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The case for shale

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Flying on

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Over the hedge

US shale producer EOG Resources has cautioned that its oil and gas hedges will hurt its third-quarter results.

Sitting DUCs

A large uptick in drilled but uncompleted oil and gas wells was seen over the past month, with almost all of these located in the Permian Basin.

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COMMENTARY

SHALE GAS

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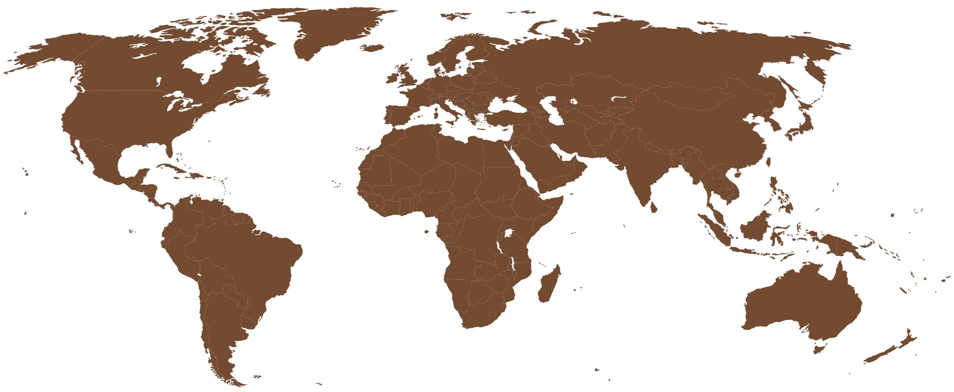


Have a question or comment? Contact the editor – Anna Kachkova (annak@newsbase.com)

Rising prices and imports underline case for UK shale

Work has restarted on Cuadrilla's controversial well in the UK, where the company hopes to demonstrate the economic benefits of shale gas, writes Jeremy Bowden in London

UK

WHAT:
Cuadrilla began hydraulic fracturing for gas in Lancashire on October 15.

WHY:
The company has been beset by years of environmental protests.

WHAT NEXT:
Plentiful shale gas supply would reduce the need for imports and displace coal from the energy mix.

DRILLING of the first shale gas well in the UK for six years has once again sparked extensive protests. While the vocal opposition draws attention to potential environmental risks, it fails to recognise how important shale gas could be for the UK's future energy security.

Cuadrilla began hydraulic fracturing for gas in Lancashire on October 15 after a court removed the final legal hurdle three days earlier. The firm will spend three months fracking two horizontal wells – the first since 2011, when drilling work caused earth tremors, prompting protests, tighter regulation and delays. Once the tests are complete, Cuadrilla will need to apply for further permits if it wishes to move forward with commercial development, in what is a very heavily monitored operation.

A traffic light system is in now place that may force the company to suspend operations if it triggers a very modest seismic event. "We must stop if tremors reach 0.5 on the Richter scale," said Cuadrilla's CEO, Francis Egan. In Europe the cut-off is much higher at 2.5/2.7, in order to accommodate geothermal drilling, and last week UK Energy Minister Claire Perry said the tight regulations put in place after the 2011 tremors could be relaxed.

Egan emphasised a cautious approach to development, with Cuadrilla first doing what he called a "mini-fracture" to make sure there were no more headline-grabbing earth tremors. "We are now commencing the final operational phase to evaluate the commercial potential … If commercially recoverable, this will displace costly imported gas with lower emissions, significant economic benefit and better security of energy supply for the UK."

The UK government has taken away local authority control on planning applications for fracking, as it claims the process is essential to avoid a growing reliance on imports. The Oil and Gas Authority (OGA) currently forecasts a rise in UK import dependence from the current level of around 50% to 66% by 2030.

In Europe, the reliance on imports is forecast to be even more extensive, with estimates of a rise from 50% now to 70% by 2025 and 80% by 2035. This trend will be driven by soaring demand and the displacement of coal with gas, in tandem with ongoing falls in domestic production.

Nevertheless, fracking across most of Europe remains banned, including in Scotland. At Westminster, the opposition Labour party has indicated it will ban fracking should it come to power.

Market signal

Rising prices in northwest Europe are already signalling that gas markets are tightening, and that shale supply could be needed to help meet demand.

After an early summer lull, UK and European gas and power prices resumed the upward trend seen earlier in the year, pushing levels up to twice the price of two years ago, and the highest for this time of year since 2013, when oil prices were over US$100 per barrel. The rises have largely been caused by tighter fundamentals, while a sharp jump in European carbon prices has also increased demand for gas at the expense of coal.

Furthermore, strong Chinese gas demand is keeping LNG out of Europe by pushing up Asian LNG prices, leaving the continent increasingly dependent on gas pipeline imports and its dwindling domestic output.

BP's CEO Bob Dudley, speaking at London's recent Oil & Money conference, said there was a systemic risk from under-investment as public opinion in the West demanded action to address climate change. If this took place before the

"The UK government has taken away local authority control on planning applications for fracking.

energy transition had made significant progress, there could be a threat to energy security and the global economy. "Renewables are growing at a remarkable rate," Dudley said, estimating that they could supply about a third of the energy mix by 2040. "But we still need to meet the remaining two-thirds of demand."

Michael Bradshaw, professor of global energy at Warwick Business School, said that if shale gas could be produced at scale, it could be part of the solution. "For the moment, at least, natural gas is the most important element in the UK's energy mix, and if gas can be decarbonised, it can be part of the solution," he said. "If the industry is able to gather pace and scale, it is expected that costs will come down."

Reserves in the Bowland Shale, which Cuadrilla is targeting, could be as much as 34 tcm, of which 10% could be recoverable.

"If successful, it'll be huge – thousands of jobs and a source of gas for the UK to stop us importing it," said Cuadrilla's Egan. "Natural gas will be used for many decades… Of course, we'd all like to not use fossil fuels tomorrow, but we still need to heat our homes, cook food and keep the lights on. However well renewables are doing in the electricity sector we're going to need gas for heating – it's the lowest carbon fossil fuel and producing it domestically is better than importing it from Russia or the Middle East," he said.

Cutting emissions

In the US, cheap shale gas has been behind a commercially driven switch away from coal to gas and renewables, which has helped achieve a sharp reduction in carbon emissions over recent years – at no cost to the tax-payer.

"The US is reducing its emissions by replacing coal with gas, and the opposite is happening in this country," said Egan, referring to recent rises in coal use in the UK, which have come about largely as a result of the tighter gas market and higher prices.

Left unchecked, this could lead the recent falls in UK emissions to reverse – providing a significant environmental argument in favour, rather than against, fracking.

And even in a zero-carbon world, gas plus CCS could provide a critical part of the generation mix, maintaining a need for gas well into the future. In recent research, McKinsey's estimated that the Dutch power system would need 14 TWh of flexible zero-carbon generation of this sort to go with 90 TWh of renewable wind and solar, in order to meet the country's ambitious 49% emissions reduction target for 2030.

