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ENERGY FINANCE WEEK

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In this week's issue

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Virgin acquires developer BMR in clean energy push

MARKET

MAKING good on commitments to scale up renewables use in the Caribbean and further afield, Sir Richard Branson's Virgin Group has announced the acquisition of a regional renewables developer.

The UK-based conglomerate is buying BMR Energy of New York, also known as Blue Mountain Renewables, and BMR Wind, Virgin confirmed to NewsBase.

Privately held BMR is a Caribbean-oriented firm that has just inaugurated its first wind project, a 36-MW facility in Jamaica. BMR also invests in Latin America.

Entrepreneur Sir Richard spoke at the ribbon-cutting ceremony for the wind project. He said that his primary interest was not to make a return on his investment, but to be part of what he described as a global push to achieve carbon-neutral status by 2050.

At the ceremony, Branson said that clean air "is something that has no boundaries and that it is incumbent that we get the windmills out there, get the solar out there, get the wave energy out there, and create a green energy revolution that brings the cost of energy down for everybody."

He continued: "I have long believed this is an important sector and something I'm very passionate about. The potential for renewable energy across the world is huge, especially here in the Caribbean where we benefit from an abundant supply of sun and wind."

It appears that Branson, who lives in the Caribbean – he famously owns Necker, a 74-acre (299,467 square metres) island in the British Virgin Islands – may not stop at a single clean energy investment. "I decided recently that we needed to get one, get one or two core [clean energy] companies under our belt so that we can actually get out there and speed up this revolution," Branson told attendees, according to the Jamaica Observer.

"We were delighted to acquire BMR and we will be out there trying to hustle and bustle governments all over the Caribbean and other countries to hurry up towards carbon neutrality by 2050," added the multi-billionaire.

"Personally I don't need to make money out of it, if it makes a bit of money, fine, if it doesn't, fine," he said, according to the newspaper.

Joining the revolution

Despite Branson's subdued analysis of the acquisition, it may signal a shift in focus for Virgin Group. As major tech companies such as Microsoft and Apple move into the development, production and selling of renewable electricity, climate-conscious companies like Branson's looking for investment growth may be next to enter the space.

Branson has previously invested in M-Kopa Solar, a Kenyan company that sells solar panels to rural residents throughout East Africa.

Other investors in fast-growing M-Kopa have included Generation Investment Management, a fund co-founded by former US Vice President Al Gore, and AOL's co-founder, Steve Case.

Last year, Branson was one of dozens of leading CEOs and entrepreneurs involved in the Breakthrough Energy Coalition, unveiled during the COP 21 UN climate summit in Paris.

BMR already has ties to the international multi-lateral finance community, albeit modest compared to the scale of what may be to come for Virgin.

The Jamaica wind project was built with a US$62.7 million financing package that included a US$42.7 million senior loan from the Overseas Private Investment Corporation (OPIC), a US$10 million senior loan from the IFC – part of the World Bank – and a US$10 million loan from the IFC-Canada Climate Change Program.

Promisingly, the opening of the wind farm is not the end of momentum for Jamaica either. At the event, Minister of Science, Energy and Technology Andrew Wheatley said that the government was in the process of finalising an agreement for the construction of a 33.1-MW solar project at Paradise Park.

Costing around US$50 million, the Eight Rivers Energy-developed facility would be built during 2017 and begin supplying the grid in 2018.

According to the Jamaica Information Service, the government will also launch a new RFP for a further 100 MW of renewables capacity, and 50 MW in a separate waste-to-energy RFP.■

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Canadian producers cautiously optimistic about recovery

Several Canadian oil and gas producers have increased their capital expenditure guidance as they prepare to ramp up drilling from the end of 2016

NORTH AMERICA

AFTER two years of retrenchment and cutbacks, Canadian producers finally appear ready to start loosening the purse strings, albeit cautiously. Oil prices are up by nearly 70% since February and producers are adjusting spending and activity plans in anticipation of more reliable fundamentals in the second half of the year.

Capex increases

Encana surprised nearly all analysts by announcing that it would increase its capital expenditure for 2016 by an estimated US$200 million, or more than 20%, from its previous guidance of US$900 million to US$1 billion for the year. Although most of the extra capex will go towards the company's Permian Basin operations in the US, it shows increasing confidence in the market on both sides of the border.

On an earnings call, Encana's president and CEO, Doug Suttles, said the company's austerity measures were paying off with a 32% reduction in production costs, enabling it to increase output from its core shale plays by about 13,000 boepd. Although the company posted a net loss of US$601 million in the quarter, it achieved a small operating profit – US$89 million – the first in nearly two years.

Likewise, Canadian Natural Resources Ltd (CNRL) told investors it had the capacity to increase production by over 200,000 boepd should oil prices stabilise in the US$50 per barrel range. On its earnings call, CNRL said it would increase its capital spending by C$50 million (US$39 million) to drill 140 more oil wells than it had previously planned in the second half of the year.

The sum is modest in the context of the company's C$3.5-3.9 billion (US$2.7-3.1 billion) capex budget, but it shows a degree of cautious optimism as oil prices appear to be stabilising after nearly two years of extreme volatility.

The lifeline could not have come soon enough for Penn West Petroleum, a firm that has been on death watch for the past three years. Despite posting a C$132 million (US$103 million) net loss in the second quarter, the company announced plans to nearly double capex to C$90 million (US$70 million) from a previous budget of C$50 million. It now expects to increase it further, to C$150 million (US$117 million), in 2017.

Part of the reason is that Penn West was able to obtain significantly higher proceeds from the sale of its south Saskatchewan assets – some C$937 million (US$729.43 million) – as a result of the oil price recovery in recent months. This in turn allowed it to reduce its debt to C$491 million (US$384 million) from over C$2.1 billion (US$1.6 billion) at the end of last year. The company is now in compliance with its debt covenants and in good standing with its lenders.

There are no longer insolvency concerns and Penn West seems poised to build on its second-quarter production of 63,000 boepd after eight straight quarters of contraction. The company's share price has more than doubled since June, to C$2.19 (US$1.71) on the Toronto Stock Exchange as of August 16, although the stock remains barely a tenth of its value prior to the downturn.

Preparing to drill

Given that oil is a trickle-down economy, Canada's troubled oilfield services companies are preparing – or rather desperately hoping – for renewed activity later in the year. According to the Canadian Association of Oilwell Drilling Contractors (CAODC), rig counts have doubled since July, to 111 as of August 8, or 17% of all available rigs. The total is not far off the 22% utilisation rate recorded at this time last year, giving some rare glimmers of hope to the beleaguered services sector.

While reporting second-quarter results, Precision Drilling's president and CEO, Kevin Neveu, said he expected rig counts to bounce off decade lows later this year as producers recalibrated spending in response to higher oil prices. The company's second-quarter losses doubled to C$57.7 million (US$45.1 million) from C$29.8 million (US$23.3 million) a year earlier. Precision's revenues, at C$164 million (US$128 million), were half the level it achieved in the same quarter of

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2015. Meanwhile, Ensign Energy Services said producers were hanging on to contracts in anticipation of higher demand for rigs later in the year.

Ensign posted a C$35 million (US$27 million) net loss in the second quarter compared to a profit of C$1 million (US$782,312) a year earlier and saw its revenues fall 47% to C$175.9 million (US$137.6 million) from over C$333 million (US$261 million) in the same period of 2015.

Unlike competitor Trinidad Drilling, Ensign reported almost no early terminations of contracts for idle rigs, although it said that half as many rigs were working in the second quarter. The caveat is that the second quarter is the seasonal low part of Canada's drilling season and it is not unusual to keep inactive rigs on standby for the busier autumn and winter season.

