Shale technology turns on new and old tight targets in the San Juan Basin.
Unconventional interest in oil and gas reservoirs begins to stir again in the San Juan Basin, the reigning world champion producer of coalbed methane gas.
A 2014 USGS assessment estimated the San Juan Basin holds 50 trillion cubic feet of undiscovered gas, 19 million barrels of undiscovered oil and 148 million barrels of NGL.

The Mancos Shale is ubiquitous across much of the Rockies, including the San Juan Basin, where it ranges from 1,500 to 2,000 feet in thickness and exhibits four distinct hydrocarbon systems within it. While the Mancos is normally pressured, it has a high permeability and saturation compared to other shales, making it favorable to advanced fracking techniques. Brooks characterizes the Mancos as having world-class permeability, thickness and gas-in-place.
“It’s a huge resource,” he said. “We’re talking tens of T’s [trillion cubic feet of gas], potentially hundreds of T’s. It’s a lot of gas.”

The Mancos remains untapped due to the shadow of coalbed methane—or CBM. “Why go to 7,000 feet TVD [total vertical depth] for 6 Bcf when you can get 5 Bcf at 3,400 feet from a vertical well?” Brooks questioned. But now, with CBM production maturing in the San Juan Basin, “It’s a slam dunk; the Mancos is the next big thing.”

Lawler is another believer. When Lawler was being considered in 2014 for the role of CEO of BP’s newly created Lower 48 business, an autonomous business unit focused on shale plays and intended to act more like an independent, a portion of BP’s legacy San Juan Basin assets—acquired in the Amoco merger—were up for sale. Even before being hired, Lawler asked BP to put a hold on selling the assets, which it did. Just three years later, the San Juan is a strategic element of BP’s Lower 48 program.

“I noticed there were a de minimis number of horizontal wells drilled on the asset base, and this is an area of rich hydrocarbon accumulation,” Lawler said. “I’ve always had a view these properties were loaded with many opportunities, and I didn’t want to see the company sell any additional properties until we had a chance to review the potential of each hydrocarbon system and apply the latest horizontal technology and stimulation techniques. I wanted us to test some of these zones to see what kind of commercial outcomes could be achieved.”

Today, BP’s Lower 48 business unit holds some 6 million acres across the U.S. and 570,000 acres within the San Juan, including the 2015 acquisition of Devon Energy Corp.’s famed NEBU, or Northeast Blanco Unit, a CBM-producing powerhouse. Across its vast acreage position, BP had no reserves assigned to the Mancos Shale when Lawler took over. Even before drilling its first operated Mancos well, the 33,000-acre-NEBU acquisition was an effort to core up the Mancos with a contiguous position. Located on the western edge of Rio Arriba County and near the Colorado border, it was here that BP drilled the successful NEBU 604.

“Our strategy was to establish a new play within our own acreage position,” Lawler said. The thickness and areal extent of the Mancos formation “are substantial.” While BP had participated in other horizontal Mancos tests, the NEBU 604 was its first operated effort.

Although he did not disclose specifics, he said, “We brought modern shale development techniques, the very latest, to the Mancos and applied them to this well. We wanted to see what we could achieve with modern technology. We wanted to test it and prove up a multiwell drilling program that would eventually create significant value for the company.”

The well cost was not disclosed, but it involved a large amount of data collection. Nonetheless, Lawler said, the well will earn a return greater than the cost of capital employed. He anticipates further wells in the play to generate a 20% rate of return—minimum. BP began drilling its second Mancos well in the fall. “We think our entire position is prospective for Mancos.”

BP identifies some 400 horizontal Mancos locations on the NEBU unit alone, based on 5,000-foot-lateral wells. The company plans five additional 10,000-foot lateral wells to appraise the Mancos in 2018.

While nomenclature varies from north to south through the basin, the brittle upper Mancos Shale A and B gas-bearing zones dominate the deep basin in the north, while the interlaced, oil-rich Gallup sandstones are the target of choice in the shallower southwestern region.
**BETTING ON THE FLANK**

Jerry McHugh Jr. is a prospector. Although his company, San Juan Resources Inc., operates some 40 wells in the San Juan Basin, McHugh excels at aggregating acreage in a complicated region, particularly federal/fee tracts, and divesting some or all as drilling projects to others. He’s a regular at the NAPE exhibitions.