In the UK, the Committee on Climate Change (CCC) recently reported on how much cheaper using gas and CCS would be than simply relying on renewables to meet the country's 2050 emissions reduction target. The CCC now says it could almost halve the cost, and the Energy Technology Institute estimates use of CCS could add 1% per year to GDP.

While gas prices in Europe and Asia have risen sharply over the past year as consumers switch away from coal and demand has expanded, prices in the US have barely changed owing to the ample cheap supply of shale gas. This is likely to keep the US on track for lower emissions as more coal is displaced. But more expensive gas will make this harder elsewhere, which sharpens the argument for fracking to unlock new reserves.❖

"Shale gas plus CCS could provide a critical part of the lower carbon generation mix.

Eagle Ford celebrates 10-year anniversary of first oil

The Eagle Ford shale continues to play an important role 10 years after entering production, but is trailing behind the most prolific unconventional regions for both oil and gas, writes Ros Davidson

EAGLE FORD

WHAT:
The Eagle Ford's production is rising again after the downturn, but cannot compete with the Permian.

WHY:
Investors are more focused on the Permian, though pipeline bottlenecks may cause their attention to shift temporarily.

WHAT NEXT:
The Eagle Ford may also encounter takeaway capacity bottlenecks in the medium term.

THE Eagle Ford shale play in South Texas produced first oil 10 years ago this month. Since then, crude output in the region – consisting of light oil, natural gas and condensate – has been on more of a roller-coaster than the oil-rich Bakken in North Dakota, which is of a similar vintage.

Turnaround in fortunes

Activity in the Eagle Ford, a relatively mature play, contracted more than in any other major shale play in the two years following the oil price crash. This was in part because the Eagle Ford has the steepest base decline among major liquid plays in the US. It contains a mix of oil and condensate reservoirs, and the latter tend to decline faster.

The Eagle Ford also had fewer operators for whom the play was their core business. This is in contrast to the Bakken, which was a major area of focus for drillers such as Continental Resources, Hess, Whiting Petroleum and Oasis Petroleum. During the downturn, Eagle Ford operators started looking elsewhere, especially to the other tight oil region in Texas – the booming Permian.

Prior to the crash, the Eagle Ford had been demonstrating dramatic growth from 2012-14. But long gone are the days when producers rushed into the play through major investments, such as Devon Energy, which spent US$6 billion on acquiring an Eagle Ford position in 2013.

Promise remains

Despite this, it is not worth counting the Eagle Ford out yet. The play has evolved, and production there is expected to continue rising steadily – or at least remain stable – for 10-15 years, unless there is another major oil price shock. Whether future output ever equals or exceeds the region's 2014-15 peak depends in large part on the exact price of oil.

"It is not a hot play," the University of Texas at Austin's co-principal investigator of shale studies at the Bureau of Economic Geology, Svetlana Ikonnikova, told *NewsBase Intelligence (NBI)*. "It's kind of lukewarm," she added.

The Eagle Ford's oil output is still 20-25% below its peak before the price crash, although gas output is close to its historic high. Older wells generally produce more gas and some drilling in the region is now shifting to areas – such as in the south – that are more gas-rich.

New technological advances will, however, help the Eagle Ford recover, and current wells have good economics. Ikonnikova pointed to a "wine-rack" drilling pattern so that different formations in the region, such as the Austin Chalk and the gas-rich Olmos formation, can be tapped more easily. Longer laterals will also add to the region's output, as well as the use of more proppant – in line with the impact they are having in other shale regions. WildHorse Resource Development is among those testing the limits in the use of more sand during the hydraulic fracturing process in the Eagle Ford.

And some of the largest shale producers, who have been investing in the multi-horizon Permian as fast as they can but are now coming up against takeaway capacity constraints, may now look more favourably on the Eagle Ford. The pipeline capacity bottlenecks in the Permian are not expected to start easing until the second half of 2019.

Meanwhile, the Eagle Ford is also becoming more appealing again for medium-sized and smaller operators. It is close to the Gulf Coast, and enough infrastructure was built to accommodate the 2014-15 peaks of oil and gas production. As a result, there is less of a bottleneck in pipeline capacity than in the Permian.

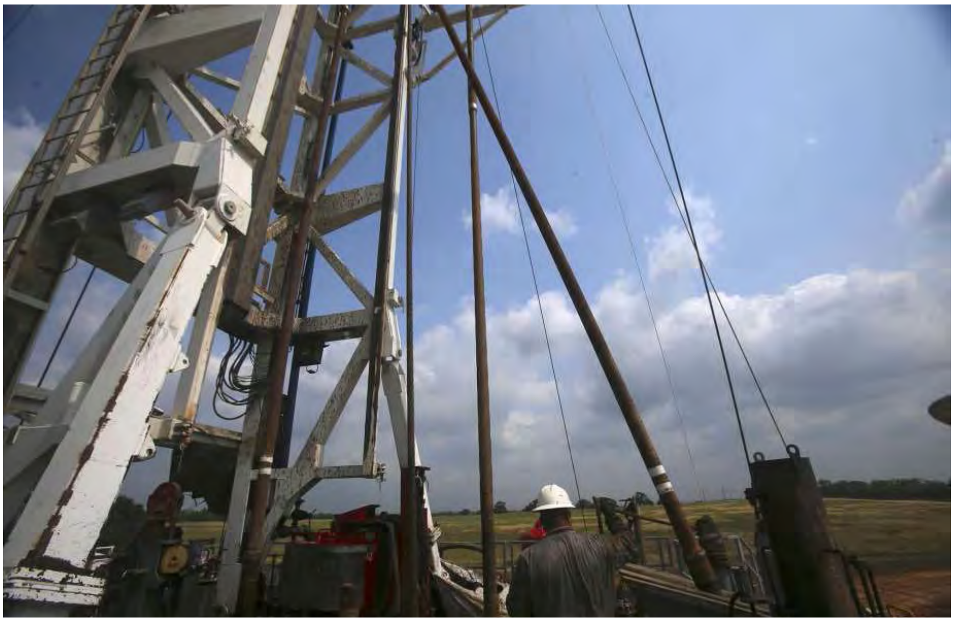
Some newer operators such as WildHorse jumped into the Eagle Ford during the downturn. The company is now the second largest acreage holder in the play after EOG Resources, with roughly 400,000 net acres (1,619 square km) positioned in the region's liquids-rich core.

> "Some newer operators such as WildHorse jumped into the Eagle Ford during the downturn.

Great expectations

Indeed, the Eagle Ford may be on track for record merger and acquisition (M&A) activity in 2018, delegates at the DUG Eagle Ford Conference in San Antonio heard in late September.

Scotiabank Global Investment Banking's



energy director, Robert Urquhart, said that while the Permian had seen US$45 billion of deals since the start of 2017, the Eagle Ford shale came in second amongst US oilfields with US$15 billion.

