HARTENERGY

Marcellus Shale

The 2011 Playbook

A supplement to

Oil and Gas Investor

E&P

MIDSTREAM Business

UGcenter.com
Marcellus Shale
The 2011 Playbook

A supplement to *Oil and Gas Investor, E&P,* and *Midstream Business*

HART ENERGY
1616 S. Voss, Suite 1000 | Houston, Texas 77057
Tel: +1 (713) 260-6400 | Fax: +1 (713) 840-8585
www.hartenergy.com

2011 Unconventional Playbook Series

The 2011 Marcellus Shale Playbook is the eleventh in Hart Energy's exclusive series of comprehensive reports delving into North America's most compelling unconventional resource plays. The lineup of topics addresses the plays everyone is talking about and delivers answers to essential questions on reservoirs, active operators, economics, key technologies, and infrastructure issues. Each playbook features a full-color map highlighting fields, drilling activity, and significant wells. This playbook also includes a full-color infrastructure map.
To learn more, visit www.ugcenter.com/subscribe

Table of Contents

On the cover: A rig tests the Marcellus Shale in the Appalachian Basin. *(Photo courtesy of Chesapeake Energy Corp.)*

WEB EXCLUSIVES

CALIFORNIA'S MONTEREY HAS CELEBRITY POTENTIAL

In search of the next star-studded unconventional target? Look no further than California.
UGcenter.com

BAKKEN LAND ACQUISITION IN NORTH DAKOTA PEAKS

After riding a five-year high, land acquisition in core areas of the Bakken Formation has peaked.
UGcenter.com

ARGENTINA'S UNCONVENTIONAL HEART: THE NEUQUEN

Now that French politicians are (temporarily) taking the Paris Basin off the table, Argentina's Neuquen Basin has become one of the world's top shale-resource plays.
UGcenter.com

COMPLETIONS DATA SHOW BARNETT, PICEANCE/UINTA PLAYS MOST ACTIVE

During first-quarter 2011, 1,755 wells were completed in 13 major U.S. unconventional plays.
UGcenter.com

MOST READ ON THE WEB

1. California's Monterey Has Celebrity Potential
2. Rig Count Update: The Majors Make Their Move
3. Argentina's Unconventional Heart: The Neuquen
4. Marcellus Trismus?
5. Granite Wash Growth

WEBINARS

The Eagle Ford Shale, Leading a Remarkable Shift Toward Rich Gas and Oil Plays

The Eagle Ford play in South Texas has exhibited stunning growth in its short history, and that growth continues unabated. With aggressive operator drilling schedules, it is possible for Eagle Ford production to exceed 5 Bcf per day in 2020. Learn about the top producers, their acreage positions, and the reasons this prolific play has a bright future ahead.

The Permian, Petroleum, and Unconventional Activity

The Permian Basin of West Texas and southeast New Mexico is one of the premier US producing provinces. Although its conventional reservoirs are heavily developed, today's unconventional prospects offer attractive targets to long-time players and new entrants alike. Such unconventional plays as the Wolfberry and Bone Spring are enjoying surging activity, thanks to operators' successes with application of the latest drilling and completion techniques.

A US flag adorns the top of a drilling rig mast working the Marcellus Shale. *(Photo courtesy of CONSOL Energy Inc.)*

Monetizing Marcellus

In short time, operators have proven the Appalachian Marcellus' production potential. They're working now on increasing recovery and getting the bounty to markets.

By Nissa Darbonne
Contributing Editor

In December 2007, Range Resources Corp. announced the newest US shale gas play, reporting three new horizontal Marcellus tests that made 3.7, 4.3, and 4.7 MMcfe in their first 24 hours. Just more than three years later, more than 2,500 horizontal wells have now been drilled through the Appalachian Formation, making a combined 2.5 Bcf per day, of which some 10% is being surfaced by Range alone.

And exploration of its and fellow leaseholders' acreage is far from exhausted. In the coming 30 months, some 125-plus rigs will drill 6,000-plus wells and do 50,000-plus frac stages in the play, estimated Robert MacKenzie, managing director, energy and natural resources, FBR Capital Markets.

Why drill this gas at below US $5? The reasons are plenty. The Marcellus offers both dry gas and yet-higher-premium, Btu-rich gas liquids in a fuel-thirsty Northeast market. Some production is 1,400 Btu, or 1.4 times the energy content of a thousand cubic feet of dry methane, so the actual price producers are fetching is $6-plus per Mcf when factoring in the liquids.

Other reasons are market anomalies. A great deal of drilling is being paid for by US producers' joint-venture partners in the play, from Statoil, Mitsui & Co. Ltd., and Sumitomo Corp. to Reliance Industries Ltd.

Also, some early leaseholders are rushing to hold their acreage before the initial term — usually five years — begins to expire in 2012 and 2013. Lease renewal is possible, but at a new price: Early entrants put together land at less than $100 an acre; today, entry costs $7,000-plus an acre in outright purchase, and entry via joint venture is averaging $14,000-plus.

The No. 1 lease owner in the western Pennsylvanian heart of the play, Range Resources Corp. has pared its lateral lengths, for example, to stretch its capex budget and beat the clock on the expiration of a large portion of the 1.1 million

Marcellus Oilfield-Services Demand

	2010	2011E	2012E
Average rig count	93	125	145
Drill days/well	20	19	17
Wells to be fraced	1,659	2,405	3,062
Days to complete/well	7.1	6.4	5.8
Frac days (total)	11,700	15,374	17,902
HP/fleet	30,000	32,500	32,500
Fleets needed	46.7	62.2	72.6
Total HP needed	1.40MM	2.02MM	2.36MM

Demand for rigs and pressure-pumping crews is expected to grow in the Marcellus play. *(Source: FBR Capital Markets)* acre portfolio it's amassed, almost all of this in 2007 and 2008 before its late-2008 initial well news set off the land rush.

A Pennsylvanian-age black shale up to 900 ft thick in some areas at depths of between 2,000 and 7,200 ft, the Marcellus's production potential is still yet to be determined. For example, Range reported a 10 MMcfd well in 2009 — the highest IP in the Marcellus at the time. More recently, Cabot Oil & Gas Corp. drilled two 30 MMcf IP wells.

Not even on the super major gas field map four years ago, the Marcellus was catapulted to the "second-largest gas field in the world" spot in 2009 by industry and academia as well results began to prove the production potential. Even Russia has taken notice: It is no longer the world's No. 1 gas producer, as Marcellus and other US shale gas output pushed the US to that title in 2009 in an annual BP Plc global oil and gas review.

The BP research team's 2010 report, which is due this summer, is expected to find the US continuing to hold that top position as gas exploitation has yet to slow down and the Marcellus play, while nascent, is better understood with each well, lateral, and frac job. Producers report decline rates are flattening and EURs are growing.

The Appalachian output is turning gas market dynamics on its head in the US and even globally as the new indigenous supply within the world's top gas market will mean LNG imports to US shores remain noncompetitive. And North American petrochemical manufacturers are enamored of the Marcellus' NGLs, particularly the ethane and propane that are low-cost feedstocks compared with crude oil-based naphtha.

A rig stands out against a wooded horizon as it prepares to drill in the Marcellus fairway. *(Photo courtesy of CONSOL Energy Inc.)*

Producers' greatest emphasis in their Marcellus programs now is on monetization of the bounty.

Slower declines, growing EUR

At press time, Cabot reported new whopper Marcellus wells: IPs from the pair came in at some 30 MMcf each, with 21 and 26 frac stages and lateral lengths of between 5,000 and 6,000 ft. The company's average well previously IP'd at 16 million MMcf, and the newest wells suggest an EUR of at least 15 Bcf per well.

The wells cost some $7.5 to $8 million. "This sort of type curve should generate acceptable economics with gas as low as $2," said Biju Perincheril, equity-research analyst for Jefferies & Co. Inc.

In north-central Pennsylvania, longtime Rockies gas producer Ultra Petroleum Corp. expects to have twice as many wells online this year as last, more than doubling production. First-quarter 2011 net output alone of 93 MMcf/d was as much as half of full-year 2010 production. It might get to 150 MMcf/d this summer.

"Our decline curves are getting flatter, and our EURs are increasing," said Mike Watford, Ultra chairman, president, and CEO. For example, the EUR on its Kenton 902-1H well was 3.8 Bcf after 60 days of production. After 150 days online, it is now expected to make 4.8 Bcf, or 26% more.

Ultra holds 260,000 net acres, with some of its gross position operated by Shell Oil Co. via the major's purchase of private Appalachia-focused independent East Resources Inc. last year. Some is operated by Anadarko Petroleum Corp.

Lately, Ultra's Marcellus wells — of which there are 105 gross — have an average lateral of 5,173 ft and 14 frac stages. IPs are averaging 6.5 MMcf. In western Tioga County, Pa., the 6,700-ft-lateral Pierson 810 5H well with 27 frac stages went into sales at 10 MMcfd. An offset, it has an EUR of more than 8 Bcf.

"It's one of our best wells in the field," said Doug Selvius, Ultra director, operations. "It appears EURs for these new long-lateral wells could be nearly twice our 3.75 Bcf-type curve." The B factor it has been using in the play is 1.7; indications are that 1.5 or less may be more accurate, added Brad Johnson, vice president, reservoir engineering and development.

In Butler County, Appalachia-based Rex Energy Corp. is using more sand and tighter clusters in its completions. Its IPs are averaging 3.6 MMcf on three wells on which it used a new, enhanced frac design, and indications are that the EUR is 4.4 Bcf there. In Westmoreland County, two new Rex wells operated by Williams Cos. Inc. averaged 3.4 MMcf/d in their first 155 days online, exceeding the area's type curve of 3 MMcf/d and an EUR of 3.0 Bcf.

In northeastern Pennsylvania, where Southwestern Energy Co. has some 173,000 net acres that are prospective for Marcellus, it made 2.8 Bcf, net, in the first quarter — 4.5 times its fourth-quarter 2010 net. It is also posting some remarkable 90 day-plus production figures: Three wells in the Greenzweig area in Bradford County that came online in October are making an average 6.3 MMcf/d each, three online since November are making 4.3 MMcf/d each, and three online since February produce 5.8 MMcf/d each.

"We're getting all of the infrastructure in place ... We're really excited that the wells are coming in much better than we expected," said Steve Mueller, Southwestern president and CEO.

Southwestern pioneered the Fayetteville Shale gas play in Arkansas, so it is well-versed in shale well engineering and economics. There, a 10% return to investors is being made at just under $4 gas; in the Marcellus, Mueller said, "even three months ago, we were talking about it being in the $3.80s. Now, we're talking in the low $3s."

For Pittsburgh-based Consol Energy Inc., the Marcellus made 4.7 Bcf in the first quarter, four times the company's year-earlier sales. It tripled its leasehold in that time frame to total 750,000 acres by buying 500,000 acres from Dominion for $3.5 billion in cash. "There were a lot of questions about that," said Brett Harvey, Consol chairman and CEO, "but it's showing very good results ... And now we've shown very good results in the questionable (Marcellus) areas that we purchased in central Pennsylvania."

Bill Lyons, Consol chief financial officer, added that all of its leasehold is held by fee or production so "we were able to drill for economics as opposed to holding leases."

The rush to HBP

While some operators are reporting 9,000-ft laterals and more than 20 frac stages with IPs of 15 million-


SUCCESS POWERED BY
EXPERIENCE
THE EAGLE ADVANTAGE
At Eagle Land Services, we understand how critical the success of your project is. Our experienced project managers partner with our clients to leverage resources and to develop strategies for success on every job, no matter how large or small. For over 30 years, Eagle has been providing quality land services, getting results ahead of schedule and under budget. Our landman network and management team include licensed attorneys and certified and registered petroleum landmen. We are passionate about what we do and how we do it. Experience matters! That's the Eagle Advantage.
EAGLE
LAND SERVICES INC
877.224.5ELS
eaglelandservices.com
Leasing | Title | Legal | Mapping | Reporting

Single-Well IRRs: Marcellus v. Eagle Ford; Liquids v. Dry Gas									
Crude Price	**$60**	**$70**	**$80**	**$90**	**$100**	**$110**	**$120**	**$130**	**$140**
Marcellus Liquids	67.2%	71.8%	76.5%	81.5%	86.7%	92.2%	98.0%	104.0 %	110.3%
Eagle Ford Liquids	46.4%	62.2%	81.1%	103.8 %	131.0%	163.6 %	202.5 %	249.3 %	305.6 %
Gas Price	**$3.00**	**$3.50**	**$4.00**	**$4.50**	**$5.00**	**$5.50**	**$6.00**	**$6.50**	**$7.00**
Marcellus Gas	7.5%	14.5%	23.6%	35.1%	49.4%	67.2%	89.1%	116.1%	149.3%
Eagle Ford Gas	(1.0%)	0.6%	4.9%	10.3%	17.2%	25.8%	36.5%	49.4%	64.8%

Marcellus wet gas further drives the economics of the play, and its dry gas receives premium pricing, making it profitable to produce in a lower gas-price regime. *(Note: Average for all producers; some producers have better or poorer individual-well IRR. Source: FBR Capital Markets)*

plus, Range Resources is focused on holding its acreage right now, using average lateral lengths and frac stages.

Range will spend some 86% of its $1.4 billion 2011 capex budget in the play, with some of the funds coming from the $900 million sale of its gas-prolific Barnett Shale properties. The love the Marcellus is showing Range is so rewarding that it expects to grow companywide production 10% this year, even without the Barnett contribution that made some 25% of its total output last year.

By the end of this year, it expects to have 400 MMcf/d into sales, up from 200 MMcf/d in December. At year-end 2012, it expects to be producing 600 MMcf/d. Even more remarkable: Most of this growth will be from wells having modest 2,500-ft laterals and eight-stage fracs.

Jeff Ventura, Range president and COO, said, “Our plan for 2011 is to drill moderate lateral lengths and fewer wells per pad and retain our acreage in this prolific play, not only for the Marcellus potential but also for the Upper Devonian and Utica shales.”

It has 285,000 net acres HBP now and 790,000 more left to hold. The average 2,500-ft-lateral, eight-stage frac well in its southwestern Pennsylvania acreage costs some $4.1 million and proves an EUR of 5 Bcfe. At $5 gas, that’s a 99% rate of return. Even at “$4 gas forever,” Ventura said, it’s 74%.

“It’s not (more) optimal (than longer laterals and more stages), but it’s pretty darn good ... We can drill more wells and hold more acreage and still generate really strong rates of return.”

Dave Porges, chairman, president, and CEO of EQT Corp., which holds 3.4 million acres in Appalachia that it has targeted for other formations, said that, when drilling for both well economics and to hold acreage, “it is probably true that shorter laterals make more sense because what you want to do in that circumstance is touch as many of those leases as possible.”

Early entrants to the play that secured five-year lease terms will be approaching expirations in 2012 and 2013. But, if able to drill solely for top well economics, “we are absolutely convinced that longer laterals are better, at least up to 9,000 ft, which is as far as we’ve drilled to date,” Porges said.

EQT plans a few longer laterals this year, but its average new-well lateral will be at least some 9,000 ft. “We are absolutely convinced, based on what we’ve done, that longer is better from an economic standpoint,” he said.

EOG Resources Inc. is also working to HBP. “(On) the dry-gas side of our ledger, we’re focusing essentially ... where we have to drill to hold acreage: The Marcellus, Haynesville and, to a lesser extent, the Horn River (Basin),” said Mark Papa, EOG chairman and CEO.

The company planned to sell its Marcellus position last year to fund its many other high-potential

plays — particularly oily ones — but the deal came undone. Papa said he isn't interested in putting EOG's Marcellus leasehold into a joint venture — a tack several other producers are using to pay half or more of drilling costs and to free cash for developing more Marcellus and other assets.

Papa said, "The question really boils down to 'Do we want to devote some of our staffing to basically educating someone else on a shale play and we do 100% of the technical work for perhaps a 50% net interest in the production?' We would just prefer to do 100% of the technical work for 100% of the production."

Take-away, export

Where does all the gas go? Alan Armstrong, president and CEO, Williams Cos., which is both a producer and pipeline operator in Appalachia, said, "The Marcellus is really infrastructure-constrained on many fronts right now."

About two thirds — that is, 1.3 Bcf a day, up from 500 MMcf a year ago — of all Marcellus production from Pennsylvania this spring was going into the Tennessee Gas Pipeline (TGP), which El Paso Corp. operates. The company has $1 billion of expansion projects under way in the northeastern US, including the 30-in.-diameter 300 Line, to keep up with the growing output.

Some producers are more takeaway-advantaged than others. Range is prepared to handle the 400 MMcf/d it expects to be making from Marcellus at year-end — and more. In southwestern Pennsylvania, its Houston 3 processing plant will bring capacity to 335 MMcf/d, and its Majorsville 2 plant will add more, totaling a combined 390 MMcf/d. Also, gathering capacity from the wellhead will be 575 MMcf/d by year-end, said Ventura.

All of this burgeoning Marcellus production is expected to affect gas markets across North America on a level not seen since possibly the completion of the Rockies Express (Rex) pipeline into Appalachia from the west or the 1 Bcf/d Independ-

Patterson-UTI's Rig 251 drills to the Marcellus in Susquehanna County, Pa. *(Photo courtesy of Chief Oil & Gas Co.)*

ence Hub line, Independence Trail, from the deepwater Gulf of Mexico.

Ultra Petroleum's Marshal Smith, CFO, said the additional Marcellus supply will back out gas that normally goes into the US Northeast from the Gulf Coast and elsewhere in the Lower 48 and from Canada. "So then you get backed up in both regions...We're seeing the results of that, and we'll continue to see the results in terms of a further narrowing of basis differential and a flattening of basis differential across the country."

James Crandell, commodities research analyst for Barclays Capital, noted that net daily imports into the Northeast declined by 0.6 Bcf in 2009 from 2008 and another 0.5 Bcf in 2010. "Indeed, pipeline operators have been reacting by requesting, and receiving, permission to reverse the direction of flow on pipelines that traditionally hauled Canadian gas to the Northeast," Crandell said.

Yet, said Greg Ebel, president and CEO of midstream operator Spectra Energy Corp., "If you go out 20 years, you're still going to find about 40% of the gas produced in the Lower 48 coming from the Gulf Coast region."

Far out on the horizon, the back-up in Appalachia may be relieved by the export of US gas, which would also push up US gas prices. In mid-May, LNG operator Chenier Energy Inc. received Department of Energy (DOE) approval to export gas from South Louisiana to any country with which the US does not prohibit trade. It is now working for Federal Energy Regulatory Commission permits to construct the 2 Bcf/d liquefaction facility at its existing Cameron Parish, La., LNG import terminal. The target construction completion date is 2015.

Upon news of the DOE permission, the Nymex price of natural gas for June delivery jumped 26 cents to $4.34; for December 2015 delivery, 18 cents to $6.45; and, for April 2016 delivery, 17 cents to $6.16.

Also on the Gulf Coast, Freeport LNG Development LP has made a similar application to the DOE and would export gas from its Freeport, Texas, LNG import facility.

Market watchers expect that most of the gas exported from the Gulf Coast would come from neighboring areas — including the Eagle Ford, Barnett, and Haynesville Shale gas plays. This would take pressure off Gulf Coast gas flow into Appalachia and improve the price for local Marcellus gas.

Yet possibly on the horizon as well is the export of Appalachian gas itself —f rom Dominion Resources Inc.'s Cove Point LNG import terminal in Maryland, where Statoil is among buyers of imports and is also a Marcellus gas producer via its joint venture with Chesapeake Energy Corp. Dominion reported earlier this year that it is considering applying for DOE permission to export from Cove Point.

Crandell noted that the Marcellus is already making 2.5 Bcf/d. "Over the next several years, Marcellus production could grow to a multiple of today's level, paced only by infrastructure build-out." The greatest risk of production curtailment is in Susquehanna and Bradford counties in northeastern Pennsylvania and in Washington, Greene, and Fayette counties in the southwest. "(These) are developing most rapidly and could become glutted if takeaway capacity is not built expediently," Crandell said.

Meanwhile, where is the excess gas going today? Crandell said 96 Bcf of new storage capacity has been created in New York, West Virginia, Ohio, and Pennsylvania.

New demand

Besides creating new markets abroad for excess Marcellus and other US gas, users' interest at home is piqued. In the heart of the Marcellus play, Pittsburgh-based United States Steel Corp. is already experiencing sales growth from providing tubulars to gas wellsites.

It is also looking at using more natural gas in its furnaces, reducing its dependence on coke (carbonized coal) as availability of this raw material has become more constrained and expensive and as markets have become more volatile.

"We could realize further benefits from this now-abundant, competitive, and environmentally friendly source of energy," said John Surma, US Steel chairman and CEO. "This could be as basic as increasing natural gas injection in our blast furnaces to replace costly purchased coke and lower our CO2 emissions."

It is already injecting more natural gas into its furnaces now, improving its profit structure. To use yet more natural gas, it will have to retrofit furnaces. And this will be worth it, Surma said.

He broke it down this way: Coke may cost $300 to $400 per ton, and natural gas is below $10. Reducing coke used in making one ton of raw steel from 800 lb to, say, 600 lb is a significant profit-margin improvement. The company makes 32 million tons of raw steel a year in North America and Europe.

"There are blast furnaces in the world that go to 400 (lb of coke per ton of raw steel), and we may as well try to get there," he said. "… It's meaningful. It's a meaningful portion of that total coke load — if you think about it — of 800 pounds per ton of raw steel."

Among electric power generators, northeastern US coal-switching to natural gas was evident in 2009 and 2010 as gas supply was readily available and considerably cheap, even relative to coal. Crandell said, "Gas demand in power generation has been the main source of growth for Northeast (gas) markets." Switching back to coal is possible, but power generators will stick with natural gas as long as it's cheaper, he noted.

And the wet gas the Marcellus gives up is making for an entirely different specialty chemicals game in North America. Containing ethane, propane, butane, and even natural gasoline, the wet gas has captured the attention of US petrochemical manufacturers. The potential is even a leading conversation today in The Dow Chemical Co.'s C-suite.

Andrew Liveris, Dow chairman, president, and CEO, said securing supply of less expensive raw materials is essential to cost competitiveness. "The specialty chemical company graveyard is littered with companies that didn't understand the strategic importance of integration."

Demand for ethane is almost entirely for making ethylene, which is made into polyethylene or plastic. Ethane for which there is no demand is simply left in the gas stream and sold to customers as extra-Btu natural gas. The producer doesn't get paid as much for it as it would if the ethane were stripped out.

World's 10 Largest Natural Gas Fields*

Field Name	Country	Recoverable Reserves (Tcf)
South Pars/North Dome	Iran and Qatar	1,235
Marcellus	**United States**	**489****
Urengoy	Russia	222
Yamburg	Russia	138
Hassi R'Mel	Algeria	123
Shtokman	Russia	110
South Iolotan-Osman	Turkmenistan	98
Zapolyarnoye	Russia	95
Hugoton	Unites States	81
Groningen	Netherlands	73
Bovanenko	Russia	70

** Rafael Sandres, "Global Natural Gas Reserves: A Heuristic Viewpoint," March 2006. ** Dr. Terry Engelder, Penn State University, August 2009.*

By a 2009 estimate, less than two years into the play, the Marcellus had already exceeded recoverable reserves of eight of the world's largest gas fields. The estimate keeps growing as producers further prove the shale's potential and horizontal technology is now being applied to Upper Devonian and Utica shales.

Getting paid for it

Range Resources aims to get paid for it. And it's a bundle: In recent years, ethane has been priced at an average of 46% that of the Nymex price for West Texas Intermediate (WTI) crude oil. Simple methane or dry gas: 9%.

US gas producers describe having liquids in their mix these days like this: Even 25% WTI for gas liquids is worth more than 100% Nymex for dry gas.

Range is working on two firm-purchase deals with ethane consumers — Dow on the Gulf Coast and Nova Chemicals Corp. in Sarnia, Ontario — for the ethane it's making from its wet gas Marcellus acreage to further drive its rate of return from the play.

It's no small amount of NGLs that Range expects to make. For example, in the liquids-rich window of Range's leasehold, it appears that the smallest completion type (eight-stage frac, 2,500-ft-lateral) well will make 5 Bcfe, of which 3.6 Bcf is dry gas or methane and 239,000 barrels are NGLs. With a 3,500-ft lateral and 12 frac stages: 6.7 Bcfe or 4.1 Bcf of methane and 425,000 barrels of liquids.

"Maybe we can turn that into 500,000 bbl a well," Range's Ventura said, "… Given the huge acreage position we have on the liquids-rich portion of the play, this could be very impactful."

Across its leasehold, Ventura estimated that Range could make 307 to 463 million bbl of liquids with the small completion scheme. "I would expect the performance could continue to climb with time as we get better and better about what we're doing. So it's not unreasonable to think we'll reach the high end … with 463 million bbl of liquids," Ventura said.

But the potential for revenue uplift doesn't stop there – this is the price Range receives when the ethane is left mixed with the methane when put into pipe to market.

"Once we start extracting ethane, it's going to double our liquid yields, so the 463 million bbl becomes 926 million bbl net to Range," said Ventura. "And then, if we can get better about where we land (our wells) and how we drill and complete, really, you're approaching 1 billion bbl."

A rig towers over the trees surrounding the Marcellus Shale in the Appalachian Basin. *(Photo courtesy of Chesapeake Energy Corp.)*

Efforts to monetize the ethane began virtually with Range's work on the play several years ago, said John Pinkerton, Range chairman and CEO. In time, it has teamed with other wet gas producers to leverage the combined supply power. The prospective buyers are impressed with the figures, he added.

"This is going to be a lot of ethane. ... At the end of the day, we'll get gas-plus for the ethane, which is something that we never thought would happen two years ago. We were hoping it would, but now, it's clearly going to happen. ... It will have a big impact on our realizations and our margins and, obviously, enhance the intrinsic rate of return," he said.

Range and midstream operator MarkWest Energy Partners LP, which is the largest gas processor and fractionator in Appalachia, have two plans for getting the ethane to markets upon users' signatures on firm purchase agreements. In one, "Mariner East," 50,000 bbl of ethane a day would be piped to Philadelphia and put into Pennsylvania-based pipeline operator Sunoco Logistics Partners LP ships. It can be sold into any market — to Dow and other users on the Gulf Coast, to US Northeast plants, and even abroad.

In the other, "Mariner West," 65,000 bbl a day would be put in an existing Sunoco Logistics pipeline, modified for ethane export at Vanport, Pa., and sent to Nova Chemicals at Sarnia, the old Lake Huron oil town that hosts a large petrochemical industry. Beginning this summer, MarkWest will be able to recover more than 40,000 bbl per day of ethane from wet Marcellus output and, by mid-2012, 70,000 bbl per day.

Frank Semple, MarkWest chairman, president, and CEO, said of the Marcellus, "This significant shale play is a game changer for natural gas supply in the US."

Reversing Gulf Coast pipe

A competing ethane export plan is conversion of Spectra Energy's Texas Eastern pipeline in Pennsylvania and Ohio and El Paso's Tennessee Gas Pipeline system from Ohio to the Gulf Coast into an ethane line, the Marcellus Ethane Pipeline System (MEPS). It would carry 60,000 bbl of ethane a day to Dow Chemical, ChevronPhillips, and other petrochemical manufacturers whose announcements recently of expanding their ethane demand, primarily on the Gulf Coast, are encouraging, said Doug Foshee, El Paso chairman, president, and CEO.

"Others have estimated that this could result in an additional demand in the Gulf Coast of more than 250,000 bbl a day of ethane," Foshee said. "... We believe our MEPS project is best positioned to move the large volumes of ethane produced from the Marcellus to the Gulf Coast, and we continue to work ... to get this one over the finish line."

Spectra is a 50/50 partner with El Paso on MEPS, which is an $800 million to $1 billion project. Ebel noted, "Right now, you don't have a way to get the ethane from the Marcellus down to the Gulf Coast. So I think the advantage you have is some pipeline that's not being utilized, which El Paso brings to the table. The Gulf Coast is a 600 or 650 million b/d market. And that's where you want to be taking the ethane."

Ebel notes too that MEPS is advantaged in that it is expandable to several hundred thousand barrels. "That expandability piece is going to be really valuable," he said. "That expandability of a pipe ... is going to serve them (on the Gulf Coast) better than, say, a marine solution," Ebel said.

The big prize to petrochemical makers is that ethane is far cheaper than naphtha feedstock. Pinkerton said, "You have a global economy that's using naphtha. You have this huge push of 'How do I get off naphtha and get to ethane?' I think what you see is this global movement to the cheapest feedstock that you can. And you'll do all the ethane that you can."

On the Gulf Coast, Dow is restarting an existing ethylene cracker and increasing its feedstock flexibility for several other crackers. "But we're not stopping there," Liveris said. The arrangement with Range "will give us access to the liquids from the Marcellus ... and complements the ethane and propane supply contracts that we already have in the Eagle Ford and other shale gas regions."

Producers are eager to get the product out of the gas stream it is putting in pipe, as shippers can — and are legally required to — reject gas that is too wet. MacKenzie estimates that new liquids-rich production across the US, such as from the Marcellus and Eagle Ford, will make more than 200,000 extra barrels of ethane a day by next year.

Williams Cos. is interested as both a producer and user. It operates a 1.35 billion lb/year olefins cracker at Geismar, La., on the Mississippi River that also makes 90 million lb of polymer-grade propylene. Its olefins team also runs 200 miles of ethane pipeline and a 500 million lb/year propylene splitter.

Armstrong noted that more than 80% of the petrochemicals manufactured in the US use natural gas, while about 60% of olefins produced in the world are made from oil. "When you look at the cost advantage natural gas has over oil, you start to craft a picture of how advantaged the US is because of low-cost gas," he said.

Further experiment

While creating markets for Marcellus dry and wet gas, operators are also working to improve best E&P operating practices. In Bradford County, EOG Resources' new, proprietary frac scheme, designed specifically for the Marcellus play, was used on the Guinan 2H that IP'd 9 MMcf and on the Hoppaugh 3H that IP'ed 14 MMcf.

Loren Leiker, EOG senior executive vice president, exploration, said, "(It's) a specific completion technique that's proprietary to EOG and we can't really talk much about the details." Further shrouding the secret is that, on both wells, EOG has 100% interest. "But we work really hard, gathering the data and analyzing the data, and continue to refine our completion techniques for each play," Leiker said. "And so they're very specific, and it's working out really well for the company."

In Westmoreland County, Consol Energy is spacing fracs at between 250 and 300 ft, and it will test tighter in the future. Two recent wells in central Pennsylvania came on, combined, at 15 MMcf/d — remarkable because industry has been skeptical of the productive potential of that region, said Nick DeIuliis, Consol president.

Meanwhile, Ultra Petroleum is at work in improving its wellsite selection and lateral landing. As it went into the play, it ran Schlumberger Ltd.'s EcoScope multi-function LWD tool in its first 18 or so wells, steering it and taking petrophysical data across a 4,300-ft section as opposed to just at one point within the well bore.

This has added some $200,000 to the cost of each well, but it is worth it, said Selvius. "Ultra's in a unique position with our dataset, because it is unlike most others out there. ... And we've got a lot of data other operators don't have," he said.

EQT is experimenting with a new frac-geometry design and has used it in 13 wells. "We continue to see higher IPs per lateral foot treated with this new design," said Phil Conti, CFO. The five wells to which the new geometry has been applied that have been online for more than 100 days were making 60% more gas than others.

The company won't disclose more details on the technique yet but reports that these wells cost an extra $1 million. Steve Schlotterbeck, EQT senior vice president, E&P, said, "While we are clearly seeing higher production rates initially, it's very important that we get a little longer production history so we can accurately calculate the return we are getting for that extra million dollars (per well)."

Range, while applying a standard lateral and frac to most wells to secure its acreage, is still conducting some experiments too with longer laterals and more frac stages and where the lateral lands in the formation — high, low, or in the middle. "It varies depending on where you are in the play, even where you are within a county, we believe," Ventura said of the sweet landing spot. "Whether you're wet or dry is important too."

Having pioneered the Marcellus play, Ventura noted that Range carried 100% of the initial cost of science. "We're not doing that anymore." Early on, it and others were building acreage and didn't share much information.

"At this point, I think companies are more cooperative than they are competitive," Ventura said. "So not only is Range doing experiments, but other companies out there are drilling laterals up to 9,000 ft and putting a bunch of stages in them. So we can learn not only from our wells but from others."

Field costs, taxes

In 2008, average horsepower deployed per Marcellus well was some 6,000, according to MacKenzie. Lateral lengths averaged 3,000 ft; frac stages, seven. In 2010, the averages were remarkably different: Wells were put on as much as 30,000 hp; producers pushed lateral lengths to 5,000 ft; and frac stages averaged 15, he said.

Today some operators are taking laterals to 9,000 ft and testing farther. Some 90 rigs are at work in the play this year, and more than 140 are expected to be at work in 2012.

EQT has begun tracking its total lateral lengths and fracs to measure its work rather than just number of wells, since each of its Marcellus wells is more intense than last year's. By this past April, it had spudded 167 Marcellus horizontals; among those producing into sales, 1,450 frac stages were applied, and another 861 fracs are planned for wells waiting on completion, said Conti.

Operators report experiencing oilfield cost inflation in Appalachia, but not so much more than throughout the Lower 48. John Manzoni, president and CEO, Talisman Energy Inc., said it has long-term contracts for completions work, so its cost there is fairly constant. "But clearly, material costs, diesel, sand, all of those sorts of things have seen some quite significant pressure between the fourth quarter and the first," he said.

Conti expects further cost inflation next year. A typical 5,300-ft lateral EQT well will cost $6 million-plus. "Most of the money for the Marcellus, at least, is spent on fracing," he added.

Ultra Petroleum's well costs in Tioga and Potter counties are averaging $4.3 million, while deeper wells in Clinton and Lycoming counties cost between $6 and $7 million. "Like other operators in the trend, we're experiencing cost pressure on the completion side, but are managing to offset those increases on the drilling and water handling (side)," said Selvius.

Meanwhile, leasing costs are not softening, making the play still costly if seeking to renew leases or capture more. "Frankly, we've been waiting for economic circumstances to have caused the lease bonuses to have dropped, though I have to acknowledge that doesn't really seem to have happened very much," said Porges.

And a new invoice is on the horizon: a Pennsylvanian type of severance or production tax. Currently, the state doesn't have an oil and gas severance tax, and legislators are considering an "impact tax."

"It's a severance tax disguised as an impact-fee tax," said Paul Smith, Talisman executive vice president, North American operations. The state's new governor, Tom Corbett, is opposed to a severance tax but has said he is willing to consider the impact tax. Producers have said they would support a transparent impact fee that is based on their actual activity and with the areas involved being the actual beneficiaries of the proceeds.

"With gas prices where they are today, one needs to be very careful about the imposition of a severance tax with capital mobility being very mobile," said Smith. "And I think that's the message the governor of Pennsylvania is fully aware of."

Environmental concerns

Yet more costs are associated with true or false beliefs about how oil and gas is drilled for and produced in Appalachia. When Semple talks about increasing processing and NGL takeaway capacity from the Marcellus, "we are not factoring into our plans any impact on production from the rhetoric, if you will, of fracing technology in particular," he said.

He believes the industry will get past it, "but it's something that we just need to keep a real focus on."

