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A death foretold

It was financial concerns, not political pressure, that put a stop to TransCanada's Energy East plan, paving the way for Keystone XL.

Forging ahead

The US Federal Energy Regulatory Commission has approved the start of construction on the NEXUS gas transmission project.

Weighing a sale

Apache expects to carry out some sort of sale of its Alpine High asset in 2018-19, after having spent a planned US$1 billion on it by the end of 2018.

Cutting financing

BNP Paribas will no longer do business with companies working in shale or oil sands, after coming under pressure from environmental groups.


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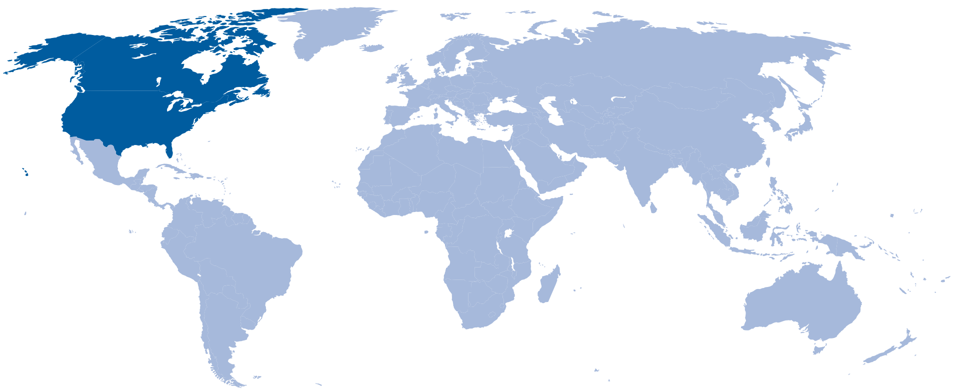


Have a question or comment? Contact the editor – Anna Kachkova (annak@newsbase.com)

Energy East: Chronicle of a death foretold

It was financial concerns, not political pressure, that put a stop to TransCanada's Energy East plan, writes Monte Stewart, paving the way for Keystone XL

CANADA

WHAT:
TransCanada has scrapped its ambitious oil pipeline plan to Canada's east coast.

WHY:
The project was commercially unsustainable.

WHAT NEXT:
More capacity is needed so Keystone XL moves to the front of the line.

AS is par for the course, Canadian politicians and regulators are being blamed for the death of Energy East. However, TransCanada's decision to scrap the proposed C$15.7 billion (US$12.6 billion) project ultimately came down to low oil prices, reduced demand – and a little help from US President Donald Trump.

Today's oil prices, at around US$50 per barrel, are significantly lower than they were when TransCanada proposed building Energy East in 2013. Meanwhile, as a University of Alberta energy economist, Andrew Leach, and others have noted, the supply balance was much more stretched at that time.

Energy East, which was designed to ship Alberta oil to New Brunswick while mostly using existing dormant pipe, became an alternative to Keystone XL for Canadian producers as they sought to secure increasing supplies of Alberta oil sands bitumen to overseas markets. The plan also stemmed from growing opposition in the US, with it becoming clear that former US president Barack Obama would scrap the Keystone XL plan – and he eventually did by denying it a permit in 2015.

TransCanada, therefore, needed an alternative to Keystone XL, after already having invested substantial sums in the cross-border project.

The change of president in the US, with Trump taking a consistently pro-pipeline stance, made the decision to scrap Energy East an easy one. TransCanada had already begun construction on Keystone XL's Canadian leg and, as Leach noted, the decision to stick with the cross-border pipeline offers a chance for the company to make some gains from its past investments.

Money talks

The pipeline firm was looking at a C$3 billion (US$2.4 billion) write-down related to Keystone XL's demise, versus a smaller one tied to the death of Energy East. Now, presumably, the lower write-down on Energy East will still spell a large tax write-off for the pipeline firm, which effectively killed the project by suspending its application for federal approval.

Leach went on to note producers that contracted to ship their oil on Energy East still would have been locked into paying shipping fees if the project was built, but there was not enough demand for their product. By scrapping the project, TransCanada wisely let producers off the hook – and deliberately pointed out that they would not have financial responsibilities for work done thus far – so that they could commit to shipping via Keystone XL.

Enbridge's proposed Northern Gateway project, intended to transport Alberta bitumen to the West Coast, was also once also in the mix as a possible alternative to Keystone XL. This, though, likely never stood a chance of being completed for economic reasons, even before Canadian Prime Minister Justin Trudeau's Liberal government rejected it.

Attribution error

Federal and Alberta Conservatives were quick to blame both Trudeau and Alberta Premier Rachel Notley for Keystone XL's demise. The Conservatives have frequently criticised Trudeau for failing to champion Canadian causes. This comes despite his government approving the Pacific NorthWest LNG project in British Columbia, which was also scrapped for financial reasons, as well as Kinder Morgan's Trans Mountain oil pipeline expansion and Enbridge's Line 3 replacement, which would transport Canadian crude to the US Midwest.

Notley's Conservative critics suggest that her New Democratic Party (NDP) hurt Energy East's chances of success by increasing energy companies' costs through a carbon tax – which is part of a federally mandated programme – and a cap on oil sands emissions.

The Conservatives are conveniently overlooking the fact that the previous federal government, led by them under Stephen Harper, failed to approve any major pipeline project during almost 10 years in office. Harper espoused a come-one-come-all approach to energy investors, but his cold relations with Obama led to

> "The change of president in the US, with Trump taking a consistently pro-pipeline stance, made the decision to scrap Energy East an easy one.

▸▸

little progress on Keystone XL's approval the first time round.

Harper's obvious disdain for China and his opposition to greater foreign ownership in the oil sands hardly made Chinese investors feel welcome at a time when their capital could have increased several energy projects' chances of being completed. It was unlikely that many Chinese investors would have sought a majority interest in Canadian firms, but Harper was pandering to supporters who – not always realistically – feared the loss of Canada's natural resources to foreign state-owned companies.

Critics have also blamed the National Energy Board (NEB) for Energy East's death. The federal regulator's new rules, set by the Trudeau government, require that upstream and downstream emissions be factored into the approval process – along with the financial viability of a given project.

However, as Leach also noted, the reality is that, with Keystone XL going ahead, the NEB was unlikely to approve Energy East, because there would not have been a need for it. Simply put, TransCanada would only have had enough capital to build one pipeline anyway.

Now, TransCanada has ensured that at least one of its projects will get built and, therefore, the firm stands to gain financially over the long term. However, Energy East's demise still poses problems for Canada and its oil sector.

For starters, the country also is set to lose a reported C$35 billion (US$28 billion) in economic output, and Canadian producers will have to continue to sell much of their oil to the US at discounted prices.

"People in Canada have to understand that the big winner here is President Trump," a former premier of New Brunswick and Canadian ambassador to the US, Frank McKenna, told BNN.

In addition, Eastern Canada will have to continue importing roughly 700,000 bpd of oil from such political hotspots as Iraq, Algeria, Nigeria and Saudi Arabia to meet demand, never mind that there is ample supply available in Western Canada.

Alternative links

With Alberta oil sands production increasing, Canadian producers will also need to find a way to send their oil to offshore markets, particularly Asia, where long-term demand is still strong, despite the Chinese government's quest to curb emissions significantly. According to the Canadian Association of Petroleum Producers (CAPP), Canada will need an additional 1.5 million bpd of pipeline capacity by 2030 to handle forecast production growth.