This is three times as high as in the Bakken and 50% higher than in the South Central Oklahoma Oil Province (SCOOP) and Sooner Trend Anadarko Basin Canadian and Kingfisher Counties (STACK) plays in Oklahoma. In one transaction last year that boosted the Eagle Ford's figure, for example, Anadarko Petroleum sold gas-rich acreage in the western Eagle Ford with favourable well economics to Sanchez Energy for US$2.3 billion.

Capacity concerns

However, there are some concerns that oil takeaway capacity may yet become an issue in the Eagle Ford. Rystad Energy's vice president of shale analysis, Artem Abramov, notes that around 200,000 bpd of crude is shipped from the Permian the Gulf Coast, some of it via the Eagle Ford, putting additional pressure on the latter play's pipeline network.

There might be a midstream bottleneck 2-3 years down the road in the Eagle Ford as oil production continues to grow, he told *NBI*.

Meanwhile, gas takeaway capacity to the Gulf Coast is tight, and a large proportion of output is shipped to Mexico. Gas exports from the Eagle Ford across the border to Mexico currently stand at 3.2-3.3 bcf (91-93 mcm) per day, according to Rystad estimates. This figure accounts for almost half of the Eagle Ford's output.

Of this, 1 bcf (28 mcm) per day is transported to Mexico via legacy pipelines and 2.2-2.3 bcf (62-65 mcm) per day is shipped via the NET Mexico system, which came online in 2015. The new Impulsora system, from the Eagle Ford to Monterrey in Mexico, has yet to be used.

What next?

Future Eagle Ford oil and gas production is looking healthy enough, but despite being the second most productive tight oil region in the US, it remains hard for the play to compete with the Permian Basin. Indeed, *NewsBase Research (NBR)* expects that – even with the pipeline bottlenecks – the Permian will continue to account for the bulk of US tight oil growth in the near and medium term.

BP agreed in July to buy BHP's shale assets for US$10.5 billion, but it has yet to say what it will do with the miner's Eagle Ford acreage. Prior to the downturn, Devon and BHP's 50:50 joint venture comprising roughly 100,000 gross acres (405 square km) was the single largest position in the Eagle Ford in terms of oil production.

According to the most recent US Energy Information Administration (EIA) forecast, the Eagle Ford is anticipated to produce 1.42 million bpd of oil this month, and 1.44 million bpd in November. This would keep the Eagle Ford in second place nationally, after the Permian, among the seven major tight oil regions in the US.

Beyond that, production is expected to rise slowly as new wells struggle to offset steep declines from the base production. Rystad projects that with oil at US$70 per barrel, Eagle Ford oil production will exceed the 2014 peak by about 2020.

Medium-term natural gas output can be harder to predict. Current prices are so low and gas production varies widely in different parts of the region. Ikonnikova anticipates that gas output could rise to perhaps 20% above the 2014-15 peak, unless development moves to the north of the play where there is less gas.

In the short term, the EIA projects that the Eagle Ford's gas production will reach 7.12 bcf (202 mcm) per day this month and 7.24 bcf (205 mcm) per day in November. This puts it in fifth place nationally among the leading US shale gas regions. The play's production figures for both oil and gas are by no means small, but the Eagle Ford appears set to trail behind the most prolific shale regions as the US unconventional boom continues evolving.❖

> "There are some concerns that oil takeaway capacity may yet become an issue in the Eagle Ford.

YPF in talks on FLNG unit with Exmar

ARGENTINA

ARGENTINA'S state-run YPF is considering the purchase of a FLNG vessel to enable it to export surplus natural gas during the summer and sustain production growth from the Vaca Muerta shale.

YPF, the country's biggest gas producer, would order the FLNG unit from Belgium-based Exmar, a source at the Argentine company said on condition of anonymity.

The FLNG vessel would be installed in Bahia Blanca, a port in southern Buenos Aires province where YPF has been importing LNG for the past decade with IEASA, another state-run company.

IEASA ended a contract with US-based Excelerate Energy for the provision of a FLNG unit in October. The vessel would have been used to import LNG, but the contract was terminated as improved domestic gas supply has reduced the need for imports and opens up the possibility of exports.

YPF would use the same infrastructure in Bahia Blanca's deepwater port to moor the FLNG and gear it up to export supplies piped in from the Vaca Muerta.

The source said that if the project progresses, the FLNG vessel would start operations in the first quarter of 2019, allowing it to take advantage of a seasonal glut in gas supplies during the warmer months. The terminal would have capacity to process 2.2 mcm per day (0.8 bcm per year).

YPF and other companies are looking at export opportunities as gas production surges with the development of the Vaca Muerta, one of the world's biggest shale plays. The country's gas output expanded 8.1% year on year to 133.8 mcm per day (49 bcm per year) in August, led by a 233% increase in output from Vaca Muerta to 20.5 mcm per day (7.5 bcm), according to data from the Energy Secretariat.

The increase is starting to raise concerns that an oversupply of gas during the warmer months of October to April will slow gas production. Demand fluctuates widely between summer and winter, ranging from 115 mcm per day (42 bcm per year) to peaks of 180 mcm (66 bcm).

While the Vaca Muerta can supply the winter peaks, wells would have to be closed during summer unless the supplies are exported.

Argentina began exporting supplies this year to Chile, which had been buying up to 20 mcm per day (7.3 bcm per year) as recently as the mid-2000s, and it is looking to export again to Brazil and Uruguay. But the country will have to look beyond the regional market if it is serious about scaling up development of the Vaca Muerta. This would require the country to move beyond FLNG infrastructure and establish permanent onshore liquefaction terminals to be competitive with other major LNG exporters such as Australia, Russia, Qatar and the US.

On October 5, Argentine President Mauricio Macri signed a preliminary deal with Qatari Emir Tamim bin Hamad Al Thani to work on projects to develop the Vaca Muerta, with [particular focus on the export of gas.

Argentina anticipates ramping up gas exports from virtually zero this year to 100 mcm per day (37 bcm per year) in 2023, with production forecast to surge to 238 mcm per day (87 bcm per year) by that point.❖

"YPF and other companies are looking at export opportunities as gas production surges with the development of the Vaca Muerta.

Argentina scraps gas tariff hike amid public discontent

ARGENTINA

The government is betting on the development of the Vaca Muerta to turn around more than a decade of dwindling gas production.

ARGENTINA'S government last week backtracked on plans to raise natural gas tariffs, with consumers complaining of the punitive impact it would have as the economy tanks and inflation surges.

Energy Secretary Javier Iguacel had announced the hike earlier in October, saying consumers would pay an additional tariff over a 24-month period beginning on January 1, 2019.

This would compensate gas producers for an estimated US$545 million in losses from the currency's plunge in value against the dollar of over 100% since April. Gas distributors in the country have fallen behind in payments, and, although they charge their customers in pesos, they buy their supplies from producers in dollars.