Producers have formed the Marcellus Shale Coalition to jointly collaborate with and provide facts about oil and gas drilling to community members, legislators, and regulators. An ongoing matter has been water disposal.

Rex Energy and others are using a closed-loop drilling system and not open pits for disposed mud and cuttings. Solids are being sent to landfills that can handle these. Meanwhile, at press time, Pennsylvania's Department of Environmental Protection (DEP) suspended disposal of drilling wastewater at 15 facilities that had been permitted to accept it.

Dan Churay, Rex president and CEO, said, "We re-use our frac water multiple times before we ultimately dispose of the remaining flowback. However, until DEP concerns are satisfied, we, along with other members of the Marcellus Shale Coalition, have heeded this request and ceased disposing of any remaining flowback water at these previously permitted wastewater treatment plants."

Rex is trucking wastewater and injecting it into permitted wells in Ohio. Cost-wise it had been using disposal wells in Ohio for some time anyway, so it's not seeing a big cost jump because of this, Churay said.

Sample Marcellus Transactions/Acre

Announced	Buyer	Seller	Value ($MM)	Net Acreage	$/Acre
Aug 2010	Reliance Industries Ltd.	Carrizo Oil & Gas Inc.	$392.0	62,600	$6,262
May 2010	Royal Dutch Shell	East Resources Inc.	$4,700	650,000	$7,230
May 2010	Williams Cos. Inc.	Alta Resources LLC	$584	42,000	$14,000
May 2010	BG Group Plc	Exco Resources Inc.	$950	93,000	$5,914
Apr 2010	Reliance Industries Ltd.	Atlas Energy Inc.	$1,700	120,000	$14,100
Mar 2010	Consol Energy Inc.	Dominion Resources Inc.	$3,475	491,000	$4,000
Feb 2010	Mitsui & Co. Ltd.	Anadarko Petroleum Corp.	$1,400	100,000	$14,000
Dec 2009	Ultra Petroleum Corp.	NCL Appalachian Partners LP	$400	80,000	$5,000
Aug 2009	Enerplus Resources Fund	Chief Oil & Gas LLC	$406	116,000	$3,500
Nov 2008	StatoilHydro ASA	Chesapeake Energy Corp.	$3,375	585,000	$5,769
Jun 2008	Antero Resources Corp.	Dominion Resources Inc.	$347	114,259	$3,037
Apr 2008	XTO Energy Inc.	Linn Energy LLC	$600	152,000	$4.13

Entry into Marcellus-shale acreage via purchase has topped $7,000/acre; via joint venture, more than $14,000. *(Source: Jefferies & Co. Inc.)*

Chevron Corp., which bought Appalachia-based independent Marcellus operator Atlas Energy Inc. earlier this year, noted the new DEP prohibition as well. It was already Atlas' and now Chevron's plan to discontinue disposal at Pennsylvania facilities by year-end 2011, said Gary Luquette, president, Chevron North American E&P Co. Like Rex, it will put wastewater into disposal wells in the future.

DeIuliis said, "More regulation, I think, is going to be the norm, to say the least. And it's going to be across a range of issues with regards to the Marcellus from water sourcing, water discharge, and standards of water discharge to where the water can be discharged and stream-crossing permit issues for pipelines and gathering lines. And just about everything in between.

"So it's coming. And we are prepared to partner with the regulatory agencies on the gas side, just like we've done historically on the coal side, and the industry is going to need to be in a position to do so as well."

Production from some of Consol's wells is being curtailed while the company waits to combine the full output potential of several wells that so fewer stream-crossing permits are needed to get production to big pipe, thus to processing and users.

Crandell said, "Despite concerns about drilling in some states — notably, New York — and a few public spats about drilling in Pennsylvania, in aggregate, drilling in the broader Marcellus should result in production growth for some time."

Stacking shales

Additional horizontal experimentation in the Appalachian gas basin is into the Upper Devonian shale, which is shallower than the Marcellus, and into the Utica, which is deeper.

Rex Energy plans a first Utica test well in July and is drilling its first horizontal test of the Upper Devonian, through which it has drilled some 20 times now to reach Marcellus. Pat McKinney, Rex executive vice president and COO, said, "Our geologists feel really good about what they're seeing as far as the (Upper Devonian) thickness and extent out there (in our core area)."

Range brought two Upper Devonian horizontals online earlier this year, picking locations more than five miles apart. The first IP'd 5.1 MMcf; the second, a constrained 2.5 MMcf, consisting of 1.9 MMcf of dry gas and 91 barrels of NGLs. The average IP was 3.8 MMcfe.

The second well has a flatter decline rate and higher EUR than the first, said Ventura. "For our first two horizontal wells in the Upper Devonian shale, we're encouraged about the results and the potential it has for unlocking the ... resource potential," he said.

It wasn't until Range's seventh Marcellus horizontal that it reached an average IP of 3.8 million, he added. Reserves in the Upper Devonian appear to be 2.5 to 3.5 Bcfe per well. "This is significantly ahead of where we were in the Marcellus at this point in time," he said.

Range plans three or so additional Upper Devonian tests this year. Early indications are that the shale will be wet where the Marcellus is wet and dry where the Marcellus is dry. Gas in place should mimic the Marcellus too in acreage where both are prospective, Ventura said.

"If, in a particular area, gas in place is 100 Bcf per section in the Marcellus, the gas in place in the Upper Devonian in aggregate would be 100 Bcf. So it about doubles what you have in that area," he said.

The company seeks more data on the Upper Devonian. "But we know we have hydrocarbon," Ventura said. "We know we have wet gas. We know it can produce commercial rates even after our first two tries."

Range's early Marcellus wells tested various lateral landing depths. A first well IP'd a discouraging 20,000 cf, but another made 1 MMcf and another made 3.6MMcf. "Now, in that same area, we're getting 10 to 15 MMcf. Our best well was 26 MMcf/d. And that's just moving where you land the well in the section and has nothing to do with lateral length or frac stages," Ventura said.

"I think the same thing will be true of Upper Devonian."

In the Utica, Range's next horizontal test will be later this year, and a third is planned for early 2012. It is expecting other operators' work on Marcellus, Upper Devonian, and Utica to further prove up its own acreage. Very few wells have been drilled to Utica, as it is deeper than Marcellus, while thousands of wells have been drilled through Upper Devonian on their way to Marcellus and other formations.

"If you go way to the east, you're going to lose the Utica (window)," Ventura said. "If you go far west, you'll lose the Marcellus and Upper Devonian." The economically productive Upper Devonian, Marcellus, and Utica appear to be stacked in southwestern Pennsylvania, the heart of the Marcellus play and Range's core area, Ventura said. "So a lot of our acreage in the southwest could have stacked pay potential in all three horizons."

Ultra Petroleum Corp. is holding off on trying the Utica. Bill Picquet, Ultra senior vice president, operations, said, "The Utica is active under our acreage. It's gas-bearing, and it's got the kind of look you like to see, but it's deep. It's 11,000 ft to probably as deep as 14,500 or 15,000 ft in the southern part. It's out there.

"(But) you need better than $4 gas to make the Utica."

EQT Corp. has drilled one Upper Devonian in western Virginia and will drill one this year in southwestern Pennsylvania. Otherwise, said Conti, "Our plans for the Utica right now are to sit tight and watch what our competitors are doing and, if that ends up being the next big thing, we'll be right there with them."

Marcellus Moves to Prime Time

An emerging play only three years ago, the Marcellus has earned a reputation as the nation's top gas shale play.

By Don Lyle
Contributing Editor

It took hundreds of millions of years for the Marcellus Shale to overcome tectonic events, geologic stress, technology challenges, and economic handicaps to take a premier position among North American shale plays.

Heavy muds and plankton dropped to the seafloor some 365 million years ago, which decayed under high pressure, and cooked into relatively impermeable pores of the resulting shale. Nature helped out some 300 million years ago. Gas under high pressure created natural fractures in the shale, and 280 million years ago, folding of the earth's crust formed a ridge and valley system in eastern Pennsylvania that caused further fracturing.

The vertically oriented pre-folding fractures lend themselves to horizontal drilling and modern multistage frac treatments.

That shale layer is shallower and thinner in Ohio but has more organic content. The thicker eastern shale contains more free gas, a hint of flush initial production and slow decline rates, according to Lash and Engelder.

The Marcellus is the lowest member of the Middle Devonian Hamilton group, which includes the Moscow, Ludlowville, and Skaneateles shales. Its thickness ranges from 25 ft to more than 100 ft in southern New York, and the shale thickens to more than 250 ft in northeastern Tioga County in Pennsylvania.

The play covers some 95,000 sq miles of economic pay in six states, according to the US Department of Energy (DOE), and 19,000 sq miles may contain economically recoverable resources.

ICF International has estimated technically recoverable reserves at 31 Tcf of gas.

Operators have taken advantage of opportunities in the Marcellus. By 2009, the West Virginia College of Business and Economics calculated that the play had created 7,600 jobs and US $2.35 billion in business in West Virginia and could potentially create almost 20,000 jobs by 2015.

An American Petroleum Institute report has estimated the contributions of the Marcellus at 280,000 jobs and $6 billion in government revenues.

The shale drew more than 800 drilling permits in 2008 and 500 permits in West Virginia in 2009 following a collapse in gas prices.

A *Pittsburgh Post Gazette* article in June 2010 said 1,985 Marcellus drilling permits had been issued in 2010 alone, and 763 wells had either been completed or were under construction in Pennsylvania.

A September 2010 report by the Energy Information Administration has credited the Marcellus, with the Haynesville and Fayetteville shales, for their strong contributions to the highest proved US gas reserves since 1971.

The economics account for that popularity. In a 2010 presentation, Range Resources revealed its results from liquids-rich Marcellus production in southwestern Pennsylvania. The company said it expected ultimate recoveries of 5 Bcfe of natural gas based on 95 wells and could drill and complete a well for $4 million. Using a gas price of $4/Mcf, the company anticipated a 60% internal rate of return, or 47% including land, gathering, pipeline, and processing costs. Using a gas price of $7/Mcf, all-in returns jumped to 105%.

Key Players

AB Resources LLC

- *Net acres: 90,000*
- *Launched Marcellus campaign in 2009*

Privately held AB Resources LLC holds more than 90,000 net acres with potential for some 3,000 Marcellus wells but considers its prime property to be in southeastern Pennsylvania and northern West Virginia, where it has potential for more than 1,000 horizontal Marcellus wells.

The company, which also operates as AB Resources Pennsylvania LLC and AB Resources Ohio Inc., had more than 25 wells permitted, drilling, or recently completed in the Marcellus as of April 2011, according to IHS Energy records. These were in Fayette, Greene, and Somerset counties in the liquids-rich portion of the play in southwestern Pennsylvania.

AB used its base of Appalachian Basin properties to launch its Marcellus campaign in early 2009, when it hired experts from companies with Marcellus experience to spearhead midstream and upstream operations.

Later that year, the company agreed to have Caiman Eastern Midstream LLC build and operate pipelines and other midstream facilities in AB's prime acreage, an agreement that gave AB rights to as much as 60,000 MMBtu of firm capacity and additional potential on a 30-mile-plus gathering system as well as capacity on a planned 120 MMcfe/d of natural gas in a cryogenic processing plant.

While the Becksville, Ohio-based company operates all of its assets, it also invites industry participants to join in its programs.

Alta Resources Co. LLC

- *Works Friendsville and Montrose areas in Susquehanna County*
- *Backed by Denham Capital*

Denham Capital-backed Alta Resources Co. works the Marcellus Shale play near Friendsville and Montrose in Susquehanna County in northeastern Pennsylvania.

In early April 2011, IHS Energy Inc. credited the company with four new-field discoveries in the play, although Alta did not report production results from its wells.

A Feb. 17, 2009, report by Denham said its backing would help Alta add 20,000 to 25,000 acres "to its extensive lease position in northeastern Pennsylvania." At that time, Alta had operations in Arkansas, Texas, Louisiana, and Alabama.

The 1H Carrar well is one example of Alta's newfield wildcat success. The company spudded the horizontal well about 7 miles north of Montrose on Nov. 29, 2009, and the well found the Lower Marcellus at a vertical depth of of 5,749 ft. Alta completed the open-hole Marcellus well on Jan. 16, 2010, from 10,068 ft to 10,088 ft total depth.

Anadarko Petroleum Corp.

- *Exited 2010 with 330 MMcf/d gross production in the play*
- *Has 6 Tcf of net risked resources on 760,000 gross acres*

From its fledgling start in 2008, Anadarko Petroleum Corp., the world's largest independent oil company, grew into a major operator in the Marcellus Shale by early 2011.

It entered a joint venture with Chesapeake Energy Co. in the play and quickly grew to boss its own operations. By April 2011, IHS Energy listed some 285 wells permitted, drilling, or recently completed by Anadarko in the Marcellus. According to the company's fourth-quarter 2010 operating report, it also doubled its Marcellus production from the previous year, exiting 2010 with a gross 330 MMcf/d of natural gas. Additional infrastructure construction helped the company achieve that production rate.

From earlier estimates that a Marcellus horizontal well would ultimately produce between 4 Bcfe and 6 Bcfe, it raised its projection to the high end of that range.

Anadarko planned to run 10 or more drilling rigs in the play during 2011 to drill approximately 250 wells.

The company's current operations are in Centre, Clinton, and Lycoming counties in Pennsylvania, and due to its proximity to major gas markets in the East, the Marcellus will be the only dry-gas play funded for exploration in 2011.

Anadarko also increased its production potential when it signed a joint-venture agreement with Japan's Mitsui & Co. Ltd. Mitsui entered the Marcellus with a 32.5% interest in Anadarko's operations in central Pennsylvania for $1.4 billion. Via its newly formed subsidiary, Mitsui E&P USA LLC, the company will earn some 100,000 net acres by funding 100% of Anadarko's 2010 development costs in the Marcellus and 90% through 2013.

According to a March 2011 presentation, Anadarko had more than 6 Tcf of net risked resources in the Marcellus from a gross 760,000 acres (260,000 net) in the play.

Antero Resources Corp.

- *Increased holdings to 171,000 acres*
- *97% of 2010 production from 37 horizontal wells*

Antero Resources Corp. gained its foothold in the Marcellus play in West Virginia and Pennsylvania through a preliminary deal with Dominion Resources that gave the company 205,000 acres of lease rights in mid-2008.

That deal shrank to 114,259 acres for $347 million by November 2008 as the recession put a stranglehold on profit potential. By the end of March 2011, however, the company increased its holdings to 171,000 acres, of which only 8% was considered to be proved.

At the end of 2010, Antero was operating five rigs in the play, all in northern West Virginia, according to the company's first-quarter 2011 report. Production stood at a gross 143 MMcf/d of natural gas (106 MMcf/d net) at year end, 97% of which was from 37 horizontal wells.

Antero expected to add another 30 MMcf/d of deliverability with the completion of the Jarvisville Lateral, an extension of the Bobcat Lateral pipeline, and an additional 46 MMcf/d of compression capacity.

For 2011, Antero said it would devote 73% of its $559 million capital budget to the Marcellus Shale and would continue to operate five rigs in the play.

Cabot Oil & Gas Corp.

- *Net acres: 200,000*
- *Drilled first commercial gas well in Susquehanna County*

Cabot Oil & Gas Corp., with unconventional properties throughout the country, places the Marcellus Shale at the top of its list.

High returns tell the tale. Using a $5/MMBtu gas price, Cabot expects an internal rate of return in excess of 100%. Comparatively, the company found that the best return from any other play in the nation was 90% from the Bakken Shale at $90 oil, according to public internal return reports. "Our Marcellus gas play competes with all the best oil plays," the company concluded in a March 2011 presentation.

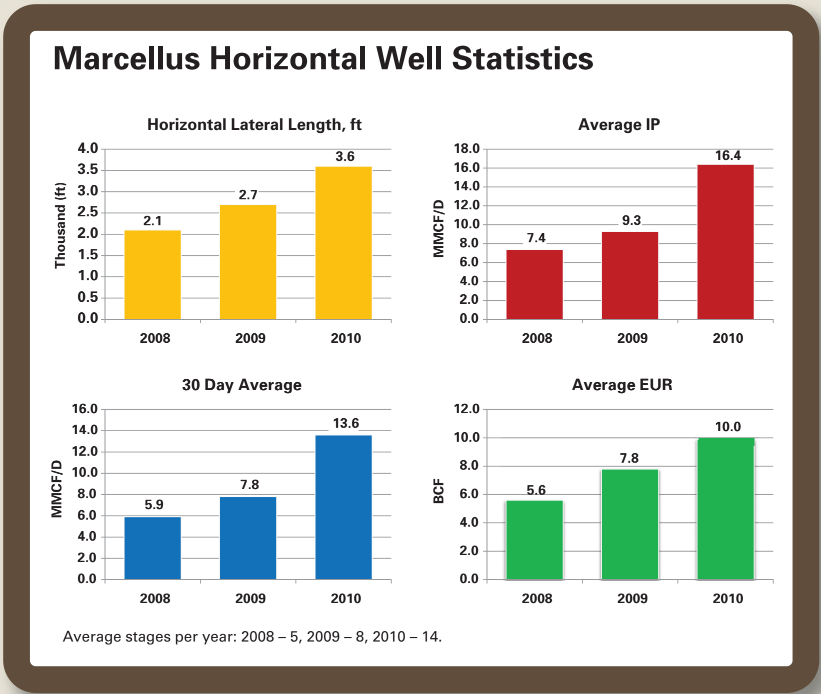
In the same presentation, Cabot said average estimated ultimate recoveries rose from 7.8 Bcf of natural gas per horizontal well in 2009 to 10 Bcf in 2010. The company now holds 200,000 net acres of Marcellus land in Susquehanna County, Pa., up from 160,000 net acres two years earlier.

Cabot's operations are concentrated in Susquehanna County, where it had 200 wells permitted, drilling, or recently completed in April 2011, and only 19 wells in six counties in West Virginia, according to IHS Inc.

For 2011, it planned to invest most of its $600 million capital budget in the Marcellus and in the Eagle Ford Shale in South Texas.

Cabot's record in Pennsylvania speaks to the company's competence and history. It drilled the first commercial gas well and the first horizontal well in Susquehanna County. The company has drilled seven of the top 10 producing wells in Pennsylvania, and it also drilled the first well fractured with 100% recycled water in the state. Cabot recycles 100% of its flowback and, in 2010, converted to rigs that use closed-loop systems to handle its cuttings to minimize the amount of wastewater generated.

Between 2008 and 2010, its average horizontal laterals grew from 2,100 ft to 3,600 ft. Initial well potentials rose from 7.4 MMcf/d to 16.4 MMcf/d, and initial 30-day average production climbed from 5.9 MMcf/d to 13.6 MMcf/d. Average frac stages increased from five to 14 in the same period.



The Marcellus responded favorably to learning-curve improvements for Cabot's properties. *(Graph courtesy of Cabot Oil & Gas Corp.)*

For 2011, the company plans to keep five rigs and one frac crew working to drill 51 horizontal and three vertical wells. That level of activity should increase its Susquehanna County production from 300 MMcf/d in March 2011 to about 420 MMcf/d by the end of October.

To handle increased production, Cabot planned to raise takeaway capacity from 550 MMcf/d in May 2011 to 1.2 Bcf/d by adding gathering and pipeline capacity and compression.

Carrizo Oil & Gas Co.

- *Net acres: 118,000*
- *JVs with Avista and Reliance*

Carrizo Oil & Gas Co. maintains its commitment to its major operations in the Barnett and Eagle Ford shales, but its Marcellus properties in Appalachia hold a high position on the company's priority list as it moves from property acquisition to development.

By April 2011, the company had accumulated more than 118,000 net prospective acres in the formation in New York, Pennsylvania, and West Virginia. Much of its activity is tied to joint ventures with Avista Capital Partners and Reliance Industries Ltd.

Carrizo previously held 143,000 gross acres in the Avista joint venture, mostly in New York and Virginia. Avista contributed cash and capital to form a 50-50 joint venture. Avista later sold 57,700 acres to Reliance.

The Reliance joint venture covers 115,000 aces in Pennsylvania, where Carrizo is the operator with a 40% interest.

In an April presentation, the company said it planned to keep two rigs running in the Marcellus on its Pennsylvania properties in the Reliance joint venture. It raised its drilling budget in the play from $8 million in 2010 to $41 million in 2011 as it dropped planned acquisition spending from $37 million to $3 million. In its year-end 2010 report, Carrizo said it held 3 Bcfe of natural gas in proved reserves in the play and had one rig running in Susquehanna County and one rig running in Wyoming County, both in Pennsylvania.

According to the presentation, Carrizo said an average well cost $2.8 million to drill, and the company had found net reserves of 6.2 Bcf at a cost of 62 cents/Mcf. Those figures delivered a 27% rate of return using a Nymex gas price of $4/MMBtu.

Chesapeake Energy Corp.

- *Runs 32 rigs in the Marcellus*
- *Brought in Statoil as a partner*

Despite plans to adjust production toward liquids, Chesapeake Energy Corp. remains by far the most active driller in the Marcellus Shale. Out of its 156 operated rigs in the US, Chesapeake currently has 32 rigs running in the play.

The company held 16.5 Tcfe of proved reserves at the end of first-quarter 2011, of which 956 Bcfe is from the Marcellus. Of the company's 289 Tcfe of unrisked, unproved resource potential, 96 Tcfe, or approximately one-third, is in the Marcellus. In addition, 1.73 million of its 14.3 million net acres and 290 MMcfe/d of its 3 Bcfe/d average daily production in April 2011 was in the popular Appalachian Basin formation.

As it has in other areas of the country, Chesapeake

Dense woods frame many of the well sites in the Marcellus fairway in Pennsylvania and West Virginia. *(Photo courtesy of Chesapeake Energy Corp.)*

brought in a partner to help with development costs. Statoil bought into the Marcellus play in November 2008 for a 32.5% interest in 585,000 acres. It paid $1.2 billion up front and is carrying Chesapeake drilling costs up to $1.45 billion. Upside includes more than 21,000 unrisked net undrilled wells.

According to IHS Inc. records, Chesapeake had permitted, was drilling, or had recently completed 1,115 wells in 11 Pennsylvania counties and a further 172 wells in 11 West Virginia counties by mid-April 2011.

Chief Oil & Gas LLC

- *Drilled first Marcellus well in 2007*
- *Sold 228,000 net acres to Chevron*

Chief Oil & Gas LLC, one of the biggest and earliest operators in the Barnett Shale play, is following up with a similar path to success in the Marcellus Shale.

Chief drilled its first well in the Marcellus in 2007 in Lycoming County, Pa., later drilling four more wells by year end. By the end of March 2011, the company had grown its position to 131 wells with nine rigs working on more than 353,000 acres. Those properties were in Pennsylvania, West Virginia, and Maryland. The company has applied for two drilling permits near Friendsville in Garret County, Md., but officials in that non-producing state currently are working on oil and gas regulations.

Chief reached a production milestone of 100 MMcfe/d of natural gas in November 2010.

In May 2011, it sold 228,000 net acres to Chevron Corp. for an undisclosed price. The sale left Chief with 125,000 net acres in the play in Bradford, Susquehanna, Tioga, Sullivan, and Wyoming counties in northeastern Pennsylvania.

Following the sale, the company planned to exit 2011 operating three rigs on its Marcellus properties in addition to its non-operated interests.

Chief also took a leading role in community relations, conducting some 200 facilities tours. In November 2010, the company established closed-loop drilling on all of its new wells. It was one of a number of companies to publicly reveal the makeup of its fracturing treatments and has recycled flowback water from wells.

Chief has invited partners into its Marcellus operations to share costs. In August 2009, the company signed a joint development agreement

The Barto compressor station in Lycoming County, Pa., keeps Marcellus gas moving to markets. *(Photo courtesy of Chief Oil & Gas Co.)*

with Enerplus Resources Fund in which Chief and the Tug Hill Inc. investment firm sold 30% of their combined Marcellus interests for $406 million in cash and a 50% carry on drilling and completion costs. Chief, which had drilled 31 wells by that time, continued as operator, producing 8.7 MMcfe/d from 552,000 gross acres.

In December 2010, Chief and Radler 2000 Ltd. Partnership sold approximately 50,000 net acres with 15 producing wells and another 11 wells awaiting completion to EXCO Resources Inc. for $459 million.

Citrus Energy Corp.

- *Opened Wyoming County to Marcellus production*
- *Holds interests in 25,000 gross acres*

Castle Rock, Colo.-based Citrus Energy Corp. has grown with the help of property acquisitions and drilling programs since its formation in 1989. Lately, the company has turned its attention to the Marcellus Shale play in Pennsylvania.

The company had three wells in Columbia County and 24 wells in Wyoming County, both in Pennsylvania as of April 2011, according to IHS Inc. These wells were either permitted, drilling, or recently completed wells.

Citrus holds interests in 25,000 gross acres of leases in Armstrong, Clarion, and Wyoming counties in Pennsylvania and opened Wyoming County to Marcellus production for the industry in June 2010.

The company planned to drill 20 wells in 2011 and 2012.

Citrus' acreage is located near pipelines and has been high-graded with seismic analysis. It has water use permits for its wells, and more than 90% of its acreage is geologically drillable, according to public records.

It also is trying to recycle 100% of the water used in its operations.

CONSOL Energy Inc.

- *Has rights to 750,000 Marcellus acres*
- *Acquired 100% of Marcellus operator CNX*

CONSOL Energy Inc. grew to be the leading gas producer in the eastern US with a big boost from its coal, coalbed methane, and gas well operations, and its future gas production is fixed on Marcellus Shale operations.

A bare hilltop provides the stage for a Marcellus fracture treatment. *(Photos courtesy of CONSOL Energy Inc.)*

Coal operations helped establish the land base, and 4,000 coalbed methane and 9,000 conventional wells provided production and experience. That background "has positioned us to maximize production in the 750,000 acres of Marcellus Shale for which we currently have the rights," the company said on its website.

The company's Marcellus operations started with its 83.3% ownership in CNX Gas. With a foundation of CONSOL land, CNX had 186,000 net acres prospective for the Marcellus and 15.7 MMcfe/d of natural gas production from five horizontal wells in the play by April 2009.

A year later, CONSOL paid $3.475 billion for the Appalachian exploration and production business of Dominion Resources Inc., a purchase that added 1 Tcf of proved reserves and 41 Bcf of annual production and tripled the company's Marcellus properties to approximately 750,000 acres.

Sand used to prop open fractures mixes with frac liquids at a Marcellus completion site.

In June 2010, CONSOL completed its acquisition of the remaining interest in CNX it did not already own and closed trading in CNX stock.

By year-end 2010, CONSOL held 752,336 net acres of Marcellus properties with a low-end potential resource of 20.3 Tcfe and a high-end estimate of 40.5 Tcfe.

Its proved developed Marcellus reserves had grown to 140 Bcfe and proved undeveloped reserves to 719 Bcfe. Total proved, probable, and possible reserves reached 3.9 Tcfe.

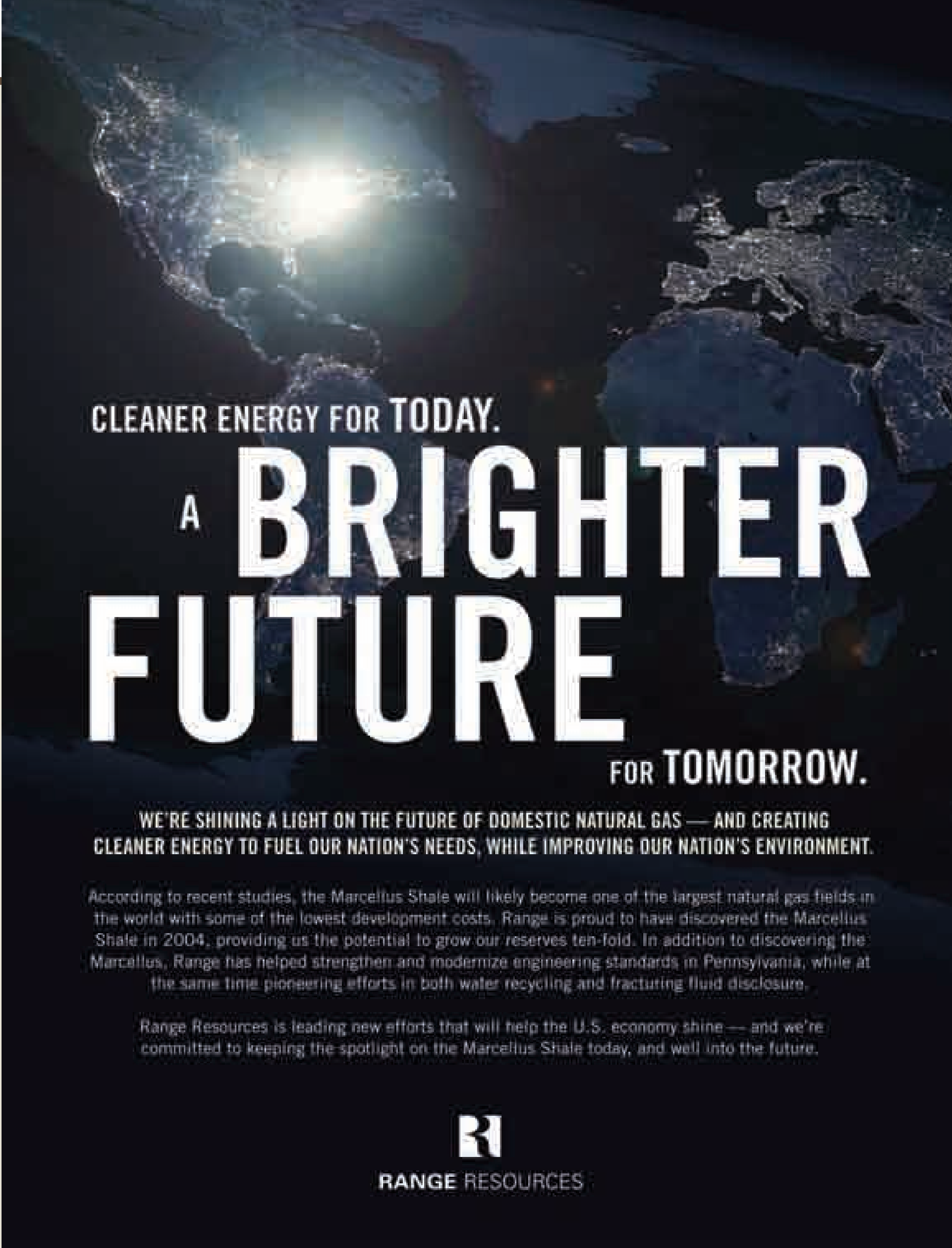
At that time, CONSOL said it expected to drill 70 horizontal wells in the Marcellus during 2011, up from 24 in 2010.

By the end of first-quarter 2011, the company was ahead of schedule with 13 horizontal wells drilled to the formation – seven in southwestern Pennsylvania, four in central Pennsylvania, and two in northern West Virginia. It had four rigs working the Marcellus and Utica shales.

Energy Corp. of America

- *Marcellus activity began in the late 1970s*
- *Estimates 1 Tcfe of recoverable resources in Green County*

Energy Corp. of America operates in Appalachia under its own name and that of its wholly owned subsidiary Eastern American Energy Corp., a history that goes back more than 45 years.


CLEANER ENERGY FOR TODAY.
A BRIGHTER FUTURE
FOR TOMORROW.
WE'RE SHINING A LIGHT ON THE FUTURE OF DOMESTIC NATURAL GAS — AND CREATING CLEANER ENERGY TO FUEL OUR NATION'S NEEDS, WHILE IMPROVING OUR NATION'S ENVIRONMENT.
According to recent studies, the Marcellus Shale will likely become one of the largest natural gas fields in the world with some of the lowest development costs. Range is proud to have discovered the Marcellus Shale in 2004, providing us the potential to grow our reserves ten-fold. In addition to discovering the Marcellus, Range has helped strengthen and modernize engineering standards in Pennsylvania, while at the same time pioneering efforts in both water recycling and fracturing fluid disclosure.
Range Resources is leading new efforts that will help the U.S. economy shine — and we're committed to keeping the spotlight on the Marcellus Shale today, and well into the future.
RANGE RESOURCES

Trucks line up for a horizontal well fracture treatment in the Marcellus Shale. *(Photo courtesy of Energy Corp. of America)*

Its Marcellus operations began in the late 1970s as the company investigated the shale in a cooperative program under the DOE.

It started working the play seriously in 2005 and accelerated its activity in 2009. By that time it had drilled 155 Marcellus wells.

Although the company and its subsidiary have drilled in both Clearfield and Greene counties in Pennsylvania, the focus clearly has been in Greene County, where IHS Inc. listed Energy Corp. with 20 wells and Eastern American with 43 wells permitted, drilling, or recently completed in mid-April 2011. In May 2009, Energy Corp. said it planned to drill 75 Marcellus horizontal wells over the next three years and estimated it had 1 Tcfe of recoverable resources in Green County alone.

The combined companies also are active in Logan, Upshur, and Webster counties in West Virginia.

Energy Corp. is dedicated to being a zero-discharge company as it has recycled nearly 100% of its liquids.

In July 2010 the company established the ECA Marcellus Trust I and raised $176 million. That trust has 14 producing horizontal Marcellus Shale wells and plans to drill 52 horizontal wells over the next four years, all in Greene County, according to an October 2010 article in *Oil and Gas Investor* magazine.

Enerplus Corp.

- *Entered play in 2009 with Chief/Tug Hill JV*
- *Expects 45 MMcfe/d of 2011 net production*

Enerplus Corp., which started business in 1986 as Enerplus Resources Fund, Canada's first oil and gas royalty trust, entered the Marcellus in a big way with major purchases in 2009 and 2011. The play now holds top ranking as the company's largest natural gas investment opportunity.

In 2009, Enerplus paid $411 million for a 21.5% working interest in 540,000 gross acres in the Marcellus from Chief Oil & Gas and investment company Tug Hill Inc., with Chief retaining operatorship.

The following year, Enerplus added another 75,317 net acres in Pennsylvania; West Virginia; and Garrett County, Md., for $169.3 million. It operates 70,833 of those acres.

According to Enerplus, Chief drilled 60 gross wells (11.7 net to Enerplus) in 2010. Enerplus participated in another 62 gross wells (1.9 net) with other operators. It had planned to tie in 67 gross wells through 2010, but shortages of pipeline infrastructure and frac crew availability limited the tie-ins to 38. In spite of the limitations, Enerplus finished the year with average gross daily production of natural gas at 91 MMcfe/d (18 MMcfe/d net), with another 120 MMcfe/d to 140

MMcfe/d awaiting completion or tie in. The company had an average 20% working interest in the additional production potential.

Also at year-end 2010, an independent engineering report by Haas credited the company with 52.4 Bcfe of proved reserves and 117.2 Bcfe of proved and probable reserves in the Marcellus, up 370% from the end of 2009. It also had 3.9 Tcfe of best-estimate contingent resources.

Enerplus planned to invest $160 million in the Marcellus in 2011 out of a planned total natural gas budget of $320 million, and the company expects to exit the year with 45 MMcfe/d of net production. A fourth of that investment will be directed toward liquids-rich production in Pennsylvania and West Virginia, while 30% will be aimed at delineation activity to maintain leases and identify drilling potential. Some 45% of the outlay will go to development drilling on areas with estimated ultimate recoveries of 4.5 Bcfe to 5.5 Bcfe per well.