McHugh has worked the San Juan for 37 years, first for Dugan Production and then McHugh & Associates, his father’s independent, before leaving in 1990 to start his own venture. Both oil and gas prices have made the economics tougher in the past few years, he noted, but recent well results and movement in asset transactions have him encouraged.

He is currently offering two prospects, one along the eastern flanks of the basin near the towns of Lindrith and Cuba, and where less historic production proves up the acreage.

The first, known as West Lindrith, includes 9,200 net acres, or 32,000 including a partner’s interest in Rio Arriba County, N.M. The prospect targets unconventional Mancos, Dakota oil and Pictured Cliffs gas. The lack of legacy drilling in the area is cause for excitement, he said.

“The areas where we have leases have not had large ‘cumes of vertical production. We think the rock is breakable, but the reserves are not highly fractured or depleted. In other words, it wasn’t low-hanging fruit when the vertical Mancos wells were drilled in the ‘80s. It hasn’t been tested horizontally.”

The prospect includes two federal vertical permits.

But McHugh is most eager to promote his McSimms Federal Unit, a 5,500-acre tract further north in Rio Arriba County prospective for three dry gas Mancos zones. McHugh is permitting two pads in the Carson Forest with 16, 10,000-foot laterals per pad. This block is offset by the 6 Bcf Black Hills’ 724 well a half mile to the east, with a 1-mile lateral but fracked only in 12 stages. BP’s recent NEBU well is 20 miles west. An independent consultant models wells with 2-mile laterals at 11 to 15 Bcf EUR per well, with 32 potential locations in two zones.

“It’s an exciting, challenging project,” McHugh said.

On a development scenario, he models 13 Bcf per well at $6 million well costs. “If you can develop them one after another at $6 million per well with those kinds of reserves, it’s about a 90% IRR at $3 flat. That’s very economic.”

Low-hanging Fruitland

Despite the Mancos upside, it’s not the primary focus of BP’s near-term San Juan program. In fact, the coalbeds are Lawler’s first love.

“The San Juan is a prolific coal basin,” he said, one of the most prolific CBM regions in the world. “a very rich system with exceptionally high natural gas content.” And it’s far from depleted.

BP is attacking the Fruitland Coal Formation with multilateral wells “that have economics that exceed any other basin in the U.S.,” Lawler said. “We’re commercializing unconventional coal with innovative drilling technology.”

Before the fall of 2014, BP had not drilled a new CBM well here in seven years. Lawler wanted to revisit the concept with modern technology. “The idea was to drill these coal zones with multilaterals to achieve a capital efficiency that would place coalbed methane production in the same economic categories as some of the major shale plays in the U.S.”

Since the spring of 2015, BP has drilled dozens of CBM wells. Despite low gas prices, Lawler deems these low-pressure, shallow-decline wells “very rich. We’re in full development. We’ll do tens of thousands of acres with this method.”

In La Plata County, just across the Colorado state line, the Tiffany development features four wellbores from one pad with 13 total laterals, representing 55,000 feet of zonal interconnectivity. Collectively, the four wells currently produce just under 25 MMcfd. At only 3,000-foot depth, even with multiple laterals, these wells cost around $2 million per wellbore with EURs up to 12 Bcf per well. This capital efficiency delivers “jazzed economics,” better than 100% rate of return.

“The returns are stellar, and we have hundreds, perhaps thousands, of the multilateral CBM wells to drill.”

Another advantage of multilaterals is the small environmental footprint. “This is an environmentally responsible way to develop the field,” he said.

All future BP Lower 48 CBM wells will be developed with multilaterals. The 2018 Mancos wells will all be single-lateral wellbores, but the company plans to test the multilateral concept in the shale wells as well. “We have multilateral wells in Wyoming, Oklahoma and Texas that are landed in sandstones and carbonates, so the goal is to transition to multilateral development in shale wells.”

While the multilateral concept isn’t new—it’s commonly used offshore and in Alaska, where surface restrictions require reaching multiple targets from a single site—fracture stimulating those multilaterals from a single-host wellbore is the latest version of the technology.

“The goal is to fully stimulate multiple laterals through a single, low-cost take point. We are continuing to innovate with more and longer laterals, and we are utilizing proprietary lateral junction technology.”

In addition to minimizing the environmental footprint and being more capital efficient, the multilateral concept allows additional pay zones to be tapped that might otherwise be uneconomic to drill from a standalone wellbore. “They enable development of zones that wouldn’t normally be produced, and in some cases, strengthen the economics of existing plays,” he said.