The peso has been losing value with the strengthening dollar sparking capital flight from emerging markets, with the crisis coming to a head in April. This saw the peso weaken further, which in turn deepened distributors' debt with producers.

Iguacel responded with the plan to charge consumers more to compensate producers, but this approach was attacked by consumers as well as politicians within and outside the ruling coalition.

Less than two weeks later, the administration of President Mauricio Macri scrapped the additional tariff and said it would instead sell a bond and take other steps to compensate the producers for their losses this year and for other debts.

The government also said it would introduce changes so that any such plans for tariff hikes must first get congressional approval.

While the current law allows extra tariff increases, the move came at a sensitive time, with the economy forecast to contract 2.5% this year and inflation likely to surpass 40%. The opposition lashed out at the government for the proposed hike, saying it was favouring the oil sector at the expense of consumers. "You can't always put the cost on the consumers," said Marco Lavagna, a leading opposition congressman.

Even so, there are concerns that without compensating the producers there could be a backlash in investment and future production. The government is betting on the development of the Vaca Muerta to turn around more than a decade of dwindling gas production that had caused shortages and a spike in imports.

The government must do something to reduce the debt with gas producers "so that investment continues to come," Luciano Laspina, a congressman for the ruling Cambiemos coalition, said on Radio La Red. "We are not defending the companies, we are defending legal security so that we have a future with energy."❖

Saltwater disposal well operator expands

APPALACHIAN BASIN

WASTEWATER and logistics company Nuverra Environmental Solutions has agreed to buy Clearwater Solutions, an operator of saltwater disposal wells in the Appalachian Basin, which encompasses the Marcellus and Utica shales, for US$41.9 million.

Scottsdale, Arizona-based Nuverra already has a strong presence in the Bakken and Haynesville shale plays, and is expanding in the Marcellus and Utica. It said the acquisition would more than double its saltwater disposal well capacity in the US Northeast. The company added that Clearwater's disposal wells at the Clearwater Three and Clearwater Five locations offered several offloading lanes and disposal capacity of 17,500 bpd. These wells are located in Guernsey County, Ohio, where shale drilling activity is booming.

The acquisition "significantly improves our competitive position in the Northeast marketplace due to the added capacity of the new wells and logistical advantages for our trucking business", Nuverra's interim CEO, Charlie Thompson, said in an October 5 statement. "Based on recent volume statistics, Nuverra will be the second largest commercial operator of [saltwater disposal wells] in the region," he added. "Clearwater's 2018 forecasted normalised EBITDA is approximately US$8 million before synergies. Synergies expected to be realised through integration with our trucking operations would reduce the post-synergy acquisition multiple to less than four times EBITDA."

Nuverra said its two largest shareholders had provided financing of US$32.5 million towards the transaction in the form of a bridge loan that would be repaid with proceeds from a planned offering to shareholders of common stock purchase rights. The rights offering will be made available to all shareholders on a pro rata basis and bridge loan lenders have committed to purchase the shares underlying any rights that are not exercised by other holders. In addition, Nuverra amended its first lien term loan to extend its maturity and received an additional US$10 million of term loan proceeds that funded a portion of the Clearwater purchase price.❖

Comstock seeks to grow in Haynesville

HAYNESVILLE

Jerry Jones acquired an 84% stake in Comstock in April.

COMSTOCK Resources is reportedly seeking to invest in further acreage and projects in the resurgent Haynesville shale play following its high-profile takeover by Dallas Cowboys owner Jerry Jones earlier this year.

According to a report by Bloomberg, the company is considering new takeovers in the region. While no further details were provided on potential deals, it is believed that a previously mooted purchase of Covey Park Energy is unlikely to progress.

Along with assets in the Eagle Ford and Bakken plays, Comstock currently holds proven reserves in the Haynesville of roughly 2 tcf (57 bcm) of gas equivalent, producing roughly 235 mmcf (6.7 mcm) equivalent per day in the first quarter of 2018.

Last month, the US Energy Information Administration (EIA) released new figures showing that Haynesville gas production had reached levels not seen since its 2012 peak. Output averaged 6.4 bcf (181 mcm) per day in June 2018, representing 8.5% of total US dry gas production. In 2012, output from the Haynesville averaged 7.4 bcf (210 mcm) per day, or over 9% of total US output.

The Haynesville shale is located at greater depths than other gas plays in the US, increasing the cost of production, which makes it more vulnerable to the impact of fluctuating gas prices. The formation is located at depths of around 10,500-13,500 feet (3,200-4,115 metres) compared with depths of 4,000-8,500 feet (1,219-2,591 metres) for the Marcellus formation.

However, improvements in both efficiency and drilling technology have helped offset these challenges, prompting firms to reassess the region's potential. The play's proximity to the Gulf Coast – where LNG exports are booming – is also increasingly attractive to drillers.

Jones acquired an 84% stake in Comstock in April, contributing his producing Bakken oil and gas properties – valued at US$620 million – in exchange for common stock. This marked a turnaround in fortunes for the company following years of struggles owing to low oil and gas prices.

"This combination provides Comstock with substantial cash flow to invest in their high-return Haynesville shale drilling programme and the capital to grow their already substantial inventory of drilling prospects," he said at the time.❖

COAL-BED METHANE

China approves new CBM projects

CHINA

THREE new coal-bed methane (CBM) projects in China approved by the central government will have US$1.12 billion invested in them with a target of jointly producing almost 1.5 bcm per year when fully operational, according to state media.

All three developments, based in the major northern coal-mining province of Shanxi, will involve "external co-operation", a term news agency Xinhua uses to mean foreign or non-state companies.

The blocks in question are Chengzhuang and Mabi in the Qinshui Basin and Liulin in the Ordos Basin, Shanghai Securities Journal reported, citing China's National Development and Reform Commission (NDRC).

Private foreign-owned G3 Exploration earlier announced it had won approval with partner China National Petroleum Corp. (CNPC) to expand the Chengzhuang block with permission to drill an additional 147 production wells. The block is already producing CBM from 114 wells. *(See UOGM Week 40)*

G3 was formerly known as Green Dragon Gas.

The identities of the Mabi and Liulin developers have not been disclosed. Usually CBM developments involve partnerships with CNPC or its subsidiary China United Coalbed Methane (CUCBM). Mabi was previously known to be operated by AAG Energy Holdings, in a joint venture with CNPC, while Liulin was a partnership between CUCBM and Fortune Liulin Gas. It has not been confirmed whether ownership has since changed.

The Chengzhuang block partners will invest 590 million yuan (US$85 million) over two years to boost output to 180 mcm per year, Shanghai Securities Journal said.

But the biggest project will be at Mabi, where US$670 million is due to be spent over four years with the aim of producing 1 bcm per year.

The Liulin block is expected to receive investment of US$370 million over three years with the goal of achieving output of 300 mcm per year.