Nonetheless, Ensign is Canada's second largest publicly traded company and is considered a bellwether for the broader energy services market. Despite the losses analysts upgraded their share price forecasts into the C$10 (US$7.82) range, expecting the company to outperform the broader market.

What next?

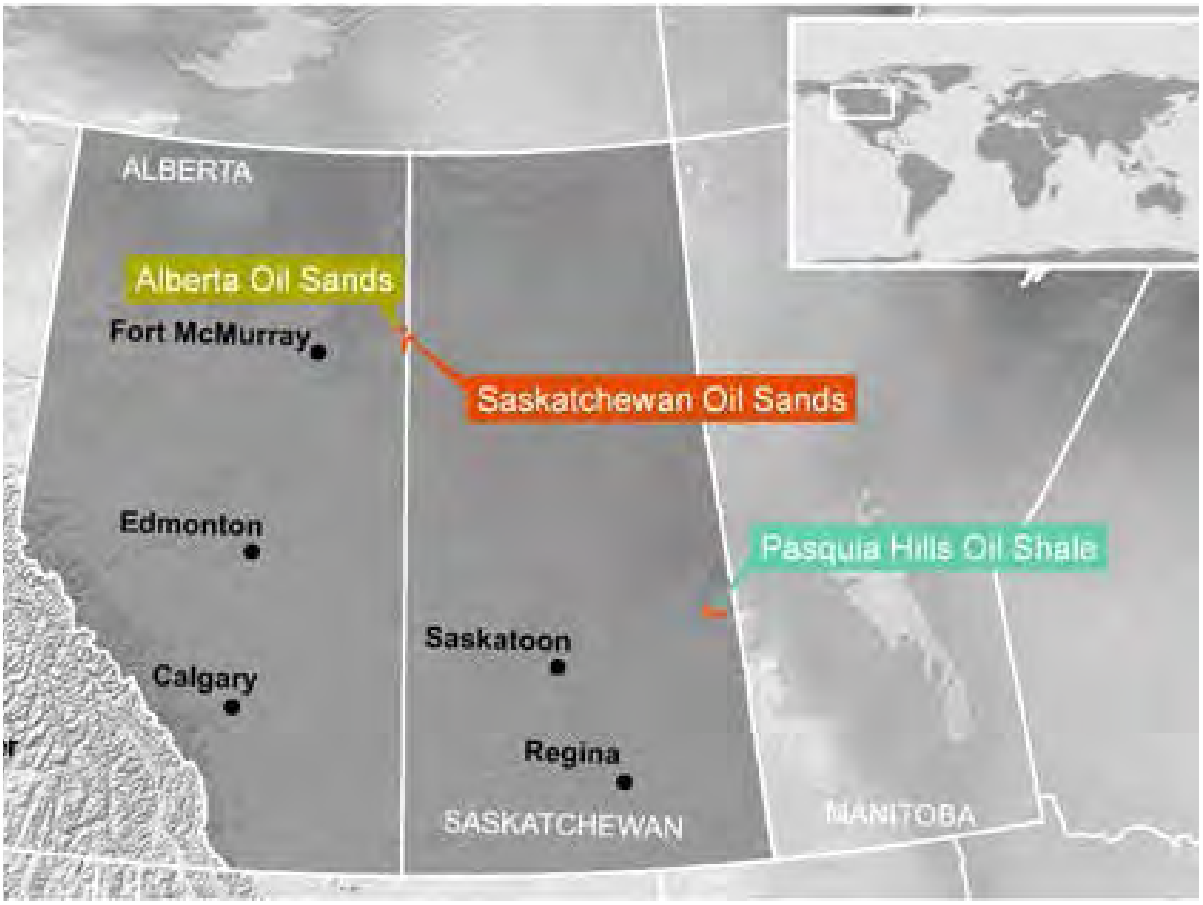
Even with all the newfound optimism, it is not enough to call it a full-blown recovery.

Analysts at ARC Financial are still expecting industry cash flows to drop to barely C$18 billion (US$14 billion) in 2016, down 30% from last year and 75% from 2014.

Cash flow is a more important leading indicator of the overall health of the industry than revenue or earnings because it reflects the amount of money producers have to invest in new wells and infrastructure. By that metric, the amount of new funds available for capex increases will be muted at best.

However, after nearly 10 straight quarters of consecutive declines, there finally appears to be a light at the end of the tunnel.

Depending on the direction of oil prices it could either be a welcome exit or an oncoming train.■



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Oilfield services players face debt fallout

North American oilfield services providers are facing several more difficult years in which they are expected to struggle with their combined debt load

NORTH AMERICA

HAVING been hit particularly hard during the oil industry downturn as client demand has fallen away, North American oilfield services and drilling companies have more tough times ahead. They hold combined debt worth more than US$110 billion, which is due to mature in the next five years. This could severely challenge firms already reeling from low oil prices, according to a report published on August 9 by Moody's Investor Services.

The market leaders, including the three largest players – Schlumberger, Halliburton and Baker Hughes – are in comparatively good financial health. But the concern among Moody's analysts is that a number of smaller-sized oil services companies will fail to pay back loans if low crude prices persist. Since January 2015, 83 oilfield services companies have already filed for bankruptcy in North America, according to law firm Haynes & Boone. And more services firms will face debt-servicing challenges that include severely limited refinancing options, the Moody's report said.

The report, 'Pressures mount as strained OFS companies face US$110 billion maturity wall', said most of the debt was issued between 2011 and 2015, when oilfield services were in high demand. Now a US$110 billion debt load is spread among the 67 companies assessed by Moody's – through more than US$60 billion of bond and term loans and US$45 billion in revolver commitments.

Worryingly, speculative-grade companies – those with a Moody's rating lower than Baa – account for 65% of all the individual bonds and loan maturities on the horizon. Moody's noted that three of those companies – Ion Geophysical, Stallion Oilfield Holdings and IronGate Energy Services – have either entered into a distressed debt exchange or have failed to make interest payments.

Furthermore, over 70% of the rated high-yield bonds and term loans that mature between now and 2018 are rated Caa1 or lower, Moody's said. This is in addition to roughly US$3.1 billion of rated and unrated committed revolvers among issuers rated Caa1 or lower expiring by 2018.

Double whammy

When oil prices are low, explorers and producers typically cut back on drilling and require less in terms of products and services from providers. As a result, when oil prices began to drop in mid-2014 and shale producers in particular started to cut back on spending and drilling, many of the providers that had borrowed heavily to expand during better times were hit hard by shrinking demand. This added new pressures to their debt repayment schedules in a tightening double whammy.

With rig counts falling until recently, and WTI oil prices still below US$50 per barrel, the services sector has – unsurprisingly – not been posting profits. Moody's noted that "refinancing needs across the sector are significant".

Among the top services providers, these issues are less pronounced. Baker Hughes has used its US$3.5 billion cash injection from the merger break-up fee paid to it by Halliburton to clean up its balance sheet. During the second quarter, Baker Hughes eliminated US$1.1 billion in long-term debt to improve its total debt to capital ratio of 17.4% – compared to Schlumberger at 32% and Halliburton at 57% – and even has more cash on hand than total debt.

Halliburton, for its part, closed the second quarter of 2016 with long-term debt totalling US$12.2 billion. According to its quarterly filing, Halliburton recorded a 9% year-over-year decline in revenue for the second quarter, at US$3.84 billion. It posted a net loss of US$3.2 billion, thanks in part to the merger termination fee, compared to net income of US$54 million in the second quarter last year. Meanwhile, Baker Hughes took on US$2.8 billion in asset and goodwill write-downs in the recent quarter, while Schlumberger engaged in write-downs worth US$2.54 billion, leading to a US$2.1 billion loss and a 38% year-on-year revenue decline. But although Schlumberger's pre-tax income margins fell to 10%, this was still ahead of its market peers. And the company's balance sheet is in comparatively good shape, with more than US$10 billion in cash despite four acquisitions concluded during the three months.

