwest Territories. And the initial exploration flurry showed that the deposit is dry gas, lacking the liquid byproducts that kept drilling going elsewhere.

The last newsletter circulated by the Horn River Basin Producers Group (HRBPG), in early 2013, included a brief public explanation of why the region should lower expectations until further notice.

"While there has been significant attention drawn to activities in the HRB, including media announcements and development activity

Horn River Basin (continued)

updates, it should be noted that current commercial viability has not yet been established for the area," said the group. "While infrastructure needs are being constructed for parts of the basin, companies continue to look at ways to reduce overall costs in order to make this project more economically viable in the future given the state of gas prices over the near term."

Canadian industry attention shifted to the Montney and Duvernay shale formations because both are within reach of established road and pipeline networks, and both yield high concentrations of liquid byproducts. The Montney straddles north-central BC and Alberta, with some of its richest zones lying along southern legs of the Alaska Highway in the well populated and served Dawson Creek-Fort St. John area. The Duvernay is accessible within an area of northwestern Alberta that is laced with pipelines, roads and other services developed over a long history of conventional gas drilling.

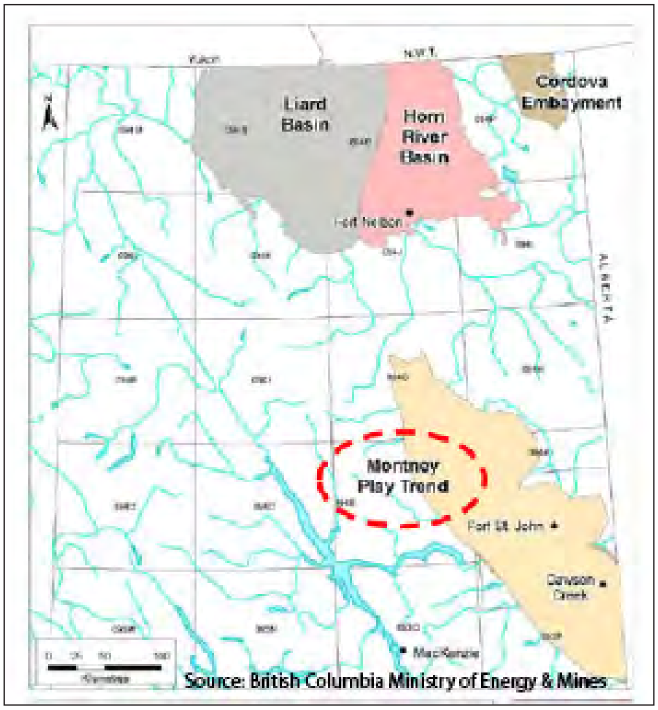
How the Horn River ranks in the Canadian industry scale of priorities shows in the current edition of an annual assessment by the National Energy Board (NEB): *Short Term Canadian Natural Gas Deliverability 2015-17.*

In the NEB's mid-range case, with a mild price recovery emerging gradually, "Western Canada deliverability falls in 2016 before increasing in 2017 as gas-directed activity increases with a continued focus on higher productivity wells. Tight gas activity grows over the projection with 901 tight gas wells drilled in Western Canada in 2017 including 544 in the Montney tight gas play. The Duvernay Shale play continues to see most Canadian shale gas activity with 40 wells drilled in 2017, compared to five wells in the Horn River Basin; activity in this dry-gas resource could increase if additional markets emerge in Canada and the U.S., or if activity increases in preparation for LNG exports."

Liard Basin

The Liard Basin is another unconventional shale gas play, located just to the west of the HRB. The two plays are separated by the Bovie fault zone, a major structural feature. According to the OGC, the Liard is comprised of a layer of sedimentary rocks more than five kilometers (16,404 feet) in thickness, which includes thick, organic shales within the Upper and Lower Devonian Besa River strata. In September 2015, the OGC said the Liard reporting area encompassed 934,304 hectares (3,607.4 square miles), of which 12,150 hectares (46.9 square miles) were being used for oil and gas activities. In a separate report in February 2015, the OGC said 11 unconventional wells were permitted in the Liard in 2013, with a total of 22 wells permitted since April 2005.

According to the OGC, oil and gas drillers began to explore the Liard in 2008. Preliminary estimated ultimate recovery (EUR) rates,



booked in 2013, totaled 100,000 Bcf, based on production from four existing wells – two vertical and two horizontal. Three vertical and two horizontal test wells were drilled and stimulated in the Liard between 2009 and 2013, in an area previously without any deep test wells. Initial test results were 7 MMcf/d for a vertical well and 30 MMcf/d for a horizontal well, which the OGC called "very promising and among the best of any shale play in North America." The commission, using a decline analysis, forecast an EUR of 8 Bcf/well for the vertical wells and 19 Bcf/well for the horizontal wells.

Cordova Embayment

The Cordova Embayment — another unconventional shale play that includes dry gas from the mid-Devonian Muskwa-Otter Park and Evie formations — is situated just to the east of the HRB and shares geologic characteristics. It covers approximately 2,700 square kilometers (1,042 square miles) and is bordered by the aforementioned Devonian Carbonate Barrier Complex. And like the HRB, it is where the Muskwa-Otter Park and Evie formations are overlain by the Fort Simpson shales, and underlain by the Keg River platform carbonates. According to the OGC, the Cordova hasn't been explored as much as the HRB, possibly because it is thinner (70-120 meters) and a more normally pressured reservoir. But the OGC said the Cordova "contains a significant number of wells and infrastructure" associated with the development of the overlying Helmut field Jean Marie formation. The commission said the Cordova's reporting area encompassed 269,006 hectares (1,038.6 square miles), of which 7,492 hectares (28.9 square miles) were being used for oil and gas activities.

Horn River Basin (continued)

According to the OGC, the first gas wells were drilled in the Cordova in 2008. The commission added that as of Dec. 13, 2013, there were 21 horizontal and five vertical wells drilled there. Annual production was 11.9 Bcf in 2013, with 21 wells in production at year's end. The OGC estimated that the Cordova held 87.6 Bcf of raw gas in remaining reserves in 2013.

Interestingly, much of the potential interest in the Cordova is coming from Asia. Mitsubishi Corp. purchased a 50% stake of Penn West Energy Trust's Cordova acreage in 2010, and a year later sold pieces of its stake to Chubu Electric Power Co. Inc., Tokyo Gas Co. Ltd., Osaka Gas Co. Ltd., and South Korea's Korea Gas Corp. (KOGAS). Nexen Inc., the Canadian subsidiary of China National Offshore Oil Co. (CNOOC), also holds acreage in the Cordova (see *Daily GPI*, May 10, 2011; Aug. 25, 2010; and *Shale Daily*, July 1, 2011).

Jean Marie Formation (not pictured)

This natural gas play is more a mix of traditional conventional, carbonate, and tight sands. There have been very few horizontal wells drilled here to date.

Activity started out strong beginning in 2008, when several oil and gas companies — including Nexen, EOG Resources Inc., Apache Corp., Encana Corp., Devon Energy Corp. and Quicksilver — began taking a serious interest in the aforementioned shale plays. Eleven producers, in an effort to share information about the basin and minimize land surface disruptions, formed the HRBPG in 2010 (see *Shale Daily*, Nov. 22, 2010). Encana's history dates back even farther, to 2001, and by 2008 was the busiest operator in the HRB. Encana and Apache formed an area of mutual interest, and controlled more than 400,000 acres at the center of the HRB (see *Daily GPI*, April 9, 2008). Apache's net stake with Encana was 207,000 acres at the time, but it began to build its position in the Liard in 2009. By June 2012, Apache had amassed 430,000 acres in the Liard, which held an estimated 48 Tcf, or 8 billion boe (see *Shale Daily*, June 15, 2012).

In December 2012, a subsidiary of Chevron Corp. acquired a 50% stake in the proposed Kitimat liquefied natural gas (LNG) export facility planned for BC, and a 50% interest in 644,000 acres in the HRB and the Liard, effectively becoming a joint venture (JV) partner with Apache (see *Daily GPI*, Dec. 26, 2012). Encana and EOG, formerly 30% non-operating owners in Kitimat and the Pacific Trail Pipeline, sold their interests and exited the JV. Under the deal, Chevron Canada Ltd. acquired about 110,000 net acres in the HRB from Encana, EOG and Apache, and about 212,000 net acres in the Liard from Apache. But by 2014, Houston-based Apache was looking to monetize most of its international portfolio (see *Daily GPI*, July 31, 2014). Apache sold its 50% stake in Kitimat and its related upstream acreage in the HRB and the Liard to Australia-based Woodside Petroleum Ltd. for $854 million in April 2015 (see *Daily GPI*, April 2, 2015; Dec 15, 2014).

Meanwhile, Nexen doubled its position in the HRB to more than 300,000 acres in 2010, and began looking for partners to help develop the leasehold and possibly delve into LNG exports (see *Daily GPI*, July 16, 2010). Nexen landed Japan's Inpex Corp. as JV partner in 2011 (see *Shale Daily*, Nov. 30, 2011).

In January 2013, Quicksilver, at that time swamped with debt, said in an operations update that during the previous month it had ramped up production in the HRB to 100 MMcf/d of raw gas from nine wells (see *Shale Daily*, Jan. 7, 2013). Over the next two months, Canada's National Energy Board (NEB) denied TransCanada Corp. permission to build the Komie North pipeline, a project that would have connected HRB production to TransCanada's system in Alberta (see *Shale Daily*, Feb. 26, 2013; Feb. 4, 2013). At the time, the rejection was seen as a boon to Quicksilver, since it was project's sole producer. But Quicksilver's efforts to find a JV partner in the HRB foundered (see *Shale Daily*, May 8, 2013), and despite filing with the NEB for permission to liquefy its HRB production and export it to Asia (see *Daily GPI*, July 29, 2014), Quicksilver filed for bankruptcy in March 2015.

In February 2013, the NEB said it was "plausible" that HRB production could grow to 3.5-4.0 Bcf/d. Current low natural gas prices are choking off some investment in the play for now, but most operators in the HRB have up to 10 years before they start losing their lease positions. However, in order to achieve significant large scale production in the HRB, we believe the industry must overcome the following issues that face all the natural gas formations in northeastern BC:

Lumpy Progress on Infrastructure

Spectra Energy currently has 1.2 Bcf/d of treating capacity and gathering pipelines in the Ft. Nelson area, including the 250 MMcf/d Ft. Nelson North processing facility it placed in service in 2013 (see *Daily GPI*, May 7, 2013). On the other hand, Enbridge Inc. and its partners announced in October 2012 plans to defer both phases of its proposed 800 MMcf/d Cabin Gas Plant indefinitely (see *Daily GPI*, Oct. 23, 2012). That additional 800 MMcf/d of capacity is probably not necessary to accommodate current production and drilling activity in the region, but we believe the decision to delay the project does underscore the lack of coordinated infrastructure growth between producers and midstream companies that is typical of more developed and less remote natural gas areas, such as the Marcellus Shale.

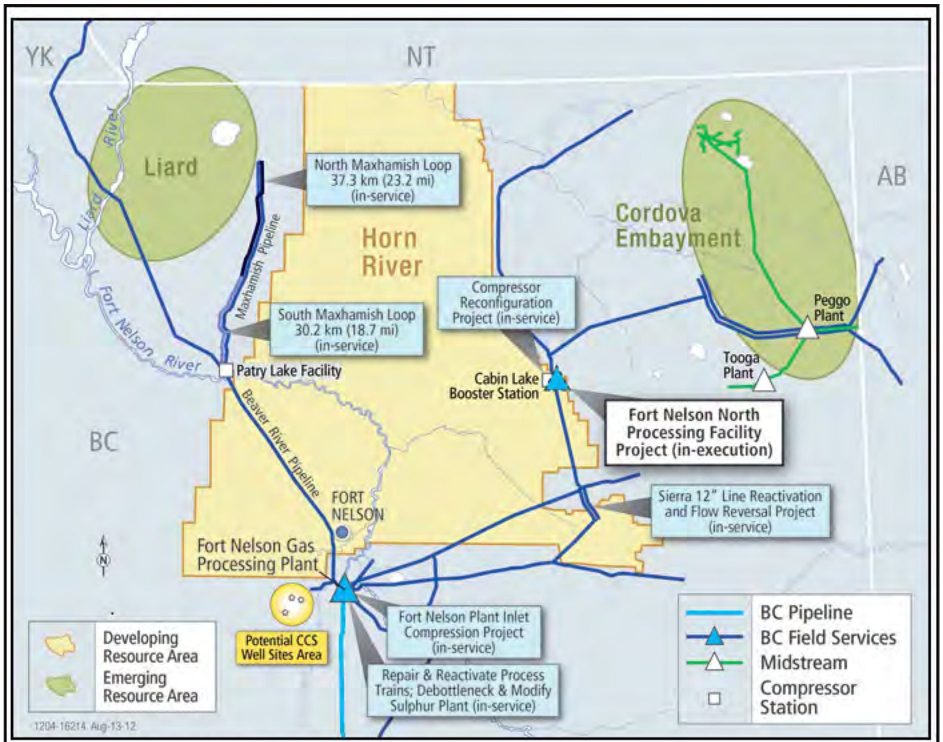
Relatively Poor Economics

Despite the fact that royalty rates in BC are quite low by industry standards, in February 2013, the NEB estimated that supply costs in the HRB averaged C$3.50/Mcf (U.S. dollar at par), well above competing gas plays in the United States. Much of that cost is no doubt the result of high transportation costs spread over lower volume. A lack of infrastructure always creates something of a

Horn River Basin (continued)

chicken and the egg problem. High drilling costs prevent producers from drilling, which in turn makes them less likely to underwrite gathering and pipeline projects. On the other hand, if producers had enough infrastructure in place, they could ramp up production, and lower unit costs.

But even after prolific drilling and anticipated efficiency improvements improve economies of scale, HRB expenses are still projected to average C$2.20/Mcf in time, the NEB concluded. Moreover, producers must contend with weak basis differentials, and HRB production is dry gas, so they do not receive an economic uplift from NGL sales.



Source: Spectra Energy

According to the Short-Term Canadian Natural Gas Deliverability 2014-2016 report issued by the NEB in May 2014, drilling in deeper dry gas formations like the HRB would not be significant unless prices were to reach US$6.00/MMBtu, which the NEB calls its higher price case. If prices were to average US$6.00/MMbtu in 2016, then the NEB assumes HRB shale gas deliverability increases from 380 MMcf/d in 2013 to 468 MMcf/d in 2016. In its mid-range case, where prices would average US$4.35 in 2016, "drilling in the HRB is minimal at 14 wells in 2016." But in its lower price case, prices average US$3.75 in 2016, which the NEB believes would be too low to spark any new drilling in dry gas plays.

As of December 3, 2015, the 2016 CME/NYMEX futures strip stood at just US$2.40/MMbtu, which would suggest little to no new drilling in the HRB area for the foreseeable future.

Competing Supply

Gas volumes flowing east on TransCanada's mainline have decreased in recent years, in no small part because of they must now compete with growing volumes from the Marcellus Shale. Moreover, if the Ohio Utica/Point Pleasant Shale formation and maybe even the Upper Devonian Shale reach full development mode, that may compete directly with gas from TransCanada into the Midwest. HRB gas also has to contend with other emerging Western Canadian plays, such as the Duvernay, Montney, and possibly even the Bakken Shale if more gas infrastructure is built there. Western Canada will no doubt need growing production from unconventional sources to help counter natural declines in its legacy production. However, given these other emerging areas, HRB production may not be necessary to achieve that.

LNG Export Facilities to the Rescue?

According to the Natural Resources Canada, as of Nov. 30, 2015, there were 16 LNG export facilities proposed for the west coast of BC. The newest to receive NEB approval is Cedar LNG Export Development Corp., a venture of an aboriginal community, the Haisla Nation (see *Daily GPI*, Dec. 1, 2015). Cedar LNG received a 25-year license to export 7.6 Tcf of gas at a rate of about 800 MMcf/d from the port of Kitimat. If any of the projects are built, Canadian producers would be in prime position to take advantage of any cost spread in Asia. We believe the HRB is particularly well suited for exports, since it is relatively closer to the coast of BC than most other Canadian producing regions, and it is dry gas, so that would likely give it some cost advantage over more liquids rich gas that would first have to have those liquids removed.

But there are several major impediments working against potential Canadian LNG exports that may prove to be too difficult to overcome. First and foremost, persistently low commodity prices have caused oil and gas companies to rethink projects they have on the drawing board. In December 2015, an analysis by Tudor Pickering Holt & Co. found at least 150 global natural gas and oil projects – including several LNG export projects – could be deferred for at least another five years (see *Daily GPI*, Dec. 3, 2015). Other analyses by Wood Mackenzie Ltd. and Rystad Energy came to the same conclusion (see *Daily GPI*, July 28, 2015; Dec. 5, 2014). Among the projects shelved: Chevron's proposed Kitimat LNG export facility.

Horn River Basin (continued)

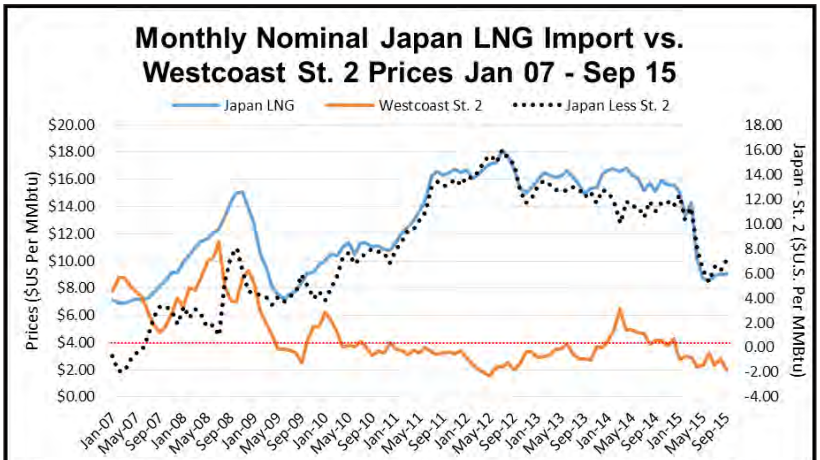
Status of Proposed LNG Export Facilities in British Columbia & Oregon As of December 4, 2015

Facility	Owners	Location	Max Annual Sendout (Bcf/y)	Applicaion Date	Application Status	Term	License Issued?
KM LNG Operating General Partnership	Chevron, Apache*	Kitimat, B.C.	468	12/9/2010	Approved	20 years	Yes
LNG Canada Development Inc.	Shell, Mitsubishi, KOGAS, PetroChina	Kitimat, B.C.	1180	7/27/2012	Approved	25 years	Yes
Prince Rupert LNG Exports Limited	BG Canada	Prince Rupert, B.C.	1062	6/17/2013	Approved	25 years	Yes
WCC LNG Ltd.	ExxonMobil/Imperial Oil	Kitimat, B.C. or Prince Rupert, B.C.	1461	6/19/2013	Approved	25 years	Yes
Woodfibre LNG Export Pte. Ltd.	Pacific Energy Corp.	Squamish, B.C.	105	7/23/2013	Approved	25 years	Yes
Pacific NorthWest LNG Ltd.	PETRONAS	Prince Rupert, B.C.	~960	7/26/2013	Approved	25 years	Yes
Jordan Cove LNG L.P.	Veresen	Coos Bay, OR	566	9/9/2013	Approved	25 years	No
Triton LNG Limited Partnership	AltaGas Pacific Partnership, Idemitsu	Kitimat, B.C. or Prince Rupert, B.C.	115	10/29/2013	Approved	25 years	N/A
Aurora Liquefied Natural Gas Ltd.	Nexen, INPEX, JGC Exploration	Prince Rupert, B.C.	1140	11/29/2013	Approved	25 years	N/A
Oregon LNG Marketing Company LLC	Oregon LNG	Warrenton, OR	473	1/13/2014	Approved	25 years	N/A
Canada Stewart Energy Group Ltd.	Stewart Energy	Stewart, BC	1475	3/5/2014	Incomplete	25 years	N/A
Kitsault Energy Ltd.	Krishnan Suthanthiran	Kitsault, B.C.	988	4/4/2014	Under review	20 years	N/A
WesPac Midstream-Vancouver LLC	WesPac Midstream LLC	Delta, BC	146	6/20/2014	Under review	25 years	N/A
Steelhead LNG (A) Inc.	Steelhead LNG	TBD (but along the B.C. Coast)	310	7/7/2014	Under review	25 years	N/A
Steelhead LNG (B) Inc.	Steelhead LNG	TBD (but along the B.C. Coast)	310	7/7/2014	Under review	25 years	N/A
Steelhead LNG (C) Inc.	Steelhead LNG	TBD (but along the B.C. Coast)	310	7/7/2014	Under review	25 years	N/A
Steelhead LNG (D) Inc.	Steelhead LNG	TBD (but along the B.C. Coast)	310	7/7/2014	Under review	25 years	N/A
Steelhead LNG (E) Inc.	Steelhead LNG	TBD (but along the B.C. Coast)	310	7/7/2014	Under review	25 years	N/A
Woodside Energy Holdings Pty Ltd.	Woodside Energy	Grassy Point, BC	1022	7/18/2014	Under review	25 years	N/A
Quicksilver Resources Canada Inc.	Quicksilver Resources	Campbell River, BC	960	7/28/2014	Under review	25 years	N/A
Cedar 1 LNG Export Ltd.	Haisla Nation	Kitimat, B.C.	142	8/28/2014	Under review	25 years	N/A
Cedar 2 LNG Export Ltd.	Haisla Nation	Kitimat, B.C.	284	8/28/2014	Under review	25 years	N/A
Cedar 3 LNG Export Ltd.	Haisla Nation	Kitimat, B.C.	284	8/28/2014	Under review	25 years	N/A
Orca LNG Ltd.	Orca LNG	Prince Rupert, B.C.	1169	9/4/2014	Under review	25 years	N/A
NewTimes Energy Ltd.	NewTimes Energy Ltd.	Prince Rupert, B.C.	584	2/11/2015	Under review	25 years	N/A

*Apache announced its intent to sell its interest in Kitimat LNG in July 2014.

Source: Compiled by NGI's Shale Daily from National Energy Board of Canada filings

Other roadblocks include the ability of producers to obtain firm supply contracts at favorable pricing. Canadian LNG would flow to the Far East, and there are already several major projects being built to export LNG to that area, particularly in Australia. Every day that Canada is unable to start building its own export facilities is another day some other gas producing nation can. We believe many BC export facility project owners are holding out hope that they can receive oil based prices for their LNG, even though we also think that buyers in the Far East would prefer prices that are linked to a gas index, such as the Henry Hub. Another challenge is that many of the proposed pipelines that would connect Canadian production to these BC export facilities are facing major aboriginal resistance within the province. If such opposition does not prevent these pipes from being built, it may delay their progress long enough for buyers in the Far East to seek LNG from other nations.



Source: FRED, NGI's Bidweek Survey, World Bank, NGI's Shale Daily calculations

The BC government reached out to the oil and gas industry in June 2015, urging the companies to keep momentum with programs despite low commodity prices (see *Daily GPI*, June 26, 2015). Like all his BC government peers, Ken Paulson, COO of the OGC, said no one believes all of the BC LNG projects can possibly make it into construction but that the terminal and pipeline sponsors are still striving to advance them. "One thing is for sure. We've got a lot of gas in BC and we're producing more and more of it — it's up every month this year. It doesn't really show any sign of changing," Paulson said.

Provinces

British Columbia

Horn River Basin (continued)

HORN RIVER SHALE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres
Husky Energy[1]	460,000
Woodside[2]	320,000
CNOOC/Nexen Energy	300,000
Penn West Energy	237,000
ExxonMobil/Imperial Oil	170,000
Encana[3]	159,000
EOG Resources	127,000
Quicksilver Resources	126,500
ConocoPhillips	120,000
Chevron[2]	110,000
Storm Gas Resources	78,000
BV Land Corp.	N/A
Chubu Electric	N/A
Crew Energy	N/A
Devon Energy	N/A
First Reserve (Stone Mountain Resources)	N/A
Insignia Energy	N/A
JOGMEC	N/A
Kogas[3]	N/A
Lightstream Resources	N/A
Mitsubishi	N/A
Osaka Gas	N/A
Paramount Resources	N/A
Pengrowth Energy Corporation	N/A
PetroChina	N/A
Questerre	N/A
TAQA North	N/A
Tokyo Gas	N/A

[1] Includes Jean Marie
[2] Includes Liard Basin acreage
[3] Kogas has a farmout agreement with Encana to earn 50% interest in 174,000 acres
Source: Compiled by NGI from company documents

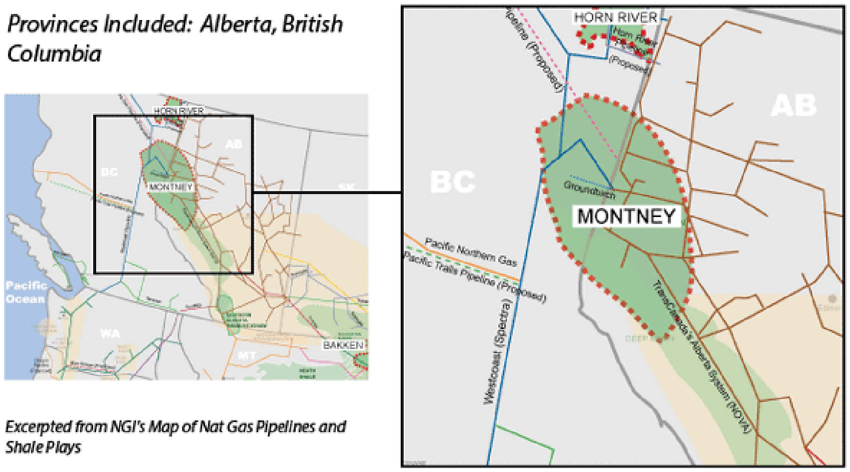
MONTNEY RESOURCE PLAY

Background Information

Startling exceptions to gloom pervading first-half 2015 corporate statements confirm that a sweet spot — where rich resources compensate for poor prices — is emerging in Western Canada's endowment of natural gas steeped in liquid byproducts.

Seven Generations Energy Ltd. scored growth of 117% in oil production, 172% in gas liquids, 129% in gas and 20% in revenue. Painted Pony Petroleum Ltd. posted output gains of 41% in gas and 9% in liquids, plus its first oil production.

Provinces Included: Alberta, British Columbia



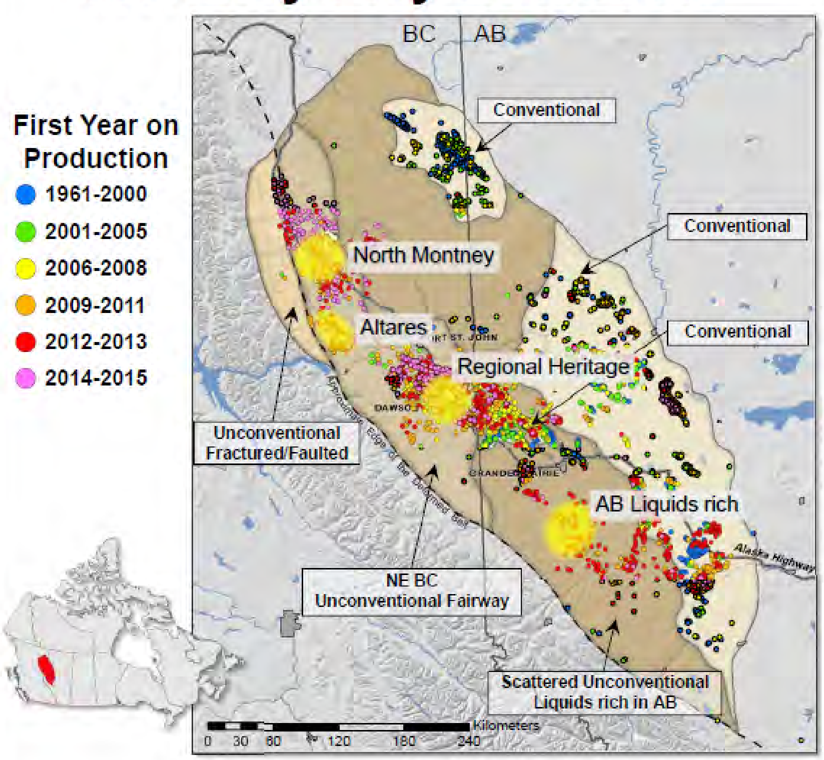
Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

Both companies focus on a geological formation known as the Montney Shale. The structure carpets a 130,000-square-kilometer (52,000-square-mile) region that straddles the border between northern Alberta and British Columbia (BC). Seven Generations works in Alberta. Painted Pony is active in BC. Although a remote frontier by standards of the urban population in Canada and the Lower 48 United States, the area is the most accessible shale or tight gas, liquids and oil zone on the northwestern fringe of the industry.

The region is within vigorous one-day drives on paved roads from the Alberta capital of Edmonton. Lying at varying depths, the thickness of the resource-soaked geological carpet is 100-300 meters (328-984 feet).

The formation spans a region where conventional vertical drilling, pipelines and processing plants have been well established since the 1950s. The territory includes Canada's latest homestead farming frontier and three northern service and industrial centers: Grande Prairie in Alberta, and Dawson Creek and Fort St. John in BC. The Alaska Highway starts at Dawson Creek

Montney Play Evolution



Source: Unconventional Gas Resources

The emerging growth employs Canadian adaptations of horizontal drilling and hydraulic fracturing. Thanks to the advanced technology, Painted Pony's investor material calls the Montney "one of North America's premier natural gas resource plays, larger in scope and with similar future potential as the Marcellus play of the northeastern U.S." The firm adds that the new methods spell access to raw deposits that its experience indicates average 2 Bcf of hydrocarbons per square mile (see *Shale Daily*, Aug. 17, 2015).

Montney Resource Play (continued)

Processing and pipeline firms are building plants and laying conduits, reducing shortages of facilities that have fallen short of field capacity and at times limited producer sales and profits.

AltaGas Ltd. and TransCanada Corp.'s Alberta and BC pipeline network, Nova Gas Transmission Ltd., are each carrying out C$1 billion-plus (US$770 million-plus) growth programs.

TransCanada subsidiary Nova Gas Transmission Ltd. (NGTL) is proposing a C$470 million (US$352 million) addition for production from a rich zone in the Montney geological formation known as Tower Lake (see *Shale Daily*, Sept. 11, 2015).

In a construction application to the National Energy Board (NEB), NGTL observes that the supply source for its proposed Towerbirch Expansion is only 3.5% of BC's share in the Montney region, which straddles the BC-Alberta boundary.

But the planned facilities are supported by eight-year contracts to deliver 590 MMcf/d of gas for an international partnership developing a 414-square-kilometer (160-square-mile) spread of Tower Lake drilling rights.

The shale gas sweet spot is west of the southernmost leg of Alaska Highway between Dawson Creek and Fort St. John. The 87-kilometer (52-mile) Towerbirch route parallels the northeastern BC road, then veers east to NGTL's main network in Alberta.

"The Montney play, which was formerly characterized as tight and uneconomic, has been successfully commercialized with the application of horizontal drilling and multi-stage hydraulic fracturing," NGTL's construction application said.

"The Montney formation holds one of the largest unconventional gas resources in North America and is one of the most economic formations in the Western Canada Sedimentary Basin, with production reaching approximately 3 Bcf/d in just a few years."

The Tower Lake producers are prime drivers of the increasing output. The Towerbirch Expansion gas delivery contracts are held by a venture called the Cutbank Ridge Partnership, owned 60% by Encana Corp. and Japan's Mitsubishi Corp.

Unlike other big items on the TransCanada-NGTL growth agenda, the Towerbirch line is scheduled for immediate construction to go into service by Nov. 1, 2017 regardless of the fate of BC liquefied natural gas export terminal proposals.

Along with migration of supply development to the Canadian industry's "near frontier" of BC shale areas, the Towerbirch project highlights rising demand by Alberta thermal oilsands extraction plants.

While aging Alberta wells continue natural depletion, NGTL forecasts that Tower Lake production will quadruple in 10 years by rising to 1.2 Bcf/d as of 2025 from 300 MMcf/d. The compact area already has 9.5 Tcf of reserves recoverable by the current stage of evolving Canadian fracking technology, NGTL said.

Over the same period, total Alberta consumption is projected to climb by nearly 50% to 6.94 Bcf/d from 4.67 Bcf/d.

During 2015-2025 gas purchases by still-growing oilsands operations are forecast to jump by 91% to 3.56 Bcf/d from 1.86 Bcf/d.

Purchased gas as fuel for steam heat-driven production systems accounts for about 70% of bitumen plant fuel consumption recorded by the Alberta Energy Regulator (AER). The total, currently forecast to hit 5.1 Bcf/d in 10 years, also includes gas byproducts of the oilsands process and fuel used by production site power stations.

"Oilsands demand continues to be a strong market," NGTL said. TransCanada's western network is also working on facilities additions for northern Alberta projects that began before the current low on the oil price cycle and aim to outlast the slump.

Denver-based Meritage Midstream Services is partnered with Canadian International Oil Corp., a Calgary-based firm owned by an array of private capital investment houses, on a pipeline system near Grande Prairie designed eventually to carry up to 225 MMcf/d of gas and 10,000 b/d of liquids.

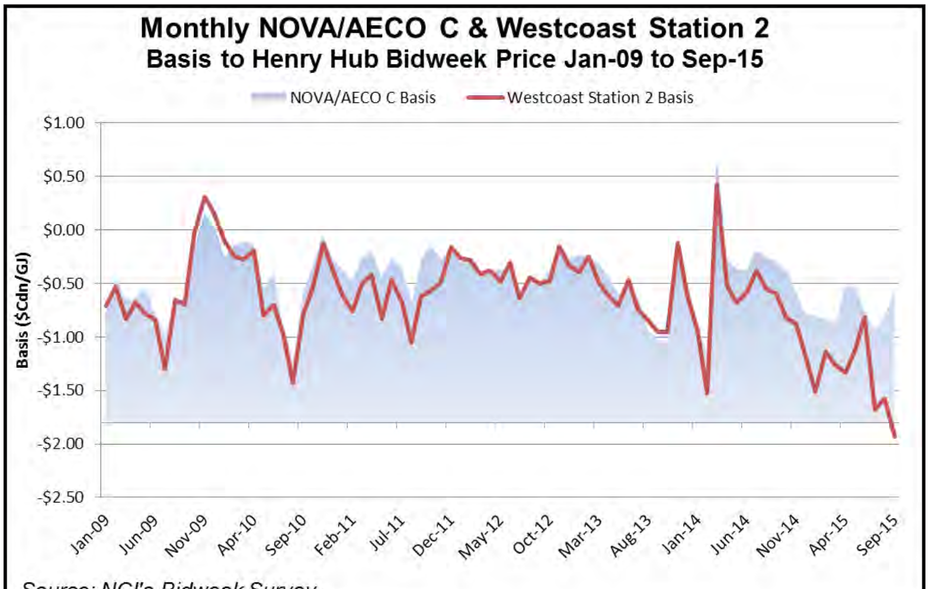
The Canadian industry is voting with its drilling rigs in favor of continuing development. During the first 40 weeks of 2015, a scorecard kept by TD Securities Inc. showed nearly 500 horizontal well licenses made the Montney the most popular drilling target. Despite an industry-wide drop of 54%, the Montney total was off by only 5% compared to the same period of 2014.

The activity is making a start on developing astronomical potential documented in a 2013 federal-provincial resource appraisal by the AER, the BC Oil and Gas Commission, the BC Ministry of Natural Gas Development, and the National Energy Board (NEB).

In the report's conservative scenario for most likely "recoverable" or "marketable" reserves, the Montney was rated as holding 449 Tcf of natural gas, 14.9 billion bbl of liquid byproducts and 1.1 billion bbl of oil.

The figures are liable to grow as experience is gained in the deposit, added the appraisal by earth sciences arms of the government agencies. A high-case forecast pegs Montney supplies at 645 Tcf of gas, 21 billion bbl of NGLs and 2.4 billion bbl of oil.

Montney Resource Play (continued)



Source: NGI's Bidweek Survey

The Montney is the first supply source earmarked for liquefied natural gas (LNG) export terminals proposed on the Pacific Coast of BC. The deposit's most active developers include the Pacific Northwest LNG project led by Malaysian state energy conglomerate Petronas and its Progress Energy subsidiary in Calgary.

But high-priced overseas destinations are not the only places where Montney gas is forecast to fare well. The NEB's current Canadian "deliverability" projection, released in June, rates the new northern BC and Alberta output as some of the lowest-cost gas in North America and becoming competitive with Marcellus Shale production. In fact, Credit Suisse estimated in August 2015 that the Montney has NYMEX natural gas breakeven prices between $0.75 and $3.50 per MMbtu, thereby making the Montney one of the most economical producing regions in North America.

A big reason for the favorable increase in well economics has been the adoption of more advanced drilling and completion techniques in the Montney, particularly from operators who have had success in other unconventional formations. For example, Encana noted on its 3Q15 conference call that the industry has been drilling horizontal wells in Montney for more than a decade, but "In the past year, we have doubled the productivity of our wells through increasing frac intensity. As a result, Montney generates returns of greater than 60%." Murphy Oil also has reported improved performance in the Montney, as a result of lessons learned in the Eagle Ford.

Experience with horizontal drilling and fracking is sharply cutting costs. TransCanada's Nova, in a facilities construction application to the NEB that draws on confidential industry information, says the full "supply cost" of putting Montney production into the market dropped by nearly 60% to C$2.69 (US$2.07) per MMBtu from C$6.45 (US$4.97)/MMBtu between 2006 and 2013.

Efficiency continues to improve. So far this year alone, Seven Generations reported an 8% reduction in well costs, with average drilling time down to 48-50 days from 60 and fracking operations pared to three to four days from a week.

TransCanada has already constructed the 1 Bcf/d Groundbirch Pipeline to transport gas from the Montney to its NOVA system in Alberta, and has proposed two pipelines that would transport Montney based natural gas to the Canadian West Coast. One is the Prince Rupert Gas Transmission Project, which would move supply from the North Montney near Fort St. John, BC to the planned Pacific Northwest LNG export terminal in Port Edward near Prince Rupert, BC. The other is the 1.7 Bcf/d Coastal GasLink Pipeline Project, which would transport both Montney and Horn River gas to Shell's planned 12 million ton/year LNG export facility near Kitimat.

Several executives with Canadian Junior E&P companies noted in October 2014 that there is a general lack of processing capacity in the northern Montney, a point TransCanada drove home in its application with the NEB to build the North Montney extension of its Groundbirch Mainline. "It is NGTL's understanding that Progress Energy and other customers will construct several gas plants or work with current operators to upgrade existing plants," the company noted in its filing. "Approximately 14 gas plants will be required to process the gas expected to be produced by 2020. The customers are also in discussions with midstream companies to secure the sale and transport of NGLs associated with increased gas production," For now, however, the presence of Alliance Pipeline lessens the need for additional local processing capacity somewhat, because that pipe hauls unprocessed wet gas down to be processed at the Aux Sable plant in Channahon, Illinois.

Natural gas pipeline takeaway capacity is also a problem, and although it is being addressed in the longer-term with the projects already mentioned, ongoing restrictions on TransCanada Mainline have forced some curtailments from the Montney at various times in 2015. That has helped crush Station 2 prices, so much so that deals into St. 2 approached zero at several points during the year.

Montney Resource Play (continued)

Provinces

Alberta, British Columbia

Pipelines

Natural Gas: Alliance, Coastal Gas Link (proposed), NGTL Merrick Mainline (proposed), NGTL North Montney (proposed), Prince Rupert Gas Transmission (proposed), Spectra

Crude Oil: Alberta Clipper, Energy East, Northern Gateway, TransMountain

MONTNEY SHALE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
PETRONAS (Progress Energy Canada)*	1,060,500	UGR Blair Creek	70,000
Canadian Natural Resources	1,043,000	Canbriam Energy	62,000
ARC Resources*	704,000	Chinook Energy*	56,960
Long Run Exploration	600,000	Sasol Ltd	56,000
Encana	590,000	Cequence Energy*	55,680
Birchcliff Energy*	560,832	Blackbird Energy	49,920
ExxonMobil*	545,000	Husky Energy	47,000
Kelt Exploration	527,661	Bonavista Energy	43,008
Black Swan Energy	421,075	Respol (Talisman)	42,333
Seven Generations Energy	421,075	Pengrowth Energy*	32,960
Tourmaline Oil	403,200	Trilogy Energy*	32,000
Crew Energy*	303,360	Yoho Resources*	28,800
ConocoPhillips	230,000	Canadian Spirit Resources	26,044
Canadian International Oil Corp.	224,000	Arduro Resources*	15,104
Kicking Horse Energy*	218,101	Stonehaven Exploration	2,240
Paramount Resources*	201,600	Athabasca Oil Corp.	N/A
Chevron	200,000	Mitsubishi	N/A
Apache	148,000	PetroChina	N/A
Painted Pony Petroleum	139,049	Saguaro Resources	N/A
NuVista Energy	120,400	Shell	N/A
Murphy Oil	117,000	Sinopec Daylight Energy	N/A
RMP Energy	115,723	Spyglass Resources	N/A
Leucrotta Exploration*	110,080	Suncor	N/A
Storm Resources	107,000	Surge Energy	N/A
Advantage Oil & Gas	87,584	Todd Energy	N/A
Delphi Energy*	74,944		

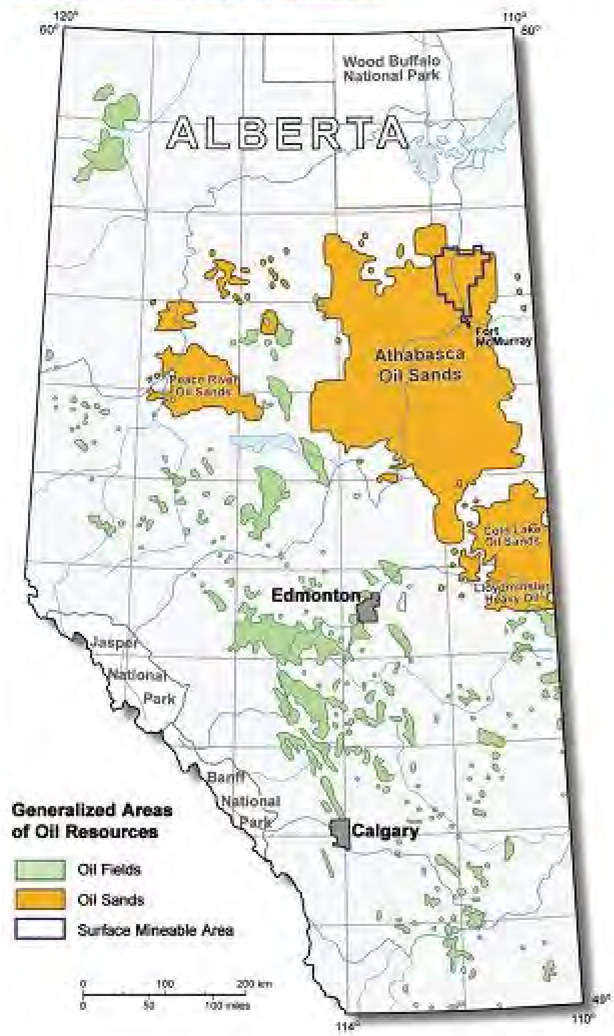
*Estimate, in most cases derived by multiplying reported net sections by 640

Source: Compiled by NGI from company documents

CANADIAN OIL SANDS

Background Information

Oil sands have been exploited by humans for thousands of years and have been used for purposes ranging from energy, to adhesives, and even to waterproofing boats. Oil sands deposits are composed of a mixture of thick, heavy hydrocarbon called bitumen and sand. Bitumen is considered to be an extra-heavy oil defined by the World Energy Council as having an API gravity of less than 10 and a reservoir viscosity of no more than 10,000 centipoises; it is often said to feel similar to cold molasses. Because of these characteristics, bitumen will not readily flow through pipelines by itself. Heat and/or a diluent must be added to get the bitumen to flow. Common diluents include naphtha, gas condensates and light oils, which combined with bitumen are often referred to as "dilbit." Obviously adding these substances increases the transportation costs because of added volume and weight.



Generalized Areas of Oil Resources

Source: Energy Resources Conservation Board and Alberta Geological Survey

According to the American Petroleum Institute, the majority of bitumen is produced through surface mining, but this is limited by the fact that only about 20% of oil sands resources are recoverable in this way. The remaining 80% are too deep to mine effectively and must be recovered through "in-situ" techniques, several of which have been pioneered by the industry. In-situ, Latin for "in position," involves drilling a well to extract bitumen and is often accompanied by a technique called Steam-Assisted Gravity Drainage (SAGD), which involves pumping steam through a horizontal well to liquefy the bitumen, so that it can flow down into a second horizontal well and be pumped to the surface. Another process similar to SAGD is called Cyclic Steam Stimulation (CSS), which differs from SAGD in that it uses only one well pipe for both the injection of steam and the extraction of bitumen. It does this by injecting steam and allowing the well to "soak" before reversing the flow to draw out the liquefied bitumen. In its annual report for 2014/15, the Alberta Energy Regulator (AER) said it regulated 50 thermal in-situ projects and nine oil sands mines.

Although ExxonMobil Corp. and Imperial Oil Ltd. both claim the first patents for both SAGD and CSS, a new generation of recovery techniques took the Canadian Heavy Oil Conference by storm in November 2015. N-Solv Corp. has developed a recovery method that substitutes steam heated to 200-220 C (390-430 F) with 40-60 C (100-140 F) baths of propane or butane. A pilot plant north of Fort McMurray has produced more than 60,000 bbl since 2Q2014, with operating costs of less than C$20/bbl (US$15). Meanwhile, a consortium of oil producers, pipelines and technology contractor Harris Corp. has started a two-year trial of a system called ESEIEH, pronounced "easy" and short for Enhanced Solvent Extraction Incorporating Electromagnetic Heating. Like N-Solv, ESEIEH uses pairs of horizontal wells drilled in close parallel across oilsands deposits. One well in each pair houses a long, low frequency microwave antenna. Propane warmed up to 70-80 C (160-175 F) serves as an underground heat conductor. In both new technologies the fluid is recycled, not lost in the production process. Experiments to date indicate that operating costs of an ESEIEH extraction network would only be C$10-14/bbl (US$7.50-10.50/bbl) of bitumen production. Finally, Imperial's 3Q2015 report to shareholders disclosed that a solvent extraction method will be incorporated into its next oil sands development. Imperial calls its variation on the new technology theme SA-SAGD, short for Solvent-assisted, Steam-assisted Gravity Drainage. The technique figures in a megaproject called Aspen, which would tap a 1.2 billion bbl deposit too deep to mine that is 45 kilometers (27 miles) north of Fort McMurray, for up to 162,000 b/d and forecast to cost C$11

Canadian Oil Sands (continued)

billion (US$8.2 billion) over two stages of construction (see *Daily GPI*, Nov. 6, 2015).

The World Energy Council (WEC) reported in December 2014 that Canada has the largest deposits of oil sands, and holds about two-thirds of the world's total. Other substantial oil sands deposits can be found in Russia, Kazakhstan and the United States. According to the WEC, oil sands in Alberta hold 1.73 trillion bbl of oil, and Canada is the world's leading producer of oil from oil sands, with more than 40% of Canadian oil production originating from oil sands in 2008. The Government of Alberta reports that the province's oil sands hold the third-largest oil reserves in the world, after Venezuela and Saudi Arabia. AER added that at 841 million bbl (2.3 million b/d), raw crude bitumen production accounted for 80% of the province's total crude oil and bitumen production in 2014. Overall raw bitumen production increased 11% from 2013 to 2014, thanks to a 6% increase in mining projects and a 14% increase in in-situ projects. AER added that of total bitumen production, 47.4% was used as feedstock for upgraders, yielding 953,000 b/d in production. Refineries in Alberta processed 311,000 b/d of upgraded bitumen and 23,000 b/d of non-upgraded bitumen. The province also holds 166 billion barrels of bitumen in established reserves.

Canada's oil sands resources are located in three major deposits: 1) the Athabasca deposits in Northeast Alberta, 2) the Cold Lake deposits, also in Northeast Alberta, and 3) the Peace River deposits in Northwest Alberta. According to Albertan government, these areas collectively underlie 142,200 square kilometers (54,903 square miles) of territory, but reserves shallow enough to mine (up to 75 meters) are found only within the Athabasca area. The surface mineable area equals about 4,800 square kilometers (1,853 square miles) and accounts for just 3.4% of the total oil sands area. The provincial government said that between 1999 and 2013, approximately C$201 billion (US$150.6 billion) was invested in the oil sands industry, hitting a record high C$27.2 billion (US$20.4 billion) in 2012. According to the Canadian Energy Research Institute (CERI) — which cited estimates from ARC Financial Corp. and the Canadian Association of Petroleum Producers — investment in the oil sands reached a new record, C$30.8 billion (US$23.1 billion), in 2013.

Being at the forefront of oil sands development, operators in Canada are encountering many challenges related to resource intensity and transportation. Both surface mining and in-situ are water intensive processes and in-situ especially requires quite a bit of energy, often in the form of natural gas to turn the water into steam. Water is usually used to remove sand and mud from the extracted bitumen and, in order to recycle as much as possible, the used water is left to sit in tailing ponds so that mud and sand sink to the bottom and the top layer can then be reused. Natural gas use is also extremely high with oil sands projects. In August 2015, CERI reported that oil sands crude extraction accounted for 46.7% of Alberta's primary energy production in 2014, according to AER figures. Also in 2014, the oil sands industry accounted for 33.6% of end-use energy demand in the province. CERI projected that gas demand by the oil sands industry will increase from about 2.5 Bcf/d in 2014 to a peak of 4.9 Bcf/d in 2030, before slowly declining to 4.5 Bcf/d by 2050.

Oil sands operators must not only take water, natural gas and labor costs into consideration, but also the market price for the extracted oil because sufficient, sustained volatility in any of these key variables could result in a shift in the ultimate economic viability of what are already capital intensive projects. These and other factors, such as the political environment in both Canada and the United States, are important concerns for the future of Canadian oil sands development.

That said, 2015 was not a particularly good year. First, world oil prices remained stuck in low gear. According to data from the U.S. Energy Information Administration (EIA), the FOB spot price for West Texas Intermediate (WTI) crude at Cushing, OK, averaged $50.46/bbl for the first 10 months of the year, reaching a high of $59.82/bbl in June, but bottoming at $42.87/bbl two months later. And while analysts with Tudor, Pickering, Holt & Co. and Evercore ISI, as well as economists with the Bank of England, said in November that crude oil prices could climb as high as $80/bbl by late 2016, others aren't convinced; Goldman Sachs kept its WTI oil price forecast for 2016 at $45/bbl (see *Daily GPI*, Nov. 19, 2015).

Then there's the tortured saga of Keystone XL — the controversial, 1,700-mile, 830,000 b/d crude oil pipeline that was to transport dilbit from Hardisty, Alberta to Steele City, Nebraska. After years of regulatory review and delays, the President Obama officially rejected the $8 billion project in November, denying TransCanada Corp. the necessary presidential cross border permit through the U.S. State Department (see *Shale Daily*, Nov. 6, 2015b). TransCanada also withdrew its application with the Nebraska Public Service Commission, but the company said it did so only because it lacked the federal permit; TransCanada maintains that it still has support from shippers and other stakeholders, and that the pipeline is the safest option to deliver both Canadian and U.S. crude to refineries in the Midwest and on the Gulf Coast (see *Shale Daily*, Nov. 18, 2015). The project could also receive new life if a Republican wins the White House in 2016, but all three Democratic candidates are opposed (see *Shale Daily*, Sept. 24, 2015).

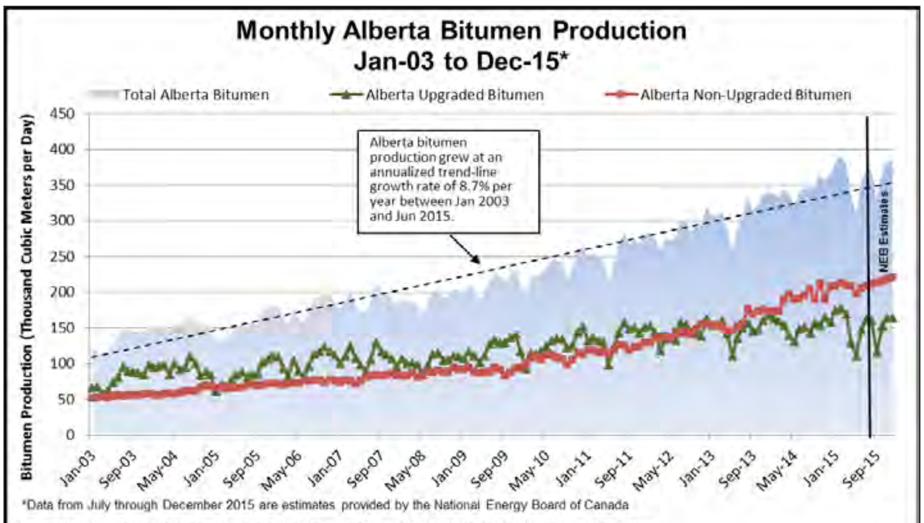
On Oct. 19, 2015, the Liberal Party won the Canadian federal election and Justin Trudeau became the nation's new prime minister. During the campaign, Trudeau said he supported the Keystone XL pipeline. After Obama rejected the project, Trudeau said he was not surprised by the decision and voiced disappointment. Other reports, however, said he was relieved. Albertans also elected a new provincial government in May 2015. The new regime, led by

Canadian Oil Sands (continued)

Premier Rachel Notley and the New Democrats, pledged to craft economic policies on a more "diversified" footing, rather than one dependent on energy prices and exports of unprocessed bitumen, crude oil and natural gas (see *Daily GPI*, May 7, 2015).

Since the rejection of Keystone XL, TransCanada said it will continue growing its natural gas supply network in Alberta and neighboring British Columbia, but at a reduced rate (see *Daily GPI*, Nov. 16, 2015). Its subsidiary, Nova Gas Transmission Ltd. (NGTL), is currently building or waiting for regulatory approval of C$2.7 billion (US$2 billion) in facilities for up to 4 Bcf/d, with completion expected in late 2016 and the fall of 2017. A new round of projects estimated to cost C$570 million (US$428 million), with 2.7 Bcf/d of capacity, is expected to come online in 2018. An increase in the use of fuel by Alberta thermal oil sands operators was cited as one of the main drivers behind expanding the 25,000-kilometer (15,000-mile) NGTL system.

Analysts with IHS Energy reported in July 2015 that despite increasing costs, environmental concerns and delays in adding new takeaway pipeline capacity, oil sands production increased more than 128% (1.2 million b/d) between 2005 and 2014, putting Canada in third place in terms of global oil supply growth. They added despite low commodity prices, oil sands production remains on track to grow by another 800,000 b/d by 2020. IHS reiterated that its previous research had determined that construction and operation of the Keystone XL pipeline would not have a material impact on greenhouse gas emissions, since refiners on the U.S. Gulf Coast will continue to demand heavy crudes. But oil sands producers are increasingly relying on railroads to take crude to market. According to IHS, the movement of both oil sands and non-oil sands Canadian production, both exported and transported entirely within Canada, rose from negligible levels in 2010 to nearly 190,000 b/d toward the end of 2014. And Keystone XL isn't the only pipeline to generate controversy. Three pipelines located entirely within Canada – TransCanada's Energy East (1.1 million b/d) pipeline (see *Daily GPI*, April 24, 2015), Kinder Morgan's Trans Mountain Expansion (890,000 b/d) project (see *Daily GPI*, April 4, 2014) and Enbridge Inc.'s Northern Gateway (525,000 b/d) pipeline (see *Daily GPI*, Dec. 20, 2013) – have all elicited some degree of public opposition. All three would also transport oil sands production.



Source: National Energy Board of Canada, NGI's Shale Daily calculations

During the third quarter of 2015, Canadian Natural Resources Ltd. (CNRL) reported production volumes at its Horizon oil sands mine averaged 131,779 b/d of synthetic crude, a 61% increase over the previous third quarter, and said a C$13 billion (US$11 billion) project to double production to 250,000 b/d was on track and 74% complete. Also during 3Q2015, ConocoPhillips reported its first oil production from its Surmont Phase in-situ oil sands facility in Alberta, and expects production to ramp up through 2017, adding 118,000 b/d gross capacity. Total gross capacity for Surmont 1 and 2 is expected to reach 150,000 b/d (see *Daily GPI*, Oct. 30, 2015). Meanwhile, Imperial Oil Ltd. and ExxonMobil Canada completed the second phase of an expansion of its Kearl oil sands project in June 2015. Imperial holds a 71% stake in the project, located 70 kilometers (43 miles) north of Fort McMurray, while ExxonMobil holds the remaining 29%. The project is expected to reach about 345,000 b/d of production by about 2020 (see *Daily GPI*, Jan. 16, 2015).

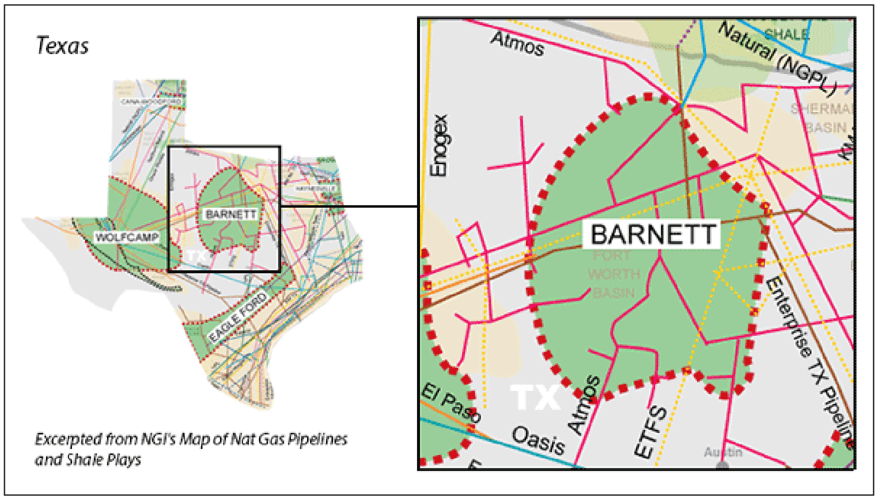
Local Major Pipelines

Crude Oil: Access Pipeline, Alberta Clipper, Enbridge, Keystone, Keystone XL (Proposed), Northern Gateway (Proposed), Pembina, TransCanada East Coast Pipeline Project (Proposed), TransMountain

BARNETT SHALE

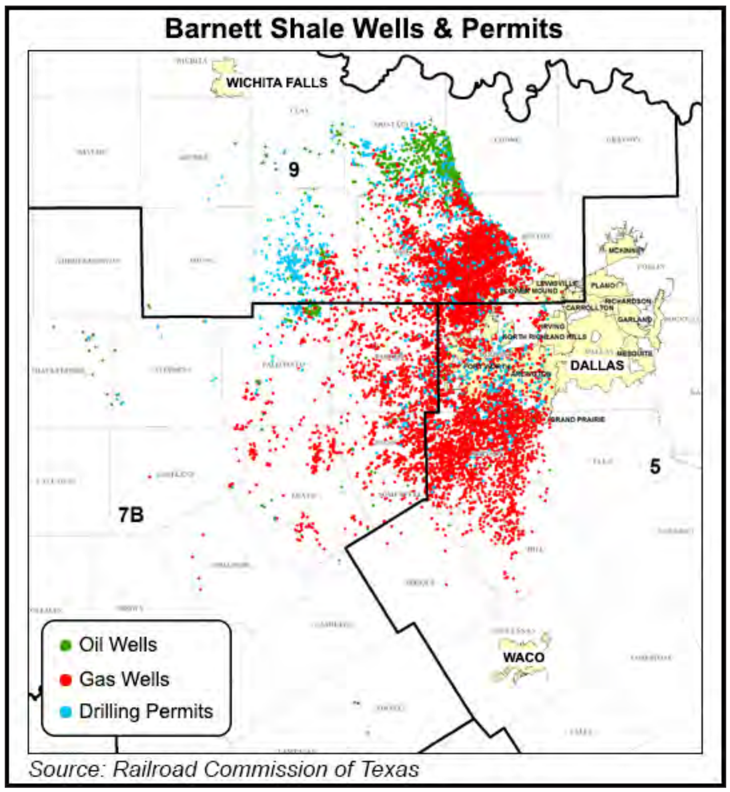
Background Information

The Barnett Shale is considered to be the "granddaddy" of all U.S. shale plays as it was the formation in which Mitchell Energy & Development first successfully implemented the technology necessary to unlock shale gas in the early 1990s. The North Texas shale basin is widely believed to be one of the most prolific natural gas fields in the United States, but it yielded the top producer role to the Marcellus Shale in 2012 when its annual production average topped out at 5.74 Bcf/d and the Marcellus rose to an annual average of 7.66 Bcf/d.



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

The core area of the Barnett Shale is in Denton, Johnson, Tarrant and Wise counties, and is largely dry gas, although Wise County is generally oilier. Much of the more recent activity in the Barnett has been in the more liquids-rich portions of the play, particularly in Montague, Cooke, Jack and Wise counties. Jack and Palo Pinto counties have also seen an uptick in drilling in recent quarters for the Marble Falls horizontal tight oil play, a formation that lies directly above the Barnett Shale.

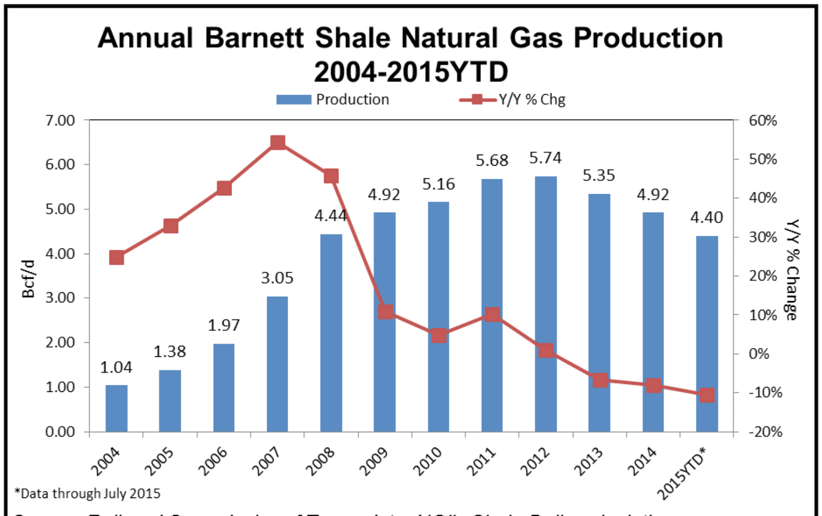


But activity in the Barnett Shale is still dominated by natural gas, and recent evidence suggests that the play may have reached its decline phase. After posting double-digit year-over-year growth rates in every year but one between 2003 when it produced 0.834 Bcf/d and 2011 when it was 5.68 Bcf/d, total estimated Barnett natural gas and liquids production increased just 1.1% in 2012. In 2013, Barnett natural gas production declined by 6.8% to 5.35 Bcf/d. In 2014 production of 4.92 Bcf/d marked an 8.0% decline, and through July 2015, the decline pro-rated to approximately 10.6% at 4.4 Bcf/d. Production declines, of course, correspond with lower prices for natural gas and crude during the period, but the more recent reduction in output may have been exacerbated by the March 2015 bankruptcy filing of Quicksilver Resources, the sixth largest Barnett producer in 2014. As of this writing, Quicksilver was going through the Chapter 11 process, and was scheduled to receive bids for the sale of its assets by the end of November 2015.

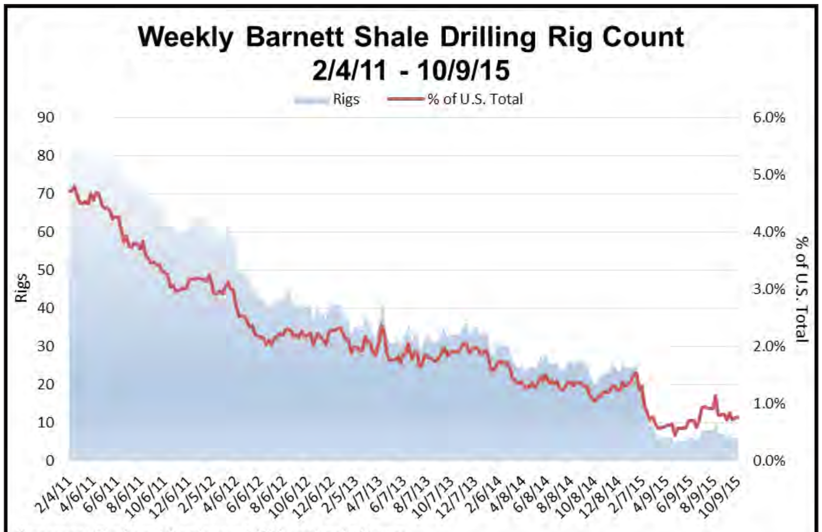
The Barnett Shale rig count has also plummeted over the last several years, falling from 82 rigs in February 2011 to a mere six in early October 2015. Three of those rigs were targeting oilier areas, most likely the Marble Falls.

Based on August 2015 data, the Railroad Commission of Texas ranked Barnett Shale counties Tarrant, Johnson, Wise and Denton as the first, fifth, eighth and ninth, respectively, top total natural gas- (gas well gas and casinghead gas) producing counties. No Barnett counties cracked the top-10 for oil production. In Texas the play is clearly overshadowed by the Permian Basin and Eagle Ford Shale when it comes to crude output.

Barnett Shale (continued)



Source: Railroad Commission of Texas data, NGI's Shale Daily calculations



Source: Baker Hughes, NGI calculations

1H15 Top Barnett Shale Producers

Rank	Operator	MMcfe/d	Est Mkt Share
1	Devon Energy	1204.3	26.4%
2	Chesapeake Energy	918.4	20.1%
3	ExxonMobil/XTO Energy	639.7	14.0%
4	EOG Resources	478.8	10.5%
5	Enervest	324.9	7.1%
6	Quicksilver Resources	263.7	5.8%
7	Trinity River Energy	105.6	2.3%
8	Vantage Forth Worth Energy	92.0	2.0%
9	ConocoPhillips	69.8	1.5%
10	Fuse Energy	55.1	1.2%
11-137	Others	410.5	9.0%
	TOTAL	***4562.6***	***100.0%***

Note: Production figures include dry gas, NGLs, condensate, and crude oil

Source: Railroad Commission of Texas, NGI's Shale Daily calculations

One thing that may revive production gains in the Barnett — or at least slow its rate of decline — is the potential to refrack older wells that were completed using shorter laterals, and less advanced technology. In fact, Enlink Midstream opined on its 3Q15 conference call that refracking has "tremendous opportunity for its customers" in the Barnett, and will help ENLK stem volume declines in its Barnett midstream systems, which in October 2015 were falling at 6.5% year-over-year pace. Devon Energy, the leading producer in the Barnett and the major sponsor of Enlink, estimates that it costs $1.2 million to refrack a horizontal Barnett well, but that doing so would add 2 Bcf to the per well reserve potential. Devon planned to refrack 25 horizontal Barnett wells in 2015, and was in the process of assessing the results from vertical refracks in the areas as well.

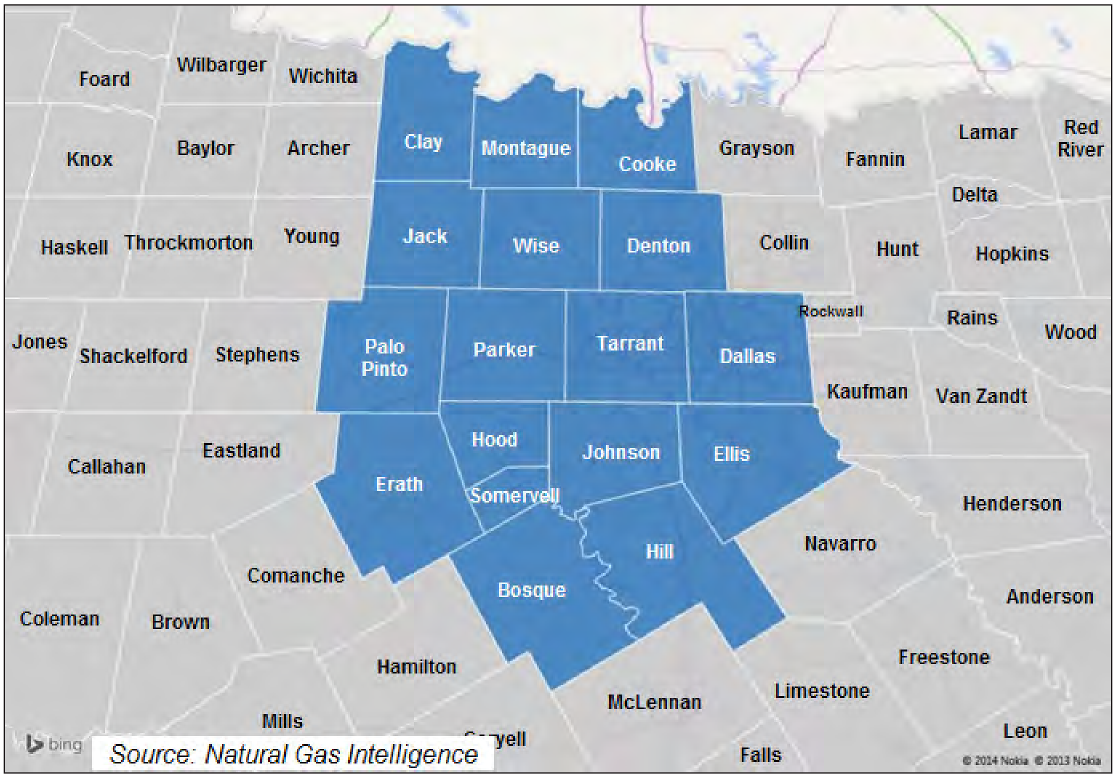
Increasing exports to Mexico, along with emerging LNG exports in the Gulf Coast, could also help support Barnett producers, either directly through increased production, or indirectly through higher netbacks.The Barnett Shale region has experienced numerous small earthquakes and minor seismic events over the last couple of years, and many residents and municipal leaders have blamed these on drilling waste injection wells operated for the benefit of Barnett Shale producers. A 2015 investigation by the Railroad Commission of Texas, however, did not find any definitive link between injection wells and seismic activity (see Shale Daily, Sept. 11, 2015).

Also during 2014 and 2015, the Barnett was home to the nation's first successful — albeit temporary — municipal ban of hydraulic fracturing. In 2014, voters in the Barnett Shale town of Denton, TX, overwhelmingly voted in favor of a fracking ban in their city (see Shale Daily, Nov. 5, 2014). However, the move was met by a quick response from industry and state lawmakers. Legislation was enacted to limit the ability of municipalities to ban fracking and interfere with the oil/gas industry in general. The Denton ban was essentially outlawed (see Shale Daily, May 26, 2015).

Barnett Shale (continued)

Counties

Texas: Bosque, Clay, Cooke, Dallas, Denton, Erath, Hamilton, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Somervell, Tarrant, Wise



Source: Natural Gas Intelligence

NOTE: The Railroad Commission of Texas also includes Archer, Clay, Comanche, Coryell, Eastland, Ellis, Shackelford, Stephens, and Young counties as being prospective (albeit noncore) for the Barnett, but we do not include these counties in our definition, either because the majority of those counties are not prospective, they are not commercially viable, and/or they have yet to be developed.

Local Major Pipelines

Natural Gas: Atmos, Crosstex N. Texas, Energy Transfer, Enterprise Products, Gulf Crossing, NGPL, OkTex Pipeline, Tolar Hub

Crude Oil:* Amdel (Sunoco), Basin, BP Pipelines, BridgeTex, Central Texas (Sunoco), CK Red River (Plains Pipeline), Enterprise Crude Pipeline, North Texas (ConocoPhillips), NuStar, Pegasus (ExxonMobil), Permian Express II (Sunoco), Phillips 66 Pipeline, Seaway, Sunoco Pipeline, SXL, Texas (Sunoco), West Texas Gulf (Sunoco)

NGLs: Arbuckle, Cowtown, Energy Transfer, Enterprise Products, NGL Parker (EnLink), Southern Hills, Sterling I, Sterling II, Texas Express NGL, Tolar (DCP), West Texas LPG (Chevron)

*The Barnett is not nearly as prospective for crude oil as it is for natural gas, although certain sub-formations within the Barnett, such as the Marble Falls, do produce some crude oil. These pipelines underlie the counties that make up the Barnett, although not all of them may receive crude production in this area.

Barnett Shale (continued)

BARNETT SHALE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Devon Energy	615,000	JW Operating	N/A
EOG Resources	298,000	Knickerbocker Land Resources	N/A
ExxonMobil (XTO Energy)	230,000	Kornye-Tillman Company	N/A
Chesapeake Energy	215,000	Krocan Energy	N/A
ConocoPhillips	133,000	L A Productions	N/A
Newark Energy1	100,000	Lakota Energy	N/A
Atlas Resource Partners1	88,000	Lone Star Land & Energy II	N/A
Quicksilver Resources	85,600	Luxor Oil & Gas, Inc.	N/A
Legend Natural Gas	52,000	McCutchin Petroleum Corporation	N/A
Vantage Energy	37,000	Merit Energy	N/A
Paloma Resources	10,000	Milagro Exploration	N/A
Fairway Resources	3,700	Modern Exploration, Inc.	N/A
Adexco Operating Company	N/A	Moncrief, C. B.	N/A
Apexco, Inc.	N/A	Nautilus Exploration, Inc.	N/A
Arrington Oil & Gas	N/A	Oakridge Oil & Gas	N/A
Arrowhead Productions	N/A	OxEnergy Incorporated	N/A
Aruba Petroleum	N/A	OXXN	N/A
Beacon E&P	N/A	P & D Operating, Inc.	N/A
Bend Petroleum Corp.	N/A	Peba Oil & Gas, Inc.	N/A
Best Petroleum Exploration	N/A	Pendragon Oil Co.	N/A
Big Star Exploration	N/A	PK Gath & Oilfield Svcs, Inc.	N/A
Bluestone Natural Resources	N/A	Premier Natural Resources LLC	N/A
Borderline Operating Corp.	N/A	Primera Energy	N/A
Briar Energy Corporation	N/A	Primexx Operating Corporation	N/A
Brigadier Operating	N/A	Proco Operating Co., Inc.	N/A
Burk Royalty Co., Ltd.	N/A	Proven Reserves Management, Inc.	N/A
Burnett Oil	N/A	Red Oak Gas Operating Company	N/A
Cal-Tex Fossil	N/A	Regal Energy Operating	N/A
Canan Operating, Inc.	N/A	Rife Energy Operating	N/A
Canyon Operating, LLC	N/A	Roil Mineral & Land Co.	N/A
Century Petroleum, Inc.	N/A	Roxanna Oil	N/A
Chief Oil & Gas	N/A	Ryder Scott Management, LLC	N/A
Citation Oil & Gas	N/A	Sable Operating Co.	N/A
Collins & Young	N/A	Sanders Oil & Gas, Ltd.	N/A
Cornerstone Oil & Gas	N/A	Sauder Management Company	N/A
Crown Exploration II	N/A	Scout Energy Management	N/A
Cumming Company, The	N/A	Shidler, Mark L., Inc.	N/A
Dallas Production, Inc.	N/A	Slate Holdings	N/A
Dark Horse Operating Co.	N/A	Spindletop Oil & Gas	N/A
Denton Oil & Gas	N/A	Stephens & Johnson Operating Co.	N/A
Dimock Operating Company	N/A	Strata Operating, Inc.	N/A
Dorchester Minerals	N/A	Tanglewood Oil & Gas Llc	N/A
EagleRidge Energy	N/A	Tema Oil & Gas	N/A
Edge Resources Operating	N/A	Texxol Operating Company, Inc.	N/A
Endeavor Energy Resources	N/A	Threshold Development Company	N/A

Barnett Shale (continued)

BARNETT SHALE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Enervest	N/A	Tokyo Gas	N/A
ENI	N/A	Torch Operating	N/A
Excel Oil & Gas, Inc.	N/A	Tower Resources	N/A
Felderhoff Production Company	N/A	Tracer Operating, Inc.	N/A
Finley Resources, Inc.	N/A	Trans-Texas Energy Group	N/A
Frost Brothers Resources	N/A	Tree Operating, LLC	N/A
Fuse Energy	N/A	Trinity River Energy	N/A
G & F Oil, Inc.	N/A	Trio Consulting & Management, LLC	N/A
G.A. Hawkins Operating	N/A	Tsar Operating Company	N/A
Gardner Production	N/A	Upham Oil & Gas	N/A
Giant NRG Co.	N/A	US Energy Development Corp.	N/A
Grand Operating, Inc.	N/A	Vargas Energy	N/A
H3 Operating LLC	N/A	Victory Eagle Utility Sv Y, Inc.	N/A
Hale Drilling & Production, Inc	N/A	WBH Energy Partners	N/A
Hess, Jerry Operating Co.	N/A	West Texas Assets, LLC	N/A
Hilltex Operating Company	N/A	Western Chief Operating	N/A
Hillwood O & G	N/A	Western Production Company	N/A
Hunt Operating, LLC	N/A	Willowbend Investments	N/A
HW Operating, LLC	N/A	Winfield Operating Co.	N/A
IPR Energy Partners, L.P.	N/A	Wise Exploration	N/A
Joint Resources Co.	N/A	WY Woodland Operating	N/A
Jones Energy	N/A	Wynn-Crosby Operating	N/A
JRJ Oil & Gas LLC	N/A		

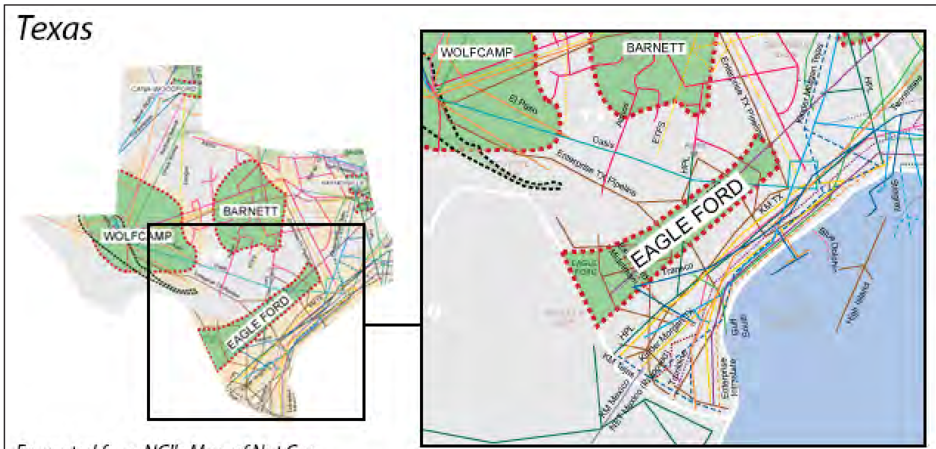
[1] Listed as Marble Falls

Source: Compiled by NGI from company documents

EAGLE FORD SHALE

Background Information

The Eagle Ford Shale, which is located in South Texas and features separate dry gas, wet gas/condensate, and crude oil windows, may only have about six years of production history, but it has quickly become one of the hottest resource plays in North America.