These approvals follow calls by the Chinese State Council, of which the NDRC is a part, for greater efforts at a national level to tap the country's unconventional gas resources as demand rockets.

The national oil companies (NOCs), which dominate unconventional gas developments, have meanwhile called for an extension of state subsidies to support production growth beyond 2020, when current subsidies for CBM and shale gas are due to end.❖

EOG warns on third-quarter hedging impact

US

US shale producer EOG Resources has cautioned that its oil and gas hedges will hurt its third-quarter results. In an October 9 filing with the US Securities and Exchange Commission (SEC), Houston-based EOG warned of a non-cash loss of US$52.1 million in the third quarter on commodity derivative contracts.

In the filing, EOG cited a difference between its realised price for crude oil and gas sales during the quarter and the prices due at New York Mercantile Exchange (NYMEX) delivery locations as the reason for the loss. It said that benchmark crude prices had averaged US$69.50 per barrel during the quarter, while it had hedged 134,000 bpd, or about 35% of its prior period's production, at roughly US$60 per barrel.

EOG is nonetheless thought to be better positioned than some of its peers in terms of its hedging exposure. Estimates earlier this year by Bloomberg New Energy Finance indicated that EOG was the least-hedged US producer for 2018 by percentage of crude production, with just 9% of output hedged. According to Refinitiv I/B/E/S, EOG is still expected to report a profit of US$1.48 per share in the third quarter compared with a profit of US$0.19 per share in the same quarter last year.

Between 2015 and 2017, during the oil price downturn, US oil companies generated US$23 billion in gains from hedging, according to Wood Mackenzie. Producers were typically hedging barrels at higher-than-market prices to lock in future production and insulate against the low crude prices. While the recent oil price rally has been a boon for US producers, those that have hedged future output at prices capped below current crude price levels are looking at upcoming losses.

Hedging contracts could result in US$7 billion in losses if WTI prices were to stabilise at US$68 per barrel this year, Wood Mackenzie said in April. According to the consultancy, most companies hedge around 30% of their oil production on average, so they have enough output to sell at full market price and book gains when crude prices are rallying.❖

Permian leads increase in DUCs

US

A large uptick in drilled but uncompleted (DUC) oil and gas wells was seen over the past month, with almost all of these located in the Permian Basin.

In data released on October 15, the US Energy Information Administration (EIA) counted 3,722 DUC wells in the Permian last month, up by 194 from a month earlier. The 5% increase came alongside a total rise of 192 from August to September across the seven major shale regions monitored by the agency, with DUC counts declining in several other plays to offset the gains in the Permian.

Across all of the seven regions, there were 8,389 DUCs last month, up from 8,197 in August.

Two other regions – the Anadarko Basin and the Eagle Ford shale – saw far lower increases in DUCs compared with the previous month – at 31 and 18 respectively. In the remaining four regions, the EIA found that more wells were completed in September and so the number of DUCs decreased.

The Permian has been leading the charge in DUC counts since October 2016. In September 2017, the basin had 2,112 DUCs, so the count has risen by 76% in one year. The total across all seven regions in September 2017 was 6,329. A year before that, there were 1,148 DUCs in the Permian, and thus the year-on-year increase was slightly higher at 84%, but the Eagle Ford count was a little higher with 1,205 DUCs out of 5,414 across all seven regions.

DUCs have been multiplying in the Permian because while investment in the region has been on the rise, pipeline and infrastructure bottlenecks have emerged and producers are increasingly having to wait to bring new wells online.

The Permian's shortfall in pipeline capacity is not expected to be eased until the second half of 2019. Meanwhile, there is also a shortage of hydraulic fracturing crews in the basin, as well as of truck drivers and other labour, which increases costs in the short term.

There have also been limited supplies of pressure pumping equipment and proppant, though these are being alleviated.

But given the various bottlenecks – and particularly takeaway capacity – the differential between the wellhead price in Midland, Texas – in the Permian – and the storage hub at Cushing, Oklahoma had widened to nearly US$20 per barrel in August, the biggest in years. This encouraged the tendency among drillers to keep oil in the ground.

The WTI Midland-Cushing differential has now eased to less than US$8 per barrel for October delivery and to almost zero for delivery at the end of next year.

Permian oil production has been forecast by the EIA to reach an estimated 3.496 million bpd in October, and 3.549 million bpd the following month. Total production across the seven regions is projected to hit 7.616 million bpd this month and 7.714 million bpd in November.❖

Vista to develop Oklahoma frack sand mine

OKLAHOMA

VISTA Proppants and Logistics has announced the development of a 1.0-1.5 million ton (907,185 tonne to 1.4 million tonne) per year frack sand mine in Oklahoma. The project will serve customers primarily operating in the South Central Oklahoma Oil Province (SCOOP) and Sooner Trend Anadarko Basin Canadian and Kingfisher Counties (STACK) plays. It will be the company's first mine in Oklahoma. Vista also has three mines in Texas.

In-basin sand for use in hydraulic fracturing is becoming more popular in the Mid-Continent region and the Permian Basin, as well as in Canada. This is because of the higher cost of transporting the proppant over long distances from the Upper Midwest, where it has traditionally been mined. In addition, fears that finer-mesh sand – such as that from Texas and Oklahoma – will lead to lower oil and gas production over time have not yet materialised.

Vista said that it had completed the purchase of the 1,150-acre (5-square km) mine site in Oklahoma, northeast of Fay, and that it had ready access to water, electricity and natural gas. "We plan on producing both 100-mesh and 40/70 products with solid crush and other characteristics designed to best serve the growing need for in-basin sourced frack sand," said Vista's CEO, Gary Humphreys.

Fort Worth-based Vista also provided an update on the expansion of its West Texas mine facility in Winkler County. Operations there started in March and the mine is now operating at its initial capacity run rate of 3 million tons (2.7 million tonnes) per year of Texas Premium White sand. The mine will be expanded to 5 million tons (4.5 million tonnes) per year. The company received a new source review permit for the facility in August.

Other miners have also been moving into Oklahoma. Pennsylvania-based Preferred Sands announced plans for an in-basin sand mine in May to serve well operators in the STACK and SCOOP plays. It planned to bring the mine, capable of producing 3 million tons per year, online in the third quarter.

And in June, Texas-based Alpine Silica said it would start constructing a 3 million ton per year mine in Oklahoma by the end of the year. Alpine Silica said it had secured nearly 51 million tons (46 million tonnes) of reserves for the mine, which will also be located near Fay.❖

NEWS IN BRIEF

POLICY

Intense fight over Colorado oil and gas setbacks could end with national precedent

A years-long fight over how close oil and gas drilling can safely be to places where people live and work is coming to a head with an unprecedented November 2018 ballot measure that would ban such operations within at least half a mile of homes, schools, businesses and waterways.

Proposition 112 is pitting homeowners against Fortune 500 companies and even neighbor against neighbor. The stakes involved are immense in a state that is the nation's seventh-largest oil producer and fifth-biggest supplier of natural gas.