Consequently, Energy East's demise means that Kinder Morgan now faces more pressure to see its Trans Mountain expansion project completed. The outcome of a current court case, in which the Alberta and BC governments are disputing the country's need for the pipeline, has likely become more pivotal to producers' long-term chances.

If the case does not work out in Kinder Morgan's favour, Energy East's demise will still be about money – namely another project's lost investment and lower potential long-term revenues for the entire Canadian oil and gas sector.❖

> "Energy East's demise means that Kinder Morgan now faces more pressure to see its Trans Mountain expansion project completed.

FERC greenlights construction on NEXUS gas line

US

THE US Federal Energy Regulatory Commission (FERC) has approved the start of construction on the NEXUS gas transmission project, the agency said on October 11. The plan covers the construction of 257.5 miles (414 km) of new natural gas pipelines, from Kensington, Ohio to DTE Gas' system west of Detroit, in the Ypsilanti Township, in Michigan.

NEXUS is owned 50:50 by Spectra Energy Partners, which is the operator, and DTE Energy, the parent company of DTE Gas. Spectra merged with Canada's Enbridge in February of this year. The project is estimated to cost slightly over US$2 billion.

The link will transport 1.5 bcf (42.5 mcm) per day of gas from Appalachian shale gas supplies to northern Ohio, southeast Michigan, the Chicago Hub in Illinois and the Dawn Hub over the border in Ontario, Canada. The pipeline will also have four compressor stations. Capacity at the pipeline is 59% subscribed.

FERC's approval came with three locations that required further filings. Two of the points of concern in FERC's approval were environmental, while the third was over safety concerns about horizontal directional drilling (HDD).

The agency gave a certificate of public convenience and necessity in August for the NEXUS plan, following an environmental impact statement in November 2016. Work on the pipeline may begin as soon as this month, with a targeted start date of the third quarter of 2018.

The pipeline has faced some local opposition, led by the Coalition to Re-route NEXUS (CORN), which tried – and failed – to have the pipeline shifted. However, FERC's August filing noted that 93% of the required access had already been given to the pipeline without the use of eminent domain. ❖

Targa sets out Permian pipeline plan

PERMIAN BASIN

TARGA Resources, Kinder Morgan and DCP Midstream will build a natural gas pipeline from the Permian Basin to the Corpus Christi area, on the Gulf Coast. Work will be carried out by Houston-based Targa's joint venture with a subsidiary Kinder Morgan – which had already teamed up with Denver-based DCP – on the already announced Gulf Coast Express (GCX) pipeline. DCP is owned by Canada's Enbridge and Phillips 66.

A letter of intent (LoI) has been signed between the newcomer to the deal, Targa, and the two existing partners. Some specifics have yet to be pinned down.

The parties have agreed that Targa will own a 25% equity interest in the GCX project, and will commit significant volumes to the proposed project, including certain volumes provided by Pioneer Natural Resources, a joint owner in Targa's WestTX Permian Basin system and one of the largest producers in the Permian Basin.

The GCX plan will now have capacity of approximately 1.92 bcf (54 mcm) per day, which would include a lateral into the Midland Basin of some 50 miles (80 km) of 36-inch (914-mm) pipeline and associated compression to serve gas processing facilities owned by Targa, as well as those owned jointly by Targa and Pioneer. The line is still expected to be completed in the second half of 2019.

Targa also announced a firm agreement to sell a 25% joint venture interest in its previously announced Grand Prix NGL pipeline to funds managed by Blackstone Energy Partners. Grand Prix will be a new 300,000 bpd common carrier NGL pipeline also from the Permian Basin to Mont Belvieu, Texas – just east of Houston – and with expansion capability to 550,000 bpd.

Blackstone's EagleClaw Midstream Ventures and Targa have also executed a long-term raw product purchase agreement for transport and fractionation services. Deal prices were not revealed. ❖

Progress eyes Deep Basin sale

ALBERTA

PROGRESS Energy is reportedly planning to sell its Deep Basin oil and gas asset in the province of Alberta, as market conditions continue to exert pressure on operations in Western Canada.

The firm, which is a subsidiary of Malaysia's state-run energy firm Petronas, has enlisted BMO Capital Markets to advise on the sale, according to a Reuters report. BMO Capital Markets is the investment banking subsidiary of Canadian Bank of Montreal.

Petronas said the sale would enable Progress to focus on future investments in its North Montney assets, which offer it a "significant growth opportunity", the report added. The company's North Montney assets are located in British Columbia.

Progress, which was acquired by the Malaysian major for US$5.87 billion in 2012, claims to be the largest holder of contiguous Montney land. More than 13,000 drilling locations have been identified in the area and around 215 wells have been drilled to date, according to information on the company's website.

In July, Petronas abandoned plans to build the US$29 billion Pacific NorthWest LNG project, for which it had received approval in 2016 from Canadian regulators, dealing a major blow to the country's energy industry.

One of the largest resource developments in the country, Petronas co-owned the Pacific NorthWest LNG project alongside Indian Oil Corp. (IOC), Japan Petroleum Exploration (JAPEX), Sinopec and Brunei National Petroleum.

The project, to be built on Lelu Island, would have received natural gas from the North Montney region via the Prince Rupert Gas Transmission project. There was significant opposition to the scheme from environmentalists, who said it would contribute to greenhouse gas (GHG) emissions.

Petronas said at the time that it was cancelling the project – which was expected to export to Asian markets – because of "changes in market conditions". In particular, it blamed a long period of depressed prices and shifts in the energy industry.

Canada's fragile LNG industry has been hit hard in the last few years by sliding international oil prices, with several projects being pushed back, such as Chevron Canada's proposed Kitimat LNG project, also in BC.❖

RIL begins withdrawal from US shale

US

INDIA'S Reliance Industries Ltd (RIL) has agreed to sell one of its major upstream shale gas projects in the Marcellus to BKV Chelsea, a subsidiary of the US-based Kalnin Ventures, for US$126 million.

The company is planning to sell its 60% stake in the assets, which are operated by RIL's former joint venture partner, Carrizo Oil and Gas, and which it bought for US$392 million in 2013. The sale announcement was made on October 6. Carrizo also sold its stake in the Marcellus assets, also to Kalnin, for US$84 million at the same time.

RIL had invested heavily in US shale, with more than US$8.2 billion spent by 2016 on joint ventures across four major assets. Three of these projects were exploration-based, with a fourth venture with Pioneer Natural Resources focused on midstream transport, processing, storage and marketing. Most of its investments were in shale gas, which has suffered particularly hard as a result of the glut.

At the company's AGM in July, RIL's managing director, Mukesh Ambani, said: "Reliance's US shale gas ventures have faced challenging times due to prices at their lowest in a decade. Reliance and its partners continue to improve efficiencies and we will continue to look at rationalising these portfolio investments."

The 2016-17 annual report said that, given the weak prices, the company was focused on preserving value by "high grading of the portfolio and reducing operating costs. The business is taking a cautious approach to resuming development and focusing on conserving cash and retaining optionality."

RIL's aggregate capital investments in its joint ventures have dropped to just US$200 million, a 78% drop year on year, and the company has adopted a "zero drilling" policy to save costs. The company still appears to be planning to retain some shale assets, but some analysts believe it will follow in the footsteps of BHP Billiton, which intends to sell off its US shale assets following a US$7.2 billion write-down.❖

Apache plans 2018-19 Alpine High sale

PERMIAN BASIN

APACHE plans to have spent US$1 billion on its Alpine High asset by the end of 2018. In 2018-19, it expects to carry out some sort of sale of this asset, the company's CEO and president, John Christmann, said in an update on October 9. Apache is also considering a sale of its midstream facilities on this project.