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

According to the Railroad Commission of Texas, Petrohawk (now part of BHP Billiton) drilled the industry's first Eagle Ford well in LaSalle County, TX, in 2008. That first well has led to a surge in Eagle Ford drilling activity, so much so that production has grown from basically nothing in 2009 to respective totals of 1.07 million b/d of crude oil, 278,423 b/d of condensate and 5.26 Bcfe/d of natural gas in July 2015, subsequently making the Eagle Ford one of the most prolific oil- and gas-producing basins in the county. Still, the commodity price rout that began in 2014 and continued through 2015 was taking its toll on the Eagle Ford, too. EIA was projecting production declines in the Eagle Ford as recently as November 2015 (see *Shale Daily*, Nov. 9, 2015).

Annual Eagle Ford Shale Oil & Gas Production & Issued Permits

Year	Oil (Bbls/d)	Condensate (Bbls/d)	Liquids As % of Total	Nat Gas (MMcf/d)	Gas As % of Total	Total (MMcfe/d)	Total (MBOEPD)	*Y/Y % Change*	Drilling Permits Issued
2009	843	2,300	26.6%	52	73.4%	71	11.8	*N/A*	94
2010	15,149	18,784	38.7%	322	61.3%	526	87.6	*642%*	1,010
2011	129,795	80,531	50.6%	1,232	49.4%	2,494	415.7	*374%*	2,826
2012	400,715	163,273	56.6%	2,595	43.4%	5,979	996.5	*140%*	4,143
2013	733,538	234,673	59.5%	3,955	40.5%	9,764	1,627.4	*63%*	4,416
2014	1,059,201	280,232	61.3%	5,068	38.7%	13,105	2,184.1	*34%*	5,613
2015YTD*	1,073,130	278,423	60.7%	5,258	39.3%	13,367	2,227.9	*2%***	1,879***

* Production data through July 2015 **Change versus daily rate for all of 2014 ***Permit data through September 2015

Source: Railroad Commission of Texas, NGI's Shale Daily calculations

The production growth in the Eagle Ford has increased, despite the fact that the drilling rig count in the play has fallen from 259 rigs on May 25, 2012 to 80 rigs in early October 2015. Part of the decline is because of the transition to multi-well pad drilling, which enables more wells to be drilled per rig. National Oilwell Varco estimated that as of September 2015, 93% of the Eagle Ford wells being drilled were on pad deployment. Production growth has also been helped by a number of other factors, such as downspacing, the migration to longer laterals, and better completion techniques. For example, Rosetta Resources (now Noble Energy), SM Energy, Pioneer Resources, and Cabot Oil & Gas have all reported better well results by pumping more sand during hydraulic fracturing.

Part of the allure of the Eagle Ford area is it is home to several stacked oil and gas formations that lie above and below the Eagle Ford, such as the Olmos and Austin Chalk, and the Buda and Georgetown Lime. The Pearsall Shale also lies beneath the Eagle Ford.

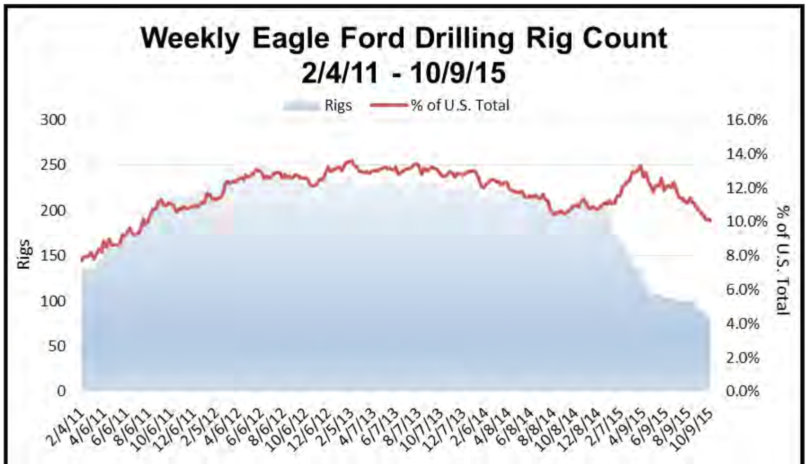
Several companies are testing whether the Upper Eagle Ford and Lower Eagle Ford are in fact separate formations in certain parts of the play, which would likely increase the number of productive wells that could be drilled in the formation. According to an October 2015 presentation by Earthstone Energy, there were more than 30 Upper Eagle Ford wells completed by multiple operators. So far, companies such as Rosetta Resources and Pioneer Natural Resources have reported "encouraging" test results. Carrizo Oil & Gas, ConocoPhillips, Devon Energy, Encana, Goodrich Petroleum, Penn Virginia, SM Energy Inc, and Swift Energy all either have

Eagle Ford Shale (continued)

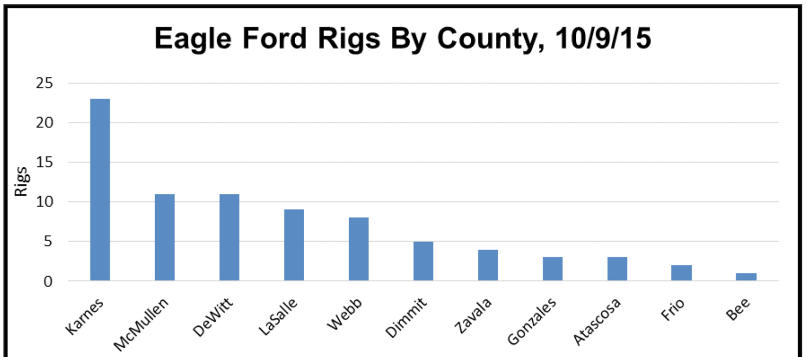
drilled or are in the process of drilling wells in the Upper Eagle Ford.

Marathon Oil Corp. was producing from both the upper and lower Eagle Ford during the summer of 2015; however, at that time management also was scaling back activity to deal with depressed commodity prices (see *Shale Daily*, Aug. 7, 2015). Still, the Eagle Ford remains an important engine for growth for Marathon and others. Marathon said in November that its Eagle Ford play was economic even with lower prices (see *Shale Daily*, Nov. 6, 2015). Several sources have said some portions of the Eagle Ford remain economic at $35/bbl NYMEX, particularly in and around Karnes County, TX.Unlike in the burgeoning Bakken Shale play in North Dakota and Montana, where energy infrastructure was practically non-existent a decade ago, crude oil and natural gas pipeline takeaway capacity is relatively plentiful out of the Eagle Ford Shale. Moreover, there are several major crude oil refineries in South Texas, particularly in the Houston and Corpus Christi areas, so Eagle Ford producers already have something of a readily available captive market for their supply nearby.

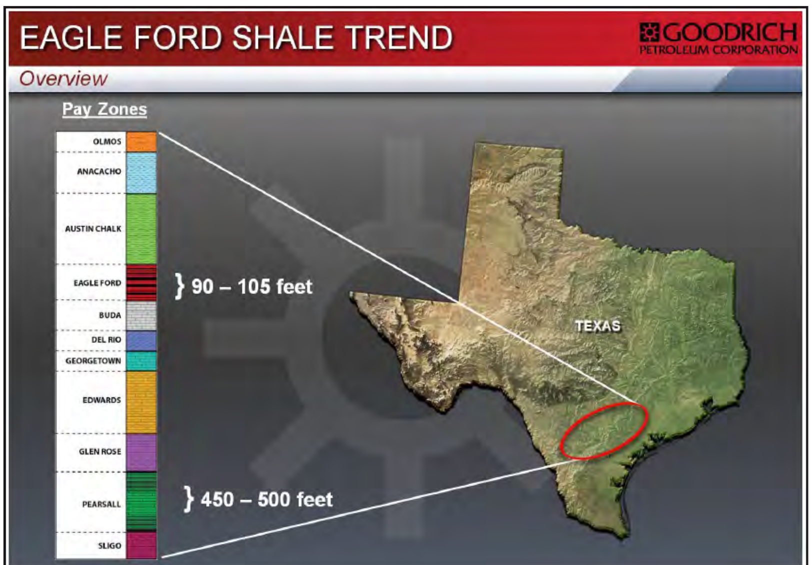
There has been concern that the United States as a whole may not be able handle the growing amount of lighter crude oil production, such as that coming from the Eagle Ford. Some refiners have expanded or are expanding capabilities to handle light crude. Valero Energy is one such company. Also planned are new/expanded crude blending facilities in the Gulf Coast region that would allow for crude to be better tailored to meet refiner specifications. One of these facilities, the Hazelwood Energy Hub, was proposed for South Louisiana in October 2015 (see *Shale Daily*, Oct. 6, 2015). Energy interests and their supporters in Washington have also been working to lift or relax a ban on the export of U.S. crude oil (see *Shale Daily*, Oct. 8, 2015; Sept. 10, 2015), and in August 2015, the U.S. government approved a plan that will allow the U.S. to trade up to 100,000 barrels per day of light oil and condensate with Mexico in exchange for heavier oil.



Source: Baker Hughes, NGI calculations



Source: Baker Hughes



Source: Goodrich Petroleum

The U.S. also has been exporting more natural gas to Mexico to support increasing gas fired generation in that country. U.S. exports to Mexico currently stand at 3.4 Bcf/d, but could grow up to 6.0 Bcf/d by 2020, especially if Pemex is slow to increase its domestic production. The Eagle Ford is in prime position to step up natural gas exports to Mexico, and several pipeline projects are designed to do just that, including the 2.1 Bcf/d NET Mexico Pipeline that went into service in December 2014, and the proposed 500 MMcf/d Nueva Era Pipeline in Mexico that would receive gas from a border interconnect in Webb County, TX.

Eagle Ford Shale (continued)

A more immediate problem is what to do with the surging condensate production in the U.S., in general, and in the Eagle Ford in particular, where said production has grown from practically nothing in 2009 to nearly 250,000 b/d in July 2014. Condensate is typically too light to be in much demand by U.S. refineries, which are geared more toward processing heavier oil. As a result, condensate tends to trade at a significant discount to crude in the United States. Several operators have either proposed or are in the process of building condensate splitters, but we believe that this is a relatively limited solution because the economics of splitters rely heavily on the demand for naphtha.

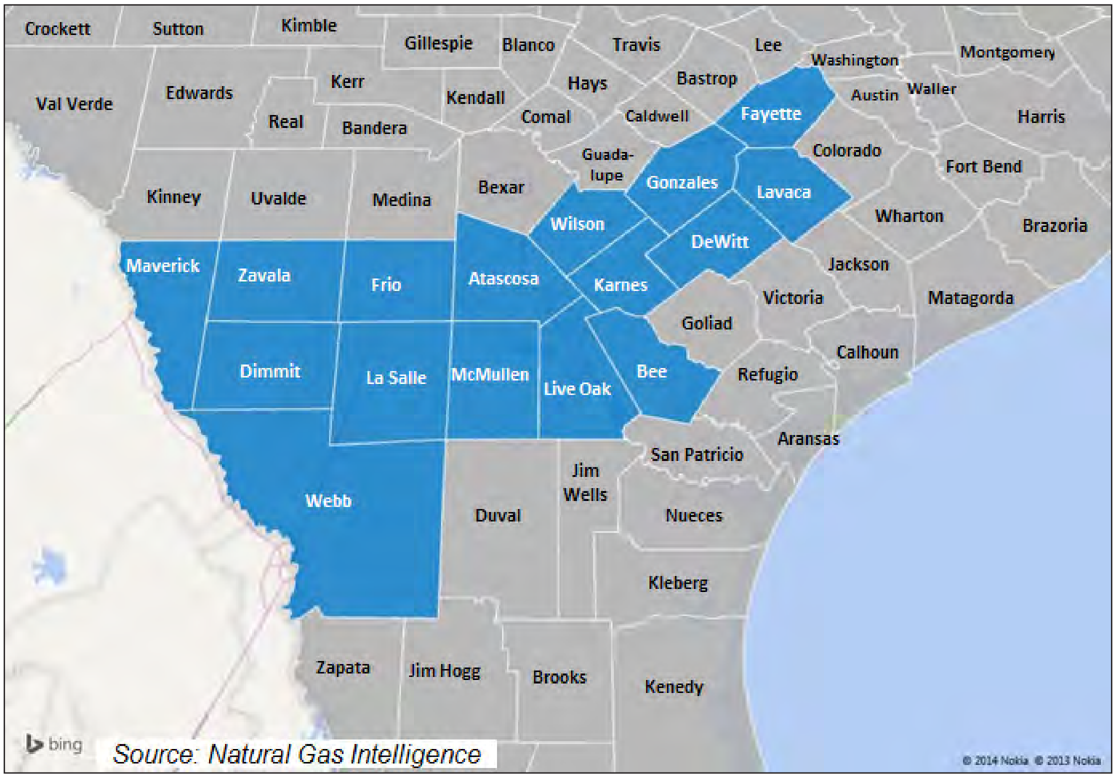
More than a dozen Texas counties comprise the Eagle Ford Shale. Because the play is so prolific, a number of Eagle Ford counties routinely feature in Railroad Commission of Texas (RRC) top-10 lists of producing counties for crude oil, natural gas, and condensate.

According to RRC data from August 2015, five Eagle Ford counties were among the state's top-10 crude producers. They are Karnes, La Salle, DeWitt, McMullen and Gonzales. Top natural gas-producing counties (including casinghead gas) in the Eagle Ford were Webb, Dimmit, DeWitt, Karnes and La Salle. And when it comes to just condensate production, the Eagle Ford is a leader in the state, with seven of the top-10 producing counties in August 2015: Dimmit, Karnes, DeWitt, Webb, Live Oak, La Salle and McMullen.

While the rig count was declining in the Eagle Ford during 2015 — as it was just about everywhere else — producers plying the play were focusing their activity on Karnes County, which is in the heart of the play (see *Shale Daily*, Oct. 16, 2015). Karnes County accounted for 23 of the October 9, 2015 rig count, followed by DeWitt and McMullen Counties with 11 rigs each.

Counties

Texas: Atascosa, Bee, DeWitt, Dimmit, Fayette, Frio, Gonzales, Karnes, LaSalle, Lavaca, Live Oak, Maverick, McMullen, Webb, Wilson, ZavalaNOTE: The Texas Railroad Commission also lists Brazos, Burleson, Grimes, Lee, Leon, Milam, and Robertson Counties as being prospective for the Eagle Ford, but we consider those to be part of the Eaglebine play.



Source: Natural Gas Intelligence

Eagle Ford Shale (continued)

Local Major Pipelines

Natural Gas: Eagle Ford Crossover, Energy Transfer, Enterprise Products, Gulf South, HPL, KM Tejas, KM Texas, NET Mexico, NGPL, Tennessee, Texas Eastern Transmission, Transco

Crude Oil: Double Eagle, Energy Transfer, Enterprise, ETC Rio Bravo, Harvest, Kinder Morgan, Koch Pipeline, Longhorn, NuStar, Plains, Springfield Pipeline, TEPPCO South, VEX PipelineNGLs: Aegis, Copano, Energy Transfer, Maverick Field NGL System, Phillips 66 (LPG), Sand Hills, Texas Pipeline, Three Rivers

EAGLE FORD NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
EOG Resources	624,000	Lucas Energy	3,300
Chesapeake Energy	449,000	PT Saka Energi Indoesia	3,000
BHP Billiton	300,000	Adams Resources Exploration*	2,300
BP/Lewis Energy Group	300,000	Alta Mesa Holdings	1,850
Apache Corp.	288,000	Panhandle Oil & Gas	1,840
ConocoPhillips	220,000	EnerVest*	1,760
Sanchez Energy	207,000	Tenth Avenue Petroleum (Jadela)	784
CNOOC	200,000	Petrolympic	320
Marathon Oil	180,000	El Indio Investment Corp.	50
SM Energy	180,000	1776 Energy Operators	N/A
Anadarko Petroleum	162,000	BlueStone Natural Resources	N/A
Blackbrush Oil & Gas	160,000	Buffco Production	N/A
Murphy Oil	135,591	Cheyenne Petroleum	N/A
Pioneer Natural Resources	126,500	Circle Star Energy	N/A
Reliance Industries	103,500	Crimson Energy	N/A
Penn Virginia	100,000	Cypress E&P	N/A
EP Energy	94,000	Dan A Hughes Co.	N/A
ExxonMobil	90,000	Eagle Oil & Gas	N/A
Cabot Oil & Gas	89,000	Eagle Rock Energy Partners	N/A
Carrizo Oil & Gas	84,000	EagleFord Energy Inc.	N/A
Bluescape Resources	74,000	Fasken Oil & Ranch	N/A
Devon Energy	72,000	GAIL India Ltd.	N/A
Swift Energy	70,000	Hall Phoenix Energy	N/A
EXCO Resources	65,900	Hunt Oil	N/A
Escondido Resources II	60,000	Ironwood Oil & Gas	N/A
Talisman	60,000	JGC Energy Development	N/A
Statoil	58,000	Korea National Oil Corp	N/A
Terrace Energy	53,000	Laredo Energy	N/A
Noble Energy	50,000	Manti	N/A
Encana	43,200	Modern Exploration	N/A
Sundance Energy	40,000	Mueller Exploration	N/A
Mitsui	39,000	Overton Energy	N/A
Sabine Oil & Gas	34,800	Primera Energy	N/A
Zaza Energy	30,200	Repsol	N/A
Matador Resources	29,877	Rock Oil	N/A
Argent Energy Holdings	26,188	Rosewood Resources	N/A
Newfield Exploration	25,000	San Isidro Development Co.	N/A
Lonestar Resources*	24,757	Schlumberger	N/A
Magnum Hunter	24,000	Sea Eagle Ford	N/A

Eagle Ford Shale (continued)

EAGLE FORD NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Baytex Energy	23,000	Shale Hunter LLC	N/A
Earthstone Energy	22,585	Southern Bay Operating	N/A
Comstock Resources	22,000	Stonegate Production Co.	N/A
Riley Exploration	19,980	Strand Energy	N/A
Goodrich Petroleum	17,000	Talon Petroleum	N/A
Paloma Resources	17,000	Texon Petroleum	N/A
Wapiti Energy	12,883	Tidal Petroleum	N/A
Abraxas Petroleum	10,819	Union Gas Operating Co.	N/A
Contango Oil & Gas	9,500	Valence Operating Co.	N/A
Doxa Energy	8,800	Venado Oil & Gas	N/A
U.S. Energy	7,725	Viceroy Petroleum	N/A
Dynamic Production	5,000	Weber Energy Corporation	N/A
Atlas Resource Partners	4,000	Wellstar Corp.	N/A
Occidental Petroleum	4,000	XOG Operating	N/A

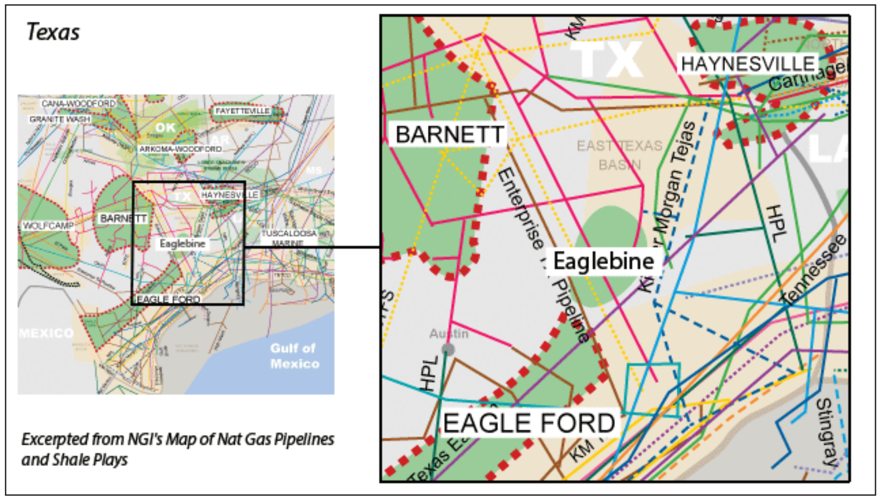
*Estimated

Source: Compiled by NGI from company documents

EAGLEBINE

Background Information

The Eaglebine is an emerging horizontal oil play in East Texas whose name is a hybrid of the Eagle Ford Shale and the Woodbine sandstone formation.



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

There is no set definition of the Eaglebine per se, but after reviewing company documents from known operators in the area, we generally characterize the Eaglebine as being located in Brazos, Burleson, Grimes, Houston, Lee, Leon, Madison, Milam, Robertson and Walker counties, TX, and resting anywhere between the Austin Chalk and Buda Lime formations underneath those counties.

The Railroad Commission of Texas actually includes most of those counties (except for Houston County) in its definition of the Eagle Ford, but we believe the Eagle Ford in those counties exhibits a higher silt and carbonate content. Therefore, we believe these Eagle Ford counties are considered by most of the industry to be a separate formation from the more familiar Eagle Ford Shale, which is located in the Maverick Basin to the west.

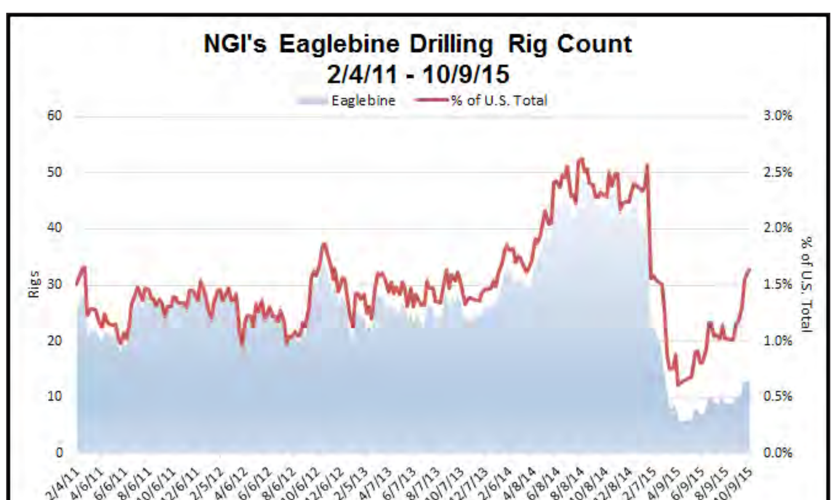
The Eaglebine area has been drilled vertically for years as the play is home to a number of other pay zones, such as the Austin Chalk, Buda Lime, Bossier Sands, Deep Bossier, Edwards, Freestone Trend, Georgetown, Glen Rose and Wilcox formations. Drilling activity in this region had been fairly active since at least 2011, but we believe activity in the Eaglebine had helped the rig count in the area to double in 2014. However, the play is still in its early stages.

As of early October 2015, the rig count in the Eaglebine had fallen sharply and was hovering around 13 units in the midst of the oil and natural gas price collapse. Of those 13 rigs, five were in Burleson County, followed by three in Madison, two in Brazos, two in Lee, and one in Grimes County. One year earlier there were 44 rigs active in the Eaglebine.

Early horizontal drilling results confirm the presence of light oil in the Eaglebine, and many operators and analysts have expressed optimism about the play. But the trick with the Eaglebine, as it is with all emerging plays, is to figure out the right drilling formula (lateral lengths, proppant, completion methods, etc.) to produce the oil commercially.

To wit, Encana has drilled at least 12 wells in the Eaglebine, but in its July 2013 corporate presentation, the company said its strategy in the area is to "establish commerciality through longer laterals and improved completion design." However, there was no discussion of the Eaglebine in the company's third quarter 2015 earnings release nor during the associated conference call.

Small cap stock ZaZa Energy (ZAZA, market cap $16 million as of 12/16/14 but only $2.2 million in mid-November 2015 as ZaZa struggled with liquidity in the midst of the commodity price collapse) is the publicly traded company that might be most closely associated with the Eaglebine (which it calls Eaglebine/Eagle Ford East), since ZaZa has declared the Eaglebine as being its primary focus. The company has partnered with partner EOG Resources to develop a large portion of its acreage. In a mid-2015 operations update, ZaZa said it had about 140,000 gross (35,000 net) acres



Source: Baker Hughes, NGI's Shale Daily calculations

Eaglebine (continued)

within an area of mutual interest with EOG Resources in the Eagle Ford East. "Our operational strategy is focused on drilling proven, highly-economic Buda-Rose vertical stack and frack wells that will increase our cash flow, production, and reserves," ZaZa CEO Todd Brooks said at the time.

Halcon Resources has also sparked interest with its El Halcon play, which is in the Lower Eaglebine. In November 2015 the company said it ran one rig in the play during the third quarter of 2015, spudded four wells and put three online. Wells were performing at the company's 452,000 boe type curve for the area on a per lateral foot basis.

"The drilling program at El Halcon is in development mode and the Company expects to drill two to four wells per pad throughout the remainder of this year and in 2016," the company said in its third quarter earnings press release. There are currently 102 Halcon-operated East Texas Eagle Ford wells producing and three company-operated wells being completed or waiting on completion, it said.

Anadarko Petroleum Corp. is another substantial Eaglebine acreage holder. The company says on its website that it has "achieved encouraging results in this emerging play, with wells demonstrating estimated ultimate recoveries of approximately 350,000 BOE with 90% oil composition...Anadarko is continuing to evaluate the potential of this area, while leveraging key assets that include a variety of gathering, compression and treatment facilities serving the midstream market throughout the area.

Clayton Williams Energy said on its 3Q15 conference call that it re-fracked its original East Eagle Ford well in Lee County, which they drilled 3-4 years ago. No results just yet, but if it works, it could have "big implications," according to the company.

Much of the acreage in the Eaglebine area may already be held from existing wells in the area that target other formations, so this may serve as something of a barrier to entry for those looking to lease Eaglebine acreage, everything else being equal. ZaZa also has said there is horizontal drilling potential in what it calls the "Buda Rose," which lies immediately below the lower Eaglebine interval and includes the Buda, Edwards, Georgetown and Glen Rose formations, among others.

Sunoco Logistics Partners' Eaglebine Express crude pipeline serves the play with 60,000 b/d of capacity to coastal refineries.

In January 2015, Knight Warrior LLC said it was proceeding with a 160-mile crude pipeline to serve Eaglebine producers with service from the East Texas Eaglebine/Woodbine to Houston refining and export markets. The pipeline was scheduled for startup in the second quarter of 2016.

Counties

Texas: Brazos, Burleson, Grimes, Houston, Lee, Leon, Madison, Milam, Robertson, Walker

Local Major Pipelines

Natural Gas: Atmos, Enbridge Ghost Chili lateral, Energy Transfer, Enterprise Products, Gulf South, KM Tejas, Texas Eastern

Crude Oil: BP Pipelines, BridgeTex, Enterprise Crude Pipeline, ExxonMobil, Knight Warrior (proposed), Koch, Longhorn, Plains, Seaway, Sunoco Pipeline, SXL Interstate, TEPPCO South, West Texas Gulf (Sunoco)

NGLs: Arbuckle, Enbridge, Energy Transfer, Seminole, Southern Hills, Sterling, Sterling II, Sterling III (Proposed), Texas Express

EAGLEBINE/WOODBINE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Halcon Resources[1]	300,000	Lucas Energy	400
Apache	288,000	Circle Star Energy	N/A
SM Energy	215,000	Crimson Energy	N/A
Clayton Williams	170,000	GE Energy Financial Services	N/A
EOG Resources[2]	118,500	Halex Oil	N/A
Anadarko Petroleum	92,000	Hall Phoenix Energy	N/A
Legacy Reserves	89,000	JBL Energy Partners	N/A
KKR	60,000	Laredo Energy	N/A
Energy & Exploration Partners	57,275	Leexus Oil LLC	N/A

Eaglebine (continued)

EAGLEBINE/WOODBINE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
ZaZa Resources[2]	41,200	Meidu	N/A
Amerril Energy LLC	40,000	Petromax	N/A
Ursa Resources Group II	40,000	Quantum Energy Partners	N/A
Sun Resources	23,217	Range Resources	N/A
Cubic Energy	22,800	Rosewood Resources	N/A
BlueStone Natural Resources	22,000	Terrace Energy LLC	N/A
Contango Oil and Gas	16,000	Vess Oil Corp.	N/A
Baytex Energy	14,000	Weber Energy Corporation	N/A
Lonestar Resources	10,730	Wellstar Corp.	N/A
Evolution Petroleum*	3,252	Woodbine Production Corp.	N/A
Sanchez Production Partners	1,480		

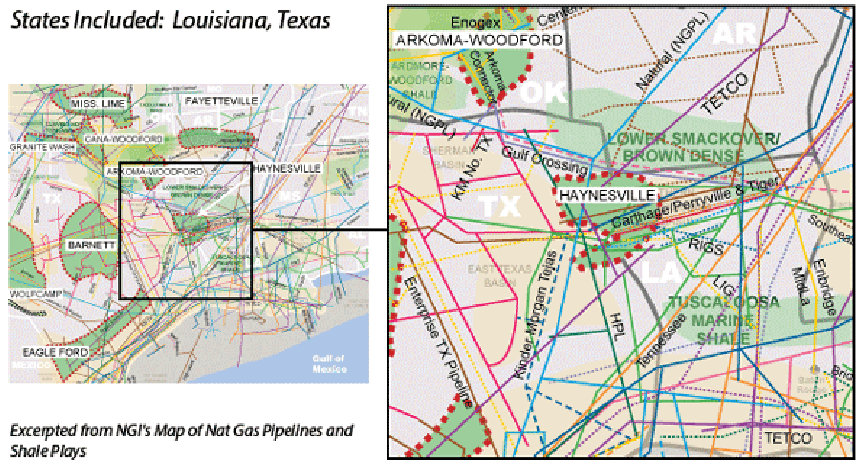
[1] 101K is their El Halcon play. HK owns another 199K net acres in the Woodbine.
[2] Totals account for the ZAZA/EOG JV. Range Resources holds an undisclosed minority interest in the JV acres.
Source: Compiled by NGI from company documents

HAYNESVILLE SHALE

Background Information

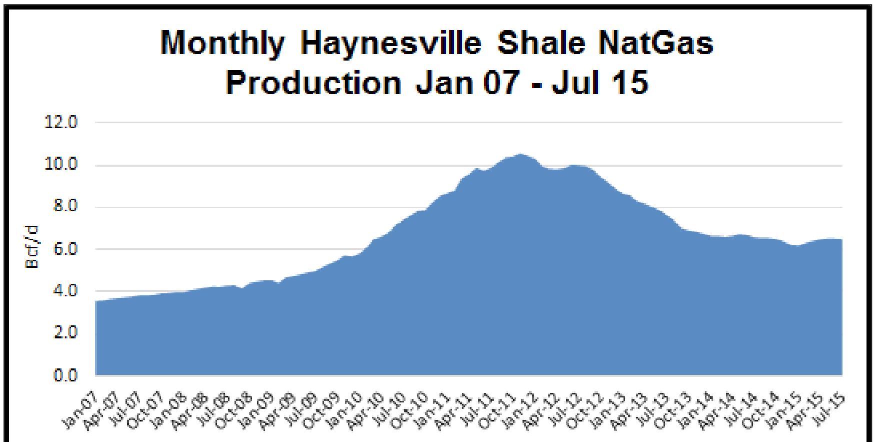
The Haynesville Shale is a massive dry natural gas formation in Northwest Louisiana and East Texas that lies at true vertical depths between 10,000 and 14,000 feet. The play was discovered by Chesapeake Energy in early 2008, and that triggered a substantial wave of leasing activity in the area. Companies have also reported success in developing the Bossier Shale, another gas formation that lies just above the Haynesville. Many operators simply call the area the Haynesville/Bossier Shale, although they are in fact separate producing formations.

States Included: Louisiana, Texas



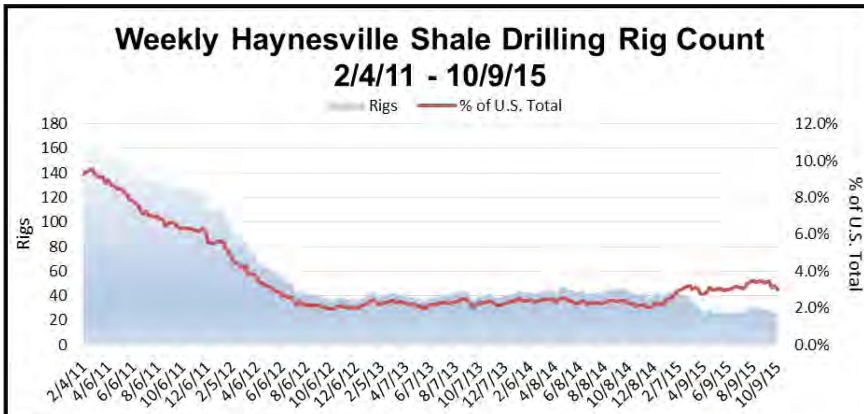
Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

The "sweet spot," or "core" of the Haynesville is generally considered to be on the Louisiana side of the play, and has been the focus of most horizontal drilling activity by operators thus far. As of Oct. 9, 2015, six of the 24 rigs working the play were in DeSoto Parish, LA. A typical horizontal Haynesville well costs between US$7 million and $8 million to drill and complete, depending mostly on lateral length and the cost of rigs and pressure pumping services. One of the main characteristics of the Haynesville Shale is that it is over-pressurized, which has contributed to some very high initial production rates.



Source: EIA, NGI calculations

Many early horizontal wells in the Haynesville came on with initial 24-hour production rates in excess of 20 MMcf/d, which are very high by historical standards. That high pressure also helps minimize initial lifting costs in the Haynesville, since those wells do not need to go on pump as quickly. On the other hand, the higher pressure also contributes to extremely high first year decline rates, which can be as much as 85% in the area. Operators believe that choking back initial production rates in the Haynesville helps increase estimated ultimate recoveries (EUR) of those horizontal wells. Dry gas production in the Haynesville went from virtually nothing in January 2008 to a peak of 7.2 Bcf/d in January 2012, but production later fell by 46% to just 3.9 Bcf/d in August 2014. As of October 2015, gas production from the Haynesville was nearly 6.5 Bcf/d, according to the U.S. Energy Information Administration.

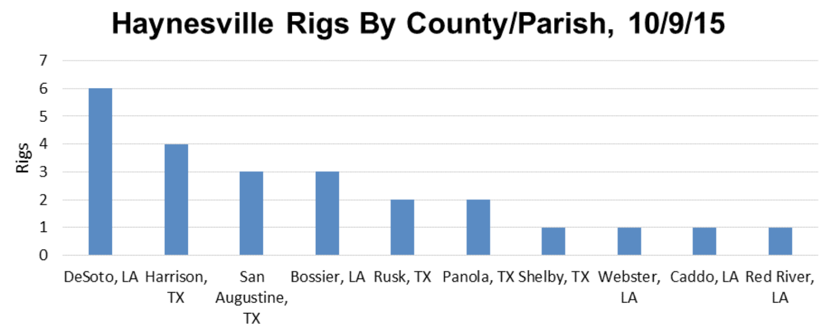


Source: Baker Hughes, NGI calculations

As previously mentioned, the Haynesville rig count was at 24 rigs in early October, a far cry from a mid-2010 peak of 185 rigs. Prior to the commodity price rout of late 2014-2015, the Haynesville rig count was holding around 39-47 rigs since December 2013.

Haynesville Shale (continued)

Being a basin that produces dry gas, the Haynesville had fallen out of favor among most producers, who opted instead to pursue liquids-rich plays, which were offering higher netbacks than dry gas, at least before the oil price collapse. Additionally, as an early mover among the shale plays, most acreage in the Haynesville was held by production, so producers were not compelled to drill in order to keep it.



Source: Baker Hughes

However, beginning late in 2014 and continuing during 2015, some producers again took a shine to dry gas and the Haynesville.

The move back to the Haynesville was led in part by Comstock Resources Inc., which opted to increase Haynesville activity as low oil prices made Eagle Ford Shale and Tuscaloosa Marine Shale activities less attractive (see *Shale Daily*, Dec. 18, 2014). Spring of 2015 saw an uptick in drilling activity in the Haynesville (see *Shale Daily*, April 24, 2015).

The Haynesville is well positioned to capitalize on three emerging trends on the demand side of the industry: growing petrochemical capacity in the Gulf Coast region, the scheduled retirement of coal fired electricity generation in the next several years, and the emergence of LNG export facilities. The Haynesville could become a significant U.S. supply region to the rest of the world by 2020, for the following reasons:

- The formation is located close to the four to five LNG export terminals expected to come to fruition along the Gulf of Mexico.
- Haynesville production is dry gas, so it does not have to be processed before being liquefied.
- Several industry sources estimate there are between 35,000-50,000 wells left to be drilled in the play, so production is scalable.
- There are already plenty of gathering facilities and pipelines in place in the region, so infrastructure bottlenecks are much less likely to be an issue.
- Texas and Louisiana are both "pro-oil and gas" states, so those local governments would likely encourage increased production from the Haynesville.
- BG Group, which is among the largest international LNG trading firms, has a presence in the Haynesville. BG has a 50/50 production joint venture with Exco Resources in the play, and it signed on to be an anchor shipper from Cheniere's Sabine Pass LNG Export facility, which is expected to be phased into service around the beginning of 2016. BG Group is poised to be acquired by Royal Dutch Shell, however, and commentary around the deal by executives and analysts has made little mention of the company's shale holdings (see *Daily GPI*, April 8, 2015).

EXCO Resources said in October it was shutting down Eagle Ford drilling to focus on the Haynesville/Bossier Shale for better returns (see *Shale Daily*, Oct. 30, 2015).

Supporting the idea that the Haynesville is a prime source of natural gas to be liquefied for export, a study completed in late 2015 said liquefying and shipping gas from the Haynesville to power generators would result in lower emissions than firing power plants with coal (see *Daily GPI*, Oct. 6, 2015).

The Haynesville is also a prime target for recompletion of existing horizontal wells. As one petroleum engineer explained to *NGI* in November 2014, not every horizontal well or formation is a candidate for refracks, but several companies have reported "encouraging results" from recompleting existing horizontal wells in the Haynesville. The refrack market in the Haynesville was gathering pace in 2015 and, as predicted by one Houston-based analyst, was on track to exceed $500 million in activity by 2020 (see *Shale Daily*, Oct. 2, 2015). In early November 2015, Comstock management said refrack programs in the Haynesville as well as the Eagle Ford showed much promise, but refracking activities were put on hold because of low commodity prices.

Well economics estimates for the Haynesville are all over the map, causing responses ranging from "we are excited about the play" to "what we see in the Haynesville Shale play are companies that blindly seek production volumes rather than value, and that care nothing for the interests of their shareholders." That latter opinion appeared in a recent Forbes op ed piece that pegged breakeven prices in the Haynesville at $6.50 NYMEX. Credit Suisse calculated the breakeven prices for the Haynesville Core and Tier 1 to be about $4.30 and $5.80, respectively, based on NYMEX prices in August 2015. About the best breakeven estimate we have seen for the Haynesville core is $2.50-3.25 from RBC Capital Markets. None of those estimates make the play economic at current prices.

However, we note most of those calculations were likely made using older assumptions that were based on older technology, and therefore could be underestimating the estimated ultimate recovery (EUR) potential of the play. Operators in the Haynesville

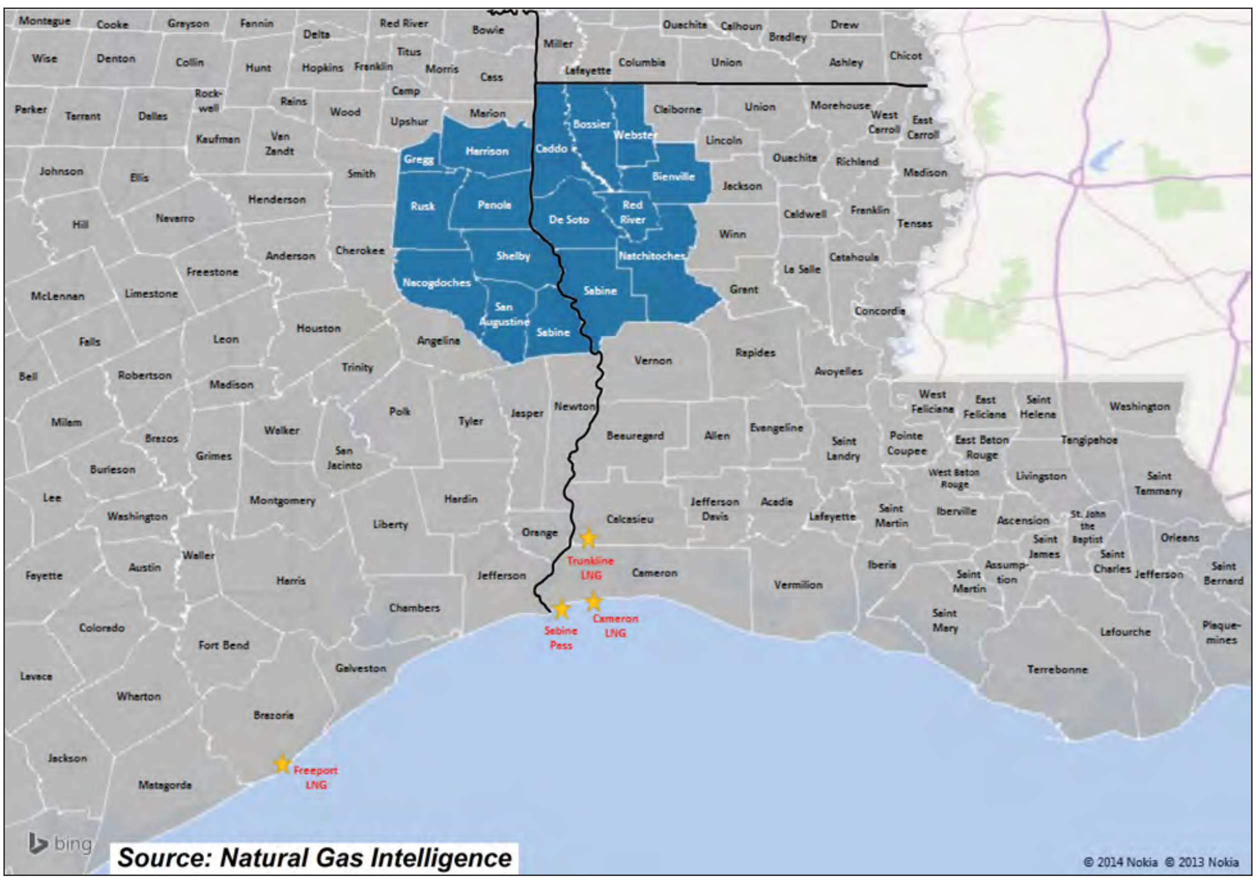
Haynesville Shale (continued)

are catching up with the trend prevalent in other basins to drill longer laterals and use more proppant. As QEP Resources CEO Chuck Stanley said on the company's 3Q15 conference call, "I think that there has been a fundamental change in Haynesville economics as a result of some operators in who pushed the size of stimulation that we have historically pumped up to in some instances over 3,000 pounds per foot – per lateral foot, 3,000 pounds of proppant per lateral foot, which has made a noticeable difference in early time well performance."

Stanley also observed that "the lateral length has been increased. When we were actively developing our Haynesville asset our typical lateral length was 4,500 feet or so. And today most operators have moved to roughly 7,500 foot laterals, so they are drilling cross unit wells. And that was a regulatory challenge back in the day when everybody was active, but the state has reacted positively to proposals from other operators."

Goodrich Petroleum made similar statements on its 3Q15 call. "We are very encouraged by early results for offset operators like our friends at Comstock in the Haynesville who are using a new completion design with a significantly higher proppant concentration. We have drilled or participated in 93 wells in the Haynesville with a typical EUR of approximately 6 Bcf per well from approximately 4,600-foot laterals using the old completion design which is less than half of the proppant currently being pumped. By increasing the proppant from 1,100 pounds per foot to 2,500 or even 3,000 pounds per foot, we are seeing approximately 50% improvement in short lateral EURs, where we are projecting 9 Bcf from 4,600-foot laterals that generate a 25% rate of return at $3 gas.

However, the wells improve as you drill longer laterals. We are projecting 15 Bcf per well from 7,500-foot laterals and a rate of return of approximately 40% at $3 gas. From our analysis which is consistent with what we are seeing from many of the offset operators, we see 1.8 to 2.0 Bcf per thousand feet and ultimately expect to drill up to 10,000-foot laterals which at 2 Bcf per 1,000 foot would equate to 20 Bcf wells. With the longer laterals, you will see better rates of return as we believe EUR per foot is linear, and drill and complete costs decrease per foot for extended reach laterals."



Source: Natural Gas Intelligence

Haynesville Shale (continued)

Counties/Parishes

Louisiana: Bienville, Bossier, Caddo, DeSoto, Natchitoches, Red River, Sabine, Webster

Texas: Gregg, Harrison, Nacogdoches, Panola, Rusk, Sabine, San Augustine, Shelby

Local Major Pipelines

Natural Gas: Acadia Gas Pipeline, Atmos, Carthage Hub, CenterPoint Energy, Enterprise Products, Gulf South, HPL, KM Tejas, Louisiana Intrastate Gas, Mississippi River Transmission, NGPL, RIGS, Southern Natural, Tennessee, Texas Eastern Transmission, Texas Gas Transmission, Tiger Pipelin

Crude Oil:* Arklatex (Plains Pipeline), BKEP Pipeline, BP Pipelines, ExxonMobil, Mid Valley Pipeline, North Louisiana System (ExxonMobil), Paline Pipeline, Plains, Sunoco Pipeline, SXL, West Texas Gulf (Sunoco)

NGLs:* ATEX, Black Lake Pipeline, DCP Midstream, Enable Ethane System, Enbridge, Enterprise Products, Markwest Carthage System, San Jacinto Pipeline, Sterling I, Sterling II, Sterling III (Propsed), TEPPCO

*The Haynesville tends to be mostly natural gas production, and dry gas production at that. These pipelines traverse the counties that contain the E TX Haynesville, and are included for completeness. NGLs from this area are more likely to come from more liquids rich gas plays, such as the Cotton Valley.

HAYNESVILLE/ BOSSIER NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Chesapeake Energy	387,000	Endeavour Corp.	3,300
Freeport-McMoRan*	241,521	Adams Resources Exploration*	2,056
ExxonMobil	240,000	BEUSA Energy	N/A
Anadarko Petroleum	210,000	BP	N/A
BHP Billiton	200,000	Camterra Resources	N/A
EOG Resources	143,000	Eagle Oil & Gas	N/A
Samson Resources	116,000	Enduro Operating LLC	N/A
GEP Haynesville, LLC	112,000	Fortune Resources	N/A
Vine Oil & Gas	107,000	Indigo Minerals	N/A
EXCO Resources	84,000	J-W Operating	N/A
Chevron	70,000	Keba Energy	N/A
Sabine Oil & Gas	70,000	LINN Energy	N/A
BG Group*	68,000	Nadel & Gussman	N/A
Comstock Resources	68,000	Riley Exploration	N/A
ConocoPhillips	68,000	Rosewood Resources	N/A
QEP Resources	50,000	Sanchez Energy	N/A
EP Energy	38,000	SM Energy	N/A
Penn Virginia	32,600	SND Operating	N/A
Goodrich Petroleum*	25,500	Southwestern Energy	N/A
Matador Energy	24,396	Tellus Operating Group	N/A
Vanguard Natural Resources	23,000	Texex Petroleum	N/A
Marathon Oil	20,000	Thunderbird Resources	N/A
Contango Oil & Gas	4,300	Wildhorse Resouces	N/A
Cubic Energy	3,800		

*Estimate

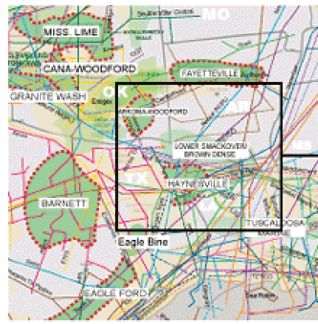
Source: Compiled by NGI from company documents

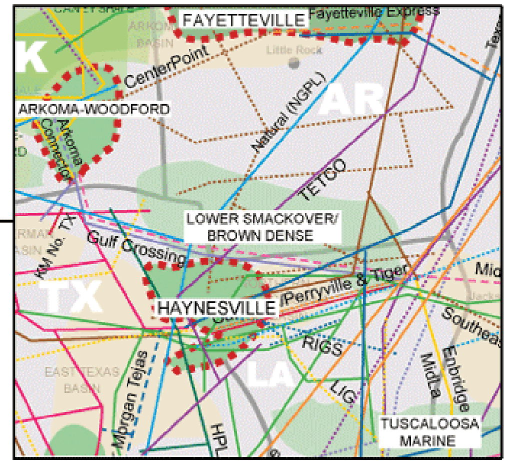
LOWER SMACKOVER/BROWN DENSE

Background Information

The Lower Smackover/Brown Dense is an oil and gas reservoir underlying northern Louisiana, parts of southern Arkansas and Mississippi – although some geologists say the formation could extend as far east as Florida. The LS/BD has been an "emerging" play for years, as operators work near and around it. The Upper Jurassic age, kerogen-rich carbonate source rock ranges in vertical depths from 4,000 to 11,000 feet. The thick, muddy carbonate is believed to be the source rock for plays that include the Upper Smackover formation, which has been producing oil and gas since the 1920s.

States Included: Arkansas, Louisiana





Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

In recent years, unconventional operators were testing various areas using horizontal drilling and hydraulic fracturing techniques, with a promise that the region could become another viable resource play using new drilling methods. It remains an emerging play. However, some of the best results as of 2015 remained old school – verticals.

The formation gets deeper as it moves from the Northwest to the Southeast, with 21st century pioneers up to now mostly testing wells in Louisiana and Arkansas.

Southwestern Energy Corp., considered the biggest leaseholder today, had about 304,371 net acres at the end of 2014, which it obtained at an average cost of $831/acre. Southwestern's leases have an 81% average net revenue interest and an average primary lease term of three years, which could be extended for up to four more years. The company is currently analyzing 75 miles of 3-D seismic data it recently acquired in Union Parish, Louisiana.

At the end of 2014, however, Southwestern still had drilled only 14 operated wells, six of which were producing. Southwestern has acquired 75 miles of 3-D seismic data and was in the process of analyzing that data and the results in early 2015. However, Southwestern was putting more funding into other onshore plays, and in October 2015 was attempting to find a partner to help fund its LS/BD acreage.

A dearth of information exists about the full potential of the LS/BD as Southwestern has only drilled a handful of wells, and other operators have not publicly issued much information to date.

Another Houston-based independent, Linn Energy LLC, reported in July 2015 that it had found a Smackover interval that extended into its Bossier trend, which overlays the Haynesville Shale. Linn encountered the Smackover interval as it was proving up the prospectivity of its Bossier intervals in Louisiana. CEO Mark Ellis said the company was producing from the interval at initial production rates of 4 MMcfe/d.

Other operators holding leases in the play are said to include ExxonMobil Corp., which in 2013 had an estimated 215,000 net acres. Devon Energy Corp. confirmed in 2011 that it had 40,000 net acres across the formation, but little intelligence has been issued since. Breitburn Energy Partners LP in late 2014 also said it had "numerous workover and drilling projects" planned across the Louisiana region, including in the Smackover. Also said to have stakes are Bonanza Creek/Border Exploration, Epsilon Energy/JW Operating, Eagle Rock and Vision Exploration.

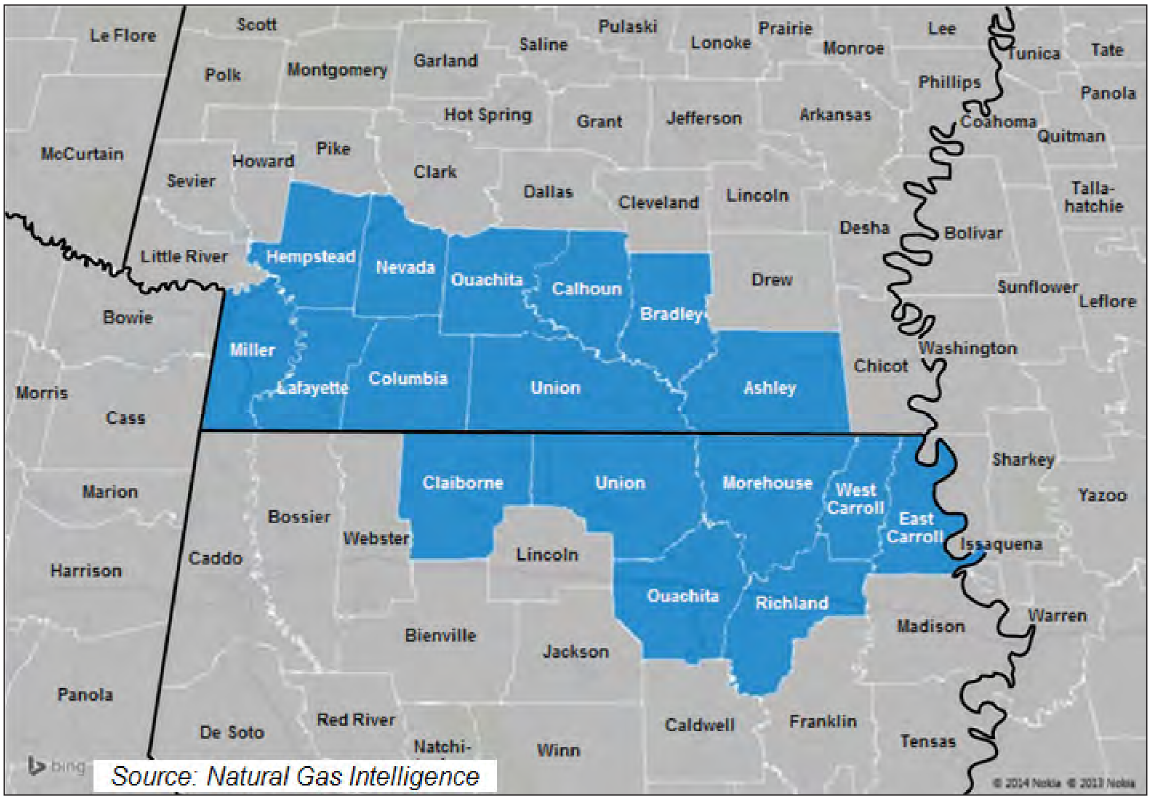
Takeaway exists for natural gas production, as the area is host to several pipelines, including Louisiana's Perryville hub in Richland and Ouachita parishes. However, early drilling indicated the formation may produce sour gas, which would need to be treated before becoming pipeline quality.

Counties/Parishes

Arkansas: Ashley, Bradley, Calhoun, Columbia, Hempstead, Lafayette, Miller, Nevada, Ouachita, Union

Louisiana: Clairborne, East Carroll, Morehouse, Ouachita, Richland, Union, West Carroll

Lower Smackover/Brown Dense (continued)



Local Major Pipelines

Natural Gas: ANR, CenterPoint Energy, Columbia Gulf, Gulf Crossing, Gulf South, Louisiana Intrastate Gas, Midcontinent Express, MidLa, Mississippi River Transmission, Perryville Hub, Southeast Supply Header, Southern Natural, Tennessee, Texas Eastern Transmission, Texas Gas Transmission, Tiger Pipeline, Trunkline

Crude Oil: Arklatex (Plains), Mid Valley Pipeline

NGLs: ATEX, TEPPCO

LOWER SMACKOVER/BROWN DENSE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Southwestern Energy	304,000	Eagle Rock	790
ExxonMobil	215,000	Cabot Oil & Gas	N/A
WhitMar Exploration	120,000	Devon Energy	N/A
LINN Energy*	30,000	JW-Operating	N/A
Western Energy Production	30,000	Rosewood Resources	N/A
Epsilon Energy	10,139	Vanguard Natural Resources	N/A
Bonanza Creek	6,000	Vision Exploration	N/A

*Estimate

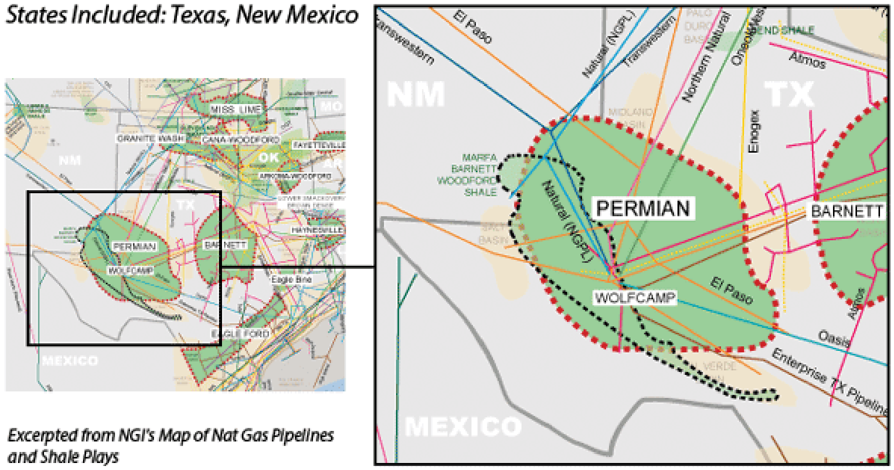
Source: Compiled by NGI from company documents

PERMIAN BASIN

Background Information

The venerable Permian Basin's liquid gold has attracted oil and natural gas prospectors for decades. The energy bounty hiding beneath the sparse lands encompassing nearly all of West Texas and a portion of southeastern New Mexico might be nonexistent to casual travelers passing through. But don't let the dearth of people fool you. Traffic is fairly constant on the two-lane paved roads, as pick-up trucks ferry workers and 18-wheelers carry supplies to the drilling sites that sit behind high metal fence.

States Included: Texas, New Mexico



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

Mule deer and javalinas share their land with the oil rigs and the man camps that dot the landscape. A sulfury smell often permeates the air, along with the dust that clings to jeans and boots. "Y'all smell that? It's the smell of money," West Texans will tell you.

The Permian's energy riches cover an area about 250 miles wide and 300 miles long, a whopping 75,000 square miles, with oil and gas produced from depths of a few hundred feet to miles below the surface. The basin contains one of the world's thickest deposits of Permian-aged rocks from an era 299 million to 251 million years ago, when the basin reached its maximum depth of 29,000 feet.

And that thickness is what separates the Permian from everything else. In terms of the thickness of the hydrocarbon producing zone, the Bakken Shale averages 10-120 feet in thickness, while Eagle Ford Shale formations are 150-300 feet thick. The Permian offers formations that are 1,300-1,800 feet, which is 12 times the Bakken thickness. Within the Permian are three large sub-basins stacked with various reservoirs of limestone, sandstone and shale. The Midland and the Delaware, the two big targets for producers today, are separated by the Central Basin Platform (CBP). Other sections of the Permian include the Northwest Shelf, Marfa Basin, Ozona Arch, Hovey Channel, Val Verde Basin and Eastern Shelf.

Today producers mostly are dropping their drillbits into the Midland and the Delaware zones. The Midland's multi-layer zones are highlighted by the Spraberry and Wolfcamp formations, while the Delaware, about 2,000 feet deeper, also features the Wolfcamp Shale, as well as the frequently targeted Bone Spring Sand and Avalon formations.

Noticeably absent from the recent surge in drilling is the CBP, which features more conventional formations, as well as enhanced oil recovery operations using waterfloods and carbon dioxide. However, that is not to say that the CBP does not play a major role in the Permian. The CBP in Andrews, Ector, and Gaines counties, TX, is one of the most prolific crude producing areas in the Permian. The Wolfcamp Shale underlies the CBP, so there also is some potential unconventional upside in this area as well.

Six formations provided about 60% of the increase in Permian production between 2007 and 2014, according to the U.S. Energy Information Administration. In no particular order, they were Bone Spring, Delaware, Glorieta, Spraberry, Wolfcamp and Yeso. We highlight all the major focus areas in the Permian in the table below, followed by maps that show the various sub-basins in the Permian and a breakout of Permian crude oil production by county since 2014.

Resource Play	Type/Primary Target	Location
Abo Formation	Tight Sands – Oil	NM, W. TX
Avalon Shale	Shale – Gas	NM, W. TX
Bone Springs (2nd & 3rd)	Tight Sands – Oil	NM, W. TX
Cline Shale	Shale – Oil	W. TX
Penn Shale	Shale – Oil	W. TX
Spraberry	Tight Sands – Oil	W. TX
Wolfberry	Shale/Tight Sands – Oil	W. TX
Wolfbone	Shale/Tight Sands – Oil	W. TX
Wolfcamp Shale	Shale – Oil	NM, W. TX
Yeso Formation	Carbonate – Oil	NM

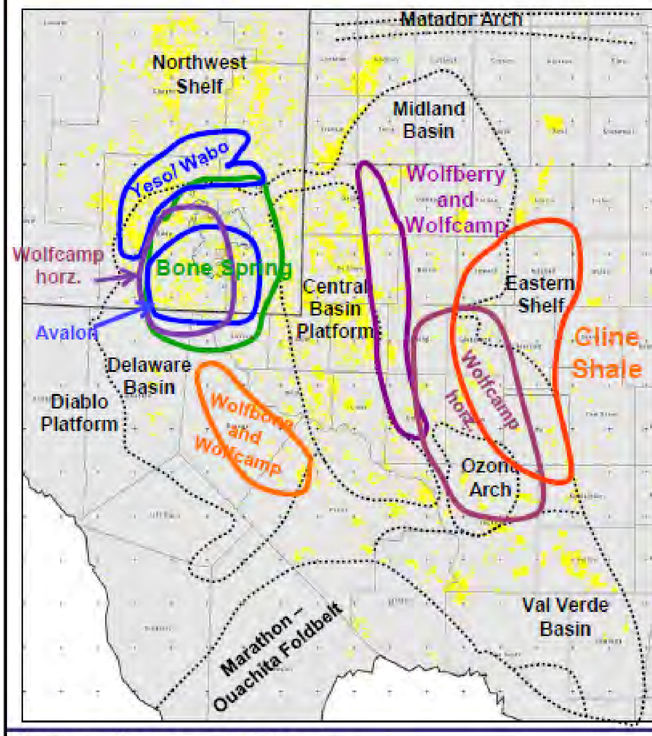
Permian Basin (continued)

The Permian has been reliably pumping oil and gas since the 1920s, but horizontal drilling and hydraulic fracturing in oil reservoirs has led to a boom that began about 2012. In 2008, oil production was about 710,480 b/d in the Texas portion. Between January 2007 and August 2015, crude oil production in the Permian grew from 843,000 b/d to 1,961,000 b/d, an annualized trend-line growth rate of 10.6% per year. Not bad for a "mature" play that first began producing more than 90 years ago.

Even as crude oil prices declined in the last half of 2014 and through 2015, the Permian continued to be one of the only places in the United States where oil production kept rising (see *Shale Daily*, Nov. 9, 2015). Natural gas production also has risen steadily. Between 2008 and 2014, gas production in the Texas side of the Permian climbed from 3,529 MMcf/d to 4,201 MMcf/d. Between January and September 2015, the region was one of the few areas where gas production still was rising to an average of 4,636 MMcf/d. In June 2015, RBN Energy estimated the rate of return in the Delaware Basin to be as much as 27%, making it one of the highest return plays in the United States at the time.

Deal making across the United States fell through 2015, but the Permian still accounted for the biggest and the most. During the third quarter, the Permian was the most active onshore play for

Permian Basin Plays



Source: Occidental Petroleum

Estimated Cumulative Jan 2004 - Jul 2015 Permian Basin Crude Oil Production By County

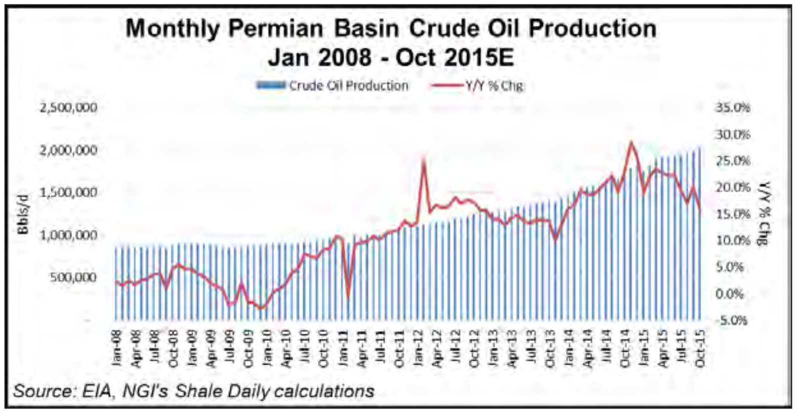
County	State	District	Million Bbls	County	State	District	Million Bbls
Eddy	NM	2	97.9	Chaves	NM	2	2.2
Lea	NM	1	96.7	Crosby	TX	8A	1.7
Andrews	TX	8	39.9	Hale	TX	8A	1.7
Upton	TX	7C	37.1	Sterling	TX	8	1.6
Midland	TX	8	36.6	King	TX	8A	1.5
Martin	TX	8	36.1	Lubbock	TX	8A	1.4
Ector	TX	8	32.0	Coke	TX	7C	0.8
Reeves	TX	8	27.6	Dickens	TX	8A	0.7
Gaines	TX	8A	26.1	Lynn	TX	8A	0.6
Reagan	TX	7C	25.9	Runnels	TX	7C	0.6
Ward	TX	8	25.9	Schleicher	TX	7C	0.5
Glasscock	TX	8	25.4	Tom Green	TX	7C	0.5
Yoakum	TX	8A	23.8	Lamb	TX	8A	0.4
Scurry	TX	8A	18.4	Concho	TX	7C	0.3
Irion	TX	7C	17.0	Roosevelt	NM	1	0.3
Hockley	TX	8A	15.7	Menard	TX	7C	0.2
Howard	TX	8	15.5	Cottle	TX	8A	0.2
Loving	TX	8	15.2	Sutton	TX	7C	0.1
Crockett	TX	7C	12.3	Terrell	TX	7C	0.1
Crane	TX	8	11.1	McCulloch	TX	7C	0.1
Pecos	TX	8	10.7	Motley	TX	8A	0.0
Culberson	TX	8	5.3	Floyd	TX	8A	0.0
Winkler	TX	8	5.1	Kimble	TX	7C	0.0
Terry	TX	8A	4.6	Brewster	TX	8	0.0
Dawson	TX	8A	4.4	El Paso	TX	8	0.0
Kent	TX	8A	4.1	Hudspeth	TX	8	0.0
Mitchell	TX	8	4.1	Jeff Davis	TX	8	0.0
Borden	TX	8A	3.8	Presidio	TX	8	0.0
Cochran	TX	8A	3.6	Bailey	TX	8A	0.0
Garza	TX	8A	3.0	**TOTAL JAN 2014 THROUGH JUL 2015**			**700.2**

This chart lists all counties in Texas within District 7C, 8 & 8A, and although the Railroad Commission of Texas includes them all in its Permian production totals, not every county in these Districts may in fact be prospective for the Permian (or have any current production). Texas counties include condensate production.

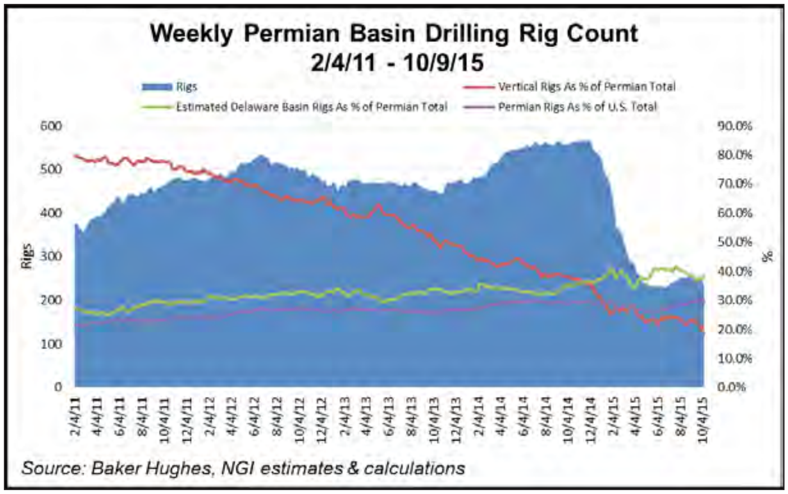
Source: Permian Basin Coalition (map), New Mexico Oil Conservation Division, Railroad Commission of Texas, NGI's Shale Daily Calculations

Permian Basin (continued)

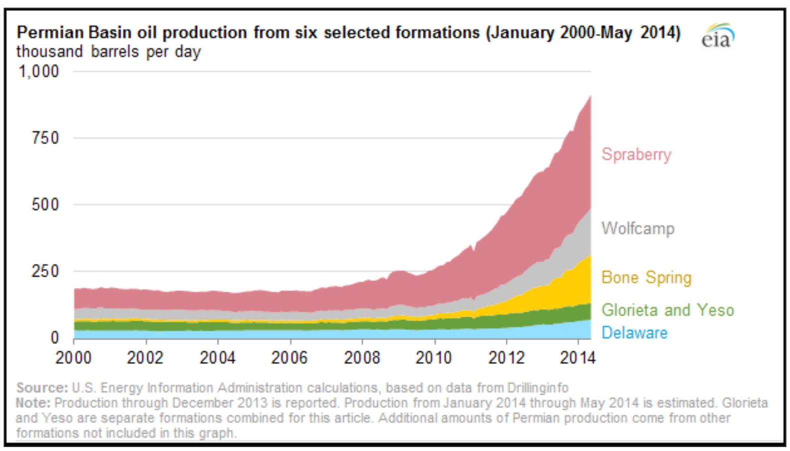
deals, with seven worth $4.1 billion (see Daily GPI, Oct. 28, 2015). And while the Permian only accounted for only one deal during 2Q2015 that was worth more than $50 million, it was the highest valued transaction in all onshore plays at $3.9 billion: Noble Energy Inc.'s acquisition of Rosetta Resources Inc. (see *Shale Daily*, May 11, 2015). Chinese investment firm Yantai Xinchao Industry Co. Ltd. in October 2015 also agreed to pay $1.31 billion to purchase property in the West Texas counties of Borden and Howard (see *Shale Daily*, Oct. 26, 2015).



Three things stand out in the graph to the right that underscore the renewed interest in the Permian. First, it is home to most of the U.S. drilling activity. In February 2011, the Permian claimed 21.7% of the total working rigs in the United States. That figure climbed to 29.6% as of early October 2015. Second, which we believe represents an important secular change, is that horizontal and directional drilling are becoming far more prevalent in the region. More traditional, vertical rigs represented 80% of the rigs in the Permian in February 2011, but that figure was down to just 19% in early October 2015. Finally, the chart illustrates the rise of the Delaware Basin, which we estimate has increased from 27% of all Permian rigs at work in early February 2011 to nearly 40% in early October 2015.



As shown in the adjacent EIA chart, the Spraberry and Bone Spring formations have yielded most of the gains in production thus far, in no small part because those formations were already well known to operators. Both were drilled vertically for years, are served by an established infrastructure, and have responded well to horizontal drilling, thus leading to the ramp in their production. However, another driver behind the current and expected future rise in Permian production is coming from the Wolfcamp and the Delaware sub-basin.



Drilling in the Wolfcamp, which underlies much of the Permian Basin, has risen in prominence thanks to horizontal drilling and hydraulic fracturing. Industry consultant Wood Mackenzie estimated that spending in the Wolfcamp during 2014 would near that of the Bakken, with capital expenditures surpassing $12 billion – about 80% of Bakken spend. The Wolfcamp was ranked third in tight oil play spending behind the Eagle Ford and the Bakken shales in 2014 and could overtake the Bakken for the No. 2 spot as early as 2017. Wolfcamp crude and condensate production is expected to reach 700,000 b/d by the end of the decade, according to Wood Mackenzie.

Many of the biggest operators have legacy holdings in the Permian that have allowed more time to experiment with fracturing and laterals. ExxonMobil Corp., Occidental Petroleum Corp., ConocoPhillips and Apache Corp. are among those that have had acreage for years. But it's a hot spot for the newbies as well as foreign operators.

ExxonMobil., already the biggest natural gas producer in the United States, has a Permian leasehold that extends more than 1.5 million net acres, but it still has not been satisfied. Between January 2014 through August 2015, subsidiary XTO Energy Inc. executed five

Permian Basin (continued)

agreements in the Permian's Midland sub-basin, giving it another 135,000 operated net acres (see *Shale Daily*, Aug. 6, 2015).

"The recent emergence of strong Lower Spraberry results, combined with the established Wolfcamp intervals, demonstrates the significant potential of the stacked pays in the Midland Basin core," said XTO President Randy Cleveland. Encana Corp., long a top North American player, didn't enter the Permian until late 2014, paying $7.1 billion to acquire Athlon Energy Inc. The deal handed the Calgary operator 140,000 net acres in the heart of the Midland sub-basin (see *Shale Daily*, Sept .29, 2014). EOG Resources Inc. rarely makes acquisitions, but in late 2015 it bolted-on 26,000 net acres in the Delaware through three transactions for $368 million (see *Shale Daily* Nov. 9, 2015).

Oxy, one of the biggest legacy leaseholders in the Permian, is finding better returns in Texas than anywhere else, including in the Bakken Shale. In fact, returns in the Permian were strong enough that Oxy decided to sell its Bakken acreage in 2015 (see *Shale Daily*, Oct. 29, 2015).

"Simply put, acreage in North Dakota cannot compete with our acreage in the Permian," CEO Vicki Hollub said. Permian production hit 116,000 boe/d in 3Q2015, 6% higher sequentially and 51% higher year/year.

Devon Energy Corp. is another good example of how experimentation is paying dividends in the play. The Oklahoma City explorer has holdings across the United States, but it considers the Delaware to be its crown jewel (see *Shale Daily*, Nov. 4, 2015).

"Really, our most intense focus area for 2016 will definitely be the Permian Basin and our work in the Delaware," said Devon's Tony D. Vaughn, executive vice president of exploration and production. "As we've approached our work in the Delaware Basin, we've really highlighted the second Bone Spring and the Delaware Sands as probably being the two most prolific from a rate-of-return perspective...We'll probably see us have a little bit more influence from the Leonard interval in 2016.

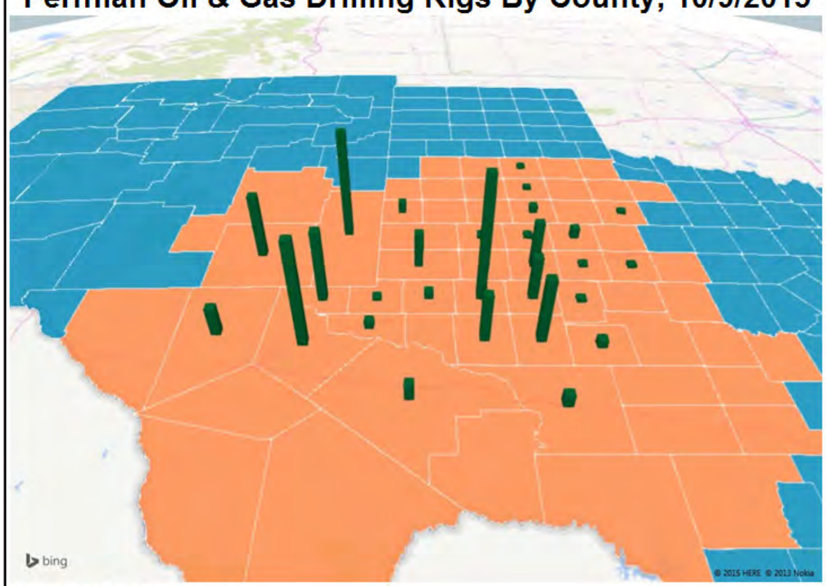
"We're also contemplating really how to appropriately develop the stacked-pay sands. And the Wolfcamp's got up to four different intervals. We have assessed that. We're getting a lot of industry activity on the Texas side of the basin moving right up to our play. Now we're starting to see the industry...understanding the play."

Pioneer Natural Resources Co. also relies on the Permian to fuel its onshore growth. The largest leaseholder in the Spraberry/Wolfcamp had a total of 800,000 gross acres in 2015, a contiguous land holding that allows for drilling horizontals with laterals of 7,500-10,000 feet. And that matters to the bottom line. "The longer lateral length wells pay out in approximately 18 months, which is twice as fast as the shorter lateral length wells," management said (see *Shale Daily*, Nov. 3, 2015).

Longer laterals in the Permian also were proving to be a boon to Cimarex Energy Co. during 2015. During the third quarter, it had 13 wells with 10,000-foot laterals targeting the Wolfcamp D interval with average initial production of 2,308 boe/d (see *Shale Daily*, Nov. 5, 2015). Five more 10,000-foot laterals were planned for early 2016.

Apache Corp.'s extensive legacy holdings in the Permian were said to be a major reason that Anadarko Petroleum Corp., another Permian player, attempted an $18 billion merger in late 2015 (see *Shale Daily*, Nov. 11, 2015). In the U.S. onshore, the Permian is Apache's the biggest focus, where it has worked for decades. Although it had dropped all but 10 of its 42 rigs in the play by 3Q2015 because of sliding oil prices, the Houston producer still reported a 14% gain in natural gas production from 3Q2014, with oil output down by 1%.

Permian Oil & Gas Drilling Rigs By County, 10/9/2015



Source: Baker Hughes

Apache was targeting the Bone Spring and Wolfcamp formations, and it also was working in the Spraberry. In addition, the operator branched out to the Yeso formation in the Northwest Shelf in 2015, where average completed well costs had fallen by half through experimentation.

Permian Basin (continued)

Permian-focused Concho Resources Inc. is another example of a smaller producer that's performing above average in the Permian. During 3Q2015, the operator had record production, despite low oil prices, beating its guidance with output of 149,304 boe/d, a 31.6% increase year/year (see *Shale Daily*, Nov. 16, 2015). Horizontals in the Delaware produced 88,500 boe/d, a 60% jump from 2014 and 8% higher sequentially.

"The blocking and tackling that we've talked about at the end of this quarter, and the real high quality acreage we were able to add in our core areas at really good prices, that's the kind of activity we're going to continue to stay focused on," Concho CEO Tim Leach said. "We live in the Permian Basin, so we think we're aware of everything that's going on out here. Our day-to-day business is this focus on our core areas and the smaller stuff."