Lawler suggested two additional historic producing zones—the Mesa Verde and Dakota Sands—as potentially benefiting from high-rate, multilateral completion technology. “This is what makes the San Juan so intriguing; there are multiple layers of undeveloped or underdeveloped zones in the region.”

The company’s 2018 capex in the San Juan should be about $150 million, he said.
BP currently produces some 100,000 barrels of oil equivalent per day (boe/d) from the San Juan, primarily gas, but its acreage position also encompasses oil opportunities in the southern end of the basin. “That’s something we’ll look at in the future as well,” he said.

Lawler characterizes the play as one of the richest basins in the world, but with very few horizontal wells to date. “It’s interesting that the activity in the area is so low, given it’s such a rich hydrocarbon province. There are three types of opportunities in the San Juan Basin: large, source rock horizontal developments like the Mancos; horizontal redevelopment of existing conventional zones; and entirely new areas and intervals of coalbed methane development.”

The potential here is material but not yet defined, he said. “This is an area that shouldn’t be discounted. Significant opportunity exists if you’ve got the mindset and technical skills to unlock the various opportunities. We have one of the most talented technical teams in the business, and our teams have an entrepreneurial, commercial mindset.

“Let’s just say our confidence in this becoming a major play is high.”

**Hilcorp’s entry**

The first discovery well in the San Juan was drilled in 1911. It has a storied past of conventional production over the past century from multiple formations, and over the past three decades it has become the highest producing coalbed methane region in the world. The bowl-shaped basin in the northwest corner of New Mexico and extending into southern Colorado sits on the western side of the ancient Cretaceous interior seaway. The deeper northeastern side of the basin is prone to gas; the shallower southwestern region more so to gas liquids and oil.

Although the San Juan Basin has been tightly held by major oil and gas companies over the past several decades, signs point to a changing of the guard as long-time, legacy assets began changing hands in recent years. Most prominently, ConocoPhillips Co. exited its legacy 1.3-million-acre position in 2017 in a $3-billion deal to Hilcorp Energy Co., acquired in partnership with private-equity firm The Carlyle Group.

Hilcorp’s intentions are fuzzy. CEO Greg Lalicker, in an emailed response, said that while other companies of comparable size have moved to unconventional assets, “Hilcorp has remained focused on creating value by finding new opportunities in mature, conventional oil and gas fields,” referencing the company’s redevelopment of legacy fields in Texas, Alaska and Louisiana.

“Short term, we have begun to identify opportunities in the basin by simply working the existing wellbores and assets,” which have seen an immediate boost in production, he said. Five workover rigs are active on the newly acquired assets, “and we expect that number to grow over the next year.”
Lalicker alluded to upside in the unconventional, however.

“Part of the intrigue in purchasing the San Juan Basin assets was the multiple formations in the region, both conventional and unconventional in nature,” he said. “Currently, we are focusing on the Fruitland Coal, Mesa Verde and Dakota formations, with plans to begin evaluating additional horizons in 2018.”

And the company will favor gas over oil, at least for now.

“The San Juan Basin, we believe, is full of opportunity. Hilcorp will continue to evaluate the San Juan Basin resources in an effort to get the best return on our investment, in a safe and responsible manner. The play will continue to be dominated by natural gas production for the near term, and beyond that we are hopeful other opportunities may develop from this acquisition.”

**Private equity’s push**

As certain public companies high-grade their portfolios and sell out of legacy positions in the San Juan, private equity is quietly entering the space. Aside from BP’s acquisition of Devon’s NEBU asset, private companies have dominated every transaction. Denver-based Enduring Resources LLC, backed by EnCap Investments, acquired Chevron’s San Juan assets, and DJ Resources LLC, with capital from Trilantic Capital Management, bought a portion of Elm Ridge Resources Inc.’s properties in 2017.

Former XTO Energy executives Bob Simpson and Vaughn Vennerberg are in the play as well, having acquired dry gas assets from Energen in 2014. Their company, Morningstar Partners LP, also operates under the subsidiary, Southland Royalty. Logos Resources II, in partnership with ArcLight Capital Partners, bought Energen’s liquids package in 2016. It recently announced another large acquisition.