The Alpine High development is an "extremely large wet gas play", he continued, with more than 3,500 economic locations. Based on 4,400-foot (1,340-metre) laterals, wells should cost US$4-6 million, with net present values of US$5-8 million. Beyond the wet gas play, there are another 1,500 locations.

For a high-end well, the NPV rises to as high as US$19 million, the executive said. Longer laterals may improve these calculations further. One of the "upper range" wells will generate positive returns, from oil and NGLs, even if gas prices are zero, the company claims.

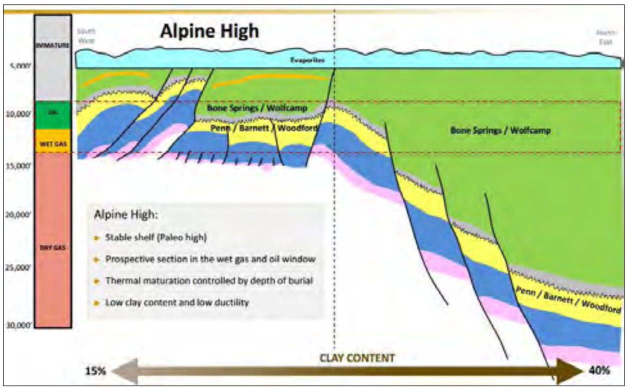
As the company learns more about the play, it expects well results to improve – even while keeping its rig count flat from 2017 to 2018.

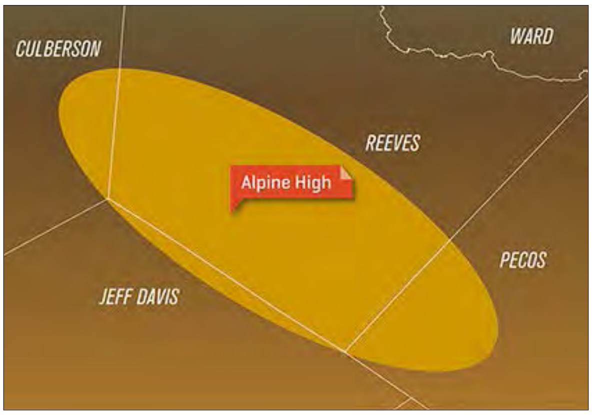
While Apache has a muted view of gas prices, cutting its expectations for 2018 from 2017, Alpine High's economics are driven by low costs and the "tremendous volumes" of oil and NGLs.

The company has drilled around 70 wells in the play over the year, providing it with greater insight into the fairway, while also starting work on infrastructure to support the development. Apache has 336,000 acres (1,359 square km) of licences on the play, up 9% since September 2016.

The Alpine High is made up of three zones: the northern flank, the crest and the southern flank. The northern part is the largest, covering around 56% of the acreage and with Apache having drilled 54% of its wells there. Christmann pointed out, though, that this drilling emphasis did not necessarily mean that this was the most attractive. Rather, these were where initial leases were acquired, with nearer-term expirations.

Apache has been tight-lipped about some aspects of the Alpine High, it acknowledged. The company said, when it announced the discovery of the play in September 2016, it had chosen not to disclose information about the "seal integrity of the source rock, the impact of deep-seated faults and shallow geologic complexities".





The company said its knowledge of these problems had allowed it to make progress on the Alpine High, an area that had frustrated all previous operators. Of the 3 billion barrels of oil originally in place (OOIP) on the project, Apache expects to recover around 13%.

Infrastructure

Work on gas infrastructure began in November 2016 and first gas sales were achieved on May 3 of this year, ahead of the target of the end of June. Apache said it had drawn on experience from its work in the Permian Basin and in Egypt to carry out this plan.

Apache installed 14 miles (22.5 km) of takeaway trunkline, 4 miles (6.4 km) of gathering lines and five production facilities, with a connection to the Comanche Trails pipeline. Work is continuing, with 70 miles (113 km) of trunkline, running from the north and south, under way. Two of the five sections of this larger plan have been completed, covering 42 miles (68 km).

Gas processing capacity is currently at 200 mmcf (5.66 mcm) per day and by the end of this year should have reached 330 mmcf (9.3 mcm) per day from five facilities. Gas is being sold into Mexico, at a slight premium to the Waha daily benchmark.

Oil and NGLs are being trucked from the play, at a cost of US$3 per barrel, but by 2019-20 a pipeline should have been built.

Given the appeal of these midstream assets, Apache said it was considering some sort of sale, although there is not yet a clear plan.❖

CURRENT ALPINE HIGH PRODUCTION

Gas: 101 mmcf (2.86 mcm) per day
Oil: 1,425 bpd
NGLs: 2,025 bpd

BY THE END OF THE YEAR
Gas: 125 mmcf (3.54 mcm) per day
Oil: 1,900 bpd
NGLs: 3,000 bpd

BNP cuts shale, oil sands financing

NORTH AMERICA

BNP Paribas will no longer do business with companies working in shale or oil sands, the French bank said on October 11. The institution, which describes itself as "the bank for a changing world", said it would support clients in the energy sector "committed to being part of the energy transition".

Other areas in which BNP will no longer operate include transportation of oil and gas from shale and oil sands, in addition to any exploration or production work in the Arctic. This move follows an earlier decision to reduce support for coal mines and coal-fired power plants. At the same time, the bank intends to increase total financing for renewable energy to 15 billion euros (US$17.7 billion) and also provide 100 million euros (US$118 million) for start ups working on "innovative solutions for energy transition".

BNP went on to say it was taking this step in order to do its part to achieve the International Energy Agency's (IEA) scenario of limiting global warming to 2 degrees Celsius by the end of the century.

The bank, which aims to be carbon neutral by the end of this year, said the production of shale and oil sands result in high levels of greenhouse gases (GHGs) and also have a harmful impact on the environment.

The bank's prohibition on shale extends to LNG terminals that "predominantly" liquefy gas from this type of resource.

"We're a long-standing partner to the energy sector and we're determined to support the transition to a more sustainable world," said BNP's CEO, Jean-Laurent Bonnafe. "As an international bank, our role is to help drive the energy transition and contribute to the decarbonisation of the economy. As we have announced, we're committed to working with and supporting those energy sector partners who have decided to make environmental issues a central part of their business policy."

In a longer note on LinkedIn, Bonnafe said reform of the energy system was essential for further progress in civilisation.

France banned hydraulic fracturing in 2011. In 2016, the French government raised the prospect of a ban on imports of shale-derived LNG.

Impact

In hindsight, signs of pressure on BNP have been mounting for some time. Aside from the environmental justification cited by the bank, there is also a matter of reputational risk.

"Aside from the environmental justification cited by the bank, there is also a matter of reputational risk.

BNP has signed on to a number of LNG projects in the US, including Texas LNG and Mangolia LNG. Its involvement in the former led to the publication of a report in March critical of the bank's support.

BNP's prohibition on shale extends to LNG terminals that "predominantly" liquefy gas from this type of resource

"Given that the country of France has banned fracking, a French bank supporting this project would be cynical at best, and hypocritical at worst," the report, from Rainforest Action Network (RAN) and Save RGV from LNG, said. It also raised concerns about BNP's commitments to a stable climate and the impact on local communities.

Finally, the report also raised BNP's signing of the Equator Principles as incompatible with its Texas LNG support, saying this posed "irreversible and unprecedented risks".