Opponents say increased setbacks would put tens of thousands of people out of work, plunge Colorado into a recession and jeopardise US energy independence.

An industry-backed political action committee, Protect Colorado, collected about US$33 million through September 26, 2018 to defeat the initiative.

That sum, which dwarfed the amount the other side raised, has made Proposition 112 one of the most expensive referendums in state history.

Proponents counter that industrial operations pollute the air and threaten health and safety. Colorado Rising, the committee leading the effort, has highlighted more than a dozen fires, leaks and explosions since 2017. Several have been deadly, and the loss of life is one likely reason Proposition 112 supporters succeeded this time in getting enough signatures to put the measure on the ballot.

As the November 6, 2018 midterm election nears, both sides are going door to door and holding rallies, especially in the most populous counties near Denver.

According to Tracee Bentley, executive director of the Colorado Petroleum Council, the state is considered "a bellwether." If Proposition 112 were to pass, she said: "We are certain we would see it pop up in a couple years in other oil-and-gas-producing states."

The showdown comes as applications to drill in the shadow of the Rockies tripled in the past year and oil production hit record highs.

The nation's fourth-largest oil field based on proved reserves lies beneath the Front Range here, ensuring that more rigs will go up in metropolitan areas dealing with historic growth.

Current law requires wells to be set back 500 feet from homes and 1,000 feet from schools. The referendum would push that to 2,500 feet and allow local governments to increase it even farther.

THE WASHINGTON POST, October 15, 2018

Ohio Supreme Court rules to keep anti-fracking initiative off the ballot

Voters won't be deciding next month whether there should be oil and natural gas extraction and waste disposal in Columbus. The Ohio Supreme Court has denied an effort by environmental group Columbus Community Bill of Rights to get the issue on the ballot after it filed a motion for reconsideration in September 2018.

"We are discussing many tactics to face the issue of frack waste in our watershed, as ▸▸

well as the roadblocks to initiatives that many communities and efforts are experiencing," said Carolyn Harding, a member of Columbus Community Bill of Rights.

This marks the third attempt the environmental group has made to get the measure on the ballot. The group was hoping to gain voter support to establish a "bill of rights" for residents related to quality water, soil, and air protection as well as ban on oil and gas extraction activities within the city. It's unclear if the group will try to get the item on a future ballot.

In 2015 and 2017, there were not enough signatures collected. However, in this latest effort the group collected 12,134 signatures, far surpassing the 8,990-signature requirement. The city of Columbus signed off on the initiative on July 30 2018.

In August, the Franklin County Board of Elections questioned the proposed ballot measure's legality. The Supreme Court ruled in favour of the Board of Elections. Terry Lodge, a Toledo-based attorney who is representing the Community Environmental Legal Defense Fund, previously told The Dispatch the board overstepped its authority because it considered the substance of the proposal.

"[The Board of Elections members] are limited to counting signatures and making sure the forms are filled out right," he said.

On October 5 2018, the Supreme Court upheld its previous decision, which found that the Board of Elections members "properly determined that the proposed ordinance is outside the city's power to enact legislation."

THE COLUMBUS DISPATCH, October 12, 2018

SHALE GAS

US OKs startup of part of Enbridge Ohio-Michigan NEXUS natural gas pipeline

US energy regulators approved Canadian energy company, Enbridge's request to put part of its US$2.6 billion NEXUS natural gas pipeline from Ohio to Michigan into service.

NEXUS is one of several gas pipelines designed to connect growing output in the Marcellus and Utica shale basins in Pennsylvania, West Virginia and Ohio with customers in other parts of the United States and Canada.

Enbridge said the facilities the US Federal Energy Regulatory Commission (FERC) allowed the company to put into service will enable it to transport about 27.4 mcm per day.

1 bcf (28.3 mcm) of gas is enough to fuel about 5 million homes for a day.

Once the 255-mile (410-km) NEXUS project is fully in service, it will be able to carry up to 42.4 mcm per day of gas from the Marcellus and Utica shale fields to the US Midwest and Gulf Coast and Ontario in Canada.

NEXUS is a partnership between Enbridge and Michigan energy company DTE Energy.

Enbridge said it put part of its US$200 million Texas Eastern Appalachian Lease (TEAL) gas pipeline project into service.

TEAL is an expansion of Enbridge's Texas Eastern system designed to deliver 26.9 mcm per day of gas to NEXUS.

When it started construction of the NEXUS pipe in late 2017, Enbridge estimated the TEAL and NEXUS projects would enter service in the third quarter of 2018.

Enbridge said it completed the NEXUS project in September 2018 when it asked FERC for permission to put part of pipeline into service.

New pipelines built to remove gas from the Marcellus and Utica basins have enabled shale drillers to boost output in the Appalachia region to a forecast record high of around 832.5 mcm per day in October from 685.2 mcm per day during the same month in 2017.

That represents about 36% of the nation's total drygas output of 2.2 bcm per day expected on average in 2018. A decade before, the Appalachia region produced just 45.3 mcm per day, or 3% of the country's total production in 2008.

REUTERS, October 11, 2018

Shell reaches milestone on plastics plant in Northeast, potentially a Gulf competitor

Shell has completed a substantial step in the construction of its plastics production complex in Pennsylvania, a project expected to catalyse similar developments in the Northeast if the region continues to build the pipelines and storage needed to support a petrochemicals hub rivalling that along the US Gulf Coast. The oil major's petrochemicals unit has installed the project's largest piece of equipment: a 285-foot cooling and condensation tower for gas and other hydrocarbons. It spent more than three weeks in transit up the Mississippi and Ohio rivers and required the one of the world's largest cranes to lift it into place.

The company is building an ethane cracker, which processes the natural gas liquid ethane into ethylene, which will be the feedstock for on-site production of polyethylene, the world's most common plastic. Three units will churn out 1.6 million metric tonnes of polyethylene a year to be sold as tiny plastic pellets for use in packaging, automobiles, furniture and consumer goods.

The project is the largest of its kind in the Northeast, which has lagged the US Gulf Coast in petrochemical developments despite ample supplies of natural gas from the Marcellus and Utica shale formations spanning Pennsylvania, Ohio and New York. The region is home to numerous companies that produce bottles, packaging and other goods, but the plastic pellets needed to make them often come from elsewhere.

The Shell project, however, will change that. A report last year by research firm IHS Markit noted that nearly 75% of US demand for polyethylene is located within 700 miles of southwestern Pennsylvania, where the company's site is located.

HOUSTON CHRONICLE, October 14, 2018

TransCanada puts part of West Virginia Mountaineer natgas pipeline into service

Canadian energy company TransCanada Corp told US energy regulators that the company's Columbia Gas Transmission unit put part of its US$3 billion Mountaineer XPress natural gas pipeline into service in West Virginia.