The privately held Logos could be considered a consolidator in the San Juan Basin, and it is growing into one of the largest players there. At press time, the Farmington, N.M., company, led by Jay Paul McWilliams, announced it would acquire WPX Energy’s gas portfolio in the basin. Expected to have closed the deal by year-end, Logos will take over operations on 134,000 net acres and 73 MMcft/d in production—including the original Rosa discovery wells.

The position offsets BP’s recent headline well. “We’re getting prime acreage in the Mancos gas window,” said McWilliams following the announcement. “Given that much of the historical development of the play has seen 800 pounds per foot of proppant pumped into the reservoir, we think there’s upside in putting in a Haynesville [Shale] type of completion design on the wells.”

Logos’ position spans San Juan, Rio Arriba and Sandoval counties in New Mexico, and La Plata in Colorado. By acreage and production, the upstart is one of the largest players in the San Juan Basin. Since inception in 2016, Logos II has amassed some 283,000 net acres pro forma the WPX acquisition.

This is McWilliams’ second turn in the San Juan. After leaving Linn Energy Inc. in 2011 as business development lead engineer for an acquisitive company, he partnered with Boston private-equity provider ArcLight in 2012, which he had built a relationship with while at Linn. He proceeded to acquire or farm into 57,000 gross San Juan Basin acres. Logos I drilled seven horizontal wells and 22 vertical oil wells, and operated some 60 wells overall, before exiting in 2014 with more than 1,700 boe/d of production to an undisclosed public independent.
Despite the sprawling acreage position, Logos II has drilled very few new wells since inception, with most of its acreage HBP. “We’ve been waiting on the sidelines to see prices stabilize before we put the drillbit to work,” said McWilliams.

This past year Logos did drill two vertical wells and two horizontals into the lower Gallup bench in the oil window in San Juan County at depths of 5,500 feet with “very phenomenal results” from the first horizontal, and “very promising results” from the latter. One well featured a 5,000-foot lateral, the other 7,500 feet, stimulated with “a more aggressive frac than folks have been using in the San Juan historically,” he said. Although he kept the stimulation recipe close to the vest, he acknowledged using nitrogen to fracture due to lower reservoir pressure, a completion technique common in the play.

“We’re stepping it up from there, but we didn’t get too aggressive because, while we want to be on the cutting edge of completions, we don’t want to be on the bleeding edge.”

Wells drilled into the lower Gallup cost about $4 million with facilities, he said. Logos’ lower Gallup well garners rates of return “well north of 50%” with a 30-day IP of 800 to 900 boe/d. For EUR, he points to WPX Energy, which Logos partners with on several wells, and which reports EURs of 600,000-plus boe. “We certainly agree,” he said, stating that he believes 750,000 boe is “very achievable.”

The two vertical wells were to gather data. “There have been a lot of holes poked in the ground in the San Juan,” McWilliams said, “however, a lot of the logs are 30 years old, and what’s available in the public realm is pretty low quality. We like to drill verticals up front to gather good technical data to determine if there is horizontal potential.”

Drilling and completion technology in the basin has changed very little over the past 20 years, he said. “There was not a lot of step-changing technology necessary to drill good, economic wells, so there’s still a turn of opportunity throughout the basin to take what’s being done everywhere else across the country and put it to work in the San Juan.”

With the WPX acquisition, McWilliams foresees a rig running for most of the upcoming year, split between the gas and oil windows. “We expect to be a lot busier going into 2018. Our goal is to further prove up the Mancos gas window. We want to prove that with enhanced completions, we can make these wells work even at these prices.

“The great thing about the Mancos gas play is that, while there haven’t been a ton of wells drilled, there hasn’t been a bad well drilled,” he said. “Everything drilled is north of 5 Bcf, even those drilled in 2010. It’s a true resource play. We feel confident the geology is similar across a large portion of our acreage.”

Also, the WPX package comes with a plethora of undeveloped Fruitland Coal acreage, which McWilliams would like to attack. Logos will drill one well there with as many as eight laterals.

Beyond that, “We’re doing a lot of technical work to try to determine additional benches, evaluating them from top to bottom to see where we can turn the bit sideways and put the big fracks on them. Some of them are promising.”

One of the horizontal wells drilled this year was in one of these benches outside the lower Gallup but in the Mancos system.

“I don’t know if it can compete with the Permian with all of its different benches, but I definitely think there is more than one bench prospective here in the basin.”

Logos pursed more than $2 billion for marketed assets last year, including making plays for Conocophillips’ and Chevron’s large packages. So how much dry powder does the company have for acquisitions?