In April, BNP sold its US$120 million interest in the Dakota Access pipeline, a US$2.5 billion link constructed by Energy Transfer Partners. The pipeline was controversial and sparked local protests and a broad-based financial push to make financiers rethink, under the slogan "Defund DAPL". ING also sold out of the project, in March. BNP, in June, was warned against financing Kinder Morgan's Trans Mountain pipeline expansion, which would carry oil from Alberta to the Pacific Ocean.

BNP has also been involved in a pipeline in Mexico, which carries natural gas from Texas to power plants – acting as a replacement to fuel oil.❖

WITHHOLDING FINANCING

Rabobank will not finance oil sands and shale activities, while ABN Amro will not help oil sands and Arctic work, according to BankTrack.

OPEC's call on US output

US

THE oil market has shown some signs of rebalancing but the US has a "shared responsibility" in this, OPEC's secretary general, Mohammad Barkindo, said in India this week. The OPEC official went on to say there was a need to sustain the rebalanced market and that extraordinary measures could be taken, "including expanding the membership".

"This is a shared responsibility of all producers, be they conventional or non-conventional, short or long-cycle investors. We all, at the end of the day, when all is said and done, belong to the same industry and operate in the same markets. We urge our friends in the shale basins of North America to take this shared responsibility with all the seriousness it deserves, as one of the key lessons learnt from the current, unique supply-driven cycle," Barkindo said.

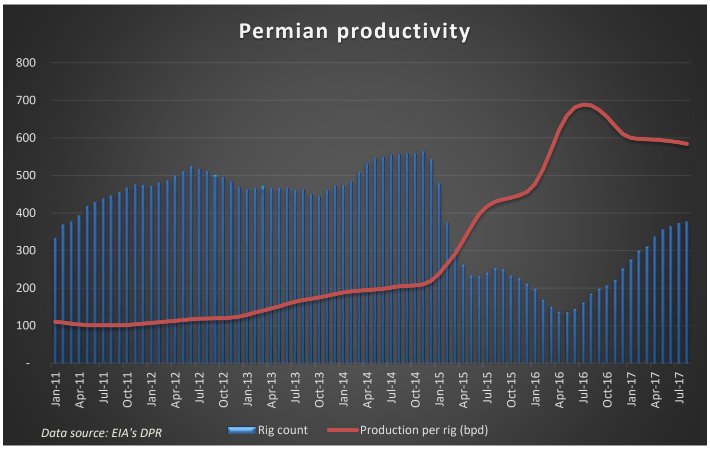
In another speech, on October 9, Barkindo expressed concerns about how investments are balanced across projects. Noting increasing demand for oil, the official said that investments were expected to pick up slightly in 2017-18. However, "it is clear that this is not anywhere close to past levels and it is more evident in short-cycle, rather than long-cycle projects, which are the industry's baseload".

The official went on to note slowing tight oil growth in the first half, citing reduced productivity from wells, particularly in the Permian. He also said there were "growing concerns" from investors.

Barkindo's take on the oil market is both wrong and right. There is no chance that US producers, focused on short-cycle shale oil, will be willing to reduce production for the greater good of a rebalanced oil market. As with many such free rider problems, enforcing a collective cut would require government action, which seems highly improbable – in addition to being likely illegal.

Constraints

Where Barkindo is right, though, is noting the fundamental problems facing the sector, as



exemplified in the Permian. Recent data from the US Energy Information Administration's (EIA) drilling productivity report show the production per rig gaining ground in late 2014 and rising to a peak in mid-2016, before trailing off subsequently.

Recent price strength has allowed producers to dust off hedging programmes, which had trailed off in response to low prices.

A note this week from Bank of America Merrill Lynch (BofAML) gave US$50 per barrel as the number at which a majority of shale plays are "in the money". It went on to say a US$1 per barrel move in future 2018 prices would drive a 60,000 bpd change, in the price band between US$40 and US$60 per barrel.

BofAML went on to say data from the New York Mercantile Exchange (NYMEX) showed the recent price rally had allowed large-scale hedging for next year. "If producers manage to increase these hedge ratios, they can limit the sensitivity of production to spot prices and continue to increase output in 2018," the note said.

Offsetting this bullish tone, though, the report also noted lower momentum in shale production this year. Part of this it blamed on prices but it also highlighted a steady decline in incremental rig efficiency throughout 2017. There will be an impact on rig productivity numbers from drilled-and-uncompleted (DUC) wells but this is compounded by seeking less attractive targets.

Barkindo's reference to investors was also notable. Oil and gas stocks have been disappointing for investors and there is a feeling that companies are starting to take note. Evidence of this came with Anadarko Petroleum's plans to carry out share buybacks in September.

The pursuit of "growth at any cost" has been the mantra of the US shale patch for some time, with the market largely rewarding those companies that outline aggressive capex and production plans – and punishing those with a more sober disposition. Changes on this front, coming at a time of continued OPEC determination, may just help shore up the delicate market balance.❖

Rigs under pressure

US

BAKER Hughes, a GE company (BHGE) reported a count of 936 rigs on- and offshore on October 6, three down from the prior week. The rig count serves as a lagged indicator of optimism. Even so, the count is up 413 from a year earlier, when prices were lower.

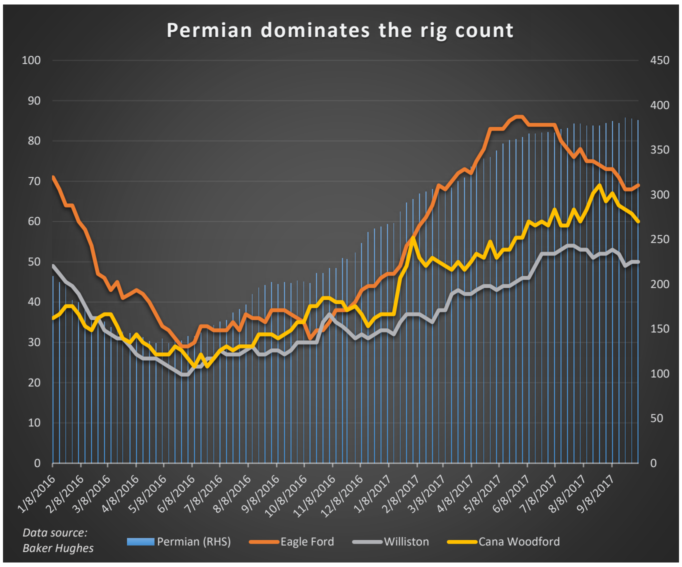
The company reported this was the third weekly drop in a row. A peak this year of 958 was achieved at the end of July. In contrast, the offshore count stayed steady at 22 this last week.

Oil and gas rigs were each down two in the tally, with horizontal and directional down five. September's average was 922 onshore, compared with 930 in August. Oil prices have been hovering at just below US$50 because of high inventories and production globally.

The Baker Hughes report is closely watched and is considered an indicator of confidence in the sector. However, given the time lag between the oil price moving, giving operators sufficient confidence to order a rig and have that delivered, can be around three months.

Even the prolific Permian Basin has seen a dip. Drillers scaled back by three rigs in Texas. Land prices and oilfield services have become too high in the region, and infrastructure is struggling to catch up.

Wood Mackenzie reports that in the Permian, the US' most productive shale region, drillers spent US$35 billion to acquire acreage West Texas in the nine months ending in the early spring. Land deals in the last six months have not even reached US$5 billion.



Elsewhere onshore, drillers idled two rigs apiece in Wyoming and Pennsylvania, with one cut in Louisiana, said the GE-owned company. Colorado and Oklahoma each upped their count.