There is some disagreement among several prominent sources as to which counties should be included in the Permian Basin. The Railroad Commission of Texas (RRC) includes all counties within its Districts 7C, 8, and 8A in the varying production and other operating statistics that appear on the Permian portion of its website, yet it includes a different slate of counties in its official definition of the play on that same site. The U.S. Energy Information Administration assumes its own mix of counties in its production estimate of the play, and the Permian Basin Coalition uses a slightly different combination as well. We summarize these variances in the table below.

Counties

Texas: Andrews, Borden, Brewster, Cochran, Coke, Concho, Cottle, Crane, Crockett, Crosby, Culberson, Dawson, Dickens, Ector, Edwards, Fisher, Floyd, Gaines, Garza, Glasscock, Hale, Hockley, Howard, Hudspeth, Irion, Jeff Davis, Kent, Kimble, King, Knox, Lamb, Loving, Lubbock, Lynn, Martin, McCulloch, Menard, Midland, Mitchell, Motley, Nolan, Pecos, Presidio, Reagan, Reeves, Runnels, Schleicher, Scurry, Sterling, Stonewall, Sutton, Taylor, Terrell, Terry, Tom Green, Upton, Val Verde, Ward, Winkler, Yoakum

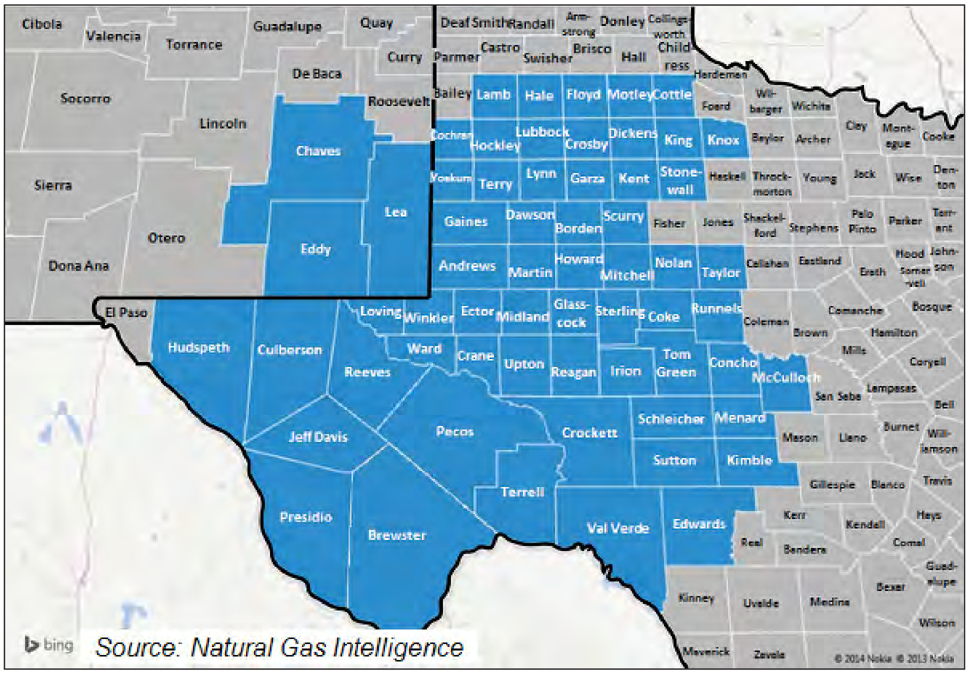
New Mexico: Chaves, Eddy, Lea

Counties Included In the Permian Basin Varies By Various Sources

County	State	RRC Districts 7C, 8, 8A	RRC Permian Web Page	EIA	Permian Basin Coalition
Andrews	TX	X	X	X	X
Bailey	TX	X		X	
Borden	TX	X	X	X	X
Brewster	TX	X			
Chaves	NM	N/A	N/A	X	
Cochran	TX	X	X	X	X
Coke	TX	X	X	X	X
Concho	TX	X			X
Cottle	TX	X			
Crane	TX	X	X	X	X
Crockett	TX	X		X	X
Crosby	TX	X	X		X
Culberson	TX	X		X	
Dawson	TX	X	X	X	X
Dickens	TX	X	X		X
Ector	TX	X	X	X	X
Eddy	NM	N/A	N/A	X	X
El Paso	TX	X			
Fisher	TX			X	X
Floyd	TX	X			
Gaines	TX	X	X	X	X
Garza	TX	X	X	X	X
Glasscock	TX	X	X	X	X
Hale	TX	X	X	X	
Hockley	TX	X	X	X	X
Howard	TX	X	X	X	X
Hudspeth	TX	X			
Irion	TX	X	X	X	X
Jeff Davis	TX	X	X		
Kent	TX	X	X		X
Kimble	TX	X	X		
King	TX	X			X
Knox	TX				X
Lamb	TX	X	X	X	
Lea	NM	N/A	N/A	X	X
Loving	TX	X	X	X	X
Lubbock	TX	X	X		X
Lynn	TX	X	X	X	X
Martin	TX	X	X	X	X
McCulloch	TX	X			X
Menard	TX	X			X
Midland	TX	X	X	X	X
Mitchell	TX	X	X	X	X
Motley	TX	X			
Nolan	TX		X		X
Pecos	TX	X	X	X	X
Presidio	TX	X			
Reagan	TX	X	X	X	X
Reeves	TX	X	X	X	X
Roosevelt	NM	N/A	N/A	X	
Runnels	TX	X			X
Schleicher	TX	X		X	X
Scurry	TX	X	X	X	X
Sterling	TX	X	X	X	X
Stonewall	TX				X
Sutton	TX	X		X	X
Taylor	TX				X
Terrell	TX	X		X	X
Terry	TX	X	X	X	X
Tom Green	TX	X	X	X	X
Upton	TX	X	X	X	X
Val Verde	TX			X	X
Ward	TX	X	X	X	X
Winkler	TX	X	X	X	X
Yoakum	TX	X	X	X	X

Source: Compiled by NGI's Shale Daily from the sources listed at the top of the table

Permian Basin (continued)



Local Major Pipelines

Natural Gas: Atmos, Comanche Trail (proposed), El Paso, Energy Transfer, Enterprise Texas Pipeline, KM Texas, NGPL, Northern Natural, Oneok Westex Transmission, Roadrunner Transmission (proposed), Trans Pecos (proposed), Transwestern, Waha Hub

Crude Oil: Amdel (Sunoco), Basin, BP Pipelines, BridgeTex, Centurion, Enterprise Crude Pipeline, Kinder Morgan Wink Pipeline, Longhorn, Mesa (Plains), Mesa (Sunoco), Mobil, Oasis, Pecos River, Permian Express II, Phillips 66, Plains Cactus, Shell Pipeline, Sunoco Pipeline, Sunrise Pipeline (Plains), SXL, SXL Permian Express, West Texas Gulf (Sunoco), West Texas Pipeline

NGLs: Chapparal, Energy Transfer, Halley Liquids Line, JAL Products Line (Regency Energy Services), Lone Star Express (proposed), Lone Star West Texas, Mesquite Liquids System, MexTex NGL System, Pecos River, Permian Connector, Phillips 66, Quanah Pipeline, Rocky Mountain (Enterprise Products), Sand Hills, Seminole, Targa Midstream, West Texas LPG (Chevron)

SELECTED PERMIAN BASIN NET ACREAGE POSITIONS

Last Updated December 2015

Company	Net Acres	Company	Net Acres
Occidental Petroleum	2,500,000	EXCO Resources	18,200
Chevron	1,500,000	EV Energy Partners	11,416
ExxonMobil (XTO Energy)	1,500,000	Pryme Energy*	11,346
Apache	1,295,000	Trinity River Energy	8,700
ConocoPhillips	1,100,000	Fleur de Lis Energy	7,200
Devon Energy	900,000	American Standard Energy	6,500
Concho Resources	700,000	Legacy Reservces	6,000
Pioneer Resources	692,000	Caza Oil & Gas*	4,256
WPX Energy	670,000	Adams Resources Exploration*	3,676
Shell	618,000	Samson Oil & Gas	130
EOG Resources	356,000	Archer Petroleum	N/A
Anadarko Petroleum	255,000	Big Star Oil & Gas	N/A
Cimarex Energy	235,000	Blue Whale	N/A
BHP Billiton	200,000	Bopco LP	N/A

Permian Basin (continued)

SELECTED PERMIAN BASIN NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
EP Energy	180,000	Burnett Oil	N/A
FireWheel Energy LLC	160,000	Circle Star Energy	N/A
Dorchester Minerals	152,000	Citation Oil & Gas	N/A
Vanguard Natural Resources*	144,668	Cobra Oil & Gas	N/A
Encana	140,000	Continental Resources	N/A
Discovery Natural Resources	135,000	CrownQuest	N/A
Approach Resources	130,000	Endeavor Energy Resources	N/A
Parsley Energy	125,543	Energy & Exploration Partners	N/A
SandRidge	95,170	EnerVest	N/A
Whiting Petroleum	92,700	ExL Petroleum	N/A
Matador Resources	90,672	Fasken Oil & Ranch	N/A
American Energy Partners	85,000	Field Point Petroleum	N/A
Diamondback Energy	85,000	Henry Resources	N/A
Three Rivers Operating Company	82,000	Hess	N/A
Broad Oak Energy	75,000	JM Cox Resources	N/A
Energen*	73,307	Lario Oil & Gas	N/A
EQT Corporation	73,000	LCX Energy	N/A
Kinder Morgan*	66,105	Lime Rock Resources	N/A
Clayton Williams	66,000	Lynden Energy	N/A
RSP Permian	63,000	Memorial Production Partners	N/A
SM Energy*	62,500	Meritage Energy	N/A
Noble Energy*	56,000	Mewbourne Oil	N/A
Ring Energy	32,000	Parallel Petroleum	N/A
Abraxas Petroleum	30,891	Peregrine Petroleum	N/A
Windsor Energy	29,381	Pike's Peak Energy	N/A
Quicksilver Resources	27,600	Summit Energy	N/A
Callon Petroleum	27,366	Texland Petroleum, L.P.	N/A
ENI	26,250	U.S. Energy Corp.	N/A
QEP Resources	26,073	Unit Petroleum	N/A
Carrizo Oil & Gas	26,000	Urban Oil & Gas	N/A
Ajax Resources LLC[1]	25,800	Viper Energy Partners	N/A
Antares Energy	25,800	Wellstar Corp.	N/A
Eagle Rock Energy Partners	22,666	XOG Operating	N/A
Resolute Energy	22,100	Yantai Xinchao Industry Co. Ltd	N/A
Chaparral Energy	19,000	Yates Petroleum	N/A

*Estimate
[1] Pro forma for purchase from W&T Offshore set to close Jan. 1, 2016.
Note: In its March 2011 investor presentation, Occidental Petroleum notes that are more than 1,500 operators in the Permian Basin.
Source: Compiled by NGI from company documents

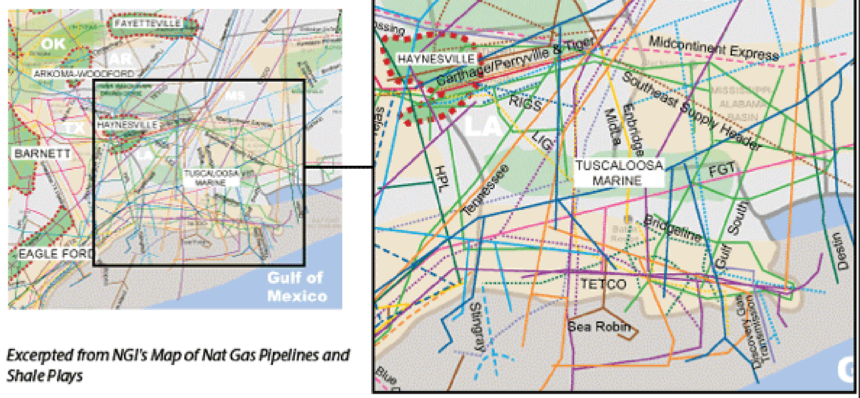
TUSCALOOSA MARINE SHALE

Background Information

The Tuscaloosa Marine Shale (TMS) along the Louisiana/Mississippi border is one the most polarizing unconventional formations in North America, at least in the eyes of the investment community.

On the one hand, it has the potential to emerge into what one analyst described as a "potentially serious" oil play. On the other, the formation presents some geological challenges that have slowed its development thus far. But just as operators seemed to be overcoming these early hiccups, lower oil prices have impeded its progress even further.

States Included: Louisiana, Mississippi



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

Initial wells in the TMS produced anywhere from 85%-100% light crude oil (38° - 45° API), with the remainder being liquids-rich natural gas, from true vertical depths between 10,000-15,000'. This high oil content has some investors salivating in the hopes that the TMS may turn out to be the next Eagle Ford, and from a geological standpoint, the Tuscaloosa Marine Shale is in fact similar to the Eagle Ford Shale in Texas. A portion of the TMS even has been called the Louisiana Eagle Ford shale. But unlike the Eagle Ford in Texas, the TMS has a varying degree of clay/silt content that has led some to question the ultimate commerciality in portions of the play. This may explain why much of the early horizontal drilling activity to date has been centered in Amite, Pike, and Wilkinson Counties, MS, and Avoyelles, East Feliciana, West Feliciana, St. Helena, and Tangipahoa Parishes, LA.

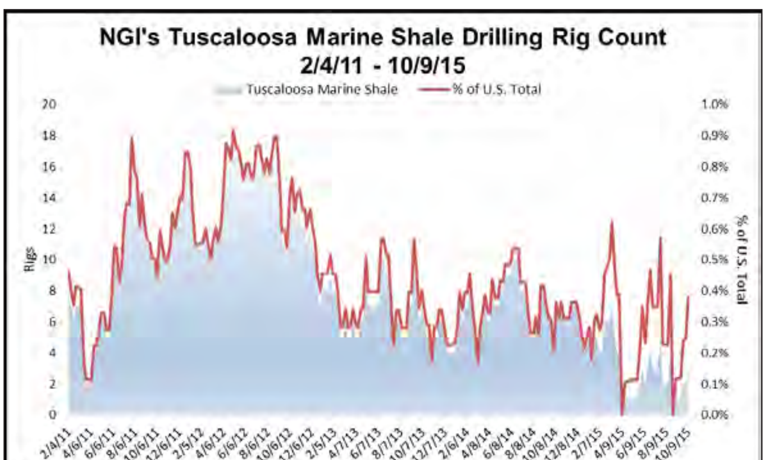
There are many wells in the TMS region already, since the area is also home to the more conventional Austin Chalk formation.

According to Baker Hughes data, there were 15 drilling rigs in the counties and parishes that comprise the TMS as of October 24, 2014, but activity has fallen off in the last year because of depressed commodity prices. We estimate only 3 rigs were working in the TMS area as of 10/9/15, 2 in Franklin County, MS, and the other in Adams County, MS. Interestingly, all three of these rigs were vertical, which suggests they were either being used to drill science wells, to hold leases, or possibly to target other formations.

Goodrich Petroleum reported on its 3Q14 conference call that there had been 52 horizontal wells drilled in the TMS as of October 2014, with 21 of those coming in 2014. Compare that to the more than 16,300 permitted wells in the Texas Eagle Ford through August 2014, and you get a sense of how much more drilling activity is needed to further delineate and de-risk the TMS in order to truly compare it to more established oil resource plays such as the Eagle Ford and Bakken shales.

Many of the initial wells in the TMS were negatively impacted because the target wells were in what the industry has dubbed the "rubble zone," although Sanchez Energy COO Chris Heinson notes this isn't actually a real zone. Rather, it is a highly fractured area that lies just above the Richland Sand.

"People have gotten themselves into trouble when they have tried to land above that Richland Sand because of the rubble zone: [there's] just no telling how far it may extend vertically in the section. So some operators who were trying to avoid it ended up



Source: Baker Hughes, NGI's Shale Daily calculations

Tuscaloosa Marine Shale (continued)

intersecting highly fractured zones when they landed north of that Richland sand," Heinson explained.

However, Goodrich Petroleum and Halcon Resources both noted they have overcome this problem by setting the intermediate casing that approaches the pay zone at steeper angles. This, along with the general experience benefits that come from drilling more wells, have led to improved well results. During its 2Q14 conference call, Encana noted that seven of the last ten industry wells in the TMS had met its normalized type curve expectations, although all seven of those wells were drilled by Encana itself.

But even with the benefit of experience, operators in the TMS continue to turn in inconsistent results. In August 2014, a couple of Goodrich Petroleum TMS wells came in with underwhelming initial production rates compared with earlier wells, Sanchez Energy was sidetracking the lateral of its first operated TMS well after running into trouble, and Halcon Resources had experienced problems with its second TMS well. Part of the issue could be the presence of less natural fracturing in these wells, and that is a problem that may be difficult to overcome in the future. As Goodrich Petroleum CEO Gil Goodrich noted on the company's 2Q14 earnings conference call, his firm has been working with Schlumberger to map natural fracturing in the TMS, but it is still early in the process. Others are engaged in similar efforts, he said, adding that it is "a little bit difficult." It is doubtful that the natural fracturing will show up on 3-D seismic surveys at resolutions fine enough to be helpful, Goodrich said, leaving the hunt for the best-fractured portions of the play largely up to "trial and error."

Still, Goodrich seemed far more upbeat on the company's 3Q14 conference call, noting that "during the third quarter, we continued to make meaningful progress in the Tuscaloosa Marine Shale. We and our industry partners have delivered an increasing number of consistent high rate wells, free of major mechanical or operational problems, and further demonstrated the repeatability of the play within the rapidly emerging core fairway.

Recent industry drilling success aside, now operators in the TMS face another potentially crippling problem: low crude oil prices, which has seen development in the play drop off significantly. For much of 2015, Baker Hughes data and *NGI* calculations revealed that most weeks there were 1-4 rigs in operation in the TMS, with a number of weeks where there was absolutely no activity.

Goodrich noted on its 3Q14 conference call that its breakeven price in the TMS is closer to $50 per barrel, given certain advantages in the play, such as a low basis differential to WTI, friendly royalty rates, and a lack of a meaningful severance tax until payout. That may be true, or at least true for Goodrich, but we would expect sustained lower crude oil to delay the overall industry transition of the TMS from a science to a development area. In August 2015, Credit Suisse opined that the TMS generated an internal rate of return (IRR) of just 5% given the NYMEX crude oil and natural gas strips at that time, meaning the play had lower than breakeven economics, assuming a 10% cost of capital.During a 2Q15 conference call, Sanchez Energy CEO Tony Sanchez III said the company was focusing on its Catarina prospects in the Eagle Ford Shale, and that drilling and completion activity would be curtailed in the TMS, where it holds 66,000 net acres (see *Shale Daily*, Aug. 11, 2015).

In July 2015, Goodrich's CEO announced that the company had sold some of its Eagle Ford acreage — a move that some analysts said positioned the company as more of a TMS pure-play operator (see *Shale Daily*, July 27, 2015). However, weak commodity prices have put development goals on hold.

In September 2015 Louisiana Oil and Gas Association President Don Briggs said the state's oil and gas industry is in the midst of a crisis it hasn't seen since the 1980s, and things could get worse if commodity prices remain low for an extended period of time (see *Shale Daily*, Sept. 1 2015).

"We've already seen several bankruptcies," Briggs said in the interview with *NGI's Shale Daily*. "Companies that are highly leveraged in a downturn like this are looking at [their options, which could include] Chapter 11. And if we have a continued period of time where this environment we're in lasts for six to eight to 10 months, we will certainly see more. These are some very difficult times. There are companies looking for acquisitions and others looking for buyers. That's a normal process when you're going through a downturn like this. It's very much like what happened in the mid-80s. At the beginning, we didn't compare this downturn to that one, but in a lot of ways they are very similar."

The weak commodity environment has seen the country's oil and gas rig count plummet, and Louisiana has been no exception.

The number of drilling permits issued in Louisiana has also fallen off. According to Briggs, for the first seven months of 2015 a total of 390 permits were issued, down 55% from 868 permits over the same time frame in 2014. Of the 2015 total, 167 permits have been issued in three parishes in the north: Caddo, DeSoto and Lincoln, but those are more Haynesville Shale and likely Cotton Valley focused.

The TMS was largely an afterthought during the round of 3Q15 earnings conference calls. Goodrich Petroleum noted on its call that it moved the play into development mode in 2015, and continues to be enthused about its potential once oil prices recover, particularly since they believe they can increase TMS EURs by drilling longer laterals and using more proppant per stage. However, the message seems to be lost on the investment community, as analysts didn't ask management a single question on the call. As of

Tuscaloosa Marine Shale (continued)

11/26/15, GDP's stock price stood at a 52-week low of $0.43/sh., down from its 52-week high of $7.59/sh.

Similarly, Sanchez Energy dedicated only one out of 34 slides in their November 2015 investor presentation to the TMS (and it was in the appendix), and spent only 5% of their 2015 capex budget on the play. Still, the play is not completely forgotten. Dallas-based exploration and production company Aresco LP said in December 2015 that it has acquired "a substantial working interest" in the TMS in Louisiana and Mississippi. The company said a four-well drilling program targeting the lower TMS "A" Sand would begin immediately. Aresco's newly acquired acreage covers 11 prospect areas containing up to 47 drilling locations across 20,000 acres in Louisiana and Mississippi. The seller was not disclosed (see *Shale Daily*, Dec. 7, 2015).

Counties/Parishes

Louisiana: Allen, Avoyelles, Beauregard, Catahoula, Concordia, East Feliciana, East Baton Rouge, Evangeline, Grant, LaSalle, Livingston, Natchitoches, Point Coupee, Rapides, Sabine, St. Helena, St. Landry, St. Tammany, Tangipahoa, Vernon, West Feliciana, Washington

Mississippi: Adams, Amite, Franklin, Pike, Walthall, Wilkinson

Local Major Pipelines

Natural Gas: ANR, Columbia Gulf, Florida Gas Transmission, Gulf South, Kinder Morgan Louisiana, Louisiana, Intrastate Gas, Pine Prairie Energy Hub, Southern Natural, Tennessee, Texas Eastern Transmission, Texas Gas Transmission, Transco, Trunkline

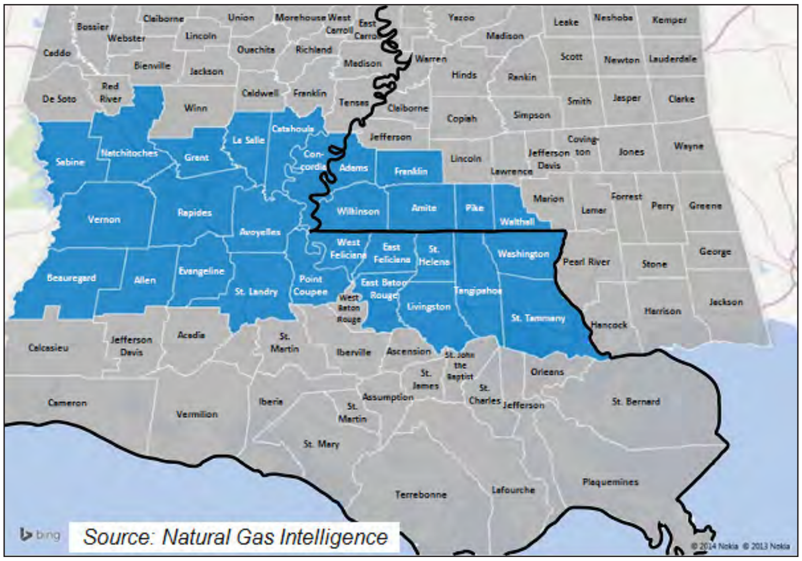
Crude Oil: Capline, Genesis, Mississippi/Alabama (Plains), North Louisiana (Exxon)

NGLs: Centennial, Dixie

Tuscaloosa Marine Shale (continued)

TUSCALOOSA MARINE SHALE (TMS) NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres
Indigo II Minerals LLC	325,000
Halcon Resources	316,000
Goodrich Petroleum	307,000
Encana	200,000
EOG Resources	180,000
Sinopec	88,333
Comstock Resources	82,000
Sanchez Energy	66,000
Amelia Resources[1]	55,000
Helis	55,000
Bear Peak Resources, LLC	30,000
Contango Oil & Gas	29,000
Yuma Companies[2]	29,000
Lighthouse Petroleum	65
Aresco LP	N/A
Exchange E&P	N/A
Justiss Oil	N/A
Manti Resources	N/A
Mitsubishi	N/A
Plateau Energy LLC	N/A
Pryme Energy	N/A
Stone Energy	N/A
Swift Energy	N/A

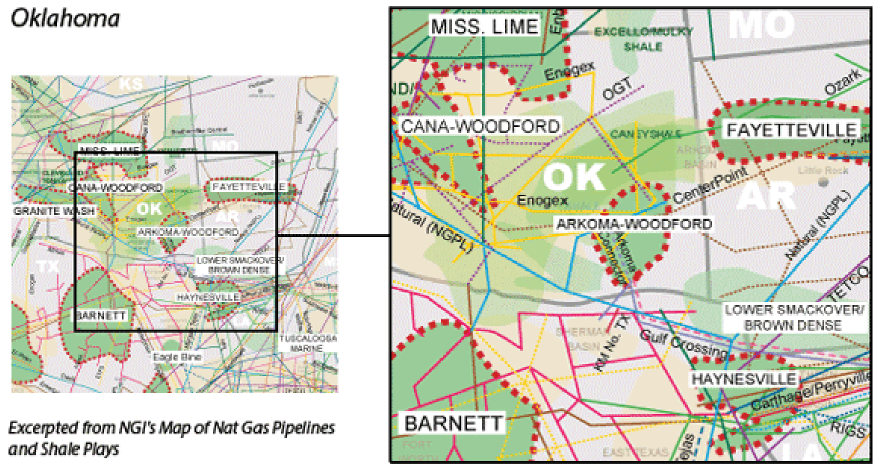


[1] Currently marketing this acreage.
[2] Estimate based on a 33% working interest in 88,000 acres.
Data Source: Compiled by NGI from company documents

ARKOMA-WOODFORD SHALE

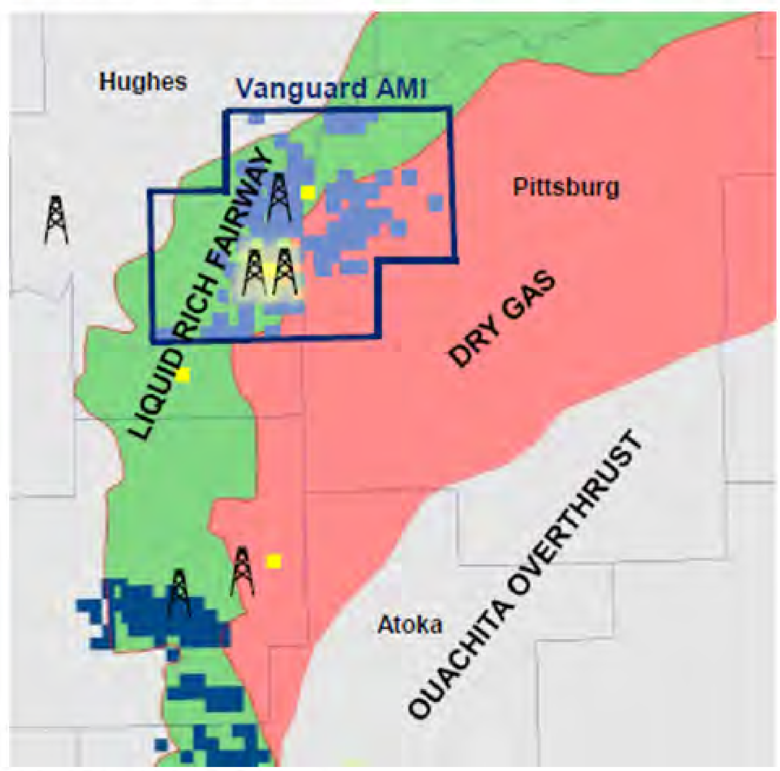
Background Information

The Arkoma-Woodford may have been one of the first unconventional plays to emerge in the United States, but a "first mover" advantage doesn't always lead to longer-term success. According to the Tulsa Geological Society, the play kicked off with vertical drilling in 2003, and saw its first horizontal well in late 2004. The Arkoma-Woodford is primarily a dry natural gas formation, although gas on the western half of the play tends to be somewhat more liquids rich than that on its eastern half. The majority of horizontal drilling in the Arkoma-Woodford has been centered in Atoka, Coal, Hughes, and Pittsburg counties in Southeastern Oklahoma, with some scattered activity in McIntosh County, OK as well.



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

Arkoma-Woodford Wet/Dry Gas Windows



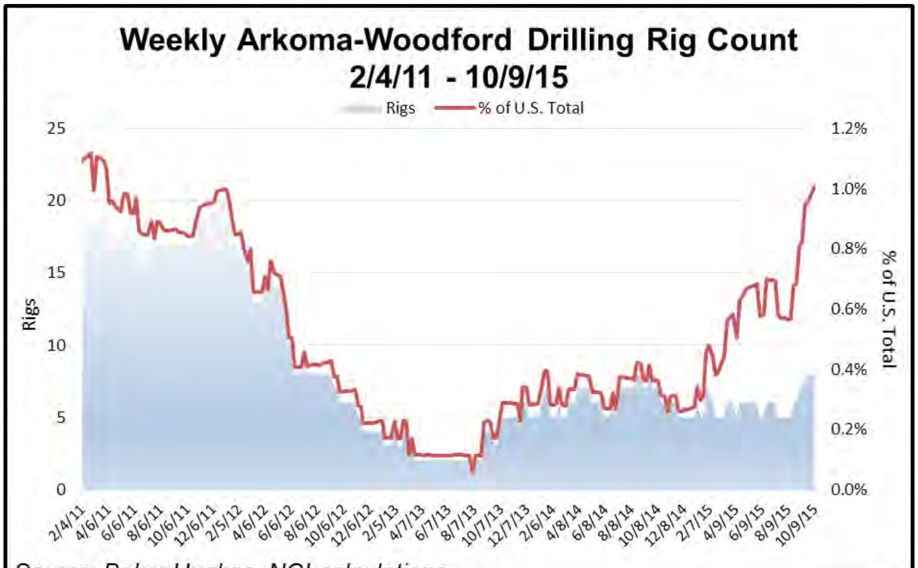
Source: Jones Energy

At one point in 2008, there were more than 50 drilling rigs working the Arkoma-Woodford, but these days, low gas prices have all but choked off investment in the region, particularly in the dry gas window. Most publicly traded companies barely even mention the play in their investor relations presentations anymore, and rig activity in the Arkoma-Woodford has slowed to a near standstill. There were just 8 drilling rigs in the Arkoma-Woodford in early October 2015, three each in Coal and Pittsburg counties, and the other two in Hughes County. That low rig count could be explained in large part by poor drilling economics in the area. At several points in 2015, Credit Suisse calculated the breakeven NYMEX price for the Arkoma-Woodford to be ~\$5.75/MMbtu, among the highest for gas driven resource plays in North America.

Despite such economic headwinds, those 8 rigs were actually 2 more than were working the Arkoma-Woodford the year prior, which makes it only one of two unconventional regions (along with the Cana-Woodford) that could boast a year-over-year increase in its operating rig count. However, we believe this is the result of the Arkoma rig count already being so low, and from a handful of operators who are targeting the core areas of the play, where drilling economics are likely somewhat better.

ExxonMobil is the largest Arkoma-Woodford acreage holder, followed by Newfield Exploration and Vanguard Natural Resources. PetroQuest had been a major player in the area, but the company sold the majority of its Woodford position in 2015.

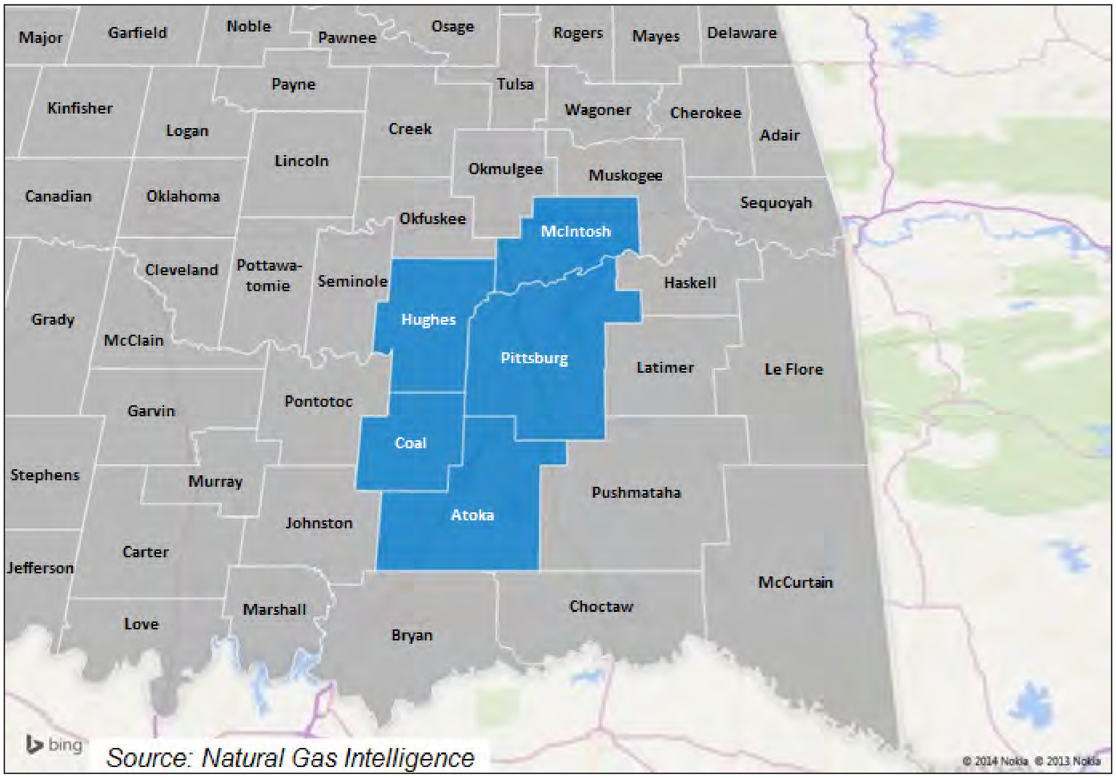
Arkoma-Woodford Shale (continued)



Source: Baker Hughes, NGI calculations

Counties

Oklahoma: Atoka, Coal, Hughes, McIntosh, Pittsburg



Source: Natural Gas Intelligence

Arkoma-Woodford Shale (continued)

Local Major Pipelines

Natural Gas: Arkoma Connector, CenterPoint Energy, Enogex, Gulf Crossing, Midcontinent Express, NGPL, OGT, Ozark

ARKOMA-WOODFORD SHALE ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
ExxonMobil[1]	385,000	Panhandle Oil & Gas	N/A
Newfield Exploration	146,000	PetroQuest	N/A
Vanguard Natural Resources	73,140	Sanchez Production Partners	N/A
Bravo Natural Resources	56,000	Sedna Energy LLC	N/A
Silver Creek Oil & Gas	40,000	Sinclair Oil & Gas Company	N/A
Riley Exploration Group[2]	33,000	SLT Dakota Operating Inc	N/A
Continental Resources	26,530	Southern Resources Inc	N/A
Jones Energy	17,292	Southridge Energy	N/A
Avatar Energy	N/A	Taylor R C Operating Co LLC	N/A
BP	N/A	Tilford Pinson Exploration LLC	N/A
Chesapeake Energy	N/A	Unit Corporation	N/A
Cuesta Petroleum Inc	N/A	Urban Oil & Gas Group LLC	N/A
Enlink Holdings	N/A	Wagner Oil Company	N/A
Foundation Energy Management	N/A	Ward Petroleum	N/A
Kaiser-Francis Oil Company	N/A	WhitMar Exploration	N/A
Osage Exploration	N/A	Yale Oil Association Inc	N/A
Pablo Energy II	N/A		

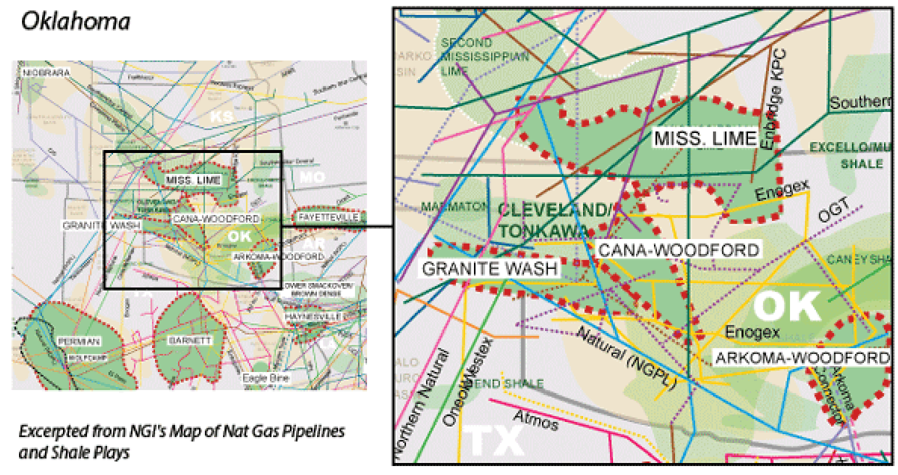
[1] May include some Ardmore Basin acreage.
[2] Cinco Resources had 33,000 net acres and was acquired by Riley Exploration in May 2015

Source: Compiled by NGI from company documents

CANA-WOODFORD SHALE

Background Information

The Cana-Woodford (also known as the Anadarko-Woodford) is a liquids rich shale formation that is named after Canadian County, OK, although the formation underlies several counties in the western half of the state. Production in the Cana-Woodford kicked off in the 1930s from conventional vertical wells, with the industry's first horizontal well coming in 2007. More recently, however, the counties that comprise the Cana fairway have been targeted for emerging oil plays, such as the SCOOP and STACK formations.



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

The Cana is a relatively deep formation, ranging from 8,000'-16,000' in true vertical depth, with some wells reaching total measured depth greater than 20,000'. In 2011, the U.S. Energy Administration went so far as to declare the Cana-Woodford the deepest commercial horizontal shale play in the world. Similar to the Eagle Ford and the Ohio-Utica formations, the Cana features a dry gas, a condensate, and an oil window. Much of the industry activity in the Cana has been in the more liquids rich portions of the play. In early 2015, Continental Resources completed its first well in the northwest Cana-Woodford via a joint development agreement with a subsidiary of South Korea's SK Group aimed at natural gas drilling (see *Shale Daily*, May 7, 2015; Oct. 27, 2014).

Unlike the Bakken Shale, which features a large number of operators, several of whom have amassed land holdings of more than 500,000 net acres, the majority of Cana-Woodford acreage is held by just a handful of companies, most notably Devon Energy, Newfield Exploration, Continental, Marathon Oil, and Cimarex Energy.

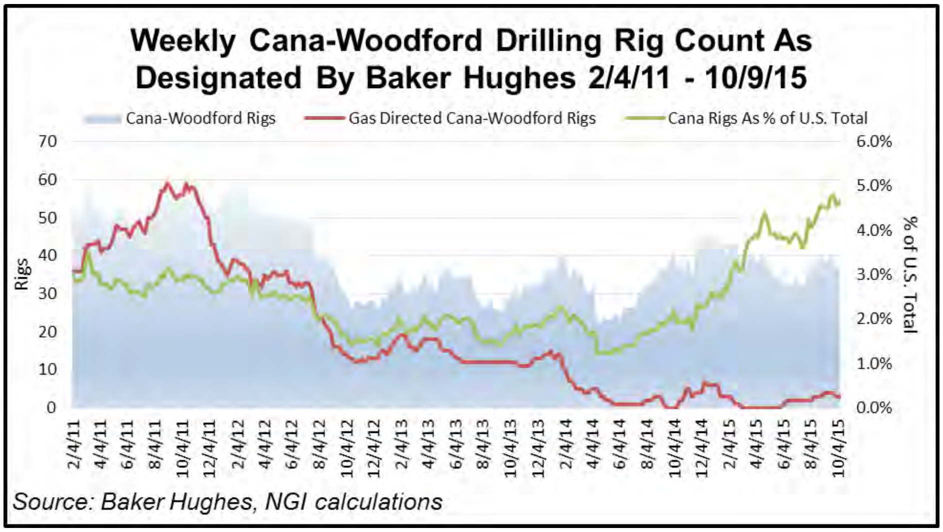
Overall drilling rig counts in the Cana started to decline in July 2012, quite possibly as operators finished drilling to hold and delineate acreage, and because of lower gas prices, but have leveled off more recently. There were 37 rigs operating in the play in early October 2015, flat from a year earlier. But a deeper dive into that data suggests that not all those rigs are actually targeting the Cana-Woodford, per se. According to Baker Hughes data, 17 of those 37 rigs were focused on oil targets in Grady County, most of which are likely targeting the SCOOP formation. Fourteen of the remaining 20 rigs were focused on oil targets in Blaine and Canadian counties, meaning they were more likely focused on the STACK plays. Only three rigs targeted natural gas. For more information on these two areas, please see Oklahoma Liquids Plays.

The Sooner Trails Pipeline proposed by Southern Star Central Corp. and a unit of NextEra Energy Inc. would connect receipt points in the Cana-Woodford footprint and elsewhere in central and southern Oklahoma with interstate and intrastate natural gas pipeline markets in Bryan County, OK, and Lamar County, TX (see *Shale Daily*, Aug. 20, 2015). Potential receipt points include DCP Okarche Plant, OFS Canadian Valley Plant, Enlink Cana Plant, Enable South Canadian Plant, DCP Chitwood Plant, OFS Knox Plant, Enable Bradley Plant, Woodford Express Grady Plant, and alternates. The primary points of delivery would be at the Bennington and Lamar hubs, with potential interconnects at NGPL, Midcontinent Express Pipeline, Gulf Crossing Pipeline, ETC Fuels, ETC Houston Pipeline, Enlink Crosstex and Kinder Morgan North Texas Pipeline. The 250-mile pipeline would provide up to 1.2 million Dth/d of capacity to serve local distribution companies, industrial end-users, power generators and other regional demands. Assuming regulatory approval, Southern Star and NextEra anticipate Sooner Trails service to begin in early 2018.

In addition, Enable Gas Transmission began conducting a binding open season in November 2015 for its proposed Cana & Stack Expansion (CaSe) to provide additional natural gas takeaway capacity from the Cana and the STACK. Initial capacity would be between 190-490 MMcf/d.

Oklahoma regulators have been cutting back the volume of drilling wastewater that operators may inject into disposal wells in two counties just outside the Cana-Woodford's eastern edge in response to induced seismicity that has been blamed on such wells (see *Shale Daily*, Aug. 4, 2015). The Oklahoma Corporation Commission's Oil and Gas Conservation Division plan affects northern Oklahoma and southern Logan counties.

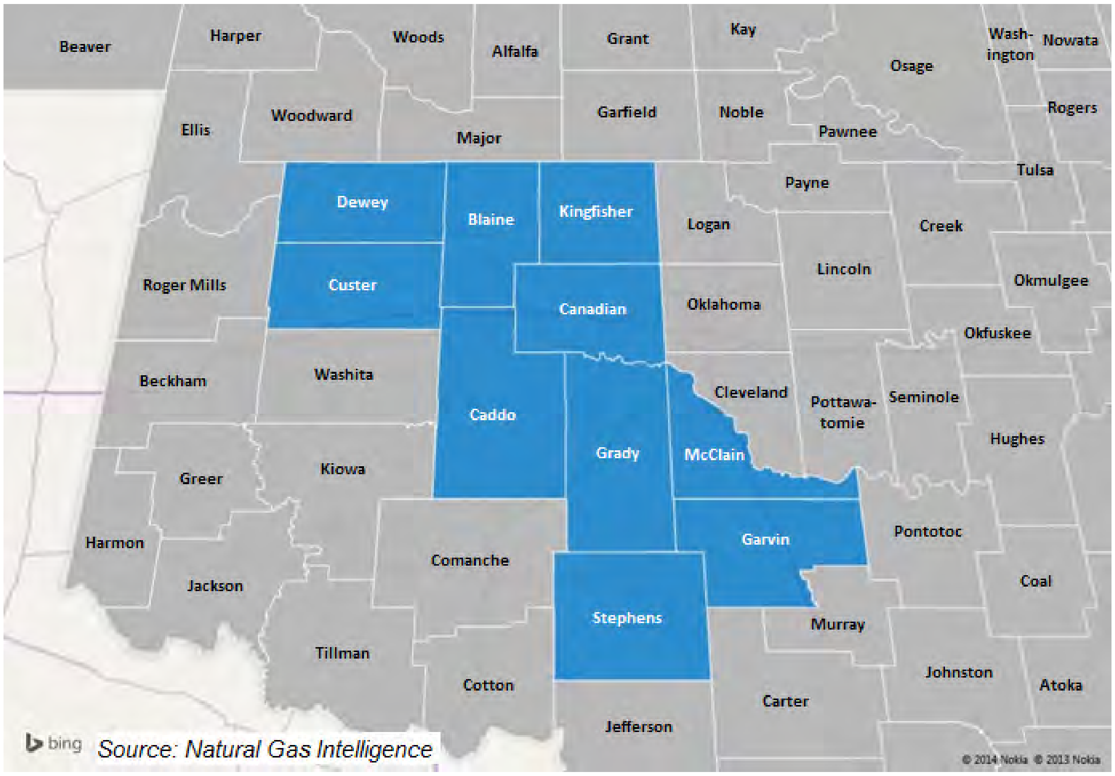
Cana-Woodford Shale (continued)



Source: Baker Hughes, NGI calculations

Counties

Oklahoma: Blaine, Caddo, Canadian, Custer, Dewey, Garvin, Grady, Kingfisher, McClain, Stephens



Source: Natural Gas Intelligence

Cana-Woodford Shale (continued)

Local Major Pipelines

Natural Gas: CenterPoint Energy, Enable Gas Transmission's Cana & STACK Expansion (proposed), Enogex, NGPL, OGT, OkTex Pipeline, Panhandle Eastern, Sooner Trails (proposed), Southern Star

Crude Oil:* Basin, Centurion, Cherokee, CK Red River, Phillips 66

NGLs: Southern Hills

*The Cana-Woodford itself is not much of an oil target, but the SCOOP & STACK formations that lie within the Cana fairway certainly are. For more on these two formations, please see Oklahoma Liquids Plays.

CANA-WOODFORD NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres
Devon Energy	280,000
Newfield Exploration	170,000
Marathon Oil	142,000
Cimarex Energy	128,000
Chaparral Energy	69,500
Chesapeake Energy	35,000
Vitruvian Expoloration II	35,000
Continental Resources[1]	31,400
SK Group[2]	21,956
Vanguard Natural Resources	16,600
Range Resources[3]	15,000
Apache Corp	N/A
Chevron	N/A
Longfellow Energy	N/A
Panhandle Oil & Gas	N/A
Red Mountain Energy	N/A
Samson Resources	N/A
Southland Energy Corporation	N/A
Unit Corporation	N/A

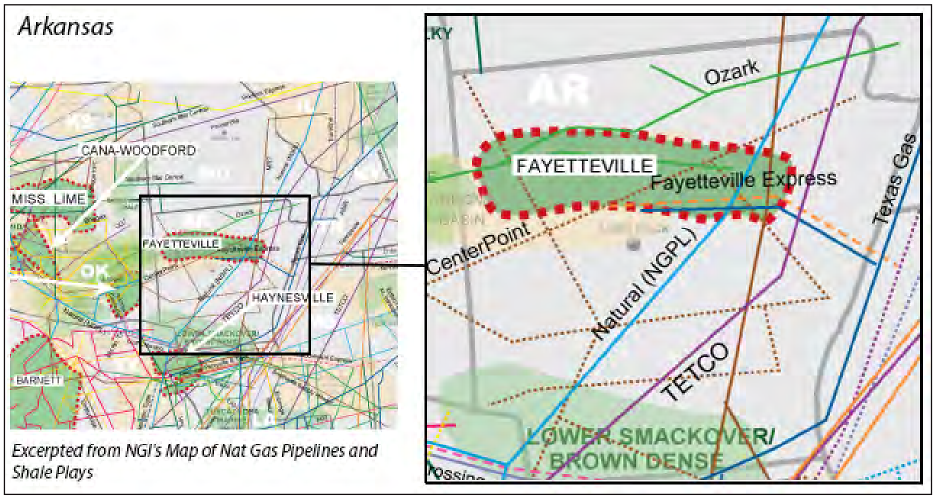
[1] NW Cana acres only. Does not include acres in the SCOOP.
[2] Estimate. CLR agreed to sell 49.9% of 44K net acres to SK Group in October 2014.
[3] Excludes another 25,000 net acres prospective for Woodford oil.

Source: Compiled by NGI from company documents.

FAYETTEVILLE SHALE

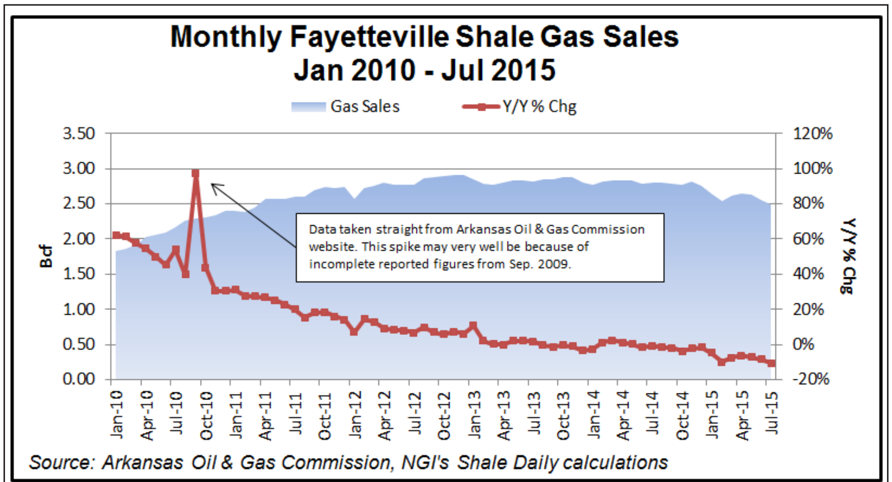
Background Information

One of the first U.S. shale plays to be developed en masse, the Fayetteville Shale is a dry natural gas formation located on the Arkansas side of the Arkoma Basin. The 2,838-square mile play held 20.4 Tcf of technically recoverable natural gas as of January 1, 2013, according to the Energy Information Administration.

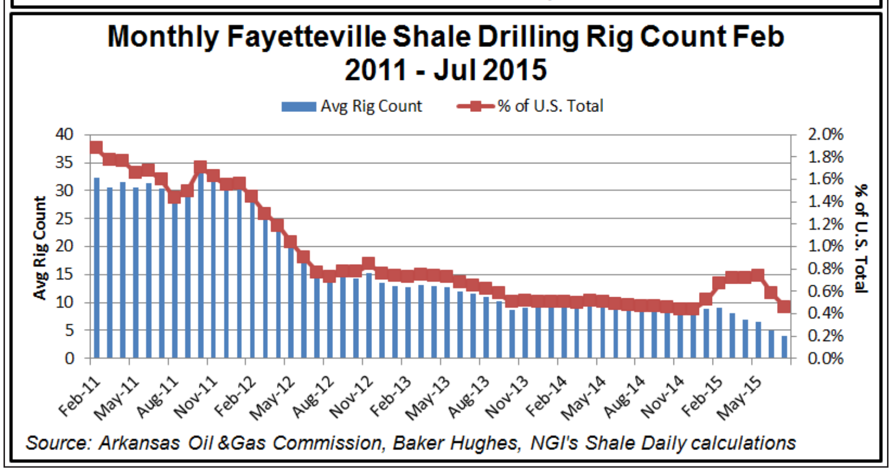


Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

Southwestern Energy (SWN) remains the dominant player in the Fayetteville. The company discovered the play, and held 888,000 net acres there as of October 2015. According to statistics from the Arkansas Oil & Gas Commission, there were 15 operators in the Fayetteville in 2015, but almost 100% of total 2015 production came from just three: SWN, through subsidiary SEECO, BHP Billiton and ExxonMobil/XTO Energy.



But SWN, which made its name in the Fayetteville, has over the past two years shifted its focus to the Appalachian Basin, and the importance of the Fayetteville to the company is waning. In 2Q2011, SWN had 107 Bcfe of production in the Fayetteville, which accounted for nearly 88% of the company's total quarterly production. By 2Q2015, production out of the play had inched up to 121 Bcfe, but made up less than half of SWN's total production. In 2015, SWN, like so many other oil and natural gas industry businesses, was forced to lay off employees because of tumbling commodity prices (see *Shale Daily*, Aug. 7, 2015). Most of SWN's layoffs were from its Fayetteville Shale operations.



Fayetteville Shale (continued)

2014 Fayetteville Production By Operator*

Operator	Sales (Bcf)	% of Total
Southwestern Energy	747.5140	73.2%
BHP Billiton Petroleum	140.2277	13.7%
ExxonMobil/XTO Energy	131.8388	12.9%
Arrington Oil & Gas Operating, LLC	0.9128	0.1%
D90 Energy, LLC	0.2320	0.0%
Hall Phoenix Energy, LLC	0.1866	0.0%
Lime Rock Resources III-A, L.P.	0.0747	0.0%
Broman Oil & Gas LP	0.0587	0.0%
Foundation Energy Management, LLC	0.0074	0.0%
Lawco Exploration, Inc	0.0040	0.0%
XOG Operating, LLC	0.0005	0.0%
TOTAL	**1,021.0572**	**100.0%**

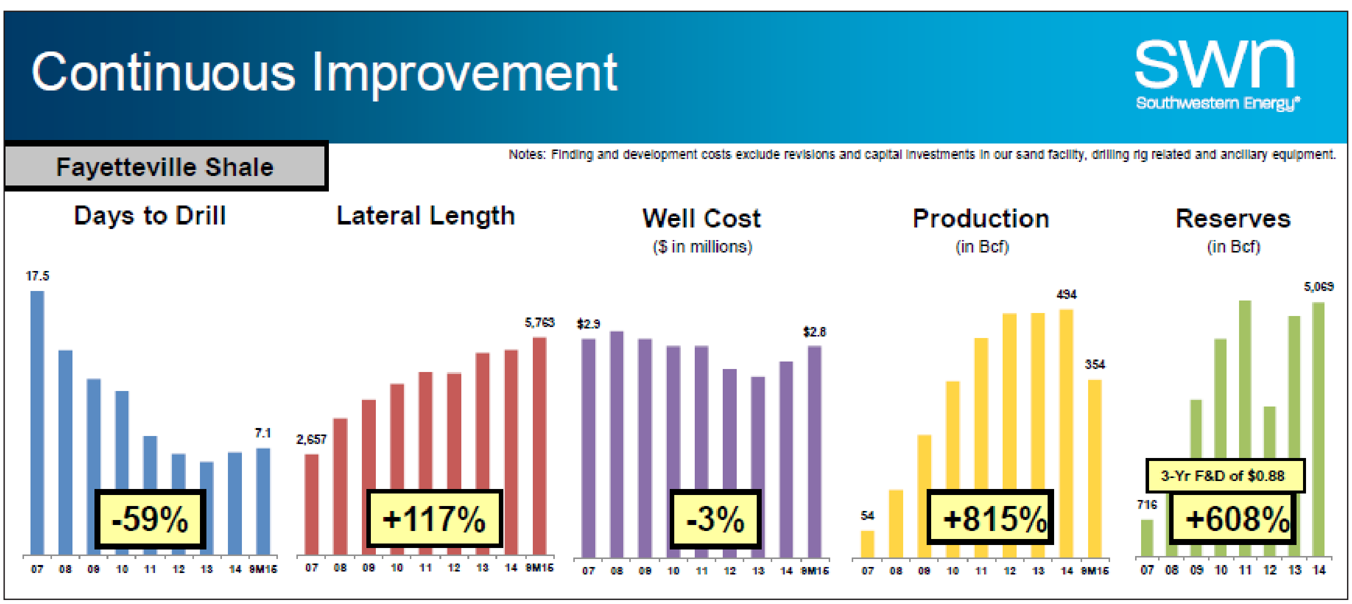
*Note: Gross figures. Net figures per company exclude royalties and adjustments for working interest. For example, in 2014, SWN reported net Fayetteville production of 494 Bcf, ~34% less than the 748 Bcf gross total reported by the Arkansas O&G Commission.

Source: Arkansas Oil & Gas Commission, NGI's Shale Daily calculations

Southwestern conceded during its 3Q15 earnings conference call that the Fayetteville is a "swing" area for them in terms of where they would add incremental investment dollars, and will most likely remain that way in the future. Since SWN is more focused on the Appalachian these days, and because Southwestern is the largest player in the Fayetteville, that means the drilling economics of the Marcellus Shale in particular could very well be the main driver behind the future growth potential of the Fayetteville.

Another major presence in the play, BHP Billiton Ltd., put its Fayetteville assets up for sale in 2014, but received little interest from potential buyers (see *Shale Daily*, Oct. 27, 2014).

Production growth in the Fayetteville began slowing about two years ago, leading to some speculation that perhaps the play had reached a more mature stage. However, the Bureau of Economic Geology at The University of Texas at Austin concluded in a 2014 study that the Fayetteville Shale at the time had 38 Tcf of technically recoverable reserves left, 18 Tcf of which was economical at $4.00/Mcf. At that price, the study's authors argued that production from the Fayetteville would plateau during the period of 2012-2015, and would begin a gradual decline as the annual well count decreases. Credit Suisse pegged breakeven prices in the Fayetteville core to be ~$3.50/MMBtu NYMEX at various times in 2015, while RBC Capital put them more in the $2.75-$3.25 range. RBN Energy estimated in July 2015 that at a $2.75 NYMEX price, the Fayetteville would generate returns of just 5% — and that assumed a 25% reduction in drilling and completion costs.

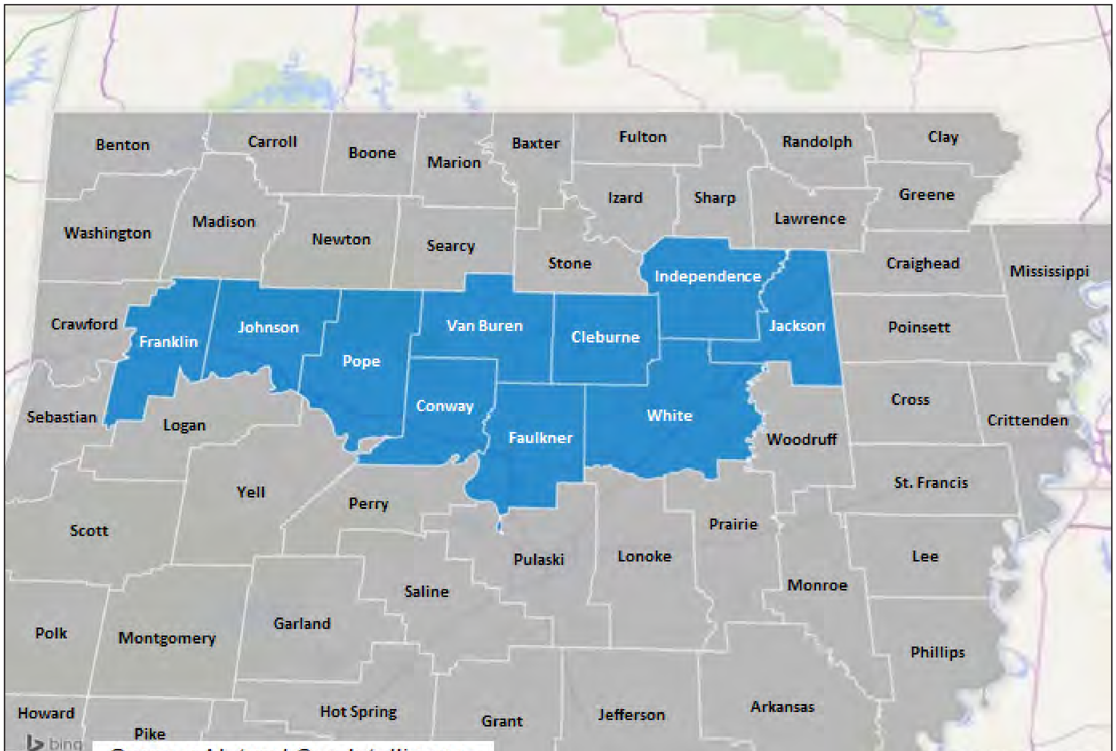


Fayetteville Shale (continued)

Since the time of the aforementioned study, natural gas prices and activity in the Fayetteville have stumbled. In early October 2015, there were just four rigs operating in the Fayetteville, less than half the nine in the play a year earlier. Those four rigs were concentrated in Conway (2), Faulkner (1), and White (1) counties.

Counties

Arkansas: Cleburne, Conway, Jackson, Johnson, Faulkner, Franklin, Independence, Pope, Van Buren, White



Source: Natural Gas Intelligence

Production in the Fayetteville has stagnated to such a degree that FERC in mid-2015 cleared Ozark Gas Transmission LLC to abandon to an affiliate 159 miles of mainline natural gas transmission facilities that had been serving the play (see *Shale Daily*, June 2, 2015). The abandoned facilities were to be leased to Magellan Pipeline Co. LP for conversion to refined petroleum products service.

Low natural gas prices and a consequent pullback from drilling in the Fayetteville have hit Arkansas hard, with gross natural gas severance tax revenue falling to $10.88 million during July-September 2015, a 54% decline from the year-ago period, when it was nearly $23.87 million, according to the Arkansas Department of Finance and Administration (see *Shale Daily*, Oct. 13, 2015).

Local Major Pipelines

Natural Gas: CenterPoint Energy, Fayetteville Express, Mississippi River Transmission, NGPL, Ozark, Texas Eastern Transmission, Texas Gas Transmission, Trunkline

Crude Oil:* Pegasus (ExxonMobil)

NGLs:* ATEX, TEPPCO

*The Fayetteville is a dry gas formation. We have included these pipelines for completeness.

Fayetteville Shale (continued)

FAYETTEVILLE SHALE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Southwestern Energy	888,000	Denali Iron & Disposal	N/A
ExxonMobil (XTO Energy)	792,960	Dynamic Production	N/A
BHP Billiton	400,000	Foundation Energy Management	N/A
BP	135,000	Foxborough Energy Company	N/A
Hall Phoenix Energy	27,000	Lawco Exploration	N/A
Dorchester Minerals	11,464	McCutchin Petroleum	N/A
Panhandle Oil & Gas*	10,635	ReoStar Energy	N/A
Vanguard Natural Resources	5,300	Sequel Energy	N/A
Arrington Oil & Gas	N/A	Terra Renewal, LLC	N/A
Broman Oil & Gas	N/A	Typhoon Energy	N/A
D90 Energy	N/A	XOG Operating	N/A

*Estimate

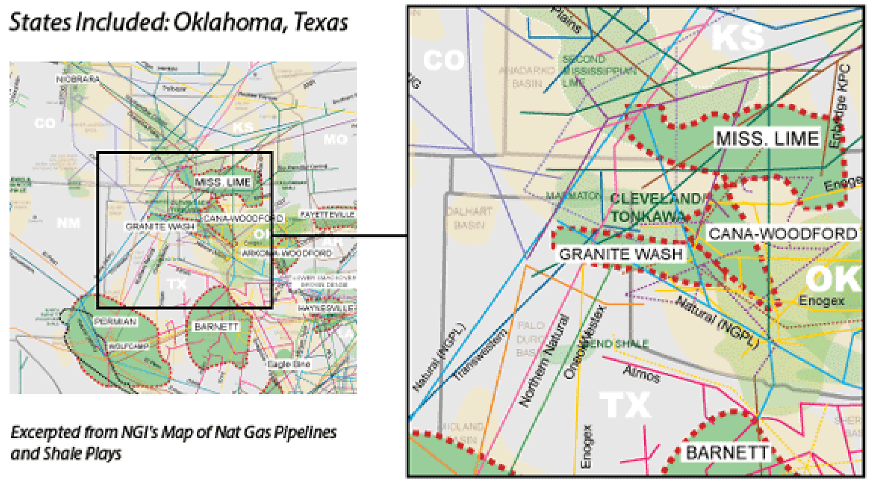
Source: Compiled by NGI from company documents

GRANITE WASH

Background Information

According to the American Association of Petroleum Geologists, the Granite Wash (GW) is a liquids-rich tight sands play about 160 miles long and 30 miles wide, covering parts of Western Oklahoma and the Texas Panhandle. We at *NGI's Shale Daily* place the GW in Hemphill, Roberts, and Wheeler Counties, TX, and Beckham, Custer, Roger Mills, and Washita Counties on the Oklahoma side of the play.

States Included: Oklahoma, Texas

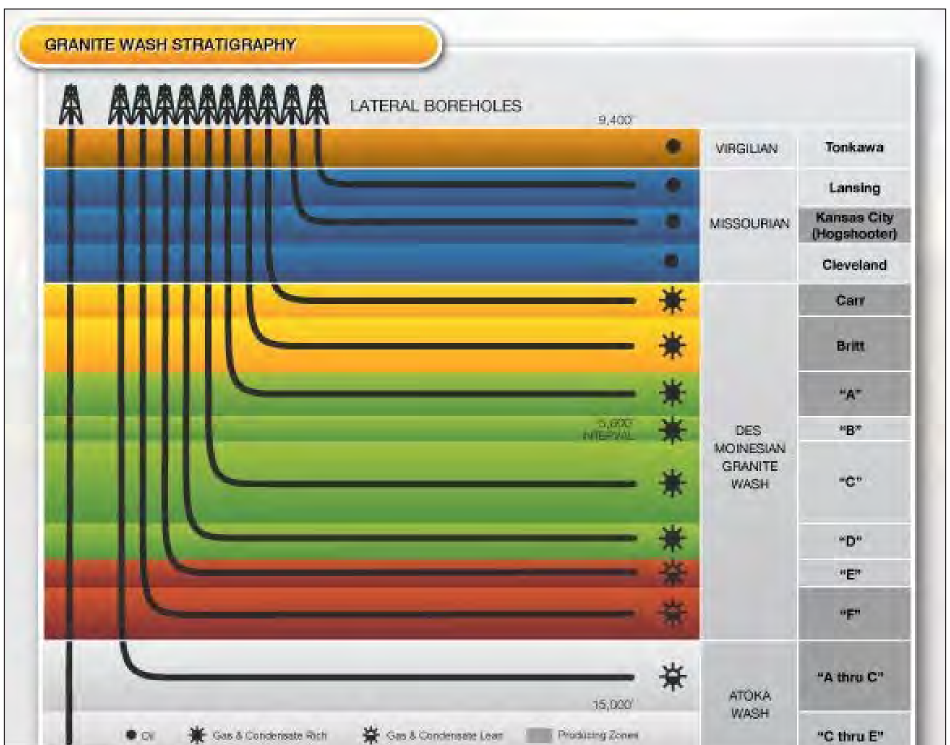


Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

Even though there were already many existing wells in the Granite Wash area, the advent of horizontal drilling combined with hydraulic fracturing has given the decades-old play new life. Most producers' earlier wells were vertical, drilled through the Granite Wash to targets in the Atoka or Morrow formations of the Anadarko Basin.

The Granite Wash is one of the deeper unconventional formations in North America, lying at depths between 10,000'-14,500'. There are a number of layered washes, or zones, within the GW. These zones are listed as "A," "B," and so on, as shown in the chart below.

Gas in the Granite Wash tends to be liquids-rich, with natural gas liquids and condensate typically accounting for 30-40% of well production. Just below the Granite Wash is the Atoka Wash, which has five intervals of its own, but is more of a dry gas formation. Atop the Granite Wash are several oilier intervals, most notably the Tonkawa, Cleveland, Hogshooter, and the Marmaton (not pictured). For more information about these formations, please see the Oklahoma Liquids Plays page.



Source: Linn Energy

Granite Wash (continued)

In 2009, Forest Oil COO J.C. Ridens explained the peculiarities of the Granite Wash. "The overall Granite Wash producing trend was set up by a mountain front originated from northwest to southeast," Ridens said. "The Wichita mountain front became the source of deposition as the erosion of the mountains occurred, and these granitic sediments were deposited in a direction primarily southwest to northeast, and lobes coming off the mountains, thus the term 'Granite Wash.'

"A very basic way to view this depositional environment is to lay your hand on the table, viewing your knuckles as the mountain front and your fingers as the lobes that were subsequently deposited. Much like your fingers, the lobes of the Granite Wash are fairly straight [and] do not exhibit the serpentine nature of mature stream channels, thus making the geology fairly predictable."

Weekly Granite Wash Drilling Rig Count
2/4/11 - 10/9/15

Source: Baker Hughes, NGI calculations

"This significantly increases the value of this production strength," Ridens said of the liquids output. The results give "us further confidence in the huge potential that this play has to offer. We estimate that a horizontal well here will recover about 6.5 Bcfe, compared to about 1.5 Bcfe for a vertical well. This means we are getting about four times the reserves for a little over twice the cost comparing a horizontal to a vertical well."

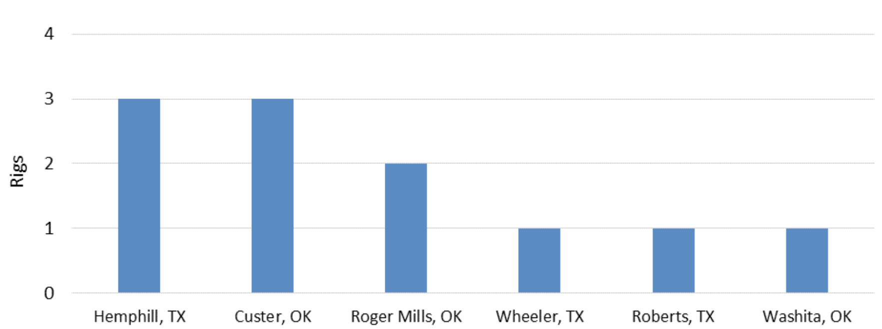
In 2003, operators were drilling wells in the Granite Wash tight-sand gas reservoir with estimated ultimate recoveries of around 1 Bcf/well, according to the Oklahoma Geological Survey. But the switch to horizontal drilling in the play created some eye-popping results. Many initial horizontal wells drilled in 2008-2009 turned in 24-hour IPs in excess of 20 MMcf/d, which were similar to the gaudy results being registered in the Haynesville Shale at the time.

Initial horizontal efforts in the Granite Wash focused more on natural gas, but by 2014 operators had refocused their drill bits toward the shallower oily intervals within the Granite Wash area. In mid-2011, oil-focused rigs accounted for just 18% of the rigs working the play, but that number was closer to 65% in November 2014. More recently, rig counts in the Granite Wash have fallen precipitously. There were just 11 rigs operating in the Granite Wash in early October 2015, an 83% decline from the 64 rigs in the play a year earlier.The Granite Wash had 8.8 Tcf of technically recoverable natural gas as of January 1, 2013, according to the Energy Information Administration.

Some of the largest operators in the Granite Wash are Apache, Chesapeake Energy (both directly and via its Granite Wash Trust), ConocoPhillips, Devon Energy, EnerVest, Marathon Oil, Sabine Oil & Gas, and Samson Resources.

Operators in the play haven't been immune to the pitfalls associated with depressed commodities markets: in 2015, Houston-based Sabine, struggling with heavy debt and deflated oil/gas prices, filed for Chapter 11 bankruptcy protection (see *Shale Daily*, July 15, 2015). The independent, which also has significant operations in the Cotton Valley Sand and Haynesville Shale in East Texas, the Eagle Ford Shale in South Texas and the Haynesville in North Louisiana, expected to continue operations and "emerge with increased financial flexibility and a sustainable capital structure that will enable us to devote capital to grow our business," said CEO David Sambrooks. And in November 2015, Chesapeake Granite Wash Trust,

Breakout of Granite Wash Rigs By County, 10/9/15



Source: Baker Hughes, NGI's Shale Daily calculations

Granite Wash (continued)

which owns royalties in Chesapeake wells in the play, cut its quarterly dividend by 9.7%.

Credit Suisse consistently listed the Granite Wash as one of the highest breakeven plays in North America in 2015, with a breakeven NYMEX price of ~$5.75/MMBtu. Furthermore, RBN Energy estimated in July 2015 that the typical Granite Wash well generated negative rates of return at that time, in the order of -2% to -6%.

Counties

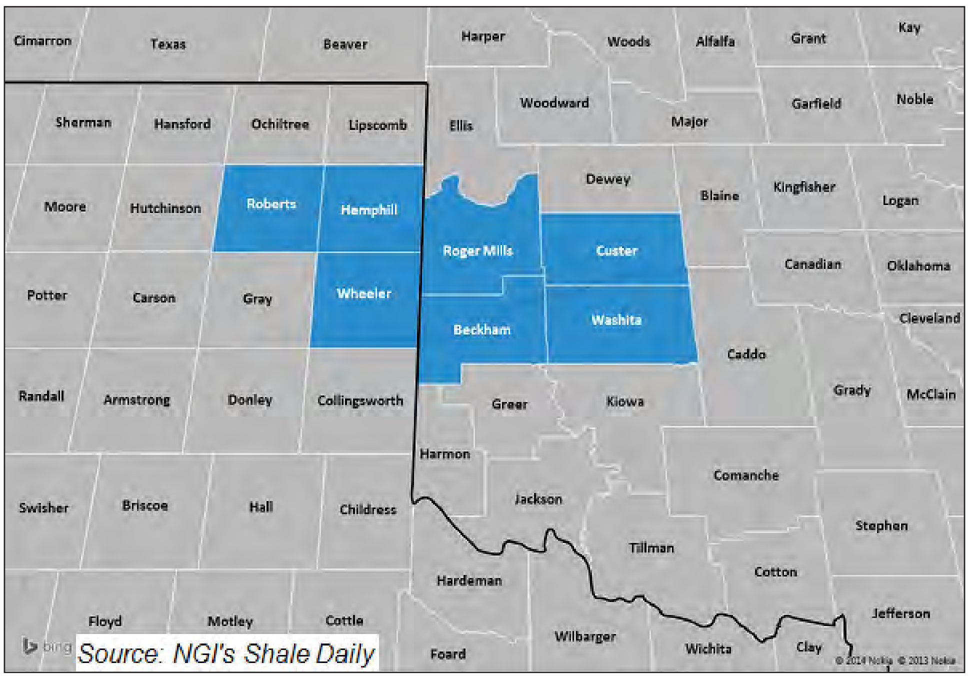
Oklahoma: Beckham, Custer, Roger Mills, Washita
Texas: Hemphill, Roberts, Wheeler

Local Major Pipelines

Natural Gas: ANR, CenterPoint Energy, El Paso, Enogex, NGPL, Northern Natural, OGT, Oneok Westex Transmission, Panhandle Eastern, Southern Star, Transwestern

Crude Oil: Glass Mountain, Phillips 66

NGLs: Blue Line (ConocoPhillips), Southern Hills



Source: NGI's Shale Daily

GRANITE WASH NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Apache	418,000	Hancock Leon	N/A
Chesapeake Energy	334,000	Indigo II Minerals	N/A
EnerVest	95,000	Investors Resources Corp	N/A
Devon Energy	66,000	JCB II Enterprises, LLC	N/A
Marathon Oil[1]	57,000	JMA Energy Company	N/A
Samson Resources	57,000	Jo-Allyn Oil Co Inc	N/A
Unit Corporation	50,100	Jones L E Operating Inc	N/A
Templar Energy	42,000	K C Resources Inc	N/A
Sabine Oil & Gas	36,900	Kaiser Francis Oil	N/A
Chesapeake Granite Wash Trust	26,400	Key Production Company Inc	N/A

Granite Wash (continued)

GRANITE WASH NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Panhandle Oil & Gas	15,885	Kirkpatrick Oil Company Inc	N/A
Penn Virginia	9,800	KKR	N/A
Jones Energy	6,617	L C B Resources LLC	N/A
Vaalco Energy	1,120	Laddex, LTD	N/A
Parallel Energy	400	Latigo Oil And Gas Inc	N/A
Aghorn Operating	N/A	Le Norman Operating LLC	N/A
All Exploration LLC	N/A	Legacy Reserves	N/A
Amarillo Exploration, Inc.	N/A	Lighthouse Oil & Gas LP	N/A
Arrow Oil & Gas	N/A	Lime Rock Resources	N/A
Atchley Resources Inc	N/A	Little, Quintin Co.	N/A
Athena Energy	N/A	Lorentz Oil & Gas LLC	N/A
Barbour Energy Corporation	N/A	Maduro Oil & Gas Llc	N/A
Blake Production Company Inc	N/A	Magnum Energy Inc	N/A
Blue Grass Energy	N/A	Marion Energy Inc	N/A
Blue Water Energy Solutions	N/A	Merit Energy Company	N/A
BP	N/A	Mewborne Oil Co.	N/A
Bracken Operating	N/A	MSG Oil & Gas	N/A
Breitburn Operating Lp	N/A	NEAS Operating	N/A
BRG Lone Star LTD	N/A	Oil Tactics of Oklahoma	N/A
Burlington Res Oil & Gas Lp	N/A	Okland Oil Company	N/A
Buttram Operating Company	N/A	Olympia Oil Inc	N/A
Caerus Oil and Gas	N/A	O'Neal Oil Co.	N/A
Carbon Economy	N/A	Overflow Energy, LLC	N/A
Chaco Energy Company	N/A	PEBA Oil & Gas	N/A
Chapparal Energy	N/A	Princess Three Operating LLC	N/A
Chevron	N/A	Quantum Resources Management LLC	N/A
Choice Exploration	N/A	Questa Energy Corporation	N/A
Cholla Petroleum	N/A	Range Resources	N/A
Cimarex Energy	N/A	Red Rocks Oil & Gas Operating LLC	N/A
Cirrus Production Company	N/A	Rimrock Gas Company	N/A
Comanche Exploration Co	N/A	Rio Petroleum, Inc	N/A
ConocoPhillips	N/A	Rosewood Resources	N/A
Corlena Oil Co.	N/A	Sabre Operating Inc	N/A
Crawley Petroleum Corporation	N/A	Samson Lone Star	N/A
Creed Operating Co	N/A	Sanguine Gas Exploration	N/A
Crest Resources	N/A	Stamic Oil	N/A
Crown Petroleum	N/A	Stephens Production Co	N/A
Cummings Oil Company	N/A	Sundown Energy Lp	N/A
D.W.P. Production	N/A	Sunlight Exploration	N/A
Diamond S Energy Co.	N/A	Sweetwater Exploration Llc	N/A
D-Mil Production Inc	N/A	Tack Operating LLC	N/A

Granite Wash (continued)

GRANITE WASH NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Dominion Oklahoma Texas E&P	N/A	Texakoma Operating	N/A
Dorchester Minerals	N/A	Tom Coble Oil & Gas	N/A
Driftwood Storage LLC	N/A	Turner Energy Services	N/A
Duncan Oil Properties Inc	N/A	Ward Petroleum	N/A
Eagle Rock Energy	N/A	White Stone LLC	N/A
Exok Inc	N/A	Whiting Petroleum	N/A
ExxonMobil/XTO Energy	N/A	Wildhorse Operating Co.	N/A
Faulconer Vernon E Inc.	N/A	Williford Energy Company	N/A
Fortay, Inc.	N/A	Wynn-Crosby Operating LP	N/A
Frontier Alliance LLC	N/A	Zeiders Bros Oil & Gas Co Llc	N/A
Gulf Exploration LLC	N/A	Zenergy Inc	N/A
H&L Operating Co. LLC	N/A	Zephyr Lone Star	N/A
Hall Edward L	N/A		

[1] Includes Granite Wash and other Pennsylvanian Sands plays.