In a January presentation to analysts, the company said it held some 200,000 net acres of land in Pennsylvania, West Virginia, and Maryland and planned to drill 27 net wells in 2011.

Using a Nymex gas price of $5/MMBtu and 5 Bcf of ultimate recovery per well, it expected a 26% internal rate of return, payout in 3.4 years, and a net present value – discounted at 12% a year – of $2.37 million per well.

EnerVest Ltd.

- *One of the top Appalachia producers in 2008*
- *Farmed out 9,500 net acres to PetroEdge*

EnerVest Ltd. and its EV Energy Partnerships LP affiliate (EVEP) held some 12,000 wells across the US and was one of the top producers in Appalachia in 2008, largely from formations shallower than the Marcellus. The well count has grown, and the company is actively dealing in its Marcellus interests.

In 2008, EnerVest had interests with Marcellus potential in Ohio and West Virginia through EVEP and was just beginning to evaluate its Marcellus-prospective properties. At that time, EnerVest had some 250,000 acres held by shallower production but with potential for Marcellus development, and EVEP had another 35,000 acres with Marcellus potential.

In 2008, EnerVest felt the Marcellus was not an ideal investment for a master limited partnership because of the capital-intensive investment required for such a resource play, but it decided to participate while others made the investment.

In December 2009, the parent and its affiliate announced an agreement with PetroEdge Energy LLC. In the deal, PetroEdge gained access to 9,500 net acres (7,760 from EVEP) in Harrison, Marion, Doddridge, Barbour, Upshur, and Randolph counties in north-central West Virginia.

PetroEdge agreed to earn a 75% working interest in the acreage on each well it drilled and completed and a 75% interest in the total acreage if it spent $33 million on drilling and related activity in four years.

EverVest and EVEP retained their proportionate shares of the 25% working interest, and each retained net revenue interests in excess of 82% on their acreage.

EVEP continued to hold some 27,000 net acres with Marcellus potential, most of it in West Virginia.

EOG Resources Inc.

- *Net acres: 210,000*
- *Continues to market Marcellus properties*

Although committed to developing its liquids plays, EOG Resources Inc. holds a strong position in the Marcellus Shale in Pennsylvania and is actively developing good wells.

Among its principal liquids plays, EOG is active in the Bakken/Three Forks, the Eagle Ford, the Barnett Combo, and the Leonard Avalon. Its two major gas plays are the Haynesville/Bossier and the Marcellus.

According to the company's 2010 annual report, it has 210,000 net acres in the Marcellus with 3.3 Tcf of potentially producible resource, all in Pennsylvania. It holds a half interest with a net 160,000 acres in Elk and Clearfield counties and 100% of its 50,000 acres in Bradford County.

Bradford County produced the company's best well through February 2011. The Hoppaugh 3H well tested for an initial potential of 14 MMcf/d of natural gas. At least one well in Clearfield County tested for more than 9 MMcf/d.

During 2010, the company completed its infrastructure requirements in Pennsylvania. That allowed it to finish the year with 40 MMcfg/d of gross production (20 MMcfg/d net).

For 2011, EOG planned to drill 45 gross wells (30 net).

At press time, the company was willing to make a deal for its Marcellus properties. In November 2010, EOG planned to sell 50,000 acres with production of 7 MMcf/d in Bradford County to Newfield Exploration Co. for $405 million. The companies canceled the deal the following month.

In January 2011, Seneca Resources Corp., a subsidiary of National Fuel Gas Co., bought EOG's interest in properties producing from the Marcellus in Tioga County, Pa., for $23 million. Seneca already operated the properties under a joint venture signed with EOG in 2006.

Epsilon Energy Ltd.

- *More than 130 net horizontal locations*
- *Farmed out 50% stake to Chesapeake*

Ontario-based Epsilon Energy Ltd. has grown from an initial well in the Marcellus play in 2007 into a solid operator with a major joint venture on its Pennsylvania properties three years later.

In an April 2011 presentation, the company said it held 38,800 gross acres (18,450 net) prospective for the Marcellus shale and a drilling inventory of more than 130 net horizontal locations. It was producing 7 MMcf/d, all in Pennsylvania.

In February 2010, Epsilon farmed out a 50% interest in 11,500 gross acres (5,250 net) in Susquehanna County, Pa., to Chesapeake Energy Corp. for $100 million. Chesapeake operates the properties, which hold proved reserves of 8.64 Bcf of natural gas and 14.1 Bcf in probable reserves. The companies could drill more than 43 horizontal wells on the property.

Chesapeake paid $5 million in cash up front and will carry the first $95 million of Epsilon's 50% share of leasehold, drilling, completing, equipping, and gathering costs through August 2012. By April 2011, Chesapeake had drilled 18 farmout wells, with two completed and awaiting pipeline connection.

Epsilon also held 27,300 gross acres (12,695 net) in the Marcellus Shale in New York, where it is the operator with a 47% interest. The properties have 100 MMcf of proved gas reserves with more than 90 potential drilling locations.

The company drilled four wells on the New York properties in first-quarter 2010 and is waiting for fracture equipment.

EQT Corp.

- *Estimates total Marcellus resource potential at 20 Tcfe*
- *Drilled 90 horizontal wells in the play in 2010*

EQT Corp., already one of the biggest gas producers in Appalachia, used the Marcellus Shale to significantly increase the company's production, reserves, and prospects.

At year-end 2008, EQT had just begun working its 400,000 acres, containing an estimated 900 Bcfe of natural gas, in the Marcellus. The company counted an unrisked reserve potential in the play between 6.9 Tcfe and 9.9 Tcfe. It planned to drill 40 to 45 wells on its 460 Marcellus locations in southeastern Pennsylvania and northern West Virginia at an average cost of $4 million per well, targeting an estimated recovery of 3.2 Bcfe per well.

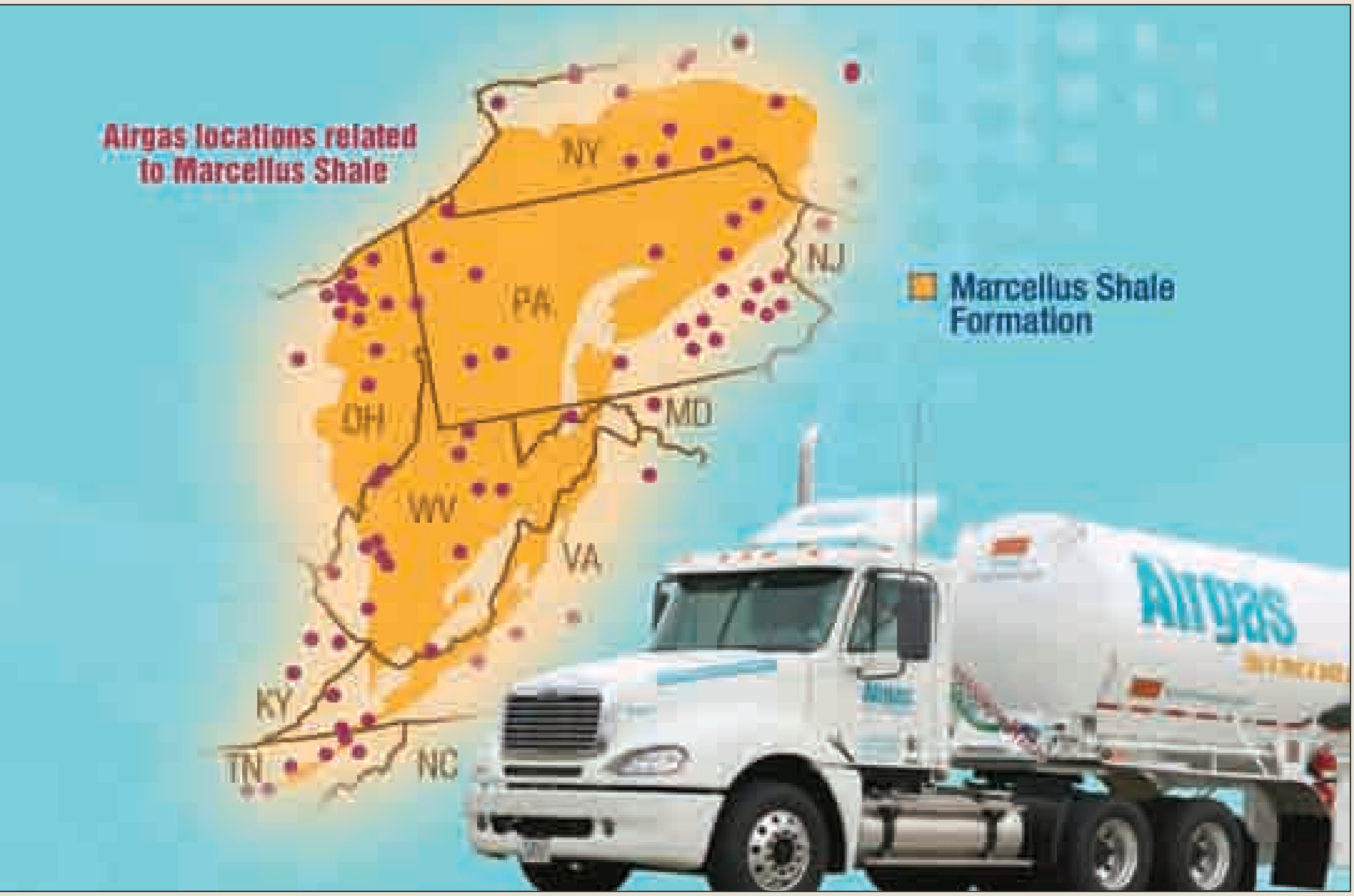
By the end of 2010, the Marcellus had grown to 577 Bcfe in proved developed reserves, 2.3 Tcfe in proved undeveloped reserves, 4.2 Tcfe in probable reserves, and 5.2 Tcfe in possible reserves for a proved, probable, and possible (3P) total of 12.2 Tcfe. That was a significant gain from nearly 4 Tcfe a year earlier and more than its Huron and coalbed methane estimates combined.

EQT also estimated a total Marcellus resource potential on its properties at 20 Tcfe.

Well performance had improved as well.

Daily sales from the company's Marcellus wells reached 142 MMcf/d at year-end 2010, and EQT expected that number to climb to 250 MMcf/d by the end of 2011.

EQT drilled 90 horizontal wells in the Marcellus Shale in 2010 with an average pay zone of 3,735 ft. The company has planned 86 Marcellus wells in 2011 with an average length of 4,200 ft at a cost of $413 million. It also has planned to spend $94 million to expand its Equitrans Pipeline system and $69 million to expand its Marcellus gathering system to handle additional production from the play.



The company's first-quarter 2011 report said Marcellus horizontal wells drove sales to 43 Bcfe, up 43% from first-quarter 2010 and 11% higher than fourth-quarter 2010. Marcellus wells accounted for 37% of EQT's total gas sales in first-quarter 2011, up from 13% a year earlier.

Daily sales in first-quarter 2011 averaged 178 MMcf/d. That figure is expected to climb to 280 MMcf/d by the end of the year, according to EQT, providing total sales of 180 Bcfe for the year – 34% higher than the previous year.

EQT drills its wells on pads. In addition to saving space, the ability to skid the drilling rig on the pad reduces mobilization costs from $200,000 to only about $20,000. It also drills "fishhook" lateral wells in which the wellbores cross during the bend to horizontal. That design picks up 1,150 ft of net pay lost in the space between bends in conventional opposing horizontal wellbores.

EQT also drills through the upper section of the Marcellus, through the Purcell and Cherry Valley limes and into the lower Marcellus. Those techniques have more than doubled well productivity since 2008, the company said in a March 2011 presentation.

That presentation also noted the company drilled the two best Marcellus wells in the industry in 2010 from its Greene County, Pa., properties. The 590036 Phillips well tested 23 MMcfe/d, and the 5900834 Cooper well tested 22.1 MMcfe/d.

Overall, EQT earns a 78% after-tax internal rate of return from its Marcellus wells at a Nymex price of $5/MMBtu.

EXCO Resources Inc.

- *Entered Appalachian venture with BG*
- *140,000 net acres with Marcellus production potential*

EXCO Resources Inc. set a growth path in Appalachia in 2004 with acquisitions designed to make it a major force of production in the area. The company now holds a substantial position in the Marcellus Shale play.

The company acquired North Coast Energy in 2004 for $225 million and added properties from EOG Resources Inc. in central Pennsylvania for $395 million in 2008. In 2010, it entered a joint venture for upstream and midstream Marcellus and Huron properties in Appalachia with BG Group plc.

EXCO focused on evaluating its Marcellus acreage in 2009 and continued through 2010. About 60% of that fairway already was held by shallower production. With the announcement of the BG venture, the company also planned to assemble more acreage in the basin.

Under that agreement, BG paid $800 million in cash and agreed to spend $150 million in capital development in the Marcellus in exchange for membership interests in companies that held half of EXCO's Appalachian assets, including more than 5,000 potential Marcellus drilling locations. The $150 million carry includes 75% of EXCO's development costs, most likely through 2012.

In December 2010, Chief Oil & Gas and Radler 2000 Ltd. sold 15 producing wells, 11 wells awaiting completion, and some 50,000 net acres of Marcellus land, primarily in Lycoming, Sullivan, and Columbia counties in Pennsylvania, to EXCO for approximately $459 million.

By 2011, EXCO had properties in 23 Pennsylvania counties and 29 West Virginia counties.

According to its fourth-quarter 2010 report, EXCO's Appalachian properties held 200 Bcfe of proved reserves and 400 Bcfe of proved, probable, and possible reserves. The company held 815,000 gross acres (379,000 net) in the basin, of which 140,000 net acres had Marcellus production potential.

Moving into 2011, EXCO had improved its understanding of the Marcellus Shale, including the size and breadth of the play, core areas, and the regulatory requirements. The company's large held-by-production acreage gave it time to plan for development, and EXCO began implementing appraisal and development plans and the infrastructure it needed.

Of the $976 million capital budget planned for 2011, EXCO has allocated $82 million for exploration, drilling and completion costs, field operations, land acquisition, and seismic analysis in Appalachia.

Exxon Mobil Corp.

- *$41B blockbuster deal in the Marcellus*
- *XTO acquisition added 60 Tcfe to resource base*

Exxon Mobil Corp., the largest publicly owned energy company in the world, needs big plays to make perceptible moves in its financial statements, and the company has decided the Marcellus Shale is one such play.

Even before the company executed its $41 billion (including $10 billion in debt) acquisition of XTO


OILFIELD WISDOM
"NEVER ASK A
LANDMAN
WHERE YOUR PROPERTY ENDS"
Know what else is smart?
Saving time and money during your well's completion phase with Magnum Oil Tools.
Whether the job calls for composite plugs, cement retainers or MagnumDisk™ Frangible isolation subs, you can always count on Magnum to help maximize production while keeping project costs predictable.
Our purpose-driven engineering means better efficiency, reliability and results in any application. Work Smarter™ with Magnum Oil Tools, and get a level of well productivity that shows you really know your stuff.
Learn more at magnumoiltools.com
Magnum Oil Tools International, LLC
5655 Bear Lane, Suite 100
Corpus Christi, Texas 78405
361.299.6333
MAGNUM
OIL TOOLS
WORK SMARTER

Energy Inc. in June 2010, the company had taken a significant look at the play. In February 2008, ExxonMobil bought 152,000 acres with Marcellus potential from Linn Energy LLC. The supermajor then signed a joint-venture agreement with Pennsylvania General Energy in 2009 that gave it a 145,000-acre foothold in the play in Pennsylvania.

The XTO acquisition pushed ExxonMobil into the unconventional resource business in a big way. XTO's reserves at the end of 2009, when the companies announced the merger, had climbed to 14.83 Tcfe of natural gas from all the major shale plays in the US. A statement by ExxonMobil said the merger had added roughly 60 Tcfe and 5 million acres to its resource base.

Exiting first-quarter 2010, XTO said it was producing an average 2.9 Bcfe/d.

In an October 2008 presentation, XTO said it had 280,000 net acres of land in the Marcellus with the potential to produce 2 Bcfe to 4 Bcfe per well. At that time, XTO's 25 MMcfg/d in Appalachian production came from shallower zones. By May 2009, production had increased to 32 MMcfe/d.

Even then, the company planned to double overall production to 3.6 Bcfe/d, with the Marcellus playing a big part in that increase.

By May 2009, XTO had only completed five vertical wells in the Marcellus and was completing its first horizontal well. It kept one drilling rig working the play that year with plans to drill five to 10 vertical wells and 10 to 12 horizontal wells in the Marcellus from an inventory of 200 to 220 well locations with a potential 500 Bcfe in reserves.

At that time the Marcellus topped XTO's rate-of-return charts with a 70% internal rate of return at a Nymex gas price of $5/MMBtu.

In early May 2010, IHS Inc. listed XTO as having one of the most widespread Marcellus holdings in the industry with 102 wells permitted, drilling, or recently completed.

In Pennsylvania, the ExxonMobil subsidiary had one Marcellus well in Armstrong, Cambria, and Columbia counties, respectively, two wells each in Clarion and Clinton counties, four wells in Fayette County, 17 wells in Westmoreland County, 23 wells in Lycoming County, and 30 wells in Indiana County.

Its West Virginia Marcellus activity included one well in Boone, Calhoun, and Upshur counties, respectively, two wells in Barbour County, three wells in Marion County, and 13 wells in Harrison County.

Gastar Exploration Ltd.

- *Net acres: 81,200*
- *JVs with South Korea's Antinum*

Gastar Exploration Ltd. counts two core areas in its portfolio – the Deep Bossier and the Marcellus shale plays – and has started rolling on its Marcellus campaign.

The company has 81,200 net acres in the core Marcellus area. In November 2010, Gastar finalized a $70 million joint venture with an affiliate of Antinum Partners of Seoul, South Korea, to help with drilling funds. Gastar is operator of all the Marcellus interests in the joint venture.

The company estimates it now holds Marcellus properties with a net unrisked resource potential of 1.9 Tcfe to 2 Tcfe of natural gas and more than 634 potential drilling locations.

Gastar acquired an additional group of properties in December 2010 for $2.9 million. Those properties included some 62,000 net acres with Marcellus potential in northern West Virginia.

Its interests in these properties range from 50% to 100% with Gastar as operator.

Gastar, which completed its first vertical well in 2009, planned to drill its first horizontal well in May 2011.

Targeting the liquids-rich overpressured Marcellus zones, Gastar planned to drill 28 gross operated horizontal wells in 2011, according to an April 2011 presentation. Eleven of these wells were expected to be placed on production by year end at a cost of $141 million, including $19 million contributed in the joint venture. The company will drill two of those wells on its West Virginia property.

Additionally, the Antinum agreement calls for Gastar to drill a minimum of 12 horizontal wells and 2011, as well as 24 wells in 2011 and 2012, respectively.

Hall Drilling LLC

- *Private Marcellus operator with 70 wells*
- *Seeks to add 30+ new drilling sites a year*

Hall Drilling LLC, a privately held operating company based in Ellenboro, W. Va., is working with its exclusive leasing partner, Bluestone Energy Partners, on a solid campaign that emphasizes the Marcellus Shale.

IHS Inc. lists the company as having wells permitted, drilling, or recently completed in the Marcellus in Doddridge, Harrison, and Ritchie counties in West Virginia over the past 12 months. The company has 40 wells in Doddridge County, 29 in Harrison County, and one in Ritchie County.

According to Hall, it seeks to add more than 30 new drilling sites a year. Most of its activity is in north-central West Virginia, but the company also has turned its attention to Greene County, Pa. Most of the best-producing wells from the Marcellus are in Greene County.

Bluestone Energy Partners said it is looking for acreage in Barbour, Doddridge, Harrison, Lewis, Marion, Marshall, Monongalia, Preston, Randolph, Ritchie, Taylor, Tucker, Tyler, Uphsur, and Wetzel counties in northern West Virginia and in Greene County, Pa.

Hall currently operates wells at multiple formation depths; however, in the company's geographic focus area, the majority of its wells are targeting the Marcellus Shale formation, typically found between 6,800 and 8,100 ft below the surface.

Jay-Bee Oil & Gas Inc.

- *Operates in Marcellus as Jay-Bee Production Co.*
- *Biggest project was Smithton-Hunt-Sedalia Field*

Jay-Bee Oil & Gas Inc., which also operates in the Marcellus as Jay-Bee Production Co., has a string of wells in three fields in Doddridge, Tyler, and Wetzel counties in West Virginia.

According to IHS Inc. statistics, the privately held Union, NJ-based company had 25 wells permitted or drilled from 2009 through mid-April 2011.

Its biggest project was a horizontal drilling program in Smithton-Hunt-Sedalia Field with 11 permits issued in Doddridge County and another in the same field in Wetzel County.

One well in that field, the 1HD Horner, was scheduled to a total vertical depth of 8,000 ft with an additional 3,000 ft in the lateral section.

Jay-Bee appears to be furthest along in its Centerpoint Field, where it has drilled two wells, the 1HB Yeater and the 1HF Yeater. Both were projected to an 8,000 ft vertical depth before kickoff.

The 1HF well was spudded March 10, 2011, and the rig was released six days later. The company had planned a horizontal leg to 817 ft. The 1HB well was spudded March 18, 2011, and the rig was released March 23. The company had projected the lateral to 4,500 ft, but IHS estimated the total penetration of the well at 9,000 ft.

Jay-Bee also permitted three Jackson-Stringtown Field wells in Doddridge County, one in Tyler County, and two in Wetzel County. It permitted another two wells in Wallace-Folsom Field in Doddridge County.

Some of Jay-Bee's wells were permitted for the same location, which suggests the company is planning pad drilling at some of its sites.

J-W Operating Co.

- *Member of Marcellus Shale Committee, among others*
- *Holds 39,000 acres in JV with Endeavour*

J-W Operating Co. has been active in the Marcellus play for the past three years, both in drilling and in regulatory and research projects.

The company is a member of the Appalachian Shale Water Conservation and Management Committee, which includes large operators in the area. The group set up an alliance with the Gas Technology Institute to look for environmentally responsible and efficient ways to use Appalachian Basin water. It also is a member of the Marcellus Shale Committee, formed by the Independent Oil & Gas Association of Pennsylvania and the Pennsylvania Oil & Gas Association.

During 2009, J-W drilled two wells in Whippoorwill Field and abandoned one wildcat, all in Cameron County.

According to an IHS Inc. report, Endeavour International Corp., J-W's 50% partner, said the C-9H Pardee & Curtin Lumber Co. tested nearly 2.7 MMcf/d of natural gas from an unreported interval in the Marcellus. That late 2009 well was permitted to a vertical depth of 6,720 ft, with a horizontal lateral that reached total depth at an estimated 11,474 ft.

The joint-venture companies hold about 24,000 gross acres in that area, which Endeavour calls its Daniel prospect area.

According to an April 2011 presentation by Endeavour, the Daniel prospect could contain more than 200 drilling locations with 540 Bcf to 800 Bcf of recoverable gas and an ultimate potential as high as 2 Tcf. The companies drilled and cased the Pardee 12H and 13H wells in early 2011 and planned to expand a gathering system and acquire 3-D seismic data in the area.

Overall, the joint-venture companies hold 39,000 acres in the Marcellus play, with more than 300 drilling locations. Anticipated horizontal well costs are between $3 million and $4 million, and an average estimated ultimate recovery is between 3 Bcf and 4 Bcf.

Magnum Hunter Resources Corp.

- *Operates as Triad Hunter in Appalachian Basin*
- *Acquired PostRock Energy properties*

Magnum Hunter Resources Corp., operating as Triad Hunter in the Appalachian Basin, counts Appalachia as one of its core areas, along with the Bakken Shale in North Dakota and the Eagle Ford Shale in South Texas.

It holds some 2,000 wells producing from the Huron, Weir, and Marcellus formations in Ohio, Kentucky, and West Virginia, including 58,820 aces in the Marcellus play in West Virginia.

Magnum Hunter drilled its first horizontal Marcellus wells in Tyler County, W.Va. The Weese Hunter #1 well flowed at an initial rate of 7 MMcfe/d and the Weese Hunter #3 well at an initial rate of 5.5 MMcfe/d.

According to IHS Inc., the #1 well was completed using 12 frac stages with 2,350 psi of flowing tubing pressure through a $\frac{22}{64}$-in. choke. Produced gas tested at 1,225 Btu/Mcf.

Both the #1 and #3 wells were drilled from the same approximate location, and a company presentation in April 2011 showed as many as five horizontal laterals drilled from the same location.

Since the beginning of 2011, Magnum Hunter acquired the PostRock Energy properties in Wetzel and Lewis counties in West Virginia for $40 million. That gave the company eight proved developed producing wells, six developed shut-in wells, two wells behind pipe, and 15 proved undeveloped locations, with total proved Marcellus reserves of approximately 24.3 Bcfe and probable Marcellus reserves of 165.4 Bcfe on 11,378 gross acres (8,652 net).

For 2011, the company planned to spend $25 million on midstream work to support its Marcellus activity, including a 200 MMcf/d gas processing plant and 36 miles of pipe to connect its wells to sales lines.

Marathon Oil Corp.

- *Net acres: 80,000*
- *Farmed out 60,000 acres to private company*

With a world of choices, Marathon Oil Corp. decided to take a piece of the action in the Marcellus Shale play in Pennsylvania and West Virginia but lately, its active participation in the play has dimmed.

In a March 2009 presentation, Marathon said it held 30,000 net acres in the play at mid-year 2008 and was looking for more acreage. By March 2009, its position had grown to 65,000 net acres, and it subsequently grew to 80,000 net acres by 2010.

At that time, Marathon operated 70% of its acreage and estimated its potential recoverable reserves

between 1.05 Tcf to 1.5 Tcf of natural gas from 250 to 330 wells. It also planned to work two operated rigs in the play by 2010 and seven to nine rigs by 2013.

In its 2010 exploration budget, the company set aside funds for 20 to 30 wells in its three shale plays in the US – the Marcellus, the Woodford, and the Haynesville/Bossier.

By fourth-quarter 2010, mention of the Marcellus had dropped from the company's quarterly and year-end report, and the play was not mentioned in its 2011 capital spending plans.

Marathon's 2010 Fact Book, however, said the company held approximately 150 MMboe of net resource potential on its 80,000 net acres and had drilled seven operated wells and participated in two non-operated wells in 2009 and 2010.

It also said 2011 activity would focus on southwestern Pennsylvania and northeastern West Virginia.

In February 2011, Marathon entered a joint venture with an undisclosed company that would allow the guest company to farm in to 60,000 Marcellus acres controlled by Marathon and earn a 50% stake in the properties.

The private company also had an option to acquire Marathon's remaining acreage.

Mountain V Oil & Gas Inc.

- *Private company with 30,000 proven Marcellus acres*
- *Specializes in small well programs*

Privately owned Mountain V Oil & Gas Inc. specializes in small well programs with an emphasis on West Virginia but also has production in Pennsylvania.

The Bridgeport, Pa.-based company was founded in 1994 and holds 30,000 proven acres in the two states prospective for the Marcellus shale. Mountain V works as far north as Harrison and Doddridge counties and as far south as Logan and Kanawha counties in West Virginia and in Westmoreland, Washington, and Greene counties in southeastern Pennsylvania.

IHS Inc. listed the company with 16 wells vertical completed on its properties between 2008 and 2010. Mountain V has one completion and one abandoned location in Washington County, Pa. The completed field extension well, the 2-P229 Cecil well in Daniels Run Field, was completed in February 2010, producing 431 Mcf/d of natural gas from the Marcellus between 7,494 ft and 7,528 ft.

In Lewis County, W.Va., the 1/ECA McLaughlin development well was completed in Aspinall-Finster Field in the Marcellus in January 2008 and produced a cumulative 242 bbl of condensate and 13.9 MMcf.

According to IHS, the latest completed vertical well in mid-April 2011 was the 1 Harmon Helmick well in Upshur County, W.Va. Targeting the Marcellus at 7,350 ft, Mountain V began drilling Sept. 10, 2010, and intersected the Onandaga Lime at 7,104 ft. The company then completed the well in the Marcellus Oct. 11, 2010, testing 336 Mcf/d after a fracture treatment from perforations between 7,060 ft and 7,090 ft.

National Fuel Gas Co.

- *Expanded land holding to 745,000 acres in 2011*
- *Operating subsidiary JVs with EOG Resources*

National Fuel Gas Co., via subsidiary Seneca Resources Corp., accelerated its Marcellus Shale drilling campaign early in 2011.

Seneca already held some 720,000 acres of mineral rights in western New York and northwestern Pennsylvania, where it was the most active driller in 2007, but it had no Marcellus production at that time. By 2011, it added significant Marcellus production and expanded its land holding to 745,000 acres.

The company turned over its Marcellus properties to EOG Resources in a joint venture in 2006. EOG carried Seneca at a cost of $1.5 million per well on at least 10 wells in 2007, the first year of activity, to earn a 50% interest in up to 200,000 Seneca acres. EOG planned 18 wells in 2008 and at least 10 more in 2009, with Seneca contributing $50 million to the campaign.

Seneca also drilled on its own properties, completing its third vertical Marcellus well in Tioga County, Pa., in April 2009, and brought in a heavy-duty rig capable of drilling horizontal wells. At that time, Seneca President Matthew D. Cabell said the company had planned more than 100 horizontal wells in the Marcellus Shale play over the next several years. Meanwhile, the parent company had begun expanding its pipeline and gas processing system in the area.

In January 2010, Seneca said it planned to sell its Gulf of Mexico properties for $70 million to raise funds for additional Marcellus drilling. It also said it bought acreage in Tioga County from EOG for $23 million and added 42 Bcfe of proved Marcellus reserves.

In March 2011, the company planned to produce 80 Bcfe to 100 Bcfe of natural gas from all of its properties during its 2012 fiscal year, with 58 Bcfe to 71 Bcfe of that total coming from the Marcellus Shale, up from 33 Bcfe to 37 Bcfe in 2011.

Much of its $685 million to $800 million in capital expenditures for E&P would help the company drill 115 to 140 gross horizontal wells in the Marcellus, according to the company. Seneca will operate 80 to 95 of those wells and EOG will operate the remainder.

"We are experiencing great success in our focus areas in Tioga and Clearfield counties, with net production growing from about 15 MMcf/d to more than 120 MMcf/d in the past 12 months. We are also seeing encouraging results from new drilling on our western acreage, and we expect our rapid growth to continue as we develop additional areas across our 745,000 net acres," Cabell said.

Novus Exploration LLC

- *Focuses in Tioga and Preston counties*
- *Active in the play via Novus Exploration drilling affiliate*

Novus Exploration LLC, through its Novus Exploration LLC drilling affiliate, has put together an active wildcat, field extension, and development horizontal well campaign aimed at the Marcellus Shale.

The Royse City, Texas-based independent has focused its activity in two specific areas, Tioga County, Pa., and Preston County, W.Va.

According to IHS Inc., the company had 16 wells permitted, permits reissued, wells drilling, or wells recently completed in Pennsylvania and 10 wells in the same categories in West Virginia.

IHS reported that the company's 4H Strange development well in Tioga County began drilling May 27, 2010, intercepting the Marcellus at 6,410 ft true vertical depth and reaching 11,316 ft in the horizontal leg June 26. Novus perforated the well in 12 stages from 6,450 ft to 11,267 ft and conducted slickwater fracture treatments.

Novus completed the well July 29 and tested it at 4 MMcf/d of natural gas.

The company drilled the Bevo-2H Marvin R. Morgan field extension well in an unnamed field that previously produced from the Speechley formation in Preston County, W.Va.

Novus spudded the well May 27, 2009, and tapped the Upper Marcellus at 7,927 ft and the Lower Marcellus at 8,009 ft, both true vertical depth. Turning to horizontal, the well reached a total depth of 12,010 ft in the Purcell Lime March 25, 2010.

Novus perforated the Lower Marcellus in 10 intervals from 8,542 ft to 11,910 ft and conducted fracture treatments through all the perforations.

The well was completed April 25, 2010, and tested at 3.26 MMcf/d.

Pennsylvania General Energy

- *Drilled first Marcellus well in Elk County in 2005*
- *Holds 503,000+ acres in Pennsylvania and New York*

Privately owned Pennsylvania General Energy grew from a small Warren, Pa.-based independent in 1978 to one of the more active drilling companies in the Marcellus play by 2011.

Pennsylvania General first began buying producing wells in northwestern Pennsylvania and graduated into drilling 15 to 20 wells a year, mostly in the shallower Appalachian zones, to establish a steady income base to expand operations.

Once the shallower-well program became profitable, the company started drilling deeper with the help of seismic data.

In 1988, Pennsylvania General bought 80,000 acres of Quaker State oil and gas properties in New York and Pennsylvania.

Seven years later, it bought more land and 1,200 producing oil wells and some gas wells in Pennsylvania from Pennzoil Corp.

A pioneer in the Marcellus play, Pennsylvania General drilled its first well in the formation in Elk County, Pa., in early 2005. It maintained a strong horizontal well program in the shale since that time and planned to add three new state-of-the-art drilling rigs to its operations by the end of 2011.

The company now holds more than 503,000 acres in Pennsylvania and New York, drills approximately 100 wells a year, and plans to permit more horizontal Marcellus wells on its acreage.

IHS Inc. data shows Pennsylvania General is working hard at the Marcellus in Pennsylvania. It has permitted, is drilling, or has recently completed one well in Forest County, five in Huntingdon County, 25 in Lycoming County, 14 in McKean County, and 34 in Potter County.

Penn Virginia Corp.

- *42,000 net acres in the Marcellus core*
- *Expects year-end 2011 Marcellus production of 1 Bcf*

Like many other companies in the industry, Penn Virginia Corp. reacted to the sharp drop in natural gas prices by changing its focus to oil and natural gas liquids.

In 2009, the company still approached its Marcellus properties in Appalachia with caution as it analyzed the potential of the play. By 2010, the company had made up its mind. It sold its Gulf Coast properties and suspended drilling in lower-return gas areas in East Texas and Mississippi, instead aiming its investment funds at the Eagle Ford and Granite Wash plays in Texas and the Marcellus in Pennsylvania.

In an April 2011 presentation, Penn Virginia executives said the company held 42,000 net acres in the Marcellus core, 35,000 acres in Potter and Tioga counties in the northern Pennsylvania gas section of the play, and 7,000 net acres in southwestern Pennsylvania and New York. It also held 13,000 net noncore acres, which it was trying to sell at press time.

The company also was looking for a joint-venture partner to help with its Marcellus exploration.

Penn Virginia drilled its first well in the Marcellus in 2008 but waited until early 2011 to drill its first horizontal well. In February 2011, it drilled the A-1H Risser well and spudded the A-2H Risser well, both from the same drilling pad, in north-central Potter County. It planned to have both wells plugged into a sales line by mid-year.

The company plans to drill 14 gross horizontal Marcellus wells (13 net) during 2011 with assigned capital expenditures of $80 million. For that investment it expects a 10% internal rate of return at a Henry Hub gas price of $3.48/MMBtu. That assumes an estimated ultimate recovery of 4.2 Bcf of natural gas per well at a cost of $4.5 million each.

By year-end 2011, Penn Virginia expects to report production at 1 Bcf from the Marcellus, or 2% of the corporate total.

Penn Virginia's land encompasses between 200 and 250 Marcellus drilling locations, on which the company has an 87% working interest (76% net revenue interest).