What next?

Without any short-term improvement in oil prices, the financial health of many oilfield services providers is likely to deteriorate further before it improves. Moody's analysts expect that over a third of the 67 oilfield services players

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assessed in the report to have debt to EBITDA ratios of above 10 times in 2016 as depressed drilling activity and weak pricing hits earnings. Unsurprisingly, some of these companies are thought to be at risk of debt restructurings and defaults.

"While some companies will be able to delay refinancing until business conditions improve, for the lowest-rated entities, onerous interest payments and required capex will consume cash balances and challenge their ability to wait it out," said Moody's assistant vice president, Morris Borenstein. "We also see companies facing weakening financial covenant cushions that can accelerate default or result in expensive bank amendments that may or may not alleviate refinancing needs."

Moody's said estimates show the maturity wall "growing dramatically to more than US$21 billion" in 2018, a figure which is nearly three times the sector's total expected debt burden in 2017. The debt burden is then projected to continue rising into 2021, when nearly US$29 billion of issuance and revolvers are scheduled to come due, Moody's said.

NewsBase expects the biggest three players to weather the storm, along with a handful of smaller oilfield services companies that have continued to see solid margins and generate free cash flow, including Tetra Technologies, Natural Gas Services Group and Patterson-UTI Energy.

But other players in an already over-burdened industry will come up against barriers to access to new capital – and Moody's analysts do not expect any debt turnaround to happen soon. The report forecast that a recovery in the oilfield services industry is unlikely before mid-2017, and that companies looking to capital markets for loan refinancings or to seek new capital will struggle with heavy costs. "As a result, companies will be more dependent on cash reserves if revolver access is limited due to covenant pressure," Moody's said.

Ultimately, there is little that oilfield services companies can do to boost drilling activity in the oil and gas industry, which will be the main determinant behind any services recovery.

One of the more optimistic predictions comes from Halliburton executives, who have pointed to evidence of a market bottom and an incipient turnaround. With rig counts increasing by 26 during the second quarter, Halliburton said it expected rig count growth to continue through the second half of the year.

Also relatively upbeat was Baker Hughes' CEO Martin Craighead, who predicted that "margins across all of our segments are expected to improve sequentially" over the remainder of 2016.

Schlumberger, for its part, has been able to control its costs, staying in good financial standing as the oil industry waits for the oil price slump to end. For smaller oilfield services players, however, particularly those with considerable debt burdens, the recovery cannot begin soon enough.■

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Paramount asset sale closes after shareholder approval

NORTH AMERICA

PARAMOUNT Resources' shareholders have approved the company's previously announced sale of C$1.9 billion (US$1.5 billion) in assets to Seven Generations Energy, clearing the way for the deal to close on schedule.

Approval came on August 15, with the company subsequently announcing that the deal had closed on August 18. In a statement, Paramount said that shareholders had overwhelmingly supported the transaction with over 99% of the votes cast in favour. The approval threshold was two thirds. Paramount said it had also obtained all necessary regulatory approvals.

Seven Generations has now acquired Paramount's Musreau and Kakwa natural gas holdings, located south of Grande Prairie, Alberta. The properties, which are part of the Montney zone that straddles northeastern British Columbia and northwestern Alberta, comprise 310 net sections of land and 495 million boe of 2P reserves.

The deal cuts Paramount's production to 10,500 boepd – or about one fifth of its former level – but enables the firm to drastically reduce its debt load and gain a 10% ownership stake, the second largest holding, in Seven Generations. Under the terms of the agreement, Seven Generations is giving Paramount C$475 million (US$372 million) in cash and 33.5 million in common stock while also assuming C$450 million (US$352 million) in debt.

"We believe this transaction provides a compelling opportunity to realise premium value on a portion of our Montney acreage for our shareholders," said Paramount's president and CEO, Jim Riddell, in a statement when the deal was announced in July. "While allowing for significant deleveraging of our balance sheet, the unique structure of this transaction provides Paramount shareholders continued exposure to the considerable upside associated with the assets through the company's significant shareholdings in Seven Generations."

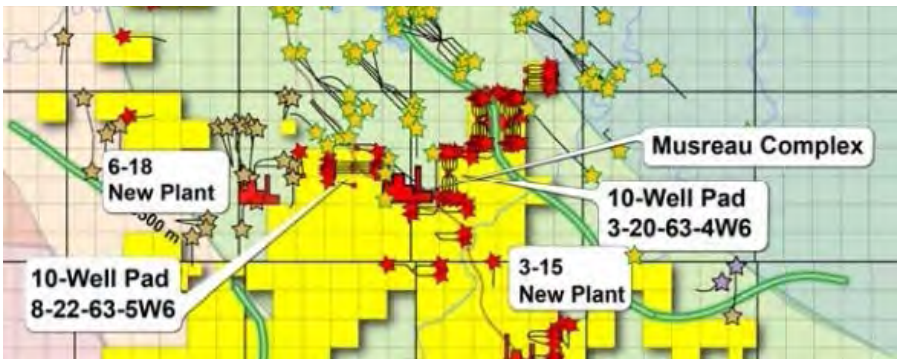
Meanwhile, Paramount will continue to own exploratory shale gas assets in the Liard Basin, which is located mostly in BC but also straddles the province's border with the Yukon and Northwest Territories.

In addition, Paramount will continue to own "northern frontier" assets in Central Mackenzie and the Mackenzie Delta, Alberta oil sands assets held through its wholly owned subsidiary Cavalier Energy and seven triple-sized rigs held through its wholly owned subsidiary Fox Drilling Limited Partnership. It will also retain its investments in other public and private oil and gas companies, including Trilogy Energy, MEG Energy, Strategic Oil & Gas, Marquee Energy and RMP Energy.

Perhaps more significantly in the short term, the deal has enabled Paramount to secure a new C$410 million (US$321 million) credit facility and proceed with its plans to acquire more properties.

"The pure play Kakwa Montney asset base of Seven Generations provides Paramount shareholders the closest proxy for continued ownership of the disposed assets while significantly reducing our indebtedness," said Riddell in July. "Following the completion of the transaction, Paramount will be well positioned to continue the development of our other Deep Basin properties at Karr/Gold Creek, Smoky/Resthaven and Valhalla, which include Montney and multiple stacked Cretaceous horizons, our Montney play at Birch in northeast British Columbia and our Duvernay play at Willesden Green, as well as improved liquidity to capitalise on new opportunities."

For Seven Generations, the deal represents its first major acquisition since it went public in 2014. Seven Generations funded the transaction partly through an equity offering that generated C$747.7 million (US$585.3 million) in total proceeds.■



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Gibsons rejects unsolicited takeover offer

NORTH AMERICA

CANADIAN midstream firm Gibsons has said it has rejected an unsolicited takeover offer from a foreign firm. Gibsons, which is headquartered in Calgary, did not name the company in question. It is not known to have been seeking a takeover.

In a statement, Gibsons said it had received "a non-binding, highly conditional proposal for discussion, from an unknown, unidentifiable foreign entity whose principals insisted on anonymity."

The statement came in response to a report in the Financial Post last week, which said that the C$2.8 billion (US$2.2 billion) takeover offer had come from a Singapore-based private equity firm, Asia Pacific Private Equity. According to the Toronto-based Financial Post, Gibsons' chairman, James Estey, sent a letter on August 2 to the Singaporean private equity firm rejecting the C$19.94 (US$15.60) per share offer. The offer was made on July 4. The Financial Post said it had obtained a copy of the letter.

Estey reportedly said the offer was "inadequate" and that "now is not an opportune time to pursue a sale of control of the corporation".