“It’s opportunity dependent,” said McWilliams. “Certainly, ArcLight has been a great capital sponsor, so it just depends on what we’re looking at.”

The latest deal involves acreage adjacent to BP’s announced Mancos well in Rio Arriba County. “We’ll be one of the largest operators in the basin after this transaction,” he said. “It’s exciting. There’s a ton of opportunity.”

**Gallup oil**

Encana Corp. was an early entrant into the horizontal Gallup oil opportunity in 2012 and remains an active explorer there today, with about 200,000 net acres. But Tulsa, Okla.-based WPX Energy began pursuing unconventional techniques in the southern oil window shortly thereafter, and today the two are the only public E&Ps with active programs in this region.

As WPX exits the San Juan gas window, it has declared the Gallup oil phase as one of its three core portfolio regions, behind the Delaware Basin and the Bakken Shale. Pro forma the sale of its gas assets in the northern half of the basin, the company will hold 93,000 net acres concentrated around the confluence of San Juan, Rio Arriba and Sandoval counties along the southern rim of the basin.

“The bottom line is these wells are very inexpensive to drill, they’re 70% oil, and the economics are phenomenal,” said Clay Gaspar, WPX COO. “They compete [for capital] every day in our high-quality portfolio.”

The San Juan Basin has been in WPX’s portfolio for decades, acquired by its predecessor Williams when it bought the Northwest Pipeline in 1983. These were the first E&P assets Williams owned. (The Williams Production & Exploration E&P assets were carved out from Williams’ pipeline portfolio as WPX, a standalone entity, in 2011.)

WPX moved its rigs from the gas window into the Gallup oil phase in 2013, “and that’s where we’ve been focused,” applying the horizontal technologies learned while drilling the gas phase previously. But in 2016, Gaspar said WPX “reinvented how we were technically
BP’S LOWER 48 EXPERIMENT

Major oil companies competing in U.S. shale plays have been accused of being too bureaucratic to compete with independents in the rapidly evolving onshore space. Each with shale positions has responded in various ways. London-based BP Plc separated its onshore U.S. shale assets in 2014 into an autonomous operating division, named Lower 48, designed to act like an independent producer. BP then hired Dave Lawler, former COO of SandRidge Energy Corp., to lead the charge. In three years the results are telling. Oil and Gas Investor wanted to peek further into the big picture.

Investor Does BP Lower 48 lean toward oil or gas weighting?

Lawler We are currently a gas-weighted company. We believe gas is a preferred fuel that benefits the environment over the long term.

Beyond the strategic importance of gas, when we consider our portfolio of investment options, we are rate-of-return focused. We don’t sort developments through the traditional lens of conventional, unconventional, oil or gas. We target saturation. We look for the richest saturation, be it oil or gas, and then we apply our specific advanced technologies—multilaterals, dendritic completion techniques, efficient artificial lift systems—to extract the highest rate of return.

We see ourselves as a highly efficient, advanced technology operator that discovers and develops zones with rich levels of hydrocarbon saturation.

Investor How do you view your current portfolio?

Lawler We think we’re in the leading shale play of the U.S. in the Haynesville, and we have built a significant footprint there over the last 12 months through a number of deals. We’ll operate seven rigs in the Haynesville in 2018, and each well will deliver exceptional returns. This play will help us drive production and cash flow growth year-on-year.

We’re also in the Eagle Ford with a large acreage position. We don’t operate that asset, but we’re one of the largest gas producers in the Eagle Ford in combination with Lewis Energy Group. We’re in the liquids window, as well as the dry gas window that’s doing very well in this price environment.

We’re in the Woodford Shale in the Arkoma Basin and in the greater Green River Basin in Wyoming, where we have a significant amount of acreage with liquid potential from multiple zones. We’re drilling multilaterals there and getting returns in excess of 20% at today’s prices.

On top of that, we have this world-class position in the San Juan Basin. I feel very confident with our portfolio. We have an exceptional set of assets, and we haven’t overpaid for those assets. In addition, we have some of the most talented employees and effective operating teams in the business.

Investor Would you want to get back into the Permian?

Lawler At the right price, but right now I feel like the cost of entry is so high that it would be prohibitive on a full-cycle basis. While all of us would love to have oil exposure in the Permian, there are a number of prolific, profitable plays across the U.S.

Investor Are you looking to get a footprint in any other play?