According to Platts RigData, September saw the first monthly drop in rigs this year, at 1,043, a decrease of 28 – down 3% – from August 2017, but up 460 on a year earlier.❖

Gulf industry recovers from Hurricane Nate

GULF OF MEXICO

US Gulf of Mexico producers are preparing to resume output after emerging relatively unscathed from Hurricane Nate. While the impact on the US was muted, the hurricane killed at least 22 in Central America.

Between 78% and 95% of the US' crude oil and gas production in the Gulf was shut down over the weekend of October 8-9, according to local sources.

Many offshore platforms were evacuated as the Category 1 hurricane crossed the Gulf, with 14 rigs, or 70% of the total, and 298 platforms, making up 40% of the total, shut down, while 10 mobile rigs were shifted away from production sites.

A large number of refineries, pipelines, terminals and onshore sites were also closed for the duration. More than 2.5 bcf (71 mcm) per day of natural gas production and 1.62 million bpd of oil production were shut down over the weekend.

Other assets, including a large stretch of the Mississippi River leading to the Port of New Orleans, were also closed to incoming deep-draft traffic, disrupting supply lines.

However, no major damage has been reported from the hurricane, which suggests that the regional industry and the crude and natural gas supplies it produces should rebound quickly this week. Some sites remained open – Royal Dutch Shell's Norco refinery in Louisiana, the Garden Banks pipeline and Chevron's Pascagoula refinery among others were all online throughout the storm.

Companies began working to restore production on October 8, with Chevron and Shell returning workers to their platforms and assessing pipelines to resume output.

Speaking to the Houston Chronicle, Lipow Associates' Andy Lipow predicted "oil and gas production should recover by the end of the week, if not sooner". The hurricane "'was very fast-moving, it doesn't seem that much damage was done to any of the offshore platforms, and the oil companies will be able to get their people back in place in short order."❖

Encana's early Sunrise

WESTERN CANADA

ENCANA'S Sunrise shale gas processing plant in Canada – the Alberta company's second facility – is now in operation after construction was completed under budget and a month ahead of schedule.

The plant, which commenced work on September 27, is the second of a trio of processing plants the company has outlined to support its work and growth in the Montney play. The first was Tower, which is now ramping up alongside Sunrise. The third, Saturn, is also ahead of schedule and is expected to be ready for start-up before the end of the year.

Towerbirch, the lateral pipeline that Encana said has been designed to connect the facilities to the NOVA Gas Transmission Ltd (NGTL) system, began work on October 1. NGTL consists of more than 25,000 km of gas pipeline and associated facilities in Alberta and northeastern British Columbia.

The system's operator, TransCanada, announced in June that it would proceed with a new US$2 billion network expansion programme.

Encana's president and CEO, Doug Suttles, said the company's ability to remain ahead of schedule and under budget for the northeastern BC plants highlighted the strength of its execution capabilities. "The new processing and midstream infrastructure now in place firmly supports our growth plan in the Montney, which is a key driver to expanding our corporate margin and delivering quality returns," he said.

Encana has an existing agreement with Veresen Midstream that enables the company to construct and operate Tower, Sunrise and Saturn via the Cutbank Ridge Partnership and on behalf of Veresen on a contract basis. This includes any future building opportunities.

Under the terms of that deal, Veresen Midstream funds and owns the plants and Encana has a fee-for-service agreement for their use.❖

NEWS IN BRIEF

POLICY

Federal District Court vacates BLM's postponement of the waste prevention rule

On October 4, 2017, the US District Court for the Northern District of California issued a decision vacating the Bureau of Land Management's (BLM's) June 15, 2017, notice that indefinitely postponed compliance dates for sections of BLM's Methane and Waste Prevention Rule.

The Methane and Waste Prevention Rule, which was adopted as a final rule in November 2016, is intended to limit venting, flaring, and leaks of natural gas from oil and natural gas production activities on public and tribal lands.

Certain provisions of the Methane and Waste Prevention Rule went into effect in January 2017, while others have a compliance date of January 2018. BLM's June 15, 2017, Federal Register postponement notice sought to postpone compliance with those requirements for which compliance would be required in January 2018 and claimed authority under Section 705 of the Administrative Procedure Act (APA).

BLM's postponement notice is one of the multiple actions taken by the Trump Administration to delay or postpone the implementation of Obama-era environmental regulations. In addition to BLM, the US Environmental Protection Agency (EPA) has taken steps to delay the implementation of the 2016 Methane Rule (which establishes requirements aimed at reducing methane emissions from oil and gas facilities constructed or modified after September 18, 2015), the January 2017 amendments to the Risk Management Plan (RMP) rules, and landfill gas/methane standards for municipal solid waste (MSW) landfills.

The Federal District Court, hearing the challenge to the BLM's June 2017 postponement notice found, that it did not have the authority to do so under APA Section 705. The court rejected BLM's use of APA Section 705 to postpone particular compliance dates for an already effective rule (as opposed to postponing the effective date of an entirely new rule), and also held that BLM had failed to establish that the postponement notice met the "when justice so requires" standard for postponement actions under APA Section 705.

ENERGY LEGAL BLOG, October 6, 2017

DOE proposes FERC action to preserve and compensate baseload generation resources

The Department of Energy (DoE) has issued a Notice of Proposed Rulemaking (NOPR) directing the Federal Energy Regulatory Commission (FERC) to take prompt action to help prevent further retirements of baseload generation resources located within the centralised markets operated by FERC-jurisdictional Regional Transmission Organisations (RTO) and Independent System Operators (ISO), pursuant to its authority under Section 403 of the Department of Energy Organisation Act.

The NOPR comes just over one month after issuance of a report by DoE staff on electricity markets and reliability that found that significant changes in the electric industry, such as low natural gas prices and the growth of renewables, are contributing to the premature retirement of coal-fired and nuclear baseload generation.

In the NOPR, DoE finds that coal-fired and nuclear generation facilities play a critical role in maintaining the reliability and resiliency of the electric grid, particularly ▸▸

during stressed grid conditions. DoE notes that coal-fired generation resources that were scheduled for retirement and nuclear generation facilities played a critical role in maintaining reliability during the Polar Vortex when fuel limitations rendered many gas-fired generation resources unavailable. The Polar Vortex occurred early in 2014 when extreme weather events caused challenges for the electricity industry. DoE points out that coal-fired and nuclear generation facilities are particularly effective in protecting against system supply chain disruptions because these units tend to maintain significant on-site fuel storage. While DoE recognises that FERC has been engaged in an extended effort to improve price formation practices in organised markets, DoE considers it to be increasingly apparent that FERC-jurisdictional organised markets are not accurately valuing the reliability and resiliency benefits provided by traditional baseload resources.
ENERGY LEGAL BLOG, October 2, 2017

UPSTREAM

Corridor announces production optimisation strategy and guidance for 2017-18

Corridor Resources has announced that it has finalised its production optimisation strategy for the period from November 1, 2017, to March 31, 2018. Accordingly, the company has provided an update of its operating and financial guidance to the end of March 2018.

Since 2015, Corridor has employed a production optimisation strategy by shutting-in all or a portion of its natural gas production during the warmer weather months, i.e. when natural gas prices at the Algonquin city-gates market (AGT) typically trade at a discount to NYMEX Henry Hub (HH), with a view to optimising the recovery of expected flush volumes to coincide with anticipated higher natural gas pricing during the winter period, i.e. when AGT natural gas prices typically trade at a premium to HH. The objective of Corridor's production optimisation strategy is to maximise its field operating netback while producing lower natural gas volumes and preserving Corridor's reserves for production in future years.