Gibsons, which is streamlining its business model, said in July that it was exploring a sale of its industrial propane business and retained RBC Capital Markets as a financial adviser in the matter. Gibsons is Canada's second largest industrial propane distribution company.

"Since entering the industrial propane market with the acquisition of James Propane in 1988, we have successfully grown the business into one of Canada's largest propane distributors, with a strategic footprint focused on oilfield applications in Western Canada said Gibsons' president and CEO, Stewart Hanlon.

"While the company has identified further growth opportunities within this business line, allocating resources to pursue these opportunities falls outside our corporate strategy of focusing on integrated midstream solutions along the North American oil and liquids production value chain," he said.

Gibsons' North American operations include the storage, blending, processing, transportation, marketing and distribution of crude oil, NGLs and refined products. It also provides oilfield waste and water management services.■

Concho buys Midland Basin assets

NORTH AMERICA

CONCHO Resources announced this week that it had struck a deal to buy assets in the Permian's Midland Basin region from Reliance Energy for US$1.625 billion.

The deal consists of 40,000 net acres (162 square km) and 10,000 barrels of oil equivalent per day of production from 326 vertical wells and 44 horizontal wells. Concho said in a statement that only one of these wells was completed in 2016.

The company said that estimated proven reserves attributable to the acquisition totalled roughly 43 million boe, and that proven developed reserves represented around 69% of the total proven reserves.

Concho said that the acquisition adds over 530 long-lateral drilling locations to its inventory. It added that two thirds of these locations were 2-mile (3.2-km) laterals, and the remaining locations were 1.5-mile (2.4-km) laterals.

The engineered locations are based on eight locations per zone in the Middle Spraberry, Lower Spraberry or Wolfcamp B, Concho said, adding that two to three of these zones were targeted per drilling spacing unit.

The deal will consist of about US$1.1 billion in cash and 3.96 million of Concho's shares. The company intends to fund part of the cash portion through a share sale. Separately, it said on the same day that it would offer 9 million shares in an underwritten public offering.

The purchase comes as Concho pushes to expand its core Midland Basin position to over 150,000 net acres (607 square km) and to raise its output in the area to 30,000 boepd.

Other companies are also still targeting the Midland Basin and the broader Permian Basin even as deal activity has been slow in other shale plays. Last week, SM Energy announced that it was buying 24,783 net acres (100 square km) in the Midland Basin from Rock Oil for US$980 million.

Then, this week, Parsley Energy said it had agreed to pay US$400 million for 11,672 gross acres (47 square km) – or 9,140 net acres (37 square km) – in the Midland Basin.■

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Parsley boosts Permian position

NORTH AMERICA

PERMIAN-FOCUSED Parsley Energy announced on August 15 that it will acquire Midland Basin assets near its existing position in Glasscock County, Texas, for US$400 million. This is its fourth such acquisition since the beginning of the year.

The purchase, from an unnamed, seller totals 11,672 gross acres (47 square km) – or 9,140 net acres (37 square km) – and consists of both undeveloped and producing acreage, as well as associated mineral and overriding royalty interests. Net production at the properties is about 270 barrels of oil equivalent per day from 67 gross – or 60 net – vertical wells.

Parsley said the acquisition also includes 240 gross – 215 net – horizontal drilling locations targeting multiple formations including the Lower Spraberry, Wolfcamp A and Wolfcamp B, as well as additional horizontal locations in the Middle Spraberry, Wolfcamp C and Cline plays.

The properties already have facilities and other infrastructure in place, including five saltwater disposal wells. Parsley will have an average working interest of around 92% at the identified drilling locations. The deal is anticipated to close on October 4. Parsley noted that its first producing horizontal well in Glasscock County, the Dwight Gooden 6-7-01AH, was acquired in May. The well, which is located 2.5 miles (4 km) from the newly acquired acreage, has a stimulated lateral of 5,890 feet (1,795 metres) and registered a peak 30-day initial production (IP) rate of 1,161 boepd – equivalent to 197 boepd per 1,000 stimulated feet (305 metres). Parsley said that the well was outperforming its 1 million boe estimated ultimate recovery (EUR) type curve by 10% for its Midland Basin Wolfcamp A/B sites nearly 90 days later. Over that time its output has consisted of 82% oil, it added. "The pending acquisition of leasehold and associated assets establishes Glasscock County as another key development area for Parsley Energy," Parsley's CEO, Bryan Sheffield, said. "Offset well performance and initial results on our first horizontal well in the area suggest that the properties to be acquired may compete with the best of our existing horizontal drilling inventory, and the acquisition of associated royalty interests boosts the return profile of these properties."

Sheffield added that the acquisition represented a major step towards a large-scale, basin-wide development programme for Parsley. The company's acquisitions have totalled US$1.2 billion over eight months.■

CVR Energy reportedly considering Delek US Holdings purchase

NORTH AMERICA

THE New York Post, citing an unnamed source, reported last week that Tennessee-based refiner CVR Energy was preparing to buy Delek US Holdings, a subsidiary of Israel's Delek Group. The subsidiary operates two refineries in Texas and Arkansas and a gasoline station network in seven US states.

The report also noted speculation that Carl Icahn, who owns a controlling stake in CVR, was also planning to build a personal stake in the oil refiner. Icahn purchased a controlling stake in CVR over four years ago and took the company public in January 2013.

Icahn sold 250,000 of his six million shares in the CVR Refining subsidiary in early August. He cut his interest to just below 70%. This would give him the right to acquire the remaining stake of the subsidiary at no premium, according to the report. A spokesperson for Icahn did not comment on the rumoured purchase. The two companies have not yet commented on the rumoured deal either. Refiners have been feeling increasing pressure this year. Oil spreads have narrowed and the price of Renewable Identification Numbers (RINs), which are used by the US Environmental Protection Agency (EPA) to track renewable transportation fuels, has increased. This system enables the EPA to monitor compliance with the federal programme that requires transportation fuels sold in the US to contain minimum volumes of renewable fuels.

The New York Post said CVR's shares had fallen almost 70% over the past year, and Delek's had dropped by nearly 60%. However, Delek's shares climbed the most in seven years after the potential deal was reported.

Delek posted a second-quarter net loss of US$7 million, against a net income of US$48.3 million in the same quarter of 2015. CVR reported a net income of US$28.4 million in the second quarter compared to a net income of US$101.9 million in the same quarter of 2015. Delek owns 48% of Alon USA Energy and has previously expressed a desire to carry out a full takeover of the company, Bloomberg reported.■

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Sabine emerges from bankruptcy protection

NORTH AMERICA

US independent Sabine Oil & Gas has emerged from bankruptcy protection as a private company over a year after its initial Chapter 11 bankruptcy filing.

The Houston-based company completed a balance sheet restructuring, including a debt-for-debt exchange and a debt-to-equity conversion, it said in a statement.

Sabine has emerged from bankruptcy with a "significantly stronger balance sheet and renewed ability to focus on creating value from its compelling asset base", the company said.

The firm said it has also closed on a new senior secured credit facility, which has commitments of US$200 million and an initial borrowing base of US$150 million.

"Sabine has successfully restructured its balance sheet, addressing its leverage and liquidity needs," said Sabine's CEO, David Sambrooks.

Sabine's main operations are located in the Cotton Valley sand and Haynesville shale in East Texas and the Eagle Ford shale in South Texas.

The company also has operations in the Granite Wash in the Texas Panhandle and the North Louisiana Haynesville play.

A total of 67 oil and gas exploration and production companies filed for bankruptcy proceedings last year, representing a 380% increase from the previous year, US-based consultancy Gavin/Solmonese said in May. And according to law firm Haynes and Boone, 90 North American oil and gas companies had filed for bankruptcy protection between the start of 2015 and August 1, 2016. The oil price collapse has hit shale players particularly hard because of the considerable debt many had already taken on when times were good.