Petroleum Development Corp.

- *Formed PDC Mountaineer JV with Lime Rock*
- *Net proved reserves: 66 Bcfe*

Petroleum Development Corp., which does business as PDC Energy, started operations in Appalachia in 1969, formed a series of successful partnerships, moved its focus to the Rocky Mountains about 12 years ago, and returned part of its concentration back to Appalachia and the Marcellus Shale in 2008.

Appalachia made up only 7% of its total production in 2010, but a Marcellus campaign is expected to increase production, according to an April 2011 presentation.

PDC drilled only two vertical Marcellus wells by the end of March 2009; it had planned seven for the year. In November 2009, the company formed PDC Mountaineer LLC, a joint venture with Lime Rock Partners, to accelerate its Marcellus activity.

Under that venture, PDC contributed approximately 115,000 net acres with 55,000 acres prospective for the Marcellus Shale. The property had some 12 MMcf/d of natural gas production from all formations and 113 Bcfe of proved reserves at year-end 2008, mostly in shallower Upper Devonian sands. PDC also contributed gathering and processing facilities and 2-D and 3-D seismic data, assets valued at $158.5 million.

On its side, Lime Rock put up $45 million, and PDC took an option to receive a second contribution of $11.5 million. Lime Rock could earn a 50% interest in the joint venture with its contributions. After that, both companies would contribute equally to operations, with PDC retaining operatorship.

During 2010, the company derisked and developed leases primarily in West Virginia. It drilled six horizontal and two vertical Marcellus wells during the year and planned nine horizontal wells in 2011, all funded by Lime Rock.

By April 2011, PDC had net proved reserves of 66 Bcfe. The company produced 4.1 Bcfe in 2009, dropped to 2.6 Bcfe in 2010, and anticipated growth to 3.2 Bcfe in 2011 from all formations. PDC also had 2,142 gross operated shallower Devonian wells and 12 Marcellus wells as well as 1,500 developed Marcellus acres and 54,600 undeveloped acres in the formation. That translated to a net 167 undeveloped well locations in the Marcellus.

The company's Marcellus experience indicated an average drilling time of 23 days and an average initial production potential of 2.78 MMcf/d on horizontal wells with an average lateral length of 3,026 ft. Those wells produced estimated reserves between 3 Bcfe and 5 Bcfe, with an energy content of 1,010 to 1,050 Btu/cf.

Phillips Resources Inc.

- *Net acres: 250,000*
- *Drilled or participated in 50+ Marcellus wells*

Phillips Resources Inc. used its extensive Upper Devonian holdings as a springboard to operate an active Marcellus campaign in Pennsylvania.

The parent company, which operates through its Phillips Production Co. and Phillips Exploration Inc. affiliates, holds some 250,000 net acres of land and operates more than 4,000 Upper Devonian gas wells in Pennsylvania.

In 2010, the company produced 80 MMcfe/d of natural gas, of which 25 MMcfe/d came from the Marcellus. Overall, Phillips has drilled or participated in more than 50 horizontal or vertical Marcellus wells.

According to IHS Inc. figures, Phillips had permitted, was drilling, or had recently completed 61 wells in Pennsylvania, including two in Allegheny County, 40 in Butler County, 18 in Fayette County, and one in Westmoreland County.

IHS reported on the company's two completions in northeastern Allegheny County, the 3H and 4H Fawn Developers. Phillips drilled the wells from a common pad about 3 miles northwest of Tarentum. The 3H well, perforated from 7,238 ft to 10,400 ft at a true vertical depth of 6,620 ft, tested at an open flow rate of 3.47 MMcf/d. Phillips drilled the lateral to the west. The 4H well, drilled to the north-northwest, perforated the Marcellus Shale from 7,008 ft to 8,860 ft and tested at an open flow rate of 1.3 MMcf/d.

Phillips also has an active public relations campaign. In August 2010, the company joined the Pennsylvania

Game Commission in hosting a public tour of a Marcellus well reclamation program.

Range Resources Corp.

- *Holds 20 Tcfe-31 Tcfe of Marcellus gas resource potential*
- *Plans to double production to 400 MMcf/d in 2011*

Range Resources Corp. effectively brought the Marcellus play in Appalachia to life, beginning with an initial well in the formation and the first slickwater frac job east of the Mississippi River in 2004.

The company assembled 1.1 million net acres in the Marcellus in two areas in Pennsylvania, the southwestern wet-gas area and the northern dry-gas area.

According to an April 2011 presentation, Range now holds between 20 Tcfe and 31 Tcfe of natural gas resource potential in the Marcellus, with additional resources in the Upper Devonian and Utica shales.

Drilling and production have progressed far enough that Range plans to fully fund its Marcellus properties in 2013. It plans to direct 86% of its 2011 capital budget toward the formation to help meet that target.

Range holds 550,000 net acres in the liquids-rich segment of the play, with potential for 307 MMbbl to 463 MMbbl of liquids and 13.5 Tcf to 20.5 Tcf of gas. Some 800 wells have significantly derisked 460,000 of the company's acres in the area. Assuming 80-acre spacing and that 80% of its acreage can be drilled, Range has room for 4,600 wells.

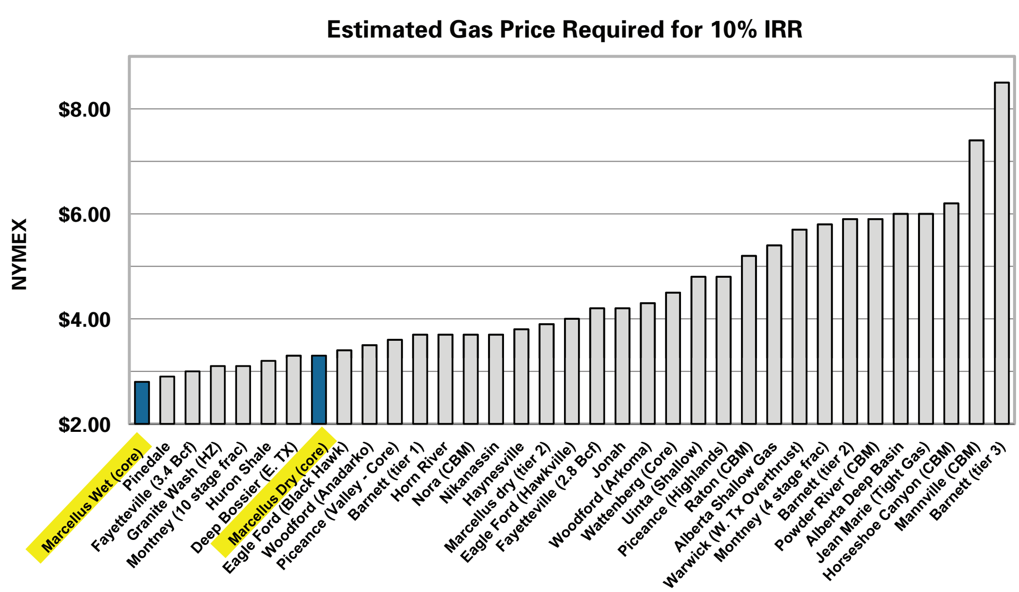
The economics are good. With an $85/bbl oil price and a $5/MMcf gas price, Range expects a 99% return on wells with a 5 Bcfe estimated ultimate recovery and a $4 million drilling and completion cost. The company's finding and development cost is 94 cent/Mcfe without land costs. With land and general and administrative costs, returns dip only to 79% and finding and development costs to 96 cent/Mcf.

Those economics provide a good reason for Range's accelerated activity from one horizontal well in 2006 to six wells in 2007 and from 47 wells in 2009 to 67 wells in 2010.

Range expects a 5 Bcfe well to produce 3.6 Bcf and 239,000 bbl of liquids.

At the end of 2010, it had 139 producing wells in southwestern Pennsylvania.

Marcellus Shale Has Best Economics



The Marcellus Shale provides some of the best rates of return of all of North America's unconventional plays.
(Source: Morgan Stanley Research Report; courtesy of Range Resources)

In the northern dry-gas segment of the play, Range permitted wells in Clearfield, Clinton, and Lycoming counties and had an area of mutual interest with Talisman Energy in eastern Bradford County. Overall, it had 240,000 net acres in the northern part of the play. The company's highest rate vertical well tested 6.3 MMcf/d, and its first two horizontal wells tested 13.6 MMcf/d and 13.3 MMcf/d, respectively.

At the time of the April presentation, Range had placed five wells on production in Lycoming County at a combined average seven-day rate of 45 MMcf/d. Another nine wells were awaiting completion, and four wells were waiting for hookups to a pipeline.

The company said that by the end of first-quarter 2011, it had four rigs running, and had produced 50 MMcf/d, and planned to triple its production by the end of the third quarter.

At year-end 2009, Range had produced 100 MMcfe/d from the Marcellus and doubled that production to more than 200 MMcfe/d by year-end 2010. It anticipates doubling production again to 400 MMcf/d by the end of 2011 and finishing 2012 with 600 MMcfe/d of production.

Rex Energy Corp.

- *Focuses on Butler County and Williams-operated JV area*
- *Holds 56,000 net acres in Pennsylvania*

Rex Energy Corp. has focused its attention on the Marcellus play in Pennsylvania over the past two years while putting together joint ventures, concentrating operations, and moving toward horizontal drilling.

The company has two distinct areas of operations – Butler County, where it operates its properties, and Clearfield, Centre, and Westmoreland, where The Williams Companies operates the properties.

Throughout Pennsylvania, Rex holds approximately 56,000 net acres. Assuming it can drill on 80-acre spacing on 75% of that acreage, the company has the potential for 525 wells and 1.3 Tcfe to 2 Tcfe of natural gas resource potential, the company said in an April presentation. That assumes ultimate recoveries between 3 Bcfe and 4.4 Bcfe per well and a 15% royalty.

In Butler County, where it operates wet-gas properties, Rex holds 47,500 gross acres (34,000 net) in a joint venture with Sumitomo. Rex is operator with a 70% interest in the joint venture, which has 385 potential drilling sites in the county plus additional production potential from deeper Utica and shallower Upper Devonian zones.

Rex will invest 65% of its $110.3 million Appalachian capital budget into its liquids-rich Butler County operations to drill 25 gross operated wells (16 net). It also plans to complete construction of a second cryogenic gas plant in the county in first-quarter 2012.

The company's five-day average production rate from four of the wells completed on its Dushel pad reached 3.7 MMcfe/d from an average horizontal section of 3,200 ft.

Rex is running two rigs in Butler County and, in mid-April 2011, still had $2.4 million in drilling carries in its venture with Sumitomo.

In its non-operated properties in Westmoreland, Clearfield, and Centre counties, Rex holds 47,000 gross acres (19,000 net) in a joint venture with Williams, which has a 50% operating stake. Rex holds 40% of that venture, and Sumitomo holds the remaining 10%. By mid-April 2011, $9.2 million in Sumitomo drilling carries remained for the partnership.

The companies plan to run two rigs for the remainder of 2011 and drill 20 gross wells (8 net). In the dry-gas area, the companies expect a 3.5 MMcf/d initial production rate and estimated ultimate well recoveries around 3 Bcf and well costs around $4.7 million through completion.

Rex also holds 17,500 gross acres (3,000 net) prospective for the Marcellus Shale and other formations in Clearfield, Centre, Somerset, and Fayette counties in Pennsylvania.

Rice Energy LLC

- *Marcellus operation grew from Denex farm-in*
- *Rick Drilling B LLC affiliate works the play*

Rice Energy LLC specializes in the Marcellus Shale through its Rick Drilling B LLC affiliate, which has a focused program primarily in Washington County, Pa.

That is one of two areas of interest for the company. It also operates in the Spraberry Trend in West Texas through its Rice Drilling A LLC affiliate.

The company started leasing Marcellus properties in 2007 and plans to drill between 300 and 350 Marcellus wells in northeastern and southwestern Pennsylvania.


Expro: giving you the complete picture
Expro's downhole video camera systems offer operators a cost effective way to 'see' downhole problems across a range of oil and gas well conditions. We have a great track record for providing the solutions to get the most from your well.
But there's more to Expro than you think. We provide tailor-made solutions across the lifecycle of a well. From exploration and appraisal through to abandonment, we offer the complete package.
Find out more at www.exprogroup.com
EXPRO
WELL FLOW MANAGEMENT™

A major part of its operations grew out of a farm-in arrangement with Denex Petroleum Corp. for Marcellus drilling rights in Washington County.

At the time, Toby Rice, chief operating officer of Rice Energy, said, "We look forward to working with Denex Petroleum, an established operator in the Appalachia Basin, in our efforts to become the leading operator in the Marcellus Shale."

Rice's operations resulted in 44 wells permitted, drilling, and recently completed in Washington County, according to IHS Inc. In the same categories, it had two wells in Fayette County, eight wells in Greene County, one well in Luzerne County, four wells in Lycoming County, and one well in Westmoreland County in mid-April 2011.

Royal Dutch Shell plc

- *Entered Marcellus via $4.7-B acquisition of East Resources*
- *Shell Appalachia to continue focusing on Tioga County*

Royal Dutch Shell plc jumped into the Marcellus play in a big way by acquiring one of the play's largest operators, Pennslyvania-based East Resources Inc.

The $4.7 billion acquisition in July 2010 gave Shell more than 700,000 gross acres (650,000 net) in the Marcellus Shale and some 1.25 million acres throughout the US.

Shell established Shell Appalachia in Warrendale, Pa., with 185 employees throughout the state and 50 employees at the heart of the operation in Tioga County. The company said it planned to continue its Tioga County focus in 2011 while exploring other parts of its leased acreage. In February 2011, working under the East Resources name, Shell planned a Utica Shale well in southwestern Lawrence County, Pa., along with Marcellus wells from the same pad.

In addition to its Tioga County acreage, the company also had a 50-50 joint venture operation with Ultra Petroleum in Potter County, Pa. East Resources also had properties in Bradford, Forest, McKean, and Jefferson counties in Pennsylvania and additional leases in the Trenton/Black River play in New York. That acreage is expected to be prospective for Marcellus production.

East drilled its first wells in 1983 in Warren and Indiana counties in Indiana. It then acquired some of Pennzoil's assets in 2000.

East Resources also owned Northern Pipeline Co. with some 400 miles of gathering system from the Butler-Clarion county line in Pennsylvania north to the New York border crossing through Clarion, Forest, McKean, Venango, and Warren counties along the way. It owned another 100 miles of gathering lines to the south through Pittsburgh to the West Virginia border and 60 miles of gathering lines in Lancaster, Chester, and Delaware counties in Pennsylvania. East Resources also owned two gas processing plants.

Snyder Brothers Inc.

- *One of the largest private Marcellus operators*
- *Produces more than 30 MMcf/d in Pennsylvania*

Snyder Brothers Inc., one of the largest privately funded independents in Pennsylvania, naturally moved into the Marcellus play from its extensive operations in the area.

The company got its start when Elmer A. Snyder and Charles H. Snyder Sr. formed a construction company in 1941, which initially grew into a coal-mining company by 1945 and into a variety of investments, including a motel, in succeeding years.

Snyder Associated Cos. Inc. started drilling oil and gas wells in the mid-1970s, and now, through Snyder Brothers Inc., drills more than 150 wells a year and produces more than 30 MMcf/d of natural gas from wells in Armstrong, Clearfield, Clarion, Fayette, Indiana, Jefferson, McKean, Warren, and Westmoreland counties in Pennsylvania.

All told, it controls more than 200,000 acres of leases in Pennsylvania.

Specifically in the Marcellus the company has a number of wells in three Pennsylvania counties either permitted, drilling, or recently completed, according to IHS Inc. Snyder Brothers had 33 active listings in Armstrong County, two in Clarion County, and four in Jefferson County as of April 2011.

Southwestern Energy Co.

- *Net acres: 173,009 in Pennsylvania*
- *Kicked off Marcellus drilling program in 2010*

Southwestern Energy Co. ramped up its Marcellus drilling program in an effort to approximate its success as the first and primary mover in the Fayetteville Shale in Arkansas.

By the end of 2010, Southwestern had spud 2,445 wells in six years, of which 2,001 were operated, and had increased 2010 natural gas production to 350.2 Bcf, up 44% from the previous year.

Southwestern began building up acreage in the play in 2007. The company had acquired 105,000 net undeveloped acres in the Marcellus Shale play in Bradford and Susquehanna counties in Pennsylvania early in 2008, added another 79,738 acres by the end of that year, and increased its holdings to 138,600 net acres in Pennsylvania by the end of first-quarter 2009. It drilled four vertical wells in 2008.

By the end of 2010, Southwestern had 173,009 net acres in Pennsylvania. It invested $118 million in the play during the year and participated in 21 wells. Six were successfully completed and 15 were awaiting completion in the Marcellus. The wells added 38 Bcfe in new reserves.

Southwestern operated all of the horizontal wells in the Greenzweig area of Bradford County. The six completed wells tested between 4 MMcf/d and 8 MMcf/d for total 2010 production of 1 Bcf.

The company followed with three more producing wells in the same area in February 2011 and increased production to 45 MMcf/d without compression.

For 2011, the company is operating two rigs in the Marcellus with an investment of approximately $265 million. That investment should result in 40 to 45 new operated wells. This compares with a $58 million investment in the Marcellus in 2008; an $80 million investment on all new ventures, including the Marcellus, in 2009; and an investment of $118 million in the Marcellus in 2010.

Stone Energy Corp.

- *Net acres: 75,000+*
- *Drilled 15 horizontal wells in 2010*

Stone Energy Corp. plans to increase its activity in Appalachia as it balances its high-production, short-life Gulf of Mexico production with lower-risk, long-life production from its Marcellus properties.

The company's investment in Appalachia is second only to its offshore investment as it has allocated 26% of its $425 million capital budget for the Marcellus in 2011.

According to an April 2009 presentation, Stone owned a 50% stake in three nonoperated and producing wells in the Marcellus in West Virginia. Two of these vertical wells on its Heather and Buddy prospects produced at a rate of 200 MMcfe/d of natural gas.

In a similar presentation in 2010, Stone had permitted horizontal Marcellus wells in Wetzel County, W.Va., and planned to drill up to 14 Marcellus Shale wells during the year. However, the company said it did not expect the wells to impact production until 2011.

According to an April 2011 presentation, Stone drilled 15 horizontal wells in 2010 and increased its holdings in the Marcellus to more than 75,000 net acres.

At that time, it planned 18 to 20 horizontal wells and planned to fracture 14 to 18 of those wells during 2011. At the same time, the company said it would try to add contiguous acreage to its holdings.

All of Stone's 2011 drilling is scheduled for northern West Virginia, where the company has planned a one-rig program to drill 16 horizontal wells on its Mary project and three horizontal wells on its Heather project. No wells are planned on the Buddy project in the same 33,000-acre area, but the company does plan to complete infrastructure there by fourth-quarter 2011.

In the Mary area, Stone will drill up to six horizontal wells from a single pad, three laterals each in approximate opposite directions from the rig location. It will space laterals 750 ft apart. The laterals will reach up to 5,553 ft.

Stone also expects to add infrastructure in third-quarter 2011 for its Katie and Andie projects in northeastern Pennsylvania, where it holds 14,000 acres.

Its remaining 28,000 acres are in the Christine project in west-central Pennsylvania.

Talisman Energy Corp.

- *Largest gas producer in New York State*
- *Plans to add 100 wells in 2011*

Talisman Energy Corp. has billed itself as the largest producer in the Marcellus Shale from a standing start in an April 2011 presentation. The company has produced the facts to back up the claim, and its growth spurt continues.

Talisman eased into the play after its Fortuna Energy Inc. subsidiary moved into New York to pursue the Trenton-Black River play. By mid-2008, the subsidiary had 64 wells producing from that formation at a combined 80 MMcf/d of natural gas, making it New York's biggest gas producer.

That year, Talisman announced a focus on the Marcellus, the Montney, and the Utica shales. In July 2008, the company said it had drilled 13 vertical pilot holes in the Marcellus since 2006, including a well with an initial production rate of 800 Mcf/d.

At that time, the company had 800,000 gross acres (640,000 net) of prospective Marcellus properties. By May 2009, it had 793,000 net aces with more than 30 Tcf of gas in place.

That also was about the time New York halted Marcellus drilling operations to examine environmental ramifications of the play. The drilling moratorium in New York was still in place in June 2011. Talisman continued drilling in the Marcellus for dry gas in a line of counties along the New York border in northeastern Pennsylvania. The company dropped its land holding estimate to 223,000 net acres of "Tier 1" properties in Pennsylvania, with more than 2,000 drilling locations.

In 2009, Talisman had 22 net wells online with an average production of 29 MMcf/d. Estimated ultimate recoveries (EURs) ranged from 3 Bcf to 7.5 Bcf per well, and 30-day initial potential rates ranged from 3.1 MMcf/d to 5.5 MMcf/d.

The following year, it had 110 net wells with an average production of 181 MMcf/d. EURs stabilized at 5 Bcf and initial production rates at 5 MMcf/d.

In 2011, Talisman said it planned to add another 100 wells with average production between 350 MMcf/d and 400 MMcf/d. EURs should remain at 5 Bcf, while initial potential rates may drop to 4 MMcf/d, it said. The company also will trend toward longer horizontal legs in 2011.

Talisman will work nine rigs in the Marcellus with a capital budget of US $800 million in 2011 and expects to finish the year with production of 600 MMcf/d. It finished 2010 with production of 315 MMcf/d, up from 65 MMcf/d at the end of the previous year.

Tanglewood Exploration, LLC

- *Has 11 active Marcellus wells*
- *Seeking funds for 16-well drilling program*

Tanglewood Exploration LLC, a five-year-old exploration company started by Tom L. Scott and Randy Wolsey in Fort Worth, Texas, to join the shale gas stampede, established operations in the Barnett Shale in North Texas and the Marcellus Shale in Pennsylvania.

Scott, the general manager of Tanglewood, leased more than 100,000 acres in the Barnett play in the Fort Worth Basin, principally acting as agent for companies including EOG Resources, XTO Energy, and Republic Energy. Wolsey is the company's operations manager and has previous experience as a contract drilling engineer in the Barnett with Chief Oil & Gas.

The company has 11 active wells permitted, drilling, or recently completed in the Marcellus play in Green County, Pa.

According to Energy Spectrum Advisors, the company's financial adviser for development of Marcellus properties, Tanglewood holds 3,000 gross acres (2,700 net) in Greene County and has access to more than 30,000 additional acres.

At press time, the company was trying to raise money for a 16-well drilling program on its existing acreage and plans to add more acreage.

Tanglewood's first horizontal well used a 3,000-ft lateral to reach an initial potential of 9 MMcfe/d of natural gas, and it drilled two additional Marcellus horizontal wells with longer laterals that were awaiting completion. The company expected ultimate recoveries of 6 Bcfe from its wells, according to Energy Spectrum.

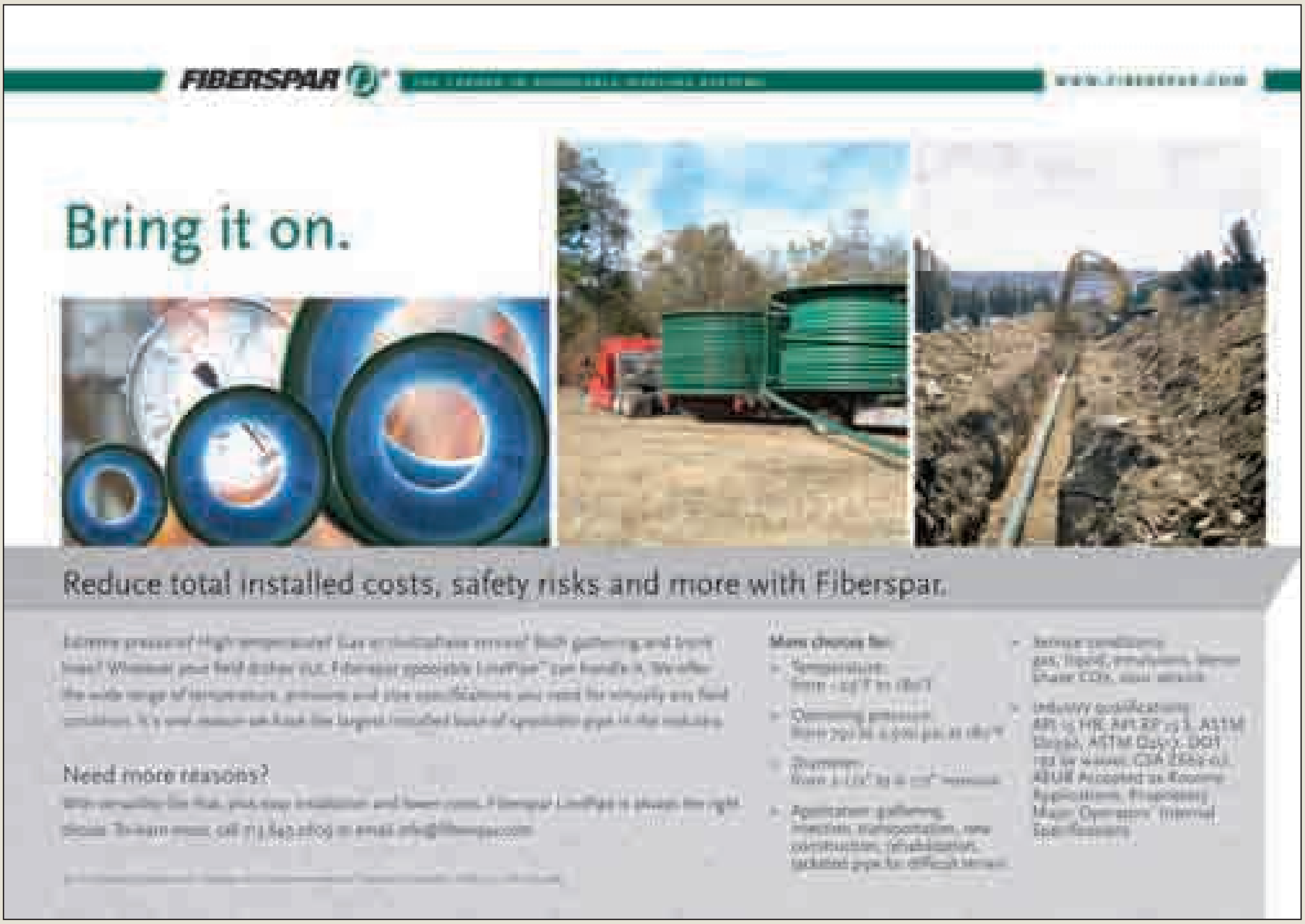
Texas Keystone Inc.

- *Operates more than 1,000 miles of pipeline*
- *Internally controls most of its operations*

Texas Keystone Inc., a Pittsburgh, Pa.-based operator with international interests, works the Marcellus Shale play from a strong base of having drilled in Appalachia since 1988.

The company has drilled more than 1,000 wells in Appalachia since it began operations and also operates more than 1,000 miles of pipeline with five compressor stations.

According to Texas Keystone, it controls many of its operations internally, screening prospects, developing operating plans, and putting together operating teams. The company's geologists and engineers analyze plays,



and its landmen handle leasing operations and regulatory requirements and also process permits.

Texas Keystone has its own drilling experts that work at drilling sites; it also maintains its own pipelines and gas processing plants and markets its production.

According to IHS Inc., the company had 20 wells permitted, drilling, or recently completed in the Marcellus Shale in early May 2011. In Pennsylvania, Texas Keystone had two wells in Cambria County, seven wells in Clarion County, and four wells in Jefferson County. In addition, it had seven Marcellus wells in Tyler County, W.Va.

Trans Energy Inc.

- *Expanded JV agreement with Republic*
- *Groves #1H set company record for lateral length*

Trans Energy Inc., a veteran producer in northern West Virginia, drilled its first Marcellus Shale well in 2008 and has not slowed activity since that time.

Before venturing into the Marcellus play, Trans Energy had interests in 271 oil and gas wells with gathering lines in Marion, Doddridge, Ritchie, Wetzel, and Tyler counties in West Virginia.

Now the company has focused its activity on Wetzel, Marion, and Doddridge counties.

In July 2010, Trans Energy expanded its joint-venture agreement with Republic Energy Ventures LLC into Marion and Tyler counties after waging a successful campaign in Wetzel and Marshall counties. In that arrangement, Trans Energy sold Republic a 50% interest in some 5,000 net acres in Marion County and 2,600 acres in Tyler County along with a small override in 6,000 acres in Wetzel County for $23.5 million in cash and $3.5 million in drilling carries.

In March 2011, Trans Energy completed the sale of 2,960 net acres to Republic for $14 million.

Trans Energy President John G. Corp said in April 2011 that the company's latest horizontal Marcellus well, the Groves #1H, set a company record for a lateral length at 5,500 ft. The company completed the well with a 15-stage frac treatment and turned it into the sales line ahead of schedule.

Earlier the same month, Trans Energy hooked its Keaton #1H well into the sales line.

A March 2011 report by IHS Inc. said the company's 2H Stout horizontal Marcellus well in Marshall County produced at an average rate of 5.3 MMcfe/d of natural gas in its first 30 days on line.

Triana Energy LLC

- *Moved into play with Morgan Stanley equity backing*
- *Partnered with Marathon to develop 82,000 Marcellus acres*

Triana Energy LLC moved into the Marcellus play in Appalachia with the help of Morgan Stanley Private Equity, as executives of the former Triana Holdings applied their skills to operations after Chesapeake Energy Corp. bought out the parent company of Columbia Natural Resources in 2005.

In January 2010, the company acquired approximately 20,000 acres of mineral rights in the Marcellus fairway in two separate transactions. One transaction was a 15,000-acre joint venture with Minard Run Oil Co. in McKean County, Pa., and the second was a 5,000-acre lease in Clearfield County, Pa.

Triana planned to drill approximately 100 horizontal wells from 27 drilling pads on the properties.

Three months later, Triana acquired some 12,000 acres of leases in Potter County, Pa., from Hanley & Bird Inc.

By that time, Triana had put together more than 30,000 acres of properties prospective for the Marcellus Shale in north-central Pennsylvania, and another 30,000 net acres of leases in West Virginia prospective for the shallower Huron shale.

By January 2011, IHS Inc. said the company had drilled a number of Marcellus wells in Pennsylvania over the past couple of years.

In February 2011, the Charleston, W.Va.-based company formed a partnership with Marathon Oil Corp. through its wholly owned subsidiary to develop some 82,000 acres of Marcellus properties in Fayette County, Pa., and several counties in northern West Virginia.

That transaction called for Triana to drill four horizontal wells on the properties during 2011 to define optimal completion patterns.

Following that optimization work, the joint-venture companies planned to drill 132 horizontal wells on 43 drilling pads. If the companies decide to fully develop the properties, they could drill up to 350 wells.

By that time, Triana operated Marcellus projects in Potter, Clearfield, and McKean counties in Pennsylvania, and Taylor and Lewis counties in West Virginia.

In April 2011, Triana had some 38 wells permitted, drilling, or recently completed, including 14 wells in McKean County and another 14 wells in Potter County, both in Pennsylvania, and two wells in Lewis County, six wells in Nicholas County, and two wells in Taylor County, all in West Virginia.

Ultra Petroleum Corp.

- *Net acres: 260,200 by year-end 2010*
- *Expects full-year net Marcellus production of 40 Bcf*

Ultra Petroleum Corp., one of the strongest players in the Jonah Field tight sand play in southwestern Wyoming, is building a similarly strong position in the Marcellus Shale in Pennsylvania.

The company bought its first Pennsylvania acreage in 2001, but it did not drill its first well for another four years. From that point, Ultra continued to drill and acquire acreage and additional geologic and seismic data to establish a solid foundation for a successful play.

By the start of 2010, Ultra had assembled some 168,900 net acres in the Marcellus fairway. It picked up another 78,000 net acres through the acquisition of a private company in 2010 and finished the year with 495,000 gross acres (260,200 net). The added land in 2010 cost the company $453.2 million.

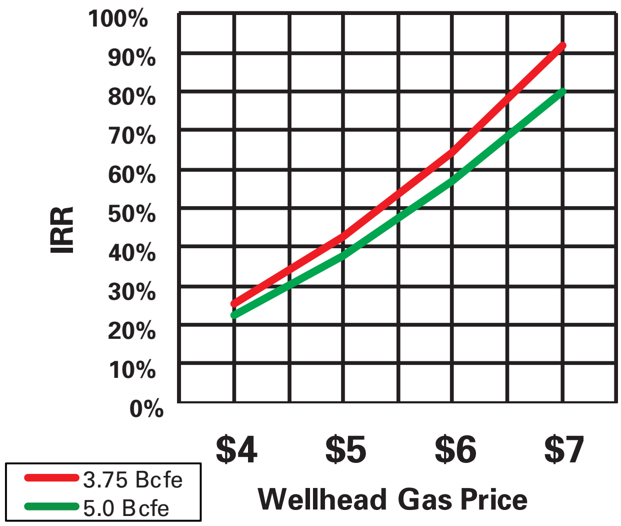
Ultra held 164,000 net acres with 75 producing wells at the end of 2010 in its northern area in north-central Pennsylvania and the remaining 96,000 net acres with 17 producing horizontal wells in its southern area in central Pennsylvania.

Ultra spent $390 million on the Marcellus in 2010 compared with $610 million on its Wyoming properties. That $390 million gave the company 116 gross wells (59 net) with an average initial production rate of 6.4 MMcf/d of natural gas, and it ended the year producing 90 MMcf/d from the Marcellus. During the year, Ultra also acquired 76 sq miles of 3-D seismic data, raising its total to 315 sq miles.

For 2011, the company budgeted $380 million for Pennsylvania, compared with $590 million in Wyoming. It planned 163 gross Marcellus wells (80 net) for the year for a full-year net production of 40 Bcf. That will include 110 drilled horizontal wells and 95 producing wells in its northern area and 53 drilled wells and 55 producers in the southern area.

In an April 2011 presentation, the company outlined economics for a 5 Bcfe well. That well would cost $6

Marcellus Shale Has Best Economics



	3.75 Bcfe	5.0 Bcfe
Well Cost:	$4.2 MM	$6.0 MM
Reserves/well:	3.75 Bcfe	5.0 Bcfe
IRR:	64%	57%
F&D Cost/mcfe	$1.32	$1.37
Payout, months:	21.1	23.3
Reserve Life, yrs:	34.9	39.6

* Economics at $6.00/Mcf wellhead price

Ultra's horizontal Marcellus wells offer a handsome return with a short payout period and long life. *(Graphic courtesy of Ultra Petroleum Corp.)*

million to complete, offer an internal rate of return of 57%, and pay out in about 23 months, Ultra said. Additionally, the finding and development costs would total $1.37/Mcf, and the well would last roughly 40 years.

Among the company's wells, Ultra tested 12.2 MMcf/d at its 902-4H horizontal well in eastern Potter County. It completed the well with a 14-stage fracture treatment.

The Williams Companies Inc.

- *Farmed in to 44,000 Marcellus acres held by Rex*
- *Added 42,000 net acres from Alta in 2010*

The Williams Companies Inc., already the 10th largest natural gas producer in the US, will solidify its gas position as it tries to make its Marcellus asset the second largest in the corporate gas portfolio.

Williams operates its Marcellus properties through its Williams Production Appalachia LLC subsidiary.