In accordance with this strategy, Corridor has shut-in all of its natural gas production on April 1, 2017. The company has now finalised its plan to partially recommence its natural gas production in November 2017, with full field production expected by December 2017.

A key component of Corridor's strategy is to enter into financial hedges and forward sale agreements over the higher priced winter period to secure a threshold of revenue and mitigate the risks associated with the volatility of natural gas prices. Accordingly, Corridor previously announced it had entered into a financial hedge at a fixed price of US$7.40 per million Btu for 2,500 million Btupd of natural gas production for the period from December 1, 2017, to March 31, 2018. Corridor has announced that it has entered into an additional financial hedge at a fixed price of US$US7.83 per million Btu for 2,500 million Btupd of natural gas production for the period from December 1, 2017, to February 28, 2018.
CORRIDOR RESOURCES (CANADA), October 11, 2017

Rex brings production on and aims high with production

Rex Energy has put the two-well Frye pad up for sale. The two wells were drilled to an average lateral length of approximately 6,300 feet and completed with an average of 42 stages. They produced at an average 24-hour sales rate per well, assuming full ethane recovery, of 9.4 mcf per day, consisting of 4.1 mmcf per day of natural gas, 820 bpd of NGLs and 70 bpd of condensate. The two wells represent, on a per lateral foot basis, the highest rates the company has achieved to date in the Moraine East Area.

The company has finished completing the four-well Wilson pad in the Legacy Butler Operated Area. The four wells were drilled to an average lateral length of approximately 9,300 feet and completed with an average of 51 stages. The four wells are expected to be placed into sales in November 2017.

Following the completion of the Wilson pad, the company has begun completing the three-well Manuel pad in the Moraine East Area. The three wells were drilled to an average lateral length of approximately 6,750 feet. The company expects to finish completion of the Manuel pad and place the wells into sales in the fourth quarter of 2017. In addition, the company remains on schedule to place additional compression for the Moraine East Area into service in January 2018.

Given the strong production results and consistent operational performance during the quarter, the company expects its third quarter 2017 production to be near the high end of the previously announced third quarter production guidance of 171-181 mcf per day.
REX ENERGY (US), October 11, 2017

Ring Energy releases third quarter 2017 operations update

Ring Energy has released its operations update for the third quarter of 2017. The company, in the three months ended September 30, 2017, completed the drilling phase on twelve horizontal wells and had initiated the drilling of two more on its Central Basin Platform (CBP) asset. The company has completed and is currently in the "clean-up" and testing phase on four of the new wells drilled in the third quarter of 2017, as well as two wells that were drilled in the second quarter of 2017. The remaining eight wells drilled in the third quarter of 2017 are awaiting completion. In addition, the company completed, tested and put into production five new wells drilled in the second quarter of 2017. On its Delaware Basin (Delaware) property, the company completed and put into production two new vertical Cherry Canyon wells that were drilled in the first quarter of 2017 and two new vertical Cherry Canyon wells that were drilled in the second quarter of 2017.

As a result, net production for the third quarter of 2017 was approximately 376,000 boe, as compared to net production of 209,000 boe for the same quarter in 2016, an approximate 80% increase, and net production of 338,000 boe for the second quarter of 2017, an approximate 11% increase. The company estimates it lost approximately 9,000 net boe of additional production in the third quarter of 2017 due to issues and delays which primarily affected natural gas production. The company also entered into two new hedging contracts in the form of "costless collars" of WTI Crude Oil prices. The first hedge on 1,000 boe production per day became effective October 1, 2017, and will continue through December 31, 2017. The second hedge, also on 1,000 boe production per day, becomes effective January 1, 2018, and continues through December 31, 2018.

RING ENERGY (US), October 6, 2017

Covenant quality of high-yield bonds from North American oil and gas sector weakens

The covenant quality of high-yield bonds issued by North American oil and gas companies has worsened since its energy-related rating downgrades in the first half of 2016, due mainly to the influx of "fallen angel" bonds with investment-grade structures,

Moody's Investors Service says in a new report that, since the beginning of last year, high-yield bonds from the energy sector have on average, provided "weakest-level" investor protections, while from 2013 through 2015 they provided "weak" protections.

A Moody's Senior Vice President, Evan Friedman, said: "The recent deterioration is primarily attributable to a shift in issuer composition in the wake of the oil price volatility that began in 2015, alongside investors' greater acceptance of weaker structures. As price volatility subsides and supply and demand continue to steer investors to the high-yield space, continued acceptance of weakening covenants is anticipated."

Bonds from midstream companies have accounted for a higher percentage of oil and gas issuance since the energy sector rating downgrades, Friedman says in "Fallen angel bonds with investment-grade structures weaken oil and gas covenants." These bonds tend to have looser restricted payments protections and thus receive weaker CQ scores, thereby negatively affecting the score for the oil and gas sector as a whole. Before the downgrades, the average CQ score for midstream bonds was 4.47, while for exploration and production bonds it was 3.82 on Moody's five-point scale, in which 1.0 denotes the strongest investor protections and 5.0, the weakest.

MOODYS (US), October 10, 2017

Carrizo increases production plans and adds hedges

Carrizo's producing assets and facilities in the Eagle Ford shale sustained no damage as a result of Hurricane Harvey, and drilling and completion operations returned to normal within a week. A temporary reduction in the company's sales volumes did occur as a result of downtime at third-party midstream facilities and Gulf Coast refineries, but the company's production and sales returned to pre-storm levels last month. Carrizo estimates the impact from Hurricane Harvey on third quarter production volumes from the Eagle Ford shale to be approximately 2,500 boepd (approximately 55% oil). However, thanks to strong underlying performance across the company's assets, Carrizo currently expects total production for the third quarter of 2017 to be above the midpoint of its previously-issued guidance range of 53,467-54,733 boepd. As a result of the storm's temporary impact on Eagle Ford production, the company is revising its crude oil production guidance for the third quarter to 34,700-34,900 bpd from 35,400-35,800 bpd.

Over the last month, Carrizo has continued to add to its crude oil hedge position through year-end 2018. For the fourth quarter of 2017, the company currently has swaps covering 15,000 bpd of crude oil at an average fixed price of US$53.44 per barrel. For 2018, Carrizo currently has three-way collars covering 18,000 bpd of crude oil with an average floor price of US$49.08 per barrel, ceiling price of US$60.48 per barrel, and sub-floor price of US$39.17 per barrel, as well as swaps covering 6,000 bpd of crude oil at an average fixed price of US$49.55 per barrel.

CARRIZO OIL AND GAS (US), October 5, 2017

MIDSTREAM

Williams Partners' New York Bay expansion project has been placed into service

Williams Partners has announced that it has placed an expansion of its Transco pipeline system to increase natural gas delivery capacity to New York City by 115,000 dekatherms per day in time for the 2017-18 heating season into service.

The New York Bay Expansion provides additional firm transportation capacity for much-needed incremental natural gas supplies to National Grid, the largest distributor of natural gas in the northeastern US. The company provides service to 1.8 million customers in Brooklyn, Queens, Staten Island and Long Island.

The New York Bay Expansion Project included horsepower additions at three existing Transco compressor facilities, in addition to modifications to existing meter and regulator stations in New Jersey, Pennsylvania and New York.