The latest companies to file for bankruptcy protection were Halcon Resources and Atlas Resource Partners in late July. And even though oil prices have rebounded somewhat since the start of 2016, more shale drillers are still expected to follow suit. Others, meanwhile, are starting to emerge from bankruptcy protection similar to Sabine, but their survival and ability to ramp up operations is by no means certain as oil prices remain below US$50 per barrel.■

Chesapeake secures US$1.5bn loan

NORTH AMERICA

CHESAPEAKE Energy, the second largest natural gas producer in the US, has secured a US$1.5 billion loan in an effort to tackle its nearly US$9 billion debt load.

The Oklahoma City-based firm said on August 17 that, as a result of strong demand, it had increased the loan size to US$1.5 billion from a previously announced US$1 billion. Interest on the loan was cut to 8.5%, down from an original offer range of 8.5-8.75%.

The producer has hired Goldman Sachs, Citigroup and Mitsubishi as joint lead arrangers on the loan, the company said in a statement.

The loan will have a five-year term and is expected to close before August 23, the company added.

It will be secured by the same collateral backing as the company's US$4 billion revolving credit facility, which is due in December 2019.

"Chesapeake expects this financing and the tender offers to improve its financial flexibility by reducing its near-term maturing debt," the company said.

The move gives the struggling producer some breathing space, at least in the short term. "The market seems to believe that they will weather the storm for at least the next few years," WL Ross managing director Shaia Hosseinzadeh, who oversees energy private equity and credit at the firm, was reported by Bloomberg as saying. Last week, Chesapeake announced that it was selling its Barnett shale acreage in Texas to Saddle Barnett Resources, which is backed by private equity firm First Reserve. The sale, along with the renegotiation of a pipeline contract, is expected to eliminate roughly US$1.9 billion of total future midstream and downstream commitments, Chesapeake said.

The firm also projected that the deal would increase its operating income by roughly US$200-300 million per year over 2016-19.

As well as asset sales, Chesapeake has tried to weather the collapse in oil prices by scaling back production and cutting jobs.

Chesapeake's CFO, Domenic Dell'Osso, said in an earnings call earlier this month that the company is focusing on lowering its total debt and that its "opportunities to enter the market are improving".■

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PGNiG plans share buy-back

EUROPE

POLISH state-run gas firm PGNiG has insisted its share buy-back is designed to allocate free cash rather than secure more influence for any particular shareholder.

CEO Piotr Wozniak told investors last week that the "rationale" for his company's move was that PGNiG "could not identify interesting assets to buy".

"[So] we decided to buy back our shares. There was not a particular offer, it was an internal decision," Wozniak said, noting PGNiG would maintain its dividend policy.

PGNiG had announced plans in July to spend up to 750 million zlotys (US$192 million) buying back its shares until the end of this year.

The firm's capital comprises 5.9 billion shares, 70% of which are held by the state. But the decision to reclaim shares raised eyebrows among some Polish financial analysts. Some claimed the move would favour the Polish Treasury against minority shareholders, analysts and fund managers,

Ipopema Securities analyst, Wojciech Kozlowski, had said on July 29 the operation would mean a dividend yield of 5% if it was addressed to all shareholders. "This … certainly strengthens the participation of the State Treasury," he said.

PGNiG posted a 30% fall in first-half operating profits to 1.8 billion zloty (US$475 million) on August 12, as revenues dipped from 20.3 billion zloty (US$5.4 billion) to 17.35 billion zloty (US$4.6 billion) year on year.

On the other hand, lower gas prices have allowed PGNiG to target a more diverse range of sources to wean the Poland from Russian imports, as the firm continues to contest Gazprom's prices through arbitration lodged in February 2015. Other available options include a deal for 1.3 billion cubic metres of Qatari LNG imported through the Swinoujscie LNG terminal, and a mooted pipeline linking Norwegian gas to Poland scheduled for 2022.

This could allow PGNiG to stop buying imports from Russia's Gazprom altogether in the future, CFO Boguslaw Marzec suggested on August 12.

"It may happen that we will not [be buying] gas at all from Gazprom. We're in a diversification programme [and] within four years we will have three main supply directions," Marzec said.■

Parkmead doubles stake in two North Sea oilfields

EUROPE

LONDON-LISTED independent Parkmead has doubled its stake in two oilfields in the UK Central North Sea. The move to enlarge its holdings in the Polecat and Marten oilfields "significantly increases" the firm's contingent oil and gas resources by around 39%.

The Polecat and Marten fields are located in Blocks 20/3c and 20/4a within Licence P2218, and lie approximately 20 km east of the Buzzard field.

Announcing the deal last week, Parkmead said it had acquired a further 50% of P2218, and now operates the licence with 100% equity.

It secured its original stake as part of the UK's 28th bid round, where it took on a total of nine new licences that cover 12 offshore blocks.

The Polecat and Marten fields – jointly estimated to hold over 90 million barrels of oil in place (BOIP) – are also located close to Parkmead's Perth-Dolphin-Lowlander (PDL) hub project in the prolific Moray Firth area of the Central North Sea.

"Polecat and Marten could be highly valuable to Parkmead's PDL project by contributing an additional 90 million BOIP to the already large oil and gas reserves base at PDL," said the company's executive chairman, Tom Cross. The deal raises the group's total contingent resources by 39%, from 42.5 to 59 million barrels of oil equivalent, he said.

In a separate operations update, Parkmead also reported strong Netherlands gas production from the onshore Diever West gas field, which "continues to perform above expectations". Gross production in July 2016 averaged 963,000 cubic metres (6,000 boepd).

The company's low-cost onshore portfolio in the Netherlands produces gas from four separate fields with a low average operating cost of just US$14 per boe.

With more money in the bank, the company is keen on more deal-making. Cross said Parkmead was working "intensively" to evaluate opportunities in its core areas of the UK and the Netherlands.■

CEZ profit down 51% in Q2

EUROPE

CZECH utility CEZ saw profits drop 51% in the second quarter on weak power prices. The company has reported a profit of 3.75 billion koruny (US$156 million) for the second quarter, down from 7.9 billion koruny (US$329 million) over the same period last year.

In addition to low wholesale power prices, CEZ blamed an asset write-down in Romania worth 900 million koruny (US$38 million). The company also cut its 2016 projection for earnings before interest, taxes, depreciation, and amortisation (EBITDA) to 58 billion koruny (US$2.4 billion) from 60 billion koruny (US$2.5 million), largely because of extensive unplanned outages at its Dukovany nuclear power plant. Dukovany is one of CEZ's most profitable power plants. Last year, three of its four 500-MW reactors were offline through late summer and autumn, cutting production by 18%. CEZ recently announced that the outages would continue this year and into 2017 as the company performs additional maintenance checks.

After the earnings report was published last week, CEZ Chief Financial Officer Martin Novak said the outages at Dukovany would cost 2.5 billion koruny (US$104 million) more than previously expected. The Czech government has faulted CEZ for the outages and suggested that management could be held responsible. Despite the tough quarter, Novak said that CEZ will still distribute its standard 60% to 80% of adjusted net income to shareholders this year.

Last week's announcement was the most recent in a string of disappointing earnings reports for CEZ. In March, the company said that net profit would drop 35% this year to 18 billion koruny (US$750 million), again because of low wholesale power prices. To weather the tough times, CEZ CEO Daniel Benes said CEZ would look for foreign investments in Germany, Poland, and other neighbouring countries to spur growth.■

Abengoa floats restructuring deal

EUROPE

TROUBLED Spanish renewables and engineering giant Abengoa announced a new restructuring deal last week, in a bid to avoid the country's largest-ever bankruptcy. A deal brokered by a hedge fund-led consortium will see the firm receive 1.17 billion euros (US$1.3 billion) of capital injection and give away 50% equity to lenders, via a structure that proposes writing off 97% of the company's debt. The agreement is a step closer to ending nearly two years of uncertainty over the company, which began with Abengoa unilaterally reclassifying bond debt in November 2014 and filing for creditor protection a year later.