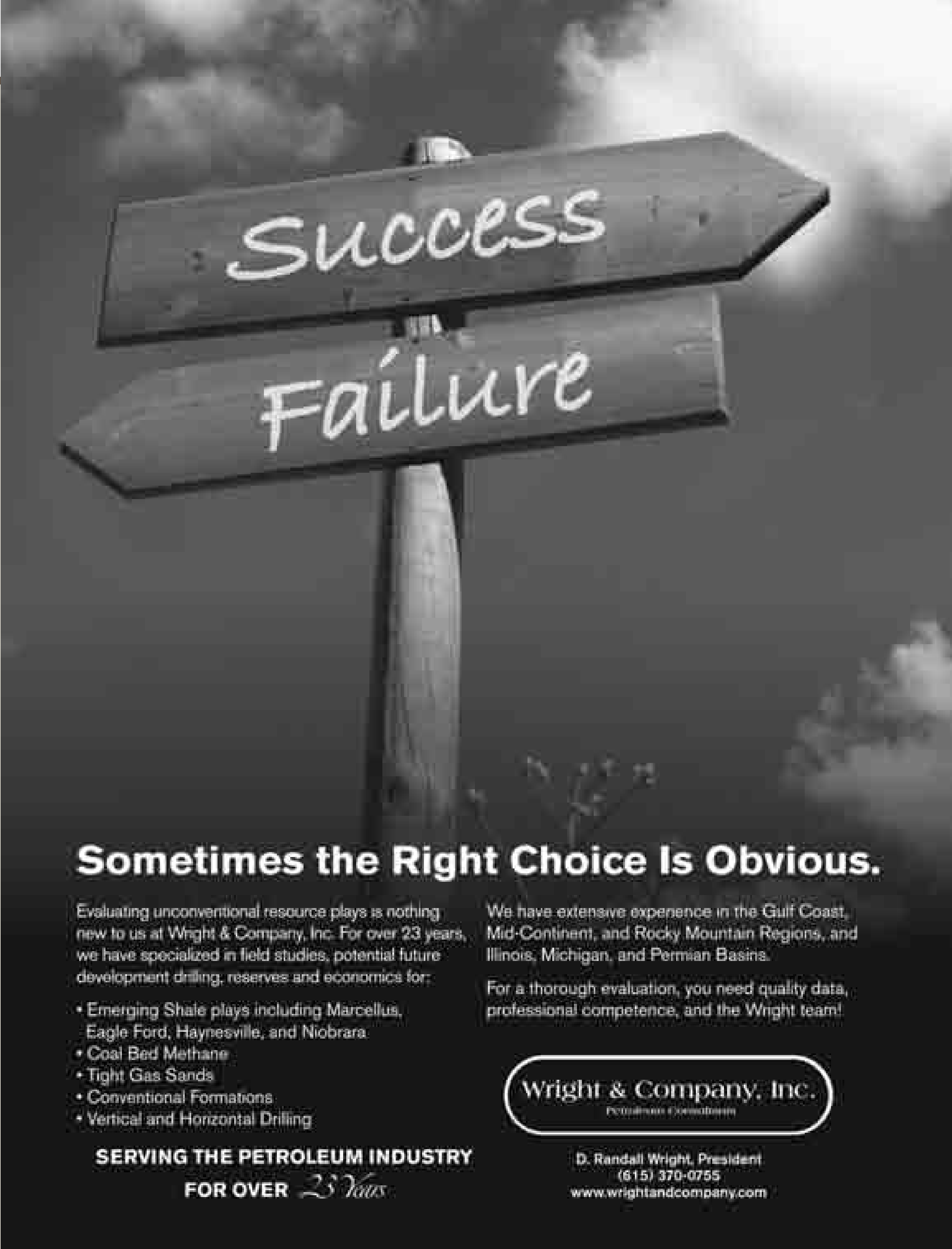
The company took a big step into the Marcellus in June 2009 when it put up $33 million to earn a 50% interest in 44,000 Rex Energy Corp. acres in the play by drilling wells in Centre, Clearfield, and Westmoreland counties in Pennsylvania.

Williams added to that position in May 2010 when it bought 42,000 net acres of Marcellus leases in Susquehanna County, Pa., from Alta Resources LLC for $501 million. That property, which contained an estimated net natural gas reserve potential of 1.2 Tcfe, became a core area in the Marcellus for the company.

When it acquired the property, Williams said it would invest $55 million in the properties in 2010 and between $100 million and $200 million by 2012. It also was looking at another 8,000 net acres in Pennsylvania at the time. That acquisition increased the company's holdings to 94,000 acres in Centre, Clearfield, Fayette, Greene, Susquehanna, Washington, and Westmoreland counties, all in Pennsylvania.

During an October 2010 conference call, Williams said it operated three rigs on its Marcellus properties and planned to double that number by fourth-quarter 2011. It also said its returns on Marcellus wells had exceeded 30%.

Also in 2011, Williams announced plans to divide the company into an exploration and production arm and a midstream affiliate. WPX Energy will take over exploration and production on the company's Piceance, San Juan, and Powder River basins in Colorado and Wyoming, its Bakken Shale properties in North Dakota, and its Marcellus properties in Pennsylvania. It also will take over Williams' 69% interest in Apco Oil & Gas International Inc. with properties in Argentina and Colombia.


Success
Failure
Sometimes the Right Choice Is Obvious.
Evaluating unconventional resource plays is nothing new to us at Wright & Company, Inc. For over 23 years, we have specialized in field studies, potential future development drilling, reserves and economics for:
• Emerging Shale plays including Marcellus, Eagle Ford, Haynesville, and Niobrara
• Coal Bed Methane
• Tight Gas Sands
• Conventional Formations
• Vertical and Horizontal Drilling
We have extensive experience in the Gulf Coast, Mid-Continent, and Rocky Mountain Regions, and Illinois, Michigan, and Permian Basins.
For a thorough evaluation, you need quality data, professional competence, and the Wright team!
Wright & Company, Inc.
SERVING THE PETROLEUM INDUSTRY
FOR OVER 23 Years
D. Randall Wright, President
(615) 370-0755
www.wrightandcompany.com

Servicing the Marcellus Shale

Drilling and completion technologies are key to increasing Marcellus gas shale activity.

By Jerry Greenberg
Contributing Editor

In most of the US shale plays, whether oil- or gas- or liquids-rich, the application of the latest drilling and completion technology has been the enabler of successful E&P and the primary reason for increased activity. This is particularly true in gas-prone shales during a low gas price environment. Horizontal drilling and geosteering technology has opened up regions to more successful drilling and production, creating the boom during the past few years in areas such as the Bakken, Niobrara, Eagle Ford, and Marcellus.

The Marcellus gas shale area covers about 95,000 sq miles in the Appalachian mountains of New York, Pennsylvania, and West Virginia, although most of the activity is in Pennsylvania. Depth of the Marcellus reservoir ranges from about 4,000 to 8,500 ft and has a net thickness of between 50 and 200 ft. Original gas in place totals about 1,500 Tcf, with about 262 Tcf of economically recoverable gas. However, with the application of the latest existing technologies and those under development, this figure could increase significantly as operators continually seek the most economic solutions to turning the estimated ultimate recovery (EUR) of 3.6 Bcf into technically recoverable resources.

The number of Marcellus gas shale operators has grown significantly during the past couple of years, attracting majors such as Chevron, which purchased acreage and prospects from another operator, and Statoil, which entered the play the same way as Chevron. Other companies have been active in the play since the beginning of its present popularity, including Anadarko, Range Resources, and Seneca Resources, to name a few. The region's relatively low well cost, averaging US $3.5 million with a finding cost of about $1.19 per Mcf of gas, is attractive even in times of low natural gas prices.

As a result, many operators are aiming more of their capital expenditures toward the Marcellus play. Anadarko estimated its 2011 capital expenditures between $5.6 and $6 billion, with about 10% of that budget earmarked for the Marcellus and Eagle Ford shales. The company anticipates operating 10 rigs in Marcellus in 2011 and participating in more than 250 wells. Anadarko also said the Marcellus "will continue to be the only domestic dry natural gas field where it will be actively drilling due to the play's proximity to premium natural gas markets that enhance the already robust economics."

Range Resources' 2011 capital budget is $1.38 billion. A whopping 86% of that figure is earmarked for the Marcellus. The remainder will be spent in the company's Midcontinent, Appalachian, and Southwest divisions. The 2011 capital budget includes $1.13 billion for drilling and recompletions, $160 million for seismic, and $35 million for pipelines and facilities.

Seneca Resources said its fiscal 2012 capital budget will be in the $685 to $800 million range. This includes the planned drilling of 115 to 140 gross horizontal wells in the Marcellus, of which 80 to 95 will be operated by the company. The remainder will be operated by EOG Resources under a joint venture with Seneca Resources. In order to concentrate its resources in its onshore prospects, Seneca sold its offshore Gulf of Mexico oil and natural gas properties for $70 million in a shift to further fund its Marcellus activities.

The company in March 2011 reached a major milestone in the Marcellus with a daily net production rate of more than 100 MMcf/d of natural gas. The company reported net production of about 120 MMcf/d from 32 operated and 27 non-operated wells.

"Longer laterals and more frac stages have allowed us to achieve outstanding results," said Matt Cabell, Seneca Resources' president.

That hasn't occurred without a price. "While our well costs have increased as a result of additional frac stages and increased service company charges," he continued, "this has been offset by higher anticipated EUR factors.

"We are now anticipating well costs of $5 to $6.4 million for wells with up to 20 frac stages and lateral lengths reaching over 6,000 ft," Cabell said. "Taking these factors into account, we expect to see results continue to improve over time, with some of our best wells achieving EURs of 8 Bcf."

Service companies are doing their best to make sure Seneca Resources and other operators achieve their production goals economically. Recent innovations include LWD tools and software, better geosteering capabilities to keep the bit steered in the formation's sweet spot, "shale-specific" drill bits, greater use of electromagnetic (EM) telemetry in conjunction with MWD tools, and high build-rate rotary steerable systems (RSS) to reach the horizontal lateral quicker.

One operator's drilling experience

Anadarko has been operating in the Marcellus Shale for several years, and it has used different tools and technologies to drill the most efficient and economical wells possible. Of course, sometimes a more expensive tool or technology must be used to save time. Over the last couple of years in the Marcellus, Anadarko has managed to shave off more than one-third of the time it takes them to drill a well to TD, from about 32 days to fewer than 20 days average, with current records in the 13-day range.

The company plans to drill about 120 wells in 2011 compared with about 50 wells drilled in 2010 and about a dozen wells from May through December 2009. Anadarko's drilling operations in the Marcellus are 100% closed loop.

The Precision 531 rig works for Anadarko Petroleum in the Marcellus Shale. *(Photo courtesy of Anadarko)*

"We are a believer in high-performance skiddable AC drilling rigs, where we have the ability to control multiple drilling parameters from an electronic touch screen control with software and algorithms that maximize ROP," said Steve Woelfel, Anadarko's drilling manager in the Marcellus. "We are working to achieve more of a factory type of process in every step of the well construction process. We typically batch-drill up to six wells per pad in development mode, which allows us to capitalize on the efficiencies of repeating the same processes with the same rig team in a short period of time where learnings required for continuous improvement are applied immediately."

The operator currently operates nine rigs in the Marcellus, including eight large drilling rigs and one rig used to spud the well and drill the top-hole section. Woelfel said he expects the company to remain at that rig level.

He added that when achieving record wells, Anadarko spent 50% to 60% of the time actually drilling. "The other 40% to 50% of the time is flat time, and that is where we are taking a hard look at how to reduce flat time during casing running and cementing operations and other parts of the well construction process," he said.

Anadarko, like many other operators in the Marcellus and elsewhere, drilled several wells with RSS with and without positive displacement motors (PDMs) and used mud pulse telemetry to send downhole data to surface. However, it recently has been using EM telemetry for faster data transmission and "shale-specific" drill bits to help increase ROP. Anadarko also recently began drilling slimhole wells with significant success, and it intends to use the slimhole technique in all of its wells beginning in summer 2011, according to Woelfel.

Drilling fluid

In 2009, Anadarko converted to synthetic-based drilling fluid from water-based fluid, which "solved a lot of our issues and problems," Woelfel said. "It has been a huge success for us. We can't get anything more inhibitive or anything slicker with a better friction factor for drilling way out in the lateral."

One of the issues synthetic-based fluid resolved was stuck pipe, a challenge to avoid when using water-based fluid due to some water-sensitive formation layers coming apart. Other challenges resolved by using synthetic-based fluid were being able to reduce rotating torque and effectively sliding far into the lateral with synthetic-based fluid.

"Synthetic-based fluid eliminated an entire casing string," Woelfel said. "With water-based mud we had problems in a couple of formations where we had to build a curve and run 7-in. casing to proceed in the Marcellus.

"When we began using synthetic-based mud, we completely eliminated the casing string and the time associated with that," he added.

Rotary steerable systems

Anadarko used RSS and still does to a certain degree, depending on the well, but Woelfel said the company can usually drill faster, particularly in the lateral section of the well, with conventional motors. Theoretically, if considerable sliding time is required to hold TVD and azimuth with a motor (a relative "tight" target window), then one ought to be able to make faster hole continuously rotating with an RSS, assuming it is capable of making the target adjustments required.

"We are in a situation where a lot of [Marcellus] exploration wells use gamma ray to steer the bit and suddenly the rock takes a 30° dip. The geology is complex; it's truncated and faulted," Woelfel said.

"A RSS is not very responsive to that kind of change," he noted. "It can turn maybe 3° or 4° per 100 ft to follow the bed dip. If I have a motor in the hole, I can turn 6°, 7°, or 8° per 100 ft and chase it down before we get out of zone."

Due to the way rotary steering is priced, Anadarko would have to save two days of drilling for RSS to break even versus a conventional motor spread, according to Woelfel. "It's very difficult to make the economics," he added.

Schlumberger and Baker Hughes have been developing high-angle RSS that can make 8° or higher bends, and up to about 16° in some cases. Woelfel said he has begun investigating them.

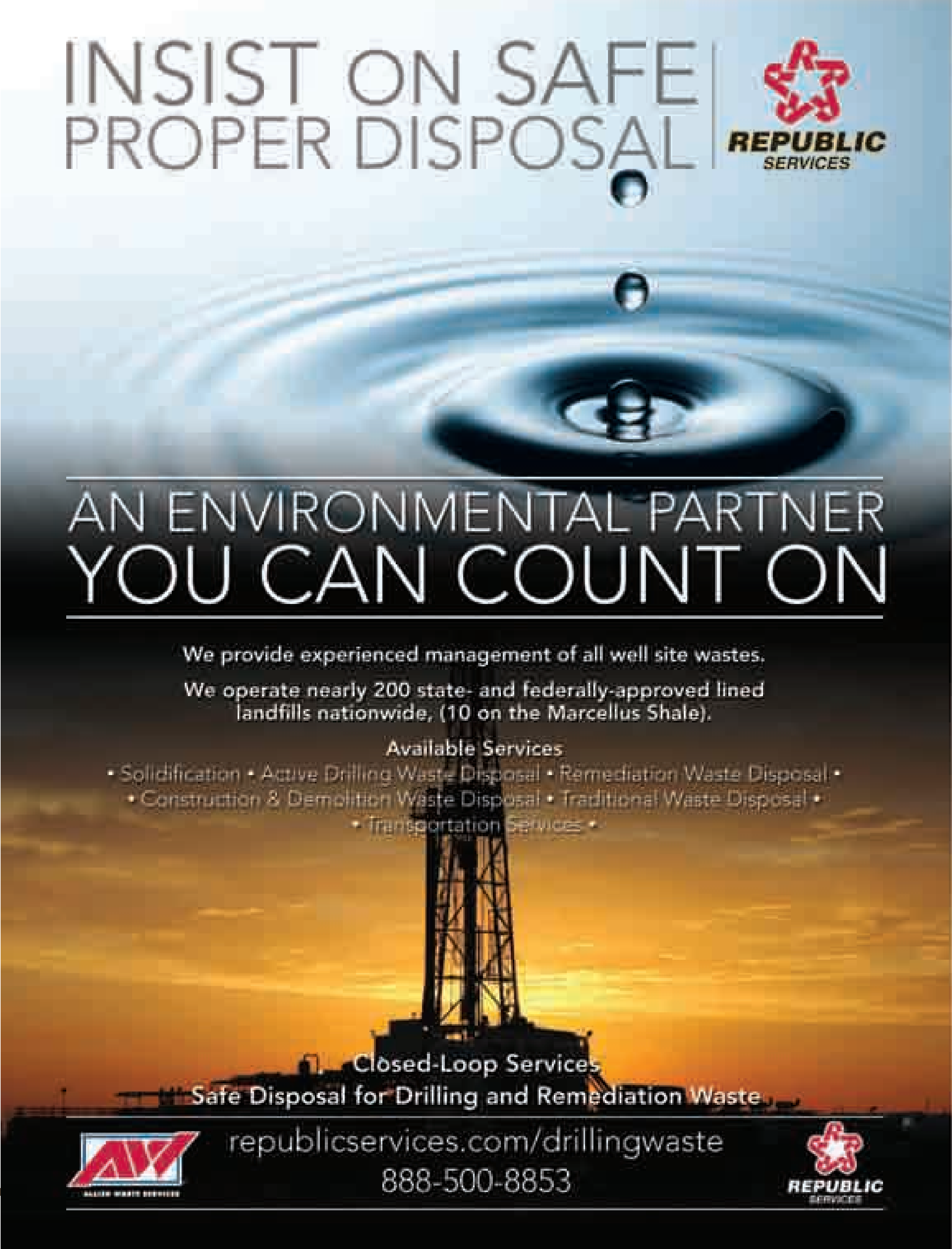
EM telemetry

"One of the technologies that turned out to be a big winner for us is EM telemetry instead of pulse telemetry," Woelfel said. "We have moved to EM with our MWD.

"Instead of pulsing gamma ray and surveys up the drill pipe, we have been successful with EM technology in the Marcellus, and that is saving us a lot of time," he explained. "This has been a game changer for us."

One of the drilling constraints in the Marcellus has been the quality of LWD, Woelfel noted, because steering the bit is more complicated than in the Maverick Basin in the Eagle Ford Shale, where Anadarko also is extremely active. "The Marcellus geology is more complicated than Maverick," he said. "What we found is that the level of quality of our gamma ray required to steer properly has to be significantly better than what we are using in the Maverick. EM has solved some of those problems."

Another real plus with an EM package, Woelfel explained, is the ability to place the gamma ray and survey closer to the bit. "With one company we are running EM with gamma ray 35 ft from the bit, and our survey point is 48 ft from the bit," he said. The


INSIST ON SAFE
PROPER DISPOSAL
REPUBLIC
SERVICES
AN ENVIRONMENTAL PARTNER
YOU CAN COUNT ON
We provide experienced management of all well site wastes.
We operate nearly 200 state- and federally-approved lined landfills nationwide, (10 on the Marcellus Shale).
Available Services
• Solidification • Active Drilling Waste Disposal • Remediation Waste Disposal •
• Construction & Demolition Waste Disposal • Traditional Waste Disposal •
• Transportation Services •
Closed-Loop Services
Safe Disposal for Drilling and Remediation Waste
republicservices.com/drillingwaste
888-500-8853
REPUBLIC
SERVICES

time required to take surveys also is significantly reduced with EM versus pulse technology.

Woelfel noted that gamma ray quality was a problem for the company over the past year. "We are making headway with EM because a lot of our issues with pulse telemetry were [due to] receiving distorted signals due to vibrations or other types of interference that affect pulse telemetry more so than EM," he explained. "EM will help our team continue to make faster hole."

Drill bits

Coupled with EM telemetry technology, Anadarko is examining new bit designs as a means to drill the curve and lateral in a single run. The company has examined and run new bit designs referred to as "shale-specific" by the bit manufacturers.

"What we have found is that the welded body bits make the fastest hole," Woelfel said. "The matrix body bit is an alloy that is more resistant to erosion compared with steel blades that are welded together, but by the nature of the construction, you can't build a matrix bit as aggressive as a welded blade bit."

According to Woelfel, the bit companies are referencing the best combination between steerability and aggressiveness. When building the curve of the well, it is usually necessary to use a bit that is stable and holds tool face in order to efficiently build the curve quickly, he said. If the bit is too aggressive, it is difficult to hold the tool face and results in slow drilling of the curve.

"When you get to the lateral you want to make 2,500 ft per day, but the bit won't drill fast if it's overly designed to hold tool face," Woelfel explained. "The compromise is to build a bit that is sufficiently stable to build the curve and sufficiently aggressive to drill as fast as your other drilling constraints allow.

"When the bit companies are talking about multipurpose bits for shales, they are talking about a bit that has balance to build the curve and drill the lateral quickly, whether it is a matrix or welded blade," he said.

The bottom line for Anadarko's Marcellus wells: "If we don't build the curve and drill the lateral in one run, we don't consider ourselves successful," Woelfel emphasized.

Slimhole drilling

Anadarko has reduced the hole size of its recent wells and has been successful to the point at which it is planning on drilling most, if not all, of its future wells in the slimhole mode. The company's completion requirement calls for a 5½-in. production casing. Originally Anadarko was drilling 8¾-in. hole. Now with its slimhole wells, the company is drilling a 7⅞-in. final section, effectively slimming everything, including the amount of cuttings from the well.

"We reduced our cuttings from our slimhole wells by 20%, and that is the cuttings that we generate from the entire well," Woelfel said. "That reduces the number of trucks used to dispose of cuttings by 20%."

From the top of the well, the operator now begins with a 14¾-in. top hole rather than a 17½-in. hole to about 700 ft. The next hole size from 700 to 2,000 ft is drilled with 10⅝-in. hole rather than 12¼-in. hole. Each of these sections is drilled about 20% faster than before. When drilling the 7⅞-in. curve and lateral (compared with 8¾-in. drill pipe previously), the drilling rate is constrained by other issues, although Woelfel said they drilled faster than before when building the curve and through the lateral.

"We place a premium on hydraulic horsepower from the rigs," Woelfel explained. "We spin that pipe as fast as we can and pump as hard as we can; our annular velocities are very high, and we end up with a good clean hole, and 5½-in. production casing goes right to bottom."

As a result, Anadarko drills wells faster, reducing the cost of cuttings disposal.

Extending productive lateral length within lease lines

RSS were considered a game changer in offshore drilling when they were developed and commercialized. RSS usually result in faster drilling, more precise placement of the well into a reservoir's sweet spot, and a smooth wellbore that aids in casing running and completion design. RSS enable an operator to drill curves and horizontal sections in one run while also steering the bit through any dips and faults in order to remain in the target formation. A

With Baker Hughes' high-build RSS, an operator can land the bit into and potentially produce from an additional 760 ft of lateral reservoir compared with a typical RSS that delivers a dogleg severity of 5°/100 ft. *(Image courtesy of Baker Hughes)*

conventional RSS has a build capability of 5° to 6°/100 ft, and as a result, the curve must begin higher in the well, requiring a long curve section and reaching the lateral section far from the vertical.

Today, service companies have been developing high-build RSS that provide all of the drilling advantages as a conventional RSS plus a few more important benefits. They include the operator's ability to enter the lateral quicker, increasing the length of the productive horizontal section and still remaining within the lease line. Baker Hughes has been gathering experience with high build-rate RSS for some time, in different environments.

"With high build-rate RSS, an operator can kick off deeper so he can maximize his performance in the vertical, reduce torque and drag, and often minimize the intervals spent in difficult zones that don't generate any value," said Olof Hummes, product manager-Rotary Steerable Systems for Baker Hughes. "We have been able to achieve build rates in the relevant range of 10° to 15°/100 ft and higher."

The high build-rate system uses expanding steering pads that push against the side of the wellbore and deflect the bit farther than the company's standard-build rate RSS. "The steering pads are designed to work in different formations from soft to very hard or brittle," Hummes said.

Additionally, the bottomhole assembly (BHA) is more flexible to manage the increased bending loads.

"We want to make sure that the fatigue life isn't compromised and the tool is not running into a situation where components begin breaking," Hummes explained.

"We are testing the high-angle RSS in different plays and have, for instance, used the system in the softer Eagle Ford and the hard Granite Wash basins to determine its capability in different formations. A large part of the testing is to be able to offer an optimized system because while it is about build rates, it also is about drilling performance," he said.

The company designed bits for the high-build RSS that optimize ROP in the target formation environment while delivering the required directional control. At the same time, the steering is completely independent of bit hydraulics or mud pressure and is not affected by changes to the flow rate, mud properties, or bit nozzle size.

With Baker Hughes' high-build RSS, an operator can land the bit into and potentially produce from an additional 760 ft of lateral reservoir compared with a typical RSS that delivers a dogleg severity of 5°/100 ft.

The company's high-build RSS have reduced the number of days to drill and complete wells in different formations, resulting in significant savings of drilling and completion costs as well as significantly increasing the length of the producing horizontal lateral section.

Directional bits for shales, EM technology, and BATS

Halliburton's Drill Bits and Services business line has developed directional drill bits specifically for shale basins, including the Marcellus, and has set several performance records. Matrix body bits are used in many of the shale basins in the US because of their durability, wear, and erosion resistance, according to the company.

Halliburton's steel body bits are run in the Haynesville and other shale basins because of the shales' high clay content as well as high temperatures and pressures. An advantage of a steel body bit is its high blade standoff with a lot of evacuation room for cuttings such as are found in the Haynesville. The company said it has not found any other shale basin where the cuttings have exceeded the cleaning capacity of its matrix body bits.

"One issue with steel body bits is that the high flow and high-speed drilling applications cause a lot of erosion to the bit and sometimes result in lost cutters," said Guy Lefort, Halliburton's US Southern Region drill bit technology manager. "We made the decision to use a more durable body material, especially for Marcellus, because it doesn't have the stickier high clay content of other shales.

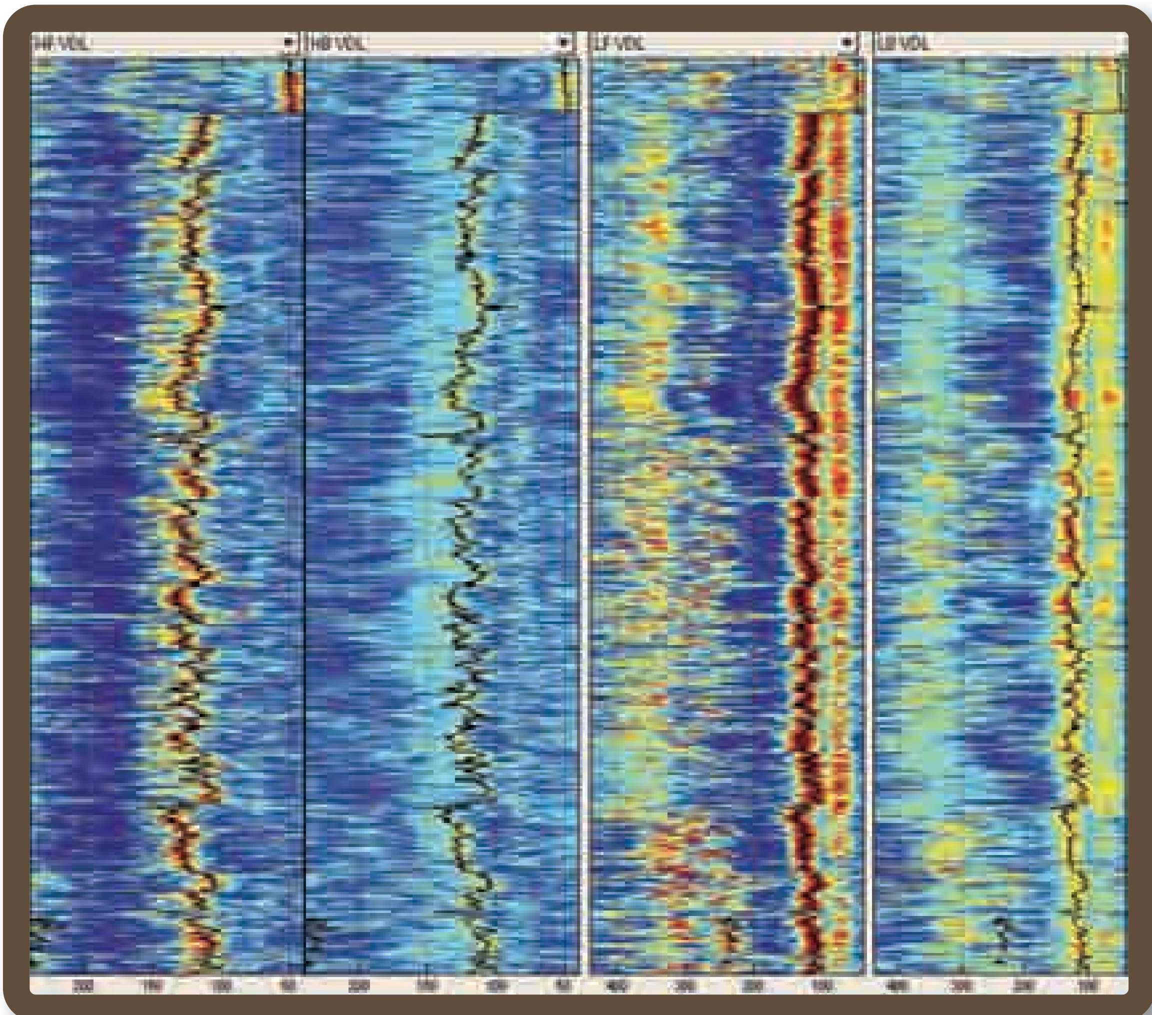
"Our shale-specific bits are our FXD series optimized for the region," Lefort said. "They have flat, short profiles and depth-of-cut control for better steerability to minimize torque and tool face issues. To obtain the hydraulic efficiency, the blades are very narrow and tall."

While Halliburton has been designing and manufacturing directional-specific bits for several years, the first-generation bit designs for the Marcellus have been available since early 2010, although the latest top-performing bits have been in the Marcellus Basin since earlier this year.

"We had brought in some designs from other areas in the beginning," Lefort said, "but we really began customizing them in the middle of 2010 even though offset information was limited due to the information sharing in this 'tight hole' environment.

"Now they are sharing more information with us, and that resulted in improved bit performance and reduced drilling days," he added.

For the Marcellus and other shale basins, Halliburton's Application Design Evaluation specialists needed to design a bit that would result in higher build rates in the curve to maximize the well's lateral length inside short lease lines. The bit designs took a four-pronged approach.



Tracks 1 and 2 show the high-frequency response for the QBAT sensor wide-band receiver (Track 1) versus a standard receiver (Track 2). Tracks 3 and 4 show the same comparison for the low-frequency response. The receivers were all mounted on the same tool, operating in extremely poor hole conditions. *(Image courtesy of Halliburton)*

First, the bit was designed to be much more laterally aggressive and steerable than in the past. Designers used modeling systems to match the bit to the drive system to achieve the build rates they wanted. Second, bit profiles became flatter and shorter.

"We also incorporated more of what I call depth-of-cut features," Lefort explained. "It is critical for the depth-of-cut features to be placed more accurately than we had in the past, and they had to match the drive system or steerable motor."

Finally, the bits had to have optimized hydraulics to achieve the ROP the operators wanted.

"The new custom-designed shale bits are able to achieve the build rates operators need plus drill at very high ROP," Lefort explained.

Case studies

Halliburton Drill Bits and Services has several case studies showing record performance bit runs with their FXD54M bits in the Bradford Field in Sullivan County, Pa. In one run, the 8½-in. FXD54M bit set a field record for ROP at 91.7 ft/hr drilling the lateral section of 3,668 ft in 40 hours with good tool face control and no downhole tool failures (DTF) or nonproductive time (NPT). The bit outperformed the offset wells, setting the benchmark in ROP and cost per ft, and was pulled out of the hole in excellent condition.

The directional drilling report showed that the bit averaged 148 hours rotating and 45.8 ft/hr sliding for an average ROP of 117.7 ft/hr without connections.

Another run established a field ROP record with a directional motor assembly in Greene County, Pa. The 7⅞-in. FXD54M set the field ROP record drilling the 4,444 ft lateral section in 42.5 hrs, averaging 104.5 ft/hr on a conventional directional motor assembly with surveys and connections included. The bit had good tool face control, no DTF or NPT, and outperformed the offset wells in ROP and cost per foot. The offsets were from 8½-in. hole sections.

In another run the 7⅞-in. FXD54M bit drilled the entire lateral section of 5,665 ft in 80.5 hrs for an overall ROP of 70.4 ft/hr and generated a cost per foot of $18.56. The bit provided good tool face control, resulted in no DTF or NPT, and outperformed the offset averages in footage drilled and ROP cost per foot. The bit emerged from the well in excellent dull condition.

Optimal bit placement

The company's Sperry Drilling business line offers several tools and software to optimally place the bit, whether drilling the vertical, curve, or lateral. Some of the tools include its RSS, EM telemetry technology, and its Bi-modal Acoustic LWD Sonic tool (BAT).

The company's EZ-Pilot RSS is being marketed as an economical system that was developed specifically for onshore applications and is being used successfully in shorter laterals typical in the Marcellus. The company also markets its full-blown Geo-Pilot RSS for longer laterals in other unconventional basins, although it also has been used in Marcellus wells.

"We are seeing some operators drill longer-length laterals to reduce their footprint," said Patrick Connors, Northeast District operations manager for Sperry Drilling. "If you can drill six 10,000- ft laterals from one pad, you can have better access to the reservoir."

The EZ-Pilot works by controlling orientation of the eccentric cam system that offsets the mandrel and the bit in the desired direction. Rotation of the cam system to change tool face orientation is accomplished by controlling an ultra high-torque DC motor powered by lithium batteries. The position of the outer housing is constantly monitored, and the tool automatically corrects the eccentric cam system setting as required to maintain proper toolface orientation.

The target tool face is set through rotary speed commands sent from the surface pulsed or electromagnetic telemetry.

EM telemetry

"In general, we run the bulk of our jobs across the Marcellus with EM telemetry," Connors said. "The EM system works in most plays. Even in Marcellus there are areas that are better than others as far as EM systems are concerned.

"We generally know where those areas are, and we also developed techniques specific to Sperry that enable us to have more access to different locations," Connors noted.

EM telemetry transmits the data signals through casing in the well or the casing of an offset well on the same pad. The technology can transmit at a higher data rate compared with mud pulse telemetry, which reduces survey time. EM telemetry transmits downhole survey data to the surface and also transmits data and commands to downhole tools such as EZ-Pilot and other tools.

EM telemetry is useful for high ROP applications where real-time logging data can be an issue, in geosteering applications with EZ-Pilot or Geo-Pilot, and in shallow TVD and extended-reach horizontal wells. A through-bore repeater system is available for increased depth range and signal strength. There are no moving parts in the system, increasing reliability and eliminating trips and NPT due to tool failure.

Sonic tools

The company's BAT and QBAT services are used to identify stress direction, rock ductility, and brittleness. BAT and QBAT can provide porosity determination and formation mechanical properties, pore pressure determination, rock strength calculations, and borehole stability analysis.

"It essentially allows the operator to drill toward the good formation rock, doing that in real time, and being able to right-size your frac job by putting your stages in the proper areas," Connors explained.