The New York Bay Expansion is the fourth of Williams Partners' projected five fully-contracted Transco expansion projects to be placed into service this year, combining with Gulf Trace, Hillabee Phase 1 and the Dalton Expansion to add more than 2.5 million dekatherms per day capacity to the Transco pipeline system so far in 2017. The partnership continues to target a fourth-quarter 2017 in-service date for its fifth Transco expansion this year - the Virginia Southside II project.

WILLIAMS PARTNERS (US), October 9, 2017

DOWNSTREAM

Fluor awarded contract for world's largest propylene oxide and tertiary butyl alcohol plant

Fluor Corporation has announced that it was selected by LyondellBasell to perform the engineering and procurement for its propylene oxide (PO) and tertiary butyl alcohol (TBA) project located at its Channelview and Bayport complexes outside of Houston. Fluor booked the undisclosed contract value into backlog in the third quarter of 2017.

The project represents the single-largest capital investment in LyondellBasell's history. When completed, the plant will produce 1 billion pounds per year of PO and 2.2 billion pounds per year of TBA. At the peak of construction, the project is expected to create up to 2,500 jobs and approximately 160 permanent positions when operational.

PO is a building block of many everyday products, including bedding, furniture, carpeting, coatings, building materials and adhesives. The TBA will be converted to fuel additives that help gasoline burn cleaner and reduce automobile emissions.

FLUOR (US), October 9, 2017

US household spending for gasoline is expected to remain below US$2,000 in 2017

The average US household expenditure on gasoline in 2017 is expected to total US$1,977, or approximately 2.4% of mean incomes of households, according to projections in EIA's most recent Short-Term Energy Outlook (STEO).

The most recent peak for household gasoline expenditures was US$2,715, or 4.0% of household income, in 2008. More recently, average household gasoline expenditures in 2015 and 2016 were near or below US$2,000, or 2.5% of total household income.

Household gasoline expenditures have fluctuated over the past 10 years as a result of changes in gasoline prices and consumption. When gasoline prices are relatively high, more of a household's income is devoted to gasoline expenditures, leading to lower gasoline consumption and efforts to improve vehicle fuel economy.

Declines in gasoline prices since 2012, however, have led to increases in vehicle travel and increases in gasoline consumption. Based on EIA's latest STEO projections, continued low gasoline prices are expected to lead to record-high gasoline consumption of 9.3 million bpd for 2017.

Lower gasoline prices have contributed to decreasing household gasoline expenditures since 2012, as gasoline consumption has generally increased. STEO estimates that gasoline prices will average US$2.48 per gallon in 2017, which is 33% lower than the price in 2012.

EIA (US), October 6, 2017

Winter heating costs likely to be higher this winter than last winter

Most US households can expect higher heating expenditures this winter (October through March) than the last two winters, according to EIA's Winter Fuels Outlook. Higher expected winter heating expenditures are the result of both more heating demands because of relatively colder weather and, to a lesser extent, higher fuel prices.

EIA's projections of heating demand are based on the most recent temperature forecasts from the National Oceanic and Atmospheric Administration (NOAA). NOAA's forecast anticipates that winter weather will be 13% colder than last winter and closer to the average of the previous 10 winters.

Because weather patterns present great uncertainty to winter energy forecasts, EIA's Winter Fuels Outlook includes projections for 10% colder and 10% warmer scenarios. In the past 10 winters, actual temperatures have been more than 10% colder than NOAA's September forecast once and warmer than the forecast twice.

EIA (US), October 11, 2017

SERVICES

Shell to use Unily to create a global digital workplace

Unily, the leading digital workplace platform has been appointed by Shell, to connect its 135,000 internal users in over 70 countries and territories.

Shell chose Unily to unite their global workforce to improve employee productivity and engagement, giving employees an easy-to-use interface to access tools and targeted corporate information. Delivered on both desktop and mobile devices, the new intranet will support a more social, seamless and digitally-enabled employee experience.

UNILY (UK), October 9, 2017

MicroSeismic announces release of real-time completions evaluation

MicroSeismic, the inventor and leading provider of surface microseismic monitoring, has announced the release of Real-Time Completions Evaluation; on-the-spot fracture modelling, dynamic SRV estimation, end of stage EUR and drainage estimation, and rapid stress analysis.

These new real-time advances in microseismic monitoring will now give operators the opportunity to increase production rates and recovery factors.

Using Automatic Moment Tensor Inversion (Auto-MTI), the dynamics of the rock failure are captured in real-time as the fracture events are detected.

The moment tensors provide a rich source of information about the geometry of fractures and the stresses that produced them.

MICROSEISMIC (US), October 9, 2017

Emerson acquires GeoFields

Emerson has acquired GeoFields, a leading global supplier of software and implementation services for pipeline integrity data collection, management and risk analysis for the oil and gas industry. GeoFields software enables pipeline operators to collect critical integrity data, perform risk modelling and high consequence area (HCA) risk analysis and prioritise pipeline integrity-related maintenance and asset management activities. Terms of the acquisition were not disclosed.

The acquisition of GeoFields helps to further position Emerson as a comprehensive solutions provider for pipeline operations management.

Emerson's extensive portfolio of pipeline solutions for the oil and gas industry includes pipeline and terminal enterprise commercial management solutions, operations management software, pipeline modelling and leak detection, SCADA systems, corrosion and erosion monitoring, valve and control solutions, flow metering and measurement technologies.

EMERSON (US), October 10, 2017

MOVES

Questerre closes private placement

Questerre Energy Corporation has announced that it has closed its previously reported private placement of 34.9 million Common Shares at 5.70 Norwegian kroner or C$0.89 per Common Share for gross proceeds of 198.9 million kroner or approximately C$31 million.

On October 4, 2017, the Financial Supervisory Authority of Norway has approved a share securities note and a summary note prepared by the company in accordance with the Norwegian Securities Trading Act. Together with the company's registration document dated August 4, 2017, the documents together form a prospectus in accordance with Section 7 of the Norwegian Securities Trading Act for the listing on the Oslo Stock Exchange of the Private Placement Shares.

The company intends to use the net proceeds from the Private Placement to strengthen its working capital, partially financing its ongoing Montney capital programme and the preliminary work for its planned pilot Utica development project in the St. Lawrence Lowlands, Quebec.

QUESTERRE ENERGY (CANADA), October 9, 2017

Subsea 7 shares rise on report of Baker Hughes talks

Shares in oilfield services firm Subsea 7 have risen on an unconfirmed report it had been in talks with Baker Hughes about a possible takeover, but that the talks have now ended.

A Wall Street Journal report said that the discussions broke down over the price but could be revived. Shares in Subsea 7 were up 6.6%. They had been up 1.9% when the Oslo stock exchange imposed a matching halt.

Earlier the stock had been trading down following a note by Goldman Sachs cutting its rating on the stock.

The chairman of Subsea 7 and its top owner with 21.3% of the shares, Kristian Siem, said that the firm would always comply with its duty to inform the market if there are material changes to the company.

REUTERS, October 11, 2017

Ensco plc completes acquisition of Atwood Oceanics

Ensco has announced the completion of its acquisition of Atwood Oceanics. Under the terms of the merger agreement, Atwood shareholders are entitled to receive 1.60 Ensco Class A ordinary shares for each share of Atwood common stock they own. Ensco and Atwood shareholders will own approximately 69% and 31%, respectively, of the outstanding shares of the combined company.

In connection with the completion of the transaction, Atwood common stock has ceased trading on the New York Stock Exchange.