However, the deal must still be approved by a high-stakes general meeting for shareholders and bondholders, expected in early October.

Spanish law demands that 75% of creditors approve any debt for equity swap by 28 October, meaning that full liquidation could still be possible. In an August 16 conference call the company said it hoped to win the approval of those shareholders by September 30. The plan includes Abengoa committing to the sale of key assets to pay back lenders. These include the 265-MW A3T Cogeneration Project currently under construction at Nuevo Pemex, a natural gas processing complex in Mexico, and those held by Abengoa's yieldco, Atlantica Yield. The yieldco owns nearly 1.4 GW of renewables assets spread across the US, Spain, South Africa and Uruguay, as part of a broader utilities portfolio.

The largest tranche of the package – a loan of 945 million euros (US$1.06 billion) which will be due in 47 months – gives the lenders the right to 30% of equity in the company. The assets listed are bellwethers of the firm's current business outlook. Prior to restructuring, Mexico represented 63% of the firm's projected income beyond 2020, and cogeneration 59% of the same forecast, according to a March Abengoa presentation.

A second tranche, of 194 million euros (US$218 million) is backed by engineering projects and a right to receive 15% of income; and a third tranche, of 30 million euros (US$34 million), is backed by A3T and Atlantica and 5% of future income. The A4T project, the next step of the same development already assigned to Abengoa, will be on hold until at least 2018.

The 10-company creditors' consortium is led by Elliott Associates, a firm which specialises in distressed debt, and is famously aggressive in ensuring compliance via courts. Abengoa's other creditors have the opportunity to join the lenders with the same terms, or face receiving just 3% of the principal of their debts with a 10-year grace period to the first payment.

The financial problems are at odds with the firm's perceived operational expertise. In 2015, during the same week that its shares crashed 30% in one day on financial concerns, MGT Power chose Abengoa and partner Toshiba to build its 299-MW biomass power plant on Teesside.■

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TransGlobe, Dana set out second quarter results

AFRICA

TRANSGLOBE Energy has made two oil finds in Egypt, the company announced on August 11. The company said the NWG 27 and NWG 38 wells had respectively found 18 million and 12 million barrels of oil in place, according to internal estimates. TransGlobe said it had drilled five exploration wells, giving it a 40% success rate.

In addition to its exploration work, the company has also pushed ahead with its development plans. The K-48 well, in the South-K field, was drilled and put into production during the quarter, with initial output of 460 bpd. More wells are planned for the field in the third quarter.

A first exploration well is planned for the South East Gharib concession, using the same rig. It added another rig in July, drilling the NWG 38. Next up is the NWG 26 well, to test a structure to the west of NWG 27. The company is planning to drill seven more exploration wells this year. Drilling costs are 30-40% below what TransGlobe had planned, a result of better contract terms and optimised drilling.

Production in the second quarter was 11,472 bpd, with a net loss of US$12.1 million. TransGlobe said it was working on a production recovery programme, which should increase capacity to 13,000-14,000 barrels per day of oil by the end of the year.

The recovery plan covers two additional wells at South-K, in addition to 16 or more recompletions and other work, such as pump optimisation, at West Gharib and West Bakr. Capital expenditure is estimated at US$33 million in 2016, down from the previous guidance of US$38 million. The savings come from its drilling programme, reductions on its recovery programme and some facility project deferrals into 2017.

A note from FirstEnergy said the exploration results were better than had been expected and that TransGlobe was "positioning itself for material production growth" in 2016, with an implied increase of 13-22%.

Dana

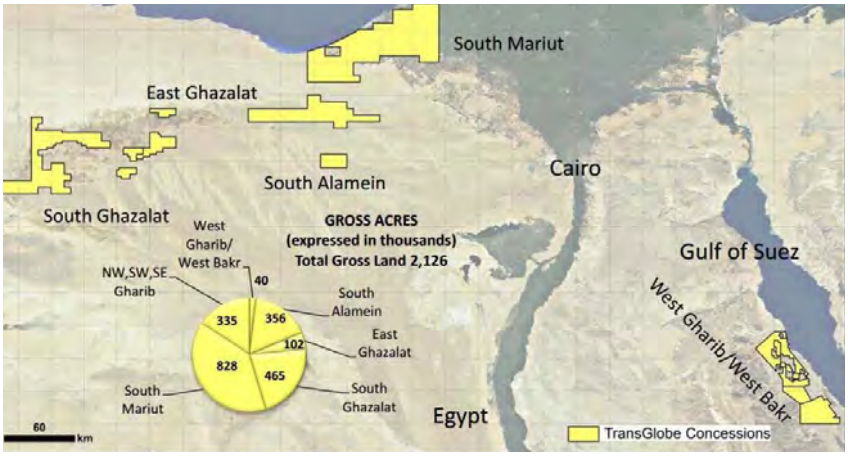
In addition to TransGlobe's results update, Dana Gas also set out its second quarter performance on August 11. Net profit in the quarter was flat year-on-year at US$7 million, while production was up as a result of an additional 4,000 boepd from Egypt's Balsam fields. Total output was 66,650 boepd in the second quarter, up 1% year on year. Egyptian production was 36,550 boepd in the quarter.

Dana also noted that BP had begun drilling the Mocha-1 well, in early May. The well is being drilled on the Nile Delta's El Matariya (Block 3) onshore concession. It will be drilled to a target depth of 6,200 metres with initial results in the fourth quarter of this year.

Dana's CEO, Patrick Allman-Ward, said there had been a "notable" production increase in Egypt, with its gas processing plant reaching maximum capacity. "We are currently drilling the deep Oligocene exploration well onshore Nile Delta and we anticipate that the well results will be known before year-end." Allman-Ward did go on to say that the "overall business environment remains challenging".

Work at Balsam was part of a production enhancement agreement with the Egyptian government, which was agreed in August 2014. This deal should provide additional production over three years and, as a result, Cairo's overdue debts to the company should be repaid by 2019.

As of the end of the first half, the amount owed by Egypt to Dana was US$230 million, up from US$221 million at the end of 2015.■



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Resgen gains backing for SA mine

AFRICA

LISTED coal miner Resources Generation (Resgen) expects to borrow US$386 million from four financiers for the completion of its Boikarabelo coal project in South Africa.

Resgen subsidiary Ledjadja Coal, which is developing the Waterberg region-based project, has agreed commercial terms with the financing syndicate for the new coal mine.

The financiers include the FirstRand Bank, acting through its Rand Merchant Bank division, Industrial Development Corporation of South Africa, Public Investment Corporation SOC and Noble Resources International.

"This is an extremely important milestone towards the construction and commissioning of the mine, which will be the second largest in the Waterberg region and will have a marked impact on the opening up of the Waterberg coal field," said Rob Lowe, Resgen CEO.

He said South Africa's largest logistics company Transnet, through its subsidiary Transnet Freight Rail, had partnered with Resgen to develop additional rail infrastructure to transport coal to the domestic and export market.

The site is currently linked by a 40-km road to the existing rail network, which terminates at the ports of Maputo in Mozambique, and Richards Bay and Durban in South Africa.

Ledjadja Coal has proposed that the new rail link would run from the Boikarabelo mine along the Steenbokpan-Lephalale Road and join the existing main line to Grootegeluk Mine. Resgen proposes to process the coal on site and stockpile it before it is transported to the market.

Separately, Resgen said it was negotiating with Export Finance and Insurance Corp. (EFIC) "with a view to EFIC joining the Financing Syndicate."