Mountaineer is one of several pipelines

designed to connect growing output in the Marcellus and Utica shale basins in Pennsylvania, West Virginia and Ohio with customers in other parts of the United States and Canada.

The US Federal Energy Regulatory Commission (FERC) approved Columbia's request to put Mountaineer's Elk River compressor station into service on October 5, 2018. TransCanada said in its latest filing to FERC that it put the station into service on October 9, 2018.

The 56.6 mcm per day Mountaineer project is designed to increase gas capacity in West Virginia. The project includes construction of 170 miles (274 km) of new pipeline in the state.

1 bcf (28.3 mcm) is enough gas to power about 5 million U.S. homes for a day.

New pipelines built to remove gas from the Marcellus and Utica basins have enabled shale drillers to boost output in the Appalachia region to a forecast record high of around 29.4 bcfd in October from 24.2 bcfd during the same month a year ago.

That represents about 36 percent of the nation's total dry gas output of 81.1 bcfd expected on average in 2018. A decade ago, the Appalachia region produced just 1.6 bcfd, or 3 percent of the country's total production in 2008.

In other news, TransCanada said last week that it placed the first Western phase of its WB XPress project into service. The Western phase is designed to move about 0.76 bcfd of gas from producers in Appalachia to consumers in the Gulf Coast. The company said it plans to finish the second Eastern phase of the $900 million project by the end of the year.

TransCanada also said it plans to finish its $600 million Gulf XPress project by the end of the year. Gulf XPress is designed to move 0.88 bcfd of gas from Appalachia to the U.S. South.

REUTERS, October 11, 2018

West Virginia natural gas industry sees steady production

A report says consumers are the winners with lower natural gas prices. "Powering West Virginia" by the Consumer Energy Alliance says the natural gas industry has realised relatively steady production and even job growth as opposed to the downturn in the coal industry in 2012. Chris Ventura, executive director of the alliance, said the alliance's latest report said natural gas cost consumers US$10 per mcf or 1,000 cubic feet in 2006 compared to US$4 per mcf today.

Ventura, who said increased production of the Marcellus and Utica shale formations has made West Virginia as the seventh-largest natural gas producing state in the country, also disputes that most of the natural gas industry jobs here have gone to out-of-state workers.

"Since 2010, West Virginia's core shale-related industry employment increased 77.54 %," Ventura said. That represents nearly 12,000 West Virginians, Ventura said. He also said the industry trucks bearing out-of-state license plates are fleet vehicles from the drilling and pipeline companies.

"That doesn't mean all the workers driving those trucks are from out of state," he said. According to the latest CEA study, oil and gas pipeline construction jobs in West Virginia grew from almost 1,800 at the end of 2016 to 5,130 by the end of third quarter in 2017 — a 185% increase. Also, since 2010, the severance tax on natural gas extraction has provided US$865.8 million to state and local governments in West Virginia. The report suggests the future of the Mountain State's energy resources and its pipeline network is under attack by out-of-state activists, some reportedly funded by foreign governments.

Ventura said the future success of the energy industry in West Virginia hinges on the ability to safely transport the oil and natural gas pulled from ground. Increased partnerships with technical and trade schools also are vital for providing workers trained in the trades. "The industry has been begging for welders," he said. Consumer Energy Alliance, which has a membership that includes nearly 300 business, agriculture, energy providers and suppliers (plus academic groups and 500,000 grassroots members) seeks the ongoing support of lawmakers and regulators. "They have been consistent in their regulations and support. … They take into account environmental effects," Ventura said. "Regulators have maintained a pretty sound approach." He reiterated the importance of their support to facilitate the construction and expansion of pipelines while caring for the environment.

THE PARKERSBURG NEWS AND SENTINEL, October 14, 2018

Select Sands announces temporary furlough at Sandtown

Select Sands announced it has placed 26 employees at its Arkansas operations on temporary furlough until further notice. This necessary step results from the current industry-wide market disruption, which has impacted demand for Select Sands' Northern White frac sand. Shipments and limited production continue, while the company continues to pursue additional opportunities.

Zig Vitols, president and CEO, states: "The recent disruption in the industry has required us to take these necessary steps to manage our business successfully while minimizing the impact to resume improvements when frac sand demand strengthens.

"We have been proud employers of a qualified workforce in our area and look forward to bringing our full team back on board as soon as possible."

SELECT SANDS, October 15, 2018

Texas pipeline company buys NGL fractionator

A company building major petroleum pipelines from the Permian Basin to Corpus Christi is buying a natural gas liquids fractionator.

San Antonio-based EPIC Midstream Holdings will buy the 64,000 bpd natural gas

liquids fractionator in Robstown, about 15 miles west of Corpus Christi, from Dallas-based Southcross Holdings.

The cost of the deal was not released.

Fractionators separate natural gas liquids into components such as ethane, butane and propane.

The facility is being upgraded to be able to process 68,000 bpd of natural gas liquids. EPIC said its natural gas liquid customers will be able to utilise the Robstown fractionator through the Sand Hills pipeline.

EPIC is currently building a 700-mile, 440,000 bpd of oil equivalent natural gas liquids pipeline out of West Texas' Permian Basin. The company is also building a 600,000 bpd crude pipeline from the Permian to the Corpus Christi region.

HOUSTON CHRONICLE, October 10, 2018

TIGHT OIL

Goldman Sachs: Shale will drive global oil growth through 2021

A new report says US shale oil and gas will continue to drive supply growth through at least 2021, though some signs point to the limits of shale resources.

The report by Goldman Sachs says US shale resources are expected to continue to grow by 1 million bpd through 2021, which would put the country at more than 13 million bpd of oil production.

In 2018 through July the US has produced, on average, 10.5 million bpd.

Goldman Sachs said several factors would point to a Shale Tail, or when US shale oil and gas production becomes less of an influence on global oil markets. They include fewer barrels of oil in the ground than initially estimated, decreases in the amount of oil coming out of each well, and a flattening of production growth.

One region where some indicators reflect the beginning of a Shale Tail is the Eagle Ford Shale. Goldman Sachs said the amount of oil in the South Texas region is being revised down.

Of the major shale plays the Eagle Ford and the Bakken in North Dakota are closest to becoming legacy plays, where production would have peaked. Goldman Sachs says the Eagle Ford and Bakken have less than 30 years of resource life, compared to the more than 90 years for the Permian.

Goldman Sachs expects Eagle Ford and Bakken production growing slowly or plateauing through 2025. The analysis says peak production growth in the Eagle Ford and Bakken were seen in 2013 and 2012, respectively.

SAN ANTONIO EXPRESS-NEWS, October 11, 2018

Resolute Energy provides preliminary third quarter production results and operations update

Resolute Energy provided preliminary third quarter 2018 production results and an operations update.Aggregate third quarter 2018 production averaged approximately 34,750 boe per day, an increase of 45% from the second quarter.