Lawler We’re always looking for opportunities, but we are satisfied with our portfolio. We have a plan that will allow us to grow within cash flow, so we don’t have to find another play.

Investor Can BP Lower 48 compete with independents?

Lawler I’d point to WoodMac for third-party validation. Of the gas companies that operate in the U.S., our production costs are now in the Top 10. The mission of the separation was to help us become competitive with our peers in the U.S., and to provide investor visibility into our asset base and performance.

We’re not trying to be the lowest-cost producer, but what we are trying to be is a company that generates significant rates of return and grows production and reserves within cash flow, and we’re achieving that. We have in fact closed that gap. So, even as a major, we’re very competitive, and in some plays, we’re leading.

Investor What should upstream executives be most alert to in this upcoming year?

Lawler I believe we need to continue to be highly disciplined, and plan investment levels under the assumption that gas prices may remain low indefinitely. I’m not trying to predict prices, but I do think that there is going to be a prolonged period of low pricing. Operating models need to be reset to match pricing being much lower than it’s been in the past, perhaps for a long time. All of us should be focused on how we sustain the businesses going forward with low prices.

Investor How do you do that?

Lawler You do it through data analytics; you do it through innovative drilling techniques, like multilaterals, and completion techniques that improve capital efficiency. And, you promote a culture of entrepreneurialism where individuals are encouraged to be creative and generate new solutions. We ask these questions frequently in our organization: How can we unlock these resources in a new way? How can data analytics optimize our operations?

This is the culture that we’re trying to implement. We are, at this point, a very entrepreneurial organization and a leader in the use of data analytics.
pursuing this incredible resource, and it’s been a renaissance. The 2016 to 2017 progress has been amazing.”

The wells proved easy to drill, at seven days or less, and in prior years “we got a little ahead of ourselves,” said Gaspar. Here, along the southwestern edge of the basin, the depositional environment is made up of Crustacean-age beaches and river deltas, porous and permeable sand intervals interlaced with shale. WPX ramped up to three rigs early on, landing laterals in the El Vado Sandstone, part of the Mancos system, but the pace led to drilling wells that had not been fully vetted.

So WPX slowed down the program during the downturn in 2015, taking the time to study the characteristics of a best-producing well. It found four characteristics. The first three are applicable to all basins: longer laterals, larger stimulations and staying within zone. The fourth is unique to the Mancos Gallup due to its sub-pressured nature.

“IT’s incredibly important to make sure that we orient the wellbore such that it is perpendicular to the natural fracture orientation of the rock,” Gaspar explained. “Drilling the azimuth in this northwest orientation is a critical breakthrough. Once we did that and combined the other three ideas, we drilled the best wells we’ve ever seen in the basin. Since we’ve taken a more measured approach, our well performance has been phenomenal.”

WPX went back to work in 2016 in the West Lybrook Unit in San Juan County, N.M. “That’s where our best wells have been. Because it is a large, contiguous unit, we knew we could orient the wells the way we want and work through that incredible amount of inventory.”

A six-well pad usually involves three wellbores directed northwest and three southeast, with pads spaced about a mile apart. Wells here average greater than 1,200 bbl/d with a 70% oil cut, with an average EUR exceeding 650,000 bbl, contingent on lateral length. Average lateral lengths are 7,800 feet. A 1-mile lateral well costs $4 million; a 1.5-mile lateral well, $4.6 million.

“Those are north of 50% returns in a $50 oil environment,” he said. The company has drilled some 160 wells in the oil play to date. Plying the silty formation is still like cutting butter; drilling for WPX, Cyclone Drilling set an industry record when Rig 32 drilled 8,370 feet over a 24-hour period along the lateral on the 745H well on the West Lybrook Unit.

Spacing for current development is generally 1,320 feet, which appears to provide the best results based on the data so far, according to Gaspar.

In 2017, WPX drilled 25 wells in the West Lybrook Unit before hitting the pause button once again toward the end of the year. In 2018, WPX plans to start work in two more units: West Escavada and South Escavada. The company identifies more than 350 Gallup wells in its inventory, with 200 of those ready to drill today. The others would require better understanding of stimulation, water production and reservoir quality to make them economic.

However, WPX’s rig won’t resume the program until about midyear, he said. The company is guiding to a half a rig in the play for 2018. Most of that reasoning is simple capital preservation across the portfolio; the Delaware Basin program will consume most of the capex.