Already EFIC, which is Australia's Export Credit Agency, is carrying out due diligence on the project after several days of discussions with Resgen on the terms of its expected support.

If all the financiers approve the credit plan, Resgen will have enough funds for the completion of the coal mine and "provide the necessary headroom for contingencies."

The company anticipates production of 18 million tonnes per year for the first five years and 32 million tonnes per year for the remaining 15 years. The mine will have a lifespan of 30 years.

Resgen's South Africa expansion comes at a time when analysts are predicting good times ahead for the country's coal industry on the back of widening international export markets such as India and opening of new ones such as the Middle East and West and East Africa.■

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Service providers bet on India's KG Basin

GE and L&T are betting that developers will invest heavily in the country's eastern offshore in the coming years

ASIA

GENERAL Electric (GE) and Larsen & Toubro (L&T) are the latest in a string of companies betting big on India's Krishna Godavari Basin (KG Basin), with the two signing a supply deal last week for equipment GE aims to sell to explorers looking to exploit the basin's hard-to-reach resources.

India's government is keen to talk up KG's potential, which is attracting renewed interest from domestic and foreign majors, especially amid fresh claims that it may contain exploitable methane hydrates.

The basin has, however, disappointed in the past and remains a complicated place to do business – not only from a geological perspective – as exemplified by unresolved rows between Oil and Natural Gas Corp. (ONGC) and Reliance Industries Ltd (RIL).

Reaching the inaccessible

Under last week's GE-L&T deal, L&T Hydrocarbon Engineering will supply GE with sub-sea manifolds used in transferring hydrocarbons into pipelines. It will make them at its modular fabrication facility in Tamil Nadu, marking the first time such equipment has been manufactured in India.

L&T Hydrocarbon Engineering expects India's offshore industry to attract nearly US$5 billion in investment over the next four to five years, mostly from state-run developers, the company's CEO, Subramanian Sarma, said. L&T hopes to bag nearly US$1 billion of contracts in the next two or three years from this renewed activity as energy development prospects in India improve, he added.

GE's South Asia oil and gas CEO, Ashish Bhandari, told Indian business daily Mint that the deal with L&T was "part of the preparatory work being undertaken by GE for projects that the company hopes to win in the KG Basin."

KG and the bulls

The excitement surrounding the KG basin was partly triggered by the government's unveiling in March of a raft of new incentives to explore for harder-to-reach deposits.

These included a more liberal gas-pricing formula that allows a higher price for natural gas produced from deepwater, ultra-deepwater and high-pressure, high-temperature (HPHT) areas. For the first half of this financial year, pricing for such areas was set at US$6.61 per mmBtu (US$182.83 per 1,000 cubic metres), compared with US$3.06 per mmBtu (US$84.64 per 1,000 cubic metres) for gas from most other fields.

The incentive worked. State-run ONGC has since committed US$5 billion to exploring its KG-DWN-98/2 (KG-D5) block in the basin, while a consortium of RIL, BP and Niko Resources is also eyeing new deepwater investments there.

All this activity should mean more business for engineering companies and other contractors, analysts have predicted.

"This is a natural outcome of [the] higher level of market certainty now available to various players in the entire hydrocarbon value chain, including in upstream exploration and production," partner and head of oil and gas at KPMG in India Anish De told Mint. "Simplification of the regulatory regime, very strong energy demand and import dependence are the other factors driving investor interest in the sector."

The government is certainly bullish. KG will likely attract new investment of 1 trillion rupees (US$14.95 billion) over the next five to seven fiscal years, Indian Minister for Petroleum and Natural Gas Dharmendra Pradhan predicted in June.

Complexities in the deep

The complexity of producing gas from KG's deepwaters cannot be ignored, however.

Although India's East Coast, and particularly the KG Basin, is rich in hydrocarbon deposits, these lie under waters 2,000-3,000 metres deep, compared with the 100-200 metres for ONGC's prolific western Mumbai High development, Pradhan noted in June. As such, the technology requirements and costs associated with KG are higher.

Earlier this month, he described the basin as one of the five most challenging fields in the world and said that while evidence of methane hydrates had been found, there was no commercially viable technology to tap it. The basin also has a history of not living up to hype.

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In June 2005, Narendra Modi – India's current prime minister but then chief minister of Gujarat – took the country by surprise by announcing that Gujarat State Petroleum Corp. (GSPC) had made India's biggest ever gas discovery at KG. The find contained 20 tcf (566.4 billion cubic metres), he said at the time, promising that production would start in 2007. More than 11 years after the first announcement there is no sign of new gas production.

RIL and ONGC also remain locked in a long-running row over their KG blocks which, without a speedy resolution, could hold back further exploration and development. RIL argues that ONGC should have made it aware in 2003 that their adjacent deepwater blocks were contiguent, that gas could migrate between the two and that there was potential for joint development. The dispute is currently being reviewed by former chief justice of Delhi High Court, AP Shah, who has until August 31 to produce a report on the matter.

What next?

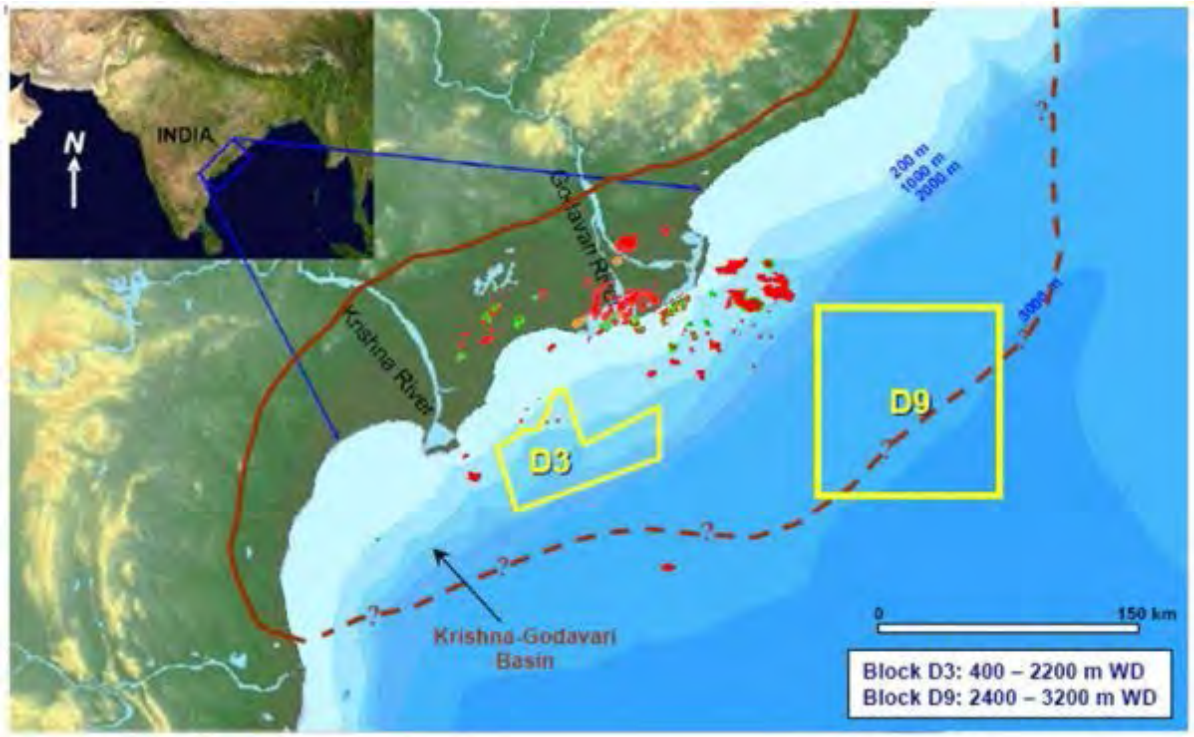
The opening half of this year has been somewhat slow in terms of oil and gas FIDs, with the second half likely to follow suit. ONGC's KG-D5 commitment was a standout in the Asia-Pacific, which only saw a handful of projects receive a green light.