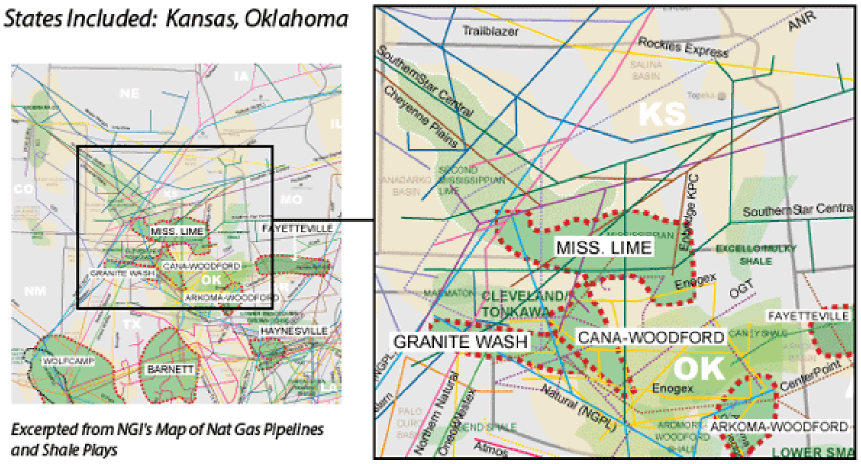
Source: Compiled by NGI from company documents

MISSISSIPPIAN LIME

Background Information

The Mississippian Lime (ML), a carbonate formation that primarily produces oil, underlies a large portion of Northern Oklahoma and Southern Kansas. The formation has been drilled vertically since the 1940s, with its first horizontal well drilled in 2007. The play lies at a fairly shallow depth (4,000-7,000 feet), and it features different drilling characteristics from shale and tight sands formations. Carbonate plays tend to be more permeable, which reduces the amount of drilling horsepower required to navigate through the rock. This, along with its shallower depth, tends to reduce drilling costs, everything else being equal.

States Included: Kansas, Oklahoma



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

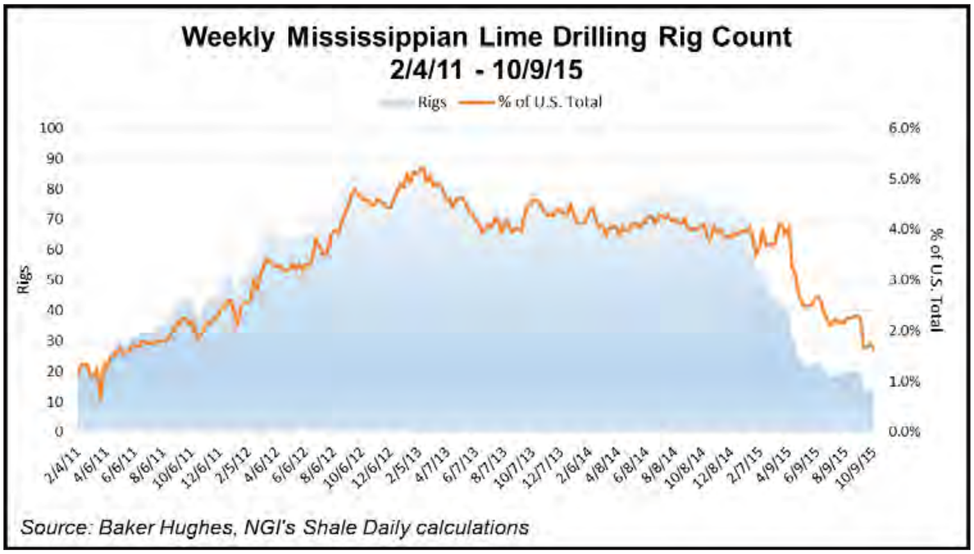
Oklahoma, one of the country's most reliable oil and gas producers, experienced a big bump in production starting in 2005 with the advent of unconventional drilling. With a stable horizontal rig count between 2011-2014, light oil production increased to nearly 300,000 b/d from less than 50,000 b/d, mostly driven by an activity shift from shale gas toward liquid-rich areas. In 2009, Woodford Shale activity across gassy Arkoma and Anadarko basins accounted for 60% of total Oklahoma unconventional drilling, but it dropped to 20% in 2014, according to Rystad Energy.

As drilling activity plunged in 2015, the "Miss Lime," as it is often called, experienced one of the sharpest declines in rig counts of all tight oil plays. Baker Hughes Inc. reported as of early October 2015 the ML rig count had fallen to 13 versus 79 a year earlier — a dropoff of 84%. 10 of those 13 rigs were working the Oklahoma side of the play. With relatively shallow well depths, oil prices under $50/bbl may not support full economic development of the play. However, many operators were making the play work even under low prices by drilling adjacent interval wells, which are numerous across the massive Oklahoma landscape.

As of October 2015, 60% of the activity was "attributable to Mississippian Lime and Woodford Shale activity across the Mississippian Trend, both with approximately 40% of light oil content, which is high for Oklahoma shale plays," Rystad noted. "Besides the shift toward liquids, Oklahoma also experienced a common shale industry trend: increased well completion intensity with positive impact on well productivity."

Well productivity has improved considerably because of a focus on the sweet spots of the Miss Lime between 2014 and 2015. Newfield Exploration Co.'s "well performance improvements were caused by both 50% increase in completion intensity and focus on the oil window of the Anadarko Basin (mainly Woodford Shale)," said Rystad.

Chesapeake Energy Corp. considers Miss Lime to be a big part of its liquids program. "In the Miss Lime, the teams have been continually outperforming in the area," Senior Vice President Jason Pigott said in 2015. "It's one area that every time we drill a well, it continues to exceed our expectations. Even at $3.00 gas and $50.00 oil, we're getting an 18% rate of return on the Miss Lime in our core, so they're really strong returns" (see *Shale Daily*, Feb. 25, 2015).



Source: Baker Hughes, NGI's Shale Daily calculations

Mississippian Lime (continued)

Chesapeake was reducing costs in the ML by targeting other intervals, including the Oswego and Meramec, at the same time. Among just those three intervals, Chesapeake has a nearly 400,000-acre position, Pigott said in November 2015 during a third quarter conference call. The company's first two 10,000-foot wells were drilled in the ML during the third quarter of 2015 for an incremental $200,000 of drilling.

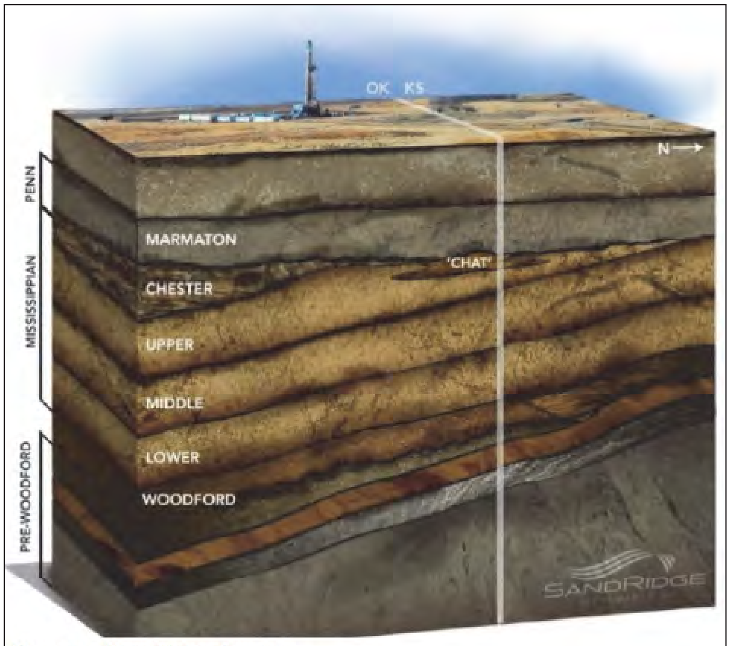
"So those economics will be competitive with Meramec, Oswego, any other formation out there," Pigott said. Wells in the Meramec had fallen to about $6.9 million from $7.1 million. By lining up ML wells while drilling other intervals, Chesapeake could "have a whole rig line of wells to do...That takes the curve down by 35%, if that is a successful program." Based on Chesapeake's internal breakeven prices across the onshore, payback in the ML "can be at two years or less."

Continental Resources Inc., Newfield Exploration Co., Devon Energy Corp. and Midstates Petroleum Inc. were among some of the many operators keeping activity high in ML and surrounding intervals during 2015. Drilling efficiencies were telling the tale, with costs dropping and better output from every new well.

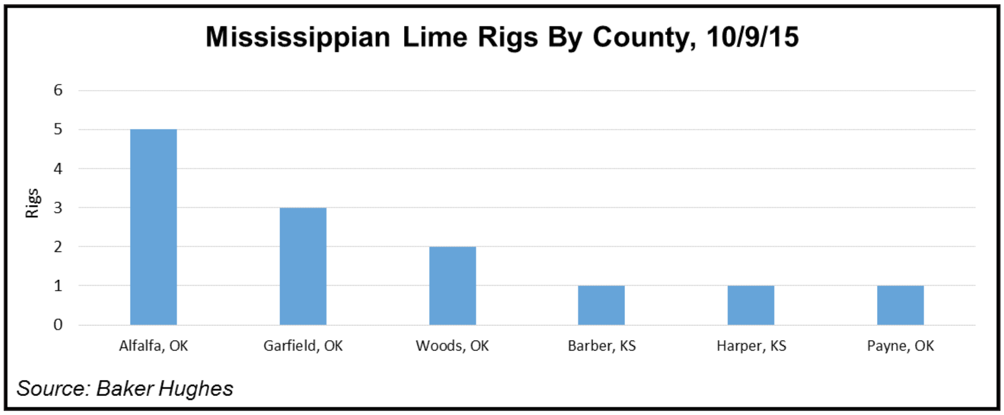
Between July and September 2015, Midstates Petroleum's ML assets were producing 27,029 boe/d. Through Oct. 26, 2015, the company had 275 wells on production for more than 30 days with an average peak 30-day production rate of 557 boe/d. Three rigs were drilling in its horizontal well program in Woods and Alfalfa counties, OK for most of the third quarter. Midstates also spud a total of 19 wells, of which eight were producing, eight were awaiting completion and three were drilling at the end of the quarter. The company also brought 19 fracture stimulated horizontal wells online. In early November 2015, the company had surpassed its year-end well cost target of $3.3 million, with average wells costing $3.1 million. At that price, "Midstates is generating rates of return in excess of 35% at current strip pricing."

Counties that make up the Northern Oklahoma portion of the Miss Lime are also prospective for several other stacked oilier intervals, including the Marmaton, Chester, Woodford Shale, and Hunton Limestone (see above).

Most operators' horizontal drilling activity has centered in Northern Oklahoma thus far, with a smattering of horizontal in Comanche, Barber, and Harper counties in Kansas along the Kansas/Oklahoma border, and a few others in the Northwest Kansas portion of the play.



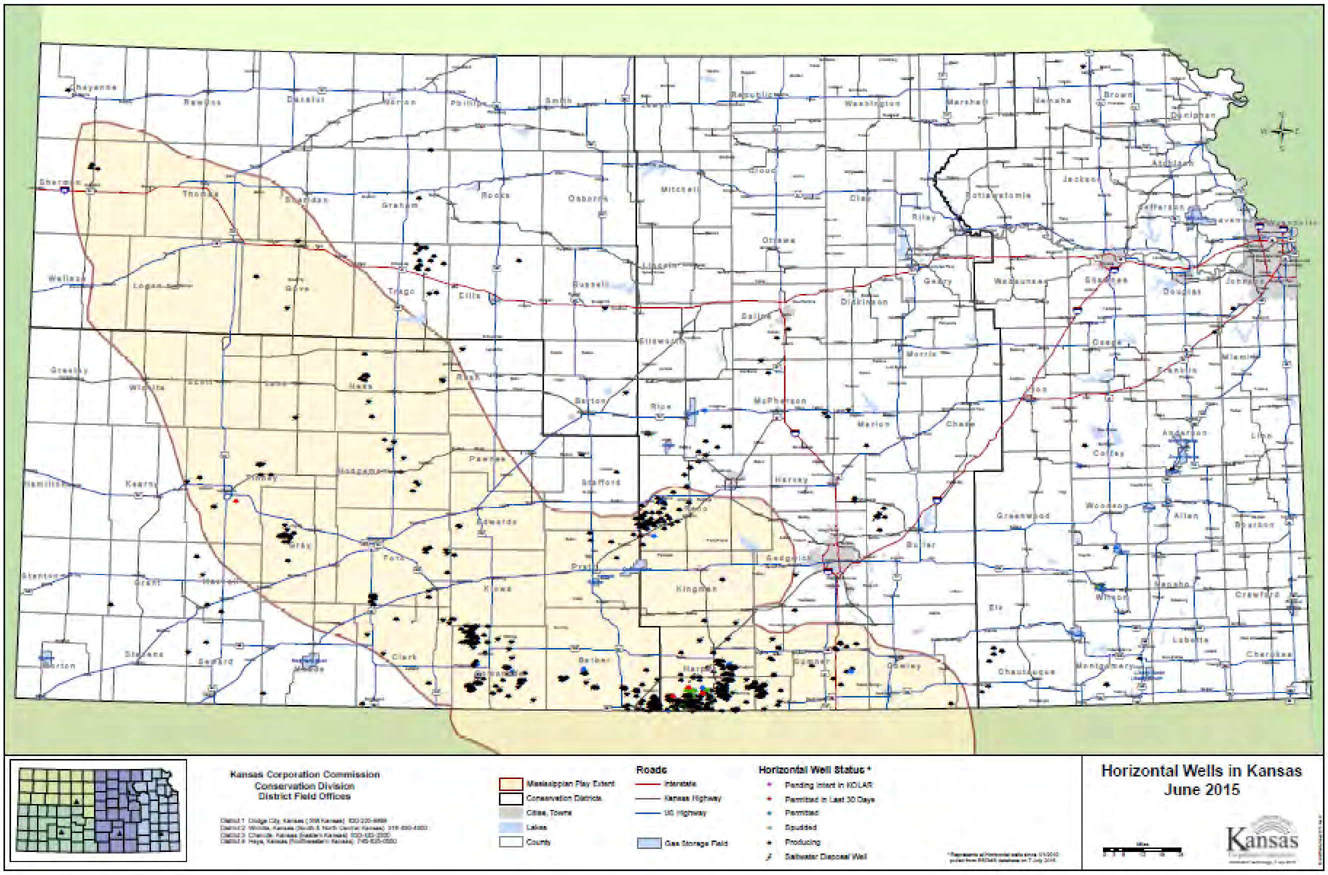
Source: Sandridge Energy



Source: Baker Hughes

The following map illustrates Kansas horizontal drilling activity through July 2014, along with those counties the Kansas Corporation Commission deems to be part of the ML fairway. However, many of those Kansas counties that are not along the Kansas/Oklahoma border may not be conducive for horizontal drilling, at least not in any meaningful economic quantities. Several major operators have abandoned or sold their ML acreage in Kansas within the last few quarters, including Apache Corp., Encana Corp., and Royal Dutch Shell plc.

Mississippian Lime (continued)



For every "good" well that's been drilled into the ML, there have been 10 "bad ones," Longfellow Energy President Todd Dutton told NGI in April 2014. Similarly, Wood Mackenzie upstream analyst Samir Sharma agreed in 2014 that at that time there had been more flops than not in the ML, telling NGI that "results haven't matched expectations." However, it is still far too early to declare the drilling in these stacked intervals a ringing success. The stacked formations within the ML fairway are so varied and the pilots are still so new that determining whether there's enough oil and liquids for the taking remains elusive. It likely will take a few more years – and better prices – before there's a move to true manufacturing.

Oklahoma City-based private Longfellow, also an ML producer, placed its chips on its Nemaha Project, a stacked oil play in Oklahoma's Garfield and Kingfisher counties. The Midcontinent formations are spread within the Central Kansas Uplift and the Nemaha Ridge, which runs between the Sedgwick and Cherokee basins in Kansas. To the south of the Los Animas Arch is the gassy Hugoton Embayment, which is north of the Oklahoma border and the prolific Anadarko Basin. Those stacks of formations are requiring science and patience, and upfront investments.

The ML is one thing. The Woodford is another. In between, "we've got a different reservoir, a different rock dynamic," said Dutton. The Kansas border is where the whispers about the oil-rich content first were heard. "And those are the counties that were getting a lot of activity. Those also are the counties where it's turning out that it's noncommercial, really...The stack play is not in a high water cut, like the Mississippi Lime," Dutton said. "In large respects, the Mississippi is...really more of a conventional reservoir, getting areas where there is a high oil saturation..."

In the stacks, producers can use unconventional drilling to their advantage by drilling down and across, fracturing through the many layers. The stacked play is varied throughout. Producers can't necessarily produce through a lateral in the Woodford or between the ML and the Woodford, said Dutton. It requires more finesse. Where ML is stacked with the Woodford, production can flow through one unit, he explained. "You get to produce out of one flow unit, or at least they are related to each other, because they sit right on top of each other."

"The stacks are good targets. It's not more expensive to develop, but yes, you have to drill more wells in the stacked formation," Dutton noted. The company's wells in 2014 cost about $4 million

Mississippian Lime (continued)

for a lateral about 4,500-5,000 feet. Operators were working to hold leases by production, but once results are more transparent, "that's when we go to manufacturing stage and make money. You drill laterals as close as you can to do it. One in the Woodford, the next in the Mississippi, then move over..."

It was taking up to 25 days to complete one well in 2014, but efficiencies were bringing the time down. The stacked intervals have been found to be a mix, some areas 55% weighted to oil, 45% to gas, another piece 60-40.

"It starts off a little more oily, and over time, it's more gassy," Dutton said. At the same time the pilots are being drilled, infrastructure is underway. "It's prudent" to get all of the infrastructure in place before the true manufacturing begins. "It's kind of like jumping off a cliff. You can't turn around easily and you've got to know what you're doing." Once the infrastructure is in, however, including for saltwater disposal, "it will be hard for anyone to compete with you," he said.

There's no land grab in sight, in part on low prices, but mostly because acreage already is held by production because it overlaps into the Cana-Woodford formations.

Counties

Note: The list and map on the next page include all counties that may be prospective for the Miss Lime, but in reality, horizontal drilling has been focused mostly in Oklahoma counties, with a handful in Kansas along along the KS/OK border.

Kansas: Barber, Butler, Chase, Chautagua, Clark, Coffey, Comanche, Cowley, Dickinson, Edwards, Elk, Finney, Ford, Gove, Grant, Gray, Greenwood, Harper, Harvey, Haskell, Hodgeman, Kearny, Kingman, Kiowa, Lane, Logan, Lyon, Marion, McPherson, Meade, Montgomery, Morris, Ness, Pawnee, Pratt, Reno, Rice, Rush, Saline, Scott, Sedgwick, Seward, Sheridan, Sherman, Stafford, Stevens, Sumner, Thomas, Trego, Wallace, Wichita, Wilson, Woodson

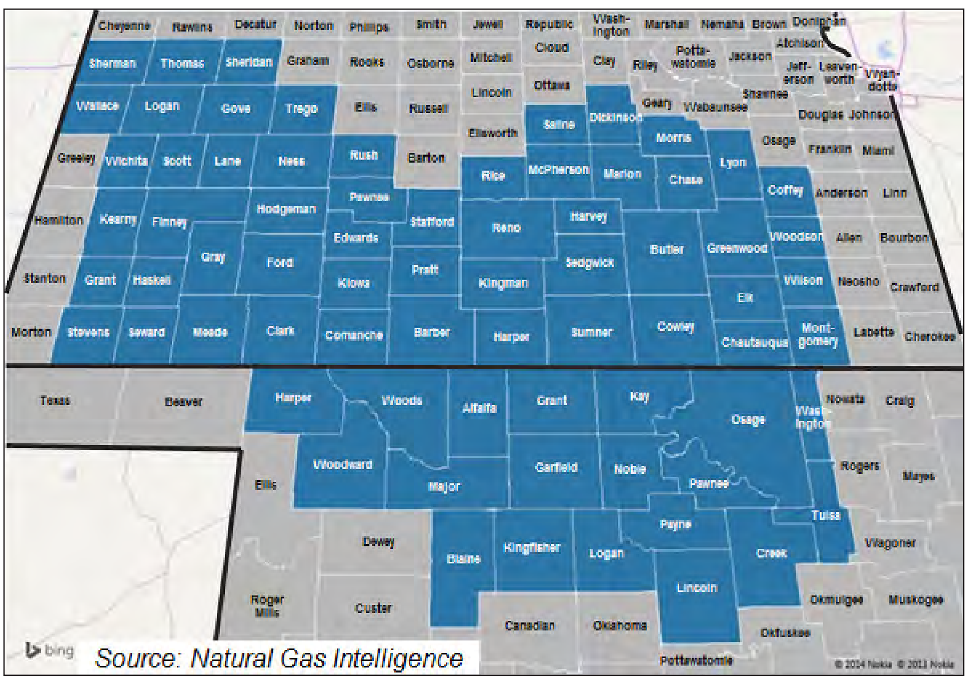
Oklahoma: Alfalfa, Blaine, Creek, Garfield, Grant, Harper, Kay, Kingfisher, Lincoln, Logan, Major, Noble, Osage, Pawnee, Payne, Tulsa, Washington, Woods, Woodward

Local Major Pipelines

Natural Gas: ANR, CenterPoint Energy, Cheyenne Plains, Enbridge KPC, Enogex, NGPL, Northern Natural, OGT, PEPL, Southern Star, Tallgrass

Crude Oil: Cushing to Whiting (BP), Glass Mountain, Keystone, Midcontinent (Ozark), Osage (Magellan), Pony Express, Spearhead, White Cliffs

NGLs: Blue Line (ConocoPhillips), South Leg (Enterprise), Southern Hills, Wattenberg (DCP)



Source: Natural Gas Intelligence

Mississippian Lime (continued)

MISSISSIPPIAN LIME NET ACREAGE POSITIONS*
Last Updated December 2015

Company	Net Acres	Company	Net Acres
SandRidge Energy	1,850,000	Armada Oil	3,200
Apache Corporation	580,000	Doxa Energy	2,900
Devon Energy	500,000	Pryme Energy	2,320
Samson Resources Company	304,000	American Petro-Hunter	2,000
Chesapeake Energy[1]	284,000	Parallel Energy Trust	650
Bluescape Resources	175,000	Calyx Energy	N/A
Range Resources	160,000	Cheyenne Exploration	N/A
Unit Petroleum	153,000	CMX Oil & Gas	N/A
Gastar[2]	126,000	D & Z Exploration, Inc.	N/A
American Energy Partners	120,000	Dorado E&P Partners, LLC	N/A
Atinum Partners	113,000	Eagle Energy of Oklahoma	N/A
Petro River Oil	103,953	Eagle Oil & Gas	N/A
Sullivan & Co.	95,514	Halcon Resources	N/A
Midstates Petroleum	80,700	Lasso Energy LLC	N/A
Redfork Energy	75,000	Lesback Oil Production	N/A
Territory Resources LLC	67,401	Marathon Oil Company	N/A
Longfellow Energy	63,000	McElvain Energy	N/A
Chapparal Energy	48,500	Orion Exploration	N/A
Sundance Energy	29,185	Pablo Energy II	N/A
Plymouth Exploration	26,000	PayRock Energy	N/A
Atlas Resource Partners	20,000	Petrodyne Resources	N/A
Fairway Resources	20,000	Reeder Operating	N/A
Natural Resource Partners LLC	19,200	Repsol YPF	N/A
AusTex Oil Limited	18,485	Samuel Gary Jr. and Assoc., Inc	N/A
Dynamic Production Inc	18,000	Sinopec	N/A
Ring Energy	17,016	Source Energy Midcon LLC	N/A
Roxanna Oil	15,000	Spyglass Energy	N/A
Slawson Exploration	13,500	Strat Land Exploration Corporation	N/A
National Fuel	9,300	Stratex	N/A
Special Energy	8,000	Tapstone Energy	N/A
Circle Star Energy	6,120	Tug Hill Operating	N/A
EnerJex Resources	5,287	U.S. Energy Development	N/A
Magnolia Petroleum	4,108	Vitruvian Exploration II	N/A
Evolution Petroleum	3,978	Woolsey Operating Co. LLC	N/A
Osage Exploration	3,757		

*Many of the acreage positions in this table are also prospective for multiple "stacked" formations, such as the Marmaton, Chester, Woodford, and Hunton formations. These stacked areas sometimes go by other names, such as Devon's Missippian-Woodford Trend, Longfellow's Nemeha Ridge acreage, Gastar's Hunton Limestone oil play, and American Energy Partners' CNOW area.

[1]Also have 71,000 net acres in the Mississippian/Meramec

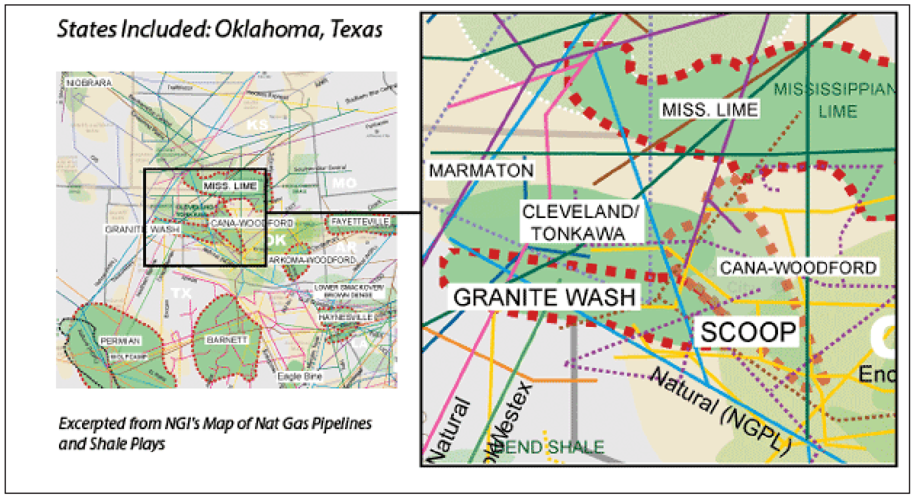
[2]Hunton Limestone position.

Source: Compiled by NGI from company documents

OKLAHOMA LIQUIDS PLAYS

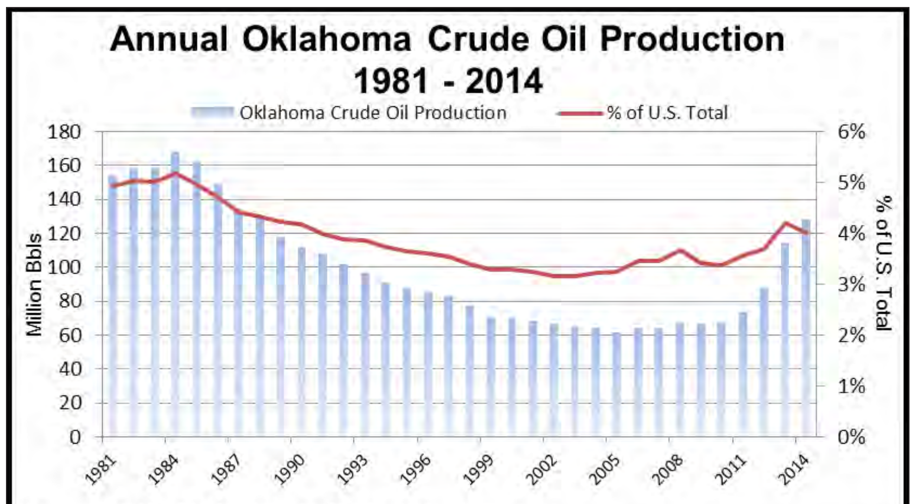
Background Information

Oklahoma, whose natural gas, oil and liquids formations are spread far and wide, is one of the top five of U.S. producing states with some of the largest oilfields. Between July 2014 and July 2015, Oklahoma also produced more natural gas than Louisiana, New Mexico or Wyoming. Best known by producers are the Anadarko and Ardmore basins, built by a plethora of stacked reservoirs that extend from the north to the south, east to west, and deep beneath the earth.



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

As producers moved from gassy targets to take advantage of higher oil prices about 2010, a lot of renewed prospecting began in the Sooner State. Oil production increased 74% from 2011-2014 to 128 million bbl, rising by nearly 300,000 b/d, according to the U.S. Energy Information Administration.



Source: EIA, NGI's Shale Daily calculations

Even with the rig count steadily in decline during 2015, Oklahoma still had surpassed its 2011 oil production by July 2015 with 73 million bbl. According to Wood Mackenzie Ltd., Oklahoma oil production could double between 2014 and 2020.

Operators have been allowed to apply their own names to producing reservoirs in the state, which has led to thousands of "inconsistently" defined units, according to the Oklahoma Geological Survey. The state is divided into six geologic regions: the Anadarko Basin, Cherokee Platform, Wichita Uplift, Ardmore Basin, Arbuckle Uplift and Ouachita Mountain Uplift. However, there are names within the names, so keeping track of where production is coming from requires a map. The biggest target of late has been the Anadarko and its stacked reservoirs, where the spotlight often has been on the Woodford Shale.

Improved drilling techniques are tapping into reservoirs today from Oklahoma's carbonate, limestone, sand and shale in other formations, which bear the names Atoka, Caney, Tonkawa, Cleveland, Marmaton, Meramec, Springer, Hunton Lime, Hogshooter and Osage, to name but a few. The Mississipian Lime, which extends into Kansas, and the Granite Wash, are further detailed in other sections.

Producers have delineated their prime targets into areas better known by their acronyms. The SCOOP covers the "South Central Oklahoma Oil Province," while north-central Oklahoma's STACK represents the "Sooner Trend (oilfield) Anadarko (basin), mostly in Canadian and Kingfisher (counties)." CNOW — Central North Oklahoma Woodford — is another acronym, while the name "Mississippian-Woodford trend" also is used.

Operators are finding it more efficient to drill within several targets at a time, which reduces costs, and the rewards may be big. Wood Mackenzie said within Oklahoma, producers primarily are working nine sub-plays, rich enough to compete with the best areas of the Bakken and Eagle Ford shales (see *Shale Daily*, Feb. 13, 2015). During 2015, as hundreds of drilling rigs were dropped, the STACK became one of the few areas in the United States where the rig count actually increased. About 25 rigs were running specifically

Oklahoma Liquids Plays (continued)

on STACK targets in November 2015, 20 of which we believe were targeting the Meramec.

ExxonMobil Corp.'s XTO Energy Inc. had one of the biggest leaseholds across Oklahoma at the end of 2014 with an estimated 1.153 million acres and gross production of 12,000 b/d of oil and 396 MMcf of natural gas. It operated in 25 Oklahoma counties. The Ardmore-Woodford dominated the work, but it also has branched out into other formations.

Newfield Exploration Co. (NFX), considered one of the top operators, said net daily production from the Anadarko had, for the first time in 3Q2015, eclipsed the combined production from its other U.S. assets. "This is quite a milestone considering that the SCOOP and STACK plays literally started from scratch just four years ago," CEO Lee Boothby said in November 2015.

The Oklahoma Corporation Commission said the top producers in the state from 2008 to 2015 were SandRidge Energy Inc., 6,732 wells drilled and completed; Chesapeake Energy Corp., 6,098; Devon Energy Corp., 4,894; Charter Oak Production Co. LLC, 3,031; and New Dominion LLC, 1,730.

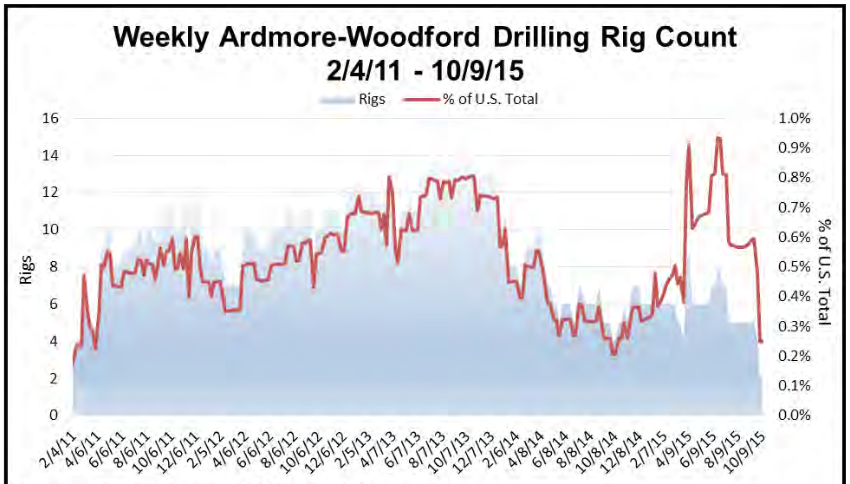
One downside to the increase in drilling activity within Oklahoma in recent years has been increased concerns about induced earthquakes. The Oklahoma Corporation Commission (OCC) has implemented an action plan to reduce the risk of such earthquakes in the Cushing, OK, area by changing the operations of some oil/natural gas wastewater disposal wells (see *Shale Daily*, Oct. 19, 2015). The issue is not new, and the OCC has been eyeing for some time injections into the Arbuckle formation as the potential cause of the quakes (see *Shale Daily*, Oct. 31, 2014; July 7, 2014).

Ardmore-Woodford Shale

The Ardmore-Woodford Shale, which extends across Bryan, Carter, Johnston, Love, and Marshall counties, is dominated by ExxonMobil, which owns more than 270,000 net acres. During the company's annual investor day in March 2015, CEO Rex Tillerson had said the company could make money in the Ardmore, Permian and Williston basins at an oil price of $55.00/bbl (see *Shale Daily*, March 5, 2015). Output from the three plays is set to double through 2017.

ExxonMobil was planning to increase volumes in the Ardmore by 36% a year between 2014 and 2017, but low oil prices had put a crimp on forecasts by the end of 2015 (see *Daily GPI*, Oct. 30, 2015).

There were as many as 14 rigs drilling the Ardmore in 2013, but those were down to just two in early October 2015. Both those rigs were operating in Carter County.



Source: Baker Hughes, NGI calculations

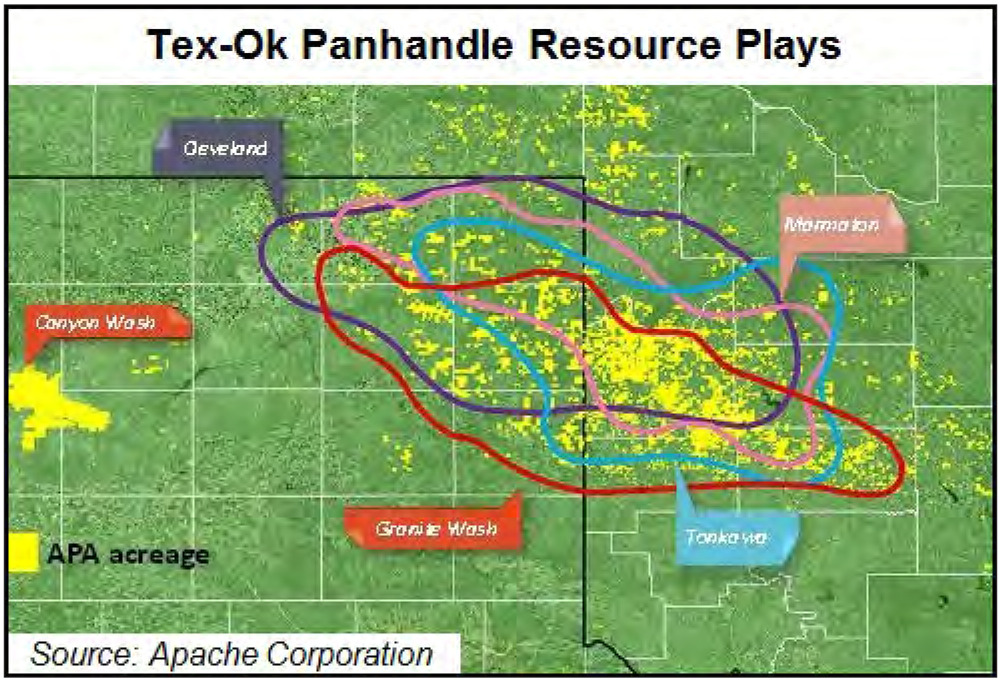
Cleveland/Tonkawa

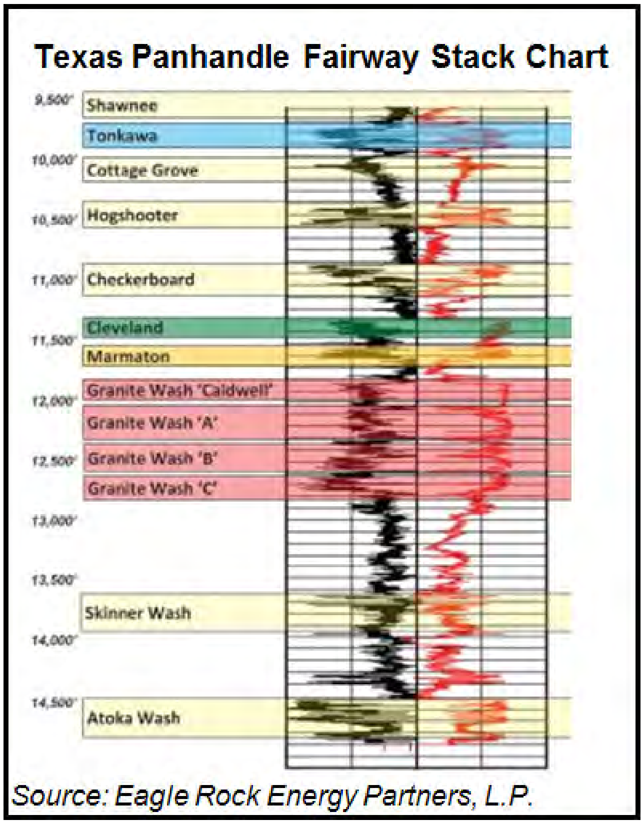
The Cleveland and the Tonkawa are actually two distinct and separate sandstone formations, but because they are at similar depths and largely overlap, many operators simply combine them into a single play. We believe the Cleveland/Tonkawa is most prospective in Oklahoma's Custer, Dewey, Ellis, and Roger Mills counties, and in Hansford, Hemphill, Lipscomb, and Ochiltree counties in Texas.

The Tonkawa is the shallower of the two horizons, with a vertical depth of roughly 7,500-13,000 feet. The Cleveland lies about 1,500 feet deeper on average. We believe production in this area tends to be 50% oil, 25-35% NGLs, and the remainder natural gas.

At the start of 2013, an estimated 165 operators were reporting production from either Oklahoma's Cleveland or the Tonkawa formations, according to the Oklahoma Corporation Commission, making this one of the heaviest targeted areas in the state. In its November 2015 investor presentation, Jones Energy Inc. listed the top 10 operators in the Cleveland in terms of undrilled locations as BP plc, Jones, Mewbourne Oil Co., Apache Corp., Chesapeake Energy Corp., Courson Oil & Gas Inc., EOG Resources Inc., Midstates Petroleum Co. Inc., EnerVest Ltd., and Templar Energy LLC.

Oklahoma Liquids Plays (continued)





Hogshooter

The Hogshooter formation, also known as the Missourian Wash, is considered by some to be part of the Granite Wash play, an area we describe in more detail in our separate Granite Wash section.

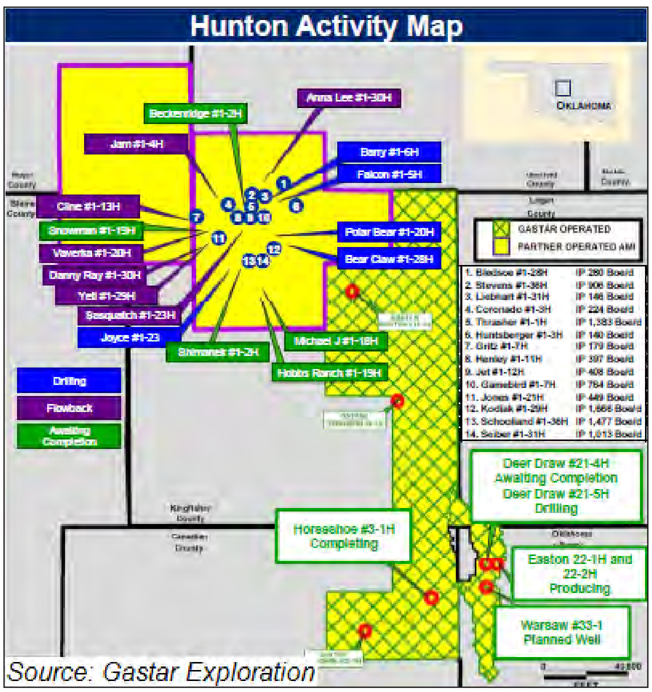
We believe roughly 70% of the production from Hogshooter wells is crude oil, and given the disparity between crude oil and natural gas prices, that would explain the surge in oil rigs that moved to the Granite Wash before oil prices fell in 2014-2015.

Oklahoma Liquids Plays (continued)

The Hogshooter, considered an emerging area in 2013, got little notice as oil prices began to sink in 2014 and beyond. Linn Energy LLC in early 2014 said it would drill 60 horizontals during 2014 to target the Mayfield area of Oklahoma. Organic production was forecast to grow by 3-4%, which at midpoint would have been about 1,085 MMcfe/d in 1Q2014 and an average of 1,105 MMcfe/d for the full year. However, with commodity prices tanking, there was little news from Linn regarding the play in 2015.

Hunton Lime

The Hunton Limestone is one of the deeper formations of the Oklahoma oil and gas layer cake, lying beneath the Woodford Shale. For that reason, operators typically do not include the Hunton as part of the STACK play, but the Hunton certainly is prospective across much of the STACK fairway.



Source: Gastar Exploration

We believe Gastar Exploration Ltd. is the publicly traded company most associated with this play, and the company has been drilling operated horizontal wells in Canadian, Kingfisher and Oklahoma counties, and participating in non-operated horizontal wells in Blaine, Kingfisher and Major counties. During the third quarter of 2015, Gastar brought online one Upper Hunton and two Lower Hunton wells and had completed a third.

According to Gastar's November 2015 investor presentation, the Upper Hunton has an estimated ultimate recovery of 347,000 boe with a 75% oil cut, which at oil prices at the time generated a 36% internal rate of return (IRR) on drilling/completion (D&C) costs of \$3.3 million. The Lower Hunton has a higher EUR at 425,000 boe, with an 82% oil cut, and a higher \$5.0 million D&C cost per well, generates a lower 22% IRR.

Marmaton

As shown in the earlier map the Marmaton formation traverses much of the same portions of Texas and Oklahoma as does the Cleveland/Tonkawa and Granite Wash. However, we note that this is the Marmaton Wash formation, which is akin to the Granite Wash. This is not to be confused with the Marmaton Lime oil play, which is a carbonate formation located primarily in Beaver County, OK, and Ochiltree County, TX. These two counties are not part of the Granite Wash fairway.

Much of the drilling in the Marmaton Lime has been done via vertical wells, but several operators said the area could be a candidate for horizontal drilling as well. Unit Corp., which was the largest acreage holder in the Marmaton Lime in 2013, estimated that 90% of the reserves in this play are liquids.

Apache, Cabot Oil & Gas, Chaparral Energy Inc., EOG, Plano Petroleum LLC, QEP Resources Inc., Raptor Petroleum II LLC, and Texas American Resources LLC all had acreage in the Marmaton Lime, among others.

Mississippian Lime

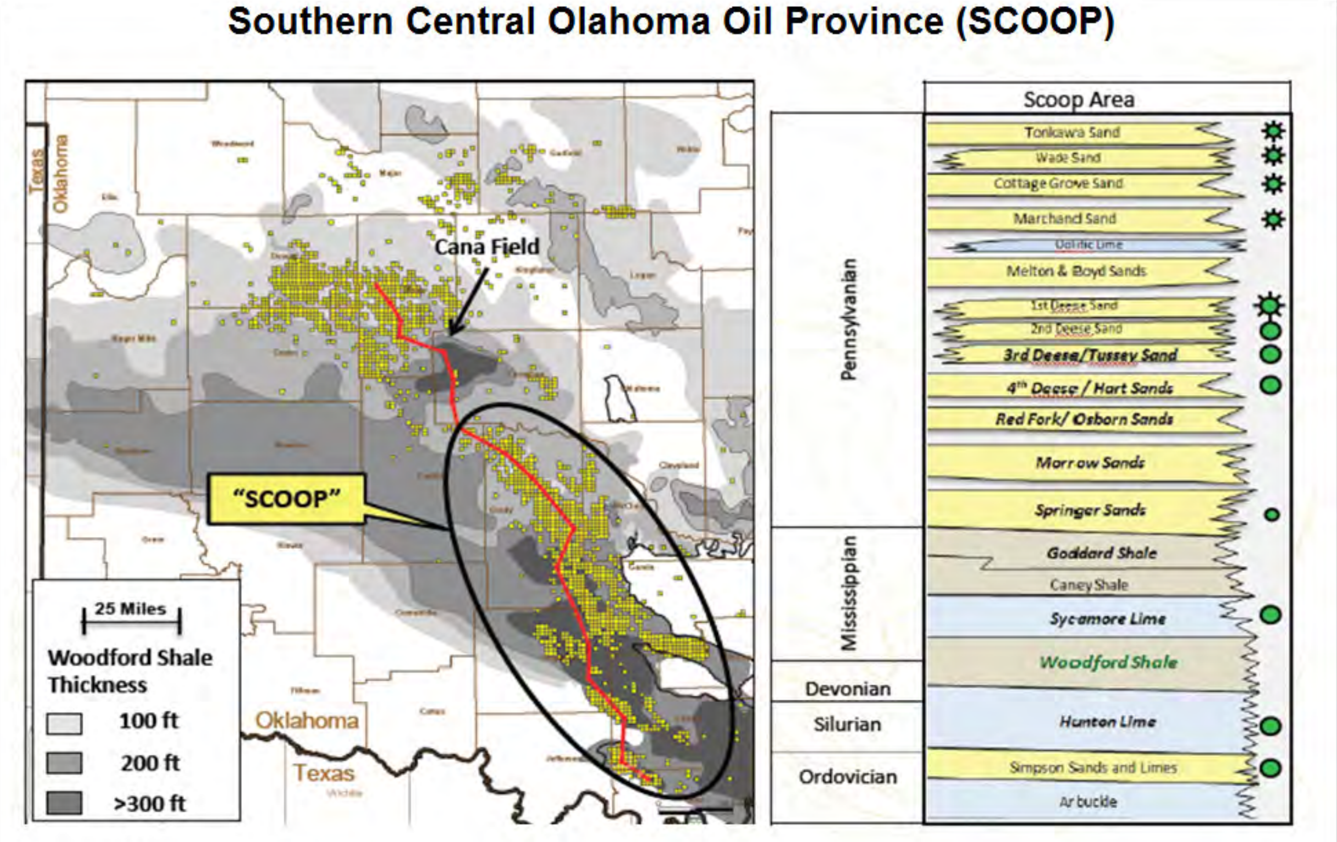
The Mississippian Lime is a massive formation that traverses parts of Oklahoma and Kansas, although much of the horizontal drilling activity to date has been concentrated on the border of each state. Please refer to our separate Mississippian Lime section.

South Central Oklahoma Oil Province (SCOOP)

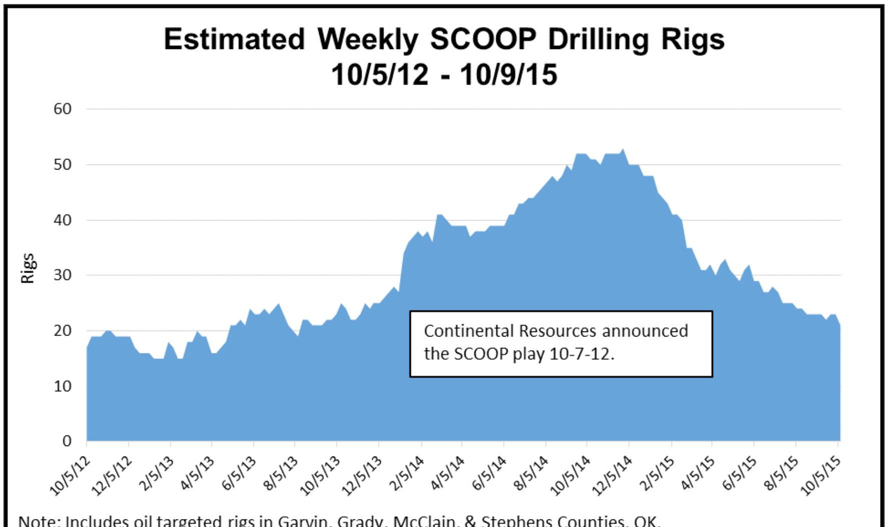
Continental Resources Inc. (CLR) introduced the world to the SCOOP in October 2012, with Oklahoma acreage in Carter, Garvin, Grady, Love, McClain and Stephens counties. Continental primarily has been focused on the Upper and Lower Woodford Shale, although management has said there could be more than 60 formations in SCOOP that would provide additional upside.

There was far less fanfare about the SCOOP relative to the STACK during 3Q2015 earnings conference calls, but we believe this is largely the result of the SCOOP being more of a known play to the investment community. The SCOOP was announced a full 13 months before the STACK, and was in development mode by mid-2015. We estimate there were 21 rigs operating in the SCOOP in early October 2015, down from a peak of 53 rigs in late November 2014.

Oklahoma Liquids Plays (continued)



Source: Continental Resources



Note: Includes oil targeted rigs in Garvin, Grady, McClain, & Stephens Counties, OK.

Source: Baker Hughes, NGI calculations

CLR's core activity has been in the Woodford/Springer formations. At the end of September 2015, the Poteet project in the Woodford had 10 wells with combined peak production rates of 146.84 MMcf/d and 3,240 b/d of oil. Woodford wells were showing initial production rates of 280 b/d and 7 MMcf/d. In the Springer, rates were 670 b/d and 867 Mcf/d.

CLR's Resource Development Manager Dan Harms said in 2014 "every Woodford well that's drilled out there gets a free look at the Springer every time," since the Springer lies above the Woodford. "We have an extremely high confidence in the distribution of this zone. We've never had a reservoir so well defined."

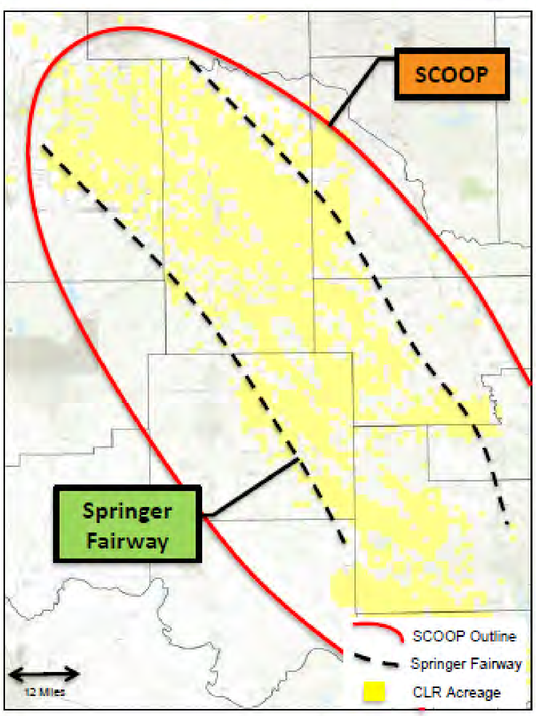
Apache, which has legacy holdings across Oklahoma, had two rigs working in the state in November 2015, one targeting the Woodford/SCOOP and the other working the Marmaton formation (see *Shale Daily*, Nov. 6, 2015). "In the Woodford/SCOOP, we are in the early stages of delineating our approximately 200,000 acres gross and 50,000 net acres," CEO John Christmann said. He noted that the Truman 28-6-6 No. 1H, tied to sales in 3Q2-15, recorded an average 30-day initial production rate of 1,949 boe/d.

Oklahoma Liquids Plays (continued)

Unit Corp. first drilled its Southern Oklahoma Hoxbar Oil Trend (SOHOT) play, which is located primarily in Grady County, OK, in 2013, and it has quickly become a core position for the company. The SOHOT holds up to six intervals, but so far, Unit has focused on two: the Marchand oil sand and the Medrano gas liquids sand. The Marchand is roughly 77% oil, and generated rates of return in excess of 100% based on October 2015 strip pricing, per Unit's November 2015 investor relations presentation. UNT plans to operate one rig there in 2016. The Medrano is roughly 28% liquids, and with a rate of return less than 20%, Unit has no plans to drill this interval until further notice.

STACK: Sooner Trend (Oilfield) Anadarko (Basin), mostly Canadian and Kingfisher (Counties)

Defining the STACK depends on which producer is asked. Newfield Exploration Co., which unveiled the STACK in November 2013, defines the play as the Meramec and Woodford shales in Oklahoma's Blaine, Canadian and Kingfisher counties. Canadian and Kingfisher are the "C" and "K" in STACK. Several other operators also include the Osage formation in their definition of the STACK, which seems reasonable, considering it is between the Meramec and Woodford. That would make the "official" definition of the STACK any layers including and between the Meramec and Woodford formations in Blaine, Canadian and Kingfisher counties.



Source: Continental Resources

But operators are including other formations in their definition of the STACK. The Oswego formation, which lies a few intervals above the Meramec, is being targeted by a number of operators, including Chesapeake, Chaparral and Gastar. The Chester formation lies just above the Meramec, and is being horizontally drilled by Chaparral, Chesapeake, and SandRidge. The Hunton Lime is located just below the Woodford, and is being developed primarily by Gastar. Furthermore, operators are having various degrees of success in counties outside the main three. For example, Chaparral includes Major and Garfileld counties, OK in its definition of the STACK, while Continental has targeted STACK intervals in Dewey and Custer counties.

"In STACK, we have now drilled nearly 70 wells and have seen strong well results across our acreage," said Newfield CEO Lee Boothby. "With each well, we gain increased confidence in the play. Although the primary focus of our STACK drilling program today is to HBP [hold by production] our acreage, we are learning about well spacing both on the surface and sub-surface and we will be ready to enter full field development in 2017."

At the beginning of 2015, Newfield's estimate to complete a well was $8.5 million. By November, the cost had fallen to $7.5 million or less. Drilling days to depth were averaging about 16 days, with some drilled in 12 days. Other operators reported drilling & completion costs of $7.0-$7.5 million during the 3Q15 earnings season as well.

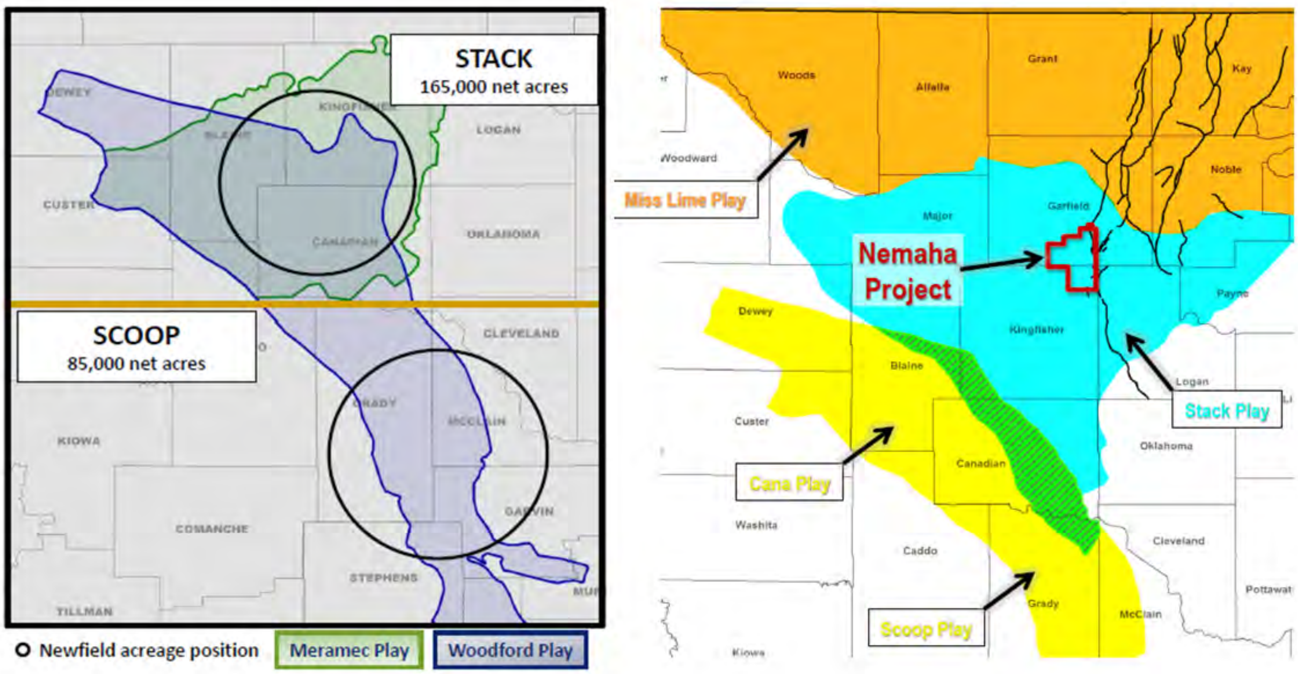
From 22 new extended lateral wells, Newfield had 68 in the STACK dataset covering more than 1,500 square miles and spanning more than 50 miles from corner to corner. Average 30-day rates from the 22 new wells exceeded wells completed in 2Q2015 by 100 boe/d. On a wellhead basis, the oil percentage averaged nearly 80% over the first 30 days of production. By the end of 2015, Newfield expected to have drilled about 100 STACK wells.

Much of the activity in the STACK so far has been centered on the Meramec, not only because of its economics, but also because it is shallower than the Woodford, and therefore a bit less expensive to drill in order to hold acreage positions. But as Cimarex Energy observed on its 3Q15 conference call, it still remains to be seen whether it will be more efficient to develop the Meramec and Woodford intervals simultaneously, or one then the other.

NGI estimated that there were 25 rigs working the STACK in early October 2015, versus 17 rigs a year prior. That makes the STACK one of only two U.S. unconventional formations to see a year/year increase in rigs, and the only one that we believe is statistically significant. The other formation, the Arkoma-Woodford, came off an extremely low starting base. We believe the majority of those 25 rigs were targeting the Meramec.

Oklahoma Liquids Plays (continued)

Oklahoma STACK Play



Source: Newfield Exploration
Source: Longfellow Energy

Todd Dutton, president of Longfellow Energy, told *NGI* in March 2014 that the STACK play may extend even further north into Major, Garfield, Logan, and Payne counties, and include that portion of the Mississippian Lime.

The area goes by other names as well, including CNOW and the Mississippian-Woodford trend, but in reality, reserves pumped from the region are defined by how deep or shallow the reservoirs are tapped.

Both the Mississippian Lime and Woodford Shale intervals are thicker in the STACK, and the portion of the Miss Lime within the STACK tends to have a higher oil saturation, with less produced water. Moreover, the Woodford is a primary producing formation in the STACK, but it is also a secondary contributor within the Mississippian Lime.

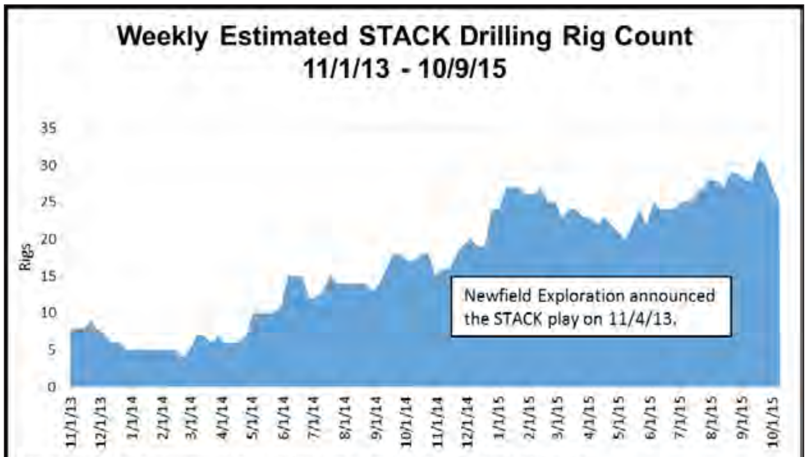
Chesapeake has more than 1.8 million net acres in the STACK area of Oklahoma, with an estimated 1,200 future locations to be drilled in the Meramec and Oswego formations alone, CEO Doug Lawler said in November 2015. Combining the STACK, Miss Lime, Oswego and Meramec targets, Chesapeake has an estimated 400,000-acre position, according to Senior Vice President Jason Pigott, who runs the southern operations.

Underlying STACK Intervals

Source: Chapparal Energy

Oklahoma Liquids Plays (continued)

Because operators can capture production from other formations when they drill, "drilling and completion efficiency have really been what's outstanding there," Pigott said. For instance, one of its 10,000-foot wells saved it $1.4 million in drilling costs versus drilling two traditional 5,000-foot laterals. "But it saves 35% on our cost to develop that field if those wells are successful," he said. The STACK interval play "has three powerhouse formations that all have great economics."



Note: Includes all oil targeted rigs in Blaine, Canadian, and Kingfisher Counties, OK.

Source: Baker Hughes, NGI estimates

Operators working in the STACK in late 2015 were attempting to core up their positions to minimize lease operating expenses (LOE) and other costs, according to Pigott. A big challenge is on the technical side, he said. For instance, the Oswego formation is thinner than some of the other targets, so the question is, is it thick enough to drill a 10,000-foot lateral? "The preference is to push these things out as far as we can, because it maximizes our efficiency of the drillbit, our LOE, minimizes surface footprint as well. So, it's a win for everybody when we can drill those cross unit laterals."

Devon Energy Corp. in 2015 was training its focus on the Meramec, where it had drilled about 20 of the nearly 100 total industry wells as of November 2015.

"When we look at the commercial expectation for the Meramec it really competes in our mind with our top-tier returns from DeWitt County [Permian Basin], the Parkman in the Powder River Basin, and also the southern portions of Lea and Eddy County in the heart of the Delaware Basin," Devon exploration chief Tony Vaughn said. "We've characterized about 500 locations there. In my own mind, that's conservative. And as we drill that out, it will have the potential to greatly improve. So it's going to be one of our go-to areas as we go forward. It's slightly more commercial than, say, the good work that we do in the Woodford right now and the Cana area."

For Cimarex Energy Inc., the Anadarko Basin has become a go-to play as well, with a big focus on the Meramec. There, Cimarex completed its first two-mile lateral during 3Q2015, the Clayton 1HX, which had a peak 30-date production rate of more than 16 MMcfe — a 72% uplift versus the average one-mile lateral drilled to date. Going forward, Cimarex planned to drill long laterals on all of its delineated Meramec acreage "whenever possible."

Gastar Exploration Co. narrowed its focus in 2015 to the Midcontinent, and specifically Oklahoma, for its "better economics and substantial upside," CEO Russ Porter said in November 2015. "On the vast majority of our leasehold, by drilling one well in any of these STACK formations, we should be able to hold all depths and maintain exposure to multiple plays with the production from that single well," Porter said. "The Woodford Shale between the Osage and Hunton Limestone is a big gassier," and while the focus was to be on oil targets until gas prices improved, it also was considering ways to participate in force pooled Woodford wells.

Counties

Ardmore-Woodford: Oklahoma: Bryan, Carter, Johnston, Love, and Marshall Counties

Cleveland/Tonkawa: Texas: Hansford, Hemphill, Lipscomb, Ochiltree, Oklahoma: Custer, Dewey, Ellis, Roger Mills

Hogshooter: See Granite Wash section

Marmaton: Beaver, OK; Ochiltree, TX

SCOOP: Carter, Garvin, Grady, McClain, Stephens (all Oklahoma)

STACK: Blaine, Canadian, Kingfisher ("official" definition}, Custer, Dewey, Garfield, Logan, Major, Noble, Payne (included in individual company definitions of the STACK) (all counties in Oklahoma)

Local Major Pipelines

Natural Gas: CenterPoint Energy, Enable Gas Transmission's Cana & STACK Expansion (CaSE) (proposed), Enogex, NGPL, OGT, OkTex Pipeline, Panhandle Eastern, Sooner Trails (proposed), Southern Star

Crude Oil: Basin, Centurion, Cherokee, CK Red River, Diamond (Plains) (proposed), Phillips 66

NGLs: Southern Hills

Oklahoma Liquids Plays (continued)

SCOOP NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Continental Resources[1]	445,000	JMA Energy Company Llc	N/A
Marathon Oil	145,000	Johnson E Lyle Inc	N/A
Newfield Exploration	85,000	Jones Energy Llc	N/A
Apache Corporation	50,000	K C Resources Inc	N/A
LINN Energy	35,000	Kaiser-Francis Oil Company	N/A
Eagle Rock Energy Partners	20,000	King Energy Llc	N/A
Unit Petroleum[2]	17,200	Kingfisher Resources Inc	N/A
ABNG Inc	N/A	Klein M E & Associates Llc	N/A
Almont Energy Llc	N/A	Le Norman Operating Llc	N/A
American Energy Partners	N/A	Lema Petroleum Inc	N/A
Anadarko Minerals Inc	N/A	Lighthouse Oil & Gas Lp	N/A
Arnold Oil Properties Llc	N/A	Lime Rock Resources Ii-A Lp	N/A
Arrow Oil & Gas Llc	N/A	Locators Oil & Gas Inc	N/A
Atchley Resources Inc	N/A	Lodestone Operating Inc	N/A
Baker Brent Oil & Gas Inc	N/A	Loto Energy Llc	N/A
Beck Resources Inc	N/A	Mack Energy Co	N/A
Blackwell Exploration & Development Llc	N/A	Meade Energy Corporation	N/A
Blake Production Company Inc	N/A	Merit Energy Company	N/A
BP	N/A	Mermac Operating Company Inc	N/A
Breitburn Operating Lp	N/A	MGE Resources Inc	N/A
BTA Oil Producers Llc	N/A	Mid-Continent Pet Mgmt Inc	N/A
Burlington Res Oil & Gas Lp	N/A	Monexco Operating Co	N/A
C & Y Casing Pulling Company	N/A	Mustang Fuel Corporation	N/A
Carbon Economy Llc	N/A	Onshore Royalties Llc	N/A
Cemoil Inc	N/A	Ouachita Exploration Inc	N/A
Chaco Energy Company	N/A	Panhandle Oil & Gas	N/A
Chaparral Energy	N/A	Rafter H Operating Llc	N/A
Charter Oak Production Co Llc	N/A	Range Production Company Llc	N/A
Chesapeake Operating Llc	N/A	Red Hawk Resources Inc	N/A
Chevron Usa Inc	N/A	Remora Operating Llc	N/A
Cimarex Energy Co	N/A	Samson Resources Company	N/A
Citation Oil & Gas Corporation	N/A	Sandridge Exploration & Production Llc	N/A
Clampitt R L & Associates Inc	N/A	Sanguine Gas Exploration Llc	N/A
Columbia Production Company	N/A	Sheridan Production Company Llc	N/A
Comanche Exploration Co Llc	N/A	Shoshone Oil And Gas Inc	N/A
Combined Resources Corporation	N/A	Singer Oil Company Llc	N/A
Crawley Petroleum Corporation	N/A	Snyder Partners	N/A
Curzon Operating Company Ltd	N/A	Spragins Ed S	N/A
Devon Energy Operating Corp	N/A	Stamps Brothers Oil And Gas Llc	N/A

Oklahoma Liquids Plays (continued)

SCOOP NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Duncan Oil Properties Inc	N/A	Sweetwater Exploration Llc	N/A
Earlsboro Energies Corporation	N/A	Tapstone Energy Llc	N/A
Encino Operating Llc	N/A	Technical Energy Services Inc	N/A
Enerquest Oil & Gas Llc	N/A	Te-Ray Resources Llc	N/A
Enervest Operating Llc	N/A	Toklan Oil & Gas Corporation	N/A
Excalibur Resources Llc	N/A	Trepco Production Company Inc	N/A
Faulconer Vernon E Inc	N/A	Tulsa Energy Partners Llc	N/A
Fossil Creek Energy Corporation	N/A	United Oil Corporation	N/A
Gastar Exploration Inc	N/A	Vanguard Operating Llc	N/A
Glacier Petroleum Co Okla Inc	N/A	Vitruvian Ii Woodford Llc	N/A
GLB Exploration Inc	N/A	Walker Keith F Oil & Gas Company Llc	N/A
Guiles Janet Dba Abbi Oil	N/A	Ward Petroleum Corporation	N/A
Gulf Exploration Llc	N/A	Western Oil And Gas Development Corp	N/A
Hamil Oil & Gas Llc	N/A	Weststar Oil & Gas Inc	N/A
Harding And Shelton Exploration Llc	N/A	Williford Energy Company	N/A
Hazlewood Oil & Gas Co Inc	N/A	Wynn-Crosby Operating Lp	N/A
Huntington Energy Llc	N/A	XTO Energy Inc	N/A
Indigo II Minerals	N/A	Zeiders Bros Oil & Gas Co Llc	N/A
JEC Operating Llc	N/A	Zephyr Operating Co Llc	N/A

[1]Also have 210,000 net acres in the SCOOP-Springer
[2]Unit calls this their Southern Oklahoma Hoxbar Oil Trend

Source: Compiled by NGI from company documents

STACK NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Newfield Exploration	210,000	K C Resources Inc	N/A
American Energy Partners	200,000	Kaiser-Francis Oil Company	N/A
Devon Energy	182,000	Kirkpatrick Oil Company Inc	N/A
Sinopec*	182,000	Latigo Oil And Gas Inc	N/A
Continental Resources	146,300	Lime Rock Resources Ii-A Lp	N/A
Chaparral Energy	100,000	Longfellow Energy	N/A
LINN Energy	85,000	Magnolia Petroleum	N/A
Chesapeake	71,000	McGee Tom Corporation	N/A
Cimarex Energy	70,000	Mewbourne Oil Company	N/A
Marathon Oil[1]	67,000	Midstates Petroleum Company Llc	N/A
Gastar	46,600	Nelson Exploration Corp	N/A
Alta Mesa Holdings, LP	N/A	Oil Producers Inc Of Kansas	N/A
Apache Corporation	N/A	Okie Crude Company	N/A

Oklahoma Liquids Plays (continued)

STACK NET ACREAGE POSITIONS
Last Updated December 2015

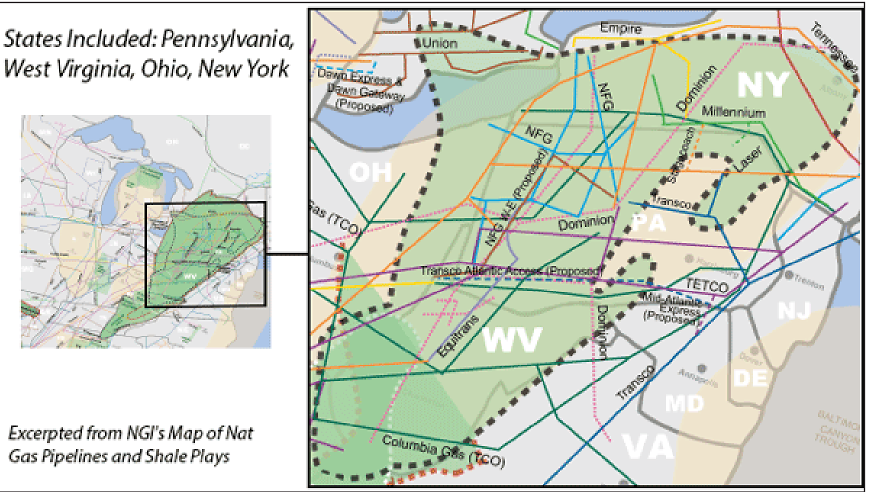
Company	Net Acres	Company	Net Acres
Arrowhead Energy Inc	N/A	PayRock Energy	N/A
Atchley Resources Inc	N/A	Pond David Well Service Inc Dba D W P Production	N/A
Beren Corporation	N/A	Range Production Company	N/A
Blake Production Company Inc	N/A	Samson Resources Company	N/A
Bogo Energy Corporation	N/A	Sandridge Exploration & Production Llc	N/A
BP	N/A	Scoggins Production Llc	N/A
BRG Production Company	N/A	Shelly Energy Inc	N/A
Chaco Energy Company	N/A	Sheridan Production Company Llc	N/A
Comanche Resources Company	N/A	Shidler Mark L Inc	N/A
Crawley Petroleum Corporation	N/A	Singer Oil Company Llc	N/A
Cummings Oil Company	N/A	Spess Oil Company Inc	N/A
Eagle Oil & Gas	N/A	Sweetwater Exploration Llc	N/A
Eagle Rock Energy	N/A	Tessera Energy Llc	N/A
Edinger Engineering Inc	N/A	Toklan Oil & Gas Corporation	N/A
Felix Energy Llc	N/A	Vanguard Natural Resources	N/A
Fourpoint Energy Llc	N/A	Vess Oil Corporation	N/A
Fuller Production Inc	N/A	WR Oil & Gas Llc	N/A
Harding And Shelton Exploration Llc	N/A	XTO Energy Inc	N/A
Indigo II Minerals	N/A	Zeiders Bros Oil & Gas Co Llc	N/A

*Estimate
[1]Marathon has 67K STACK Woodford, and 42K STACK Meramec
Source: Compiled by NGI from company documents

MARCELLUS SHALE

Background Information

States Included: Pennsylvania, West Virginia, Ohio, New York



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

The Marcellus Shale remains one of the most prolific plays in North America, in terms of both acreage and reserve potential. It is among the fastest growing sources of natural gas production in the United States, rising from less than 1.7 Bcf/d at the beginning of 2010 to 16.4 Bcf/d in July 2015. In Pennsylvania alone, according to state data, operators produced more than 4 Tcf of natural gas — mostly from the Marcellus Shale — in 2014 (see *Shale Daily*, Feb. 17, 2015). While a commodities downturn was expected to push production down to roughly 15.9 Bcf/d heading into the end of 2015, according to the EIA, the Northeast is still expected to drive a significant portion of the country's natural gas production in 2016 and beyond.

In a September 2015 survey by Jefferies LLC, analysts projected the country to exit 2016 producing roughly 72 Bcf/d, down 0.8% from 2015's projected exit rate. While slowing growth in the Northeast was partly expected to help push that number down, combined with the Utica Shale, Marcellus Shale natural gas production in West Virginia and Pennsylvania is still projected to increase 8% and 4% from 2015 levels, respectively. Although the growth needle was expected to move slower than in recent years on lower capital spending, fewer rigs and restricted takeaway, Jefferies said its model shows 2016 Northeast supply increasing by 1.4 Bcf/d year-over-year — split fairly equally between both the Marcellus and Utica. Even after a year of falling oil prices and depressed natural gas, the EIA at mid-year 2015 projected that natural gas production in the Marcellus Shale would ultimately reach an astounding 147 Tcf through 2040.

Much of the industry activity to date in the Marcellus has centered in Pennsylvania and West Virginia, where thousands of wells have been drilled. There has been limited drilling in East Ohio and Western Maryland as well. In Ohio, where operators typically drill the Marcellus from multi-well pads that share the Utica, just 43 Marcellus wells have been permitted and 28 have been drilled, according to state data at the time of this writing. The formation is also considered highly prospective in Southern New York, but a ban on high-volume

Top 20 1H15 Unconventional Pennsylvania NatGas Producers

Rank	Operator	MMcf/d	Rank	County	MMcf/d
1	Chesapeake Energy	1904	1	Susquehanna	3070
2	Cabot Oil & Gas	1799	2	Bradford	2031
3	Southwestern Energy	1134	3	Washington	1619
4	Range Resources	1056	4	Greene	1407
5	EQT Corporation	997	5	Lycoming	1388
6	Chief Oil & Gas	679	6	Wyoming	696
7	Rice Energy	540	7	Tioga	564
8	Talisman Energy	528	8	Butler	379
9	Anadarko Petroleum	510	9	Sullivan	284
10	Chevron	415	10	Westmoreland	212
11	Consol Energy	375	11	Fayette	184
12	SWEPI (Shell)	360	12	Allegheny	109
13	Seneca Resources	358	13	Armstrong	84
14	Vantage Energy	219	14	Lawrence	65
15	PA General Energy	195	15	Clearfield	53
16	ExxonMobil/XTO Energy	191	16	Elk	46
17	Alpha Shale Resources	156	17	Clinton	44
18	EXCO Resources	141	18	Beaver	28
19	Carrizo Oil & Gas	132	19	Mckean	28
20	Energy Corp of America	113	20	Jefferson	25

Note: While the majority of unconventional production in Pennsylvania is indeed sourced from the Marcellus, some unconventional production in the state comes from the Upper Devonian and Utica Shales.

Source: Pennsylvania Department of Natural Resouces, NGI calculations

Marcellus Shale (continued)

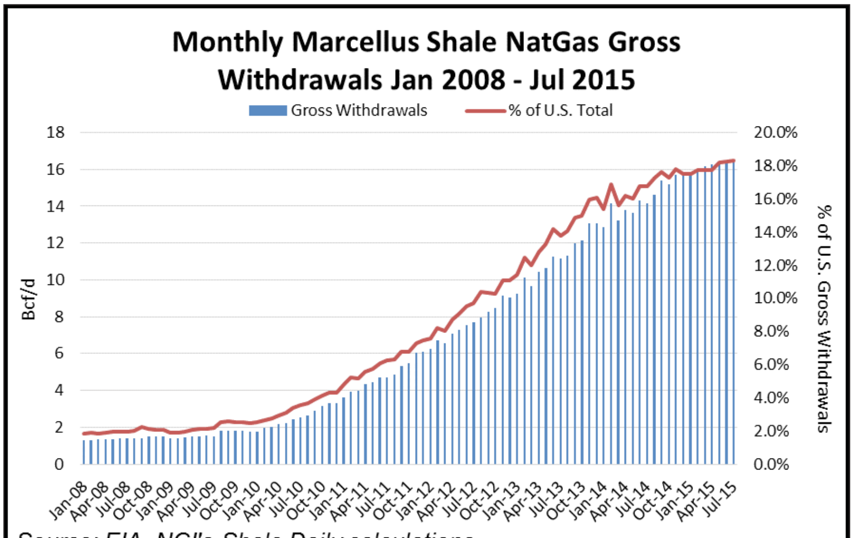
hydraulic fracturing in that state currently prevents any development there (see *Shale Daily*, June 29, 2015).