In the meantime, a backlog of a dozen drilled but uncompleted wells from 2017 will be brought online, and the technical team will have time to process all the new data. “We want to allow the team to absorb the information, and make sure that we continue with the discipline of drilling high-quality wells.”

Oil volumes from the play grew by 50% year-over-year from third-quarter 2016 to 2017, to more than 10,000 bbl/d. The San Juan Basin received about $160 million in capex in 2017, 18% of WPX’s total drill-and-complete budget.

Given its strong points, what are the industry and investors missing about the play?
“There’s a general underappreciation for the quality of the wells,” said Gaspar. “It’s not the Permian in the sense of having nine amazing landing zones, and there is a relatively concise area that will work for this play, but look at the results of those wells. They are really good wells. For those that have invested the time to look at how it stacks up regarding costs, results and economics, it’s really an amazing play.”

**Sizeable homecoming**

Even while president of TransAtlantic Petroleum Ltd., a global E&P focused on international assets in such places as Turkey, Morocco and Romania, Ian Delahunty cast his eye to the San Juan Basin. A native of Farmington, N.M., and a petroleum engineer by trade, Delahunty had participated in a few San Juan wells as a nonop investor. The opportunity proved too enticing, and he left TransAtlantic in 2014. In July 2015, he and a former team member formed Juniper Resources LLC, backed by Natural Gas Partners.

“We made the decision to step into the U.S. market and form Juniper to chase this opportunity,” Delahunty said. “Our team was formed around the concept of what we thought was an emerging and relatively underpublicized play in the oil window in the Mancos Shale. It is a sizeable opportunity, and it seemed like the market hadn’t caught up with what was turning out to be very economic play results.”

The Mancos and its Niobrara equivalents are such prolific series up and down the Rockies, he said, “that we felt strongly the San Juan would have a resurgence. Although the oil play seems to be relatively unknown, it won’t stay that way.”

As much of the San Juan Basin is controlled by legacy asset owners who focused on shallower targets, Juniper built its initial position by consolidating operated interests acquired from hometown contacts. Through these, they saw proved horizontal development trend to 400,000 to 500,000 bbl EUR wells, with drilling costs half of other basins.

“Drilling a well for less than $5 million inclusive of facilities with those types of recovery numbers is extremely attractive,” he said.
“We felt fortunate to establish a position with exposure to that opportunity.”

Subsequently, Dallas-based Juniper bought assets from privately held Coleman Oil & Gas Inc., a Farmington-based company, to raise its net acreage position to 20,000 in San Juan County.

Delahunty sees three depositional sequences as prospective on its acreage: the Gallup and Mancos A and B, and the upper Mancos. Together the sequences are about 750 feet thick. Juniper will focus on the A/B zones, Delahunty said. “Some of the best A/B wells in the play have been drilled three sections away from us by Encana,” he said. “The A/B zones are more brittle, organic-rich and consistent—what you think of as a resource play—where the Gallup seems to be more of a hybrid.”

Drilling depth here is between 4,500 and 5,500 feet total vertical depth with laterals extending 7,000 to 9,000 feet. “That’s why people get excited by bit efficiency—drilling is very forgiving in this area.”

Juniper to date has drilled two wells. The first, Pinion 305H, targeted the Gallup Sandstone with an 8,000-foot lateral and began flowing in August. The second, Pinion 306H, was drilled with a 7,000-foot lateral into the Mancos A/B and was still flowing back at press time. Both involved nitrogen fracks. Considering testing done on these early wells, Delahunty expects future well costs at about $4.6 million.

Juniper sources its own frack water from the coalbed methane zones above and believes this will help unlock cost efficiencies for other operators in the basin.

Coming into the New Year, Juniper had no rigs active in the play, but planned to bring in one rig in the first quarter to drill four to six wells in the first half of 2018 to prove up the position.

“We’ve never endeavored to be a full-development driller,” he said, with a business strategy to acquire undeveloped positions and drill strategic wells. Delahunty would like to grow to 30,000 to 35,000 acres before considering an exit. How big an acquisition would Juniper consider?

“If the deal was right, we’d be willing to do much, much more than we’ve currently acquired,” he said. “We’re looking to grow.”}

Ian Delahunty left international exploration and formed Juniper Resources LLC to explore for Mancos oil. "Drilling a well for less than $5 million inclusive of facilities with those types of recovery numbers is extremely attractive," he said.