Third quarter 2018 oil production averaged approximately 15,740 bpd, an increase of approximately 47% over second quarter 2018.

Year over year, third quarter boe production increased 54% and oil production increased approximately 40%, both pro forma for the divestiture of the Aneth Field assets.

Growth in production is being driven by the company's successful ongoing development program. During the quarter, the company spud six wells, reached total depth on thirteen wells and placed eighteen wells on production.

Third quarter 2018 net loss is expected to increase compared to the second quarter net loss of US$3.7 million due in large part to the effect of non-cash mark-to-market derivative losses.

Third quarter 2018 Adjusted EBITDA is expected to be nearly double second quarter 2018 adjusted EBITDA of US$33.7 million (a non-GAAP measure as defined and reconciled below).

This significant increase in expected adjusted EBIDTA is being driven by stronger production volumes, as well as lower unit operating and overhead costs.

Our third quarter 2018 cost structure is expected to have improved substantially from second quarter as a result of lower per unit lease operating expense and cash-based general and administrative expense.

This is primarily due to significantly higher production volumes with only moderately higher absolute operating costs and modestly lower cash general and administrative expenses from quarter to quarter.

Based on the strong results from our drilling program, the borrowing base under the company's revolving credit facility was increased nearly 50% from US$210 million to US$310 million.

This US$100 million increase ensures that we will continue to have sufficient liquidity to prosecute our business plan.

At September 30, 2018, the company had approximately US$200 million of availability under the revolving credit facility.

Rick Betz, Resolute's CEO, said: "As expected, our 2018 development program has begun to pay dividends in the form of significantly increased production and cash flow.

"Having now finished drilling four multi-well pads, we have advanced our understanding of how to execute these large capital programs and are collecting the technical data that will help us continue to improve the productivity of our assets.

"As with other producers making the shift to multi-well pad drilling in the Basin, we learn more about the reservoir and subsurface interactions with every well we drill. Additionally, through a period of intense infrastructure challenges, our midstream arrangements have served us well as we continue to move product to end markets with no significant curtailments and continue to dispose of significant quantities of produced water at advantageous rates.

"As we close out the 2018 program and look forward to 2019, we remain committed to a pad-based development program that grows production while spending within cash flow."

Resolute's board of directors, in conjunction with its financial advisors, has continued to monitor the company's competitive positioning in the Permian Basin in light of the improving industry conditions, the strong macroeconomic backdrop and recent transactional activity.

As part of its ongoing effort to maximise stockholder value, the board continues to evaluate all alternatives available to the company, including potential strategic combinations, while the company continues its Delaware Basin drilling program.

RESOLUTE ENERGY, October 11, 2018

Silver Creek closes acquisition of the Powder River Basin Midstream assets from Genesis Energy

Tailwater Capital announces that its portfolio company Silver Creek Midstream a private midstream company located in Irving, Texas, through a newly formed joint venture, closed the acquisition of the Powder River Basin Midstream assets and the associated crude oil gathering system and facility assets from Genesis Energy for approximately US$300 million. Completed in partnership with Silver Creek's financial sponsors, Tailwater Capital and The Energy & Minerals Group, this acquisition will significantly enhance Silver Creek's footprint in the Powder River Basin ("PRB") in order to better serve its customers.

The company has experienced meaningful growth over the past year having closed on both the acquisition of the Red Butte Pipeline System in December 2017 and the acquisition of the Tallgrass Gathering System in February 2018, which offered the company an immediate presence in the PRB and provided a strategic 50-mile footprint in the core of the region.

At that time, Silver Creek also announced a joint venture with Tallgrass Energy Partners to develop the Iron Horse Pipeline to transport crude oil from the PRB to Guernsey, Wyoming.

The Powder River Basin Midstream Assets will be a critical addition to the Silver Creek portfolio and should accelerate Silver Creek's ability to provide a full suite of crude services to producers in the core of the basin.

Pro forma for the acquisition, Silver Creek Midstream now owns over 190 miles of crude trunk line and gathering pipelines with multiple interconnections to downstream markets out of Guernsey. Silver Creek has significant plans for additional growth in and around the system.

"This acquisition represents a tremendous opportunity for Silver Creek," said J. Patrick Barley, founder and CEO of Silver Creek Midstream. "The addition of Genesis' Powder River Basin pipeline system along with the associated crude oil gathering and rail facility allows us to meet the evolving needs and growing demand of our customer base in the region."

"It has been exciting to partner with Silver Creek since its formation in October 2017 and we are looking forward to working with The Energy and Minerals Group to support Silver Creek's growth in the PRB going forward," said Stephen Lipscomb, Principal at Tailwater Capital. "The Genesis Powder River Basin acquisition gives Silver Creek a unique footprint to provide premium crude takeaway solutions for our various customers.

"Drilling activity in the PRB continues to gain momentum and we are thrilled to be a part of that growth going forward."

TAILWATER CAPITAL, October 11, 2018

Oil falls as US shale oil output hits record high

Oil prices fell on October 16, 2018 on expectations of an increase in US crude inventories, but reports of a fall in Iranian oil exports helped limit losses.

Brent crude was down US$0.80 a barrel at US$79.98 by 8.25am GMT.

US light crude was US$0.60 lower at US$71.18.

US crude stockpiles are expected to have risen the week previous for the fourth straight week, by about 1.1-million barrels, according to a Reuters poll ahead of reports from the American Petroleum Institute and the US department of energy's Energy Information Administration (EIA).

US oil production has increased steadily over the past five years, reaching a record high of 11.2-million bpd in the week to October 5, 2018, EIA data showed.

But infrastructure within the biggest US shale producing area, the Permian basin, has not kept pace with rising output, filling domestic tanks.

"Once pipelines and oil terminals are built connecting the Permian to the US Gulf Coast, there will be big step-up in US crude oil exports," Harry Tchilinguirian, oil strategist at French bank BNP Paribas told Reuters Global Oil Forum.

The API figures are due at 8.30pm GMT with the EIA report following at 2.30pm GMT on October 17, 2018.

REUTERS, October 16, 2018

Lilis Energy announces new credit agreement conversion

Lilis Energy, an exploration and development company operating in the Permian Basin of west Texas and southeastern New Mexico, has announced that the company has entered into a five-year, US$500-million credit agreement. The credit agreement provides for a senior secured reserve based revolving credit facility with an initial borrowing base of US$95 million.

The credit facility matures on October 10, 2023 and is secured by substantially all of the company's assets. The credit facility is led by BMO Capital Markets Corp. and SunTrust Robinson Humphrey, Inc. as Joint Lead Arrangers; BMO Harris Bank, NA as Administrative Agent; SunTrust Bank (STI) as Syndication Agent; Capital One, N.A. as Documentation Agent, and Credit Suisse AG.

The company also announced the exchange of approximately US$68 million of the existing second lien term debt to equity, in connection with the new credit facility.

LILIS ENERGY, October 10, 2018

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