Range Resources Corp. drilled the first Marcellus well in 2004, the vertical Renz #1 well in Southwest Pennsylvania's Washington County. Much of the play's initial industry development occurred in that part of the state, as well as in neighboring West Virginia. Production in those areas features a dry and a wet gas window.

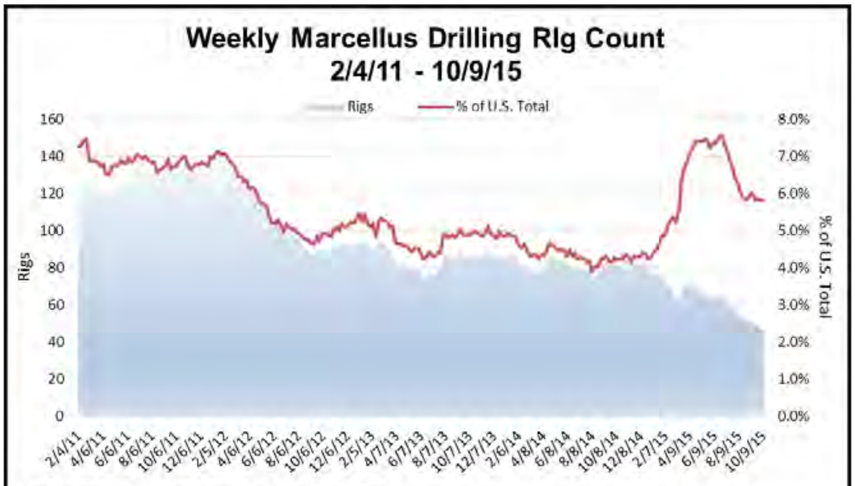
The first Marcellus well in Northeast Pennsylvania was drilled several years later. Despite the fact that production in that region is primarily dry gas, some of which has been hindered by a lack of takeaway capacity for years now, Northeast Pennsylvania is currently home to two of the state's most productive counties: Susquehanna and Bradford counties, according to state data released at year-end 2014, the latest available at the time of this writing.

Although it remains the Appalachian Basin's low-risk, high-quality asset, more of the region's leading producers, however, are slowly turning their attention away from the Marcellus to what lies underneath it. Range Resources, EQT Corp. and Consol Energy Inc. have all tested Utica Shale wells in Pennsylvania at 59 MMcf/d or more. Similar results in West Virginia have operators considering a shift in their 2016 capital budgets. The Pennsylvania tests were conducted in the southwest part of the state – in Greene, Westmoreland and Washington counties. EQT said in late 2015 that it would both suspend its Upper Devonian Shale drilling and defer some Marcellus wells to build in a 10 well deep, dry Utica program in 2016. Similarly, Consol's management said in late 2015 that they would lean more heavily on the Utica for production growth in the coming years. Range Resources has determined that, for now, estimated ultimate recoveries (EUR) in the Utica can't compete with its Marcellus assets. After the company completes a third Utica well in Southwest Pennsylvania in early 2016, it would stop and continue developing the Marcellus, management has said.

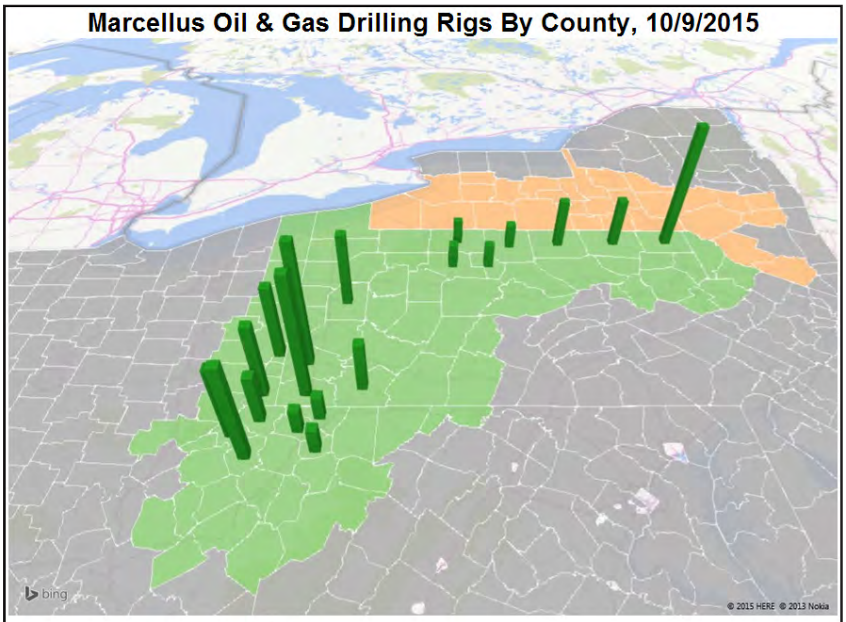
Natural gas tends to be priced differently throughout Pennsylvania and West Virginia, and



Source: EIA, NGI's Shale Daily calculations



Source: Baker Hughes, NGI calculations



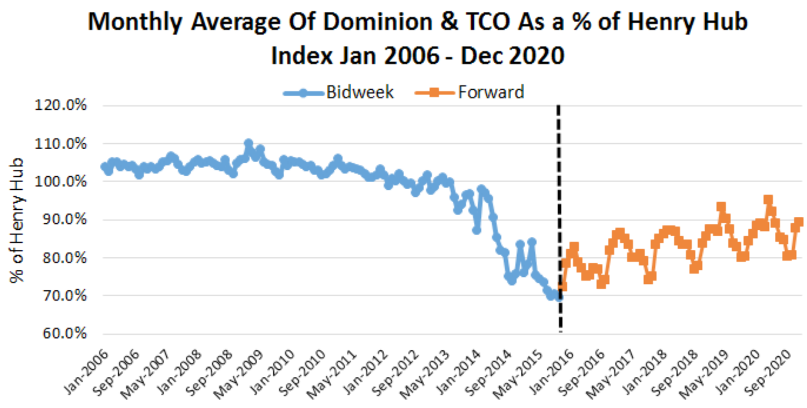
Source: Baker Hughes, NGI calculations

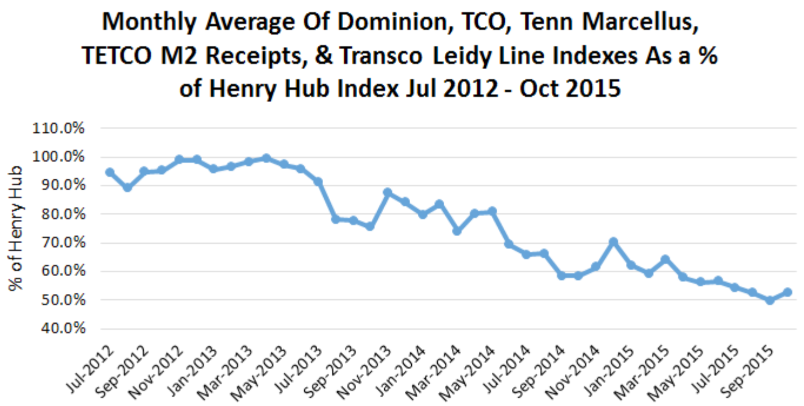
Marcellus Shale (continued)

for that reason, we have established separate Southwest Pennsylvania/West Virginia and Northeast Pennsylvania price indexes for the Marcellus Shale in our *NGI's Shale Daily* publication.The pace of production growth in the Marcellus might have been even faster to date, if it were not for a lack of midstream capacity in the area. Bottlenecks in the Marcellus will begin to ease in earnest in 2016, but the rapid growth of production in the face of pipeline constraints has done a number on basis differentials in the region. Appalachia producers used to enjoy a premium to Gulf Coast pricing, but that has all but disappeared in recent months.

In fact, weak netback prices led producers to curtail approximately 1.2 Bcf/d of production in the Appalachia as of November 2015. roughly 750 MMcf/d of which were in Bradford and Susquehanna Counties, PA.

The premium of the average of NGI's Columbia Gas (TCO) and Dominion Bidweek Indexes to the Henry Hub Index has been in a steady decline since peaking at 110.1% in February 2009, so much that the average of those two Appalachian pipes has traded at a growing discount to the Hub through October 2015. The Appalachian basis discount is even more pronounced when we take the average of Columbia Gas, Dominion, and our Tennessee Marcellus, Texas Eastern M2-Receipts, and Transco-Leidy indices. We began publishing these latter three indices at various points in mid-2012.





Note: Top chart uses *NGI's Bidweek Survey* data to compute the percent of Henry Hub figures through October 2015. After October 2015, the chart represents the same computations performed on forward price data at those locations from *NGI's Forward Look published 10/13/2015.*

Source: NGI's Bidweek Survey, NGI's Forward Look, NGI's Shale Daily calculations

But help is on the way. Several projects came on line in 2015 to help the capacity issue, most notably the Rockies Express East-to-West expansion, which added 1.2 Bcf/d of incremental westbound capacity from its easternmost point in Clarington, OH, to Moultrie, IL. The output of Appalachian producers moving to the Midwest on

Estimated Excess Appalachia Natural Gas Pipeline Takeaway Capacity 2014-2018 (Bcf/d)

From Range Resources	2014	2015	2016	2017	2018
Appalachia Production Year-End Exit Rate	17.9	20.9	23.0	26.5	27.6
Appalachia Consumption + Injections	14.6	14.2	14.6	15.0	15.2
Appalachia Gas Surplus for Export	*3.3*	*6.7*	*8.4*	*11.5*	*12.4*
Takeaway Projects - Northeast (cumulative year-end)	0.6	1.1	1.8	3.4	3.0
Takeaway Projects - Southwest (cumulative year-end)	2.8	3.6	4.6	7.6	5.0
Total Takeaway Projects	*3.4*	*8.1*	*14.5*	*25.5*	*33.5*
Excess Takeaway Estimate From Range Resources	0.1	1.4	6.1	14.0	21.1
Excess Takeaway Estimate from Eclipse Resources	2.3	4.2	10.8	18.1	N/A

Source: Range Resources, Eclipse Resources

Marcellus Shale (continued)

the large-diameter REX pipeline is expected to be felt throughout much of the continental pipeline network. As a result, and in order to more closely follow daily flows in the region on REX, *NGI* has developed the Rockies Express Zone 3 tracker.

Longer-term, there are numerous natural gas pipelines that are in various stages of development to increase takeaway capacity out of the Marcellus and Utica, so much so that both Range Resources and Eclipse Resources estimate that there will be at least 6.1 Bcf/d and 14.0 Bcf/d of excess capacity out of Appalachia in 2016 and 2017, respectively. Range forecasts that excess capacity rises to 21.1 Bcf/d in 2018.

To be fair, those estimates may prove to be a bit aggressive, since they include some projects that may not be built. For example, some of the industry's leading executives and pundits do not expect both of the competing Mountain Valley Pipeline and the Transco Atlantic Sunrise expansion line, nor both of the competing Nexus Gas Transmission and Rover Pipelines to be built. As of October 2015, three of those projects remained in progress.

But excess capacity from Appalachia does appear to be forthcoming, and we believe that will have two major implications for operators in the Marcellus in particular. One is that the ability to move Appalachian gas to many more points throughout the United States and Canada greatly increases the probability that the price of U.S. natural gas will be determined largely by the incremental cost of production in Appalachia. There is no question that the basin represents the fastest growing, and therefore the incremental source of natural gas supply in the United States. But if enough of that gas cannot move out of the region, it can only have so much impact on the price of gas in other parts of country. That will likely no longer be an issue by the end of 2018.

The other major impact is on netback prices in the Appalachia. Whether growing takeaway capacity will be enough to improve basis differentials in the Marcellus will depend on a number of factors, such as the continued pace of development in the Marcellus itself; competing supply from the nearby Utica Shale; the ability of Eastern Canada to accept more imports from the U.S., and throughput at the Cove Point LNG export facility in Maryland. Cove Point, which consists of 136 miles of natural gas pipeline to connect it with interstate lines, has already generated revenue and earnings from annual payments under regasification, storage and transportation contracts. In September 2014, the Federal Energy Regulatory Commission authorized the proposed export facility, making it the first East Coast export project to proceed after earning U.S. Department of Energy approval in 2013. Under current plans, the Cove Point export operations could be in service by late 2017, with approval to export up to 5.75 million tons of LNG per year. Construction on the facility began in October 2014 and was 47% complete in 4Q15, according to Dominion Resources Inc.

So far, it looks like future Marcellus basis differentials are expected to improve somewhat, as seen by the forward price outlook in the chart shown earlier in this section.

As previously mentioned, the Marcellus is generally considered to be dry gas, particularly in Northeast Pennsylvania. However, the gas is more liquids-rich in a number of counties in Southwest Pennsylvania and West Virginia. Several NGL pipelines have been built or proposed to handle the increase in ethane and liquids production out of this area, including Enterprise Products Partners LP's Appalachia-to-Texas Express (ATEX); Kinder Morgan Inc.'s Utica Marcellus Texas Pipeline (UMTP); Sunoco Logistics Partners LP's Mariner East 1, 2 and 3 and Mariner West. Responding to shipper demands, Sunoco launched a binding open season in September 2015 for the Mariner East 2 Expansion Project (Mariner East 3) (see *Shale Daily*, Sept. 14, 2015). NGLs would be shipped on all three Mariner East pipelines to the company's Marcus Hook Industrial Complex, south of Philadelphia, for distribution to local, domestic and international markets. Propane deliveries have already started on Mariner East 1, while ethane deliveries were expected to begin in 4Q2015. All three pipelines would have a combined capacity of 770,000 b/d.

Marcus Hook is also expected to be a major hub for international ethane exports. Petrochemical giant INEOS Europe AG became the first European company to contract for U.S. ethane feedstock in 2012, when it agreed to transport Range Resources' ethane overseas. The first U.S. ethane shipments to Europe were on track to begin in late 2015 and escalate throughout 2016 and 2017. In June 2015, INEOS accepted delivery of the first ship in an eight-vessel fleet that would specialize in the intercontinental deliveries.

Increased Marcellus production has led to a significant decline in the amount of natural gas the eastern U.S. imports from Canada. U.S. gross imports into the Eastern U.S. have fallen from 565 MMcf/d in 2009 to just 242 MMcf/d in 2014, good for a cumulative annual growth rate of -15.6%. Niagara has turned into a net export point for the U.S., and is expected to grow with several planned infrastructure expansions scheduled to come on line in the next year.

Marcellus Shale (continued)

Annual U.S. Gross NatGas Imports From Canada At Major Receipt Points (MMcf) 2009-2014

Imports into Western U.S.

Location	U.S. Pipeline(s)	2009	2010	2011	2012	2013	2014	CAGR
Sumas, WA	Northwest	309,516	332,358	313,922	312,236	333,050	359,343	3.0%
Eastport, ID	TransCanada GTN	693,892	708,806	606,099	634,194	686,449	608,147	-2.6%
Total		*1,003,408*	*1,041,164*	*920,021*	*946,430*	*1,019,499*	*967,490*	*-0.7%*

Imports into Midwest/Central U.S.

Location	U.S. Pipeline(s)	2009	2010	2011	2012	2013	2014	CAGR
Noyes, MN	Great Lakes, Viking	478,368	447,079	544,135	401,717	238,970	324,613	-7.5%
Port of Morgan, MT	Northern Border	485,026	690,466	658,934	730,988	695,152	518,386	1.3%
Sherwood, ND	Alliance	479,741	476,855	448,967	433,713	432,497	433,227	-2.0%
Total		*1,443,135*	*1,614,400*	*1,652,036*	*1,566,418*	*1,366,619*	*1,276,226*	*-2.4%*

Imports into Eastern U.S.

Location	U.S. Pipeline(s)	2009	2010	2011	2012	2013	2014	CAGR
Calais, ME	Maritimes & NE	114,081	131,035	149,736	76,540	55,248	79,590	-6.9%
Grand Island, NY	Empire	81,898	63,548	47,616	23,000	5,758	1,413	-55.6%
Niagara Falls, NY	NFG, Tennessee	188,525	88,983	32,770	3,159	1,650	2,957	-56.4%
Pittsburg, NH	Portlant Natural Gas	26,767	18,297	19,826	47,451	63,446	52,160	14.3%
Waddington, NY	Iroquois	349,980	267,227	231,831	241,506	214,671	187,219	-11.8%
Total		*565,272*	*374,507*	*284,427*	*292,116*	*279,767*	*242,336*	*-15.6%*

Source: EIA, NGI calculations

Counties

Maryland: Allegany, Garrett

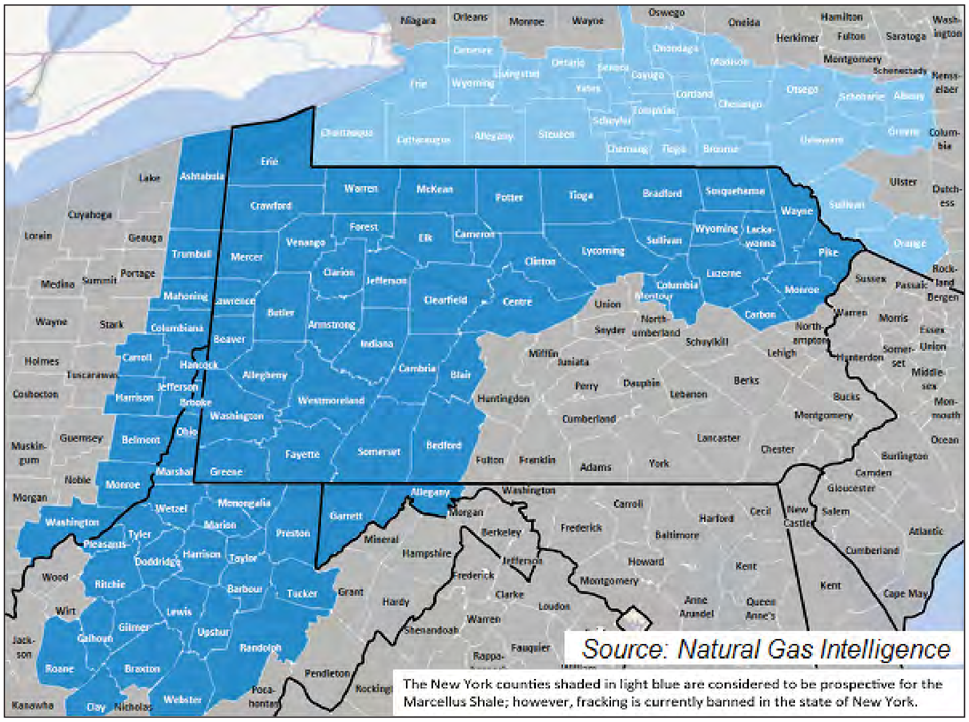
Pennsylvania: Allegheny, Armstrong, Beaver, Bedford, Blair, Bradford, Butler, Cambria, Cameron, Carbon,Centre, Clarion, Clearfield, Clinton, Columbia, Crawford, Elk, Erie, Fayette, Forest, Greene, Indiana, Jefferson, Lackawanna, Lawrence, Luzerne, Lycoming, McKean, Mercer, Monroe, Montour, Pike, Potter, Somerset, Sullivan, Susquehanna, Tioga, Venango, Warren, Washington, Wayne, Westmoreland, Wyoming

West Virginia: Barbour, Braxton, Brooke, Calhoun, Clay, Doddridge, Gilmer, Hancock, Harrison, Lewis, Marion, Marshall, Monongalia, Ohio, Pleasants, Preston, Randolph, Ritchie, Roane, Taylor, Tucker, Tyler, Upshur, Webster, Wetzel

Ohio: Ashtabula, Belmont, Carroll, Columbiana, Guernsey, Harrison, Jefferson, Lake, Mahoning, Monroe,T rumbull, Washington

New York: Albany, Allegany, Broome, Cattaraugus, Cayuga, Chautauqua, Chemung, Chenango, Cortland, Delaware, Erie, Genesee, Greene, Livingston, Madison, Onondaga, Ontario, Orange, Ostego, Schoharie, Schuyler, Seneca, Steuben, Sullivan, Tioga, Tompkins, Wyoming,Yates

Marcellus Shale (continued)



Local Major Pipelines

Natural Gas: Columbia Gulf Transmission, Constitution Pipeline (Proposed), Dominion Transmission, Empire Pipeline, Equitrans, Leidy Hub, Millennium, Mountain Valley (Proposed), Nexus Gas Transmission (Proposed), National Fuel Gas, Rover (Proposed), Spectra Carolina (Proposed), Tennessee, Texas Eastern Transmission, Transco

Crude Oil: None

NGLs: ATEX Express, Mariner East, TEPPCO, UMTP (Proposed)

MARCELLUS SHALE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Seneca Resources (NFG)	790,000	Avista Capital	N/A
Southwestern Energy*	756,149	Baker Gas	N/A
ExxonMobil (XTO)	740,325	BLX Inc.	N/A
Chevron	718,000	Burnett Oil Co.	N/A
Range Resources	640,000	Campbell Oil & Gas	N/A
EQT Corporation	600,000	Chief Oil & Gas	N/A
Shell*	598,000	Citrus Energy	N/A
Statoil	512,000	DL Resources	N/A
Consol Energy	441,000	Eagle Oil & Gas	N/A
Pennsylvania General Energy Co.	430,000	EdgeMarc Energy	N/A
Antero Resources	418,000	Endless Mountain Energy LLC	N/A
Noble Energy	350,000	Energy Corp of America	N/A
Bluescape Resources	330,000	Enervest Operating	N/A
Rex Energy*	283,100	Flatirons Resources	N/A
Anadarko Petroleum	254,000	Great Mountain Operating	N/A
Chesapeake Energy	230,000	Great Oak Energy	N/A

Marcellus Shale (continued)

MARCELLUS SHALE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Cabot Oil & Gas	200,000	Hayden Harper Energy	N/A
Talisman Energy	190,000	Hilcorp	N/A
Reliance Industries*	182,600	Hunt Oil	N/A
Mountaineer Keystone	181,000	Huntley & Huntley Energy Exploration	N/A
EXCO Resources	148,800	Infinity Oil & Gas	N/A
BG Group	145,000	Inflection Energy	N/A
Mitsui & Co.*	100,000	Jay-Bee Production	N/A
Rice Energy	91,000	JJ Bucher Producing Corp	N/A
Magnum Hunter	76,000	JM Best	N/A
Ultra Resources	76,000	Lime Rock Partners	N/A
Stone Energy*	75,100	M&M Royalty	N/A
EOG Resources	71,000	MDS Energy	N/A
Enerplus USA	52,000	Mieka LLC	N/A
Vantage Energy	48,000	Mountain V Oil & Gas	N/A
Northeast Natural Energy	45,000	Natural Resource Partners L.P.	N/A
Gastar	37,400	Novus Operating	N/A
Carrizo Oil & Gas	32,400	PennEnergy Resources	N/A
Republic Energy	30,000	Repsol	N/A
Eclipse Resources	27,660	Roxanna Oil	N/A
Dorchester Minerals	26,000	Snyder Brothers	N/A
Alpha Natural Resources	25,000	Tanglewood Exploration	N/A
Sumitomo	23,150	Tenaska Resources LLC	N/A
Trans Energy	15,598	Texas Keystone Inc.	N/A
Penn Virginia	14,000	Triana Energy	N/A
Endeavour International Corporation	13,100	True Oil	N/A
Epsilon Energy	5,750	Tug Hill Exploration	N/A
Warren Resources	5,289	UGI Corporation	N/A
Atlas Resource Partners	3,000	WGL Holdings	N/A
AB Resources	N/A	William McIntire Coal Oil & Gas	N/A
American Oil & Gas	N/A	Wilmoth Interests	N/A
Antinum	N/A		

*Estimate

Source: Compiled by NGI from company documents

ROGERSVILLE SHALE

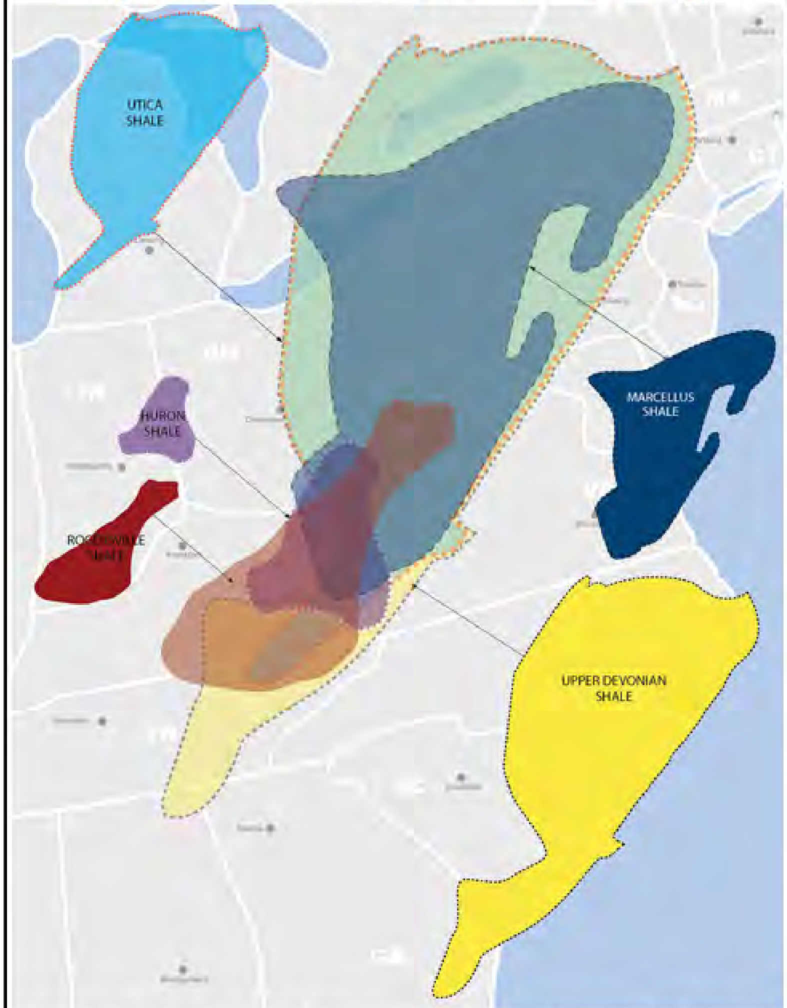
Background Information

Located in a deep sub-basin known as the Rome Trough, the Rogersville Shale is one of six formations in the Conasauga Group, which includes the Pumpkin Valley Shale, Rutledge Limestone, Maryville Limestone, Nolichucky Shale and the Maynardville Limestone. Other shales in the group have tested poorly for hydrocarbons. But there exists a limited body evidence that suggests the Rogersville could be comparable to the Marcellus and Utica Shales (see *Shale Daily*, July 24, 2015).

From 1999-2002, researchers at the Kentucky, Ohio and West Virginia Geological Surveys refined the stratigraphic framework of the Rome Trough, which underlies the Appalachian Basin. Furthermore, in a 2005 U.S. Geological Survey (USGS) report that utilized some of the states' research, and was authored in part by EQT Corp. and the Kentucky Geological Survey (KGS), researchers said the Rogersville is likely the hydrocarbon source rock for producing sandstone reservoirs in the Rome Trough of West Virginia and Kentucky.

Commercial production from the Rome Trough includes the Homer Field in Elliott County, KY, where sandstone reservoirs have produced more than 2 Bcf of natural gas, according to KGS. But the impetus for today's interest in the Rogersville is based on a series of documented wells drilled to deeper targets in the 1960s and 1970s.

Rogersville Shale Relative To Other Major Northeast Resource Plays



Source: NGI's 2016 Map of Shale/Resource Plays

The sub-basin is narrow, extending from Kentucky northeastward into Ohio, Pennsylvania and Southern New York. It remains unclear what it, or other shales in the Conasauga could hold for producers north of West Virginia. The organic rich Rogersville is thought to be confined to Kentucky and West Virginia. At a depth of roughly 9,000-10,000 feet in Kentucky and 12,000-14,000 feet in West Virginia, the formation is essentially no deeper than some Utica wells that have been drilled, making it a conceivable target. It has what KGS says is a "suitable thickness," ranging from 200 to more than 1,000 feet in both eastern Kentucky and southwestern West Virginia. Moreover, according to the KGS, the Rogersville's mineralogy, organic content and thermal maturity are all right to produce gas or liquids if "fractured to improve permeability.

"Challenges in developing a Rogersville Shale play include interpreting structure and stratigraphy in the deeper, fault-segmented parts of the Rome Trough and predicting the distribution of organic-rich intervals," KGS said. "The play concept has been proven, and economic viability will depend on the production rates established and fluid type."

As of November 2015, six modern Rogersville test locations had been permitted, with all but one of those located in eastern Kentucky's Lawrence and Johnson counties. Just five test wells had been drilled at the time of this writing. Only one of those was a horizontal well, drilled by EQT Corp. subsidiary Horizontal Energy Technology Inc. in Johnson County. Plans for more sites appear to be on the rise as other stratigraphic permits that omit the operator's name have been issued in these areas.

Chesapeake Energy Corp. has drilled two vertical Rogersville tests in Lawrence County, while Cabot Oil & Gas Corp.'s No. 50 Amherst Industries vertical Rogersville well in Putnam County, WV, was said by KGS to be producing dry gas to sales in November 2015 (see *Shale Daily*, Nov. 13, 2015). But Denver-based Cimarex Energy Co., a company that primarily operates in the Permian Basin and Midcontinent, has been a pioneer in the play. Through its subsidiary, Bruin Exploration LLC, the company obtained the first Rogersville permits in 2013 and in 2014. It drilled a vertical test well — the Sylvia Young No. 1 — in Lawrence County.

In August 2015, a completion report released by the Kentucky Division of Oil and Gas showed initial test volumes of only 19 b/d of oil and 115 Mcf/d of natural gas (see *Shale Daily*, Aug. 20, 2015). It's unclear for how long the well flowed, but it was drilled to a depth of 11,967 feet and state records show the company has since been issued a horizontal permit to kick the well out. Cimarex also has permitted a second Rogersville well to the south of the Sylvia Young, while Chesapeake has received another horizontal permit for one its test wells in Lawrence County. Head of the Energy and Minerals Section at the KGS David Harris said while Cimarex's "volumes are modest, the first vertical well may not reflect the potential of the zone."

None of the larger exploration and production companies that are currently active in the Rogersville have publicly discussed their operations there. But in a 2Q2015 earnings call with financial analysts, Cabot CEO Dan Dinges said the company has nearly one million acres in West Virginia. Although he didn't provide specifics about any particular formation, he added that the company has ongoing exploration efforts south of Wood County, WV, in the western part of the state, looking at a "deeper section" there. "We're usually cautious when it comes to discussing exploration efforts...We have a couple areas that we're continuing to look at that we think have exploratory opportunity anyway," Dinges said. "...We have enough reason to believe that it merits further capital at some time."

The viability of the play was proven decades ago. In the mid-1960s, the Inland No. 529 White well drilled in Boyd County, KY, — north of Lawrence County — yielded the first commercial oil production from Cambrian-age rocks in the Rome Trough, producing 10,000 bbl of oil and associated gas from the Maryville Limestone. Another test well drilled to the Maryville in Jackson County, WV — just north of Putnam County — produced natural gas at 6-9 MMcf/d. It was an ExxonMobil Corp. predecessor company that drilled several deep wells in the Rome Trough at the time that revealed more about the Rogersville, coring the formation with its No. 1 Smith well in Wayne County, WV, southwest of Putnam County.

As part of their efforts to refine the Rome Trough's framework, researchers at the Kentucky, Ohio and West Virginia Geological Surveys analyzed that core. They found that while the total organic content (TOC) of other cores from shales in the Conasauga Group was less than 1%, Exxon's Rogersville core showed a TOC of nearly 5%.

"A lot of this has been sort of developed off of what was seen in that core, in that old Exxon well," Harris told *NGI*. "That was the key evidence that there was organic content and there was also big gas shows when they drilled through that zone. We have those records and mud logs that show potential hydrocarbons in the zone."

Given the depth of the shale in West Virginia, the industry believes that the Rogersville is likely a dry natural gas play there, while shallower depths in Kentucky are expected to yield both oil and gas. Most agree that Rogersville exploration has likely been impeded by the commodities downturn and while leasing activity slowed heading into the end of 2015, land records show interest among a suite of producers and land brokerage firms. From January 2014 to June 2015, across a three-county stretch in Eastern Kentucky, including Magoffin, Johnson and Lawrence counties, 3,863 leases were signed for the Rogersville, according to data compiled by the mineral management firm Global Natural Resource Management Co., which works in the state. Of those, 2,127 of them were executed in Magoffin County.

At the end of June 2015, land brokerage Gulfland Appalachian Energy Inc. had the most leases with 1,073; EQT had 400; Cimarex had 378; Chesapeake had 105, and land management company Exterra Resources LLC had 466. "I've worked in the state since 2002. Cimarex came in in 2012 under the radar with [Gulfland Appalachian] and started the leasing activity in Lawrence County, but didn't expand into Magoffin until later," said Global Natural Resource's Executive Vice President Wesley Cate in a July 2015 interview with *NGI*. "I would not be surprised if you see the same kind of activity spread into Wolfe, Lee and Estill counties, KY. Just through the rumor mill, I've heard there's already some leasing activity in Lee County." West Virginia Oil and Natural Gas Association Executive Director Corky DeMarco has also confirmed that joint ventures, farm outs and land deals have been common in southwest West Virginia where the Rogersville is thought to be viable.

With so few drill bits having gone through the Rogersville, there is no reliable resource estimate. As part of work for the Colorado School of Mines' Potential Gas Agency, a group of Appalachian experts gathered in 2015. They determined that there was not enough information to adequately estimate the resource base, but one official said for now it is "quite small," adding that it would likely change as more production information is released. That is not likely to happen for a year or more as operators have either been granted or have asked for confidentiality to protect that information under West Virginia and Kentucky state laws (see *Shale Daily*, Sept. 23, 2015). The USGS has said it does not have an ongoing assessment of the Rogersville or any personnel with extensive knowledge of its resources or geological characteristics.

Counties/Parishes

Because little is known about the Rogersville's areal extent and exploration is nascent, prospective counties listed here are based on current activity and historical production.

Kentucky: Boyd, Elliott, Estill, Johnson, Lawrence, Lee, Magoffin, Wolfe

West Virginia: Jackson, Putnam, Wayne

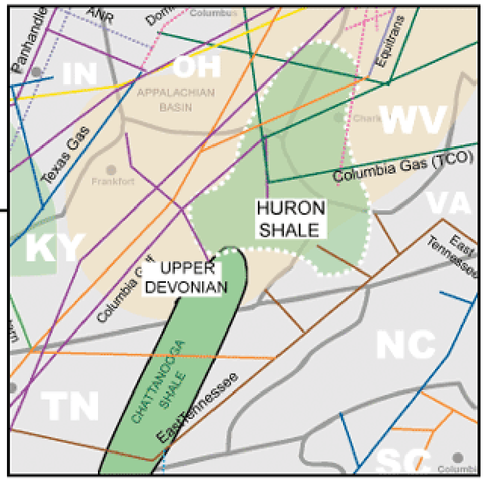
Local Major Pipelines

Natural Gas: Columbia Gas, Columbia Gulf, Dominion, Tennessee

UPPER DEVONIAN/HURON SHALES

Background Information

States Included: Kentucky, Virginia, West Virginia



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

The Upper Devonian Shale (UD) is a stacked interval that is roughly three times as thick as the Marcellus Shale, which sits just below it (the Marcellus is part of the Middle Devonian formation). Intervals within the Upper Devonian include the Cleveland, Dunkirk, Geneseo/Burket, Middlesex, Pipe Creek, and Rhinestreet shales. Most of the early unconventional drilling within the formation has thus far targeted the Geneseo/Burket shales. The UD does not overlie the entire Marcellus. It is situated in Western New York, Western Pennsylvania, Northeast Pennsylvania, Western West Virginia, Eastern Ohio and Eastern Kentucky, with a little overlap in Southwest Virginia and Northeast Tennessee. Furthermore, each of the six major zones do not necessarily appear across the entire UD fairway.

The group of shales within the Upper Devonian have substantial potential. An executive with Range Resources raised some eyebrows in the fall of 2011 when he hypothesized that the UD may hold as much gas as the Marcellus Shale. It will take plenty of drilling to prove that theory, however.

Upper Devonian

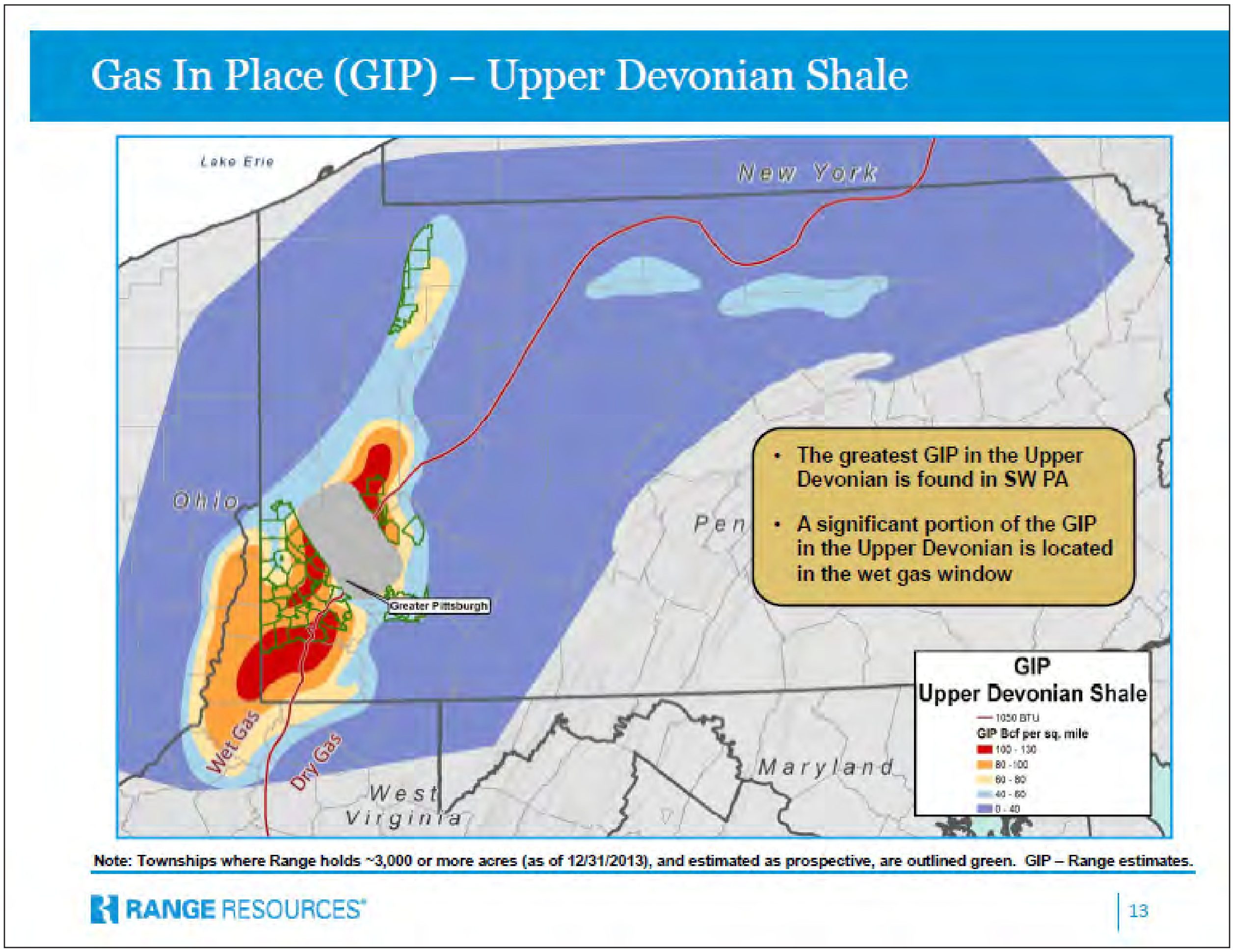
At mid-year 2015, there were about 85 producing UD wells in Pennsylvania, with another 100 or so that were drilled or in the process of completion, according to Gregory Wrightstone of Wrightstone Energy Consulting, who gave an update on the status of the play at an industry conference in Pittsburgh in June 2015 (see Shale Daily, June 29, 2015). That number was up from the 28 unconventional Upper Devonian wells that the Pennsylvania Department of Environmental Protection said were drilled at the end of 2013, when the unconventional industry began to explore the intervals in earnest. Wrightstone added that the average six-month cumulative production of an Upper Devonian well in Northeast Pennsylvania at the time of his presentation was about 530 MMcfe — nearly half the 1.02 Bcfe that a Marcellus well in the same area has been known to produce. Taken together, current well economics, competing supply from the prolific Marcellus and Utica shales, a lack of takeaway capacity and UD acreage that is largely held by production, currently finds Appalachian operators referencing the UD as a thing of the future.

While the industry has worked to identify its ultimate potential — thought to hold roughly 30 Tcf of natural gas — the formation is still a one off, a part of the Appalachian Basin's stacked pay potential that producers could eventually develop as their operations continue to unfold in the coming years and possibly decades. The formation is more important to some operators than others, and its leading driller to date has been EQT Corp. But the commodity downturn that began in Summer 2014 and showed no signs of abating heading into 2016, has forced operators to look more closely at their portfolios and their capital spending plans.

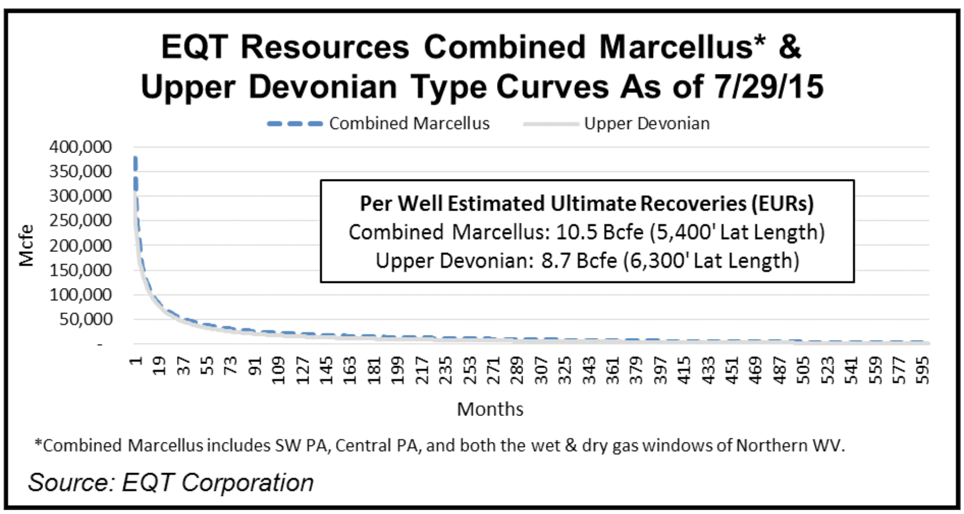
Entering 2015, EQT had outlined a plan to drill up to 40 Upper Devonian wells. But following a mid-year test of the company's Scotts Run Utica well in Greene County, PA, that showed an initial 24-hour rate of 72.9 MMcf/d, the company said in August 2015 that it would suspend its UD program (see *Shale Daily*, Aug. 3, 2015). As of July 2015, EQT had 36 UD wells online and said it would drill 24 more through the remainder of the year before phasing-out the program in early 2016.

"Given the extraordinary results of our first dry Utica well, we are accelerating our efforts in Greene County," said EQT President of Exploration and Production Steven Schlotterbeck. "Our focus is on creating a capital efficient, dry Utica development plan that leverages existing pads, existing gathering infrastructure and takeaway capacity. Consequently, we have reevaluated our competing investment opportunities and made a strategic decision to phase-out our Upper Devonian drilling program."

Upper Devonian/Huron Shales (continued)



Other leading UD drillers have shared similar views since delineation in the deep dry Utica of Southwest Pennsylvania and West Virginia began in 2014. Consol Energy Inc. tested a deep Utica well in Westmoreland County, PA, in 2015 at more than 60 MMcf/d (see *Shale Daily*, July 29, 2015). Range Resources Corp. had similar results in nearby Washington County, but that company continues to maintain that neither the Utica nor the UD can compete with its low-risk, high-quality Marcellus Shale assets (see *Shale Daily*, Oct. 29, 2015).



"We run economics on every pad and they really all compete for capital. We certainly, in the last month, have received information that tells us the deep dry Utica is now a higher rate of return than what we have anticipated," said Consol Vice President of Gas Operations Craig Neal in an interview with *NGI* shortly after the company announced its deep Utica test results (see *Shale Daily*, Aug. 25, 2015). "We have to get the costs down, but we expect to do that, and I think you will see dry Utica displace both

Upper Devonian/Huron Shales (continued)

the Marcellus and Upper Devonian drilling. But we have some attractive prospects in the Marcellus and Upper Devonian, as long as we are combining them with Marcellus or a recomplete. I don't want you to think those are not attractive. It's just that these [Utica wells] are likely better."

Early results have demonstrated that the UD's hydrocarbon content mirrors that in the underlying Marcellus, according to industry interviews in 2014 after more wells started coming online (see Shale Daily, April 28, 2014). "We have four wells tested so far around our [Washington County, PA] acreage with that dry and wet gas showing itself, and we're encouraged by the tests we've conducted through the years," Range's Vice President of Engineering Technology Joe Frantz told NGI. "One of the things is that we have so much Marcellus acreage to develop and we know the Upper Devonian is there. Once we're ready to go after it, it'll be one of those things we co-develop down the road." The UD tends to be gassy where the Marcellus is gassy, and more liquids-rich in those areas where the Marcellus features higher btu gas. For example, Rex Energy Corp. has said its horizontal Upper Devonian (Burket Shale) and Marcellus wells in Butler County, PA both contain 40% liquids in western Pennsylvania where the Marcellus has tended to be wetter.

The economics of future UD wells will no doubt improve somewhat as operators ascend the learning curve, and by the fact that many UD wells can be drilled from existing Marcellus well bores. That will save money on things like site preparation and water management. "It's true that companies have been evaluating the Upper Devonian and looking at the intervals for a while now; it's a shallow, easy target. Here's the difference where people sometimes get confused: when you talk about multi-play stacked laterals, we're talking about economies of scale," said Consol Energy Inc.'s Director of Engineering for Gas Operations Andrea Passman in a 2014 interview with *NGI* about the UD's long-term potential and its link to Marcellus wells. "You're adding something that wouldn't have worked previously on its own. The economics have changed, there's no separate factors and you're not incurring the additional costs associated with construction of all those different pieces that burden a well."

Huron

We have included the Huron Shale for completeness, but this formation has not been much of a priority for many of the large-, mid- and small-cap producers that have come to characterize the nation's shale boom in recent years. In 2012, for example, EQT, which was once a leading operator in the Huron, announced it was suspending its drilling in the play indefinitely because of low natural gas prices. EQT drilled 236 horizontal Huron Shale wells in 2010, 115 in 2011, and only 7 in 2012. It resumed drilling in the Huron in 2014, with plans to drill 120 wells. It has since suspended those operations again.

According to the U.S. Energy Information Administration, the Huron Shale, which it calls the Devonian Big Sandy Shale Gas Play, includes the Huron, Cleveland, and Rhinestreet formations within Eastern Kentucky, Western West Virginia, and Southwest Virginia. It is a mixture of shale, tight sands, and coalbed methane gas. Most of the Huron wells lie at depths between 2500' – 6500'. Given those depths, drilling the formation requires far less water and additives, said Kentucky Oil and Gas Association Executive Director Andrew McNeill in a July 2015 interview about other emerging horizons in the state, such as the Rogersville Shale. He added, however, that the Huron still accounts for a significant portion of his state's oil and gas development, saying it remains the bread and butter target for many smaller operators in the region.

Huron Counties

Kentucky: Boyd, Breathitt, Carter, Clay, Elliott, Estill, Floyd, Greenup, Harlan, Jackson, Johnson, Knott, Knox, Laurel, Lawrence, Lee, Letcher, Lewis, Leslie, Magoffin, Menifee, Martin, McCreary, Morgan, Owsley, Perry, Pike, Powell, Pulaski, Rockcastle, Rowan, Wayne, Whitley, Wolfe

West Virginia: Boone, Cabell, Calhoun, Clay, Fayette, Jackson, Kanawha, Lincoln, Logan, Mason, McDowell, Mingo, Putnam, Raleigh, Ritchie, Roane, Wayne, Wirt, Wood, Wyoming

Virginia: Buchanan, Dickenson, Lee, Scott, Wise

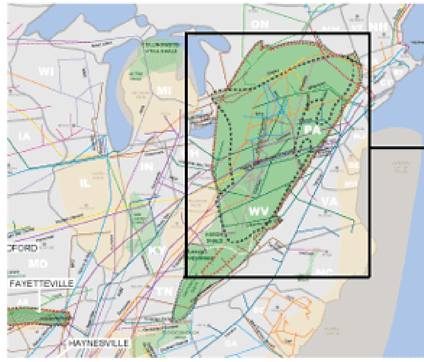
Local Major Pipelines

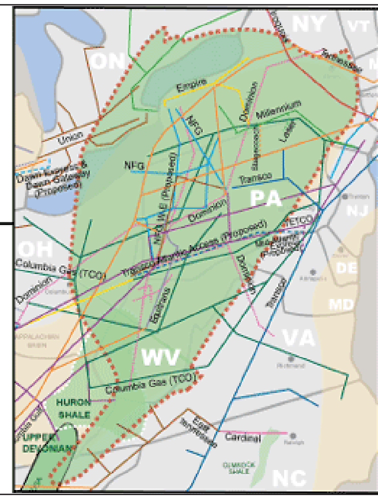
Natural Gas: Columbia Gas Transmission, Dominion Transmission, Empire Pipeline, Equitrans, Leidy Hub, Millennium, National Fuel Gas, Tennessee, Texas Eastern Transmission, Transco

UTICA SHALE

Background Information

States Included: Kentucky, Ohio, Maryland, New York, Pennsylvania, Tennessee, West Virginia, and Virginia

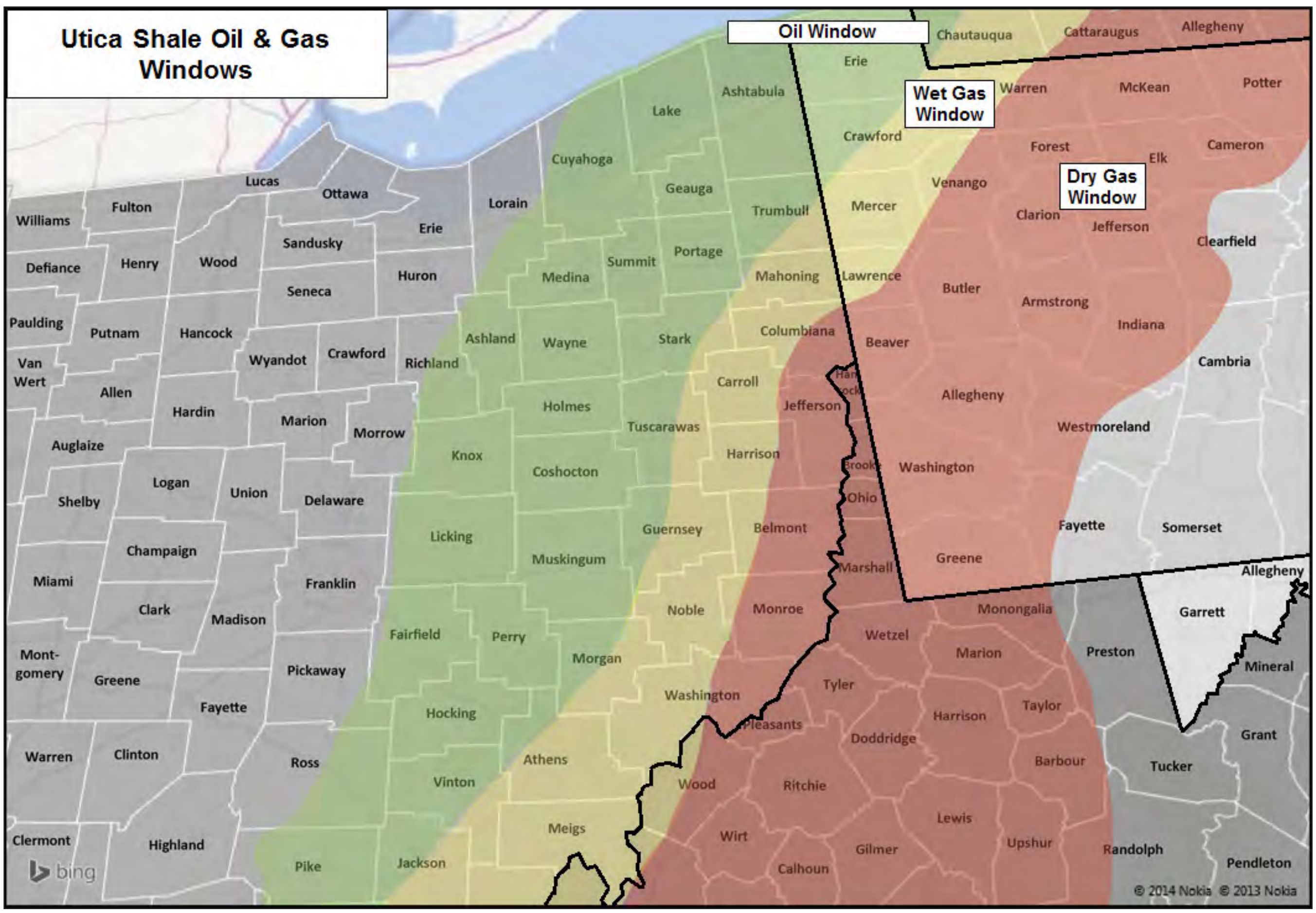




Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

The Utica Shale is a massive formation that lies beneath portions of Ohio, West Virginia, Pennsylvania, Kentucky, Maryland, New York, Tennessee, Virginia and a part of Canada. In a September 2012 report, the United States Geological Survey (USGS) estimated that the Utica has a recoverable potential of 940 million barrels of oil, and approximately 38 trillion cubic feet of natural gas. That estimate, though, has proved conservative at best. With far more drill bits having proved-up the play in Ohio, a West Virginia University-led study released in mid-2015 estimated that the Utica contains more than 20 times as much technically recoverable natural gas resources than previously thought when the USGS released its report (see *Shale Daily*, July 14, 2015).

WVU's Appalachian Oil and Natural Gas Research Consortium said the Utica contains technically recoverable resources of an astounding 782 Tcf of natural gas and nearly 2 billion bbl of oil, an estimate that surpasses the USGS's most recent estimate for all recoverable resources in the Appalachian Basin. The consortium has long been a trusted resource in the region, and at the very least, its work shows that the Utica is also comparable to the nation's largest gas field in the Marcellus Shale. In August 2011, the last time



Utica Shale (continued)

1H15 Ohio Utica/Pt. Pleasant Oil & Gas Production

Operator	Oil (Thou Bbls)	Gas (MMcf)	Total (Mmcfe)	% Share
Chesapeake Energy	3,989.1	153,438.5	177,373.2	38.1%
Gulfport Energy	1,100.5	96,476.3	103,079.5	22.1%
Antero Resources	877.6	49,565.4	54,830.8	11.8%
Eclipse Resources	1,203.8	18,744.3	25,966.9	5.6%
Hess Corporation	223.2	18,741.9	20,081.1	4.3%
Rice Energy	352.7	27,027.2	29,143.4	6.3%
American Energy	1,187.5	14,150.2	21,275.0	4.6%
Consol Energy	411.9	10,295.2	12,766.3	2.7%
Magnum Hunter	18.6	5,124.0	5,235.4	1.1%
Hilcorp Energy	0.0	2,649.0	2,649.0	0.6%
ExxonMobil/XTO Energy	17.4	2,602.7	2,706.9	0.6%
PDC Energy	330.1	1,992.0	3,972.7	0.9%
Atlas Noble LLC	38.2	1,614.9	1,844.0	0.4%
Statoil	50.9	886.5	1,191.8	0.3%
Hall Drilling	0.0	508.3	508.3	0.1%
Halcon Resources	8.7	441.2	493.6	0.1%
EM Energy Ohio	7.2	352.1	395.1	0.1%
EQT Corporation	21.9	230.1	361.2	0.1%
Artex Oil	8.0	200.3	248.6	0.1%
EnerVest	24.3	154.6	300.2	0.1%
Carrizo Oil & Gas	112.0	117.8	789.6	0.2%
Chevron	23.6	108.9	250.6	0.1%
NGO Development	3.6	24.0	45.5	0.0%
TOTAL	**10,010.6**	**405,445.4**	**465,508.8**	**100.0%**

Source: Ohio Department of Natural Resources, NGI's Shale Daily calculations

the USGS released a resource estimate for the Marcellus; it said the formation contained 84 Tcf of natural gas and 3.4 billion bbl of oil. That number, however, is likely outdated, with producers in Pennsylvania churning out more than 4 Tcf of natural gas in 2014 alone.

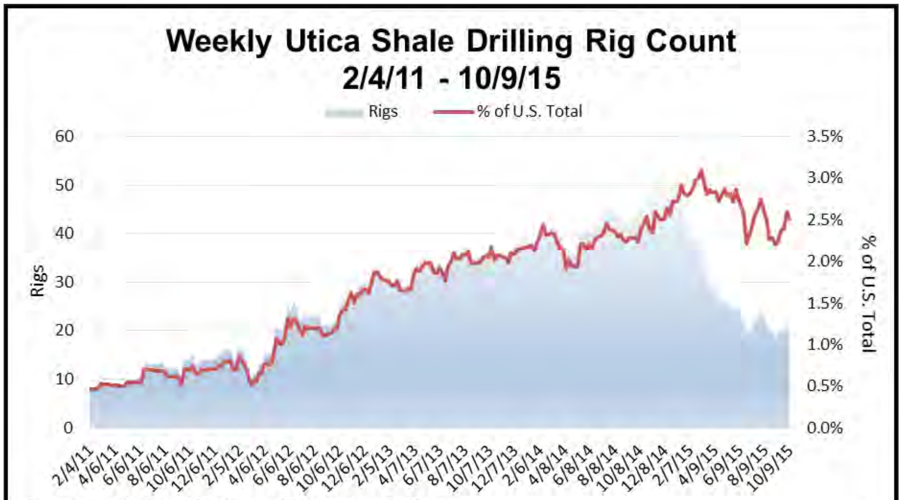
"The revised resource numbers are impressive, comparable to the numbers for the more established Marcellus Shale play, and a little surprising based on our Utica estimates of just a year ago, which were lower," consortium Director Doug Patchen told *NGI* at the time WVU's report was released. "But this is why we continued to work on the resource estimates after the project officially ended a year ago. The more wells that are drilled, the more the play area may expand, and another year of production from the wells enables researchers to make better estimates."

Despite its geologic reach, most of the oil and gas exploration and development activity in the Utica has thus far been focused in Eastern Ohio. But the boundaries have shifted slowly since early 2014, with operators setting out to delineate the formation in Northern West Virginia and more recently in Southwest Pennsylvania (see *Shale Daily*, March 26, 2014). Driven by a need to pad their reserves, grow production, and, more recently, in a shift away from falling liquids prices, several of the Appalachian Basin's leading producers have been drawn to an area with incredibly strong dry gas shows that encompasses a sort of geographic circle running from Southeast Ohio, over to Southwest Pennsylvania and down to Northern West Virginia.

The robust development in Ohio so far has been attributable to its wet and dry gas windows and the possibility of an oil window farther to the north. Production in the state has also been boosted

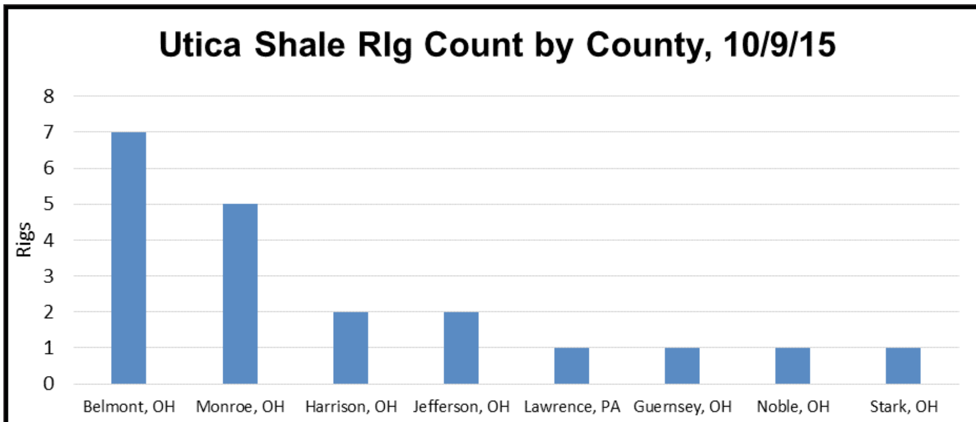
Utica Shale (continued)

by the Point Pleasant carbonate formation, which lies just below the Utica, and has in actuality served as the play's primary target. The Utica is shallower in Ohio, meaning it is relatively less expensive to drill. The Utica ranges between 2000'-8000' feet deep in Ohio, but increases to as much as 14000' deep in portions of Pennsylvania.



Source: Baker Hughes, NGI calculations

The Keystone State has increasingly become a part of the Utica horizon. In north-central Pennsylvania, more than 100 miles away from what was previously thought of as the Utica's sweetspot in Southeast Ohio, the formation ranges anywhere from 3,000-5,000 feet deeper than the Marcellus, which was once the sole target for operators in that part of the state.



Source: Baker Hughes

A Royal Dutch Shell plc affiliate has tested more than two wells in Tioga County. In late 2014, the company said its Neal and Gee wells were drilled to a total depth of 14,500 and 15,500 feet, respectively. The Gee well had an initial flowback rate of 11.2 MMcf/d, while the Neal well had a peak flow rate of 26.5 MMcf/d. Months later, Seneca Resources Corp. said its Utica well drilled on state-owned land in Tioga County, PA, had a 24-hour peak production rate of 22.7 MMcf/d. Little is generally known about Utica mechanics that far east.

As of October 2015, the Pennsylvania Department of Environmental Protection showed that 43 Utica permits have been issued in Tioga County and five Utica permits have been issued in nearby Potter County, PA. Today, although a few small operators continue to explore the Utica in the area, it remains hamstrung by both a lack of takeaway and a waning appetite for risk amid depressed natural gas prices (see *Shale Daily*, Oct. 13, 2015).

In addition to the play's inflated resource estimate, a tight, seven-county swath encircling Northern West Virginia, Southeast Ohio and Southwest Pennsylvania, where results have seemingly reinforced one another, have prompted renewed excitement about the Utica's role in pushing the Appalachian Basin's prolific gas production higher (see *Shale Daily*, Aug. 25, 2015). In Southeast Ohio and Northern West Virginia, operators have tested Utica wells between 25 MMcf/d and nearly 47 MMcf/d.

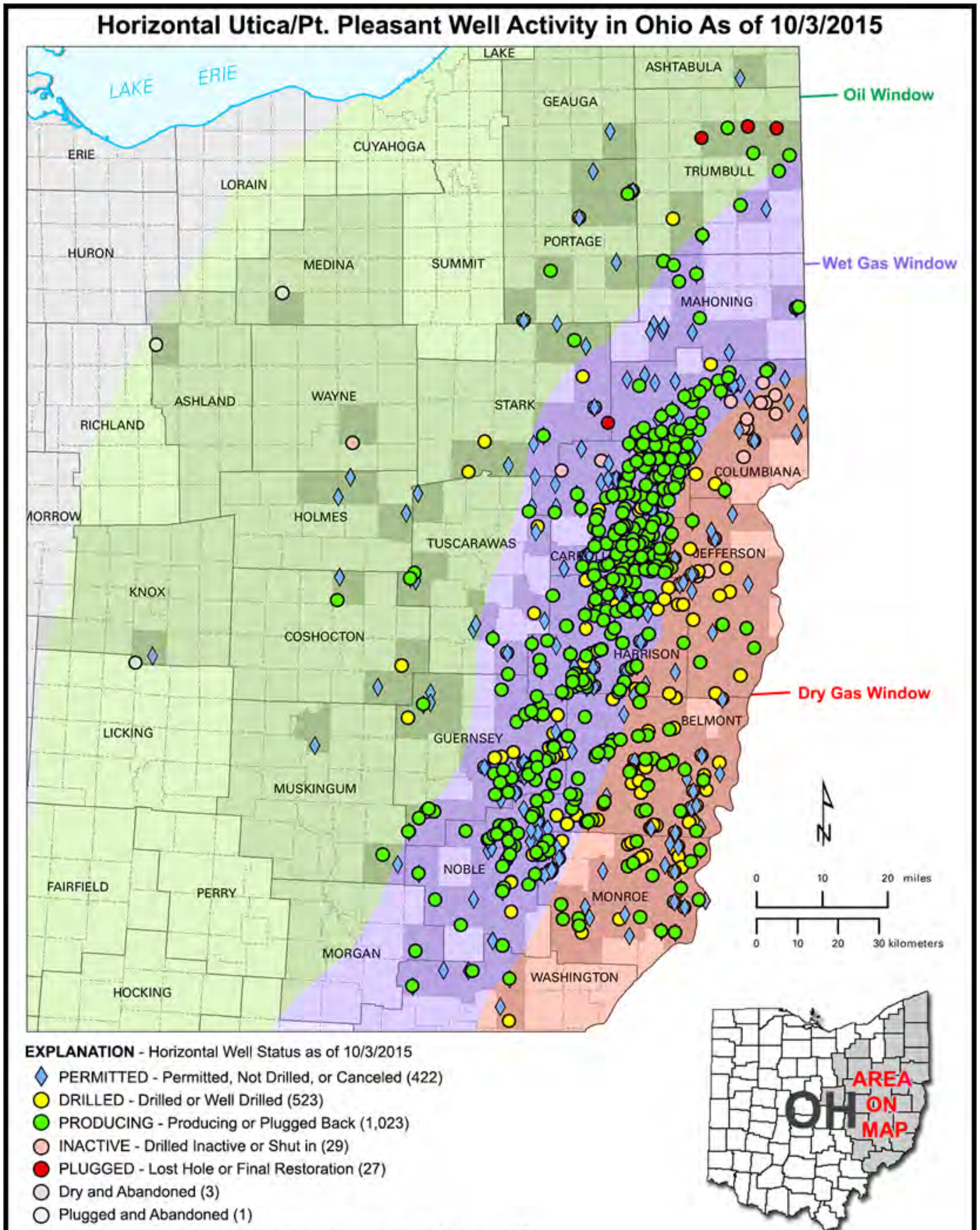
In Southwest Pennsylvania, the stakes have edged higher, where Range Resources Corp.; EQT Corp. and Consol Energy Inc. have all tested deep, dry Utica wells between 59-72.9 MMcf/d. Although those wells have come with astronomical price tags — costing about $30 million each — management teams have said they're aiming to get costs down to between $12-15 million per well. EQT has said it would suspend its Upper Devonian drilling program in 2016 and defer some Marcellus drilling to build a 10 well Utica program in Pennsylvania. Range had two other Utica wells planned for Pennsylvania at the time of this writing, while Consol was preparing to hydraulically fracture its second and indicated it was thinking along the same lines as EQT.

"Over the next two to three years [we] expect the dry Utica to become the primary focus of our development plan and a greater and greater contributor to production growth," said Consol COO Timothy Dugan of the company's acreage in Ohio and Pennsylvania. Still, the eye-popping initial production rates from the wells tested to date have financial analysts, company officials and industry onlookers concerned about decline rates. Last

Utica Shale (continued)

December, Range's Claysville Sportsman's Club Unit 11H Utica well in Washington County, PA, tested at 59 MMcf/d. It was the first such well drilled in Southwest Pennsylvania. But the company's reservoir modeling and production history led it in October 2015 to announce an estimated ultimate recovery (EUR) for the well of 15 Bcf, or 2.8 Bcf per 1,000 feet of lateral. For now, that appears to be no better than the company's leading Marcellus EUR's, which range from 17-18 Bcf, or 2.5-3 Bcf per 1,000 feet of lateral. Range CEO Jeffrey Ventura said at the time that in the current commodity price environment, the Utica wells can't compete with the Marcellus. After the company drills and completes its third Pennsylvania Utica well, it plans to drill no more in 2016.

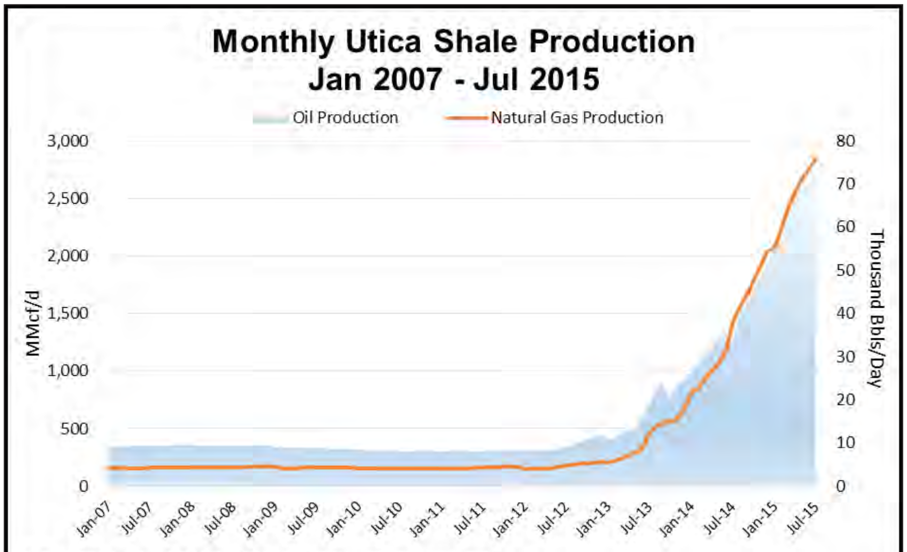
"When you look at our plan for next year, our focus is really going to be on the Marcellus. We think with those three [Utica] wells, coupled with activity around us, it'll give us a really good handle



Source: ODNR, with production windows added by NGI

Utica Shale (continued)

on what the Utica ultimately is," Ventura said of the company's plans for 2016 after it announced the Utica EUR, which was similar to one issued by EQT. "But what we know is we have 10 years worth of production history and thousands of wells that really delineate our [Marcellus] position, so that's the low-risk piece."



Source: EIA, NGI's Shale Daily calculations

For now, the wells in Ohio cost less than half what they do in nearby Pennsylvania and are still cheaper than in West Virginia. As of October 2015, the Ohio Department of Natural Resources had issued 2,065 horizontal Utica permits and 1,629 horizontal Utica wells had been drilled. Permitting and production have grown rapidly in the state since speculation began in earnest there around 2009.

Oil and gas production in the Utica has increased sharply. According to the EIA, operators were producing more than 3 Bcf/d in October 2015. Shale production in the state went from 2.5 Bcf in 2011, when the state released its first figures from five commercial Utica wells, to about 452 Bcf three years later in 2014, the latest period for which full-year data are available. In fact, while production was expected to drop in nearly every shale basin across the country, Jefferies LLC found in a September 2015 survey that Northeast supply would increase 1.4 Bcf/d year-over-year in 2016 – split fairly equally between both the Marcellus and Utica.

One key question surrounding the burgeoning potential of dry gas production in the Utica is would it simply replace higher cost production areas in other parts of North America, or would it be additive to total U.S. production? That remains to be seen, but with more than enough natural gas pipeline takeaway capacity being built out of Appalachia, gas from both the Marcellus and the Utica most likely will at least have the opportunity to displace higher cost production in the coming years. But as far as being additive to total U.S. production, at least one high profile executive in Appalachia doesn't quite see it. "In terms of near to medium-term supply, since these are Marcellus players diverting capital away from Marcellus development, PA Utica production growth really just replaces what would've otherwise been Marcellus production growth, " said Rice Energy CEO Daniel Rice, on the company's 3Q15 earnings conference call. "Therefore, we do not believe that this is an additive source of supply to the basin."

Like its counterpart in the Marcellus; natural gas processing and takeaway has been playing catch-up in the Utica for years now. The volatility of gas prices also continues to threaten the bottom line of Utica operators, especially for those that rely on it more than others do to drive earnings and growth. But a suite of high-profile pipeline projects continue to be planned for the basin. Most recently, the Rockies Express Pipeline started-up its East-to-West expansion, adding 1.2 Bcf/d of incremental westbound capacity from its easternmost point in Clarington, OH, to Moultrie, IL. Sunoco Logistics Partners LP's Mariner East pipelines are also expected to help move natural gas liquids from Ohio, West Virginia and Pennsylvania, and Marathon's proposed Cornerstone Pipeline would move condensate from the emerging hub at Cadiz, OH in Harrison County to Marathon's Canton, OH refinery. Another example is the Atlantic Coast Pipeline, which would move Utica dry gas to power generators in the Southeast.

Historically, Devon Energy Corp. was an early entrant into the Utica Shale, securing some of its first horizontal permits in 2011 in Ashland and Medina counties, OH, where it drilled and plugged dry holes. It continued to permit across a swath of land throughout the next year along the Utica's western edge, completing unsuccessful wells in Coshocton and Wayne counties in search of black oil. It even drilled as far west as Knox County, OH, which is more than 100 miles west of the play's current core in the southeast part of the state, before abandoning the Utica and selling its acreage. Activity within the oil window has been far less prevalent, and there is much debate within the industry as to just how economical this portion of the Utica will be. A slew of black oil wells has been drilled (primarily in northern Ohio), with more than two dozen volatile oil wells drilled farther south near Guernsey and Tuscarawas Counties, according to EV Energy Partners LP (EVEP). Moreover, several operators – including BP plc and Halcon Resources Corp. – have announced plans in recent years to abandon their development of the Utica's northern tier in Ohio, which today is generally perceived to consist of Mahoning, Trumbull, Stark and Portage counties, and to a lesser extent Tuscarawas County.

Utica Shale (continued)

The challenge in the oil window appears to be fracture design and minimizing reservoir damage upon completion. EVEP had been among the Utica oil window pioneers. In mid-2015, after 90 days of production, the company's closely watched Nettles 3H well in Tuscarawas County, OH, which was stimulated with a mixture of liquid butane and mineral oil instead of water, failed to meet the company's expectations. It was the latest effort to crack the code of the Utica's volatile oil window, where EVEP estimates up to 30 million bbl of oil are in place across more than 70,000 acres in Stark, Tuscarawas and Guernsey counties. The costly Nettles well was drilled in partnership with other operators to learn more about the window's rock mechanics. The test came after EVEP's joint venture partner, Chesapeake Energy Corp., had drilled its own volatile oil well in Tuscarawas County in 2014 with what EVEP said had been encouraging results. Chesapeake's Parker well, however, was super fracked using more water and proppant than an average horizontal well, EVEP management said.

"The Nettles well production is about half that of the Parker well," EVEP's Executive Chairman John Walker said in May 2015, when the company discussed the results. "We are continuing to perform additional testing on the Nettles well and in addition, Chesapeake plans to drill about six more wells in the area."

"We will eventually conquer the raw mechanics to be able to get at this 30-plus million bbl of oil in place," EVEP CEO Mike Mercer added. "But it just takes some time and money, and we are not going to be the primary company that leads the way there either."

It's only a matter of time, sources have said, before operators learn how to move oil molecules through the small pores of shale rock underneath a five-county region in northeast Ohio and a larger area to the west. Some acreage in Northwest Pennsylvania is believed to hold the same potential. In late 2015, both Rex Energy Corp. and Seneca Resources Corp. announced their intent to test more Utica wells in Northwest Pennsylvania as well (see *Shale Daily*, July 8, 2015).

Counties

Core Ohio Utica Counties: As Identified by the Ohio Department of Natural Resources: Ashland, Ashtabula, Belmont, Carroll, Columbiana, Coshocton, Crawford (immature), Delaware (immature), Fairfield, Franklin (immature), Geauga, Guernsey, Harrison, Holmes, Huron (immature), Jefferson, Knox, Lake, Licking, Lorain, Madison (immature), Mahoning, Marion (immature), Medina, Monroe, Morgan, Morrow (Immature), Muskingum, Noble, Perry, Pickaway (immature), Portage, Richland (immature), Stark, Summit, Trumbull, Tuscarawas, Union (immature), Washington, Wayne

Note: Immature counties are likely not commercially viable. As of October 2015, none of the 2,065 horizontal permits the ODNR had issued were in the immature counties.

Pennsylvania: Armstrong, Beaver, Butler, Cameron, Clarion, Crawford, Elk, Erie, Forest, Jefferson, Lawrence, McKean, Mercer, Potter, Venango, Warren, Tioga

Local Major Pipelines

Natural Gas: ANR East Project (Proposed), Clarington Hub, Cobra Pipeline, Columbia Gas Transmission, Dominion Transmission, East Ohio Gas, Mountain Valley (Proposed), Nexus Gas Transmission (Proposed), Rockies Express, Rover (Proposed), Tennessee, Texas Eastern

Crude Oil: Cornerstone Pipeline (Condensate) (Proposed)

NGLs: ATEX Express, Mariner East 2 (Proposed), Mariner West, TEPPCO, UMTP (Proposed), Utopia East (Proposed)

UTICA SHALE NET ACREAGE POSTIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Chesapeake Energy	1,090,000	Carrizo Oil & Gas	28,900
EnerVest[1]	903,000	Lario Oil & Gas Company	23,000
Consol Energy	614,000	Hess Corporation*	22,500
Shell (East Resources)	430,000	Gastar	10,200
Southwestern Energy	413,000	Atlas Resources Partners	2,900
EQT Corporation	400,000	Atinum	N/A
Range Resources	400,000	Atlas Noble LLC	N/A
Chevron	364,000	Beusa Energy	N/A
Antero Resources	333,000	Brammer Engineering	N/A

Utica Shale (continued)

UTICA SHALE NET ACREAGE POSTIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Rex Energy	315,000	Cabot Oil & Gas	N/A
American Energy Utica	250,000	EdgeMarc Energy	N/A
Gulfport Energy	247,000	Encore Energy	N/A
Devon Energy	195,000	EOG Resources	N/A
Total	155,000	Hall Drilling LLC	N/A
Halcon Resources	128,000	HG Energy LLC	N/A
Magnum Hunter	125,000	Hilcorp Energy	N/A
Eclipse Resources	101,000	Mountaineer Keystone	N/A
BP	84,000	Sierra Resources LLC	N/A
ExxonMobil (XTO)	81,452	Statoil	N/A
PDC Energy	67,000	Sumitomo	N/A
Rice Energy	56,000	Trans Energy	N/A
Stone Energy	35,000		

NOTE: Utica Shale includes Ohio, Pennsylvania, and West Virginia. This chart contains companies that are believed to be active (either directly or through non-operated positions) in the Utica. It does not necessarily include companies that ***may*** have rights to the Utica, such as those with acreage in the Upper Devonian and Marcellus Shale in NW PA.