High-build rotary steering, bits for shale, channel fracturing, expanding cement

Service companies continually listen to and work with their clients to provide technology and solutions that result in optimal drilling, completions, and production of their wells as well as develop new technologies that can further enhance performance and economics of a well. For example, operators don't use RSS in the Marcellus as much as in other shales, as many operators don't consider the cost versus the reward justified in the Marcellus. Drilling operations, although complex, are not as complex as in other shale basins. However, some operators are re-examining rotary steering now that a couple of service providers have introduced high build-rate systems to get into the lateral quicker and be able to stay there. Of course, a smooth wellbore doesn't hurt the situation, either.

High build-rate RSS

Schlumberger is one of the companies that developed a rotary steerable system that was developed and designed to drill the vertical well section, curve, and lateral in one run, eliminating flat time and improving efficiency.

"Part of the reason we developed the PowerDrive Archer, other than the advantage of drilling the well without a bit trip, which everyone cares about," said Dale Logan, Schlumberger's regional account manager for the Northeast Basin based in Pennsylvania, "is so operators can hit the reservoir earlier, which means more reservoir exposure and increased hydrocarbon potential.

"PowerDrive Archer was extensively field-tested in many US shale basins, drilling wells only previously possible with motors, and has achieved build rates exceeding 17°/100 ft," he said.

Case study

In one Marcellus well, the PowerDrive Archer RSS increased ROP 170%, cut drilling time by 10 days, and saved the operator more than $1 million. To extract Marcellus gas economically, horizontal wells are drilled from multiwell pads and completed with multistage fractures of the horizontal lateral section. The operation is complex and difficult due to surface pad collision risks, 3-D profiles with planned curvature rates of 8°/100 ft, and formations that can make directional control difficult.

The hybrid PowerDrive Archer RSS combines point-the-bit and push-the-bit steering and can drill the vertical, curve, and lateral sections in one run. Traditionally, the vertical section of a Marcellus well is air-drilled; a 9⅝-in. shoe is set; and the 8¾-in. hole section is kicked off, built, and landed in the Marcellus Formation with a PDM. Much of the time, however, the drill pipe and PDM are in sliding mode, which results in lower ROP, poor hole cleaning, and wellbore tortuosity. Additionally, trips were required to adjust the PDM's bent housing when encountering geological uncertainties, resulting in increased time and cost.

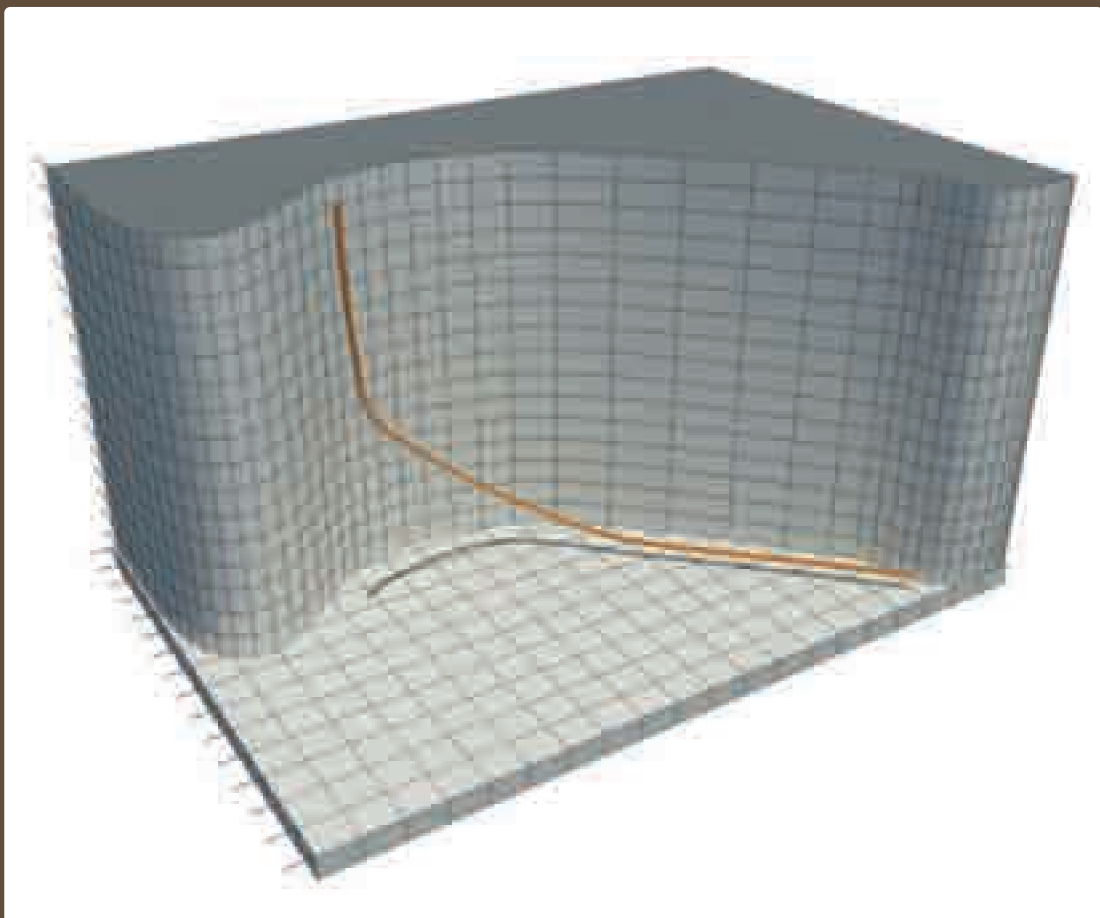
The company used its PowerDrive Archer RSS when a Marcellus operator was planning a multi-well operation and wanted to improve ROP and hole quality. The first well was drilled with a PDM to establish a benchmark. All subsequent wells were drilled with the PowerDrive Archer RSS.

These wells were typically kicked off from vertical with a long turn in azimuth of 90° or more to line up with the target while simultaneously building inclination at planned rates up to 8°/100 ft. Due to geological uncertainties approaching the landing point, higher build rates up to 17°/100 ft were sometimes required to land the well.

The ability to kick off from vertical, deliver 2-D and 3-D curves with build rates up to 17°/100 ft, drill tangent sections, and land wells on target in a single run enabled the operator to reduce drilling time from 18 days with a PDM to eight days on the 10th well drilled with the PowerDrive Archer RSS, according to the company. Average ROP increased 170% compared to the benchmark ROP. Eliminating sliding with a PDM resulted in a high-quality wellbore that allowed smooth casing runs. The operator saved more than $1 million on the first 10 wells drilled with PowerDrive Archer.

Shale optimized drill bit

A couple of bit manufacturers have developed "shale-optimized bits," application-specific bits with designs and technologies aimed at increasing performance and economics. The Spear shale-optimized steel-body PDC drill bit from Smith Bits is specifically designed for shale plays. Smith Bits' field, design, and hydraulics engineers used proprietary design and database tools including IDEAS, an integrated drillbit design platform to predict bit and BHA performance. DBOS drillbit optimization system for rock strength analysis also was utilized, as was YieldPoint RT drilling



In this well, the PowerDrive Archer rotary steering system (RSS) was able to kick off from vertical, drill a 3-D curve with more than a 100° change in azimuth, and hold an unplanned tangent section made necessary by a landing point change of more than 70 ft. The RSS quickly built to 16°/100 ft once the geological marker was found and then soft-landed the well from 85° to 90° at a 2° build rate. *(Image courtesy of Schlumberger)* hydraulics and hole cleaning simulation program and DRS drilling record system, a collection of nearly 3 million bit runs.

Manufacturing the bit from steel provides more flexibility in the design criteria and allows increased blade height to optimize the blade/body configuration for shales, according to the company. Erosion to the steel body bit that could be caused by drilling mud and cuttings was alleviated by use of computational fluid dynamics that simulated at-bit flow for optimal nozzle placement and orientation. Hard facing of the bit help protect the steel from erosion.

"By combining new bit technology with new directional drilling technology, the industry can expect another leap forward in drilling efficiency," Logan said. "The impact to the operator is that he moves to the next well quicker to drill more wells per rig per year. This is critical to operators who are under pressure to fulfill large leasehold obligations," Logan added.

Case study

EOG Resources wanted to reduce the number of days and trips required to drill the 7⅞-in. curve and lateral sections of its Marcellus wells by drilling both sections in one run. Previous bit designs were aimed primarily at either the curve or the lateral, requiring a trip to change the bit and adjust the motor bend angle at the end of the curve section. Additionally, EOG wanted to reduce NPT caused by motor and MWD failures. EOG provided BHA data, mud properties, and offset run information.

Smith Bits' engineers needed to design a PDC bit that could be run on a PDM with a lower bend angle, allowing rotation and a high ROP in the lateral section. A the same time, however, the bit had to be capable of achieving the necessary build rates of 8° to 16°/100 ft while ensuring good directional control in the curve. Long lateral drilling in shales presents additional challenges such as cuttings accumulation at the bottom of the well, which impedes access to fresh rock and results in lower ROP, packed blades, plugged nozzles, and stick/slip.

The result was the Spear 7⅞-in. SDi513 steel body PDC bit specifically designed for Marcellus shales.

The bit, in combination with a fixed bend steerable motor, drilled the 6,241 ft curve and horizontal interval in one run, eliminating trips for PDM adjustments and bit changes after landing the curve. Reduced bit and tool vibration solved the issues of PDM and MWD failures. The bit's bullet shaped steel body and other design features alleviated buildup of cuttings in front of the bit.

In comparisons with the average offset wells, total drilling time was reduced by 2.7 days, saving EOG $175,000 in rig time and bit costs. The shortened time to production also allowed more wells to be drilled in a given period.

Channel fracturing

"One recent technology that we anticipate will have an impact in shales is a new fracturing technique that has been popular in the Eagle Ford Basin," Logan said.

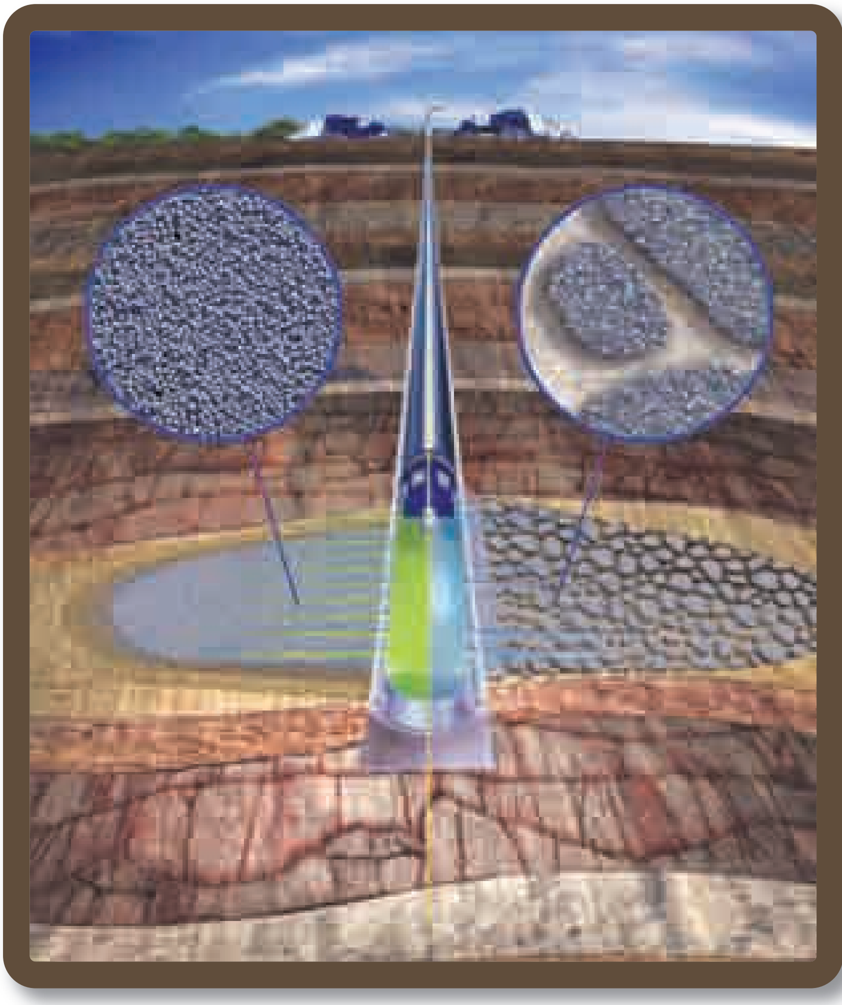
The technique, called channel fracturing, is offered by the company commercially in its HiWAY product. The technique involves mixing fibers with proppant to create channels through the fracture network to enhance conductivity of the network, Logan explained.

Rather than leaving fracture flow dependent on proppant pack conductivity, HiWAY creates stable channels for hydrocarbons to flow through, increasing the effective fracture conductivity. Operators can get better productivity from their wells, he noted, and frac jobs can be performed with less proppant. "On a typical HiWAY job we pump half as much proppant, and the amount of fibers is small," Logan said.

The successful application of channel fracturing is very much formation-specific, and it cannot be universally applied, Logan noted.

Case study

In the Hawkville Field in the Eagle Ford Basin, Petrohawk wanted to improve production and EUR from its Eagle Ford wells. Production from the area is driven by the effective stimulated reservoir volume (SRV) and the reservoir connectivity with the wellbore that can be established with hydraulic fracturing. The field has very high fracture gradients and high bottomhole temperatures at depths between 10,000 and 13,000 ft. Since the discovery of this section of the Eagle Ford in 2008, the formation has been stimulated typically with multistage horizontal completions with high-rate slickwater treatments. Recently,



The HiWAY technique creates highly conductive flow channels, so hydrocarbon flow is no longer limited by proppant conductivity. *(Image courtesy of Schlumberger)*

however, there has been a trend to use polymer-base crosslinked and hybrid treatments, which led to a moderate improvement in production.

Petrohawk and Schlumberger implemented the HiWAY technique in two wells to build an assessment. Results from the two wells were compared with those from valid offsets previously stimulated by conventional techniques. The results indicated that channel fracturing gave the first well fractured with the HiWAY technique a maximum initial rate of 14.5 MMcf/d, or 37% higher initial gas production than the best comparable offset well. The technique gave the second well a maximum initial rate of 820 b/d, or 32% higher initial oil production rate than the best comparable offset. Additional wells have been completed for Petrohawk using the channel fracturing technique, and all have shown production trends consistent with the initial test wells, according to Schlumberger.

Surface gas migration

"In the northeast US there is a lot of interest from the public in what the industry is doing and why we are doing it," Logan said. "There are a lot of shallow gas zones that are not far from where people get their drinking water, and there is concern that because of the drilling activity, that gas is migrating into drinking water."

As a result, Logan said, the industry is examining new cement systems to mitigate the risk of gas migration. Expandable cement is not a new solution, but it has not been used in the Marcellus until recently. "The cement is more flexible and makes a seal that can handle the jarring from a high-volume frac job," Logan said. "It is more likely to maintain the isolation created during the cement job because it bends and flexes rather than breaks."

The cement involves the use of multiple inert solids and engineered particles that provide maximum flexibility and expansion, according to the company, and provides positive linear expansion compared to most conventional cements that shrink, preserving well integrity during stimulation treatments. The cement can be engineered for use in shale gas wells, heavy oil environments, and high-temperature wells above 300°F. The cement can be used in temperatures ranging from 40 to 300°F.

During placement, the cement can provide optimized slurry viscosity and solids volume fraction suitable for effective mud removal and flat interface of fluids, according to the company. After placement, the result is low gel strength, short transition time, and fluid loss control suitable for gas migration environments. The cement can expand up to 2%.

Clean water is imperative for oil and gas industry

The oil and gas industry runs on water, it sometimes seems, requiring millions of gallons of water for its drilling operations and frac jobs. It's not inexpensive considering the cost of the water itself, trucking it to the well site, trucking flow-back water to a central treatment facility unless a mobile treatment unit is available, and then disposing of used water that won't be needed again. Disposing of the waste products generated by the treatment processes also is expensive depending on the proximity of a treatment facility where it can be disposed, or if, in some cases, water and waste have to be trucked to facilities in different states, as in the case with some Marcellus Shale operations. In some parts of the Marcellus, the only viable disposal option includes trucking to Ohio for disposal in salt water disposal wells.

Water is generally available for Marcellus Shale drilling and completion operations, but that doesn't mean there isn't demand for water treatment facilities for reusing flowback and produced water for the next frac job. Companies including Halliburton and M-I SWACO are continually looking at more efficient and less expensive processes for treating and cleaning flowback and produced water. Among the treatments being investigated are membrane and thermal technologies, neither of them very new but not yet used generally in shale basins.

In the Marcellus in particular, operators presently only need water to be clean enough to reuse for their next frac job. Membrane and thermal processes produce water that is too clean for operators' use, or rather the processes go beyond what operators need for reusing the water. Still, some water treatment companies are moving ahead with the membrane and thermal water treatments in the Marcellus with an eye toward the future when less water will need to be treated as the exploration and completion phase turns mainly into a production phase.

Chesapeake Energy in the Marcellus experiences about a 10% frac flowback. "We will see the initial produced water volume of about 500,000 gal during the first 10 days from a typical 5-million-gal frac in our Pennsylvania Marcellus operations," said Matt Mantell, P.E., environmental engineer for Chesapeake Energy. "The long-term produced water volume drops significantly from very little to almost nothing, and what we see over the life of a well are water volumes of only a few gallons per million cubic feet of gas produced."

Chesapeake's water management company treats the frac flowback and produced water through a sock-type filter, first through a 100-micron mesh and then a 20-micron mesh filter. The third-party water treatment company typically would set up its equipment on a pad leased by Chesapeake near the well sites to produce the flowback and produced water.

"Right now our filtration systems are working well," Mantell said, "but we are always looking for ways to improve and also looking to the future where we are going to have to begin dealing with produced water making up an increasingly large portion of the water used in our drilling and completion operations.

"We are looking at higher level treatments, not necessarily membrane or distillation systems, but treatment systems that can remove scale-causing compounds that are not removed by our present filtration system."

Controlling bacteria, recycling water

Halliburton's CleanStream ultraviolet (UV) light bacteria control process for fracturing fluid enhances environmental performance by reducing or eliminating the volume of conventional biocides required to treat the fluid. The process, which can treat up to100 bbl/min, is presently being used in Marcellus Shale fracturing operations.

"The CleanStream service unit is integrated into the fracture equipment set-up and is used to control bacteria in the frac fluid," said Larry Ryan, Halliburton's global manager of water treatment.

While UV treatment of biocides in water has been used in other industries, CleanStream service is the first use of the process in the oil and gas industry.

The service enables operators to significantly reduce the volume of biocides when treating water for aerobic and anaerobic bacteria. For example, a 5-million-gal water frac treatment that requires 5,000 gal of biocide can be implemented using one CleanStream service unit and 500 gal of biocide for conditioning. If well-site logistics permit the use of the service on the fly and long-term downhole bacteria control is not required, biocide additions can be eliminated, according to the company.

Chesapeake delivers waste water to the Wysox Water Treatment Facility in Pennsylvania. *(Photo courtesy of Chesapeake)*

"The dominant method of treating bacteria growth is still with biocides," Ryan said. "If we can eliminate the biocide from the process, we can reduce the environmental risk. UV light is ideal for that."

UV light controls bacteria growth when the cellular DNA of microorganisms like bacteria absorb the energy from the UV light, damaging their DNA structure and interfering with many cellular processes, including protein synthesis. Replication of the chromosome prior to reproduction is impaired so the bacteria are unable to produce proteins or to replicate.

The self-contained, trailer-mounted mobile units are currently in use in the Marcellus, Barnett, Woodford, and Haynesville shales and in the Piceance Basin. While the company has been focusing its use of CleanStream service in shale plays, it can be used anywhere that bacteria needs to be controlled. Because the treatment process applies to the base fluid before modifiers are added, it can be used whether the frac job is with a slickwater type treatment or a crosslinked or linear gelled fluid treatment.

Turbidity of the water plays a role in the effectiveness of the process. As turbidity increases, exposure to the light source must also increase to effectively control bacteria. A monitoring and control system for the UV light is tied to the desired treating rate and the turbidity of the water. If the water is very murky, additional units can be mobilized to the location to increase exposure to the UV lights. Two other options are to slow the treating rate or treat the water to remove the suspended solids with the CleanWave system.

This service, another Halliburton water treatment process for flowback and produced water, was also introduced in 2010. It has been used in several shale basins including the Vernal Basin in Utah as well as the Piceance and Haynesville basins. The company is preparing to use the process in the Bakken Shale this summer. Equipment for both services is trailer-mounted for mobility.

"There are some water treatment facilities in the Marcellus development area that employ relatively similar techniques to process flowback and produced water streams as the CleanWave service. These facilities may employ coagulation, filtering, separation, and pH modification in their processing" said Matt McKeon, technology manager, Northeast District for Halliburton. "However, they require a large-scale facility with settling ponds, treatment tanks, and equipment that doesn't enable mobile operation."

If the frac fluid is a combination of freshwater cut with turbid flowback or produced water at typical ratios, the CleanWave system could potentially be employed on-the-fly during fracturing operations on the turbid water stream only. The treated water would then be combined with the freshwater stream and processed through the CleanStream unit. This provides the benefit of both water treatment processes being applied at fracturing rates to only the frac water being pumped downhole.

The company's CleanWave water treatment system, which can treat 20 bbl/min, uses an electrical process that destabilizes and coagulates suspended colloidal matter in water. Easy scalability enables quickly treating the large volumes of water in reserve and flow-back pits and, depending on the operation, treating flowback and produced water online during a fracturing operation. While the CleanStream service treats water just before entering the blender, the CleanWave system prepares the flowback and produced water for reuse, removing up to 99% of total suspended solids.

When contaminated water passes through the electrocoagulation cells during treatment, the anodic process releases positively charged ions that bind onto the negatively charged colloidal particles in water, resulting in coagulation. At the same time, gas bubbles produced at the cathode attach to the coagulated matter, causing it to float to the surface where it is removed by a surface skimmer. Heavier coagulants sink to the bottom, leaving clear brine water suitable for drilling and production operations.

"One thing to keep in mind is that enhanced treatment processes like reverse osmosis and distillation typically require a step preceding that process," Ryan said, "which is similar to the filtration and electrocoagulation provided in our CleanWave system."

Frac flowback water treatment

M-I SWACO is focusing its water-treatment capabilities in providing mobile treatment technology of frac flowback at the source, presently with its filtration technology removing certain micron-sized particles from water, and its reclamation technology, which uses chemical treatment to remove constituents dissolved in the water such as calcium, magnesium, iron, and barium. "In the Marcellus we are trying to recycle as much frac flowback as possible and reuse the water for the next frac job," said Brad Billon, director, Oilfield Water Management.

The company's Aqualibrium water treatment technologies are used in numerous unconventional and conventional basins. In the Marcellus, the company has been able to save operators tens of thousands of dollars by recycling frac flowback and produced water.

"At this point in the development of the Marcellus Shale play, operators want to reuse as much of the water as they can because of their need for water to frac their next well and because recycling helps minimize the environmental and cost impacts," said Adriana Ovalle, business line manager, Oilfield Water Management. "What we have seen so far is that operators want to treat the water by filtration, reclamation, and bacteria reduction."

In one case, a Marcellus operator was fracing up to five wells per week using an average of 150,000 bbl of water per frac job. Flowback from the five wells was about 112,500 bbl/week. The operator was committed to reuse 100% of the flowback water, conserving freshwater resources and reducing the number of trucks on the road.

The company recommended the Aqualibrium filtration system designed to remove the total suspended solids up to the operator's mandated 20-micron desired size. This resulted in minimizing waste disposal and reducing the consumption of freshwater from the local township as well as reducing the number of trucks necessary to transport the freshwater from the source to the location. The process treated up to 1.8 million bbl of frac and produced water with 99% of the water recycled.

In another case, an operator was planning a 10-stage frac job that would use 100,000 bbls of water. The project would require an onsite water tank farm, purchasing and trucking water from a local town with only 100 bbl per load capacity, flowing back 10% to 30% of the frac fluid over a 10-day period, and trucking off and disposing of the flowback water.

The operator wanted to remove contaminants that could cause scaling, reduce total suspended solids to prevent formation damage, and lower total dissolved solids and minimize disposal volumes. M-I SWACO developed a frac water reclamation system to address the primary concerns of the operator and third parties while being able to reuse the flowback water on subsequent frac jobs.

Additionally, reducing water consumption from the local town reduced required trucking, maintained environmental safety, and controlled costs.

The company treated 10,414 bbl of reclaimed frac water with 99% water recovery and 125 bbl of semi-wet solid waste. The average daily processing rate during a 12-hour span was 3,000 bbl, with the maximum daily processing rate of 3,850 bbl of reclaimed fluid, significantly reducing the operator's costs.

Infrastructure Needs Follow Fast-paced Marcellus Activity

But regulatory and environmental issues may slow resource development.

By Skip Simmons
Contributing Editor

Marcellus gas development has proceeded at full throttle, and a variety of midstream infrastructure needs are following closely behind. However, very recent environmental policy changes in Pennsylvania involving water handling and treatment, the possibility of a production tax in the state, and potential new regulations related to hydraulic fracturing may slow the torrid pace of area resource development. Also, with New York state regulators seeking to reach a final policy decision related to restoration of ongoing regional development, uncertainty and timing remain there as well.

The Marcellus and Devonian shale gas plays underlie portions of six northeastern states and cover 95,000 sq miles. The majority of Marcellus shale gas development is in West Virginia, Pennsylvania, and New York, but savvy operators are eyeing the play's boundaries with a hunger for growth. This could mean more midstream infrastructure will be needed to get ever-growing resources to market, in whichever direction that may go.

Play contains hydrocarbon-rich gas

As Marcellus gas already enjoys a pipeline transportation-cost advantage compared to other supply regions, wellhead price for Marcellus gas is strong due to its proximity to many high-value, end-use gas markets and significant gas storage markets in the northeastern US. As certain portions of the Marcellus play also contain processible hydrocarbons, these developments are ultimately upgradable in commercial value due to a natural gas liquids content associated with the produced gas streams. Thus, in addition to facilities required for natural gas transportation, major new midstream infrastructure is being developed to allow natural gas liquids (NGLs) to be removed from the flowing wellhead production and deliver those products to their related markets. This infrastructure includes gas processing plants, fractionation facilities, product storage tanks, and facilities such as truck- and rail-loading as well as NGL pipelines. Those liquids, valued relative to an expected higher forward crude-oil price forecast, can be aggregated and marketed for added value above what those same products would have received had they remained in the gas stream and been priced and sold therein.

Although not as rich in hydrocarbon content as some other developing shale plays, gas processing facilities are being implemented in the Marcellus region in a number of key locations. Ironically, portions of the rich-gas streams being developed are higher in ethane content relative to other US shale developments and domestic gas sources. This higher-than-average ethane content becomes an increasing concern over time due to proximity to nearby downstream markets or regional gas-storage facilities. Today, ethane is being blended with other regional flowing gas to meet pipeline quality specifications. Many regional gas pipeline operators have signaled that ongoing area development will yield actual production volumes flowing from the richer Marcellus sources that will have exceeded regional pipeline blending options and flexibility by 2012 and thereafter. At that point, regional processing and/or treating infrastructure capabilities to remove the ethane and evacuate it from the area must be in place. Therefore, contracts that support a multifaceted, integrated regional gas processing and NGL distribution capability are being negotiated, designed, and are in initial stages of implementation and should meet the mid-2012 target date.

In March 2011, NOVA Chemical and Marcellus operator Caiman Energy announced a memorandum of understanding (MOU) for NOVA to purchase up to 20,000 b/d of ethane from Caiman's Fort Beeler gas-processing plant. In May, NOVA Chemical and Range Resources also signed an MOU for Range to provide a long-term supply of ethane from the Marcellus Shale to Nova. While negotiations are not finalized on either arrangement, Sarnia, Ontario, market demands are definitely starting to seek ethane arrangements for future needs.

Other NGL products being generated in the region are at quantities that generally can be removed and managed by truck, rail, or barge transportation to local markets. Several new processing plants or fractionators are planned, as well as connection to NGL transportation and distribution systems such as truck, rail, and NGL pipeline.

Major area gas gathering systems

Some of the major Marcellus gas gathering systems are

CURRENT MARCELLUS-AREA MAJOR GAS GATHERING SYSTEMS

Operator, System	Size/Commercial Capability
Anadarko Grugan gathering	0.2-0.6 Bcf/d. Dry gas connection to Transco Pipeline. Expanded to 1.15 Bcf/d capability.
Caiman Energy Ft. Beeler gathering, gas plant, and NGL pipeline	Process 0.12 Bcf/d, expanding to 0.32 Bcf/d by early 2011 and to 0.52 Bcf/d by late 2012. NGLs are routed to Mark West Liberty Houston, PA fractionator.
Chief Oil & Gas Gas gathering and compression	0.3 Bcf/d dry gas delivery into Transco
DCP Midstream/Magnum Hunter Eureka Hunter Pipeline	 0.2 Bcf/d dry gas to Dominion
DTE Energy Bluestone Pipeline	0.7 Bcf/d dry gas delivery to Millennium
Dominion Transmission Inc. Hastings, WV processing plant Line TL-404 project WV,PA,OH Northeast Marcellus Project PA/	 0.18 Bcf/d wet gas processing capability with fractionator capacity of 13,000 bbl/d. Storage, rail, truck, barge, and pipeline capabilities for NGLs disposition 0.3 Bcf/d wet gas gathering capability to Ft. Natrium, WV gas processing plant and fractionator NGL capacity: 32,000 bbl/d 0.2 Bcf/d Receipts from Southwest PA to Leidy Hub (2012)
EQT Midstream Gathering PA Gathering WV	 0.17 Bcf/d to Equitrans system (2011). Total 0.3 Bcf/d. 0.085 Bcf/d to Equitrans system
Laser Northeast Gathering Company, LLC Susquehanna Pipeline	 0.4 Bcf/d gathering and dry gas delivery to Millennium Pipeline
MarkWest Energy Partners Siloam NGL Complex, Kentucky	 Receives NGLs from (4) non-Marcellus regional processing plants. Temporarily, Marcellus's heavier NGLs are being trucked there until Houston, PA fractionator is complete. Fractionator has 24,000 bbl/d capability with storage, truck, rail, and barge disposition for NGLs.
Mark West Liberty Majorsville, WV gathering and gas plant	0.27 Bcf/d wet gas receipts at Majorsville, WV gas plant. Connecting NGL pipeline to Houston, PA fractionator as well as an extension of NGL pipeline to connect to Caiman Energy's Fort Beeler plant NGL pipeline
Mark West Liberty Houston, PA gathering and gas plant	0.36 Bcf/d wet gas receipts at Houston, PA gas plant. Current depropanizer at 27,000 bbl/d with full fractionator at 60,000 bbl/d (late 2011). Will have rail and truck loading facilities as well as proposed propane pipeline to TEPPCO NGL pipeline.
Mark West Liberty Mobley, WV gas plant	0.12 Bcf/d gas plant straddling portion of Equitrans pipeline. An NGL pipeline will be constructed to the Houston, PA fractionator (mid 2012).
National Fuel Midstream Covington gathering Trout Run Gathering	 0.15 Bcf/d gathering. Delivery to Tennessee 0.3 Bcf/d gathering. Delivery to Transco.
Nisource Midstream Services Gathering PA Gathering system WV	 0.1 Bcf/d wet gas to Mark West Liberty Majorsville plant 0.25 Bcf/d wet gas to Mark West Liberty Majorsville plant
UGI Energy Services Inc. Wyoming County, PA	0.12 Bcf/d dry gas gathering. Delivery to Tennessee.
Williams Pipeline Partners Gas gathering system acquired from Cabot (late 2010) Gathering expansion Springville gathering	 0.4 Bcf/d dry gas with delivery to Tennessee. Will add 0.85 Bcf/d gathering by 2013. 0.45 Bcf/d dry gas gathering. Delivery to Transco.
Williams/Atlas Pipeline JV Gas gathering/Laurel Mountain Midstream (Existing) Gas gathering/Laurel Mountain Midstream (Expansion)	 0.2 Bcf/d from regional conventional gas wells Adding 0.5 Bcf/d from Marcellus wells with delivery to TX Eastern

focused on dry-gas development and are connecting to existing regional pipelines. Others contain rich-gas streams and are being developed in association with area gas processing and natural gas liquids handling capabilities. For those associated with processible gas, gas processing plants and/or fractionators are being implemented as well as connection to local NGL transportation and distribution capabilities such as truck, rail, and future NGL pipeline capability.

Gathering systems will be expanded and/or other gathering systems will continue to be developed as regional activity remains extremely high.

Producers pushing supply further into the market region

After producing, gathering, and treating to pipeline quality where required, the Marcellus volumes are connected to regional interstate and intrastate pipelines for delivery to market centers. Many of the pipelines in the Northeast are sold out from a firm transportation capacity standpoint, both for annual gas transportation service from supply areas or from regional storage services providing firm withdrawals of gas in the winter months. Historically, many regional expansions of capacity have been driven by downstream market demand needs for additional flowing supply or storage rather than being driven by upstream supply availability. However, Marcellus producers have elected to push their supplies deeper into the market area. These interstate expansions represent a unique combination of firm capacity offerings, wherein some of the expansions are improving or completing the connectivity of Marcellus volumes to points on the regional pipeline grid where firm capacity is already available to downstream markets (i.e., a feeder role, post initial gathering), while other expansions represent availability and connection to incremental firm capacity that provides direct access to downstream markets. Numerous other projects will be evaluated for future implementation, with most of them seen as needed in the period 2013 and beyond. In the interim, the developing Marcellus supplies will effectively compete for access to existing firm pipeline capacity and market share.

Potential bumps in the road

Considering the overall commercial environment of the region, several issues may slow the current pace of Marcellus development.

First, with a recent announcement from state regulators in Pennsylvania, a number of centralized water treatment facilities in use within the state for treatment of wastewater from drilling and/or production operations were advised to discontinue such activities by May 19, 2011. These public and private water treatment facilities had been specifically using chemical treatment and filtration capabilities to provide for daily recycling of hundreds of thousands of gallons of used water and returning same to local rivers, streams, or eco-systems. This recent policy announcement now posits that these facilities are not properly equipped to remove associated pollutants and allow water to be returned into rivers and streams. Though some of the affected facilities may be able to make modifications to meet increased Pennsylvania DEP concerns, the upstream and/or midstream industry segments now must also respond with necessary techniques, technology, and infrastructure to provide an even greater portion of their future wastewater handling.

The second "bump" is the continuation of active debate on the regulations related to use and disclosure of chemicals used in the hydraulic fracturing process. Some upstream parties have taken the initiative to post their actual usage, while others maintain that confidentiality is appropriate. These dialogs are ongoing not only at the state regulatory level but also occasionally at the federal regulatory level. With the potential for misinformation entering the dialog and ongoing disputes related to published studies and their related conclusions, this critical well development activity must be monitored carefully as to potential Marcellus resource development impact.

Also, Pennsylvania is one of the few producing states that does not have a tax related to resource production. In increasingly difficult financial times, state regulators are once again floating the need for a production tax on produced resources. This tax would be considered as a added cost to area producers and could potentially affect their investment hurdles and future resource development decisions.