ENSCO (UK), October 6, 2017

Carrizo Oil and Gas announces the sale of its Marcellus shale assets

Carrizo Oil & Gas has announced that, on October 5, 2017, the company entered into an agreement to sell its assets in the Marcellus shale to a subsidiary of Kalnin Ventures LLC for US$84 million in cash, subject to customary closing terms and conditions. Additionally, Carrizo could receive contingent payments of up to US$7.5 million in aggregate based on natural gas prices exceeding certain thresholds over the next three years.

Net production from the assets averaged more than 40 mcf per day of natural gas over the first nine months of 2017. The effective date of the transaction is April 1, 2017, and the transaction is currently expected to close by the end of November 2017.

CARRIZO OIL AND GAS (US), October 6, 2017

Phillips 66 announces new US$3 billion share repurchase programme

The board of directors of Phillips 66 has approved a new US$3 billion share repurchase programme that increases the company's total authorisation for share repurchases to US$12 billion since the third quarter of 2012. The board also declared a quarterly dividend of US$0.70 per share on Phillips 66 common stock. The dividend is payable on December 1, 2017, to shareholders of record as of the close of business on November 17, 2017.

Chairman and CEO of Phillips 66, Greg Garland, said: "Returning capital to our shareholders, through a competitive, secure and growing dividend, reinforced with share repurchases, is a strategic priority for us.

"We have demonstrated this with seven increases to our quarterly dividend rate and through our share repurchase programmes. We believe our financial discipline, underpinned by prudent capital allocation, is fundamental to value creation and has enabled us to return over US$15 billion to shareholders since 2012, through dividends, share repurchases and share exchanges."

The total shares repurchased and exchanged to date represent over 20%of the shares outstanding at the formation of the company.

PHILLIPS 66 (US), October 9, 2017

Phillips 66 partners prices US$650 million senior notes offering

Phillips 66 Partners LP has announced that it has priced US$500 million aggregate principal amount of 3.75% unsecured senior notes due 2028, and US$150 million aggregate principal amount of 4.68% unsecured senior notes due 2045 in an underwritten public offering pursuant to an effective shelf registration statement on Form S-3 previously filed with the Securities and Exchange Commission (SEC).

The Partnership expects to use the net proceeds from this offering to repay indebtedness assumed by the Partnership as part of the consideration for its previously announced acquisition of an indirect 25% interest in the Bakken Pipeline and a direct 100% interest in Merey Sweeny, LP from Phillips 66 and for general partnership purposes, including funding future acquisitions and organic projects and the repayment of outstanding indebtedness under the Partnership's revolving credit facility.

Citigroup Global Markets, MUFG Securities Americas, Scotia Capital (USA), and TD Securities (USA) LLC are acting as the joint book-running managers for this offering, and BNP Paribas Securities, Deutsche Bank Securities, Goldman Sachs and Mizuho Securities USA are acting as the passive book-runners.

PHILLIPS 66 (US), October 10, 2017

Moody's assigns rating to Phillips 66 notes offering

Moody's Investors Service has assigned a Baa3 rating to Phillips 66 Partners LP's. The company's other ratings are unchanged and the outlook is stable.

The proceeds of the announced notes offering will be used to partially fund the US$1.7 billion drop down from Phillips 66 of assets consisting of Philips 66's 25% interest in Dakota Access LLC and 25% interest in Energy Transfer Crude Oil Company, LLC (together referred to as the Bakken Pipeline) as well as its 100% interest in Merey Sweeny, LP (MSLP), which owns a vacuum distillation unit and fuel grade coke processing unit at the Phillips 66 Sweeny refinery in Old Ocean, Texas.

PSXP financed approximately US$1.94 billion before fees (US$650 million of senior unsecured notes, US$750 million of convertible preferred units, US$300 million from the issuance of common units to the public, US$240 million from the issuance of general partner and common units to Phillips 66 to fund the US$1.7 billion consideration, pay other accrued liabilities including the full repayment of the revolving credit facility and put cash on PSXP's balance sheet for organic projects and general corporate purposes). Phillips 66's 25% share of Bakken Pipeline debt is US$625 million and MSLP has US$100 million of debt.

Moody's Vice President, James Wilkins, stated: "PSXP's balance of debt and equity funding for the acquisition of assets from Phillips 66 will allow the company to materially increase its scale, while only modestly increasing leverage".

MOODYS (US), October 10, 2017

Liberty Oilfield Services announces closing of term loan revolving credit facility

Liberty Oilfield Services has announced that it has entered into two new debt facilities consisting of a US$175 million, five-year term loan and a US$250 million asset-based revolving credit facility subject to a borrowing base. Upon closing, US$55 million was drawn on the new ABL, positioning Liberty with over US$100 million of available liquidity. The new debt facilities were used to retire the company's prior debt facilities and will provide liquidity to fund future growth and operations.

Chief Executive Officer of Liberty, Chris Wright, said, "Completion of the new debt facilities on attractive terms provides Liberty with the financial flexibility to execute on our disciplined organic growth strategy, and to further invest in the latest technological innovations, from custom fluid systems and integrated completion analysis techniques to next-generation equipment developments across the Liberty fleet. We continue to be driven by our relentless focus on improving our customer's well productivity."

Houlihan Lokey Capital, Inc. and Wells Fargo Securities, LLC served as the company's lead placement agents on the new term loan and new ABL financings, respectively.

LIBERTY OILFIELD SERVICES (US), October 10, 2017

Moody's rates Targa Resources

Moody's Investors Service has assigned a Ba3 rating to Targa Resources Partners LP's (TRP) proposed. US$750 million notes due 2028. TRP is wholly owned by Targa Resources (Targa).

Targa and TRP's other ratings and Targa's stable outlook remained unchanged. The note proceeds will be used to finance the redemption of TRP's US$250 million notes due 2018 and to repay borrowings under its revolver.

Targa's Ba2 Corporate Family Rating (CFR) is supported by its sole ownership of TRP, its scale and EBITDA generation which has remained sizeable despite the volatile and low commodity prices, its track record of strong execution of growth projects, and the meaningful and growing proportion of fee-based margin contribution.

Targa has increased geographic diversification, more recently in the Permian Basin, and improved business diversification through acquisitions. Targa is building a 300 bpd NGL pipeline, expected to be in service before mid-2019, that will connect the Permian Basin and its North Texas system to its Mont Belvieu complex. Its Outrigger acquisition, also in the Permian Basin, closed in March 2017 and adds over 250,000 acres dedicated under long-term contracts from a mix of active operators. These positive attributes are tempered by its material exposure to the gathering and processing business, weakness in natural gas liquids (NGL) markets that lowers its earnings on commodity sensitive contracts, its historically aggressive distribution policies, and volume risk. Targa's CFR could be upgraded to Ba1 if consolidated leverage is sustained below 4.5x, dividend coverage remains above 1.1x, and its business mix becomes less exposed to commodity price risk. The ratings could be downgraded if consolidated leverage is over 5.5x. Significant delays or cost overruns on growth projects could also pressure the ratings.

MOODYS (US), October 10, 2017

Seaport Global Securities expands energy infrastructure team

Seaport Global Securities (Seaport Global), a full-service investment bank, has announced that it has expanded its equity team with the addition of Managing Director and Senior Energy Infrastructure Analyst Bernie Colson and Managing Director and Institutional Salesman Wayne Sansiviero, whose primary focus is growing the firm's energy infrastructure business with institutional clients.

Together, they bring 41 years of experience covering the energy infrastructure space and join Managing Director and Senior Energy Infrastructure Analyst Sunil Sibal who covers both credit and equity securities in the space.

SEAPORT GLOBAL SECURITIES (US), October 10, 2017

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