*Estimate

[1]The total combined EnerVest and EVEP net acreage is 747K in Ohio and 156K in Pennsylvania.

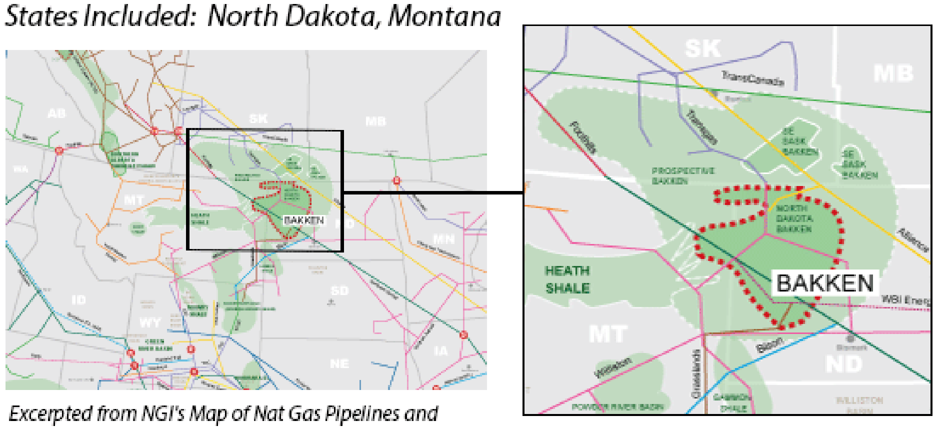
Source: Compiled by NGI from company documents

BAKKEN SHALE

Background Information

The Bakken Shale and the underlying Three Forks formation are both part of the Williston Basin, which spans portions of North Dakota, South Dakota, Montana, Manitoba, and Saskatchewan. Much of the industry development to date has occurred on the U.S. side of the border, primarily in Western North Dakota and Eastern Montana. In Canada, the majority of Bakken activity has been focused in Southeast Saskatchewan and Southwest Manitoba.

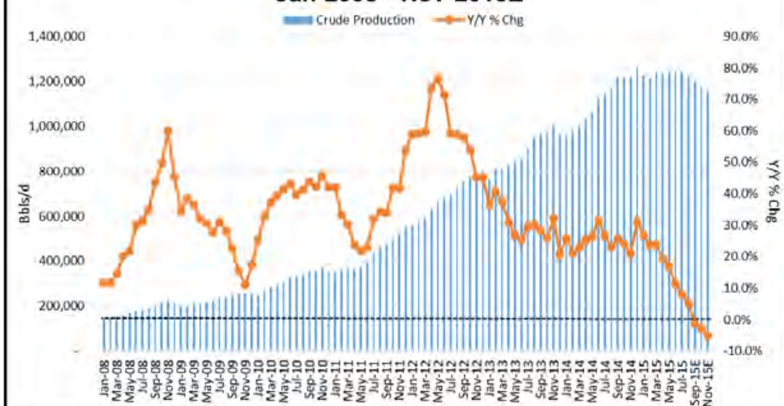
States Included: North Dakota, Montana



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

Most of the Bakken/Three Forks reserves are crude oil, and it is a high quality crude at that. The light sweet crude that is typical in the Bakken has an average API gravity of around 40, which is very similar to the West Texas Intermediate crude oil that is used as the benchmark for the NYMEX crude oil futures contract. Activity in the Bakken has been so robust that in March 2012, North Dakota passed Alaska to become the 2nd highest producing U.S crude oil state, up from 8th in 2002.

Monthly Bakken Crude Oil Production
Jan 2008 - Nov 2015E



Source: EIA, NGI's Shale Daily calculations

Although both the rig count and production was declining along with lower prices as 2015 was drawing to a close, absolute crude oil production continued to hold just above a million barrels a day at 1.16 million b/d in October 2015. It was in July 2013 that total Bakken crude production exceeded 1 million bbls/day for the first time.

Lynn Helms, director of the North Dakota's Department of Mineral Resources said in November, 2015 he expects current price and production levels to continue throughout 2016. Larger producers are slowing down as a signal to the market, he said (see *Shale Daily*, Nov. 16, 2015).

"Oil price weakness is now anticipated to last through next year, and it is the main reason for the continued slowdown," Helms said. Production and rig counts continued to drop in September, and the number of uncompleted wells increased by 98 to 1,091. Natural gas production in September dropped to 48.1 Bcf (1.60 Bcf/d) from 51 Bcf (1.64 Bcf/d) in August. Producing wells dropped slightly from an all-time high in August (13,031) to 13,025 in September. It was the first time in the last 12 years that the number of producing wells dropped.

Helms called the 2% (25,000 b/d) drop in production significant. "That's sending a definite signal to the market that oil and gas operators are not willing to do a lot of drilling or hydraulic fracturing or produce oil at these low prices," he said.

The current drop is deeper than operators would have anticipated going into this year, said Helms, noting that natural gas production also fell nearly 2% for the month.

"With the mild weather, natural gas prices are very low, under $2/Mcf, and it's probably been more than a decade since that has happened [at this time of the year]," Helms said.

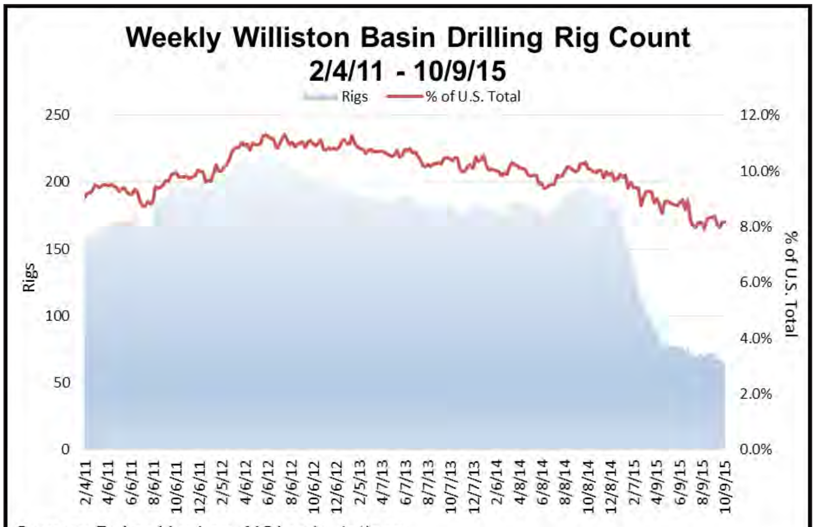
The rig count continued to fall, hitting 65 in early October after reaching 71 in September and 73 in August. Bakken sweet crude prices tumbled again, hitting $31.25/bbl in November, compared to $34.37/bbl in October. Only three of North Dakota's dozen

Bakken Shale (continued)

producing counties now have break-even prices that are below the $31.25/bbl price, he said.

"57 of the 65 rigs at work in October 2015 were in the "Big 4" counties of McKenzie, Dunn, Mountrail, and Williams, North Dakota, which we believe represents the core of the play."

Helms said it could take up to a year for drilling to reverse course and ramp upward once prices turn around. "Many of the rigs that have been idled are being scavenged for parts," he said. "It is going to take some weeks or months to put all the pieces back together, mobilize the equipment, get the crews back together and be able to get up and running again."



Source: Baker Hughes, NGI calculations

Despite the downturn Tulsa-based Oneok Partners LP was planning to start up a new natural gas processing plant in November in the heart of the Bakken Shale play in McKenzie County, ND, and that is just the beginning of a series of infrastructure additions slated for the area by the end of next year (see *Shale Daily*, Nov.10, 2015).

Oneok's 200 MMcf/d Lonesome Creek gas processing plant was set to start operations early in 2016, and the company plans to have additional processing and pipeline infrastructure in place, bringing to a close a multi-billion-dollar, six-year effort to meet demand for new takeaway capacity in the Williston Basin (see *Shale Daily*, May 20, 2014).

Related to the Lonesome Creek facility, Oneok has begun construction of a second expansion of its Bakken natural gas liquids (NGL) pipeline, a $100 million addition to boost the pipeline's total capacity to 160,000 b/d. It is scheduled to be completed in the second quarter of 2016.

The Bakken NGL pipeline was originally built as a 60,000 b/d conduit and in 2014 was expanded to 135,000 b/d, but additional capacity was needed to handle NGL volumes envisioned from Lonesome Creek.

A year ago, Oneok established a $480-680 million program for infrastructure additions in North Dakota and Wyoming, capping a six-year $7.5-8.2 billion capital expenditure program to keep pace with the U.S. domestic oil/gas boom (see *Shale Daily*, Sept. 23, 2014).

But early in 2015, Oneok suspended plans to build a trio of gas processing plants in the Bakken and two other shale basins in three states as part of a revised capital spending budget in response to the crude oil price crash (see *Shale Daily*, Feb. 24, 2015). That included suspension of construction of the Demicks Lake facility in the Williston Basin in North Dakota.

Senior executives of Continental Resources Inc., one of the biggest Bakken Shale and Oklahoma oil producers, in November held onto their optimistic view of increasing onshore production and decreasing costs, although the company also saw more red ink in the third quarter.

The company's production was up substantially in the Bakken in 3Q2015 results, with the Bakken providing 123,000 boe/d of Continental's overall production in 3Q2015 of 228,278 boe/d. Based on the quarterly results Continental has increased its production growth guidance to 24-26% this year.

In the Bakken, Continental has slashed the time from spud-to-total depth (TD) to 15 days in 3Q2015 from 17.1 days in the first quarter, COO Jack Stark said. Some of the biggest advances are coming in drilling laterals, and Stark said Continental set a record in the Bakken, completing a 9,490-foot lateral in 2.4 days. "Overall, our enhanced completion costs in the Bakken are down 27% year-to-date to $7 million." Operators reported more typical, less enhanced well drilling and completion costs more in the $6.2-$6.5 million range in October and November.

Its backlog of drilled but uncompleted wells in the Bakken grew to 123 in the third quarter, with 20-25 of those to be completed before the end of 2015.

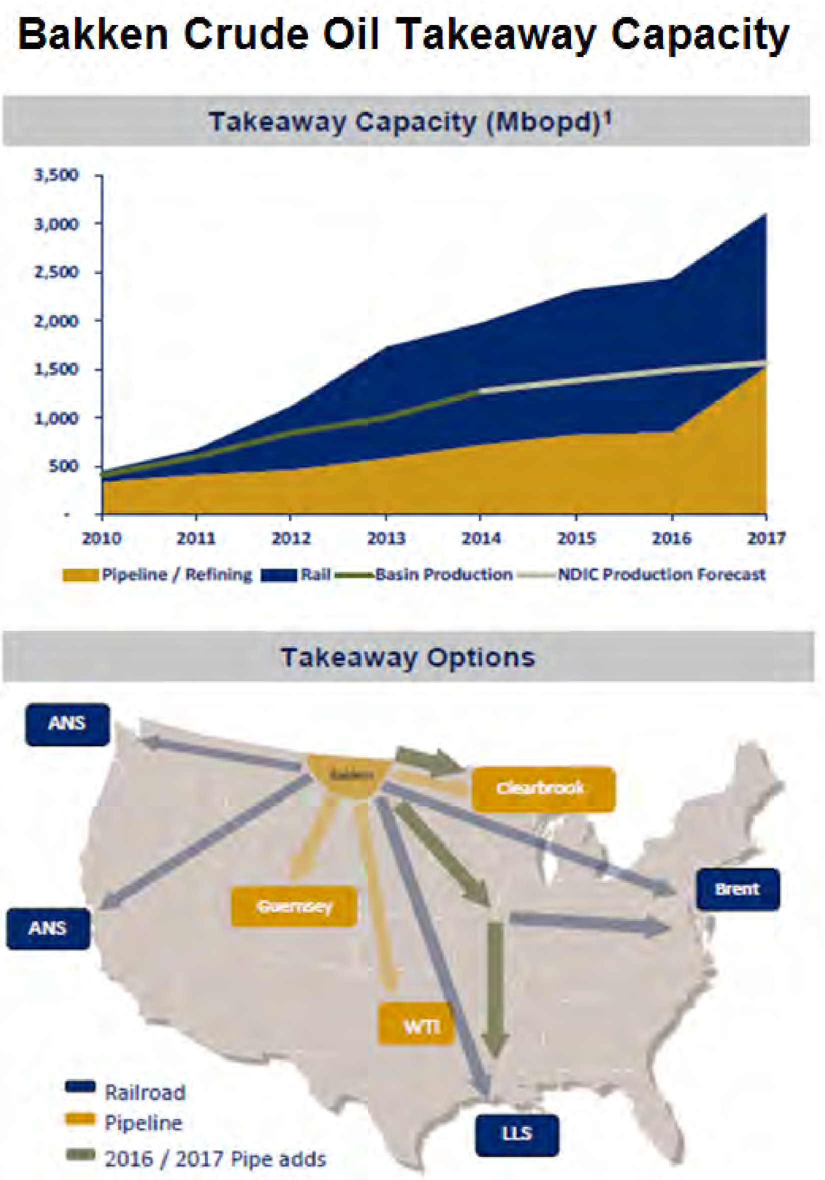
Continental plans to continue to operate eight rigs in the Bakken through the end of this year, but if prices don't begin to rise, that number would not be maintained next year when five of the eight drilling contracts expire. "We have flexibility, and we could keep all the rigs, but that won't continue unless prices begin to recover," CEO Harold Hamm said (see *Shale Daily*, Nov. 6, 2015.

Bakken Shale (continued)

The crash in oil prices threatened reversals in the joint effort of the state of North Dakota and producers to continue lowering the amounts of flared gas at the wellhead (see *Shale Daily*, July 29, 2015).

Bakken operators are drilling better and more productive wells these days. In addition to drilling wells with longer laterals, several producers are seeing improved well yields from better completion techniques. For example, Whiting Petroleum and SM Energy have reported progress moving from sliding sleeves to a cemented liner plug and perf completion process, while Continental Resources, Halcon Resources, and Oasis Petroleum all have achieved better results by using more proppant and/or slick water fracking fluids.

Technological advancements such as these are also allowing operators to recover more of the original oil in place. In May 2014, Whiting Petroleum's CEO Jim Volker remarked at an industry conference that "when we started [in the Bakken], we were seeing 10% recovery rates; now we all agree we're getting to 20%. Ten years from now it might be up to 40%. So if we do a good job, we will be able to recover the higher numbers with just the same well spacing and takeaway capacity we put in place today."



[1]Per North Dakota Pipeline Authority as of November 2015

Source: Oasis Petroleum

Before the crude oil price crash, Continental Resources' Hamm told the audience at that same conference that he sees a doubling of Bakken production to 2 million b/d by 2020 or sooner, and Oasis Petroleum's CEO Thomas Nusz added that "we have a resource life here [in the Williston Basin] that is 50 to 60 years, so it's not your father's oil business anymore," citing some technically recoverable reserve estimates for the Bakken at 24-30 billion bbl levels. "This is going to be an important part of life in North Dakota for a long time," Nusz concluded. In 2015 the bullish growth projections were replaced by cautious estimates of holding production above the 1 million b/d level.

The slowdown takes some of the pressure off the shortage of takeaway capacity. In the absence of enough pipelines, rail transportation has rallied to the rescue. According to a September 2014 analysis conducted by the University of Texas Center for Energy Economics (CEE) in Austin, rail capacity to move oil (1.49 million b/d at last estimate) out of the Bakken is unlikely to be equaled by pipelines, which have about 824,000 b/d in total capacity, up from 200,000 b/d in 2008. Rail capacity for moving oil seven years ago was basically zero, so the growth on the rail side has been unprecedented.

Rail capacity at one time accounted for 63% of the total oil transport capacity from North Dakota, but that has dropped to under 50% in late 2015." The three main rail lines that traverse North Dakota are BNSF Railway, Canadian Pacific (CP) and Northern Plains.

Bakken Shale (continued)

In the fall of 2015, the North Dakota Pipeline Authority estimated total Bakken takeaway capacity at 2.31 million b/d, while average production for the year to date was about 1.1 million b/d. The pipeline authority estimated the takeaway growing to 2.44 million b/d at the end of 2016. Rail capacity was 1.49 million and 1.59 million b/d, in those two years, respectively.

Part of growth in takeaway capacity came from the new 20,000 bbls/d Dakota Prairie Refinery that opened in summer 2015.

Enbridge Energy Partners announced the start-up date for its proposed 225,000 barrel Sandpiper Pipeline, which would carry crude oil from the Bakken, has been pushed back by a year to sometime in 2017 because of problems obtaining permits in Minnesota.

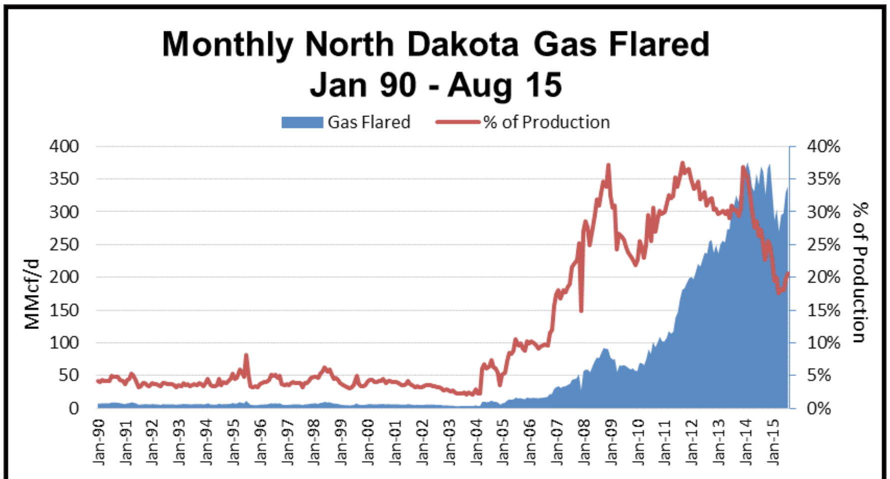
Bakken crude historically has traded at a $9-$10/bbl discount to WTI, or at roughly an 8%-10% discount to NYMEX, but was narrowing slightly in late 2015 to around $7 or $8. These discounts could contract some once more pipeline capacity comes online to complement rail capacity.

Pipeline takeaway and processing capacity is an issue on the natural gas side as well. Bakken operators are currently flaring roughly 20% of natural gas production in North Dakota because of a lack of gathering and processing capacity, although the state is working on getting that number down to 9% or less in 2020. (In October 2015 flaring was reduced to 14% statewide.) Producers have an extra economic incentive to bring that supply to market, since natural gas in the Bakken is extremely liquids rich.

Oneok is leading the charge to build more gathering and pipeline capacity in the area. MDU Resources has proposed the 400 MMcf/d Dakota Pipeline, but it remained on hold in 2015. Separately, North Dakota-based MDU's pipeline unit, WBI Energy Transmission Inc., in the spring of 2015 asked FERC to start the environmental pre-filing review process for its proposed 22-mile, 24-inch diameter natural gas transmission pipeline for taking Bakken natural gas to the Northern Border Pipeline Co.'s interstate system feeding the Midcontinent.

According to North Dakota Industrial Commission data, as of Oct. 23, 2015, Whiting Oil & Gas, Continental Resources, Hess Corporation, ExxonMobil XTO, and Burlington Northern were the five largest producers on the North Dakota side of the play.

As the low-price environment lingered on, production in the Bakken consolidated further into its four top producing counties



Source: North Dakota Industrial Commission, NGI calculations

— Dunn, McKenzie, Mountrail and Williams — (see *Shale Daily*, Aug. 20, 2015), With production essentially flat and expected to stay that way throughout most of 2016, state officials considered easing restrictions on uncompleted wells to give producers longer time periods to ride out the low commodity prices (see, *Shale Daily*, Oct. 14, 2015).

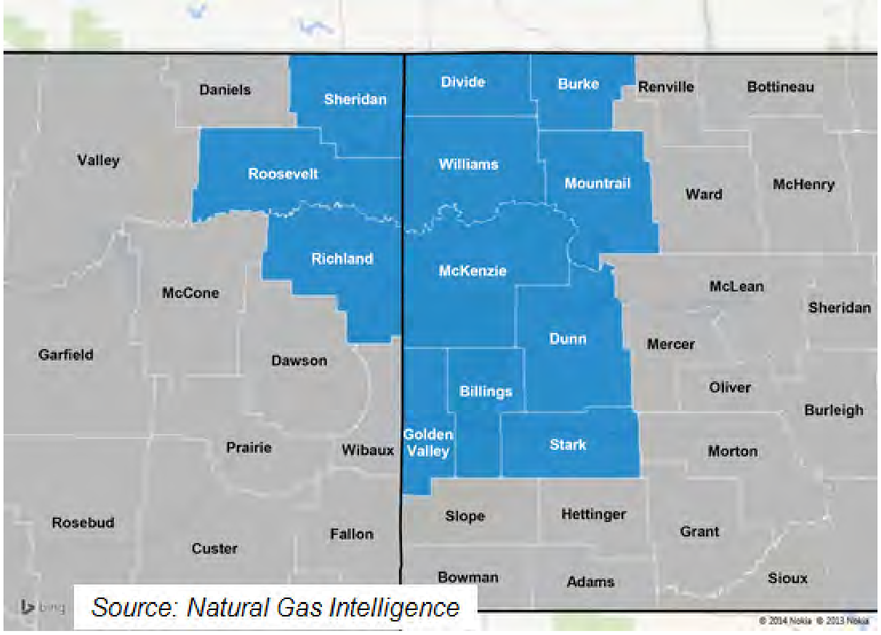
Long-standing plans for a major multi-billion-dollar fertilizer plant and related natural gas pipeline were scrapped during 2015 because the economics didn't pencil out (Oct. 30, 2015).

Counties

North Dakota: Billings, Burke, Divide, Dunn, Golden Valley, McKenzie, Mountrail, Stark, Williams

Montana: Richland, Roosevelt, Sheridan

Bakken Shale (continued)



Local Major Pipelines

Natural Gas: Northern Border, WBI Energy Transmission

Crude Oil: Bakken Pipeline (Enbridge), Bridger Pipeline, Butte, Dakota Access (proposed), Double H (proposed), Four Bears Pipeline, Keystone XL (proposed), North Dakota System (Enbridge), Plains Bakken North, Platte, Pony Express, Poplar System, Sandpiper (proposed), Tesoro, Upland Pipeline (proposed)

NGLs: Bakken NGL

BAKKEN SHALE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Continental Resources	1,074,000	Magnolia Petroleum	412
ExxonMobil (XTO Energy)	787,346	Behm Energy	N/A
Whiting Petroleum	667,668	Breitling Oil & Gas	N/A
ConocoPhillips	620,000	BTA Oil Producers	N/A
Hess Corporation	605,000	Charger Resources	N/A
Oasis Petroleum	500,000	Condor Petroleum	N/A
Lime Rock Resources	300,000	Crescent Point Energy	N/A
Marathon Oil	290,000	David H. Arrington Oil & Gas	N/A
Statoil	265,000	DW Energy Group	N/A
SM Energy	245,000	Endeavor Energy Resources	N/A
EOG Resources*	230,000	Enduro Operating	N/A
Northern Oil & Gas	169,020	Energy Quest II LLC	N/A
Halcon Resources	131,000	Evertson Operating	N/A
QEP Resources*	95,147	Filco Incorporated	N/A
Newfield Exploration	92,000	Flatirons Resources	N/A
WPX Energy	87,000	Gadeco, Inc.	N/A
Emerald Oil	86,000	Hall Phoenix Energy	N/A

Bakken Shale (continued)

BAKKEN SHALE NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Murex Petroleum	84,000	Hunt Oil Co.	N/A
Triangle Petroleum	79,000	Jayhawk Energy	N/A
Enerplus Resources Fund*	74,000	Jenex Operating	N/A
Vanguard Natural Resources	71,960	Jettison, Inc.	N/A
Magnum Hunter	65,650	Lario Oil & Gas	N/A
Cornerstone Natural Resources	60,000	Legacy Reserves	N/A
American Eagle Energy	54,250	Manti Resources	N/A
Liberty Resources II	53,000	Mountain Divide, LLC	N/A
Sequel Energy	50,000	North Plains Energy	N/A
Fidelity Exploration (MDU)	49,000	Peregrine Petroleum Partners	N/A
Missouri River Royalty Corp.	48,000	Petrogulf	N/A
Spotted Hawk Development (SHD Oil & Gas)	39,090	Petro-Hunt	N/A
Lonestar Resources	32,625	Pride Energy	N/A
Koch Exploration	29,500	Prima Exploration	N/A
Samson Oil & Gas	26,066	Ranch Oil	N/A
MBI Oil & Gas	20,460	Resource Drilling LLC	N/A
Citation Oil & Gas	20,000	RIM Operating	N/A
Natural Resource Partners	20,000	Rolling Hills Oil & Gas LLC	N/A
Magellan Petroleum	18,000	Rosewood Resources	N/A
Mountainview Energy	15,000	Sinclair Oil Corporation	N/A
Vaalco Energy	14,300	Slawson Exploration	N/A
Panhandle Oil & Gas*	11,179	TAQA Energy	N/A
Earthstone Energy	11,050	Texakota Inc.	N/A
Fram Exploration	10,500	The Triple T, Inc.	N/A
Dorchester Minerals	8,905	Thunderbird Resources	N/A
Arsenal Energy	8,364	True Oil	N/A
Stratex Oil & Gas*	8,228	Ward-Williston	N/A
Abraxas Petroleum	5,209	Wesco Operating	N/A
U.S. Energy	3,511	White Butte Oil	N/A
Wapiti Energy	2,741	WhitMar Exploration	N/A
Black Hills Corporation	1,756	Zargon Oil	N/A
Wellstar Corporation	1,164	Zavanna, LLC.	N/A
Gulfport Energy	864	Zenergy Operating Co.	N/A
Yuma Energy*	850		

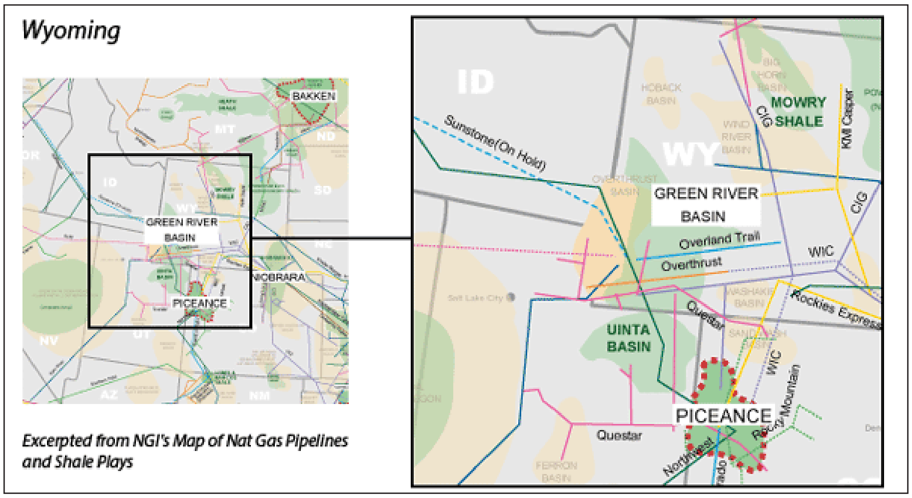
* Estimate

Source: Compiled by NGI from company documents

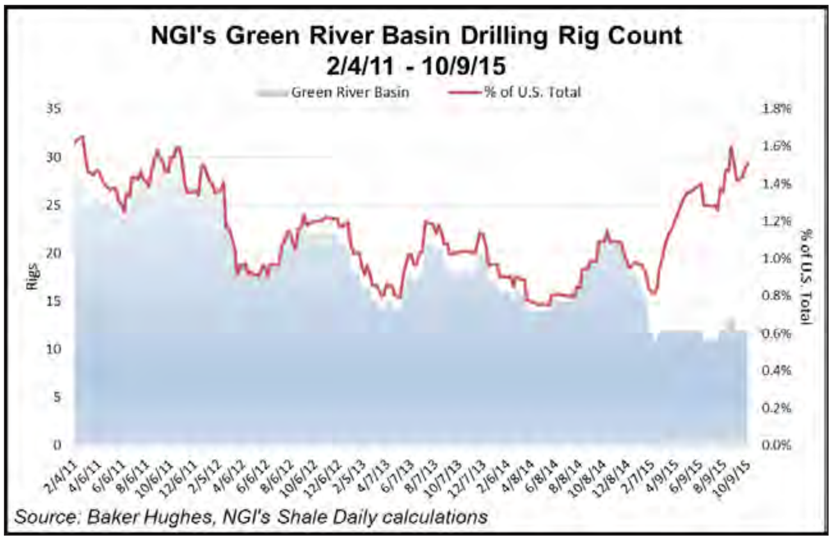
GREEN RIVER BASIN

Background Information

The Green River Basin (GRB) is actually a subset of what the United States Geological Survey calls the Greater Green River Basin, which also includes the Great Divide, Vermillion, and Washakie Basins in Wyoming, and the Sand Wash Basin in Colorado. For our purposes, we define the Green River Basin as all production within Lincoln, Sublette, Sweetwater, and Uinta Counties in Wyoming. This includes production in eastern Sweetwater County, which contains the aforementioned Great Divide, Vermillion, and Washakie Basins.



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays



Production in the GRB is dominated by natural gas and natural gas liquids (NGLs) from tight sands formations, primarily the Pinedale Anticline and the Jonah Field in Sublette County, and the Wamsutter Field in eastern Sweetwater County. In 2009, the U.S. Energy Information Administration pegged the Pinedale Anticline and Jonah Field as the 3rd and 7th largest U.S. natural gas fields as measured by proved reserves, respectively. The Wamsutter Field was 39th.

Both the Pinedale Anticline and Jonah Fields draw production from the over-pressurized Upper Cretaceous Lance Pool (which includes both the Lance and Mesaverde Formations), and produce high quality, "sweet" natural gas. The Pinedale lies at depths anywhere between 8,000'-19,000', with similar depths in the adjacent Jonah Field. The area also featured some of the first pad wells in the United States, and currently features drilling at as low as 5-10 acre spacing in some areas, among the tightest spacing allowed in the country.

The Green River Basin is a particularly environmentally sensitive area, and that has led to drilling restrictions over the years. For example, operators were not permitted to drill year round in the Pinedale until September 2008, and operators in the Pinedale were early adopters of pad drilling in no small part to minimize surface disruptions.

Overall, natural gas and NGLs have accounted for 93%-95% of annual production in the Green River Basin since 2000, although that figure may change one day if the industry figures out how to profitably extract the massive amounts of oil shale reserves that underlie the basin. For more information on U.S. oil shale, please refer to the United States Geological Survey's website.

Production growth in the GRB has been led by the Pinedale and the Jonah, which combined grew from just 14.2% of its total production in 2000 to a high of 55.5% in 2011, before slipping back to 52.1% in 2013. Both of those areas posted double digit year-over-year growth rates throughout most of the 2000s, but annual production in the Jonah has fallen significantly since 2009, and production turned negative on a year-over-year basis in the Pinedale in 2012. However, in mid-2014, Ultra Petroleum Corp., which has the largest acreage position in the Pinedale with 49,000 net acres, believed that more than 75% of the field had yet to be developed, so the production declines, in the Pinedale at least, are more likely the result of lower natural gas prices relative to crude oil than because of that area reaching a mature stage.

Green River Basin (continued)

Estimated Annual Green River Basin Natural Gas & Oil Production 2000-2014

Natural Gas Production by County (Bcf)	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Sublette															
Pinedale	**12.8**	**27.1**	**79.4**	**112.3**	**182.7**	**240.6**	**288.0**	**352.0**	**436.9**	**517.8**	**548.4**	**556.3**	**536.7**	**496.0**	**481.5**
Y/Y % Change	*N/A*	*111.7%*	*193.2%*	*41.4%*	*62.8%*	*31.7%*	*19.7%*	*22.2%*	*24.1%*	*18.5%*	*5.9%*	*1.4%*	*-3.5%*	*-7.6%*	*-2.9%*
Jonah	**125.4**	**168.1**	**217.5**	**246.5**	**247.6**	**263.9**	**289.7**	**365.4**	**412.1**	**393.2**	**354.4**	**306.2**	**269.7**	**237.1**	**188.7**
Y/Y % Change	*N/A*	*34.0%*	*29.4%*	*13.3%*	*0.4%*	*6.6%*	*9.8%*	*26.2%*	*12.8%*	*-4.6%*	*-9.9%*	*-13.6%*	*-11.9%*	*-12.1%*	*-20.4%*
Other	312.3	302.9	289.5	296.9	305.1	310.7	302.8	293.8	299.1	286.1	295.4	270.1	267.6	268.6	295.7
Y/Y % Change	*N/A*	*-3.0%*	*-4.4%*	*2.6%*	*2.7%*	*1.8%*	*-2.5%*	*-3.0%*	*1.8%*	*-4.4%*	*3.3%*	*-8.6%*	*-0.9%*	*0.4%*	*10.1%*
Total Sublette	450.5	498.1	586.4	655.7	735.4	815.1	880.5	1011.2	1148.1	1197.0	1198.1	1132.6	1074.0	1001.8	965.9
Y/Y % Change	*N/A*	*10.6%*	*17.7%*	*11.8%*	*12.1%*	*10.8%*	*8.0%*	*14.8%*	*13.5%*	*4.3%*	*0.1%*	*-5.5%*	*-5.2%*	*-6.7%*	*-3.6%*
Sweetwater	227.5	228.2	230.2	242.2	234.1	221.0	238.2	235.6	241.5	232.2	245.1	247.2	262.2	236.4	250.7
Y/Y % Change	*N/A*	*0.3%*	*0.8%*	*5.2%*	*-3.4%*	*-5.6%*	*7.8%*	*-1.1%*	*2.5%*	*-3.8%*	*5.5%*	*0.9%*	*6.1%*	*-9.8%*	*6.0%*
Lincoln	99.2	92.2	87.3	82.8	81.8	73.1	85.8	89.3	89.3	84.3	78.2	67.4	63.1	52.5	52.2
Y/Y % Change	*N/A*	*-7.1%*	*-5.3%*	*-5.2%*	*-1.1%*	*-10.7%*	*17.3%*	*4.1%*	*0.0%*	*-5.6%*	*-7.2%*	*-13.8%*	*-6.4%*	*-16.8%*	*-0.6%*
Uinta	192.9	184.4	171.2	167.6	151.7	138.6	137.4	126.3	126.7	107.9	118.6	106.3	107.2	96.0	96.9
Y/Y % Change	*N/A*	*-4.4%*	*-7.2%*	*-2.1%*	*-9.4%*	*-8.6%*	*-0.9%*	*-8.1%*	*0.3%*	*-14.8%*	*9.9%*	*-10.4%*	*0.8%*	*-10.4%*	*0.9%*
Total Green River Basin Gas (Bcf)	**970.1**	**1002.9**	**1075.0**	**1148.3**	**1203.0**	**1247.9**	**1342.0**	**1462.4**	**1605.6**	**1621.5**	**1640.0**	**1553.5**	**1506.5**	**1386.7**	**1365.7**
Y/Y % Change	*N/A*	*3.4%*	*7.2%*	*6.8%*	*4.8%*	*3.7%*	*7.5%*	*9.0%*	*9.8%*	*1.0%*	*1.1%*	*-5.3%*	*-3.0%*	*-8.0%*	*-1.5%*
Total Green River Basin Oil (Million Bbls)	**12.6**	**13.2**	**12.9**	**12.8**	**12.8**	**12.8**	**13.8**	**15.0**	**15.3**	**15.1**	**16.9**	**14.9**	**14.4**	**13.5**	**13.5**
Y/Y % Change	*N/A*	*4.1%*	*-1.7%*	*-0.9%*	*-0.4%*	*0.4%*	*7.3%*	*9.3%*	*1.8%*	*-1.2%*	*11.6%*	*-11.7%*	*-3.2%*	*-6.5%*	*0.0%*
Total Green River Production (Bcfe)	**1045.9**	**1081.9**	**1152.6**	**1225.1**	**1279.6**	**1324.8**	**1424.5**	**1552.6**	**1697.5**	**1712.2**	**1741.2**	**1642.8**	**1593.0**	**1467.5**	**1446.5**
Y/Y % Change	*N/A*	*3.4%*	*6.5%*	*6.3%*	*4.4%*	*3.5%*	*7.5%*	*9.0%*	*9.3%*	*0.9%*	*1.7%*	*-5.7%*	*-3.0%*	*-7.9%*	*-1.4%*
% Natural Gas	92.7%	92.7%	93.3%	93.7%	94.0%	94.2%	94.2%	94.2%	94.6%	94.7%	94.2%	94.6%	94.6%	94.5%	94.4%
% Crude Oil	7.3%	7.3%	6.7%	6.3%	6.0%	5.8%	5.8%	5.8%	5.4%	5.3%	5.8%	5.4%	5.4%	5.5%	5.6%
% Nat Gas From Pinedale & Jonah	14.2%	19.5%	27.6%	31.2%	35.8%	40.4%	43.0%	49.1%	52.9%	56.2%	55.0%	55.5%	53.5%	52.9%	49.1%

Source: Wyoming Oil & Gas Conservation Commission data, NGI's Shale Daily calculations

In 2015, Ultra Petroleum said it was targeting an asset sale by year's end. The Houston-based exploration and production (E&P) company was looking to reduce its debt and continue focusing production on its Pinedale Anticline in the Green River Basin of Wyoming (see *Shale Daily*, Nov. 3, 2015).

CEO Michael Watford discussed the planned asset sale in an earnings conference call. He said Ultra has "too much debt" and the company is "closing in on an asset sale that should provide a fair amount of relief." Ultra planned to strike a deal by the end of the year and was looking at "a couple of highly actionable, reasonable opportunities, so I think we'll go down the path and select one of those and get it done." He declined to specify how much production might be included in an asset sale. The third quarter was characterized by further efficiency gains in the Pinedale and a shift away from its Marcellus Shale holdings in Pennsylvania.

The rig count in the Green River has been in a general state of decline since peaking at 32 in October 2011, and stood at just 12 in early October 2015. All 12 of those rigs were in Sublette County, WY, home of the aforementioned Pinedale and Jonah fields. Ultra Petroleum CEO Michael Watford noted on the company's 2Q14 conference call that natural gas prices would need to improve to "well above $4, closer to $4.50, " before Ultra added to the four rigs it was already running in the Pinedale at that time.

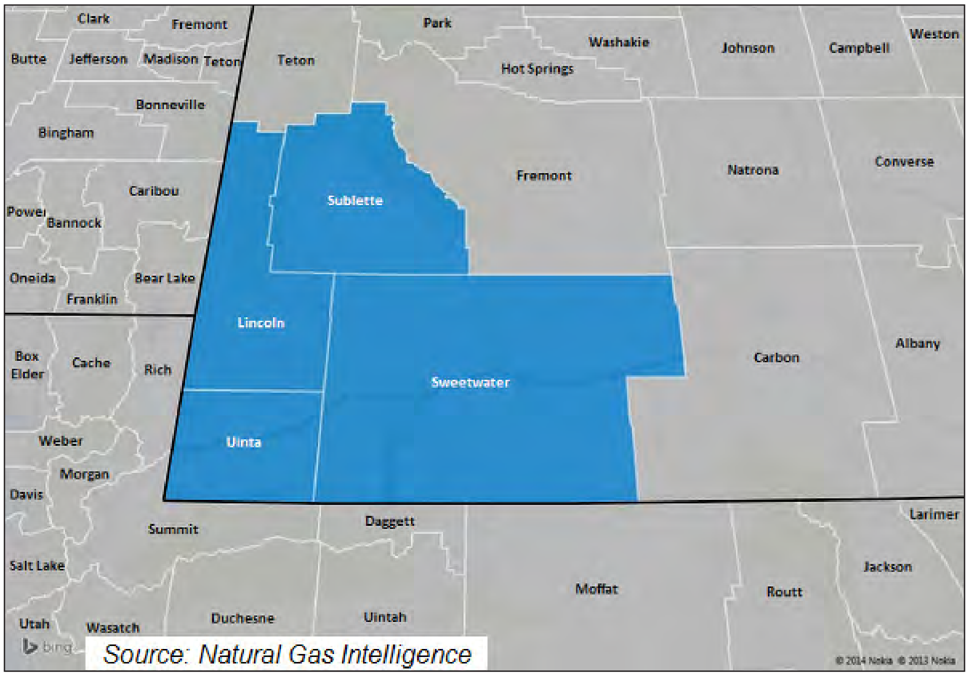
Traditionally, ExxonMobil, Ultra Petroleum, Encana, and QEP Energy combined for approximately 60% of total production in the Green River Basin, although Encana sold its assets with the US$1.8 billion sale of its Jonah assets to an affiliate of TPG Capital in March 2014 (see *Shale Daily*, March 31, 2014). In addition, the GRB is home to the major Opal natural gas hub in Lincoln County, which is the pipeline connecting point for Kern River, Northwest, Colorado Interstate Gas (CIG), Rockies Express, Questar, Overthrust, and Wyoming Interstate Company (WIC) pipelines.

Encana Jonah Field assets, now part of TPG Capital, are in Sublette County, where Jonah provided one of the largest natural gas discoveries in the 1990s. In total, Encana's area in Jonah included a productive expanse of 24,000 acres and more than 1,500 active wells. Estimated year-end 2013 proved reserves totaled 1.493 Bcfe. The transaction with TPG also includes more than 100,000 undeveloped acres adjacent to Jonah known as the Normally Pressured Lance (NPL) area. Encana CEO Doug Suttles at the time called the sale the "unlocking if value from a mature, high-quality asset." Encana sold a lot of its gassy properties to focus on liquids onshore plays, whittled its exploration list to only five plays this year: Montney Formation, Duvernay Shale, Tuscaloosa Marine Shale, Denver-Julesberg Basin and San Juan Basin (see *Shale Daily*, Feb. 13, 2014).

Counties

Wyoming: Lincoln, Sublette, Sweetwater, Uinta

Green River Basin (continued)



Local Major Pipelines

Natural Gas: CIG, Kern River, Northwest Pipeline, Opal Hub, Overland Trail Transmission, Questar, Questar Overthrust, Rockies Express, Ruby, WIC

Crude Oil: Frontier (Plains), Rocky Mountains (Plains)

NGLs: Overland Pass, Rocky Mountains (Enterprise)

GREEN RIVER BASIN NET ACREAGE POSITIONS

Last Updated December 2015

Company	Net Acres	Company	Net Acres
Samson Resources	246,000	Iron Mountain Operating LLC	N/A
Jonah Energy LLC	124,000	Kaiser Francis Oil Co	N/A
Memorial Production Partners[1]	99,712	Keba Energy LLC	N/A
Ultra Petroleum	67,000	Kings Peak Energy	N/A
Vanguard Natural Resources	24,705	Kirby Enterprise Capital Management	N/A
QEP Resources	12,673	Koch Exploration Company LLC	N/A
Samson Oil & Gas USA*	6,120	Labarge Minerals Inc	N/A
Nextraction Energy U.S.	1,900	Legacy Reserves	N/A
Escalera Resources Co	124	LINN Energy	N/A
Abraxas Petroleum	N/A	Lodestone Operating	N/A
Anadarko Petroleum	N/A	Lonetree Petroleum	N/A
Anschutz Pinedale Corporation	N/A	M&G Oil And Gas Inc.	N/A
Antler Energy	N/A	Macum Energy Inc	N/A
Bayswater E&P	N/A	Marathon Oil Company	N/A
Beartooth Oil And Gas Co	N/A	Matrix Production Company	N/A
Black Diamond Energy Of Delaware Inc	N/A	Merit Energy Company	N/A
BP	N/A	Merrion Oil & Gas Corporation	N/A
Breitburn Energy Partners	N/A	Mid Central Production LLC	N/A

Green River Basin (continued)

GREEN RIVER BASIN NET ACREAGE POSITIONS
Last Updated December 2015

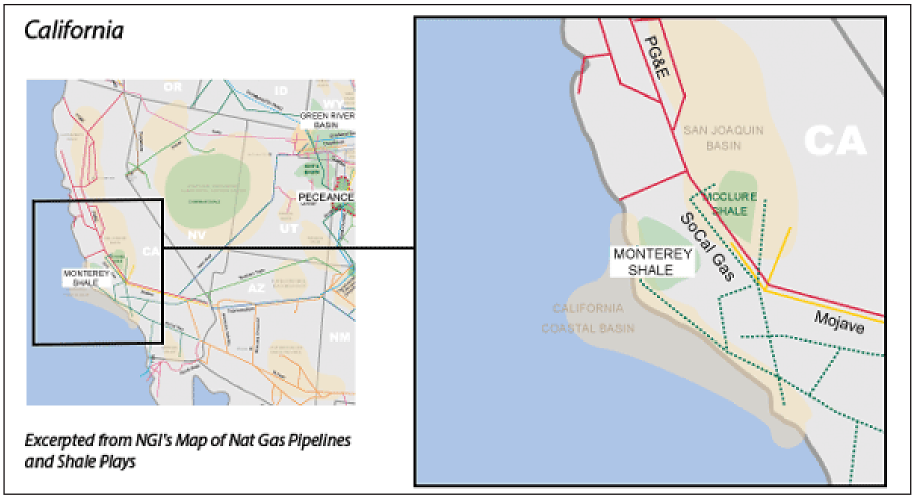
Company	Net Acres	Company	Net Acres
BTA Oil Producers LLC	N/A	Moncrief W A Jr	N/A
Caerus Oil & Gas	N/A	Nielson Capital Partners LLC	N/A
Chaco Energy Company	N/A	Omimex Petroleum Inc.	N/A
Charger Resources LLC	N/A	Pinedale Investment Inc	N/A
Chevron	N/A	Pride Energy Co.	N/A
Cody Energy Inc	N/A	RDR Well Holdings LLC	N/A
Coleman Oil & Gas Inc	N/A	Richardson Operating Co	N/A
ConocoPhillips	N/A	Saga Petroleum LLC Of Colorado	N/A
Crown Energy Partners	N/A	Salt Creek Operating LLC	N/A
Crown Oil & Gas Co Inc	N/A	Seneca Industries Inc	N/A
Denbury Resources	N/A	Sharples Phillip T Trust	N/A
Devon Energy	N/A	Spring Valley Development Co.	N/A
Diamond Oil & Gas	N/A	Sunshine Valley Petroleum	N/A
DNR Oil & Gas Inc	N/A	Synergy Operating LLC	N/A
Energy Equity Company	N/A	Thayer Donald D	N/A
EOG Resources	N/A	Thorofare Resources Inc	N/A
ExxonMobil/XTO Energy	N/A	Tokyo Gas America	N/A
Ferguson Energy Inc	N/A	True Oil LLC	N/A
Finley Resources Inc	N/A	Urban Oil & Gas Group	N/A
Fleur de Lis Energy	N/A	Urroz Oil & Gas LLC	N/A
Foundation Energy Managment LLC	N/A	Vaquero Energy Inc	N/A
GMT Exploration Company LLC	N/A	Vector Minerals Corporation	N/A
Grayhorse Operating Inc	N/A	Wesco Operating Inc	N/A
Grynberg Petroleum Company	N/A	Western American Resources LLC	N/A
Helena Resources Inc	N/A	Western Interior Oil & Gas Corp	N/A
Hewitt Operating Inc	N/A	Wexpro Company	N/A
HRM Resources LLC	N/A	WPX Energy	N/A
Hudson Group LLC	N/A	Yates Petroleum Corporation	N/A

[1] All of MEMP's Rockies acreage. The majority of this is in the Green River Basin, but some are in Larimer County, Colorado.
*Estimate

Source: Compiled by NGI from company documents

MONTEREY SHALE

Background Information



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

There is oil and gas in California's Monterey Shale formation, but it's not unconventional and it's not much, according to a means assessment of unconventional, technically recoverable resources in a portion of the Monterey formation in the deepest parts of the San Joaquin Basin, by the U.S. Geological Service in late 2015.

The Monterey Shale, primarily a crude oil formation located in both onshore and offshore Southern California at depths between 8,000'-14,000', is easily one of the most polarizing unconventional formations in North America. The Monterey had the potential to be one of the most prolific oil producing basins in the United States, or a complete bust, depending on the source. There isn't even always certainty within the *same* source. In 2011, the U.S. Energy Information Administration (EIA) estimated that the Monterey could hold up to 23.9 billion barrels of oil, which would be more than the Eagle Ford and Bakken Shales combined. However, just three years later, the EIA reversed course, and slashed its estimate of recoverable oil in the Monterey Shale to just 600 million barrels, a whopping 96% decrease from its earlier estimate. Ouch.

Estimates by the geologists in the deep basin have never come anywhere near EIA's stratosphere, starting in 2003 with an estimated mean of 121 million bbl of recoverable oil, and dropping in their latest investigation to 21 million bbl of oil, 27 Bcf of natural gas and 1 million bbl of natural gas liquids (see *Shale Daily*, Oct. 7, 2015).

The area of the potential continuous accumulation assessed in the new study was limited to where the Monterey is deeply buried, thermally mature and thought to be generating oil. USGS concluded that most of the petroleum that has originated from shale in the Monterey migrated from the source rock, "so there is probably relatively little recoverable oil or gas remaining there, and most exploratory wells in the deep basin are unlikely to be successful."

And according to the latest geological data from more than 80 older wells that penetrated the deep formation, oil or gas retention in the Monterey shale source rock "is poor, probably because of natural fracturing, faulting and folding." The resources "readily migrate from the deep Monterey formation to fill the many shallower conventional reservoirs in the basin, including some in fractured Monterey formation shale, and accounts for the prolific production there."

The data suggest there aren't a lot of unconventional resources in the Monterey's deep basin, but "there are still substantial volumes of additional conventional oil and gas resources in the Monterey formation in the shallower conventional traps in the San Joaquin Basin, as indicated by earlier assessments," USGS noted.

In 2012, USGS also assessed the potential volumes that could be added to reserves from increasing recovery in existing fields. The results of 2012 study suggested that a mean of about 3 billion bbl eventually could be added from Monterey reservoirs in conventional traps, mostly from diatomite rock.

Out in the field, early drilling results in the play have been mixed, which has no doubt contributed to differing opinions on how economic the Monterey might ultimately prove to be. On the downside, early results from Plains Exploration and Berry Petroleum have come in below expectations, and Chevron flat out told CNBC in February 2013 that the company "does not see the same level of promise in the Monterey Shale as other companies...we have not been encouraged by the results of the wells we have drilled into the formation." Similarly, while Venoco Inc. remains hopefully optimistic, it has seen some early hiccups. In its 2012 10-K filing, Venoco states: "Since 2010, we have pursued an active drilling program targeting the onshore Monterey shale formation. From that time through December 31, 2012, we have spud 29 wells and have set casing on 26 of those wells. To date, we have not seen material levels of production or reserves from the program and have, following the completion of the going private transaction, reduced our capital expenditures related to the project. However, based on the data we have gathered and the results we have seen to date at the Sevier field in the San Joaquin basin, we believe that our testing efforts and delineation drilling in the area will ultimately result in commercial levels of production from the field."

Monterey Shale (continued)

An official with the Western States Petroleum Association (WSPA) said in November 2015 that "unofficially, given the low-price environment [producers] are facing, no one is being very bullish on production – at least not in the short term. The last reassessment of the potential resource in the Monterey didn't cause much of a ripple in our world. And I'm not hearing much chatter about any major technological advances that would change the picture dramatically."

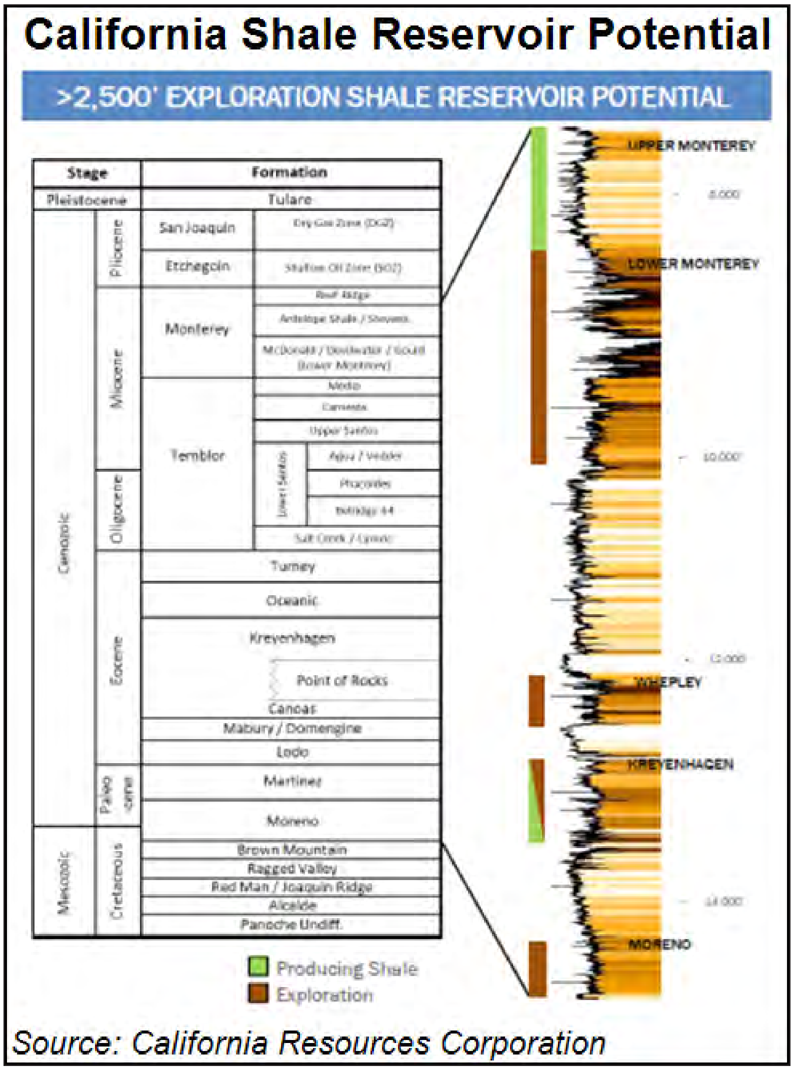
Perhaps the biggest obstacle facing Monterey operators is the fact that much of the shale in California is highly folded, which means it is far more difficult to drill the Monterey using the longer laterals that have become common practice in shale formations that feature flatter, "cake layer" levels of shale, such as the Bakken and the Eagle Ford shales.

A geologic expert on the Monterey, Richard Behl, professor of geologic sciences at California State University, Long Beach, calls the play "highly deformed" and no slam dunk for development. "We don't know how extensively fractured the rocks may be off of the tectonic structures where companies have been producing for years," Behl said. "If it is as fractured as the rocks in the higher parts of the structures, maybe the oil is lost already and we're too late. What this means is that large areas of the Monterey formation that aren't associated with the known structural and stratigraphic traps are now open to exploration; it's up to us [geologists] to come up with a model to find the places where the oil is still there."

If you get past the geological problems, there are the more onerous operating conditions within the State of California, which include (but are not limited to): slow permitting, uncertainty over fracking rules, relatively stringent environmental and land use provisions, the temporary suspension by the U.S. Bureau of Land Management to auction off California acreage in 2013, and the threat of earthquakes and other natural disasters. California has been suffering from drought for several years to the point of restricting water use. The state tends to be at the forefront on environmental protection issues and narrowly missed banning hydraulic fracturing in recent years.

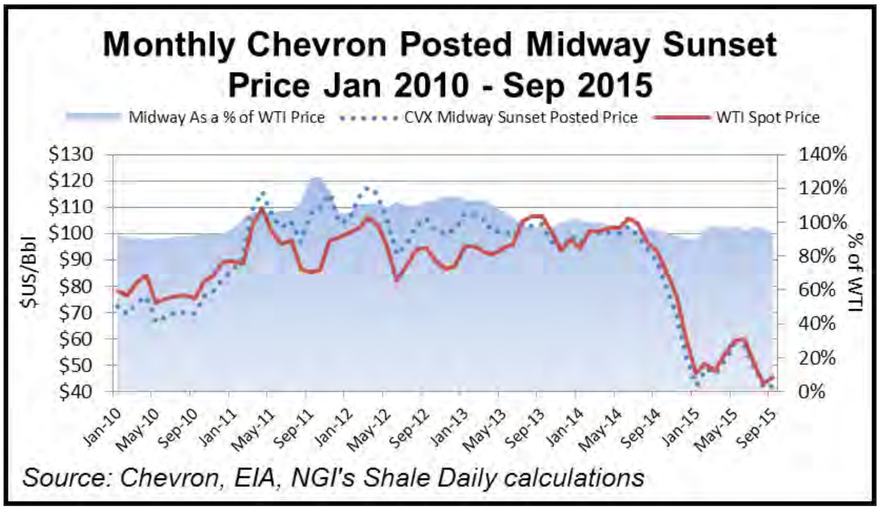
But at least one company sees great potential in the Monterey, and that company is a big one. Occidental Petroleum, which holds more than 2.3 million net acres in California, had drilled and completed more than 570 development wells in unconventional reservoirs in California through mid-2014, primarily in the upper Monterey formation, with what it calls "a nearly 100% commercial success rate." On December 1, 2014, the company completed the spin-off of its California assets into a separately traded pure-play California E&P company called the California Resources Corporation (CRC). One of the main goals of the CRC was to accelerate oil & gas production in California, including various unconventional sources such as the Monterey Shale. All of this changed with the crude oil price collapse, and CRC is now concentrating on its water and steam flood operations, along with an asset sales program designed to shed $1.6 billion in debt by the end of 2016.

Longer term, CRC hopes to grow its California oil & gas production by more than 10% per year, and its unconventional properties would be a major driver in achieving this goal. To this end, the company also plans to test various intervals within the Monterey. In its 2014 10-K filing, CRC notes it has approximately 4,800 identified drilling locations targeting unconventional reservoirs primarily in the San Joaquin basin." We have successfully produced from seven discrete stacked pay horizons within the Upper Monterey. The Lower Monterey is believed to be the principal source rock within the Monterey. We plan to apply the knowledge acquired



Monterey Shale (continued)

from our successes in the upper Monterey to other shales in the San Joaquin basin such as the Kreyenhagen and Moreno formations. The Kreyenhagen and Moreno formations are hydrocarbon source rocks that have generated oil and gas, and we believe they offer similar development opportunities to the upper Monterey due to their multiple stacked pay reservoirs and general reservoir characteristics. The lower Monterey has an extremely limited production history compared to the upper Monterey, and therefore very limited knowledge exists regarding its potential. For example, only about 25 wells have been drilled into the lower Monterey to date. However, we believe we will be able to apply knowledge we gain from the upper Monterey in the lower Monterey as well."



Source: Chevron, EIA, NGI's Shale Daily calculations

There is certainly more room for oil production in California, as the state imports more than 60% of its crude oil needs. Oftentimes, this deficit means that producers earn a premium over WTI production, depending on the grade of crude. However, the benchmark Midway Sunset price in Southern California has traded at both a discount and a premium to WTI over the past several years. For September 2015, the Midway Sunset index came in at $41.99/bbl, just 92% of the WTI price.

"We presently import more than 1.2 million b/d," said state oil/gas supervisor Steve Bohlen at Loyola Marymount University in the fall of 2014. "The big reason we import so much oil is that Californians drive almost a billion miles a day. It is conceivable that with the development of unconventional resources from the Monterey Shale formation, [eventually] we may be able to get our production up by several hundred thousands of barrels per day, maybe as much as a half-million b/d [see *Shale Daily*. Sept. 22, 2014]."

Much of California's oil imports come via rail or waterborne methods, as there are no pipelines that move crude into the state. However, Kinder Morgan has been working to change that, via its Freedom Pipeline that would transport oil from the Permian Basin to various points of delivery within Southern California. The company held its original open season for 277,000 bbls/day of capacity in 2013, but cancelled the project after receiving little interest from potential shippers. As one industry source told *NGI* in late 2014, California refineries tend to like the flexibility that comes with delivery by rail, and do not wish to be subject to the long-term contracts required to underwrite such pipeline projects. Not to mention that pipeline projects that must traverse the Sierra Nevada Mountains can create expensive engineering challenges.

But as noted by industry consultant Genscape, "many of those West Coast industry players have faced crude-by-rail permitting delays amid increasing environmental impact scrutiny," and that has led Kinder Morgan to reconsider the Freedom line, only this time with several modifications, the most important of which would be the ability to transport both crude oil and condensate. That condensate could then be exported overseas, thus giving the U.S. a second condensate export center to go along with the Gulf Coast. If built, Freedom would target a 2019 in-service date, and would require the conversion of part of the El Paso Natural Gas system into crude lines.

In addition, Questar has proposed converting the western portion of its Southern Trails natural gas pipeline that lies within California to a crude oil system, that would move crude from a rail loading facility to the various refineries in the Long Beach area. The project, known as Inland California Express, was still in the development stages as of Questar's March 2015 Customer Meeting.

Counties

California: Fresno, Kern, Kings, Los Angeles, Monterey, Orange, San Luis Obispo, Santa Barbara, Tulare, Ventura, Also prospective in portions of offshore California

Local Major Pipelines

Natural Gas: PG&E, SoCal Gas

Crude Oil: Freedom (proposed), Inland California Express (proposed), Phillips 66, San Joaquin Valley (Exxon), West Coast System (Plains)

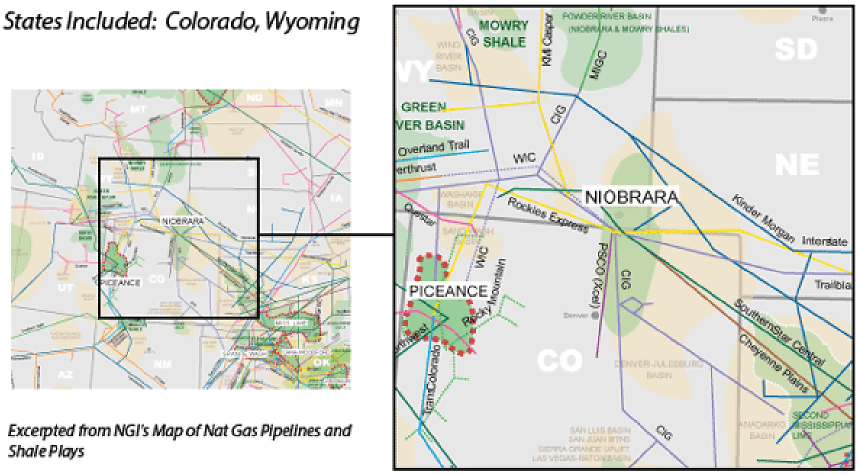
NGLs: None

NIOBRARA-DJ BASIN

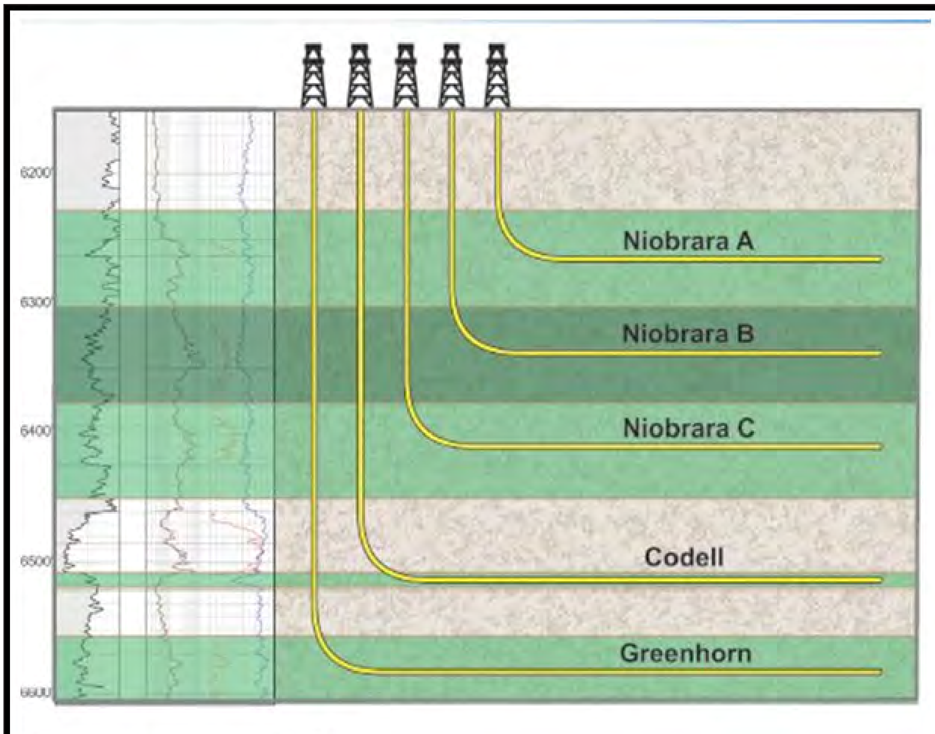
Background Information

The Niobrara-DJ Basin is a crude oil and liquids rich gas play that is located in Northeast Colorado and Southeast Wyoming. The Niobrara is located in several areas of the Rocky Mountains, including the Powder River in Wyoming and in parts of Northwest Colorado. The portion that lies within the Denver-Julesburg (DJ) Basin is a combination shale/marl/chalk/sandstone formation that lies at depths 5,500'-8,500', and is comprised of three separate zones, or "benches:" the A, B, and C benches. Just below the C bench sits the Codell tight sands formation, which is more of an emerging natural gas play, but is also garnering the interest of operators, especially those who are able to drill commingled Niobrara and Codell wells. However, the Codell is generally not prospective throughout the entire DJ Basin, since the formation tends to thin to the east. Operators have also begun drilling or are planning to test the deeper Greenhorn interval, but we believe early results from that formation have not been all that promising thus far.

States Included: Colorado, Wyoming



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays



Source: Bonanza Creek

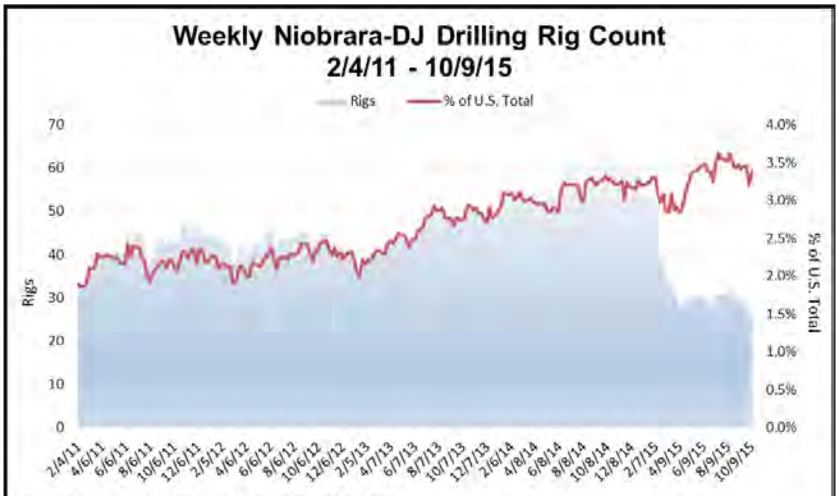
The Niobrara within the DJ Basin is actually a combination of two basins in one. On the eastern side of the DJ Basin, the Niobrara reservoir holds widespread biogenic gas deposits that are similar to those in the Antrim Basin in Michigan. This "biogenic" Niobrara gas lies at shallower depths within Northeast Colorado, and parts of Nebraska and Kansas, than the more oil rich "thermogenic" Niobrara that we described in the first paragraph. The remainder of this article focuses on the "thermogenic" portion of the Niobrara.

The DJ Basin is certainly no stranger to exploration and production activity. The Wattenberg Field, which is located primarily in Southwest Weld County, Colorado, was discovered in 1970, and was one of the 15 largest proved gas fields in 2009, per the U.S Energy Information Administration. The majority of production from the Wattenberg to date has come from vertical drilling in the Niobrara/Codell formations, and the Muddy J Sandstone, which is a tight sands play that lies several hundred feet below the Codell.

EOG Resources kicked off the trend toward horizontal drilling in the Niobrara DJ in October 2009, with its Jake well at the Hereford Ranch Field in Weld County. Much of the horizontal drilling for the Niobrara and the Codell that has occurred since has been in the Wattenberg Field in Weld County, Colorado, and to a lesser extent in and around the Silo Field in Southeast Wyoming. These have

Niobrara-DJ Basin (continued)

been the most heavily targeted areas in part because many companies already held acreage in those areas, and also because those regions have existing infrastructure.



Source: Baker Hughes, NGI calculations

Weak economics thanks to oversupply and low commodity prices (crude south of $40/bbl and natgas hovering just above $2) has crashed drilling activity across North America, and the Niobrara-DJ Basin has not been immune. According to Baker Hughes data from early October 2015, drilling activity in the play is down 56% from the first week of December 2014, with active rigs falling from 61 to 27 (see *Shale Daily*, Dec. 4, 2015). 22 of those rigs were in Weld County, CO, with 2 each in Laramie County, WY and Lincoln County, CO, and another in Elbert County, CO. However, the Niobrara-DJ Basin has been more fortunate than some other plays. Over the same period, producers have reduced drilling activity in the Powder River Basin of Northeast Wyoming and Southeast Montana by 73% – from 33 active rigs to just nine. In July 2015, RBN Energy tabbed the Niobrara as having some of the best relative economics in the United States, with average rates of return ranging from 3%-17% in the area, depending on well cost assumptions. Those figures were on par with RBN's return estimates the Eagle Ford Shale at the time.

Top 20 2014 Weld County Oil & Gas Producers

Rank	Operator	Oil Sales (barrels)	Gas Sales (MCF)	Total Sales Bcfe
1	Anadarko Petroleum	27,636,848	148,298,308	314.1
2	Noble Energy	22,155,172	124,506,099	257.4
3	Encana	6,926,196	38,413,676	80.0
4	PDC Energy	4,824,620	24,650,697	53.6
5	Bonanza Creek	5,759,869	15,132,443	49.7
6	Whiting Petroleum	2,919,704	3,132,714	20.7
7	Bill Barrett Corporation	2,019,538	5,984,706	18.1
8	Extraction Oil & Gas	2,044,774	5,663,738	17.9
9	Carrizo Oil & Gas	2,126,764	2,210,553	15.0
10	Synergy Resources	1,477,700	5,361,436	14.2
11	Great Western Operating Co.	873,439	3,246,273	8.5
12	Bayswater E&P	662,289	1,871,483	5.8
13	Mineral Resources	411,515	2,373,314	4.8
14	EOG Resources	430,140	812,289	3.4
15	KP Kauffman Company	208,937	1,748,668	3.0
16	Foundation Energy Management	78,228	383,859	0.9
17	TOP Operating Co.	42,777	190,212	0.4
18	Blue Chip Oil	23,628	271,652	0.4
19	Red Hawk Petroleum	53,308	71,666	0.4
20	Peterson Energy Corp.	45,376	97,052	0.4
	Others	323,249	989,283	2.9
	TOTAL	***81,044,071***	***385,410,121***	***871.7***

Note: We use oil & gas sales as a proxy for marketed production

Source: Colorado Oil & Gas Conservation Commission data, NGI's Shale Daily calculations

With the emergence of the DJ Basin as a leading producer, Weld County is being touted as the DJ's core. The county was on pace to become the state's major natural gas producer in late 2015,

Niobrara-DJ Basin (continued)

according to Colorado Oil and Gas Conservation Commission (COGCC) data (see *Shale Daily*, Sept. 22, 2015).

Historically, two western counties, La Plata (San Juan Basin) and Garfield (Piceance Basin), have alternated for more than a decade as Colorado's leading gas producers. But in the current low commodity price environment for both crude oil and natural gas, operators have focused on their higher-return areas, and the DJ Basin in apparently one of those. The DJ is a liquids-rich play, so producers are going after oil and getting lots of wet associated gas.

Through part of July 2015, Weld County produced 242.5 Bcf, or about one-third of the state's overall total at that time. Comparatively, Garfield County, in the far northwestern part of the state, produced 224.7 Bcf, and La Plata in the southwestern corner of Colorado had 181.3 Bcf of production.

In 2014, Garfield produced about one-third of Colorado's gas production of 1.6 Tcf with 610.9 Bcf produced; Weld was second at 388.4 Bcf with La Plata, which for many years was the state leader, third with 334 Bcf in production. Analysts are now assuming that Weld and the DJ Basin are going to take over the state's gas leadership. Various industry analytical sources, along with COGCC data point to the DJ as being on the rise, while Garfield and La Plata draw on more mature fields.

Tough economics within the industry has also led to some recent exits from the play. Encana Corp.'s U.S. subsidiary in October 2015 said it would sell its entire 51,000 net-acre portfolio in the DJ Basin for $900 million to improve its balance sheet (see *Shale Daily*, Oct. 8, 2015). The sale by Encana Oil & Gas (USA) Inc. is with a partnership formed by Canada Pension Plan Investment Board (95%) and private equity owner The Broe Group (5%). Broe's energy affiliate is Denver-based Great Western Oil & Gas Co.

"As we advance our strategy we continue to focus our portfolio and capital on our four most strategic assets, the Permian, Eagle Ford, Duvernay and Montney," said Encana CEO Doug Suttles. "Our efforts to transform our portfolio, improve efficiency and grow margins are increasing returns and strengthening our balance sheet, positioning Encana for success throughout the commodity cycle. The new entity is acquiring a quality asset along with a highly talented team."

The DJ, once one of Encana's top performers, has seen its importance to the portfolio diminish as more investment dollars have been moved to four onshore regions only: the Permian Basin, Eagle Ford Shale and British Columbia's Duvernay and Montney fields (see *Shale Daily*, Sept. 24, 2014). In May Encana had only one rig working in DJ (see *Shale Daily*, May 13, 2015).

Other E&Ps are moving into the play as well. SandRidge Energy Inc., stumbling financially as it dwells in a lower-priced commodity world, is once again attempting to diversify its operations by acquiring proved reserves and producing wells in the Niobrara formation of Colorado (see *Shale Daily*, Nov. 5, 2015). The $190 million cash agreement announced in November 2015 followed news that the Oklahoma City-based independent reported a $640 million net loss in 3Q2015, including a $1.1 billion writedown on the value of its portfolio.

The Niobrara acquisition, with privately held EE2 LLC, would give SandRidge a position in the North Park Basin in Jackson County, CO. The acreage "is largely concentrated in rural north-central Colorado and ideal for pad drilling and efficient infrastructure installation," management said. The property, 100% operated, has proved reserves estimated at 27 million boe, 82% weighted to oil, and currently is producing 1,000 boe/d from 16 horizontal wells. SandRidge is planning initially to run one rig and would increase to a two-rig program by the middle of 2016. Thirteen drilling permits already have been approved, it said. It has 3-D seismic coverage on 54 square miles, with close to half of the 136,000 acres held by production and by two federal units.

In a 3Q2015 earnings call, Noble Energy CEO Dave Stover said the company intends to focus on the DJ Basin and Eagle Ford Shale going forward (see *Shale Daily*, Nov. 2, 2015). Noting that enough has been said about the impact of lower prices on activity and earnings, Stover instead focused on the positives of better efficiencies and lower operating costs and how they will carry the company forward.

"Next year's onshore capital program will again focus on those activities with the highest returns and value," he said. The DJ Basin and Texas portfolios "should continue to attract the majority of our investment."

He added that while exploration capital will remain lower in 2016 than previous years, Noble believes it is a great environment to enhance and deepen its exploration inventory of high quality opportunities at a relatively low cost of entry. "We intend to continue achieving more while spending less," Stover said.

Noble said volumes in the DJ averaged 13% higher during 3Q15 to hit a record 116,000 boe/d. Gas processing capacity on the DCP system, following the start-up of the Lucerne-2 plant, increased to more than 800 MMcf/d, which allowed Noble to reduce line pressures in the northern part of the field, particularly the Wells Ranch area, by up to 100 psi. PDC Energy and Synergy Resources noted similar pressure reducing benefits from the Lucerne 2 plant, particularly for older, vertical wells. Moreover, the DCP Grand Parkway

Niobrara-DJ Basin (continued)

gathering project should further improve line pressures within the Wattenberg when that project enters service in early 2016.

Noble operated four drilling rigs in the DJ for most of the third quarter, but has since dropped to three with two full-time completion crews. The big news for the DJ are improved designs, with longer laterals and the use of slickwater fluid. Noble drilled 39 wells at an average lateral length of more than 7,300 feet, versus an average well of about 4,500. Production ramped up at 58 wells, equivalent to 70 standard lateral length wells.

Several operators also noted they are using the plug-and-perf method to complete wells in the Niobrara much more often these days, with PDC Energy declaring on its 3Q2015 earnings conference call that plug-and-perf is quickly become the standard completion procedure in the Wattenberg.

"Cumulative production from the slickwater completions is outperforming the hybrid gel wells by more than 20% on average after 30 days," Stover noted. For a standard lateral length well, those designed with slickwater are about 10% lower in total well cost. Based on 3Q15 activity, Noble was on target to exit 2015 in the DJ with about 40 wells drilled but uncompleted.