In spite of the possibility for some level of additional Marcellus regional upstream slowdown to that already in effect for Marcellus development in New York state, Marcellus midstream gas and NGL infrastructure development will continue. Rather than being seen as major bumps in the road, a commitment to "stay the course, yet ease back on the throttle" may have positive results for the timing and availability of midstream infrastructure. Parties have been committed to assuring that these facilities are in place to gather, treat, process, and move the developed resources into the regional markets. With the Marcellus play being heralded as "world class," regional infrastructure development in the area appears to have only just begun.

Midstream Players Focus on Myriad Challenges

Several solutions are needed for the Marcellus Shale to reach its anticipated potential.

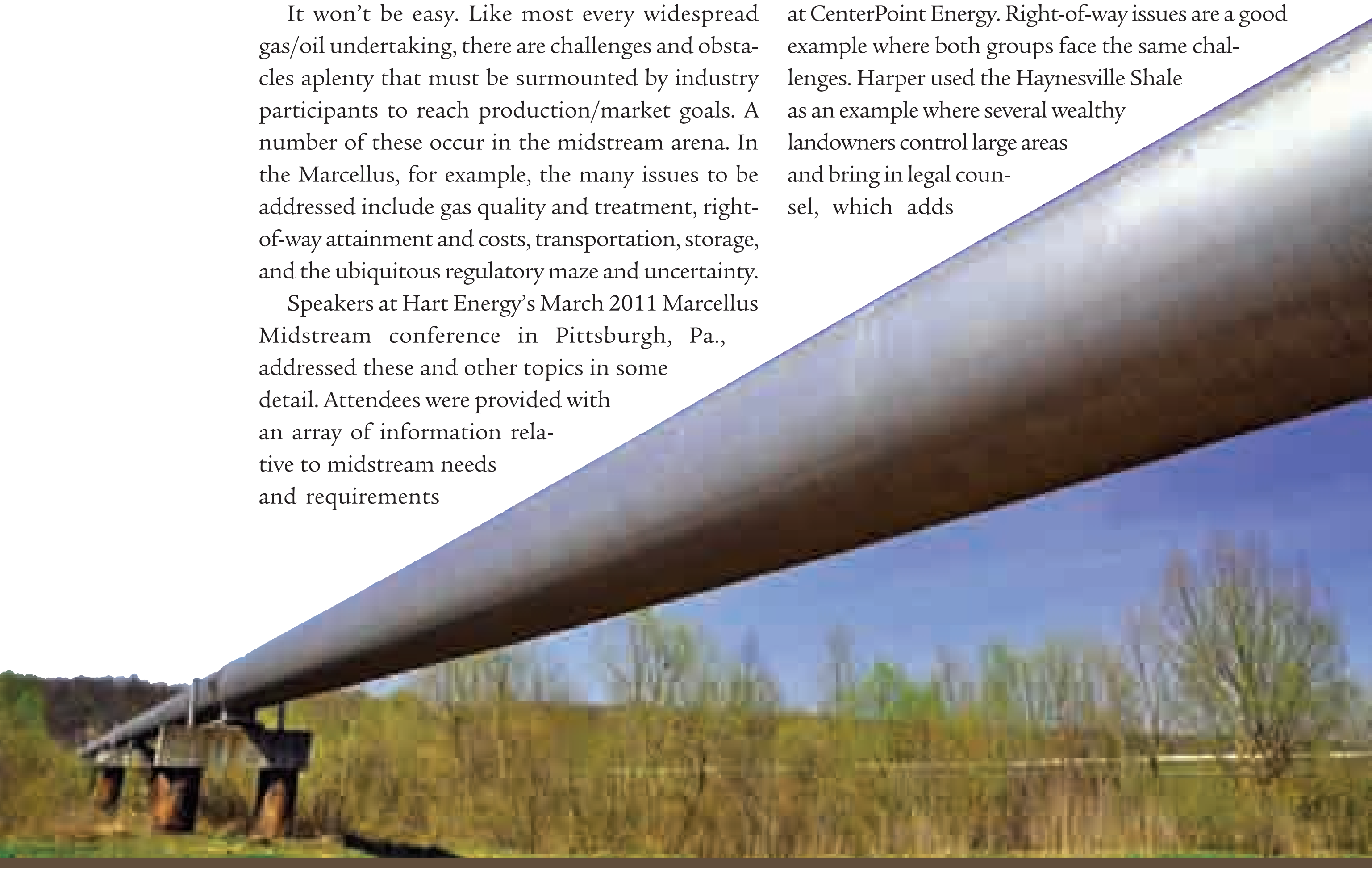
By Louise S. Durham
Petroleum Geologist

Shale plays continue to proliferate both domestically and globally, yet the Marcellus Shale play in the US remains a dominant attention-getter. The Marcellus occurs across parts of six northeastern states, with the bulk of industry activity today occurring in Pennsylvania, New York, and West Virginia. The projected recoverable reserves from the Marcellus tally more than 50 Tcf.

It won't be easy. Like most every widespread gas/oil undertaking, there are challenges and obstacles aplenty that must be surmounted by industry participants to reach production/market goals. A number of these occur in the midstream arena. In the Marcellus, for example, the many issues to be addressed include gas quality and treatment, right-of-way attainment and costs, transportation, storage, and the ubiquitous regulatory maze and uncertainty.

Speakers at Hart Energy's March 2011 Marcellus Midstream conference in Pittsburgh, Pa., addressed these and other topics in some detail. Attendees were provided with an array of information relative to midstream needs and requirements and reminded that solutions to challenges must be devised to ensure the Marcellus fulfills its anticipated potential for production and marketability.

There's been much ado about operators/producers taking lessons learned in one shale play to do better on the next. This holds true not only for upstream but midstream as well, as pointed out by C. Gregory Harper, group president, pipelines and field services at CenterPoint Energy. Right-of-way issues are a good example where both groups face the same challenges. Harper used the Haynesville Shale as an example where several wealthy landowners control large areas and bring in legal counsel, which adds



time and expense to doing the deal. Right-of-way costs for a midstream player like CenterPoint can be considerably less by entering plays early before these costs virtually explode in a hot play.

Harper commented that other issues impacting midstream operators' wallets include added expense for multiline rights for potential expansion or transporting other products, such as NGLs or produced water, extensive lead time for materials, and weather-related project time extensions. The potential for bidding wars for talent to work the really "in" plays adds to the financial headaches.

Marcellus production currently amounts to some 1.3 Bcf/d, according to Opoku Danquah, director of upstream research for Hart Energy. He noted that if takeaway capacity is put into place, US concerns about abundant gas supplies are unfounded. He emphasized that midstream providers and operators are busy placing additional gathering systems. Operator economics reportedly pinpoint the Marcellus average breakeven price to be US $4 to $5/Mcf; it was inching up toward $5 at the end of May 2011.

Danquah said that the abundant ethane produced in many areas of the Marcellus play now is being blended with flowing gas, but this will overwhelm the system by 2012. Ethane pipes are being proposed, including an outlet to Sarnia, Ontario; to New Jersey for shipment via vessel to the Gulf Coast; and to the Gulf Coast via connections to current systems.

NGL solutions

Kinder Morgan Products Pipeline has proposed the Marcellus Lateral Pipeline as the best solution for Marcellus NGLs, especially ethane, according to Karen Kabin, director of midstream development for the entity. The 248-mile, 12- to 16-in. diameter line is slated to connect to the company's Cochin Pipeline that transports propane from Alberta's gas fields to Sarnia, where several crackers are located; once built, the line is anticipated to be in service in 2012. Kabin posed the question of why ethane would travel from the Marcellus to the Gulf Coast where other supplies are in closer proximity, noting that the ethane is needed in Sarnia where the in-place crackers can use it year-round.

Ethane can be viewed as both the cost of doing business as well as an opportunity. Indeed, the presence of NGL components in the production stream in the rich areas is a bonus and a challenge. These liquids ultimately will be available to the industry throughout the Northeast as well as Sarnia, which is the site of several petrochemical plants. Gary Evans, chairman, president and CEO of Magnum Hunter Resources Corp., noted that if he were running a petrochemical company he would consider locating somewhere along the Ohio River. He said Magnum Hunter has plans to drill 15 horizontal wells in the Marcellus in 2011.

The need for infrastructure and takeaway capacity to handle NGLs from the Marcellus' considerable rich-gas production area impacts various industry players. "It's like the chicken and the egg," said Jack Lafield, president and CEO of Caiman Energy. "If the facilities are not there, you can't produce the rich gas as it's not marketable into the pipeline. The NGLs have to be fractionated to get the real value.

"The liquids products are important to the netback the producer will receive," Lafield noted. "That's the economics that make it worthwhile to drill in rich areas versus a lean area."

It will require major financial input to overcome the current infrastructure crunch in the Marcellus. Lafield said that the total investment needed to maximize producer netbacks from NGLs and reach markets will tally "billions."

The midstream companies are ramping up their efforts to resolve the problems, which include not just considerable lack of sufficient processing and fractionation capacity but also NGL pipeline issues and a local industrial market. Even now, rates of return, particularly from the liquids-rich areas, are sufficient for both upstream and midstream companies to justify expansions.

Lafield noted that Caiman and others are constructing facilities. "We'll have a fractionator in place at the end of the year; we're building the facility on the Ohio River where we'll have access to rail, trucks, barging. We'll have a wide-grade pipeline running 10 miles from the Fort Beeler complex to the river," he said.

Given the escalating drilling activity and production from the Marcellus, it comes as no surprise that storage looms as a major consideration, particularly during times of low demand. During the

Marcellus Midstream conference, John Shelton, director of storage for NiSource Gas Transmission & Storage, talked about the company's experiences in solving storage issues – the company owns 37 storage fields – and addressed opportunities presented by the Marcellus.

He noted that the company's local storage of 16 Bcf is in the heart of the Marcellus action. There is flow-path flexibility. Shelton commented also that market area storage is now a hybrid, i.e., both a market and a supply opportunity. For example, there are peak demands for the Pittsburgh market area near one of its storage facilities, and winter turnover is vital for summer reservoir capacity while supply area storage is an important "market" for summer takeaway.

> The projected recoverable reserves from the Marcellus tally more than 50 Tcf.

Continued demand by large end users, along with anticipated new power generation to come in the future and new markets and services dictate that flexibility in pipeline and storage design is essential; size, timing, structure, and complementary assets must be subtly orchestrated.

The push to develop midstream infrastructure for the Marcellus at a rate comparable to the fast pace of upstream development has caught the collective eyes of private equity investors such as Energy Spectrum Capital. Ben Davis, who is a partner with private equity midstream specialist Energy Spectrum, spoke to the conference attendees, detailing three of the companies it is backing in the shale play.

All are funded from Energy Spectrum's $612-million Fund V, and Davis noted at the time that the company was about a month away from closing its sixth fund of $900 million to $1 billion. He said it pursues both acquisition and newbuild opportunities.

One of the companies he discussed, Houston-based Laser Midstream Co. LLC, is engaged in a project that entails providing pipeline connections from Susquehanna County, Pa., across the southern New York border and on through Broome County, N.Y., where it will connect to the Millenium Pipeline. Laser is constructing 10 miles of pipe in New York and 23 miles in Pennsylvania with the targeted in-service date being this summer. A 10,000-hp compression plant with expansion potential to 30,000 hp is also being constructed.

Davis emphasized that when selecting companies for its portfolio, the number one priority is the management team. He noted there are complex barriers to development of midstream infrastructure, meaning success demands significant expertise.

Infrastructure master limited partnerships (MLPs) are having their day in the sun with the Marcellus. Rob Lane, managing director of Madison Williams, noted that investors are particularly attracted to these investment vehicles in the Marcellus Shale, where MLPs have committed more than $1 billion in infrastructure. He said that a day after announcing a project in the Marcellus, MLPs typically outperformed the AMZ, which is the Alerian MLP Index. Investment is expected to continue along with more M&A action, which has consisted of co-development deals and joint ventures for the most part. Owing to the undervaluation of natural gas accompanied by emerging areas of demand, i.e., transportation, look for investor interest in MLPs to continue.

Granted, the Marcellus play is exciting and promising, seemingly with no end in sight. Like other shale plays, however, it can't escape the myriad, far-reaching tentacles of the regulatory agencies and anti-industry citizens groups. The hope is that common sense – and fact-based information – will prevail.

Rep. Bill Schuster (R-PA) was on the speaker roster at Hart's Marcellus Midstream confab, where he noted emphatically that regulation of the natural gas industry should remain under the purview of the state's Department of Environmental Protection (DEP) rather than the federal government in order to ensure Marcellus development in the most aggressive and safe manner. He cautioned against the "one size fits all" federal mentality when it comes to regulating development of shales, which can have highly variable characteristics even within a single state.

Schuster did emphasize that the onus is on the industry to develop the Marcellus in an environmentally safe manner. Years of destructive, environmentally damaging activity by the coal industry have left the citizens wary that more damage could occur. Good stewardship on the part of the companies in the Marcellus Shale gas play is imperative. The industry also must expend more effort at the grassroots level, talking to local papers and citizens rather than focusing so much on television ads and editorials in big city newspapers.

There are a number of regulatory risks associated with moving the valuable gas and associated products to market, according to conference speaker Kenneth G. Hurwitz, who is a partner with Haynes & Boone LLP. He said gathering lines are not regulated by the FERC, and it is uncertain in Pennsylvania whether gathering companies are public utilities, which are subject to light-handed rate regulation by the Pennsylvania Public Utility Commission. This uncertain status of gathering lines in Pennsylvania and the regulatory consequences add to transaction costs and cost of entry, which could slow development. Hurwitz noted that in New York, gas corporations are subject to light-handed rate regulation by the state. They must obtain Commission approval to construct facilities and are vested with the power of eminent domain.

As for liquids pipelines, interstate rates are regulated by the FERC, and there is no statutory right of eminent domain. The risks for liquids lines include difficulty in controlling indexed rate increases. Resolving contested rate cases can require as much as a decade.

Danquah cut to the chase when he noted that Marcellus Shale development may be hobbled for some time while operators and midstream providers struggle with infrastructure constraints and regulatory and environmental complexities.

Even so, for every challenge in the Marcellus there is an opportunity, emphasized Mark Huhndorff, managing director, investment banking, midstream, coal, and alternative energy at Raymond James & Associates.

Reaching Full Potential

The economics of the Marcellus Shale from an upstream perspective reveal several concerns.

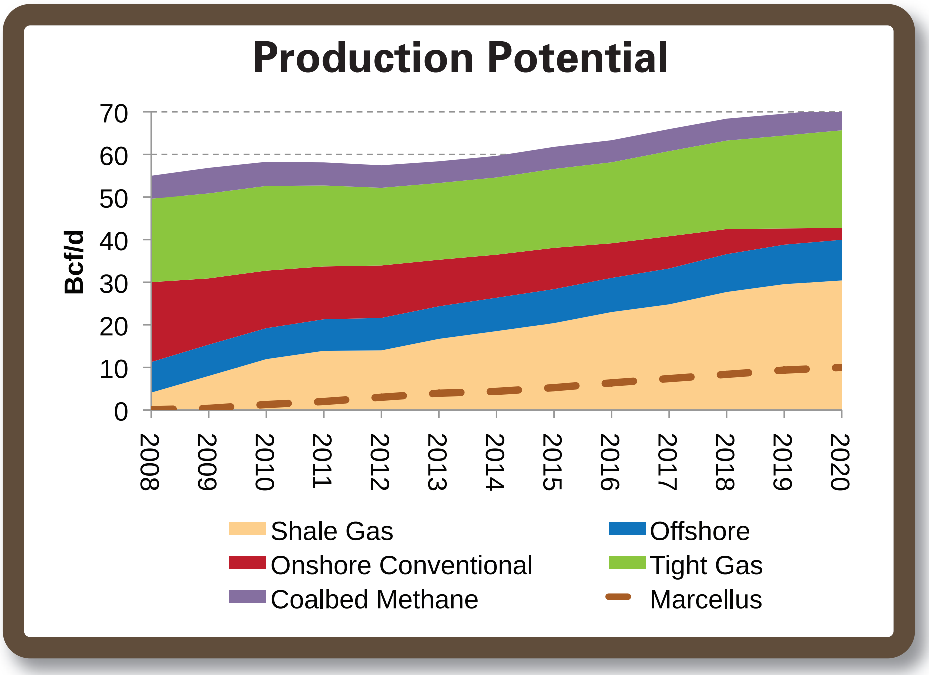
By Opoku Danquah
Director of Upstream Research, Hart Energy

With unconventional recoverable resources estimated as high as 490 Tcf, the Marcellus Shale is the most potent gas field in North America and the second largest in the world after the South Pars Field, which stretches over Iran and Qatar. No stranger to petroleum exploitation, the Marcellus region hosted the first US oil well, drilled in 1859 in Crawford County. However, even with its century-and-a-half history, some complications might impede realization of the shale's full potential from an upstream perspective.

Regulatory hiccups have been obstructive, and related environmental concerns will continue to hinder development. Insufficient natural gas demand within the Northeast region and in the US as a whole may become a hitch in this shale's development, as supply dynamics simultaneously depress prices below operator break-even bands. With vast production potential that is bound to dwarf every other natural gas play in North America, the timely evolution of infrastructure, especially in the midstream segment, will be critical to ensure the integral success of this play.

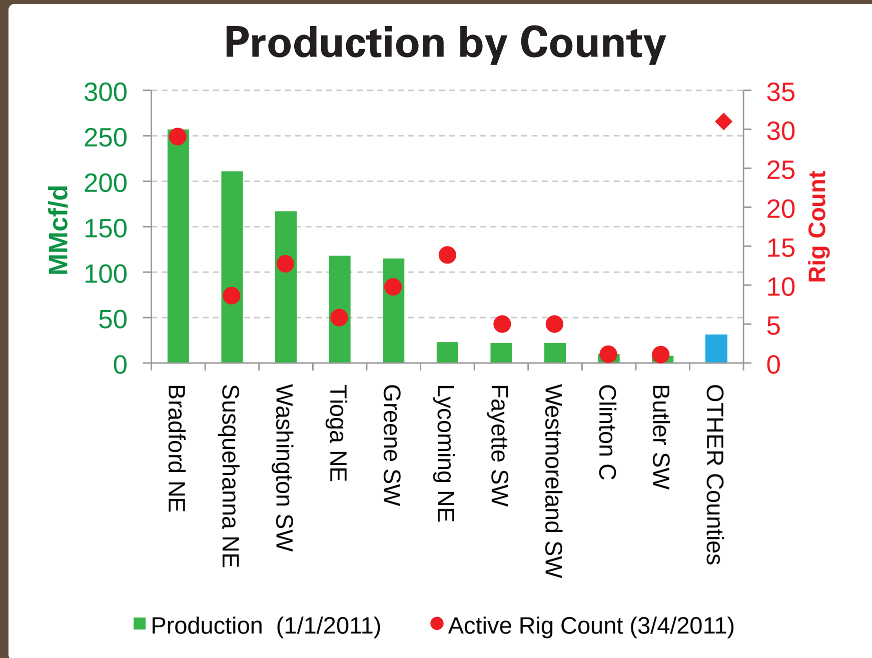
The production potential of the Marcellus Shale is overwhelming, especially if not well paced. Currently, US L-48 natural gas marketed production is about 60 Bcf/d, with shale gas representing about 24% of this total or almost 14.5 Bcf/d. Tight gas production is currently around 19 Bcf/d, while coalbed methane is more than 5 Bcf/d. Shale gas could easily represent almost 43% of total US L-48 production (30.4 Bcf/d) by 2020. About one-third of this shale production, or approximately 10 Bcf/d, will be attributed to the Marcellus. Meanwhile, onshore conventional production will taper off while offshore gas production is expected to plateau.

Current Marcellus marketed production is more than 2 Bcf per day,

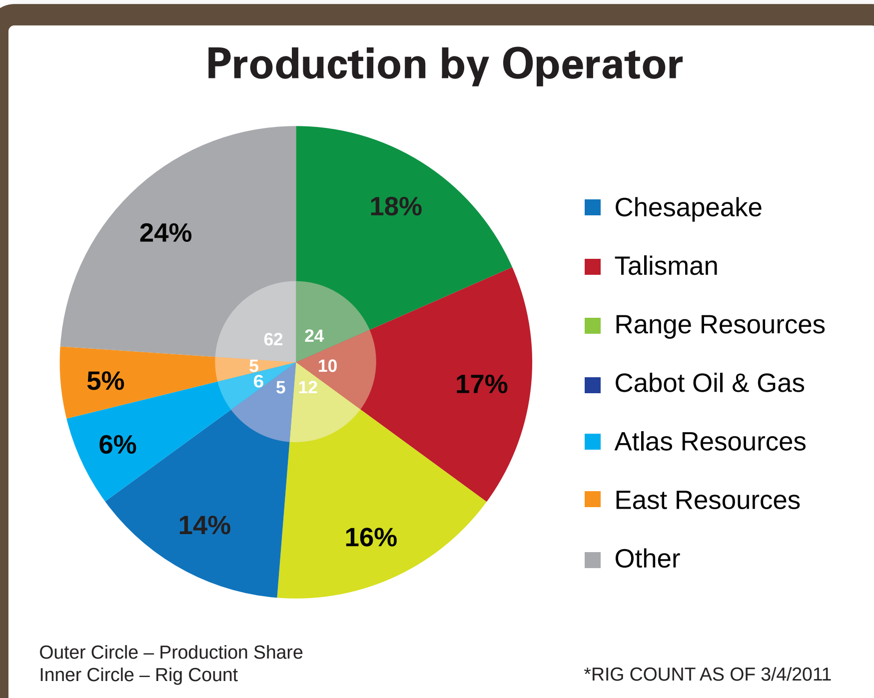


Marcellus production is about 1.3 Bcf/d, will easily exit the year over 2 Bcf/d, and should peak after 2020 at almost 10 Bcf/d. *(Source: Hart Energy)* and the ramp-up within the next decade could easily peak at 11 Bcf/d. Although Marcellus active rig counts hovered around 106 in May (representing no significant change since the beginning of 2011), operators have ascended the learning curve and have become more efficient than ever in exploiting the shale's unique terrain. Due to enhanced upstream synchronization, rig productivity has increased, whereas spud-to-completion times have decreased significantly from last year's average of about four weeks. Permit-to-spud periods also have substantially decreased, with operators taking a day or two instead of weeks. Accordingly, relatively less manpower is required to grow production.

Existing Pennsylvania production is mainly from the northeast and southwest counties. Bradford (northeast), Susquehanna (northeast), and Washington (southwest) are the top producing counties, respectively, with each producing more than 170 MMcf/d. Rig activity, however, has accelerated in other parts of the state – Clearfield, Clarion, and Centre are the up-and-coming counties to watch. Even though Bradford had the highest rig count as of March, the number of active rigs is not an indicator of production but rather a precursor. For example, Lycoming County, which had only 23 MMcf/d of production, had 14 rigs, or roughly 60% more than Susquehanna, whose production was almost 10 times (211 MMcf/d) that of Lycoming. A disproportionately higher number of rigs in counties with notably less production attests that the core acreage of the play continuously is being redefined over these early stages of development. Production will continue in the preliminary

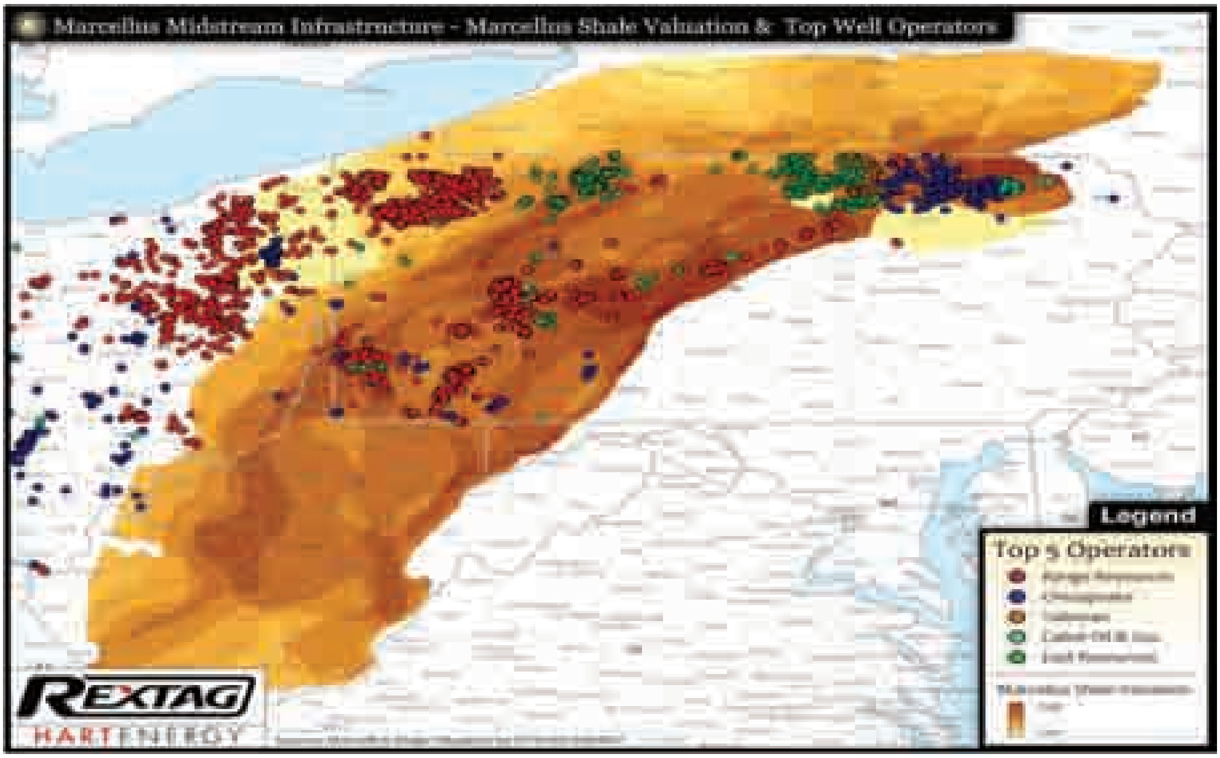


Pennsylvania production is mainly from northeastern counties, but the supply mix will change with development from other counties such as Clearfield, Clarion, and Centre. *(Source: Hart Energy; HPDI)*



As of mid-2010, the top four operators were producing about 65% of production. Rig movements indicate this will not be the case in the near future. *(Source: Hart Energy; HPDI)*

Play Valuation and Operator Acitivity



The top five operators in the Marcellus Shale are shown. *(Source: Rystad, Hart Energy's North American Shale Quarterly Report)*

counties with the highest production, but at the same time should expand out radially depending on operator activity.

Operator acreage in the Marcellus is widespread and not as contiguous and packaged as in other shale plays. This will impact expansion of the play as a whole, and as already touched on, the core acreage will continue to morph as overall development advances.

A multiplicity play

The Marcellus is a multiplicity play, and each zone is remarkably unique depending on varying characteristics such as depth, thickness, and thermal maturity. Operator margins will partly depend on the valuation traits of the geographical zone in which they operate. The top producers are currently the big four – Chesapeake, Talisman, Range Resources, and Cabot Oil & Gas, which together as of March accounted for roughly 65% of production. On the other hand, these companies only operated 40% (51 out of 124) of the active rigs. The remaining 35% of production mostly came from smaller players which operated about 60% of the rigs in the region. The structure of the pie in terms of production will therefore have to change significantly over the next decade. The big four will continue to be top producers on an individual basis, but as the total pie increases to approximately 10 Bcf/d by 2020, their aggregate production tally will shrink by almost half to approximately 32% as less notable players ramp up their production.

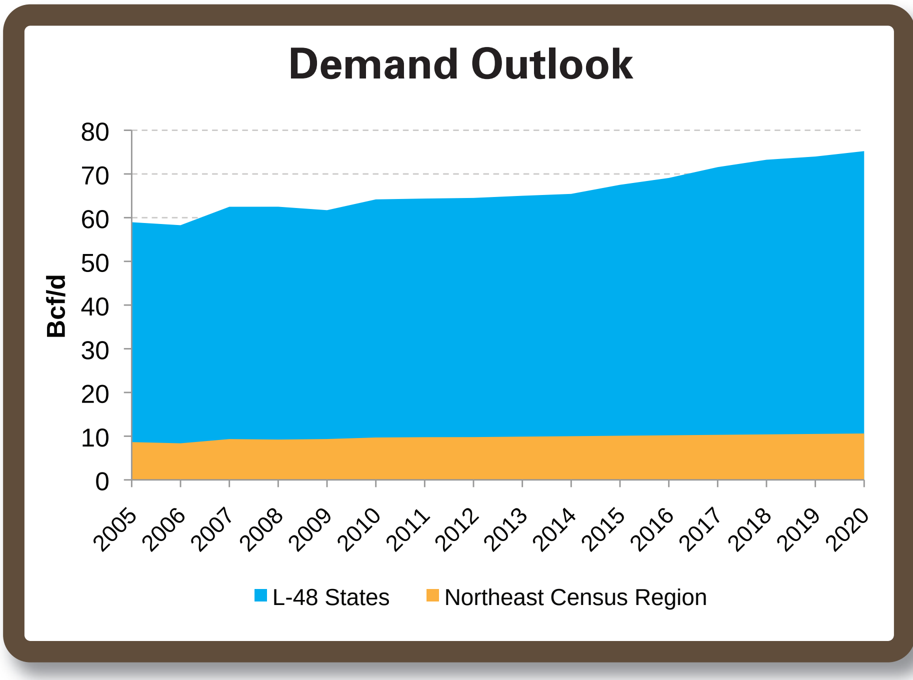
Unlike the Marcellus' promising production potential, the natural gas demand outlook for the region is not as enticing. US demand growth will be sluggish compared to gas production escalation, with the Northeast being no different from the rest of the country. With the power and industrial sectors seeing the most upside, domestic demand is expected to increase by about 15% or roughly 10 Bcf/d by 2020. However, demand in the Northeast is expected to rise by just 1

Bcf/d, from a current level of 9.6 Bcf. Supply-demand fundamentals predict a progressive decrease in prices as domestic production overwhelms natural gas demand and until producers cut back on drilling. Yet, for the Marcellus, its strategic location makes it fairly immune to lower prices compared to other shale plays.

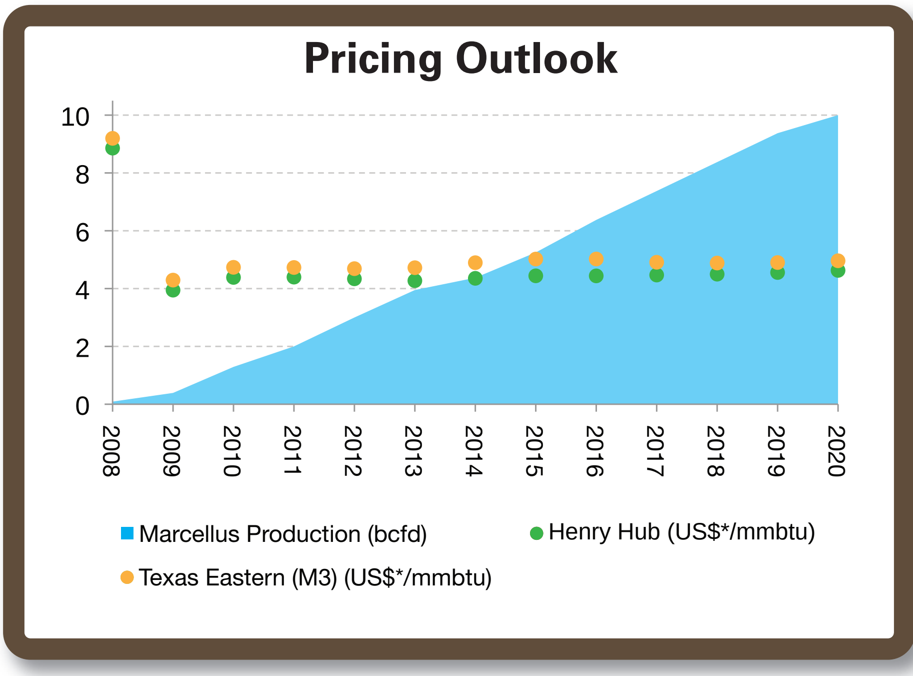
A significant advantage of the Marcellus in comparison to its shale counterparts is its close proximity to premium markets. This makes its gas sales prices higher than the US benchmark Henry Hub price and implies more producer revenue. The play also has relatively low variable costs (transportation rate plus related fuel) to route the gas downstream. Fuel on some of the regional long-haul pipelines from the Gulf Coast is 4% to 6% of the volume transported (approximately a US $0.18 to $0.20 cost to a buyer), whereas Marcellus area transportation fuel costs are generally much lower, in the 1% to 2% range.

Upstream producers will be shipping mostly to the Columbia South (Appalachia) and Dominion (North and South) points, which should all maintain a Henry Hub premium in the long term. With pipeline capacity reservations, some producers will be able to realize an even higher margin by selling at the Texas Eastern (M3) pricing point, which should at least maintain a 7% premium over Henry Hub through 2020.

Long-term pricing should facilitate Marcellus development. Fundamentals suggest a stable Henry Hub price trend with very little volatility. Most producers will continue to hedge far in advance to ensure a decent rate of return based on their breakevens. Forecasted spot prices should be in line with operator breakevens, which range between US $4 and $5 on a real basis. Any downside deviation to forecasted prices will hinder realization of the Marcellus Shale's full potential.



Overall natural gas demand growth will be sluggish, and the Northeast is no exception to this trend. *(Source: Hart Energy; EIA)*



The pricing outlook should facilitate Marcellus development as operator economics show a Marcellus average breakeven of US $4 to $5. *(Source: Hart Energy; GPCM)*

The Appalachian region has significant pipeline infrastructure, with more planned or under construction. Consequently, all of the firm downstream transportation capacity is sold out. Producers must therefore be willing to sell directly into another party's firm downstream capacity, seek upstream backhaul transportation service (and schedule for alternate forward haul on a secondary firm basis), or attempt to move or market their volumes on a riskier, interruptible transportation basis.

Traditional storage dynamics will change as more Marcellus production enters the region's pipeline system. Facility profiles will alter, as injection/withdrawal flows are no longer critically affected by erratic demand fluctuations. Storage and pipeline operators will be more adamant regarding gas-quality specification standards due to the presence of significant amounts of natural gas liquids.

In these early stages of development, ethane quantities have remained at levels that are manageable through blending, but beyond 2012, gas production from the richer portions of the play will require ethane removal and shipment. Several ethane shipping plans have been put forth, even including construction of a regional ethylene cracker.

The most likely hurdle going forward will be environmental contention calling for more stringent regulatory oversight, especially regarding possible contamination of drinking water sources by drilling fluids. New regulation that has just been passed prevents the use of riverside wastewater disposal treatment plants. Operators are now shipping wastewater by truck to Ohio, where more than 170 underground injection wells exist. The region is moving toward the trend of recycling 100% of flow-back water, which benefits major players due to economies of scale but is not always cost-effective for the smaller operators.

Whether the region will live up to its full potential remains to be seen. Nevertheless, Marcellus gas will have commendable flow longevity on its side, comparable to the region's historic past, while it aggressively competes with and displaces gas from other regions.

Environmental Regulation of Marcellus Drilling

Operators must comply with a variety of regulatory programs.