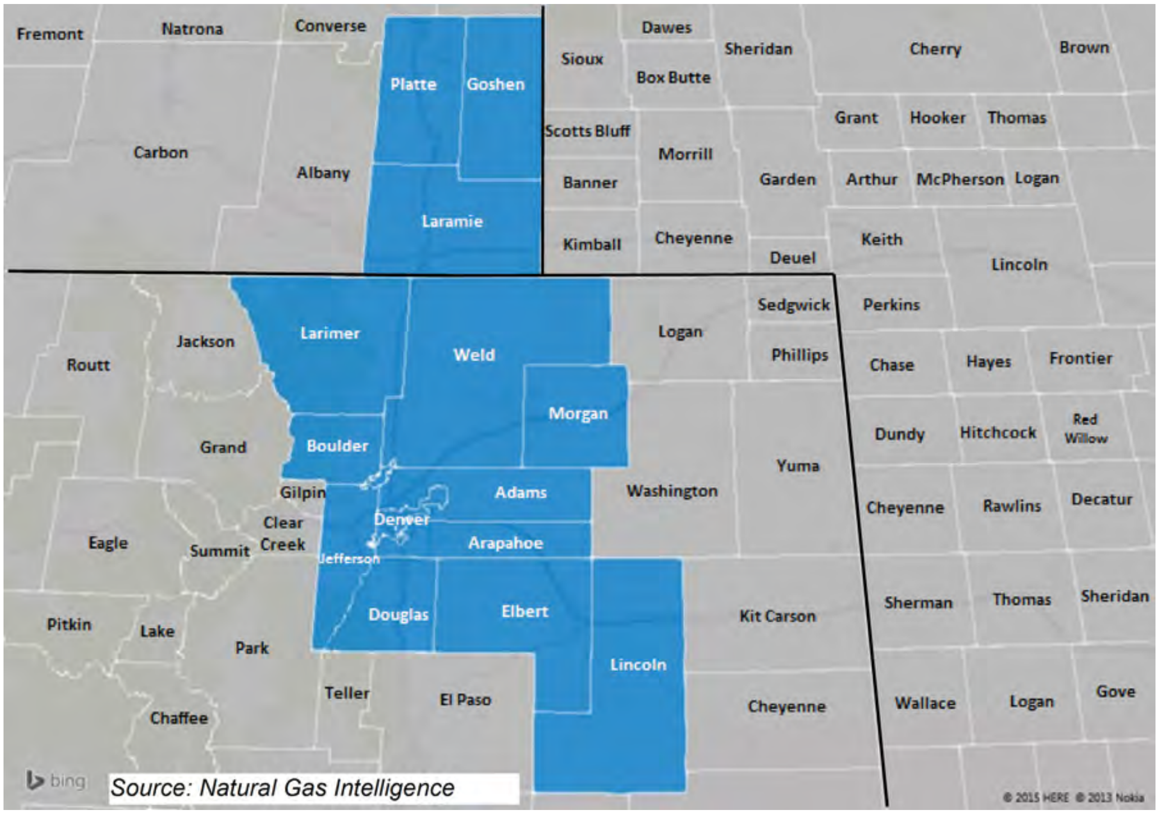
However, the Noble family of companies hit a stumbling block in late November 2015. Just a week after announcing that it would launch a public offering of shares in a new limited partnership with interests in some of its DJ Basin crude oil, natural gas and water-related midstream services, Noble Midstream Partners LP postponed it (see *Shale Daily*, Nov. 23, 2015). The Noble Energy subsidiary said it had postponed the offering "as a result of unfavorable equity market conditions" and would "continue to evaluate the timing for the proposed offering as market conditions develop." A registration statement relating to the proposed sale of the securities has been filed with the Securities and Exchange Commission (SEC), "but has not yet become effective," Noble said.

According to the original SEC filing, Noble Midstream has a 75% ownership interest in its "core assets," including crude oil gathering at the Wells Ranch and East Pony integrated development plans (IDP), natural gas gathering at Wells Ranch, and crude oil treating at all NBL DJ Basin acreage, and also a 5-10% ownership interest in its "growth assets," including crude oil gathering at the Mustang, Greeley Crescent and Bronco IDPs, and natural gas gathering at Mustang.

Counties

Colorado: Adams, Arapahoe, Boulder, Broomfield, Douglas, Elbert, Larimer, Lincoln, Jefferson, Morgan, Weld

Wyoming: Goshen, Laramie, Platte



Source: Natural Gas Intelligence

Niobrara-DJ Basin (continued)

Local Major Pipelines

Natural Gas: Cheyenne Hub, Cheyenne Plains, CIG, PSCO, Rockies Express, Southern Star, Tallgrass, WIC

Crude Oil: Grand Mesa (proposed), Platte, Pony Express, Rocky Mountains (Plains), Saddlehorn (under construction), White Cliffs

NGLs: Bakken NGL Pipeline, Front Range, Overland Pass, Rocky Mountains (Enterprise), Wattenberg (DCP)

NIOBRARA-DJ BASIN NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Noble Energy	400,000	Industrial Gas Services Inc	N/A
Southwestern Energy	380,000	Ironhorse Resources LLC	N/A
Anadarko Petroleum	350,000	Itochu Corporation	N/A
Nighthawk Energy	186,224	Johnson Production Corporation	N/A
SandRidge Energy	136,000	K P Kauffman Company Inc	N/A
ConocoPhillips	123,000	Kaiser Francis Oil	N/A
Whiting Petroleum	118,436	Kodiak Petroleum	N/A
Bill Barrett	98,188	Kugler Dean & Joe DBA D-J Oil Company	N/A
PDC Energy	96,000	Lario Oil & Gas	N/A
Synergy Resources	93,000	Lone Star LLC	N/A
EOG Resources	85,000	Lundvall Oil & Gas Inc	N/A
Escalera Resources	73,000	M E III Corporation	N/A
Bonanza Creek Energy	70,000	Machii-Ross Petroleum Co	N/A
Canada Pension Plan Investment Board JV[1]	55,000	Magpie Operating, Inc	N/A
Carrizo Oil & Gas	35,600	Mendell Niobrara LLC	N/A
Lilis Energy	31,000	Merit Energy	N/A
Continental Resources	25,000	Mineral Resources, Inc.	N/A
Slawson Exploration	24,000	Misty Mountain Operating LLC	N/A
Endeavour Corp.	19,800	Murex Petroleum Corp.	N/A
Samson Oil & Gas	16,016	O'Brien Energy Resources Corp	N/A
Contango Oil & Gas	11,200	OIL India Ltd.	N/A
Ward Petroleum Corporation	9,000	Orr Energy LLC	N/A
EnerJex Resources	3,959	Oxbow Properties Inc	N/A
Western Energy Production	3,717	Pape Oilfield Service Inc	N/A
4-H Operating Corporation	N/A	Peterson Energy Operating Inc	N/A
Anschutz Exploration	N/A	Petrogulf	N/A
Antelope Energy Company LLC	N/A	Prairie Resources	N/A
Apollo Operating	N/A	Red Hawk Petroleum LLC	N/A
Bayswater E&P	N/A	Renegade Oil & Gas Company LLC	N/A
Beren Corporation	N/A	Rosewood Resources	N/A
Black Raven Energy	N/A	RWL Enterprises	N/A
Blue Chip Oil	N/A	Schneider Energy Services Inc	N/A
Caerus Oil & Gas	N/A	Smith Energy Corp	N/A
CDM Oil & Gas	N/A	Smith Oil Properties Inc	N/A
Chaco Energy Company	N/A	Sovereign Operating Company LLC	N/A
Chesapeake Operating LLC	N/A	Stelbar Oil Corp Inc	N/A
Churchill Energy Inc	N/A	Stoneham Production LLC	N/A
Colton LLC	N/A	Sunburst Inc	N/A
Condor Energy Technology	N/A	Tarpon Oil Company	N/A
Diamond Operating, Inc.	N/A	Texas Tea Of Colorado LLC DBA Texas Tea LLC	N/A

Niobrara-DJ Basin (continued)

NIOBRARA-DJ BASIN NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
DJ Resources Inc	N/A	Thunderbird Resources	N/A
Energy & Exploration Corp.	N/A	Tidal Wave Energy Inc	N/A
Extraction Oil & Gas	N/A	Tigges Oil LLC	N/A
Fortitude Exploration Co	N/A	Timka Resources Ltd	N/A
Foundation Energy Management	N/A	Tindall Operating Company	N/A
Fountainhead Resources Ltd	N/A	Top Operating Company	N/A
Goodwin Energy Management LLC	N/A	Triton Energy Services LLC	N/A
Great Western Oil & Gas Co.	N/A	Tudex Petroleum Inc	N/A
Grynberg Jack DBA Grynberg Petroleum Co	N/A	Wellstar Corporation	N/A
Homestead Oil Inc	N/A	West Cirque Resources	N/A
HRM Resources	N/A	Whitewing Resources LLC	N/A
Hyndrex Resources	N/A	WhitMar Exploration	N/A
Indian Oil Corporation Ltd.	N/A	WY Woodland Operating LLC	N/A

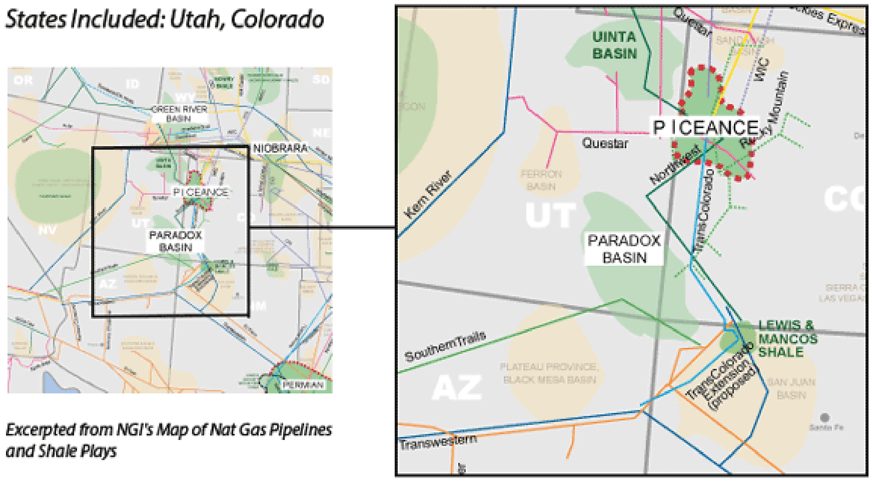
[1]Canada Pension Plan Investment Board owns 95% interest and the remaining 5% is held by the Broe Group

Source: Compiled by NGI from company documents

PARADOX BASIN

Background Information

States Included: Utah, Colorado



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

Located mostly in Southeastern Utah and Southwestern Colorado, the Paradox Basin traditionally has been known more for its conventional oil and gas production. The Aneth Field, discovered in 1956 and operated today by Resolute Energy, has produced more than 450 million barrels of oil over its lifetime, and was a top 40 field in terms of proved U.S. oil reserves as recently as 2009. Much of the production in the Aneth is now done using tertiary CO2 flooding. On the natural gas side, the Ute Dome and Barker Dome had produced respective cumulative totals of 6.9 Tcf and 4.7 Tcf at one point in 2010.

MDU Resources subsidiary Fidelity Exploration & Production noted in its June 2013 Investor Presentation that the Cane Creek "could be substantial for [our] company," with estimated gross EURs 250 to 1000+ MBOs per well. The company earmarked $180 million, or roughly 40% of its 2014 total capital budget, to the Paradox Basin, mostly to drill an additional 17 appraisal and development wells in the Cane Creek. But the results of that program were not up to par.

The company announced in September 2014 that it was revising its 2014 earnings guidance downward because of "challenges" in its Paradox drilling program.

Kent Wells, former CEO of Fidelity, said they were completing an analysis of three nonproductive wells it recently completed to determine if they needed to be stimulated through hydraulic fracturing (fracking) or another means, or whether the wells were damaged in the way they were drilled.

"I would say the results from the wells were disappointing, and we realize we have to change our completion design to make those wells economical," Wells said. "We've been very fortunate [in this basin], we have never had to frack a well, which is kind of rare in today's world. We have been able to use our natural completions, and get very good wells, but in the future I think we will need to make a shift to stimulate the wells to get the production we're looking for. Whether that is fracking or some other technique, we don't know yet. We've been working on this for quite a while."

Wells also had noted that Fidelity had been having trouble keeping production up on some of its high-producing Paradox wells, and thus, he previewed the fact that 2014 production would be "weak."

Source: Utah Geological Survey

Paradox Basin (continued)

Oil wells that were delivering 600-800 b/d dropped down in the 300-500 b/d range, he said.

In the fall of 2015, Bismarck, ND-based MDU sold Fidelity, in five separate deals, with proceeds and tax benefits of about $450 million. The transactions included operations in the Paradox Basin (mostly natural gas and natural gas liquids). The sale had been previewed for the better part of the past year (see *Shale Daily*, Nov. 3, 2015). In announcing the sale, MDU senior executives indicated that the E&P business was racking up some sizable operating losses for the year, topping $1.2 billion for the first nine months of 2015. It was not divulged who the buyers were.

Prior to the MDU sale, in early 2014, London-based Rose Petroleum plc formed a subsidiary, Rose Petroleum Utah LLC, to acquire a 75% working interest across 195,000 net acres in the Uinta and Paradox Basins of eastern Utah for $2 million, plus carry obligations. Rose was expected to make five cash payments to Rockies Standard Oil Company LLC through November 2015 and be responsible for project carryover obligations of $9.5 million in the Mancos Shale and $7.5 million in the Cane Creek Shale of Grand and Emery counties, UT. Rockies Standard will retain a 25% working interest across the acreage. (see *Shale Daily*, March 17, 2014).

The drilling program will target the Mancos Shale, which is similar to the Niobrara in Colorado. Rose Utah will develop its Mancos leases south of the San Juan Basin, where EnCana Corp. and WPX Energy Inc. have drilled about 60 Mancos wells and are producing more than 20,000 b/d of oil. Rose said that its Cane Creek leases are 12 miles north of Fidelity.'s Cane Creek Field in an area where some vertical wells have produced more than 1 million bbls of oil. Rose Utah will first be required to drill three Manco wells and one Cane Creek well in order to earn its 75% working interest in the acreage.

Bill Barrett Corporation has led the effort in the gassier Gothic and Hovenweep Shale plays, which have true vertical depths between 5,500'-8,850' (the Hovenweep is slightly shallower than the Gothic). BBG announced initial excitement over its first two horizontal wells in its Yellow Jacket prospect within the Gothic Shale in the third quarter of 2008, but subsequent results have been mixed. BBG drilled two more exploratory Yellow Jacket wells in 2012 to test the oil portion of that play, but we believe those turned out to be dry holes.

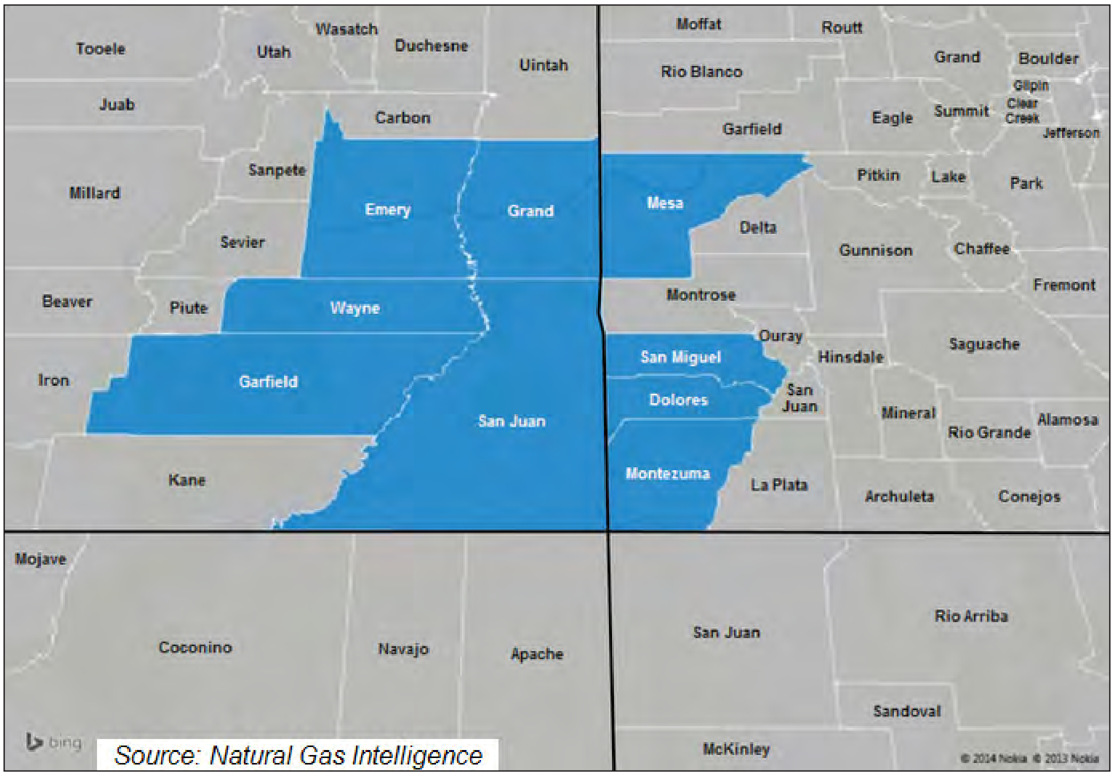
There is no doubt that low natural gas prices in recent quarters haven't been helping BBG's exploratory efforts in the Paradox. In fact, the company made very little mention of the Yellow Jacket (which the company now calls the combination of the Gothic & Hovenweep Shales) in neither BBG's 2014 10-K filing with the Securities & Exchange Commission nor its September 2014 Investor Relations presentation, other than to note it owns more than 209,000 net acres in the play. BBG has 78,410 net acres in the Paradox that are set to expire in 2015, and given current low natural gas prices, along with the company's stated focus on the Wattenberg field in the DJ Basin, we would not be surprised if BBG elected to let most, if not all, of those expiring acres go.

Counties

Colorado: Dolores, Mesa, Montezuma, San Miguel

Utah: Emery, Garfield, Grand, San Juan, Wayne

Paradox Basin (continued)



Local Major Pipelines

Natural Gas: Northwest Pipeline, Southern Trails, TransColorado

Crude Oil: Western Refining

NGLs: Rocky Mountains (Enterprise)

PARADOX BASIN NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Bill Barrett Corporation	219,528	Linde Inc	N/A
Castleton Commodities	150,000	Lodestone Operating Inc	N/A
Fidelity E&P Co. (MDU Resources)[1]	140,000	Lynden Energy	N/A
Stone Energy	35,000	Mar/Reg Oil Company	N/A
Resolute Energy	28,300	Matrix Production Company	N/A
Aleator Resources	22,000	Max D Webb	N/A
Anadarko Petroleum	N/A	Megadon Enterprises Inc	N/A
Atom Petroleum LLC	N/A	Merit Energy Company	N/A
Axia Energy LLC	N/A	Merrion Oil & Gas	N/A
Bayless Producer LLC Robert L	N/A	Monument Global Resources Inc	N/A
Beeman Oil & Gas LLC	N/A	Nacogdoches Oil & Gas Inc	N/A
Bowers Oil And Gas Inc	N/A	NNOGC Exploration & Production LLC	N/A
BP	N/A	Petro Mex Resources	N/A
Citation Oil & Gas Corp	N/A	Piceance Energy LLC	N/A
Crownquest Operating LLC	N/A	Red Mountain Energy LLC	N/A
D & G Roustabout Service	N/A	Richardson Operating Co	N/A
Diversified Energy LLC	N/A	Rim Operating Inc	N/A
DJ Simmons, Inc.	N/A	Rose Petroleum	N/A

Paradox Basin (continued)

PARADOX BASIN NET ACREAGE POSITIONS
Last Updated December 2015

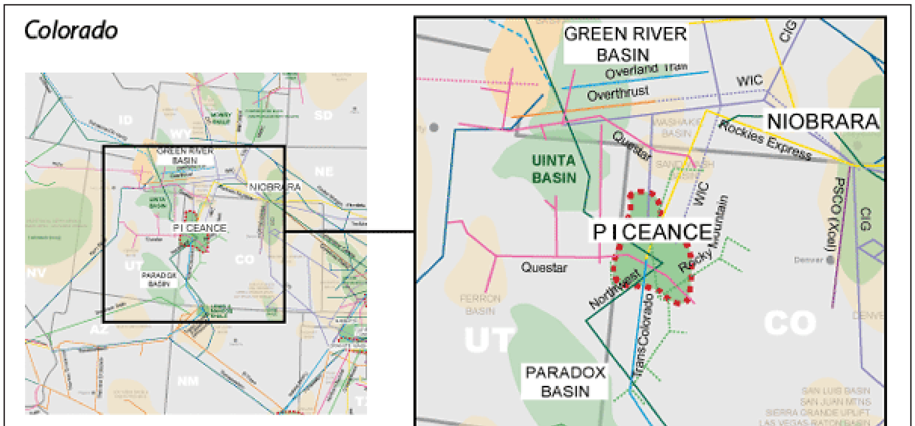
Company	Net Acres	Company	Net Acres
Dominion Production Co.	N/A	Seeley Oil Company LLC	N/A
Elm Ridge Exploration Company	N/A	Southwestern Energy	N/A
Fees Jr And Son Oil & Gas Walter S	N/A	Summit Operating LLC	N/A
Fram Operating LLC	N/A	Synergy Operating LLC	N/A
Gem & Eye Gp	N/A	US Oil & Gas Inc	N/A
Genesis St Operating LLC	N/A	Wesgra Corporation	N/A
Gordon Engineering Inc	N/A	XOG Operating LLC	N/A
Huntington Energy LLC	N/A	Yates Petroleum Corp	N/A
Linde Inc	N/A		

[1]Plus another 20K net acres under option.

Source: Compiled by NGI from company documents

PICEANCE BASIN

Background Information



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

Located in Northwest Colorado, the Piceance (pronounced pee-aunts) Basin is a tight sands formation that lies at depths between 6,000'-10,000', and features liquids rich natural gas. Although Encana Corporation is by far and away the largest acreage holder in the Piceance, with 799,000 net acres, WPX Energy (formally Williams) is the company most closely associated with the basin, since the Piceance forms the majority of WPX's proved reserves and current production.

Other major natural gas producers in the Piceance include Occidental Petroleum, and ExxonMobil/XTO, although Oxy CEO Steven Chazen noted in late October 2014 that at some point the company will likely put its Piceance Basin assets up for sale. Oxy has owned interests in the Piceance since the 1970s and currently holds approximately 187,000 net acres. The company said in late 2015 that it was maximizing its production, reducing drilling times and working to minimize its environmental footprint in the Piceance through a variety of drilling, completion and other operational technologies.

2014 Top 20 Oil & Gas Producers in Counties That Contain The Piceance Basin, By Sales

Rank	Operator	Oil Sales (Bbls)	Gas Sales (Mcf)	Total (Bcfe)	% of Total
1	WPX Energy	688,217	279,439,726	283.6	36.7%
2	Encana	764,429	226,030,678	230.6	29.8%
3	Occidental Petroleum	94,037	35,634,436	36.2	4.7%
4	ExxonMobil/XTO Energy	88,049	34,165,431	34.7	4.5%
5	Chevron	4,184,015	9,194,234	34.3	4.4%
6	Bill Barrett Corporation	327,377	31,889,442	33.9	4.4%
7	Ursa Operating	275,860	25,673,156	27.3	3.5%
8	Caerus	38,173	19,524,096	19.8	2.6%
9	Piceance Energy LLC	61,185	16,413,704	16.8	2.2%
10	Wexpro	79,011	9,100,318	9.6	1.2%
11	Noble Energy	6,450	7,638,521	7.7	1.0%
12	Linn Energy	19,560	6,931,279	7.0	0.9%
13	Marathon Oil	9,326	4,124,369	4.2	0.5%
14	Black Hills Plateau Production Co.	9,261	3,280,607	3.3	0.4%
15	SG Interests I, LLC	1,210	2,241,900	2.2	0.3%
16	Koch Exploration Co.	15,507	2,000,674	2.1	0.3%
17	Axia Energy	8,518	1,701,735	1.8	0.2%
18	Whiting Petroleum	12,490	1,633,828	1.7	0.2%
19	BOPCO LP	8,402	1,432,506	1.5	0.2%
20	Foundation Energy Management	16,701	1,353,740	1.5	0.2%
	Total All Companies	*7,207,533*	*729,515,167*	*772.8*	*100.0%*

Note: We include all oil & gas sales within Delta, Garfield, Gunnison, Mesa, Moffat, Pitkin, and Rio Blanco Counties, CO, regardless of from which formations those hydrocarbons were produced. We use sales as a proxy for marketed production.

Source: Colorado Oil & Gas Conservation Commission data, NGI's Shale Daily calculations

Piceance Basin (continued)

Much of the current production in the Piceance comes from the Williams Fork Formation within the Mesaverde Group in general, and from four major fields in particular: Grand Valley, Mamm Creek, Parachute, and Rulison. The Piceance can also be split into two different subcategories: the Piceance Highlands and the Piceance Valley. Highlands wells tend to be more expensive to drill, everything else being equal, because by definition, operators have to drill more just to get to the same starting point as wells within the lower level Piceance Valley.

As an older, more developed play, the Piceance certainly has seen its share of experience related to efficiency gains. For example, WPX drilled an average of 42.2 wells per rig in 2012, nearly double the 22.2 wells per rig it was able to drill in 2006. But as an older, more developed play, the Piceance is also no longer the fast grower it was in the early 2000s. At the start of 2015, WPX delayed completions on at least 20 drilled wells waiting for "economics to improve." At the time the Tulsa-based operator indicated that more wells could be impacted. WPX had been running eight rigs, but cut that in 2015 to an average three rigs for the year on a capital budget of $200-$225 million. WPX operates more than 4,400 gas wells in the Piceance, including some of the biggest gushers to date in the Niobrara formation (see *Shale Daily*, Jan. 26, 2015). WPX had 481 MMcfe/d of production in 3Q15, vs. 542 MMcf/d in 3Q14.

Natural gas production and permitting in the counties that contain the Piceance continued downward in 2015, leading to what could be a seventh consecutive year of lower annual production growth. Garfield County was by far the most productive in the Piceance with 295.9 Bcf through August, 2015. The next largest was Rio Blanco with 31 Bcf during the same eight-month period. Similarly, drilling activity has declined in the play as well, falling from a recent peak of 35 rigs in early 2011 down to 5 rigs in early October 2015. Those rigs were spread among Garfield (2), Gunnison (1), Mesa (1), and Moffat (1) counties. Much of the reason for this lower production growth and drilling activity has been generally weaker energy commodity prices throughout 2015.

In mid-2015 the two major E&P companies in the Piceance, Encana Corp. and WPX Energy, faced off in a court battle in western Colorado in which Encana sought an injunction to block WPX from completing a horizontal well. Encana alleged that WPX invaded its mineral holdings in part of the Niobrara Shale, drilling through adjoining properties and then out laterally through Encana holdings. WPX still needed to hydraulically fracture the well to extract the natural gas supplies, and Encana sought court action to block that from happening (see *Shale Daily*, June 17, 2015).

Annual Natural Gas Production In Counties That Contain the Piceance Basin

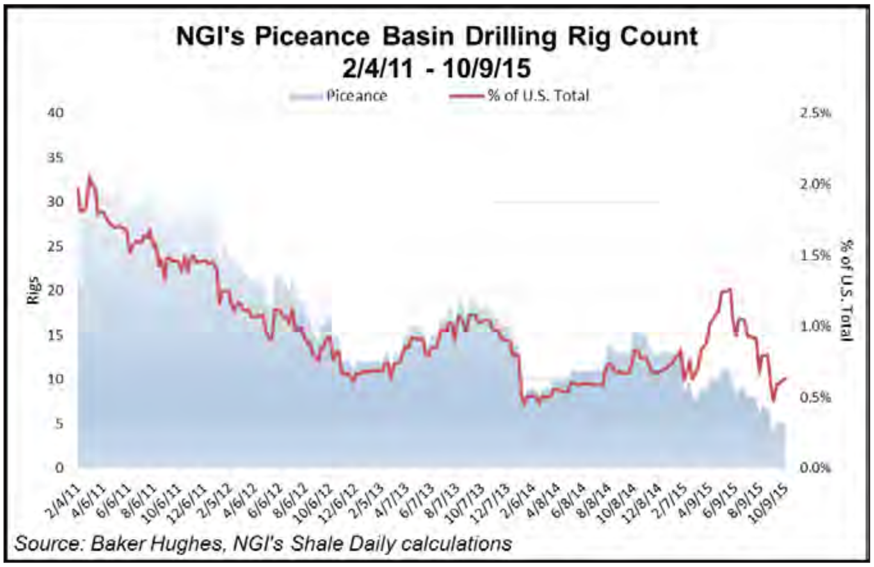
County	2001	2002	2003	2004	2005	2006	2007
Delta	0.005	0.006	0.002	0.025	0.401	0.065	0.019
Garfield	88.285	116.868	149.824	209.714	270.231	351.613	443.400
Gunnison	0.110	0.040	0.079	0.079	0.007	0.556	1.183
Mesa	5.027	7.695	9.345	7.807	10.755	15.478	30.651
Moffat	17.489	19.178	18.527	19.557	19.521	19.742	16.150
Pitkin	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Rio Blanco	31.414	35.936	34.159	33.622	37.579	48.159	48.119
TOTAL (Bcf)	142.330	179.723	211.935	270.804	338.495	435.612	539.522
TOTAL (MMcf/d)	*389.9*	*492.4*	*580.6*	*739.9*	*927.4*	*1193.5*	*1478.1*
Y/Y % Change	**12.5%**	**26.3%**	**17.9%**	**27.4%**	**25.3%**	**28.7%**	**23.9%**

County	2008	2009	2010	2011	2012	2013	2014
Delta	0.026	0.010	0.009	0.015	0.061	0.153	0.301
Garfield	565.152	610.868	648.453	676.333	701.963	653.584	609.125
Gunnison	1.475	1.410	2.078	1.901	1.965	1.477	3.609
Mesa	42.788	38.476	37.992	41.662	47.211	37.283	36.317
Moffat	20.169	17.082	19.345	18.252	17.090	17.097	16.303
Pitkin	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Rio Blanco	54.468	76.041	99.841	106.274	94.906	76.363	81.244
TOTAL (Bcf)	684.079	743.887	807.718	844.436	863.196	785.957	746.899
TOTAL (MMcf/d)	*1869.1*	*2038.0*	*2212.9*	*2313.5*	*2358.5*	*2153.3*	*2046.3*
Y/Y % Change	**26.4%**	**9.0%**	**8.6%**	**4.5%**	**1.9%**	**-8.7%**	**-5.0%**

Note: These figures are largely driven by Piceance production, but may contain some production from other formations.

Source: Colorado Oil & Gas Conservation Commission data, NGI's Shale Daily calculations

Piceance Basin (continued)



Former WPX CEO Ralph Hill noted in November 2013 that the Piceance essentially has become a mix between a growth and a more mature play. Across the Piceance Basin, "we have another, ultimately, 10,000 wells to drill, and that's without the Niobrara opportunity. So we know what we're doing there. We have a lot of wells that are on the very mature decline state of their life, so we feel we have a unique set of assets that we would be able to put into an MLP." Master Limited Partnerships are more suited to assets that feature a steady and relatively predictable cash flow stream. Many unconventional oil and gas wells exhibit hyperbolic decline curves in their first few years, which leads to huge year-over-year negative production declines. Eventually, these wells assume a more normal and steady decline curve, thus making them more appropriate to be placed in an MLP.

In late 2015, saddled with more impairment charges for its exploration and production (E&P) business, Rapid City, SD-based Black Hills Corp. senior executives decided to narrow their focus to the Piceance Basin where the company's E&P unit has been testing the Mancos Shale. In conjunction with this new approach, the company also moved forward on its plan to use natural gas reserves programs for its utilities in eight states (see *Shale Daily*, Oct. 5, 2015). In November 2015, CEO David Emery said Black Hills was transitioning its E&P operations toward "primarily serving our utilities through a cost-of-service gas reserves program while preserving the upside value potential of our oil/gas properties [see *Shale Daily*, Nov. 5, 2015]."

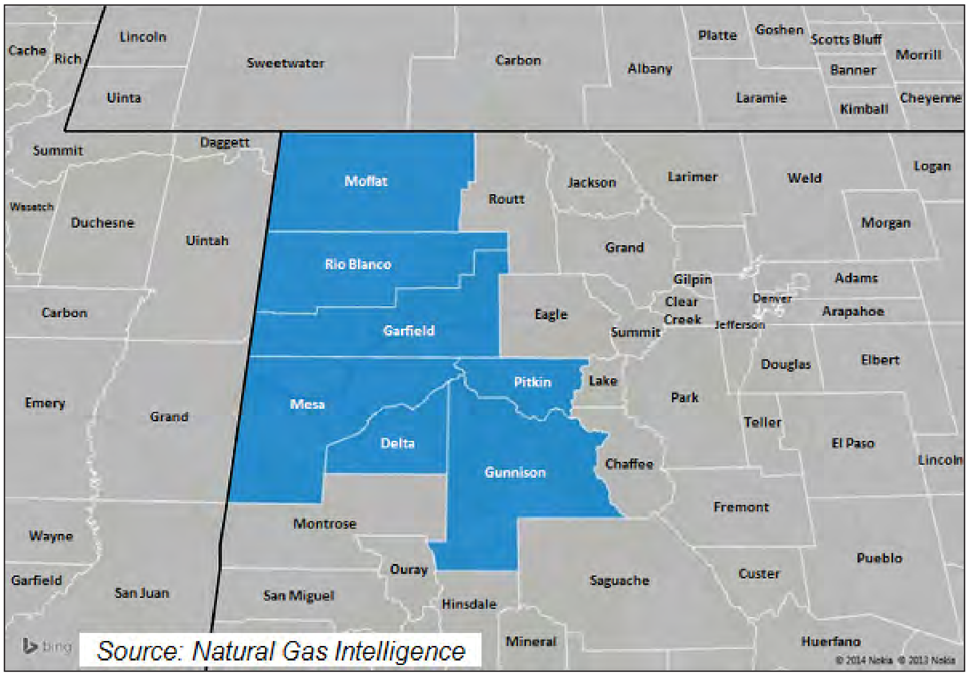
In the first half of 2015, Black Hills added two rigs in the Mancos Shale of the southern Piceance Basin, taking advantage of lower rig and service costs to accelerate its developmental drilling (see *Shale Daily*, May 6, 2015). Black Hills had three wells producing in the Mancos and expected to have as many as 10 online by the end of 2015, with long-range reserve projections of about 10 Bcf/well, Emery told financial analysts.

The Piceance is also prospective for the gassier Niobrara Shale, but like activity in the Mancos, assessment of the Niobrara within the Piceance Basin is still very much in the early innings. WPX continues to target the Niobrara Shale and CEO Richard Muncrief told investors in the past that the area is "something that could be a game changer for us." Separately, financially struggling SandRidge Energy Inc. in late 2015 diversified its operations by acquiring proved reserves and producing wells in the Niobrara in nearby Jackson County, CO in a $190 million cash agreement with privately held EE2 LLC. The Oklahoma City-based independent expected the deal to close by the end of 2015 (see *Shale Daily*, Nov. 5, 2015).

Counties

Colorado: Delta, Garfield, Gunnison, Mesa, Moffat, Pitkin, Rio Blanco

Piceance Basin (continued)



Local Major Pipelines

Natural Gas: CIG, Northwest Pipeline, Questar, Rockies Express, TransColorado, White River Hub, WIC

Crude Oil: Rocky Mountains (Plains)

NGLs: Overland Pass, Rocky Mountains (Enterprise)

PICEANCE BASIN NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Encana	742,000	Hunter Ridge Energy Services LLC	N/A
ExxonMobil	300,000	KGH Operating Company	N/A
WPX Energy	200,000	Koch Exporation Co.	N/A
Occidental Petroleum	187,000	Laramie Energy II	N/A
Black Hills Corporation	99,562	Legacy Reserves	N/A
Chevron	72,000	Linn Bros Oil & Gas Inc.	N/A
Ursa Resources Group II	60,000	LINN Energy	N/A
Fram Exploration	51,624	Locin Oil Corporation	N/A
DXI Energy	45,425	Lone Mountain Production Co.	N/A
Piceance Energy LLC*	40,000	Maralex Resources	N/A
Genesis Gas & Oil	26,440	Mastorakos D A	N/A
Endeavour International	19,800	Matrix Oil Corporation	N/A
Vanguard Natural Resources	16,075	Merrion Oil & Gas	N/A
Par Petroleum	10,066	Mesa Energy	N/A
Marathon Oil	8,400	Mont Rouge Inc.	N/A
Bill Barrett Corp.	4,184	National Fuel Corporation	N/A
Wapiti Energy	1,963	Nonsuch Natural Gas	N/A

Piceance Basin (continued)

PICEANCE BASIN NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Argali Exploration Company	N/A	Northstar Gas Co.	N/A
Augustus Energy Partners	N/A	Petro Mex Resources	N/A
Axia Energy LLC	N/A	Premium Oil Co	N/A
Bayswater Exploration & Production	N/A	Puckett Land Company	N/A
Beartooth Oil & Gas	N/A	Retamco Operating	N/A
BOPCO LP	N/A	Rio Mesa Resources	N/A
C & J Field Services	N/A	Robert L. Bayless Producer LLC	N/A
Caerus Oil & Gas	N/A	Saga Petroleum LLC	N/A
Calco DBA Callister Co.	N/A	Shawnee Oil Development Co Inc	N/A
Coachman Energy Operating Co.	N/A	Southwestern Energy	N/A
Curton Capital Corp	N/A	Stehle Oil Company	N/A
D & G Roustabout Service	N/A	Vaquero Energy	N/A
Eagle Operating	N/A	Walter S Fees Jr and Son Oil & Gas	N/A
Foundation Energy Management	N/A	Wellstar Corporation	N/A
G2X Energy	N/A	Western Interior Energy	N/A
Glade Chris Oil & Gas LLC	N/A	Wexpro	N/A
Gordon Engineering	N/A	Whiting Petroleum	N/A
Great Northern Gas Co.	N/A	Windsor Energy	N/A
Grynberg Jack DBA Grynberg Petroleum Co	N/A	XOG Operating LLC	N/A
Hayes Petroleum Company	N/A		

*Estimate

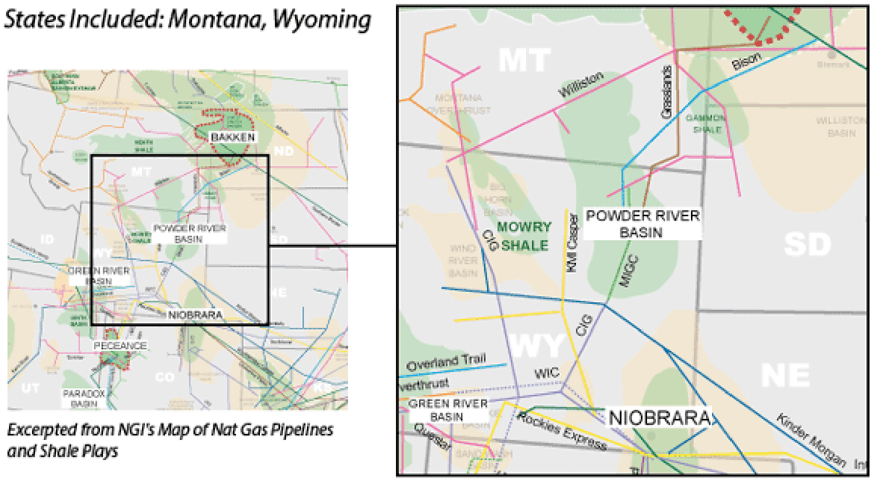
Source: Compiled by NGI from company documents

POWDER RIVER BASIN

Background Information

The Powder River Basin (PRB) in Northeast Wyoming and Southeast Montana, which is traditionally more known for its coal production, was one of the fastest growing oil producing regions in North America through the first half of 2014. However, the oil and gas oversupply situation forced national natural gas prices steeply lower during 2H14, followed by a similar crash in crude markets.

States Included: Montana, Wyoming



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

As a result, development of the Powder River Basin has slowed significantly as producers tighten their belts, laying down rigs nationally and using their reduced E&P assets and budgets on more developed plays with more certain returns. From the first week of December 2014 to the second week of October 2015, producers have reduced drilling activity in the Powder River Basin by 73%, from 33 active rigs to just nine. Over the same period, the country's most active plays such as the Marcellus Shale, the Williston Basin and the Eagle Ford Shale have declined by 44%, 66% and 61%, respectively, to 46 rigs, 65 rigs and 80 rigs.

Of the nine rigs working the PRB in early October 2015, all of which were in Wyoming, 4 were in Campbell County, another 4 in Converse County, and the final rig in Weston County.

NGI's Powder River Basin Drilling Rig Count 2/4/11 - 10/9/15

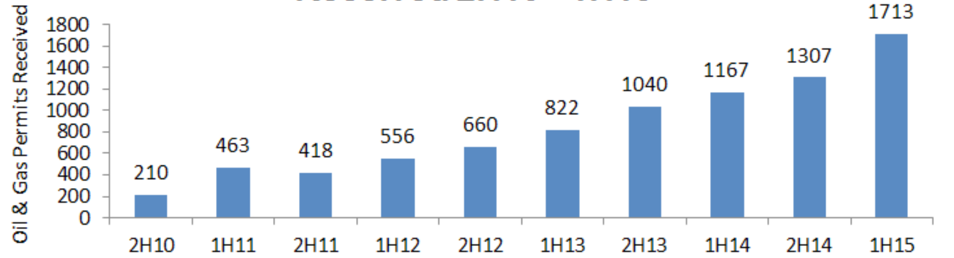
Source: Baker Hughes, NGI's Shale Daily calculations

The PRB technically stretches into Montana, but the Wyoming portion of the basin typically accounts for 98%-99% of its annual production. Back in 2014 Chesapeake Energy stated on its 2Q14 conference call that difficulty obtaining permits and a lack of gas processing plants in the PRB (historically, most natural gas production in the PRB has been coalbed methane, which is about as dry a gas as you can get, and therefore usually does not need processing) had slowed the pace of growth in the basin somewhat. However, Denver-based Meritage Midstream Service II LLC completed and brought online its new natural gas processing plant, 50 Buttes, in Campbell County, WY, in October 2014. This plant is large enough to accommodate up to 300 MMcf/d.

Takeaway capacity continues to expand on the oil side as well. The new Black Thunder oil rail terminal, which was developed jointly by Denver-based Meritage Midstream Services II LLC and Arch Coal, saw its first shipment of crude oil from the PRB in Wyoming go out in June 2014. A 99-car train operated by Union Pacific Railway carried 70,000 bbl of Wyoming crude to a refinery on the East Coast for the terminal's anchor shipper, Black Thunder Marketing LLC, a spokesperson for Meritage said. Meritage is touting the rail facility as providing "rail-to-market optionality" for PRB crude oil production. The new terminal is served by BNSF Railway, as well as Union Pacific, and it is strategically located in Wyoming's energy rich Campbell County.

Powder River Basin (continued)

Wyoming PRB Basin Oil & Gas Permits Received 2H10 - 1H15



	Campbell	Converse	Johnson	Natrona	Niobrara	Sheridan	Weston	*TOTAL*
2H10	65	62	12	31	24	2	14	*210*
1H11	144	161	15	109	17	4	13	*463*
2H11	68	175	67	81	20	1	6	*418*
1H12	110	262	101	53	13	7	10	*556*
2H12	211	304	76	26	36	2	5	*660*
1H13	277	353	68	47	51	1	25	*822*
2H13	397	438	72	67	25	0	41	*1040*
1H14	354	498	144	95	29	1	46	*1167*
2H14	448	703	76	12	45	0	23	*1307*
1H15	406	1072	69	87	14	2	63	*1713*
TOTAL	***2480***	***4028***	***700***	***608***	***274***	***20***	***246***	***3129***

Source: Compiled by NGI's Shale Daily from Wyoming Oil & Gas Conservation Commission data

Annual Powder River Basin Oil & Gas Production 2000-2014

Year	Total Oil* (Mil Bbls)	*Y/Y % Chg*	Total Nat Gas* (Bcf)	*Y/Y % Chg*	Wyoming PRB CBM (Bcf)	*Y/Y % Chg*	WY PRB CBM As % of Total Nat Gas
2000	24.6	- -	212.6	- -	150.9	- -	*71%*
2001	22.1	*-10.2%*	284.3	*33.7%*	216.7	*43.6%*	*76%*
2002	20.8	*-5.8%*	400.3	*40.8%*	337.6	*55.8%*	*84%*
2003	19.5	*-6.6%*	399.8	*-0.1%*	346.1	*2.5%*	*87%*
2004	18.5	*-5.1%*	385.2	*-3.7%*	332.2	*-4.0%*	*86%*
2005	18.0	*-2.8%*	379.6	*-1.5%*	333.2	*0.3%*	*88%*
2006	18.8	*4.8%*	420.5	*10.8%*	377.9	*13.4%*	*90%*
2007	18.6	*-1.4%*	470.3	*11.8%*	429.2	*13.6%*	*91%*
2008	17.8	*-4.2%*	577.2	*22.7%*	537.0	*25.1%*	*93%*
2009	17.8	*0.0%*	521.7	*-9.6%*	484.2	*-9.8%*	*93%*
2010	19.4	*9.2%*	571.6	*9.6%*	538.1	*11.1%*	*94%*
2011	20.9	*7.8%*	516.8	*-9.6%*	480.6	*-10.7%*	*93%*
2012	23.6	*12.9%*	443.2	*-14.3%*	401.9	*-16.4%*	*91%*
2013	26.7	*12.8%*	281.6	*-36.4%*	225.4	*-43.9%*	*80%*
2014	41.8	*56.8%*	318.7	*13.2%*	246.8	*9.5%*	*77%*

*Total includes both Montana and Wyoming PRB production, but Wyoming typically accounts for 98%-99% of the total.

Source: Compiled by NGI's Shale Daily from Montana Board of Oil & Gas and Wyoming Oil & Gas Conservation Commission data

Powder River Basin (continued)

Other options for crude takeaway are also in the works. Genesis Energy LP in November 2015 was holding an open season for a crude oil pipeline extension that would serve the Powder River Basin in Wyoming with service as early as the first quarter of 2016 (see *Shale Daily*, Nov. 12, 2015). The pipeline would be 135 miles long and capable of receiving crude oil from multiple receipt points in Wyoming's Campbell and Converse counties. Deliveries would be to the company's Pronghorn unit train loading facility north of Douglas, WY, and to its new terminal in Guernsey, WY (see *Shale Daily*, June 25, 2015). The latter offers a direct connection to the Pony Express Pipeline, as well as infrastructure that feeds regional refineries. The Phase 2 extension would also provide shippers direct rail access to a majority of the nation's crude oil unloading facilities, via two Class 1 railroads: BNSF and Union Pacific.

The Powder River Basin was the subject of many 3Q15 earnings calls by E&P companies. On Oct. 28, executives with SM Energy Inc. said they would transition one drilling rig out of the Powder River Basin in early 2016 (see *Shale Daily*, Oct 29, 2015). One week later, Chesapeake Energy Corp. CEO Robert Lawler said its asset in the basin "has progressed dramatically in the past year," adding that its estimate of recoverable resources there continues to grow (see *Shale Daily*, Nov. 4, 2015). And in a separate statement on the same day, ONEOK Inc. also reported increased production volumes from the basin.

While EOG Resources Inc. is the largest oil producer and acreage holder in the Eagle Ford Shale. David Trice, executive vice president for E&P, said on Nov. 6 that the Powder River Basin "remains a core position for EOG," despite reduced capital spending there in 2015 (see *Shale Daily*, Nov. 9, 2015).

With a goal of more precise E&P in the Powder River Basin, University of Wyoming researchers and industry in August 2015 moved into the second phase of cooperative research on the basin's geology (see *Shale Daily*, Aug. 12, 2015). The focus is on the Frontier formation, where hydraulic fracturing (fracking) has revitalized E&P activity (see *Shale Daily*, Sept. 15, 2014). New Orleans-based service company Helis Oil & Gas Co. and Oklahoma City-based Devon Energy Corp. are working with researchers at UW's Department of Geology and Geophysics and the School of Energy Resources. The Cretaceous Tight Oil Consortium is seeking the best ways to tap unconventional oil reservoirs. PRB, one of the busiest oilfields, helped spark the first phase of the research in 2012.

Initial UW research focused on the stratigraphy of tight sandstone of the Frontier. Graduate student Rebekah Rhodes used core and outcrop analysis to provide "a clearer picture of the subsurface," according to UW. The analysis is expected to help E&Ps "better model and more efficiently extract oil from deep reservoirs." In the second phase, researchers plan to analyze the interaction of fracking fluids with the minerals of the formation. "We're looking at how the fluids react with the Frontier," said UW's associate professor John Kaszuba. "'This should provide companies with information about what treatments to use downhole to maximize production." Using core samples from the Frontier and the fracking chemicals used, researchers during the next two years plan to duplicate underground temperature and pressure levels in the laboratory to analyze the geochemical reactions to gain insights into which chemicals to use or avoid in frack jobs.

Formation	Type/Primary Target
Frontier	Tight Sands - Oil
Mowry	Shale - Oil
Niobrara-Codell	Shale - Oil
Parkman	Tight Sands - Oil
Shannon	Tight Sands - Oil
Sussex	Tight Sands - Oil
Turner	Tight Sands - Oil

The combination of the earlier stratigraphic data with the geochemical research "could substantially improve well completions in the Frontier and other similar reservoirs," said assistant professor and co-leader of the research Brandon McElroy.

Even among difficult economics, some producers are doubling down in the Powder River Basin. In early December 2015 Devon Energy Corp. paid $2.5 billion to tack on 80,000 net surface areas in Oklahoma's emerging stacked reservoirs and double its position in the Powder River Basin, two onshore areas that CEO Dave Hager said were among the best in North America (see *Shale Daily*, Dec. 7, 2015).

The acquired PRB acreage, south of Devon's legacy position in Wyoming, includes production of 7,000 boe/d, 85% weighted to oil. The leasehold "is most prospective for the Parkman, Turner and Teapot formations," Vaughn noted.

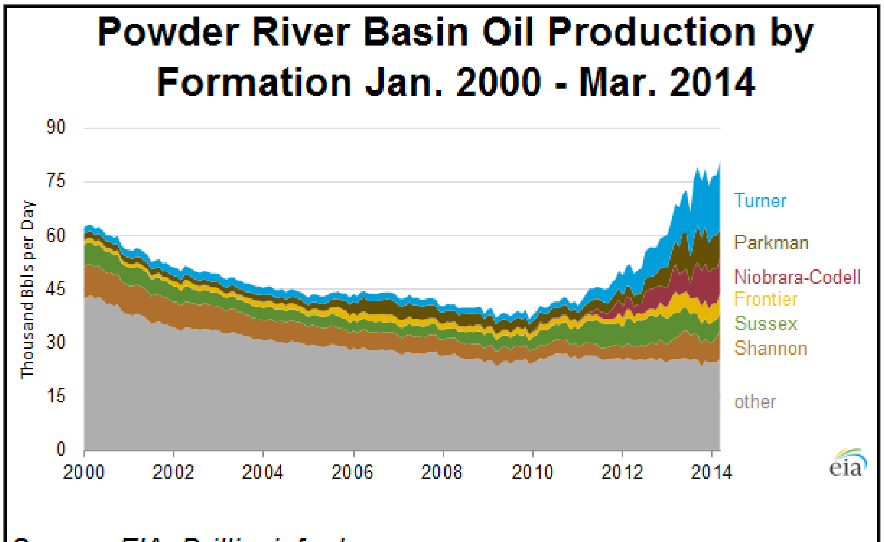
The contiguous acreage in the PRB allows for extended-reach horizontal drilling, and Devon has conservatively identified 500 development-ready locations with potential for as many as 2,700 unrisked locations as appraisal drilling further de-risks multiple formations.

"This opportunistic transaction adds scale and scope to our Powder River Basin operations, creating the largest and highest quality acreage position in the industry," said Vaughn. "Our Powder River programs are delivering some of the best returns at Devon, and we will apply our unique basin knowledge to efficiently develop and derisk this premium acreage position."

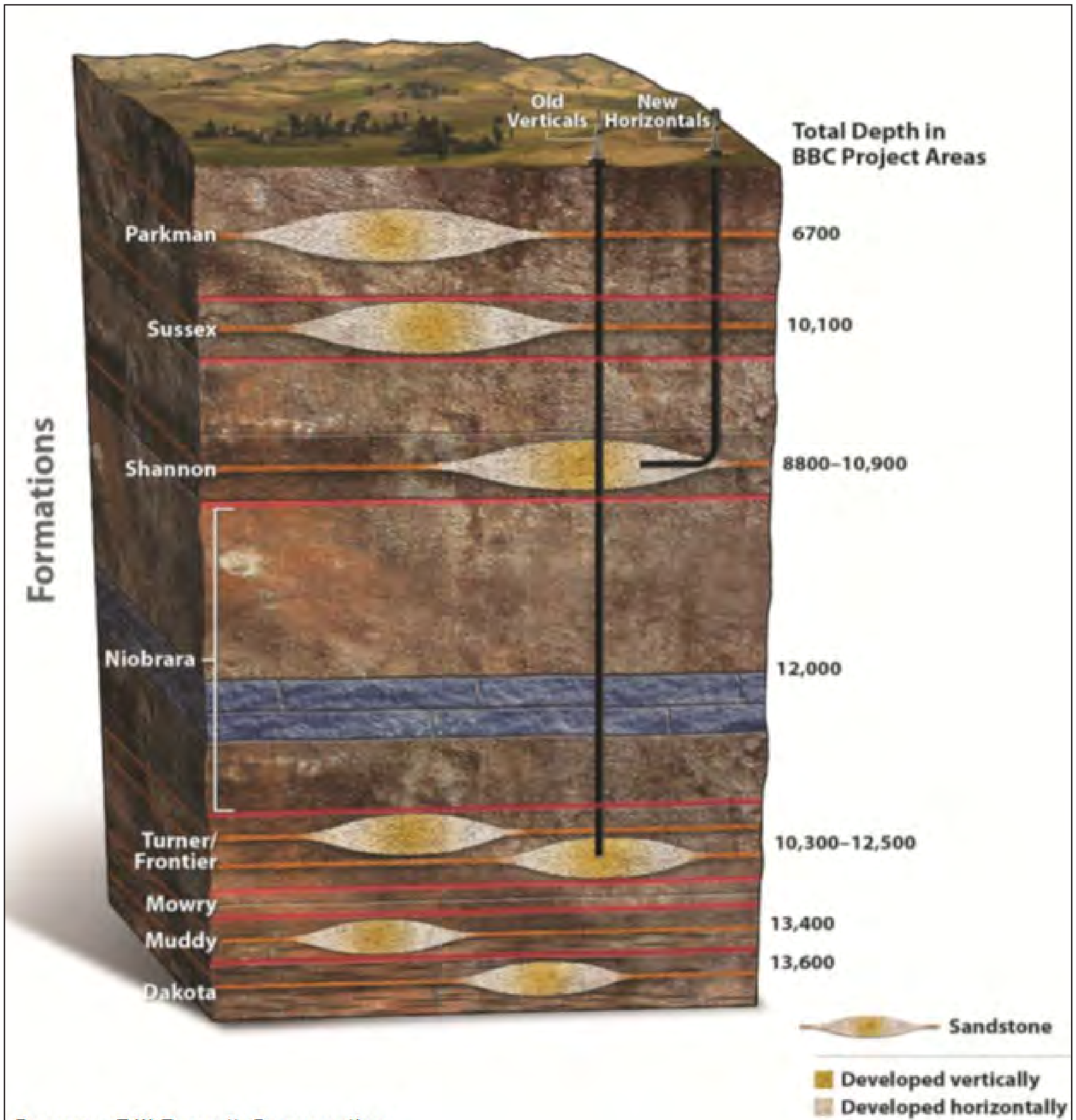
Powder River Basin (continued)

After deducting the value of current production at $30,000/flowing barrel and $100 million of midstream infrastructure, Devon secured the undeveloped leasehold at roughly $1,100/acre. Devon's PRB leasehold would double to more than 470,000 net acres once the deal is completed, with Rockies business unit's production increasing to more than 30,000 boe/d.

The play has also seen some new players entering. In September 2015 Moriah Group LLC, based in Midland, TX, is becoming one of the biggest operators in Powder River Basin after securing a bundle of CBM gas



Source: EIA, Drillinginfo, Inc.



Source: Bill Barrett Corporation

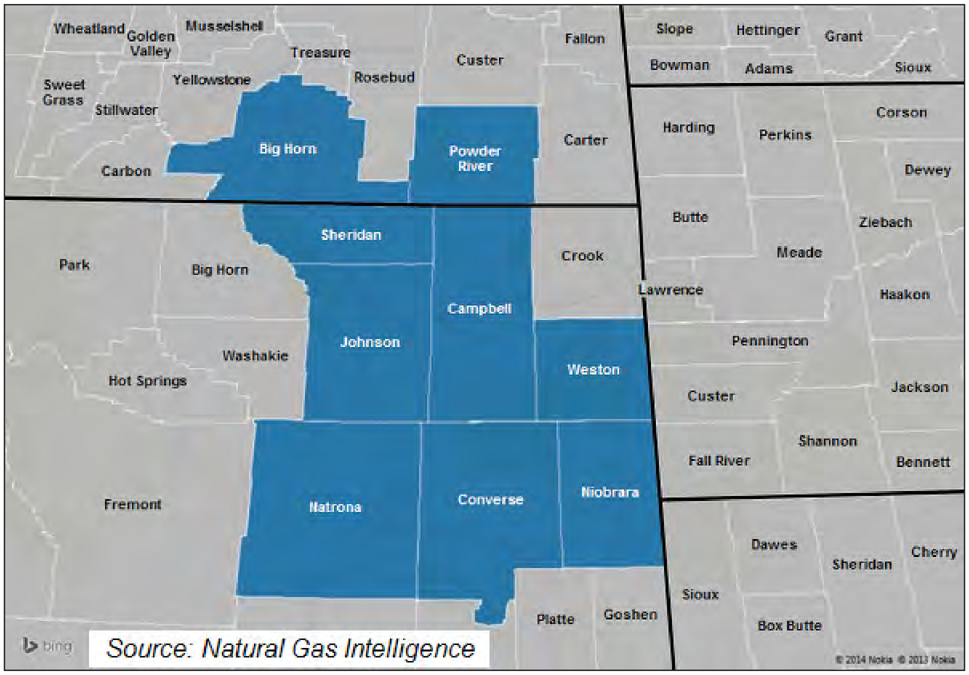
Powder River Basin (continued)

wells from WPX Energy Inc. and Anadarko Petroleum Corp., as well as a big natural gas gathering system.

Over the past couple of months, Moriah and its partners have agreed to acquire WPX's entire PRB portfolio, including its stakes in Fort Union Gas Gathering LLC, with system capacity of 1.2 Bcf/d. Fort Union is being sold to affiliate Moriah Powder River LLC for $80 million, according to WPX.

Carbon Creek Energy LLC, formed by Moriah and with private equity funding, separately is buying an estimated 7,500 gas wells in the PRB through dual transactions with WPX and Anadarko. About 2,000 wells are being purchased from WPX with 5,500 from Anadarko. About 4,500 of the wells in September produced an estimated 400 MMcf/d of natural gas. Another 800 wells are expected to ramp up.

WPX had an agreement last year to sell its CBM wells to an undisclosed buyer for $155 million (see *Shale Daily*, [Aug. 20, 2014](#)). However, that sale is said to have fallen through.



Counties

Montana: Big Horn, Powder River

Wyoming: Campbell, Converse, Johnson, Natrona, Niobrara, Sheridan, Weston

Local Major Pipelines

Natural Gas: Bison Pipeline, CIG, Grasslands, KMI-Casper, MIGC, Tallgrass, WBI Energy Transmission, WIC

Crude Oil: Express System (Spectra), Frontier, Platte, Pony Express, Rocky Mountains (Plains)

NGLs: Bakken NGL, Kinder Morgan CIG Powder River Lateral (Proposed), Powder River (ConocoPhillips)

Powder River Basin (continued)

POWDER RIVER BASIN NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Chesapeake Operating Inc	365,000	Hyperion Oil & Gas	N/A
Anadarko Petroleum	350,000	Justice Oil & Gas	N/A
Samson Resources	299,000	Kaiser Francis Oil Co.	N/A
Devon Energy	225,000	Kennedy Oil	N/A
SM Energy	171,000	Kings X Oil Company	N/A
Black Hills Corporation	96,716	L & J Operating Inc	N/A
Vanguard Natural Resources	66,866	Lappin Oil LLC	N/A
EOG Resources	63,000	Legacy Reserves	N/A
Bear Peak Resources	60,000	M & K Oil Company Inc.	N/A
Charger Resources	45,000	Mack Energy Corporation	N/A
Peak Energy	30,000	Marlin Oil Company	N/A
Linc Energy	27,821	Matrix Production Company	N/A
Argent Energy*	27,700	Maxim Drilling & Exploration	N/A
Four Corners Petroleum	25,000	Meadow Deep LLC	N/A
Fidelity Exploration (MDU)	24,000	Medallion Exploration	N/A
Abraxas Petroleum Corporation	16,333	Merit Energy Company	N/A
Escalera Resources	16,000	Merrion Oil & Gas Corporation	N/A
Liberty Resources II	15,000	Millennium Oil & Gas	N/A
Aexco Petroleum Inc	N/A	Moncrief W A Jr	N/A
Am-West Petroleum Inc	N/A	Morton Holdings LLC	N/A
Anderson Management Company	N/A	Noble Energy Inc	N/A
Anschutz Exploration	N/A	Nonsuch Natural Gas Inc	N/A
Antelope Resources Inc.	N/A	North Finn LLC	N/A
Ballard Petroleum Holdings	N/A	Northern Production Co	N/A
Bataa Oil Inc	N/A	Oilfield Salvage & Service Company	N/A
Baytex Energy	N/A	Osborn Heirs Company	N/A
Beartooth Oil & Gas	N/A	P & M Petroleum Management	N/A
Berenergy Corporation	N/A	Pathfinder Energy Inc.	N/A
Bill Barrett Corporation	N/A	Peabody Natural Gas LLC	N/A
Black Bear Oil Corporation	N/A	Penneco Exploration Company Of Wyoming	N/A
Black Diamond Minerals	N/A	Petro-Hunt LLC	N/A
Blake Production	N/A	POC-I, LLC	N/A
Blue Tip Energy	N/A	Prima Exploration Inc	N/A
Boggy Creek Production	N/A	QEP Resources	N/A
Bowden Energy Company Inc.	N/A	Ranch Oil Company	N/A
C & H Well Servicing Inc.	N/A	Richardson Operating Co.	N/A
Callaway Oil & Gas	N/A	Rim Operating Inc	N/A
Carol-Holly Oil Corporation	N/A	RKI Exploration & Production LLC	N/A
Catherine No 1 LLC	N/A	Robert Hawkins Inc	N/A
Chaco Energy Company	N/A	Seer Operating LLC	N/A
Chapman Oil Company	N/A	Sheridan Production Co.	N/A
Chemily Management Company	N/A	Skinner Oil & Gas	N/A
Cirque Resources LP	N/A	Slawson Exploration Company Inc	N/A
Citation Oil & Gas Corporation	N/A	Smith Nowlin Jr Oil Co.	N/A
CKT Energy	N/A	Sonterra Energy	N/A

Powder River Basin (continued)

POWDER RIVER BASIN NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
Cordero Oil And Gas	N/A	Sooner Operating Co.	N/A
Coronado Oil Company	N/A	Stealth Energy USA	N/A
Diamond Oil & Gas	N/A	Strachan Exploration Inc	N/A
DNR Oil & Gas Inc	N/A	Stroud Petroleum Inc	N/A
DOL Resources Inc	N/A	Sunshine Valley Petroleum	N/A
Edwards Operating Company	N/A	The Termo Company	N/A
Eland Energy Inc	N/A	Three Forks Resources	N/A
Elk Petroleum Inc	N/A	TriPower Resources	N/A
Ellbogen John P Ltd.	N/A	True Oil	N/A
Energy Equity Company	N/A	Underwood Oil & Gas	N/A
Energy Search Company Inc.	N/A	Urban Oil & Gas	N/A
EnPro LLC	N/A	Vector Minerals Corporation	N/A
ExxonMobil/XTO Energy	N/A	Ventrum Energy Corporation	N/A
Finley Resources	N/A	Ware House Industries	N/A
Fleur de Lis Energy	N/A	Warren Enterprises Inc.	N/A
Fossil Creek Resources	N/A	Wellstar Corporation	N/A
Fossil Energy Inc.	N/A	Western American Resources	N/A
Frickey Investment Management Co.	N/A	Wexpro Company	N/A
Geju Oil & Gas Inc.	N/A	Windsor Energy Group LLC	N/A
Great Western Drilling Company	N/A	Wyoil Corp	N/A
Griffiths Oil	N/A	Wyoming Resources Corporation	N/A
Harrell Oil Company	N/A	Xoil Inc	N/A
Helis Oil & Gas Co.	N/A	Yates Petroleum Corporation	N/A

*Estimate

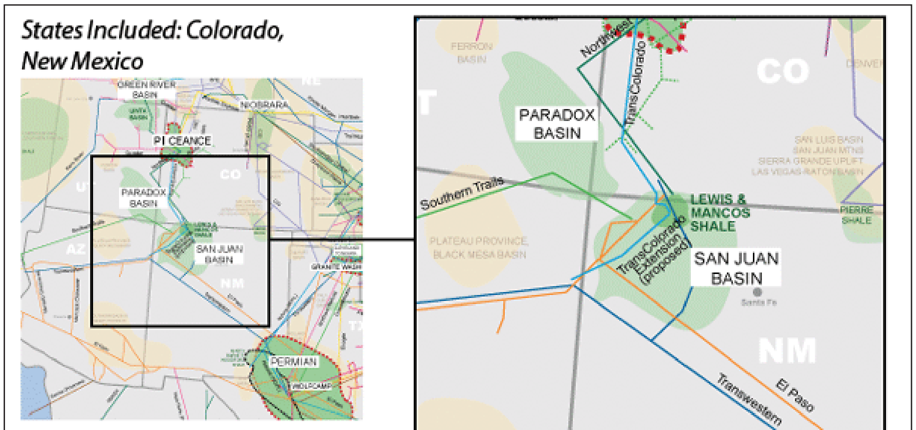
Note: Only includes companies with operations targeting the Frontier, Mowry, Niobrara-Codell, Parkman, Shannon, Sussex, and Turner formations. Some of the above figures may include acres targeting CBM.

Source: Compiled by NGI from company documents

SAN JUAN BASIN

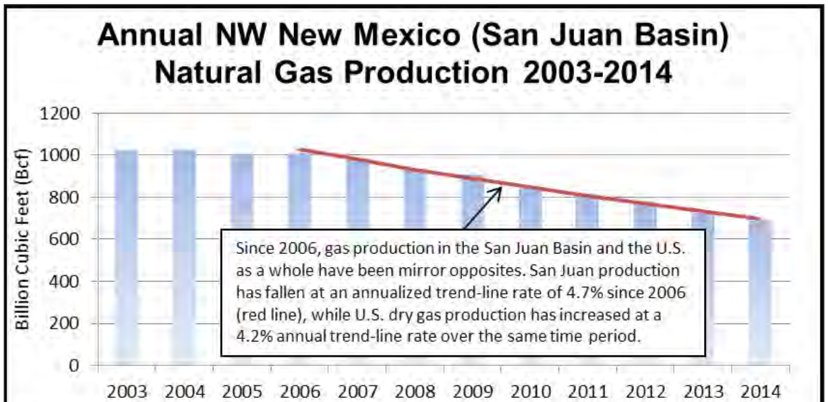
Background Information

The San Juan Basin, which is located predominantly in Northwest New Mexico and extends into Southwest Colorado, is primarily a natural gas production area from both conventional and unconventional tight sands, coal bed methane (CBM), and shale formations, although crude oil production in the region has been gaining momentum. The San Juan is one of the oldest producing areas in the United States, with the first conventional natural gas discovered in 1921, and the first CBM well spud in 1948. However, CBM production in the San Juan Basin didn't really flourish until the 1990s, thanks in large part to Federal tax credits. Overall, there are currently more than 20,000 oil and gas wells in the San Juan Basin.



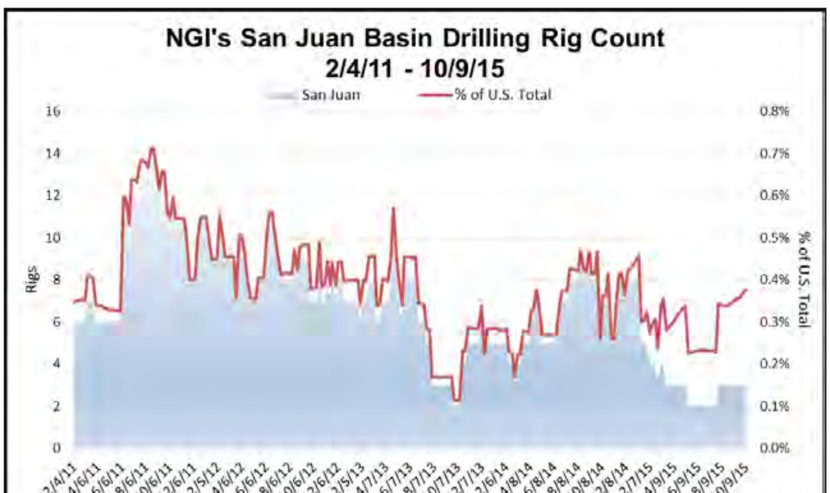
Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

In 2010, the U.S. Energy Information Administration (EIA) tabbed the combined San Juan Basin Gas Area in Colorado and New Mexico as the 2nd largest natural gas field in the United States in terms of proved reserves, with production of 1.3 trillion cubic feet in 2009. However, since 2006, total natural gas production in the San Juan Basin and the U.S. as a whole have been mirror opposites of each other. As seen in the chart to the right, New Mexico San Juan natural gas production (most of the San Juan Basin lies in New Mexico) has fallen at an annualized trend-line rate of 4.7% since 2006, while U.S dry gas production has increased at a 4.2% annual-trend line rate over the same period. Moreover, CBM continues to account for a smaller percentage of production on the New Mexico side of the play, falling from 49.5% in 2006 to 41.0% in 2014.



Source: State of New Mexico Oil Conservation Division data, NGI's Shale Daily calculations

After peaking at 14 in August 2011, the drilling rig count in the San Juan Basin stood at just 3 in early October 2015. 2 of those rigs were in Rio Arriba County, NM, with the third in San Juan County, NM.

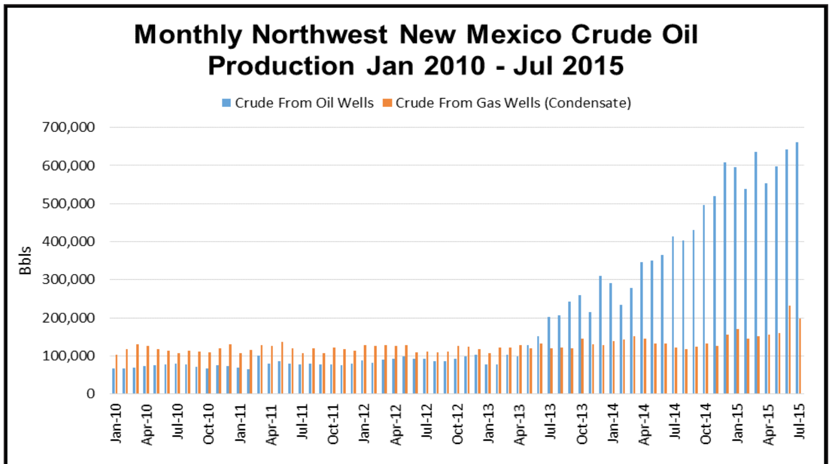


Source: Baker Hughes, NGI's Shale Daily calculations

The flood of Marcellus gas supplies to market over the past few years, which dropped the commodity's price well below the crude oil value slump, led

San Juan Basin (continued)

producers in the San Juan Basin away from the gassier part of the play and towards the oil-rich Mancos Shale portion located in the southern end of the basin. In addition to the Mancos, the San Juan Basin is also home to the gassier Lewis Shale formation. However, attempts by the industry to develop this resource largely have proven to be unsuccessful thus far.



Source: New Mexico Oil Conservation Division Data

Development of the Mancos still remains very much in the initial stages, but early mixed drilling results are starting to become more favorable. During its 2Q14 conference call, Encana reported it was in the process of advancing commercial development of the San Juan, while continuing to delineate its acreage. The company had drilled 14 wells in the San Juan as of June 2014, and noted the performance of those wells had been consistently at or above its expectations, with initial production rates between 400-500 b/d.

While the steep decline in oil prices over the last year has dampened development even in the Mancos, some producers are renewing their interest. In 2015, BP returned to its legacy holdings in the San Juan Basin, a gassy asset that was spurned for international opportunities years ago (see *Shale Daily*, Oct. 27, 2015).

"In the San Juan, we are seeing significant reduction in development costs compared to the last time we drilled in the basin back in 2009," BP CEO Bob Dudley said during a 3Q2015 earnings call. Gas wells in San Juan now "are being developed at a cost of 45 cents/Mcf." The company's first dual-lateral well in the San Juan also is showing "encouraging early performance."

WPX Energy Inc., which has been active in the San Juan Basin's oily Gallup formation, which lies within the Mancos Shale, added 14,300 net acres in the Gallup in June as part of its plan to step away from its natural gas-heavy portfolio for onshore oil prospects (see Shale Daily, June 22, 2015).

The $26 million transaction with an undisclosed seller includes around 100 drilling locations, which would boost the Tulsa independent's Mancos Gallup Sandstone locations to around 500. WPX owns or controls around 100,000 acres in the core of the Gallup oil window, where it has spud 100-plus wells since a discovery in 2013 (see *Shale Daily*, Aug. 7, 2013). Management was confident enough in the Gallup discovery in 2014 to swap coalbed methane properties in the Powder River Basin for a bigger slice of San Juan leasehold (see *Shale Daily*, Aug. 20, 2014).

Energen Corp. in February 2015 agreed to sell the majority of its San Juan natural gas assets to a private company for $395 million. The assets included about 985 net operated wells on some 205,000 net acres. On the liquids side, Energen deployed one horizontal rig for its Mancos Shale appraisal program in the San Juan Basin for the second half of 2015. Irene O. Haas, analyst for Wunderlich Securities Inc. said in August 2015 that all eyes were on the company's 2H2015. "This fall, we look forward to seeing Energen drilling its eight-well program in the San Juan Basin, which could offer positive catalysts," she said (see *Shale Daily*, Aug. 11, 2015).

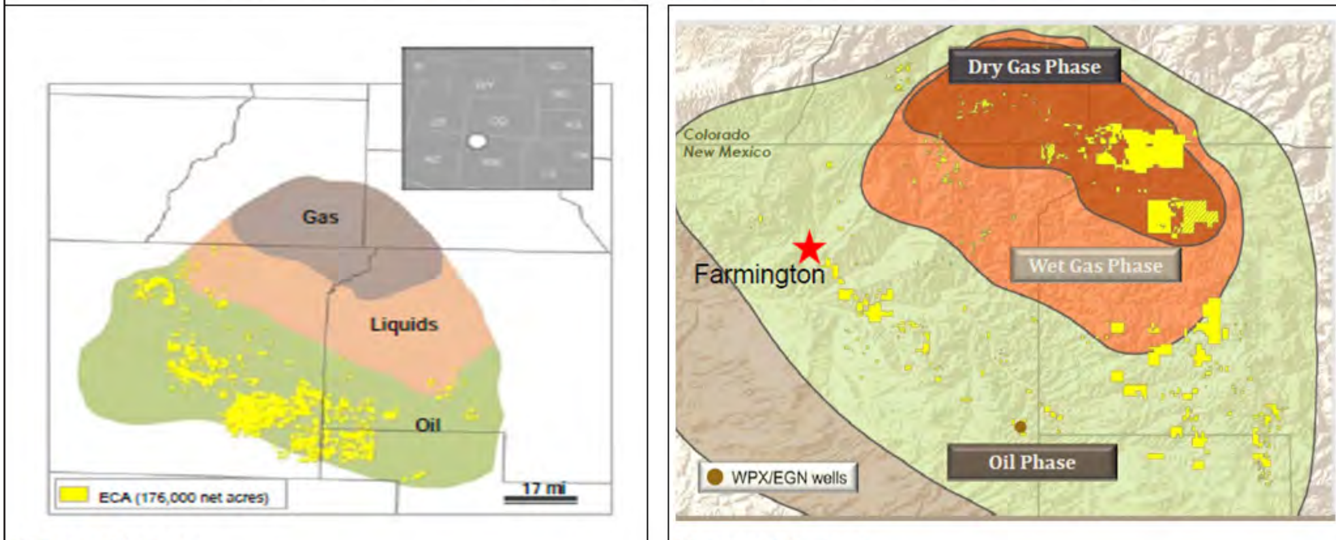
Energen's management noted on its 3Q2015 earnings conference call that it is still too early to know whether the company will dedicate more capital to the Mancos in 2016-17, and that decision would be determined in no small part by how well economics in the area compete with the company's acreage in the Midland Basin in the Permian. But even if their Mancos wells do prove to be competitive, EGN indicated permitting issues in the San Juan may restrict their ability to develop that resources at an accelerated pace.

The commodity downturn has proven to be too much for some producers. Tulsa-based Samson Resources Corp., which operates in the San Juan along with a number of other basins, filed for Chapter 11 bankruptcy in September 2015 and said it expects its restructuring to provide "a significant deleveraging" as well as $450 million of new capital (see *Shale Daily*, Sept. 17, 2015). The move had been expected; the company announced restructuring plans in August (see *Shale Daily*, Aug. 17, 2015). "The steps we are taking will allow our company to maximize future opportunities and compete more effectively with significantly less debt on our balance sheet," said CEO Randy Limbacher. "We fully expect to operate our business as usual throughout this process and to emerge as a financially stronger company."

EV Energy Partners LP announced in September 2015 that it would acquire oil and natural gas properties in four basins across the country in a $259 million drop-down from institutional funds

San Juan Basin (continued)

San Juan Basin Natural Gas, Liquids, and Oil Windows



Source: Encana

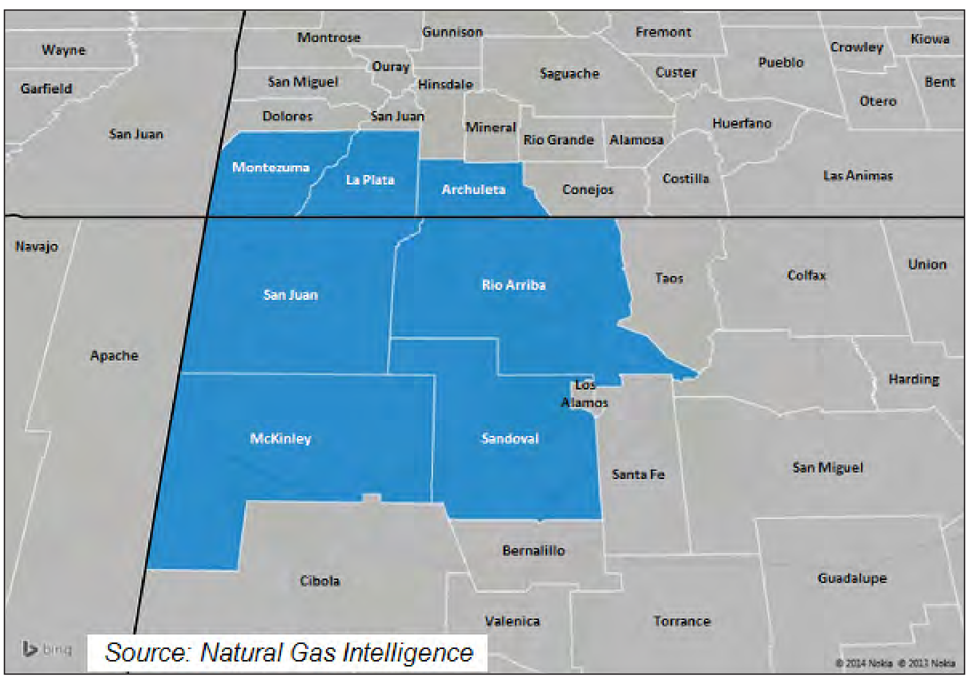
Source: Energen

managed by affiliate EnerVest Ltd. (see *Shale Daily*, [Sept. 3, 2015](#)). The properties, located in the Appalachian Basin, New Mexico's San Juan Basin, Michigan and Texas' Austin Chalk hold proved reserves of 302 Bcfe, EVEP said. In all, the deal adds more than 9,400 wells in mostly legacy fields to the company's inventory. EVEP said it expects daily production to increase 33% in the dropdown. "These assets we are acquiring have much lower initial operating risks since EnerVest has been acting as operator of these properties for the past five to ten years," said EVEP CEO Michael Mercer.

Counties

New Mexico: McKinley, Rio Arriba, San Juan, Sandoval

Colorado: Archuleta, LaPlata, Montezuma



Source: Natural Gas Intelligence

San Juan Basin (continued)

Local Major Pipelines

Natural Gas: El Paso, Northwest Pipeline, Southern Trails, TransColorado, Transwestern

Crude Oil: Western Refining

NGLs: Rocky Mountains (Enterprise)

SAN JUAN BASIN NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
ConocoPhillip[s]	900,000	Linde Inc.	N/A
WPX Energy	232,000	Lively Exploration Co.	N/A
Encana	206,000	Lizard Oil & Gas	N/A
Dugan Production Corporation	174,000	M & G Drilling Company	N/A
San Juan Basin Royalty Trust	119,000	M & M Production & Operation	N/A
Energen Resources	91,053	M R Schalk	N/A
EnerVest Energy Partners[1]	74,720	Manana Gas Inc.	N/A
Black Hills Corporation	61,806	Maralex Resources, Inc.	N/A
Samson Resoruces	61,000	Max D Webb	N/A
Merrion Oil & Gas Corp	25,000	Mcelvain Energy Inc.	N/A
LOGOS Resources	12,000	MCI Operating Of NM, LLC	N/A
Crownquest Operating, LLC	7,280	McKay Oil & Gas	N/A
Action Oil Co Inc.	N/A	Mclane Trust Dixie	N/A
Agua Moss, LLC	N/A	Minel Inc.	N/A
Alamosa Drilling Inc.	N/A	Monument Global Resources Inc.	N/A
American Petroleum Energy Co	N/A	Murchison Oil & Gas Inc.	N/A
Anderson Oil Ltd.	N/A	N M & O Operating Co	N/A
Basin Minerals Operating Company	N/A	Nancy Wilcox E Qualls	N/A
Beartooth Oil & Gas Co	N/A	NNOGC Exploration And Production	N/A
Beeman Oil & Gas LLC	N/A	Norman L & Loretta E Gilbreath	N/A
Benson-Montin-Greer Drilling Corporation	N/A	Omimex Petroleum Inc.	N/A
Biya Operators Inc..	N/A	Pablo Operating Company	N/A
Bolack Minerals Co	N/A	Parker & Parker Oil & Gas Inc.	N/A
BP	N/A	Parko Oil	N/A
Caerus Southern Rockies LLC	N/A	Patterson Operating & Pumping Inc.	N/A
Castleton Commodities	N/A	Pecos River Op Inc.	N/A
Catamount Energy Partners	N/A	Petro Mex LLC	N/A
CBM Partners Corporation	N/A	Petrox Resources Inc.	N/A
Chaparral Oil & Gas Co	N/A	PNL Operating, LLC	N/A
Chevron	N/A	Priority Energy LLC	N/A
Chuza Oil Company	N/A	P-R-O Management Inc.	N/A
Coleman Oil & Gas Inc.	N/A	Pro NM Energy Inc.	N/A
D J Simmons Inc.	N/A	R - J Enterprises	N/A
D M S Oil Co	N/A	Red Mesa Holdings/O&G LLC	N/A
David R. Hinson	N/A	Red Mountain Energy LLC	N/A
Devon Energy	N/A	Red Willow Production Company	N/A
Dominion Production Company	N/A	Redwolf Production Inc.	N/A
E L Fundingsland	N/A	Regina Oil & Gas LLC	N/A
El Pamco Inc.	N/A	Richardson Operating Co	N/A
Elm Ridge Exploration Company LLC	N/A	Ridgeway Arizona Oil Corp.	N/A
Enerdyne, LLC	N/A	Riggs Oil & Gas Corp	N/A
EP Energy	N/A	Rim Operating, Inc.	N/A

San Juan Basin (continued)

SAN JUAN BASIN NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
ExxonMobil/XTO Energy	N/A	Robert D Chenault	N/A
Faulconer Inc. Vernon E	N/A	Robert L. Bayless, Producer LLC	N/A
Four Corners Exploration Co	N/A	Roddy Production Co Inc.	N/A
Four Starr Energy, Inc..	N/A	Running Horse Production Co.	N/A
Fritz & Digman Inc.	N/A	S & J Oil & Gas Co	N/A
Gosney & Sons Inc.	N/A	Sagebrush Oil Inc..	N/A
H K Keesee And C J Keesee Trust	N/A	San Juan Resources, Inc..	N/A
Hall Energy Co	N/A	San Marco Petroleum Inc.	N/A
Hallador Petroleum	N/A	Schalk Development Co	N/A
Hart Oil & Gas Inc.	N/A	Schmidt Production	N/A
Harvard Petroleum Company	N/A	Schutz Richard E	N/A
High Plains Petroleum Corp	N/A	SG Interests I Ltd	N/A
Holcomb Oil & Gas Inc.	N/A	Shoreline Oil & Gas Company	N/A
HPOC, LLC	N/A	Simmons, Inc.. D. J.	N/A
Hubbs III, LLC	N/A	SJ Energy, LLC	N/A
Hunt Oil Co.	N/A	Standard Silver Corp	N/A
Huntington Energy LLC	N/A	Stanolind SJ LLC	N/A
J B Martinez	N/A	Synergy Operating LLC	N/A
John E Schalk	N/A	Thompson Engineering & Production	N/A
Joseph Sanchez Dba J&F Production	N/A	Three Forks Resources, LLC	N/A
KC Resources Inc.	N/A	Turner Production Co	N/A
Keystone Energy LLC	N/A	W B Hamilton Estate	N/A
Kimbell Oil Co Of Texas	N/A	Walsh Engineering Corporation	N/A
Koch Exploration Company	N/A	Wellstar Corporation	N/A
La Plata Gathering System Inc.	N/A	West Largo Corp	N/A
Lawrence W Ritter	N/A	Western Oil & Minerals Ltd	N/A
Lee M Crane	N/A	Williford Resources, L.L.C.	N/A
Legacy Reserves	N/A		

[1]EnerVest, the privately held parent of EVEP, owns acreage in the SJB as well.

Source: Compiled by NGI from company documents

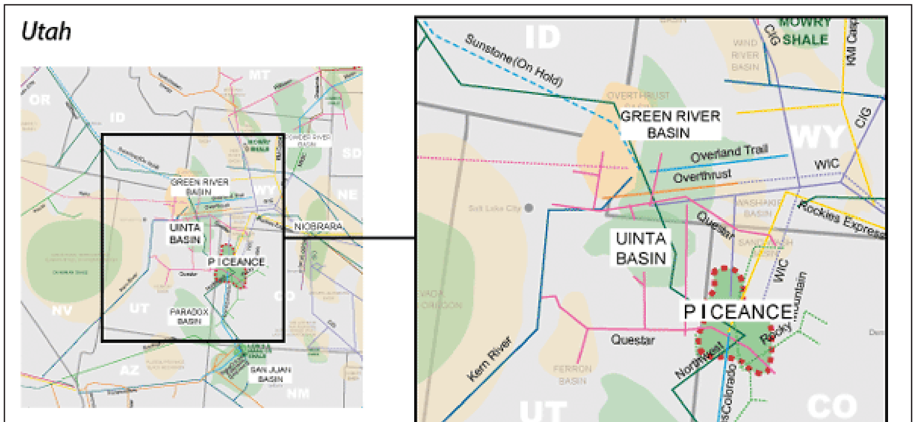
UINTA BASIN

Background Information

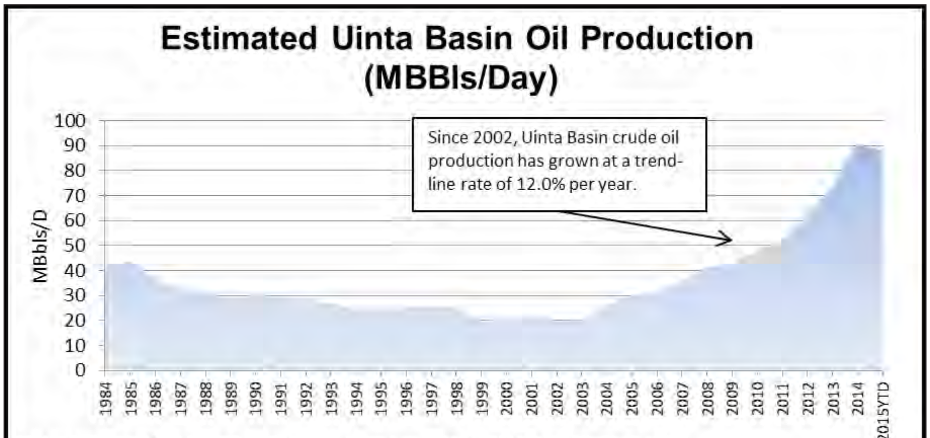
Much like the Permian Basin in West Texas, the Uinta Basin in Northeast Utah, which began producing natural gas and oil in commercial volumes in 1925 and 1949, respectively, has experienced something of a rebirth in recent years. After reaching average daily crude oil production of 44,000 b/d in 1985, annual crude oil fell by more than half, to an average 20,000 b/d in 2002. However, Uinta crude oil production has roared back to life since, rising at a trend-line growth rate of 12% per year through 2014. All this despite the fact that the drilling rig count in the basin has been in a downward trend since peaking at 39 in July 2012, falling to just five in early October 2015.

We believe a large reason for the increase in production despite lower rig activity is that operators have been drilling longer horizontal laterals in the play. For example, Newfield Exploration had drilled and completed eight super extended laterals through September 2014, and had five more that were either being drilled or awaiting completion.

The production growth in the Uinta has been led by a number of companies, including Newfield Exploration, QEP Resources, Anadarko Petroleum, Crescent Point Energy, Bill Barrett Corporation, Linn Energy, Ultra Petroleum, and Petroglyph, among others. Newfield's 225,000 acres in the Uinta Basin comprise the company's largest single asset. It's Greater Monument Butte Unit has drilled 1,900 wells there, 1,500 of which were productive wells in 2015. That constitutes the largest federal land play in the lower 48 states. Bill Barrett at the end of 2014 had reserves totaling 48 million boe, and production for the year of 2.31 million boe. Its stake in the Uinta included 1,537 drilling locations and 199,200 net

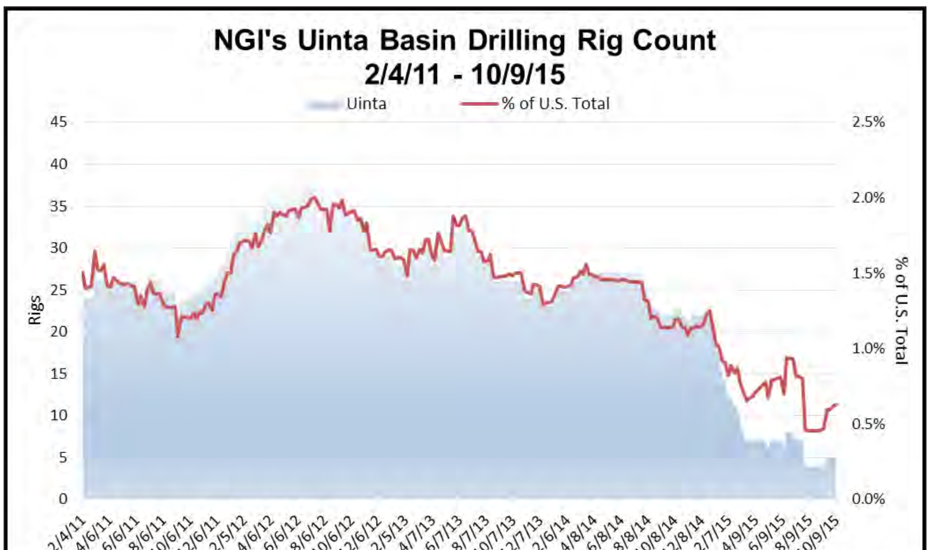


Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays



Note: Includes Duchesne and Uintah Counties only. *2015 data through June

Source: Utah Department of Natural Resources, NGI's Shale Daily calculations



Source: Baker Hughes, NGI's Shale Daily calculations

Uinta Basin (continued)

Annual Utah Oil & Gas Drilling Permit Applications By County 2010-2015YTD*

Uinta Basin Counties Highlighted in Red**

County	2010	2011	2012	2013	2014	2015YTD*
Beaver	0	0	0	1	0	0
Box Elder	0	7	0	0	0	0
Cache	0	0	0	0	0	0
Carbon	**91**	**138**	**93**	**7**	**34**	**26**
Daggett	3	0	0	0	0	0
Davis	0	0	0	0	0	0
Duchesne	**391**	**539**	**745**	**794**	**511**	**68**
Emery	**2**	**2**	**1**	**6**	**0**	**0**
Garfield	0	0	0	0	0	0
Grand	**4**	**11**	**17**	**12**	**29**	**9**
Iron	1	1	0	0	0	1
Juab	3	0	1	1	1	1
Kane	0	0	0	0	0	0
Millard	1	0	0	2	2	1
Morgan	0	0	0	0	0	0
Piute	0	0	0	0	0	0
Rich	0	2	0	0	2	0
Salt Lake	0	0	0	0	0	0
San Juan	22	12	34	50	7	1
Sanpete	2	0	0	0	2	1
Sevier	3	2	1	1	2	1
Summit	0	0	0	0	0	0
Tooele	0	0	0	0	0	0
Uintah	**662**	**802**	**1213**	**737**	**798**	**400**
Utah	0	0	0	0	0	0
Wasatch	**1**	**0**	**0**	**0**	**0**	**0**
Washington	0	0	0	0	0	0
Wayne	0	0	0	0	0	0
Weber	0	0	0	0	0	0
Total Utah	**1186**	**1516**	**2105**	**1611**	**1388**	**509**
Total Uinta Basin**	**1151**	**1492**	**2069**	**1556**	**1372**	**503**
Uinta As % of Total	***97.0%***	***98.4%***	***98.3%***	***96.6%***	***98.8%***	***98.8%***

Duchesne & Uintah Counties As % of Total	**88.8%**	**88.5%**	**93.0%**	**95.0%**	**94.3%**	**91.9%**

*Data through 10/14/15

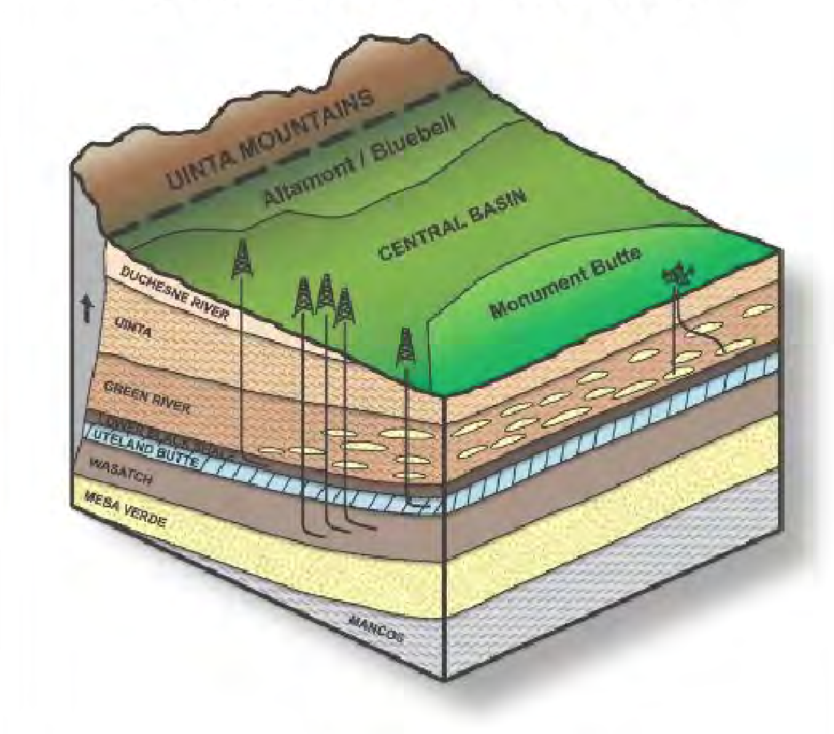
**Emery & Grand Counties also contain the Paradox Basin, so some of these permits may in fact be targeting that formation, not the Uinta.

Source: Utah Department of Natural Resources, NGI's Shale Daily calculations

Uinta Basin (continued)

undeveloped acres. However, the company shut-in approximately 1,000 b/d of Uinta production in the 2Q15 because higher well operating costs there in the face of lower oil and gas prices rendered the area less economic for the company relative to other locations in its portfolio. BBG is currently looking to exit its position in the Uinta in order to focus on its holdings in the Niobrara-DJ Basin.

Uinta Basin Cross Section



Source: Newfield Exploration

Similarly, Ultra Petroleum reported their 3Q15 Uinta production volumes were down 7% year-over-year, because of the discontinuation of its Uinta program earlier in 2015. Furthermore, the company noted during its 3Q15 earnings conference call that it would not develop its Uinta properties at then current forward prices.

Although the Uinta touches several counties in Utah, the overwhelming majority of recent oil and gas permitting activity in the Uinta -– and in the entire state, for that matter – has been focused in Duchesne (68 through October 2015) and Uintah (400) Counties. As seen in the table on the previous page, those two counties have accounted for 89%-95% of all permits received in Utah over the last five-plus years. A few other interesting takeaways from that table:

- It appears overall permitting activity in the Uinta Basin was off somewhat through the first nine-plus months of 2015, totaling 503, compared to 1,372 and 1,556 permits, respectively, for all of 2014 and 2013. Part of the reason for the fall off may be that not all permits received have been included in the Utah Department of Natural Resources database yet, but we believe two other reasons are that operators may be delaying planned activity in the region because of a lack of takeaway capacity, and because of the recent decline in crude oil prices. In 2014, the top producing counties were Uintah (309.9 Bcf), Carbon (60.4 Bcf), and Duchesne (53 Bcf), according to the state Oil, Gas and Mining Division.

- Permitting activity in Carbon County has fallen off a cliff in recent years, moving from 138 permits in 2011, to 93 in 2012, to just 7 in 2013, before rebounding somewhat to 34 in 2014 and 26 through mid-October 2015. There was 36 Bcf of production in Carbon County through Nov. 1, 2015. While the northeastern half of Carbon County is part of the Uinta Basin, the majority of activity in the county is driven by coal bed methane gas that mostly lies outside of the Uinta. CBM in general has fallen on hard times the last few years in the United States, because of lower natural gas prices. Emery County is the other main CBM producer in Utah, and permitting activity there has been virtually non-existent since 2008.

- Grand and Wasatch Counties also contain a portion of the Uinta, but of these two, only Grand County has seen any permitting activity the last five-plus years, and that activity pales in comparison to that in Duchesne and Uintah Counties.

- San Juan County had been the only county other than Duchesne and Uintah to see growth between 2009 and 2013, but permitting activity there has been stifled in 2014-2015, with just 8 combined applications during this time. San Juan County is part of the Paradox Basin. Please see our Paradox Basin section for more information about that area.

The Uinta Basin is a stacked formation that shows oil and gas pay from intervals ranging anywhere between 1,300'-18,000', in both conventional and unconventional tight sands and shale formations. Much of the drilling in the area has been and continues to be vertical, although operators have begun drilling horizontal test wells into some of the deeper formations. For example, QEP Resources reported seeing good results from their lower Mesaverde wells during its 3Q15 earnings conference call. Ultra Petroleum agreed that these QEP wells are encouraging, and noted that the success

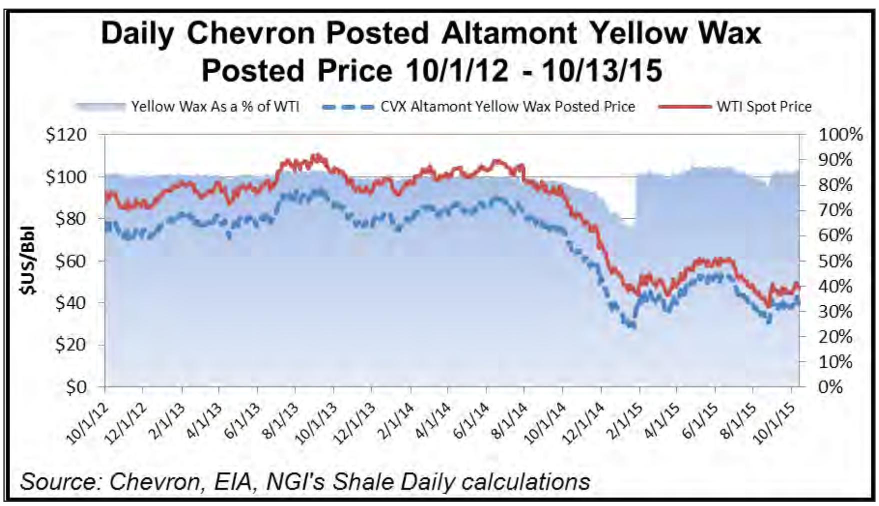
Uinta Basin (continued)

of this formation would add "hundreds" of drilling locations for them.

Operators tend to classify their holdings differently, but current drilling activity in the Uinta can be grouped into three different regions, from North to South: The Altamont-Bluebell, Central Basin, and the Monument Butte. Furthermore, we believe the subsurface geological formations/hydrocarbon systems that drillers are targeting can be boiled down to four main groups, which we describe in the table below:

Formation/ System	Depth	Intervals	Description
Green River	1300'-10000'	Green River Oil (1300'-6000'), Mahogany Oil Shale (4500'), Douglas Creek (4150'-6000'), Black Shale (5000'-6650'), Castle Peak (5200'-6800'), Uteland Butte (4500'-10000')	The Monument Butte is primarily a waterflood area that produces shallow Green River Oil. Green River production tends to be black wax. The Uteland Butte is being drilled horizontally.
Wasatch	5800'-10000'	Colton, Flagstaff, North Horn	Oil target. Production here is mostly yellow wax.
Mesaverde	9000'-12000'	Mesaverde	More of a gas play, and a combination of liquids rich and dry gas, depending on the field.
Deep	12000'-18000'	Blackhawk (12000'-13000'), Mancos/ Dakota (13000'-18000')	Focus is natural gas. Drilling here has been fairly limited thus far.

Crude oil from the Uinta tends to contain a large amount of paraffin, which creates several challenges for producers in the area. Waxy oil must remain heated in order to flow, and that tends to restrict (but not eliminate) its ability to be shipped via pipeline or rail. Much of the crude oil produced in the Uinta is transported via trucks, and because trucking is the most expensive form of oil transport, this limits the distance the oil can profitably travel to a refinery. It also affects the price of waxy crude oil. Both "black wax" (32 degrees API) and "yellow wax" (42 degrees API) that are produced in the Uinta tend to trade at a discount. For the twelve months ending October 13, 2015, both grades of wax traded at a 13%-39% discount to WTI prices.



Daily Chevron Posted Altamont Yellow Wax Posted Price 10/1/12 - 10/13/15

Source: Chevron, EIA, NGI's Shale Daily calculations

Most oil from the Uinta is refined at the five refineries that are located in the Salt Lake City area. According to Bill Barrett Corporation's Investor Relations presentation dated October 2014, Salt Lake City refiners have the ability to handle 65+ MBPD of waxy oil, with another 40,000 b/d of planned expansions. We estimate that Uinta crude oil production averaged 83,000 b/d during the first three months of 2014, so that would suggest those Salt Lake City refineries are running at full throttle with respect to the amount of Uinta crude production they can handle. But the excess production is being handled by rail capacity. As Newfield Exploration CEO Lee Boothby noted on his company's 3Q14 earnings conference call, "we are also encouraged with the significant rail volumes for the Uinta crudes today. For the first time, between 20,000 and 30,000 b/d are leaving the basin, and markets for this valuable product are expanding. We are confident that this will ultimately lead to improved differentials. Newfield's growth forecast is tied to our takeaway capacity, and we expect that our production will rapidly increase through 2016, as new refining expansions are completed on our behalf."

Prospects for added rail capacity were derailed in late 2014. Uinta Basin Rail, a proposed 100-mile rail line that would provide service between the Uinta Basin and two national freight lines 50 miles to the south, was dropped despite a coalition of seven counties

Uinta Basin (continued)

in eastern Utah securing $55 million in state funding toward the possible construction of the project.

Uinta Oil Program

Operator	Current Black/Yellow Capacity (MBbls/d)	Black/Yellow Capacity Expansions (MBbls/d)
Chevron	15,000	~5,000
Tesoro	15,000-20,000	~20,000
Holly Frontier	10,000	14,000
Big West	~15,000	-
Silver Eagle	12,000	-
Total	65,000+	~40,000

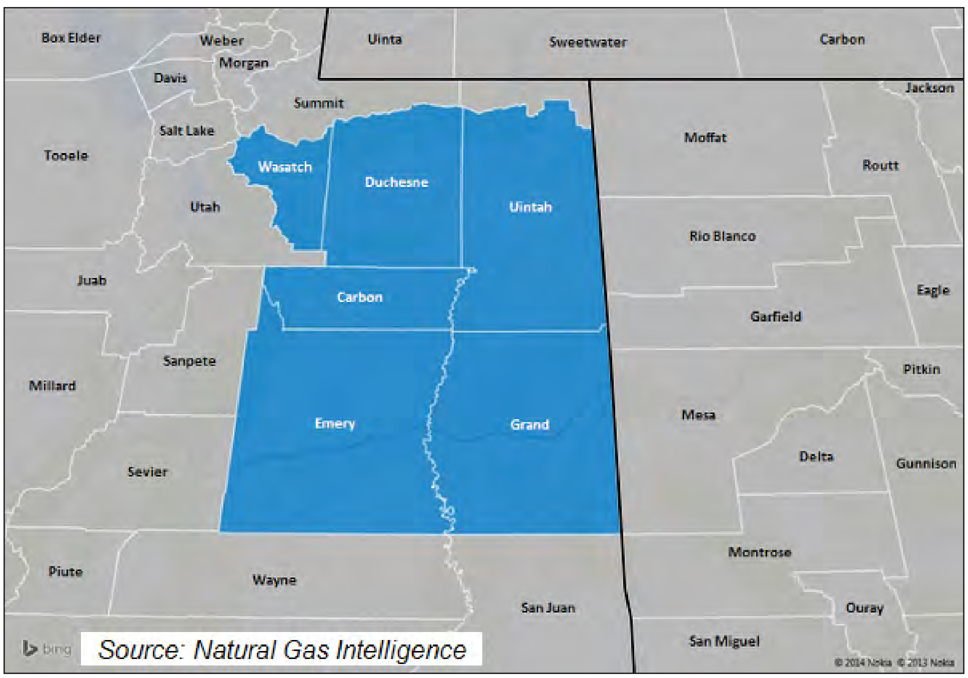
Source: Bill Barrett Corporation October 2014 Investor Presentation

Counties

Utah: Carbon, Duchesne, Emery, Grand, Uintah, Wasatch (although the overwhelming majority of production in the Uinta Basin occurs in Duchesne and Uintah Counties)

Local Major Pipelines

Natural Gas: Kern River, Northwest Pipeline, Questar, WIC



Source: Natural Gas Intelligence

Crude Oil: Salt Lake Crude (Chevron), Uinta Express

NGLs: Rocky Mountains (Enterprise)

Uinta Basin (continued)

UINTA BASIN NET ACREAGE POSITIONS
Last Updated December 2015

Company	Net Acres	Company	Net Acres
ExxonMobil (XTO Energy)*	392,480	Maximum Energy Corporation	N/A
QEP Resources	246,000	Merit Energy Company	N/A
Newfield Exploration	225,000	Moose Mountain Divide #1	N/A
Anadarko Petroleum	196,000	Mountain Oil And Gas Inc	N/A
EP Energy	177,000	Mustang Fuel Corporation	N/A
Crescent Point Energy	173,000	Nacogdoches Oil & Gas, Inc	N/A
Bill Barrett Corporation	160,000	National Fuel Corporation	N/A
Linn Energy	122,000	Negaunee, LLC	N/A
EOG Resources	94,000	NNOGC Exploration & Production	N/A
Discovery Natural Resources	83,000	Northstar Gas Company Of Texas	N/A
Vantage Energy	80,000	Northstar Gas, LLC	N/A
Wapiti Energy	42,138	Omimex Petroleum Inc	N/A
Gasco Energy	41,661	Oso Oil & Gas Properties LLC	N/A
Enervest Operating[1]	35,000	Pacific Energy & Mining Company	N/A
Marion Energy	17,735	Parker Energy Tech Inc	N/A
McElvain Energy[2]	12,501	Peak Oil Tool	N/A
Whiting Petroleum	11,454	Petroglyph Operating Co	N/A
Ultra Petroleum	9,000	Pride Ventures LLC	N/A
Thurston Energy Operating*	3,690	Quinex Energy	N/A
Anschutz Corporation, The	N/A	Resource Development Technology, LLC	N/A
Appaloosa Operating Company LLC	N/A	Retamco Operating, Inc.	N/A
Axia Energy LLC	N/A	Richardson Operating Co	N/A
Beartooth Oil & Gas Co	N/A	Rim Operating Co.	N/A
Benson-Montin-Greer Drl	N/A	Robert L. Bayless, Producer LLC	N/A
Bowers Oil And Gas Inc	N/A	Rose Petroleum	N/A
Cannon, Robert	N/A	Rosewood Resources, Inc.	N/A
Citation Oil & Gas Corp	N/A	Running Foxes Petroleum, Inc.	N/A
Coastal Plains Energy Inc	N/A	S O A L LLC	N/A
Cochrane Resources Inc	N/A	S W Energy Corporation	N/A
Creston Resources, Ltd.	N/A	Sabine Oil	N/A
CSV Oil Exploration Co	N/A	Seeley Oil Company	N/A
Del-Rio Resources Inc	N/A	SEP Cisco Dome II	N/A
Devon Energy	N/A	Stewart Petroleum Corp	N/A
Diversified Energy	N/A	Stone Energy Corporation	N/A
Elk Production	N/A	Summit Operating	N/A
Elm Ridge Exploration Company	N/A	Synergy Operating	N/A
Emery Resource Holdings LLC*	N/A	Tidewater Oil & Gas Company, LLC	N/A
Enduring Resources	N/A	Tiger Energy Operating	N/A
Enerquest Operating	N/A	Trend Oil	N/A
Evergreen Energy, Inc.	N/A	Uintah Investors LLC	N/A
Finley Resources	N/A	Uinta-Taylor Fund	N/A
Foundation Energy Management	N/A	US Oil & Gas Inc.	N/A
Genesis St Operating	N/A	Webb, Max D	N/A
Hancock, Burton W	N/A	Wesgra Corporation	N/A
Hinto Energy Inc	N/A	Western Energy Operating LLC	N/A

Uinta Basin (continued)

UINTA BASIN NET ACREAGE POSITIONS
Last Updated December 2015

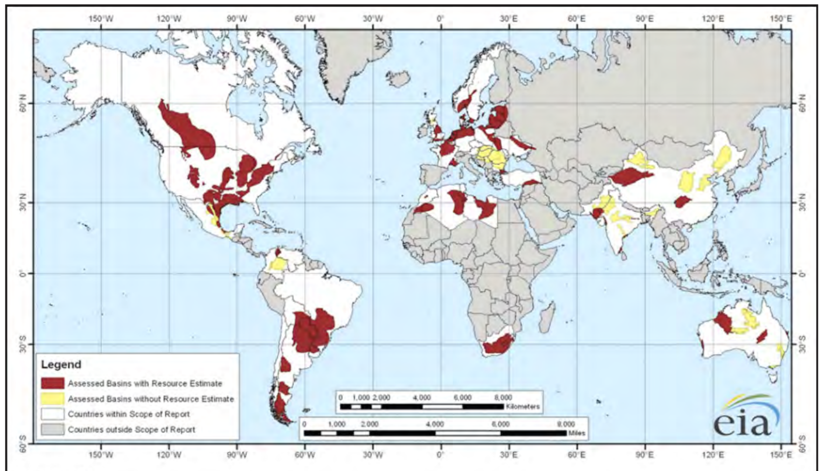
Company	Net Acres	Company	Net Acres
Homeland Gas & Oil	N/A	Weststar Exploration Co.	N/A
Intrepid Oil & Gas	N/A	Wexpro Company	N/A
JMD Energy	N/A	Whitmar Exploration	N/A
Koch Exploration Company LLC	N/A	Wind River Resources	N/A
Laramie Energy II	N/A	Wold Oil Properties, Inc	N/A
Lodestone Operating, Inc	N/A	Wolverine Gas & Oil Company Of Utah, LLC	N/A
Lone Mtn Production Co	N/A	Woosley, James P	N/A
Mar/Reg Oil Company	N/A	Yates Petroleum Corp	N/A
Matrix Production Company	N/A		

*At least a portion of their 2014 natural gas production came from coal bed methane, which means at least some of their acreage is located in Carbon and/or Emery County. The majority of Carbon County, and all of Emery County, lie outside of the Uinta Basin.
[1]Bought 35K West Tavaputs acres from BBG in 2013, but they could have more
[2]Acreage is currently being marketed

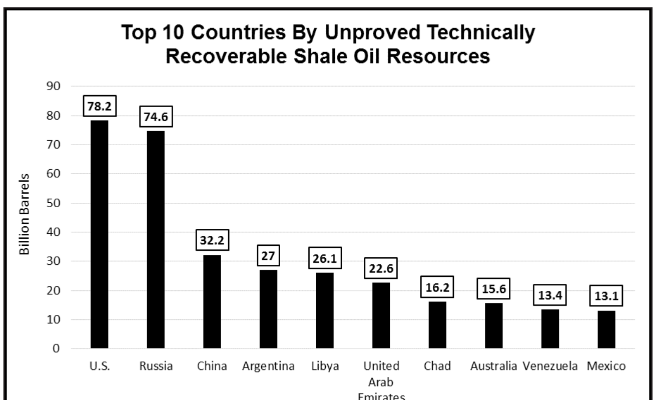
Source: Compiled by NGI from company documents

INTERNATIONAL UNCONVENTIONAL RESOURCE DEVELOPMENT

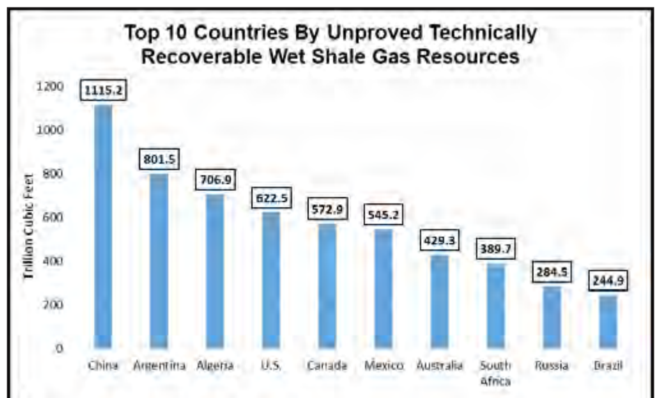
With unconventional resource development reshaping the energy potential of both the United States and Canada, the success story that has been playing out in North America has not gone unnoticed elsewhere in the world. Many U.S. operators, along with foreign producers that have entered into joint venture arrangements in the U.S. to gain access to unconventional producing technology, are eager to apply what they have learned to unconventional oil & gas basins around the world. Oil and gas bearing shale opportunities are not a unique resource to North America, and are actually well distributed across all five other habitable continents. In fact, the U.S. and Canada do not even necessarily have the largest of these oil and gas resources. According to EIA and Advanced Resources International figures, China holds the largest technically recoverable shale reserves of natural gas, and Russia takes the number one spot for shale reserves of oil outside of the United States.



Source: EIA



Source: EIA, U.S. Geological Survey



Source: EIA, U.S. Geological Survey

It is worth noting that technically recoverable reserves are usually much higher than economically recoverable reserves. Technically recoverable reserve figures also change as extraction technologies develop and the formations containing the hydrocarbons become better understood. In addition, most technically recoverable reserves can become economical in a sufficiently high price environment.

On the flip side, shale and tight sands development can be curtailed by government regulation. Not every U.S. state is friendly to the practice of hydraulic fracturing, and the same holds true from country to country. For example, in Europe, fracking is currently illegal in Bulgaria, Czech Republic, France, Luxembourg, and the Netherlands. Subsurface property rights also play a defining role. In the U.S., mineral rights are largely defined, but this is certainly not the case throughout the world.

NGI believes the biggest factors that are necessary for the successful development of unconventional oil & gas formations are:

1. Private and/or Clearly Defined Ownership of Subsurface Oil and Gas Rights
2. Availability of Capable Independent Operators, Rigs, and Fracking Equipment
3. Presence of an Established Infrastructure
4. Access to Water Necessary for Hydraulic Fracturing
5. Favorable Governmental Policy

Since covering all countries with shale potential would be beyond the scope of this writing, and would almost certainly require an entire book, we have chosen to highlight some of the areas with significant shale potential, to provide a brief summary of where

International Unconventional Resource Development (continued)

World Shale Resource Assessments As of 9/24/15

	Wet Shale Gas (trillion cubic feet)	Tight Oil (billion bbls)		Wet Shale Gas (trillion cubic feet)	Tight Oil (billion bbls)
North America			North Africa		
Canada	572.9	8.8	Algeria	706.9	5.7
Mexico	545.2	13.1	Egypt	100	4.6
U.S.	622.5	78.2	Libya	121.6	26.1
Australia			Mauritania	0	0
Australia	429.3	15.6	Morocco	11.9	0
South America			Tunisia	22.7	1.5
Argentina	801.5	27	West Sahara	8.6	0.2
Bolivia	36.4	0.6	Sub-Saharan Africa		
Brazil	244.9	5.3	Chad	44.4	16.2
Chile	48.5	2.3	South Africa	389.7	0
Colombia	54.7	6.8	Asia		
Paraguay	75.3	3.7	China	1115.2	32.2
Uruguay	4.6	0.6	India	96.4	3.8
Venezuela	167.3	13.4	Indonesia	46.4	7.9
Eastern Europe			Mongolia	4.4	3.4
Bulgaria	16.6	0.2	Pakistan	105.2	9.1
Lithuania/Kaliningrad	2.4	1.4	Thailand	5.4	0
Poland	145.8	1.8	Caspian		
Romania	50.7	0.3	Kazakhstan	27.5	10.6
Russia	284.5	74.6	Middle East		
Turkey	23.6	4.7	Jordan	6.8	0.1
Ukraine	127.9	1.1	Oman	48.3	6.2
Western Europe			United Arab Emirates	205.3	22.6
Denmark	31.7	0	**TOTAL**	**7,576.6**	**418.9**
France	136.7	4.7			
Germany	17	0.7			
Netherlands	25.9	2.9			
Norway	0	0			
Spain	8.4	0.1			
Sweden	9.8	0			
United Kingdom	25.8	0.7			

Source: EIA

non-U.S. shale development stands, and to outline some of the major issues that threaten future progress.

Canada

Canadian unconventional development has been taking off for awhile now, with many different resource plays already producing. The most important of the shale and tight sands plays are arguably the Montney, Duvernay, and the Horn River, all three of which are profiled in separate sections of the Factbook. These three formations lie in western Canada in British Columbia and Alberta. All three have active natural gas and oil production and have been producing for about half a decade. Most producers here have been focused on oil production, in no small part because of the recent decline in natural gas prices because of booming U.S. production. These lower natural gas prices have been especially harsh to western Canadian producers who, when shipping gas east via TransCanada's mainline, must compete directly with the burgeoning gas production from the Marcellus Shale.

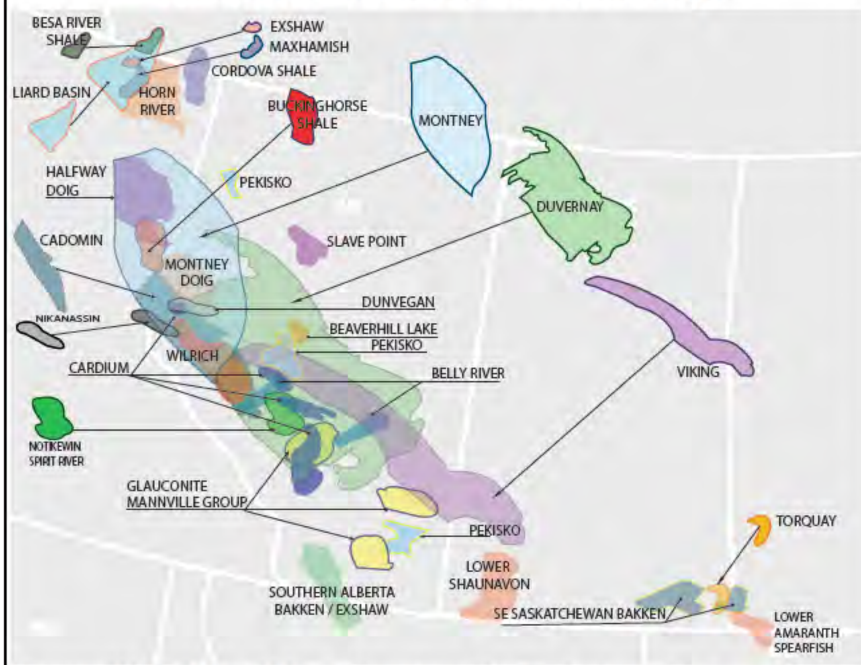
However, there may be some hope for forthcoming gas demand in Canada. As several LNG export facilities on the west coast of British Columbia are approved and potentially come on-line, demand

International Unconventional Resource Development (continued)

for local gas production may increase. But unfortunately for producers, NGI does not currently expect Canadian LNG export terminals to play a significant role in the demand picture until at least 2018, if at all. We believe many of the proposed LNG export facilities in Canada will require oil-based pricing in order to be economically viable, a stipulation which would-be capacity subscribers have been resisting. But producers could still benefit from incremental local demand for natural gas in Canada from companies using in-situ oil sands recovery techniques that often require large amounts of gas to generate steam.

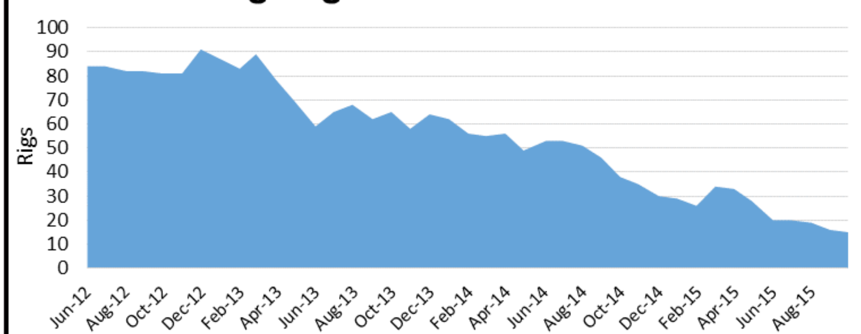
Speaking of which, oil sands/bitumen are another important source of unconventional production in Canada. For more information about that, please refer to our Canadian Oil Sands section.

Western Canada Resource Plays



Source: NGI's Map of North American Shale/Resource Plays

Monthly Mexico Oil & Gas Land Drilling Rig Count Jun 12 - Oct 15



Source: Baker Hughes

Mexico

According to the U.S. Energy Information Administration, Mexico has 545 Trillion Cubic Feet (Tcf) of technically recoverable shale gas resources, the sixth most of any country in the world. Even if Mexico were only able to convert 10% of those reserves into production, that would be enough to fuel Mexican natural gas consumption for more than 20 years, based on Mexico's 2014 dry gas consumption of 2.587 Tcf.

Most shale resources in Mexico are in the northeast near the Gulf of Mexico coast, including the Burgos Basin, and the Eagle Ford Shale, which continues down into Mexico from South Texas. The Texas side of the Eagle Ford is now pretty well understood by operators, and we believe these companies will be able to leverage their experience to the portion of the formation that lies south of the border. Eventually, that is.

In December 2013, the Mexican congress passed a bill ending the 75-year state oil monopoly, thereby finally allowing foreign companies to finally have a shot at developing Mexico's reserves. But that effort has been slow to get off the ground, and on-land drilling activity continues to spiral lower in the country (see *Daily GPI*, Aug. 14, 2014). Mexico had 84 oil & gas rigs working within its borders in June 2012, but just 15 in October 2015.

Even when unconventional development in Mexico does pick up, it won't be without complications. The geological structure of the Eagle Ford in Mexico is said to be more complex, and it may take quite a bit of practice to achieve similar results to what operators are experiencing on the U.S. side of the play. Other possible obstacles to Mexican shale production could include, but are not limited to, the capabilities of the local shale service sector, little current infrastructure in the Burgos Basin, a lack of water in the immediate area, which is necessary for hydraulic fracturing, a dearth of natural

International Unconventional Resource Development (continued)

gas processing plants, public safety concerns, and potential limits on upstream investment (albeit less so since December 2013).

Yet another threat to the developing Mexico's shale resources are fast growing natural gas imports from the United States, and the longer it takes Mexico to get the ball rolling on implementing its energy reforms, the more opportunities the U.S. will have to ship additional gas south of the border. Since 2007, U.S. natural gas exports to Mexico have grown from less than 1.0 Bcf/d to more than 3.0 Bcf/d, led by new gas fired electricity capacity in the northern part of the country. Several industry pundits estimate those exports could double by the end of the decade.

Mexico already has begun working with foreign entities on the midstream side of things, as Sempra Energy's iEnova subsidiary had invested US$3.5 billion in Mexico's gas and power infrastructure as of December 2014, and Kinder Morgan, TransCanada, and Howard Energy Partners have a presence in Mexico as well. Furthermore, Mexico's state owned power utility Comisión Federal de Electricidad (CFE) is expected to tender several other gas pipeline projects in the coming months.

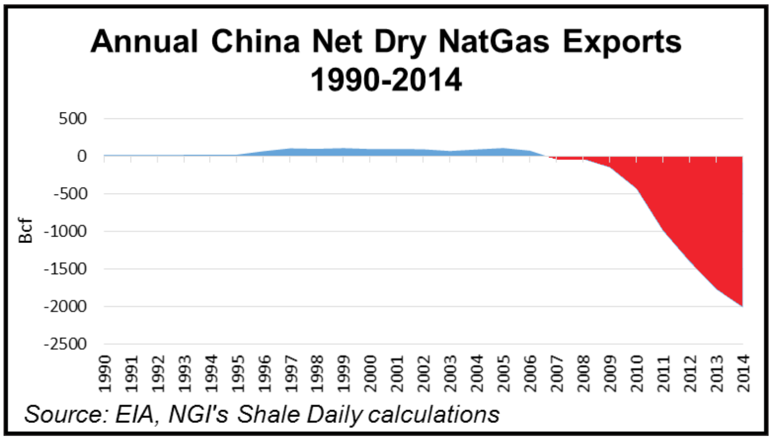
China

During the last ten years, China has morphed from being a net exporter of natural gas to importing more than 2 Tcf per year of the fuel, despite the fact that the country has the largest estimated reserve of shale gas in the world. Given that the International Energy Agency expects Chinese natural gas demand to grow by approximately 10% per year through 2019, the country is undoubtedly chomping at the bit to develop its vast unconventional resources. Thus far most shale activity in China has been focused in the Sichuan Basin, home of Fuling, the country's first shale gas field, where activity continues to grow. As recently as March 2014, China Petroleum and Chemical Corp. (Sinopec) said it had "made significant breakthroughs" in shale gas exploration and development and that it plans to develop the Fuling Field faster than previously thought, with annual production of 10 billion cubic meters (353 Bcf) by 2017 (see *Shale Daily*, March 25, 2014). Sinopec also expects to apply what they are learning at Fuling to other projects in the country. Moreover, several Chinese companies, including Sinopec, CNOOC, PetroChina, Haimo Oil & Gas, and Sinochem Petroleum, have taken non-operated joint venture positions in various unconventional oil & gas fields in North America over the last few years, in part to learn more about the technology required to unlock the unconventional formations back home.

The Tarim Basin in China holds unconventional promise as well, but most likely at a high cost. Wood Mackenzie notes the depth of the target shales in the basin could exceed 4,500 meters, and that the basin is located in a remote part of the county which is punctuated by the world's second largest shifting desert sand, thus making it difficult to access the water necessary to hydraulically fracture the rock.

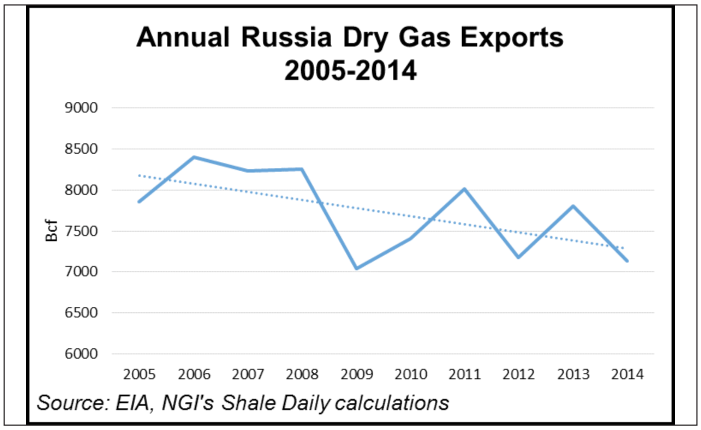
Shale development in China is not without its issues, however. Unlike in the U.S., where supply and demand dictate price, the Chinese government largely determines prices. This has caused some concern for shale gas development, since in order to entice producers to incur the risk of development, they must achieve a price high enough for them to earn an acceptable rate of return on their investment. This issue was touched on in January 2014 by Gordon Kwan, regional head of oil and gas research at Nomura Holdings, in an e-mail to Bloomberg News: "Long term, we believe the government must raise domestic selling prices for natural gas and increase shale-gas subsidies further to motivate producers."

Another factor that could potentially slow the development of shale gas development in China is the mega-contract signed in May 2014 to have OAO Gazprom supply China National Petroleum Corporation an estimated $400 billion worth of natural gas for more than 30 years, starting in 2018. By the end of this decade, Russia could be supplying almost 10% of China's gas supplies. But this development could simply defray China's dependence on LNG imports, meaning the country will still need to advance its internal shale production to meet future demand.



Russia

Russia is estimated to have the largest technically recoverable shale oil reserves of any country outside of the United States, most of which lie in the Bazhenov formation, a massive area that encompasses nearly one million square kilometers in West Siberia. According to the U.S. Energy Information Administration, the



Source: EIA, NGI's Shale Daily calculations

Source: San Leon Energy

Bazhenov holds and estimated 1.2 trillion barrels of oil, about 75 billion of which might be recoverable.

The Bazhenov underlies Russia's main conventional production region and has yet to put forth any significant production from horizontal wells. However, it seems interest may be picking up. In January 2014 Salym Petroleum Development, a joint venture between Royal Dutch Shell and Gazprom, announced that it had begun drilling on the first of five horizontal wells over the next two years. Exxon Mobil and BP have separate joint ventures with Roseneft to develop Russian shale, and as recently as March 2014, Total S.A. was rumored to be in talks with partner Lukoil regarding Lukoil's projects in the Bazhenov. Many have compared the Bazhenov to the Bakken Shale in North Dakota.

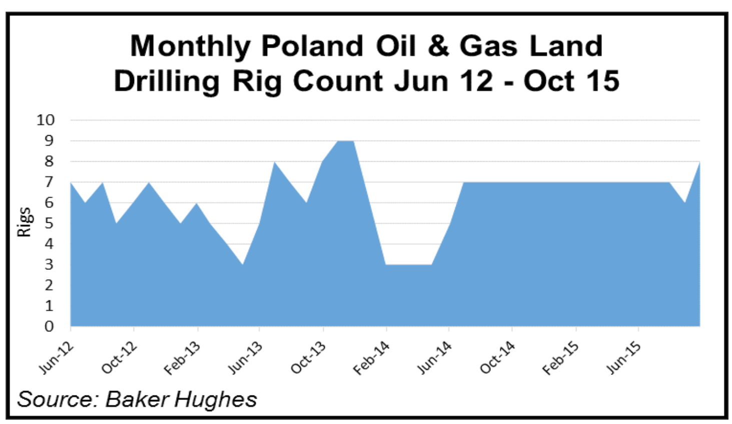
What may come of this major shale oil deposit is difficult to say given the political uncertainty of the region, particularly in the aftermath of Russia's military actions in Ukraine, and the high costs of de-risking the basin. After the dissolution of the Soviet Union, companies such as BP, ConocoPhillips and ExxonMobil have attempted operations in the country, but none had any real success. Russian oil production to date is still dominated by domestic companies the biggest of which being Rosneft, which according Eastern Bloc Energy accounted for about 24% of total Russian oil production during 2012.

Russia is also a leading exporter of natural gas to Europe, but exports from the country have declined at an annualized trend-line rate of 1.3% per year since 2005.

Poland

Some of the earliest international shale activity was focused in Poland beginning around 2007, but development has proven difficult because of geological complexity and regulatory issues. The Polish government desperately wishes to kick-start domestic natural gas production, believing it essential to relieve some of the country's dependence on gas supplies from Russia as well as domestic coal production and its associated environmental impacts. Recent tensions in the area have added pressure on regulators to entice companies to drill for Polish gas. Thus far only a handful of horizontal test wells have been drilled with no notable success, but there still may be hope yet for Polish shale development. In January 2014 San Leon Energy announced a successful vertical test in the Baltic Basin. The test demonstrated sustained production at a rate of 45 to 60 Mcf per day after six weeks of well clean-up. Encouraged by the results, San Leon plans to drill a long horizontal well with a multi-stage frack job as soon as possible. Remarking on the results San Leon Executive Chairman Oisin Fanning said, "This is the most encouraging vertical shale well test in Poland to date. We have moved a long way towards 'cracking the code' towards commercial production from our unconventional plays.

"These learnings will be put to good use in the planned multi-staged fracked horizontal well in the Lewino area, where we



Source: Baker Hughes

believe we shall be able to stimulate the entire vertical extent of the Ordovician interval with each frac, and prove commercial flow rates," Fanning added.

The drilling rig count in Poland has ranged between 3 and 9 since June 2012, but has veered toward the higher end of that range in recent months.

Other Europe

Even after the fall of the Soviet Union many European countries remain tethered to Russia for natural gas. This is especially true in Eastern Europe where the USSR built most of the pipeline infrastructure. Given the recent tension between Russia and the Ukraine, many European leaders have sounded the call for the investigation of alternative sources of energy to decrease their dependence on Russian gas. Aware of the successes on the North American continent, many operators are interested in the possibility of applying the processes of hydraulic fracturing and horizontal drilling to European oil and gas resources that would otherwise be unreachable with conventional techniques. Although European countries are trying to gain a better understanding of what resources are available to them, most are still far from commercial production. The state of European shale development was summed up quite nicely in March of 2014 by Raymond James analyst Pavel Molchanov, who said, "Shale gas production in Europe is effectively zero. Twelve months from now it will still be zero. Five years from now, it will be more than zero."

"Over the next five years, [European] countries will have to identify where their resources are and build out the infrastructure for this industry to develop — that can include developing pipelines and training workers," he said. "This also means getting the required rigs to drill for shale gas, which are in the U.S. and Canada, but don't really exist in Europe."

The road to fracking Europe's shale may be a bumpy one, however, as protests against hydraulic fracturing have been held in several European countries already. Public opposition remains a real barrier especially given the higher relative population density of Europe compared to that of the United States or Canada. It is hard to avoid drilling near communities with a "not in my backyard" stance when, in much of Europe, just about everywhere is someone's backyard. Bulgaria, Czech Republic, France, Luxembourg, and the Netherlands have already banned the practice of fracking and proposals to do so exist in other countries such as Germany. It will take some serious effort on the part of governments and would-be drillers to build trust within their communities so that Europe can begin the path toward a more energy independent future.

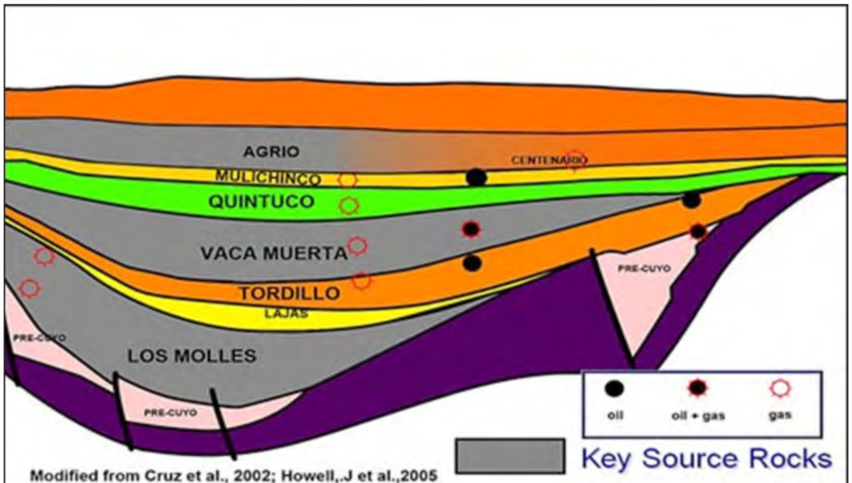
In addition, the United States is expected to have nearly 10 Bcf/d of LNG export capacity by 2020, much of which could be shipped to Europe. That would likely help reduce the urgency to develop Europe's shale reserves, everything else being equal.

One area in Europe that may be less averse to shale development is the United Kingdom, which features the Bowland Shale in Northern England, the Weald Basin in Southern England, and the Midland Valley of Scotland. But operators don't seem to be in much of a hurry to develop these resources. The United Kingdom has had 2 or fewer land drilling rigs working in each month since June 2012, and as of the end of 2014, the U.K. had no commercial shale gas production.

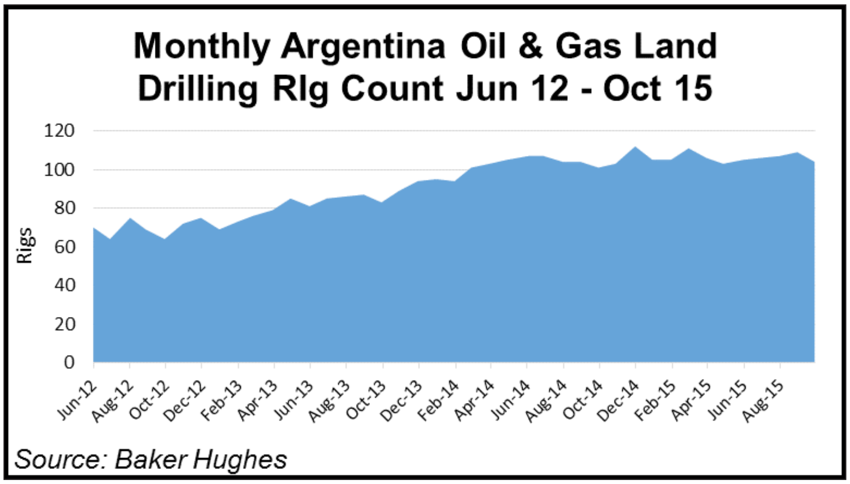
Argentina

Number four in estimated technically-recoverable reserves of shale oil and second in shale gas, Argentina clearly has large unconventional potential, which companies such as Apache, EOG, ExxonMobil and others are trying to develop. Exploration thus far has centered on the Neuquen Basin to the east of the Andes Mountains which hosts the Los Molles and Vaca Muerta shales. The EIA estimates the Los Molles shale contains technically recoverable resources of 275 Tcf of shale gas and 3.7 billion barrels of oil and condensate, while the oilier Vaca Muerta shale comes in at 308 Tcf of natural gas and 16 billion barrels of oil. YPF S.A. and Chevron reported in late 2015 the discovery of a super well, the Loma Campana 992, in the Vaca Muerta with an impressive initial production of 1,630 b/d.

Although there has been conventional oil & gas activity in the Neuquen Basin for more than 100 years, unconventional development is still very much in the exploratory phase as operators



Source: Americas Petrogas



in the area probe the underlying shale reservoirs to determine if full-scale development could be profitable. Some have had better results than others thus far and it remains to be seen if either the Vaca Muerta or the Los Molles will go fully commercial.

As recently as April 2014, Chevron signed agreements with YPF S.A. to continue the development program in the Vaca Muerta announcing plans to invest an additional $1.6 billion. Chevron has been public with its excitement over the Vaca Muerta and also its faith in the Argentine government on which Chevron spokesman Kent Robertson remarked, ".provincial governments in the area of the Vaca Muerta understand oil development. They support it. So that's one less barrier."

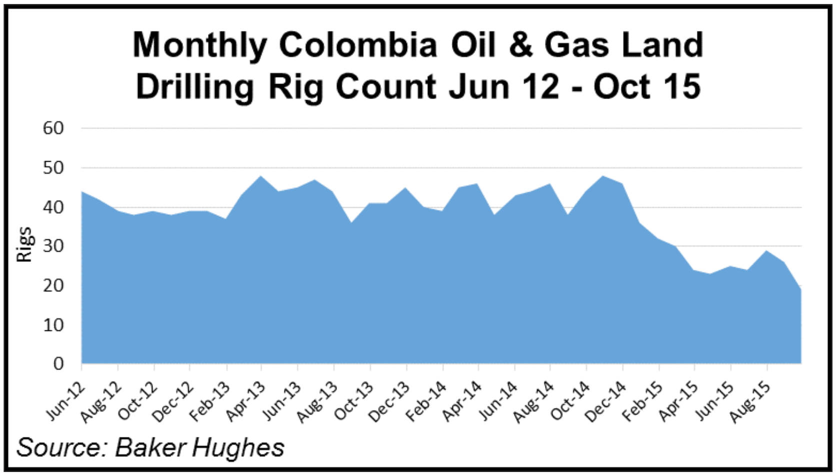
Apache has been testing the shale of the Neuquen Basin since at least 2008. The company reported results from a horizontal multi-stage well that it said produced at a rate of 7 MMcf per day during the summer of 2011. At that point the company had already drilled more than 70 unconventional wells in four Neuquen fields. However, in February 2014 Apache announced the sale of its Argentina assets to YPF S.A. in order to fund a debt reduction program as well as a share buyback.

In its first quarter 2014 conference call Schlumberger said its year-over-year growth in Argentina was strong, "driven by rig-based activity in the Vaca Muerta shale where we are also actively engaging with a number of customers on sub-surface studies and on projects to improve drilling and completion efficiency." This interest is readily apparent in the Argentina rig count, as the number of land rigs working the county has grown from 70 in June 2012 to 104 in October 2015, despite the falloff in global commodity prices over the last year.

Colombia

Unconventional oil and gas development in Colombia is still in its early innings with E&Ps just starting to take notice of what plays exist and what sort of resource potential they may harbor. "Unconventional and offshore are new frontiers we want to open in Colombia to continue incorporating reserves," Colombia Deputy Energy Minister Orlando Cabrales said in an interview with Bloomberg in March 2014. While the national oil company Ecopetrol formerly controlled all Colombian hydrocarbons, reforms were enacted in 2003 that removed the administrative/regulatory responsibilities of Ecopetrol and handed upstream regulation to the National Hydrocarbon Agency and downstream regulation and coordination activities to the Ministry of Mines and Energy. Further reforms have allowed foreign companies to purchase shares of Ecopetrol and even compete with it directly. These reforms have brought about interest in the country from companies such as Canacol Energy, ConocoPhillips, Shell, ExxonMobil, and Chevron.

Colombia has known unconventional opportunities in the form of the Middle Magdalena Valley Basin's (MMVB) La Luna Shale and the Llanos Basin's Gacheta Shale, which the EIA estimated in June 2013 contained 18 Tcf and 2 Tcf of technically recoverable natural gas, respectively. The La Luna formation has also been known to contain large amounts of oil and wet gas and according to the EIA has been the primary focus of Colombian shale exploration as recently as 2013. Some have compared the La Luna to the Eagle Ford Shale of Texas and the first results are just starting to come in. Canacol Energy, in March 2014, reported results from its Mono Arana 1 exploration well in the MMVB La Luna. The well demonstrated a 24-hour flow rate of 590 barrels of oil per day from a naturally fractured area of the formation. The company reportedly holds about 545,000 net acres in the Magdalena Basin and 1.8 million net acres in the country as a whole.



The land oil and gas drilling rig count in Colombia has drifted lower in recent months, falling from 44 in June 2012 to 19 in October 2015, but that may stabilize in the months ahead. Nabors Industries noted on its 3Q15 earnings call that the Latin American market is very challenged these days, with the exception of Colombia, since many national oil companies are stressed for funds. The company has six of its high end PACE-X rigs, which are designed specifically for multi-well pad drilling, working in the country. Similarly, Occidental Production noted on its 3Q15 that it has been operating in Colombia for more than 30 years, and would like to increase its production there, albeit in more conventional formations.

Australia

In Australia, LNG exports and pipeline infrastructure have played a large role in the unconventional development story thus far. With significant demand for LNG from Asia, Australia is in a perfect position to capitalize. On the west and northwest coasts of Australia, LNG production has been ongoing since 1989 when the first shipment from the Northwest Shelf Project was sent to Japan. The west and northwest coasts differ greatly from the east coast and are in fact completely different markets because of the lack of a connecting pipeline. Since east coast gas has to this point been unable to access existing LNG terminals, its price has been much lower than that in the western markets. However, this may be about to change. As of October 2015, three LNG export projects have been approved, two of which are operating, with the third about to enter service. These three represent a combined capacity of 31 million tons per annum. In an October 2012 assessment the Australian National Institute of Economic and Industry Research (NIEIR) projected actual exports (not total combined capacity) in eastern Australia would increase to 2 MMTPA in 2015, 20 MMTPA by 2018 and possibly 24 MMTPA by 2023.

That's quite a big order to fill, and while initially the projects are expected to use coal-seam gas as feedstock, these companies will be looking to shale and tight sands for gas down the road. The EIA and Advanced Research International Inc. recently pegged Australia's shale gas and shale oil reserves at 437 Tcf and 17.5 billion barrels, respectively. Australia's Cooper Basin features tight sands, shale, and coal seams, which could be unlocked by unconventional technology. Because of its proximity and pre-existing infrastructure, the Cooper is an obvious choice for potential development and several companies including Beach Energy, DrillSearch Energy, Santos, and Senex have active evaluation programs there.

Australian East Coast LNG Export Facilities

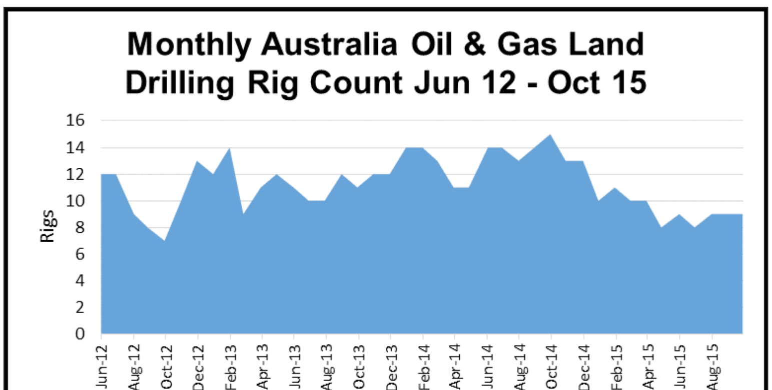
Project Name	Capacity (mpta)	Companies	Status
Queensland Curtis LNG	12	BG Group, CNOOC, Tokyo Gas	Operating
Gladstone LNG	10	Santos, Petronas, Total, KOGAS	Operating
Australia Pacific LNG Project	9	Origin, ConocoPhillips, Sinopec	Under construction (1st gas late 2015)

Source: Compiled by NGI's Shale Daily from company documents

Australian West Coast LNG Export Facilities

Project Name	Capacity (mpta)	Companies	Status
Karratha Gas Plant	16.3	BHP Billiton, BP, Chevron, Japan Australia LNG, Shell, Woodside	Operating
Pluto LNG	4.3	Woodside, Toyko Gas, Kansai Electric	Operating
Darwin LNG	3.2	ConocoPhillips, Santos, INPEX, Eni, Tokyo Electric, Tokyo Gas	Operating
Gorgon LNG	15.6	Chevron, ExxonMobil, Shell, Osaka Gas, Toyko Gas, Chubu Electric	Under Construction (1st gas early 2016)
Wheatstone LNG	8.9	Chevron, KUFPEC, Woodside, Kyushu Electric Power, PE Wheatstone, TEPCO	Under Construction (1st gas year-end 2016)

Source: Compiled by NGI's Shale Daily from company documents



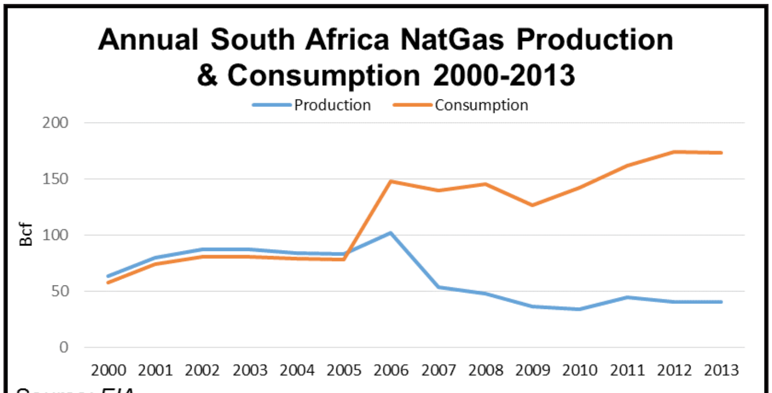
Source: Baker Hughes

On the western side of Australia there is the massive Canning Basin. While less exploration has occurred here the resource potential is solid with EIA estimating 225 Tcf of recoverable shale gas from the Goldwyer Formation alone. Buru Energy completed the first 3D seismic survey of the basin in 2009 and Mitsubishi agreed to fund a $152.4 million exploration and development program in exchange for the ability to earn 50% interest in Buru's permits. ConocoPhillips, New Standard Energy, PetroChina, Hess and Apache have been engaged in farm-in and other activities in the Canning Basin within the past five years. The Western Australia Department of Mines and Petroleum estimated in a February 2014 report that nearly 300 wells had been drilled as of November 2013. There are three existing LNG export facilities in Western Australia, and another two are under construction, the Gorgon and the Wheatstone LNG projects. Both are well along in their development, and are expected to show first gas flows in 2016.

As of October 2015, Australia had 9 land drilling rigs working the country, down from a peak of 15 in October 2014.

South Africa

According to the U.S. Energy Information Administration, there may be 390 Tcf of technically available shale gas out of the Karoo Basin in South Africa. As Shell notes on its website, "if enough natural gas is found [in the Karoo, which is primarily a gas formation], it could provide South Africa with a stable, cleaner-burning energy supply for power generation and economic activity for decades."



Source: EIA

Falcon Oil & Gas observes that "The Karoo Basin covers 600,000 sq km in central and southern South Africa and contains thick, organic rich shales such as the Permian Whitehill Formation. Until recently, the Karoo Basin was not considered prospective for productive hydrocarbons resulting in very limited modern hydrocarbon exploration onshore in South Africa."

The problem, however, has been securing permits to extract that gas, and it's a problem that has lingered for years. In 2009, the Petroleum Agency South Africa (PASA) awarded Shell a Technical Cooperation Permit (TCP) for a one-year study to determine the Karoo's natural gas potential. This study provided a better understanding of the region's geology and shale gas potential, establishing a baseline to move forward with the process of pursuing natural gas exploration.

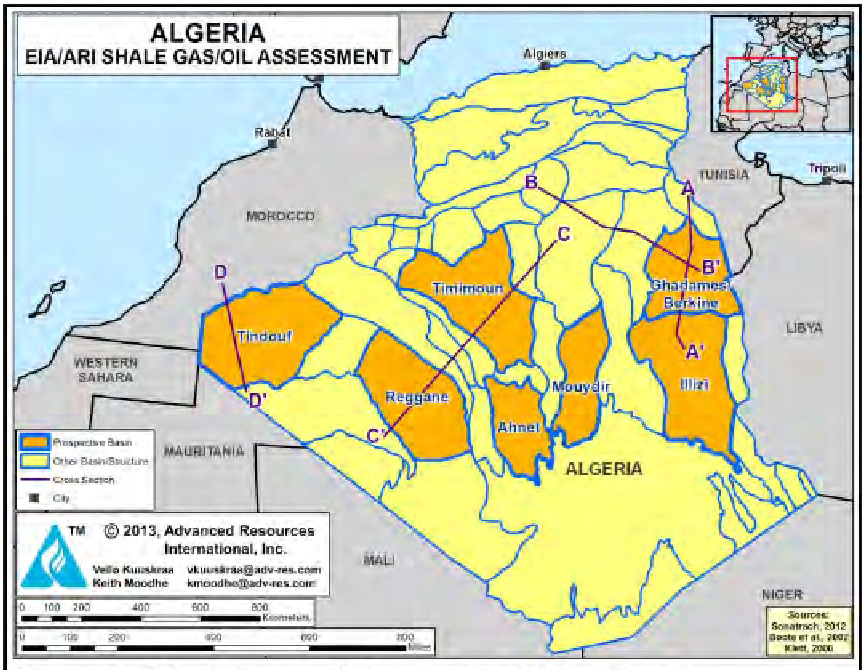
The results of this study were supposed to influence the country's decision to grant permits. But in February 2011, the South African Minister of Mineral Resources issued a moratorium on all new applications to explore the Karoo, and delayed the processing of existing permits until regulations involving unconventional exploration were published. That condition was seemingly satisfied in 2015, and Falcon expects to be awarded a license to explore for shale gas within the Karoo in 2016, along with its partner Chevron.

Shell has applied for rights to explore for natural gas in the Karoo as well, but there was no mention on its website of any progress on this front as of late November 2015.

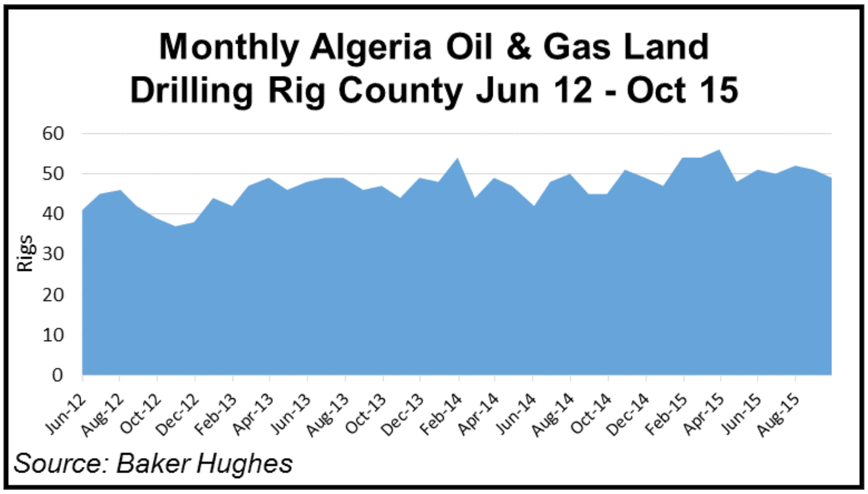
South Africa could certainly use the additional production the Karoo may provide, as gas consumption in the country has soared since 2005, while domestic production began to decline in 2006.

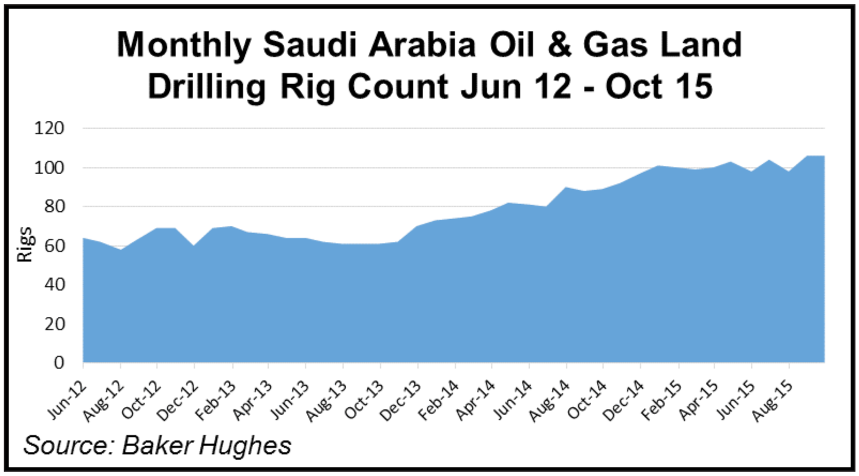
Algeria

Algeria has approximately 707 Tcf of natural gas shale reserves from several different formations, and given the history of oil and gas drilling within its borders, we believe the country is in relatively good position



Source: EIA, Advanced Resources International





to bring some of those reserves into production. In fact, Repsol YPF is leading a consortium of companies to develop the North Reggane project in the Algerian Sahara desert, and expects to have first production online in 2016.

Algeria has featured between 37 and 56 land drilling rigs since June 2015.

Saudi Arabia

Despite being one of the leading oil producers in the world, and the key OPEC nation, Saudi Arabia is far less influential on the world's natural gas front. In fact, some sources report the country doesn't produce enough for its own internal needs. Much of the country's domestic gas production is associated gas, but that mix could start to change.

In 2015, Ali al-Naimi, the minister of petroleum and mineral resources of Saudi Arabia, announced that Saudi Aramco will begin to develop its unconventional resources, in an effort to supply industrial projects within the Kingdom. This may be reflected in the country's land rig count, which has been climbing in recent months.

Saudi Aramco plans to focus on three shale areas in particular: South Ghawar, Jafurah, and the Rub'a al-Khali (a.k.a. the Empty Quarter). The country also plans to build three processing plants to support the expected increase in shale gas production.

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