By Larry Nettles and Sean Lonnquist
Vinson & Elkins LLP

The Marcellus Shale gas play spans seven states in the northeastern US, including primarily the states of New York, Pennsylvania, West Virginia, and Ohio and, to a much lesser extent, Maryland, Virginia, and Kentucky. This formation contains abundant volumes of natural gas trapped in the pore spaces of tightly packed, low permeable shale. Production of gas from the Marcellus requires the hydraulic fracturing of the shale formation, a process that involves the use of vast quantities of water orders of magnitude greater than might be used in the development of conventional natural gas wells.

Any consideration of natural gas development in the Marcellus Shale requires evaluation of the envi-

ronmental regulatory and permitting schemes governing these development activities. Governmental authorities administer a variety of regulatory programs applicable to drilling and production activities in the Marcellus Shale, and operators must comply with these program requirements, including obtaining environmental permits or other authorizations and complying with their terms.

In evaluating environmental regulatory and permitting programs, a natural gas operator should understand that governmental authorities with jurisdiction over environmental protection may exist at the federal, state, or local levels. Sometimes federal and state governmental authorities may have oversight of a regulated component of environmental protection – such as the emission of air pollutants or discharge of water pollutants – yet the federal authority may delegate responsibility for implementing the program to the state authority.

As a practical matter, however, the drilling and production of oil and natural gas is predominantly a state-regulated activity. This holds true in the Marcellus Shale, where state governments are the primary governmental authority with oversight of natural gas drilling and production activities.

Protecting potable groundwater

There are several critical issues that, in large measure, provide impetus for these regulatory and permitting programs. The first issue is the concern that the drilling or completion process, including hydraulic fracturing, could result in the seepage of downhole chemicals into potable groundwater aquifers, thereby affecting groundwater wells and drinking water supplies.

States have implemented casing and cementing standards for natural gas wells that are designed to protect potable groundwater sources. Compliance with these regulatory standards will typically be an enforceable condition of an operator's drilling permit.

At the federal level, House Democrats have reintroduced a bill (H.R. 1084) that would make hydraulic fracturing subject to regulation under the federal Safe Drinking Water Act (SDWA). Although unlikely to pass the House of Representatives this term, the bill could subject hydraulic fracturing operations to new permitting and financial assurance requirements; construction specifications; and monitoring, reporting, and recordkeeping obligations imposed under the SDWA. Such legislation also could require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third-party groups opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater.

Acquiring drilling/well work permit

Pennsylvania, West Virginia, and Ohio require the operator of an oil or gas well to obtain a drilling permit before commencing drilling operations. The requirements for each state are similar but not identical. Under the currently applicable regulatory regime, permits generally can be obtained more quickly and easily in West Virginia and Ohio than in Pennsylvania. In all three states, a natural gas well operator must obtain a drilling or well permit from the state and post a bond before commencing a new well. In the permit application, the operator must specify, among other things, the location of the well, the depth of the well, and how the operator will manage waste from the operation.

> The SRBC was created in 1970 by the Susquehanna River Basin Compact, an agreement negotiated among the states of Pennsylvania, New York, and Maryland and approved by the United States Congress and the legislatures of all three member states.

Securing sources of water

The massive amount of water that must be withdrawn and stored for use in hydraulic fracturing operations is another issue. Various state environmental agencies and regional river authorities regulate the rate and volume of water withdrawals within their respective jurisdictions. These regional water authorities, including the Susquehanna River Basin Commission (SRBC) and the Delaware River Basin Commission (DRBC), must review and approve applications for withdrawal and use of water for hydraulic fracturing projects from water sources subject to their jurisdiction. State agencies may also regulate the construction of pits or impoundments within which the withdrawn water is stored. These approvals can take time to obtain, and failure to adequately plan for securing such approvals may result in operational delays or downsizing of projects.

Because hydraulic fracturing of gas wells in the Marcellus Shale requires a substantial amount of water, operators must ensure that they arrange for adequate supplies of water and means to transport water to the well site. Potential sources of water include surface water bodies – such as rivers, streams, and lakes – groundwater, and public or private water providers such as municipal water systems or authorized private users with excess capacity.

In states where the Marcellus Shale is located, authorization to withdraw groundwater from land overlying the mineral lease typically must be obtained from the surface owner. Similarly, the right to use water from surface water bodies within or bordering the land overlying an oil and gas estate usually belongs to the surface owner and must be authorized in writing. Accordingly, the governing oil and gas lease likely addresses the operator's right to use surface and groundwater on the leased premises. An operator also may be able to contract for the right to take ground or surface water from another nearby property owner.

An operator who withdraws water from a surface or groundwater source may face liability to other surface or groundwater users if the operator's withdrawal of water reduces or affects other users' access to the water resource. Liability for reducing or affecting other water users' ability to access water supplies varies from state to state. In Ohio and West Virginia, such liability is largely governed by common law. In Pennsylvania and New York, such liability is governed by a combination of common law and statute and may depend on whether the water source falls under the jurisdiction of the SRBC or the DRBC.

Operators are more likely to avoid liability to other water users by purchasing water from a public or private water provider rather than withdrawing surface or groundwater from the leased premises. Costs for transporting water from such sources to the well site, however, may make this option less attractive.

Obtaining the contractual right to withdraw water and arranging for a means to transport the water to the well site are not the only prerequisites the operator faces. In order to legally withdraw water from any source for hydraulic fracturing purposes, the operator likely will need to obtain the approval of governmental agencies with jurisdiction over the water source.

Acquiring approval to withdraw water

Operators of Marcellus natural gas wells in Pennsylvania and West Virginia must, in most cases, obtain the approval of one or more government agencies before withdrawing water from any source for use in hydraulic fracturing operations. The trigger points and specific requirements for authorization vary from state to state. In Ohio, either prior approval or simple registration may be required, depending on the quantity of water to be withdrawn and the area of the state where the withdrawal will occur. As with obtaining a drilling permit, because of the current respective permitting schemes the procedure generally is faster and simpler in West Virginia and Ohio than in Pennsylvania.

The SRBC has jurisdiction over the area drained by the Susquehanna River and its tributaries, which includes parts of Pennsylvania, New York, and Maryland. The SRBC has the responsibility, among many others, to allocate, manage, and protect water resources in the Susquehanna River Basin.

The SRBC requires operators to obtain approval before withdrawing or using any amount of water to develop Marcellus wells in the Susquehanna River Basin. The SRBC has two mechanisms for approving water withdrawals and uses. It offers an expedited "approval by rule" process for water purchased from a source that has already received withdrawal authorization from the SRBC. Examples include public water systems and other private users who already have SRBC approval but are not utilizing their maximum authorized withdrawal amounts. SRBC personnel have reported that requests for approval by rule usually are processed and authorized by the SRBC within 30 to 40 days.

The DRBC – created in 1961 when the legislatures of Pennsylvania, New York, New Jersey, and Delaware and the US Congress passed concurrent compact legislation – has jurisdiction over the area drained by the Delaware River and its tributaries, which includes parts of Pennsylvania, New York, New Jersey, and Delaware. Like the SRBC, the DRBC has the responsibility to allocate water among various users.

The DRBC requires anyone to obtain prior approval before withdrawing groundwater or surface water in amounts equal to or exceeding 100,000 gallons per day, averaged over a 30-day period, from any location in the Delaware River Basin; or groundwater in amounts exceeding 10,000 gallons per day, averaged over a 30-day period, from wells within the Southeastern Pennsylvania Ground Water Protected Area.

Since May 2009, the DRBC has maintained a de facto moratorium on drilling for natural gas in the Delaware River Basin. Although the moratorium is still in place, the DRBC released proposed regulations in December 2010 that would allow for drilling in the basin. The proposed regulations require, among other things, commission approval for withdrawing water from the watershed. A streamlined approval process is available for certain projects, however. In reaction to these proposed regulations, in April 2011 New York Attorney General Eric Schneiderman threatened to sue the DRBC under the National Environmental Policy Act (NEPA), which requires federal agencies to extensively review any action that may result in a significant impact on the environment.

If successful, the suit would force the DRBC to undertake a review of the safety and public health risks of natural gas development in the Delaware River Basin. Such a review could potentially delay drilling in the basin for years.

Identifying and obtaining approval/methods for flow-back water disposal

Another issue of critical importance concerns the disposal of hydraulic fracturing water returned to the surface after drilling (flow-back water). Such flow-back water could potentially contain metals and other contaminants picked up during the hydraulic fracturing process. Operators must construct or obtain adequate facilities to store flow-back water. States may require permits and likely will have construction standards for impoundments and pits designed to store flow-back water.

Furthermore, care must be taken in securing appropriate discharge outlets, which typically require state permits and adequate disposal facilities that can accept and dispose of the flow-back water generated by fracturing activities. Municipal wastewater treatment facilities may not be able to properly treat the flow-back water due to concentrations of inorganic pollutants contained in the water, and the regional geology of the area where drilling is planned may preclude operators from injecting the flow-back water into deep disposal wells. There are various water purification companies that can treat flow-back water so that it can be reused instead of being discharged, but these treatment services can increase the cost of fracturing.

Operators planning to engage in hydraulic fracturing must develop a plan for handling flow-back water and obtain the requisite approvals or permits from applicable government agencies. Available options for disposing of flow-back water may include land application, injection into an authorized deep-injection well, treatment and disposal at an authorized publicly owned treatment works (POTW), treatment and disposal at a facility with a valid nation pollution discharge elimination point source permit (NPDES) or equivalent state permit, or reuse. Disposal of flow-back water into municipal wastewater treatment plants may result in those plants discharging effluent with elevated levels of metals, chlorides, or dissolved solids. Therefore, any flow-back water offered by operators to treatment plant operators for discharge will be subject to strict scrutiny to assure compliance with the treatment plant effluent limitations.

Flow-back water also may require on-site treatment before it can be

reused to prevent well corrosion. Several companies have developed technology for treating flow-back water at the well site to make it suitable for reuse.

In Pennsylvania, however, Governor Tom Corbett called on all Marcellus Shale natural gas drilling operators to cease delivering wastewater from shale gas extraction to POTWs by May 19, 2011.

Most natural gas operators do not attempt to construct and permit their own deep-injection well or treatment facility at the well site, although these options are theoretically possible. Instead, most operators arrange for their flow-back water to be transported to an existing permitted treatment or injection well facility and pay the operator of the facility to lawfully dispose of the flow-back water. Regardless of which option for disposal an operator chooses, approval from a regulatory agency will likely be required.

construct a new pipeline, the pipeline operator must first obtain an easement or right-of-way from every landowner whose land the new pipeline will cross. In most oil and gas leases, the lessor consents to the construction of necessary gathering systems through his property. Obtaining the consent of land owners who are not party to the pertinent oil and gas lease is more challenging. Contracting for the necessary easements from such non-party landowners may be slow and expensive. Eminent domain – the authority of the government to take private property at a fair price for public use – will most likely not be available to aid in acquiring easements for construction of a private gathering system. Eminent domain condemnation authority is typically limited to open access "common carrier" pipelines that agree to provide general gas transportation services to multiple customers.

A deep-injection well must be permitted pursuant to the federal Underground Injection Control (UIC) program or approved state equivalent program. Pennsylvania and New York do not have approved UIC permitting programs, so permits for injection wells in Pennsylvania and New York must be obtained from the US Environmental Protection Agency (EPA). West Virginia and Ohio, on the other hand, have federally approved UIC permitting programs. Permits for injection wells in West Virginia can be obtained from WVDEP, and injection well permits in Ohio can be obtained from ODNR.

A treatment facility that discharges treated water to a surface water body or wetland must obtain a federal NPDES permit or state equivalent. Pennsylvania, West Virginia, Ohio, and New York have federally approved NPDES permitting programs, so a party seeking to discharge treated flow-back water to a surface water body or wetland could obtain the required discharge permit from PDEP, WVDEP, the Ohio EPA, or the New York Department of Environmental Conservation, as applicable. Approval from the SRBC or the DRBC may also be required if the discharge would be to an injection well or body of water located within the jurisdiction of either of those agencies.

Delivering produced gas to market

Before an operator can begin producing gas from a natural gas well, the operator must arrange for a means to transport the gas from the wellhead to market. Accordingly, the operator must ensure that a gathering pipeline system is or will be in place in the vicinity of its well site, arrange to connect the well to the pipeline system, and enter a transportation agreement with the pipeline operator.

Clearly, new natural gas pipelines must be constructed to connect new wells in the Marcellus Shale to existing natural gas infrastructure. In order to

In addition to contracting for necessary easements from landowners, other environmental and land use restrictions may slow or preclude pipeline construction along certain routes.

For example, constructing a pipeline through a protected wilderness area may not be allowed. Additionally, if the proposed pipeline crosses a wetland or can potentially impact the habitat of any designated endangered species, additional state or federal government approvals or permits may be required. Furthermore, the government agency granting such authorizations or approvals may be required to prepare an environmental impact statement before granting the necessary authorization. The need for such authorizations could delay construction for several months.

Potential liability

Failure to comply with the applicable regulatory and permitting programs may result in the assessment of administrative, civil, and criminal penalties, as well as the imposition of remedial obligations or compensatory damages for adverse impacts to property and natural resources. Any failure to comply with applicable laws or regulations, or a failure to obtain a permit in a timely manner (or even failure to provide required notices to property owners or other interested parties), could result in the issuance of orders enjoining operators from performing some or all of their operations until such time as compliance with applicable legal requirements is achieved.

Operators also must be cognizant of the potential for litigation resulting from operating natural gas wells in the Marcellus Shale. Recently, several toxic tort suits have been filed in Pennsylvania as a result of hydraulic fracturing practices. An operator may be exposed to liability under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) in the event that soil is contaminated by hazardous substances that may be used in hydraulic fracturing.

Larry Nettles is a partner in the environmental practice group in the Houston office of Vinson & Elkins. Sean Lonnquist is an associate attorney in the environmental practice group in the firm's Washington, D.C. office.

This article is intended for educational and informational purposes only and does not constitute legal advice or services. These materials represent the views of and summaries by the author and do not necessarily reflect the opinions or views of Vinson & Elkins LLP or of any of its other attorneys or clients.

Additional Information on the Marcellus Shale

For more details on the Marcellus Shale, consult the selected sources below.

By Ann Priestman, Editor, Unconventional Gas Center

Anonymous. 2010, Hands Off the Watershed. New York Times, p. 20.

Anonymous. 2009, A Flood of Lawsuits. The Legal Intelligencer.

Anonymous. 2010, West Virginia's Regulators Act To Help Marcellus Development. American Oil & Gas Reporter, V. 53, No. 1, pp. 154-157.

Anonymous. 2010, Marcellus Attracting Variety of Interests. American Oil & Gas Reporter, V. 53, No. 11, pp. 140-141.

Anonymous. 2010, Marcellus Expansion. Oil and Gas Investor, V. 30, No. 9, p. 73.

Anonymous. 2010, Marcellus Fuels Pipeline Flow Charges. American Oil & Gas Reporter, V. 53, No. 13, pp. 141-143.

Anonymous. 2011, Marcellus Gas Production Likely to Squeeze Out Other Regions. American Oil & Gas Reporter, V. 54, No. 2, pp. 155-157.

Anonymous. 2011, Marcellus Still Relying on Technology. American Oil & Gas Reporter, V. 54, No. 2, pp. 157-158.

Anonymous. 2011, Marcellus Water Management Project to Test Use for Mine Drainage Water. DOE Fossil Energy Today, No. 2, p. 8.

Anonymous. 2011, W. V. Marcellus Has $2 Billion Impact. American Oil & Gas Reporter, V. 54, No. 2, p. 168.

Abbott, Kevin C.; Nieland, Ariel E. 2010, Leasing and Development in the Marcellus Shale Region: Avoiding the Pitfalls. Special Institute on Development Issues in the Major Shale Plays, Mineral Law Series: Rocky Mountain Mineral Law Foundation.

Aquilera, Roberto. 2010, Storage and Output Flow from Shale and Tight Gas Reservoirs. Abstracts with Programs, Geological Society of America, V. 42, Issue 4, p. 89.

Arijit, Mitra. 2010, Application of Lithofacies Models to Characterize Unconventional Shale Gas Reservoirs and Identify Optimal Completion Intervals. Abstracts with Programs, Geological Society of America, May 2010, V. 42, Issue 4, pp. 49-50.

Arthur, J. Daniel; Dutnell, Stephen L., Cornue, David B. 2009, Siting and Permitting of Class II Brine Disposal Wells Associated with Development of the Marcellus Shale. SPE Eastern Regional Meeting, SPE 125286.

Barnes, Jonathan. 2010, New Steel Mill Rises from Pipe Demand. ENR: Engineering News Record, V. 264, No. 13, p. 17.

Beims, Tim. Multifaceted Strategy Drives Range's Success in Marcellus Shale Play. American Oil & Gas Reporter, V. 54, No. 3, pp. 66-76.

Belvalkar, R., Oyewold, S. 2010, Development of Marcellus Shale in Pennsylvania. SPE Annual Technical Conference and Exhibition, SPE 134852.

Blauch, M.E.; Myers, R.R.; Moore, T.R.; Lipinski, B.A., Houston, N.A. 2009, Marcellus Shale Post-Frac Flowback Waters - Where is All the Salt Coming from and What are the Implications? SPE Eastern Regional Meeting, SPE 125740.

Bogoslaw, David. 2009, Natural Gas: New Environmental Rules Could Cloud Prospects. BusinessWeek.com.

Boyer, Diana L.; Droser, Mary L. 2009, Palaeoecological Patterns within the Dysaerobic Biofacies: Examples from Devonian Black Shales of New York State. Palaeogeography, Palaeoclimatology, Palaeoecology, V. 276, No. 1-4, pp. 206-216.

Braziel, Russell. Infrastructure Projects Connect Marcellus Shale to Ethane, NGL markets. American Oil & Gas Reporter, V. 54, No. 3, pp. 108-115.

Brown, Randy; Meckfesssel, Britney. 2010, Improving Marcellus Shale Performance Using PDC Bits with Optimized Torque Management Technology, Cutting Structure Aggressiveness, and Unique Roller Cone Steel Tooth Cutting. SPE Eastern Regional Meeting, SPE 139102.

Brynne, Grady. 2010, Magnetic Susceptibility-Based Placement of the Eifelian-Givetian Boundary in the Marcellus Shale of the Lower Hamilton Group in New York State. Abstracts with Programs, Geological Society of America, V. 42, Issue 1, p. 137.

Bull, Stephen. 2010, Marcellus Shale Gas Play Entry Opportunities Abound. Oil & Gas Journal, V. 108, Issue 4, pp. 34-36; 38-40.

Bullin, Keith A. 2009, Compositional Variety Complicates Processing Plans for US Shale Gas. Oil & Gas Journal, V. 107, Issue 10, pp. 50-55.

Colleran, Brian. 2010, The Drill's about to Drop. E: The Environmental Magazine, V. 21, No. 2.

Campbell, Bill. 2010, Marcellus Shale Moves Toward Maturity. American Oil & Gas Reporter, V. 53, No. 3, pp. 139-141.

Lee, Dae Sung; Herman, Jonathan D.; Elsworth, Derek; Kim, Hyun Tae; Hyun Suk, LI. 2011, A Critical Evaluation of Unconventional Gas Recovery from the Marcellus Shale, Northeastern United States. KSCE Journal of Civil Engineering, V. 15, No. 4, p. 679.

Doeder, Daniel. 2010, Environmental Effects of Natural Gas Production from the Marcellus Shale. Abstracts with Programs, Geological Society of America, March 2010, V. 42, Issue 1, p. 62.

Duffy, Shannon P. 2010, Judge OKs $22 Mil. Marcellus Shale Settlement (Sean J. McLaughlin). The Legal Intelligencer, pp. 18-19.

Durham, Louise S. 2009, Integrated Data Aid Decision; Shale Calls for the Unconventional. AAPG Explorer, V. 30, Issue 5, pp. 8, 10.

Durham, Louise S. 2010, A Mid-Devonian 'Perfect Storm;' Marcellus Owes Its 'Beauty' to Algal Blooms. AAPG Explorer, V. 31, Issue 9, pp. 26, 3.

Durham, Louise S. 2011, Shale Oil Has Market Impact, Too; Seismic Industry Seeks the Next Big Thing. AAPG Explorer, V. 32, Issue 3, p. 10.

Durham, Louise S. 2010, Marcellus Poised for Even More Attention. AAPG Explorer, V. 31, No. 7, pp. 18-24.

Durham, Louise S. 2010, One Shale Led to Another: Marcellus Gave No 'Big Play' Hints. AAPG Explorer, V. 31, No. 4, pp. 40-42.

Dyer, David P. 2011, The Marvelous Marcellus. EnergyBiz, V. 8, No. 1, pp. 13-14.

Edwards, Krisnne L.; Weissert, Sean; Jackson, Josh; Marcotte, Donna. 2011, Marcellus Shale Hydraulic Fracturing and Optimal Well Spacing to Maximize Recovery and Control Costs. SPE Hydraulic Fracturing Technology Conference, SPE 140463.

Efstathiou Jr., Jim; Chipman, Kim. 2011, The Great Shale Gas Rush. Bloomberg, Businessweek, No. 4219, pp. 25-28.

Engelder, Terry. 2009, Joint Sets that Enhance Production from Middle and Upper Devonian Gas Shales of the Appalachian Basin. AAPG Bulletin, V. 93, Issue 7, pp. 857-889.

Eyerly, Michael H. 2010, Will Gas Production from the Marcellus Shale Impact Water Quality in the Susquehanna River? A Snapshot of Water Quality in the Susquehanna in Summer 2009. Abstracts with Programs, Geological Society of America, V. 42, Issue 1.

Federman, Adam. 2010, To Drill or Not to Drill. Earth Island Journal, V. 25, No. 1, pp. 34-39.

Fischetti, Mark. 2010, The Drillers are Coming. Scientific American, V. 303, No. 1, pp. 82-85.

Frantz, Jr., Joseph H. 2010, Natural Gas, Range Resources, and the Marcellus Shale. Special Institute on Development Issues in the Major Shale Plays, Mineral Law Series: Rocky Mountain Mineral Law Foundation 2010, No. 5.

Freeman, Diane. 2010, 2-D Assumes Fault-Finder Role in Marcellus Shale Play. AAPG Explorer, V. 31, Issue 7, pp. 20-24.

Gottschling, John C. 2010, Marcellus Net Fracturing Pressure Analysis. SPE Eastern Regional Meeting, SPE 139110.

Gottschling, John C. 2009, HZ Marcellus Well Cementing in Appalachia. SPE Eastern Regional Meeting, SPE 125985.

Hagen, Debbie. 2010, Moving Marcellus Ethane. Oil and Gas Investor: Midstream Business Report, pp. 23-256.

Helman, Christopher. 2010, Blowout Beneficiary. Forbes, V. 186, No. 2, p. 78.

Higginbotham, Joe. 2010, Onshore Wave-Equation Depth Imaging and Velocity Model Building. Leading Edge, V. 29, Issue 11, pp. 1386-1392.

Holder, Dan. 2010, New York Watches, Waits, for Marcellus Boom. American Oil & Gas Reporter, V. 53, No. 11, pp. 129-132.

Houston, Nathan; Blauch, Matt; Weaver, Dalton III; Miller, David S.; O'Hara, Dave. 2009, Fracture-Stimulation in the Marcellus Shale—Lessons Learned in Fluid Selection and Execution. SPE Eastern Regional Meeting, SPE 125987.

Hoover, S.E; Lehmann, D. The Expansive Effects of Concentrated Pyritic Zones within the Devonian Marcellus Shale Formation of North America. Quarterly Journal of Engineering Geology and Hydrogeology, V. 42, pp. 157-164.

Huls, B. 2010, Maximizing the Marcellus Gold Rush While Minimizing Negative Impacts. Canadian Unconventional Resources and International Petroleum Conference, SPE 137078.

Hulsey, B.J. Cornette, Brian, Pratt, David. 2010, Surface Microseismic Mapping Reveals Details of the Marcellus Shale. SPE Eastern Regional Meeting, SPE 138806.

Jacot, R. Henry; Bazan, Lucas W.; Meyer, Bruce R. 2010, Technology Integration: A Methodology to Enhance Production and Maximize Economics in Horizontal Marcellus Shale Wells. SPE Annual Technical Conference and Exhibition, SPE 135262.

Kargbo, David M.; Wilhelm, Ron G.; Campbell, David J. 2010, Natural Gas Plays in the Marcellus Shale: Challenges and Potential Opportunities. Environmental Science & Technology, V. 44, No. 15, pp. 5679-5684.

Klaber, Kathryn. Rising to the Challenges in the Marcellus. Special Institute on Development Issues in the Major Shale Plays, Mineral Law Series: Rocky Mountain Mineral Law Foundation, No. 5.

Kimes, Mina. 2009, New York's Gas Battle. Fortune, V. 160, No. 8, p. 22.

Kirby, Carl S. 2010, Feasibility of Using Specific Conductance for Monitoring Streams for Marcellus Shale Hydrofracturing Waters. Abstracts with Programs, Geological Society of America, V. 42, Issue 1, p. 63.

Kuntz, Robert; Ashbaugh, James; Poedjono, Benny; Zabaldano, John; Shevchenko, Irina; Jamerson, Christopher. 2011, Pad Design Key for Marcellus Drilling. American Oil & Gas Reporter, V. 54, No. 4, pp. 111-114.

Lash, Gary G. 2011, Thickness Trends and Sequence Stratigraphy of the Middle Devonian Marcellus Formation, Appalachian Basin; Implications for Acadian Foreland Basin Evolution. AAPG Bulletin, V. 95, Issue 1, pp. 61-103.

Lee, Dae Sung; Herman, Jonathan D.; Elsworth, Derek. 2010, A Critical Evaluation of Unconventional Gas Recovery from the Marcellus Shale, Northeastern United States. 44th U.S. Rock Mechanics Symposium and 5th US-Canada Rock Mechanics Symposium, pp. 10-440.

Liermann, Laura J.; Mathur, Ryan; Wasylenki, Laura E.; Neuster, Jochen; Anbar, Ariel D.; Brantley, Susan L. 2011, Extent and Isotopic Composition of Fe and Mo Release from Two Pennsylvania Shales in the Presence of Organic Ligands and Bacteria. Chemical Geology, V. 281, No. 3-4; 24, pp. 167-180.

McDowell, Ranald R. 2010, Trace Fossils in the Tioga Ash Help Decipher Changing Paleoenvironmental Conditions in the Middle Devonian of West Virginia. Abstracts with Programs, Geological Society of America, V. 42, Issue 1, pp. 142-143.

McGivern, Tifffany M. 2010, Characterization of Surface and Groundwater Chemistry Before and After Gas Drilling and Hydro-Fracturing, Town of Maryland, Otsego County, New York. Abstracts with Programs, Geological Society of America, V. 42, Issue 1, p. 122.

McCown, Mike. 2010, Concern over Marcellus Drilling Spawns a Variety of New Rules. American Oil & Gas Reporter, V. 53, No. 12, pp. 138-140.

Mgboji, Jolly. 2010, Casing Drilling Tools Sets Multiple Records in Marcellus. E&P, V. 83, No. 6, pp. 40-41.

Montz, Burrell E. 2009, Drill Baby Drill: The Rush for Natural Gas from the Marcellus Shale Formation in New York. Abstracts, Annual Meeting, Association of American Geographers, V. 2009, p. 432.

Morgan, Patrick T. 2009, Dacryoconarids and the Eifelian-Givetian Boundary (Middle Devonian) in the Marcellus Shale of Western New York State. Abstracts with Programs, Geological Society of America, V. 41, Issue 3, p. 38.

Morris, Frank. 2010, Gravity and Magnetic Investigations in South-Central New York and Steuben County. Abstracts with Programs, Geological Society of America, V. 42, Issue 1, p. 111.

Mosher, David. 2010, Geochemical and Isotopic Characterization of Potential Gas-Bearing Units of the Utica and Marcellus Shale, New York. Abstracts with Programs, Geological Society of America, V. 42, Issue 1, p. 63.

Navarro, Mireya. 2010, Cuts in State Agency Are Troubling, Environmentalists and Gas Drillers Agree. New York Times, p. 17.

Neal, Donald W. 2010, Stratigraphy and Gas Production from the Marcellus Shale in Southern West Virginia. Abstracts with Programs, Geological Society of America, V. 42, Issue 1, p. 13.

Nicolle, R.; Snyder, Bagnell. 2010, Coal and Oil/Gas Conflicts: Marcellus Shale Development in Coal Country. Special Institute on Development Issues in the Major Shale Plays, Mineral Law Series: Rocky Mountain Mineral Law Foundation, No. 5.

Osorn, Stephen G.; McIntosh, Jennifer C. 2010, Chemical and Isotopic Tracers of the Contribution of Microbial Gas in Devonian Organic-Rich Shales and Reservoir Sandstones, Northern Appalachian Basin. Applied Geochemistry, V. 25, No. 3, pp. 456-471.

Paddock, David. 2010, Using Surface Seismic to Improve Gas Shale Profitability. Bulletin of the South Texas Geological Society, V. 50, Issue 8, pp. 11-12.

Pickett, Al. 2010, Marcellus Shale's Potential Sparks Surging Activity in Appalachian Basin. American Oil & Gas Reporter, V. 53, No. 8, pp. 188-199.

Pickett, Al. 2010, 'Supergiant' Marcellus Driving Surging Activity across Appalachian Basin. American Oil & Gas Reporter, V. 53, No. 12, pp. 50-65.

Pickett, Al. Producers, Midstream Firms Continue to Build Momentum across Marcellus Shale Play, American Oil & Gas Reporter, V. 54, No. 3, pp. 78-88.

Poedjono, Benny; Zabaldano, John; Shevchenko, Irina; Jamerson, Christopher; Kuntz, Robert; Ashbaugh, James. 2010, Case Studies in the Application of Pad Design Drilling in the Marcellus Shale. SPE Eastern Regional Meeting, SPE 139045.

Pritz, Molly E. 2010, Geochemical Investigation of Marcellus Shale Natural Gas Hydrofracturing Waters. Abstracts with Programs, Geological Society of America, V. 42, Issue 1, p. 121.

Prush, V. 2009, Major Element and Copper Isotopic Geochemical Analysis of Marcellus Shale and Associated Soils. Abstracts with Programs, Geological Society of America, V. 41, Issue 7, p. 438.

Pyron, Arthur J. 2009, Update on the Marcellus Play, Appalachian Basin, USA. SIPES Quarterly, V. 46, Issue 1, pp. 1; 17-21.

Rach, Nina M. 2009, CNX Gas Drills Record Marcellus Shale Well. Oil & Gas Journal, V. 107, Issue 3, pp. 51-55.

Reeder, Laura C. 2009, Creating a Legal Framework for Regulation of Natural Gas Extraction from the Marcellus Shale Formation. William and Mary Environmental Law and Policy Review, V. 34, No. 3, pp. 499-1026.

Renner, Rebecca. 2009, Spate of Gas Drilling Leaks Raises Marcellus Concerns. Environmental Science & Technology, V. 43, No. 20, p. 7599.

Ries, David G. 2010, Ethics in Leasing in the Marcellus Shale. Special Institute on Development Issues in the Major Shale Plays, Mineral Law Series: Rocky Mountain Mineral Law Foundation, No. 5.

Rimassa, Shawn M.; Howard, Paul; MacKay, Bruce; Blow, Kristel; Coffman, Noel. 2011, Case Study: Evaluation of an Oxidative Biocide during and after a Hydraulic Fracturing Job in the Marcellus Shale. SPE International Symposium on Oilfield Chemistry, SPE 141211.

Rotman, David. 2009, Natural Gas Changes the Energy Map. Technology Review, V. 112, No. 6, pp. 44-51.

Schaible, Brian. 2010, Onslaught of Regulations Chasing the Marcellus. American Oil & Gas Reporter, V. 53, No. 11, pp. 134-139.

Schultz, Adam J. 2010, New York's Marcellus Fracas. Oil and Gas Investor, V. 30, No. 3, pp. 64-66.

Schweitzer, R.; Bilgesu, H.I. 2009, The Role of Economics on Well and Fracture Design Completions of Marcellus Shale Wells. SPE Eastern Regional Meeting, SPE 125975.

Shen, Dong; Shcolnik, David; Perkins, Randall; Taylor, Grahame; Brown, J. Mike. 2011, Evaluation of Scale Inhibitors in Marcellus Waters Containing High Levels of Dissolved Iron. SPE International Symposium on Oilfield Chemistry, SPE 141145.

Snow, Nick. 2009, Rendell's Plans in Pennsylvania. Oil & Gas Journal, V. 108, No. 5, p. 25.

Soeder, Daniel J. 2010, The Marcellus Shale: Resources and Reservations. EOS, Trans., American Geophysical Union, V. 91, Issue 32, pp. 277-278.

Spencer, R.J. 2010, Shale Gas: Part 2, History of Shale Gas Production in North America. Reservoir, V. 37, Issue 9, pp. 21-28.

Stell, Jeanne. 2010, Caiman Energy Breaks Ground for Producers in the Marcellus Shale Play. Oil and Gas Investor: Midstream Business Report, pp. 21-25.

Stell, Jeannie. 2010, Marcellus Midstream. Oil and Gas Investor: Midstream Business Report, pp.12-16.

Stell, Jeannie. 2010, Marcellus Harmonies. Oil and Gas Investor, V. 30, No. 8, pp. 67-68.

Stevens, Scott. 2009, Gas Shale – 1: Seven Plays Dominate North American Activity. Oil & Gas Journal, V. 107, Issue 36, pp. 39-42; 44-46; 48-49.

Taylor, Bertie. 2010, Marcellus Royalty Trust. Oil and Gas Investor, V. 30, No. 10, pp. 73-75.

Toon, Steve. 2010, Marcellus Madness. Oil and Gas Investor, V. 30, No. 7, pp. 57-59.

Toon, Steve. Marcellus Momentum. Oil and Gas Investor, V. 30, No. 11, pp. 42-55.

Torkelson, Del. 2010, Marcellus and Haynesville Grab Industry's Attention as Gas Shale Giants. American Oil & Gas Reporter, V. 53, No. 3, pp. 72-89.

Travis, Matthew W. 2009, The Eifelian-Givetian Boundary in the Oatka Creek Formation, Marcellus Shale of Western New York, Based on Magnetic Susceptibility. Abstracts with Programs, Geological Society of America, V. 41, Issue 3, p. 39.

True, Warren R. 2010, JV Forms to Expand Marcellus, Huron Shale Processing. Oil & Gas Journal, V. 108, No. 21, pp. 28-30.

Walsh, Michael. 2010, Geochemical Characteristics of Leachate from the Marcellus Shale, Otsego County, New York; Results of a 100-Day Laboratory Test. Abstracts with Programs, Geological Society of America, V. 42, Issue 1, p. 122.

Ward, J.A. 2010, Kerogen Density in the Marcellus Shale. SPE Unconventional Gas Conference, SPE 131767.

Watkins, Eric. 2010, Marcellus Shale Fight Continues in New York. Oil & Gas Journal, V. 108, No. 3, pp. 29-30.

Yeager, Bryce B.; Meyer, Bruce R. 2010, Injection/Fall-Off Testing in the Marcellus Shale: Using Reservoir Knowledge to Improve Operational Efficiency. SPE Eastern Regional Meeting, SPE 139067.