IOCs and NOCs have, for the most part, leaned towards conserving capital. But costs are falling as service providers struggle to make ends meet amidst global upstream spending cuts. This will create opportunities for investors to position themselves to capitalise on recovering energy prices in the years ahead.

The buzz around KG is palpable, but may not prove justified in the near term. Before energy companies make good on investment pledges, they will need to prove to shareholders and creditors that the economics of a basin that still looks complicated and costly to develop stack up.

With the current gas price ceiling for challenging deepwater plays set at US$6.61 per million Btu and some term LNG supplies priced at US$5 per mmBtu (US$138.3 per 1,000 cubic metres), it is a tough argument to make for many within the private sector.

Service providers can look to ONGC to keep spending on eastern offshore developments. The company is, after all, under increasing pressure from the state to improve its production levels and is already squeezing its more mature assets for every last drop of hydrocarbons. It needs new production streams from KG to help keep output stable. The outlook for private investors, on the other hand, is far less clear and will be driven by project economics.■



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Mitra expands Vietnamese portfolio

ASIA

MITRA Energy last week announced it had agreed to buy stakes in two blocks offshore Vietnam from Inpex subsidiary Teikoku Oil for US$14.3 million.

Mitra will take a 30% working interest in the PSC for Blocks 05-1b and 05-c, which lie in 120 metres of waters in the Nam Con Son Basin. Idemitsu and JX Nippon each hold 35% stakes in the PSC.

Block 05-1 is home to two appraised gas and condensate discoveries, Dai Nguyet and Sao Vang, situated close to the Nam Con Son gas pipeline operated by Rosneft and PetroVietnam, Mitra said last week.

The Canada-listed firm said the contracts were "consistent" with its near-term development strategy and would build Mitra's Vietnamese portfolio alongside its U Minh and Nam Du gas finds in the Malay Tho Chu Basin.

Mitra upped its stake at U Minh and Nam Du to 70% in January after taking control of the interest formerly held by Kuwait Foreign Petroleum Exploration Co. (KUFPEC).

Following an independent CPR compiled by Lloyd's Register Senergy in April, U Minh's gross 2C resources are believed to be 64 bcf (1.81 bcm) of gas and 700,000 boe, while Nam Du is thought to have 138 bcf (3.91 bcm) of 2C gas resources.

Supply pressures

Hanoi needs explorers to uncover fresh gas reserves to replace dwindling production from maturing assets and help satisfy growing consumption.

BMI Research forecasts published in November 2015 suggested Vietnamese gas demand would grow by an average 4.9% per year to 14.1 bcm in 2024, driven by widespread usage of CNG for transport and increased gas-fired electricity generation.

In its report for the second quarter of 2016, BMI said Vietnam could become a net importer of gas by 2018.

Diminished gas output may lead to a surge in coal-fired power, and Hanoi's August 2015 energy master-plan projected that Vietnam would import 17 million tonnes of coal by 2020, up from roughly 600,000 tonnes per year at present.

Pressure from groups including the Vietnam Sustainable Energy Alliance (VSEA), which had in April warned coal would eventually generate 50% of Vietnamese electricity, reportedly led Hanoi to rework its plan to introduce more renewable power.

But Wood Mackenzie believes Vietnam could also tap more than 7 tcf (198.2 bcm) of potential gas resources to protect the indigenous share of energy production and avoid exposure to volatility on the international coal markets.

The Russian connection

Hanoi is likely to return to its historical energy partnership with Russian firms, which stretches back to the formation of Vietsovpetro with Zarubezhneft in 1981, to help revive upstream development.

On August 11, Russia's Rosneft announced that its Vietnamese subsidiary had encountered a gas and condensate discovery, subsequently named Wild Orchid, at Block 06.1 in the Nam Con Son Basin.

Rosneft said further appraisal would be necessary to confirm the volume of reserves, but noted the project could be tied back to its nearby Lan Tay production platform.

Hanoi announced a slew of agreements between PetroVietnam and Russian firms in May, including a new co-operation agreement with Rosneft, and MoUs with Gazprom for offshore gas development and LNG imports.

But veteran joint venture Vietsovpetro is understood to be struggling with maturing production amid the industry downturn, and is reportedly mulling 2,000 redundancies by 2021 to contend with low oil prices.

Upstream struggles

For its part, PetroVietnam said last week that it had generated 253 trillion dong (US$11.3 billion) in revenue in January-July, paying 50.7 trillion dong (US$2.27 billion) to the public purse, Vietnam News reported on August 12.

This compares with US$13.57 billion of revenue reportedly generated for the first six months of 2015 alone, of which US$2.9 million was transferred to the state account.

Deputy general director Do Chi Thanh said PetroVietnam had extracted 10.32 million tonnes of crude (354,455 bpd) and 6.56 bcm of gas from January-July, including 1.41 million tonnes (333,396 bpd) and 910 mcm in July.

Thanh noted crude benchmark averages had fallen by US$18 year on year to US$41.50 per barrel in July, but insisted PetroVietnam would still meet its production and business targets.■

HNA buys 80% of Tianjin Northern Petroleum

ASIA

HNA Logistics has bought an 80% stake in fuel trader Tianjin Northern Petroleum for 910 million yuan (US$137.3 million), it emerged last week.

HNA aims to use the transaction to transform itself into a supplier of aircraft and marine fuel as well as the operator of a string of gasoline stations and petrochemical bases across China, and may now also apply for its own licence to import crude oil and oil products.

HNA will also use Tianjin Northern's existing business to supply fuel for its own airline business.

Tianjin Northern has approval from the Ministry of Commerce to trade and import crude oil, fuel oil and petroleum products. HNA's parent, HNA Group, has been looking for an opportunity to deepen its involvement in the petrochemical industry for several years. The group – whose interests stretch across aviation, logistics, finance, property and tourism – signed a long-term strategic agreement in 2012 with Chinese refining giant Sinopec. In 2010, it set up Grand China Tanker.

This is the latest in a string of M&A deals for HNA Logistics which, along with its parent, is on an aggressive expansion drive.

The company announced to the Shanghai Stock Exchange in late July that it would expand its holding in Yangtze River Express to 35.1% via a capital injection. This will make it the biggest shareholder in the airline carrier, alongside its fellow HNA affiliates Hainan Airlines Group, Hainan Airlines and Lucky Air.

China's growing domestic demand for air travel is rapidly expanding aviation fuel consumption, especially around Shanghai, which is a business hub and whose Disney Resort is attracting a growing number of tourists from other parts of China.

HNA investments in Tianjin Northern and Yangtze River Express can, therefore, be seen as a complementary bet on the continued growth of China's aviation industry and its fuel requirements.

Previously an all-cargo operator, Yangtze River Express applied to the Civil Aviation Administration of China (CAAC) in 2015 to expand its scope beyond cargo operations and win the right to operate domestic passenger services from its Shanghai hub.■

ONGC accused of inflating production figures

ASIA

INDIA'S independent Comptroller and Auditor General (CAG) has accused state-run Oil and Natural Gas Corp. (ONGC) of overstating its crude oil production figures in its latest report.

The study claimed that more than 12% of ONGC's reported output consisted of condensates and gas dissolved within crude – which it referred to as off-gas – that is separated during the stabilisation process. This was despite the fact that ONGC itself defined condensate as "liquid hydrocarbon produced with natural gas, separated by cooling and other means".

The CAG said the incorrect figures saw the company pay an extra 186.26 billion rupees (US$2.79 billion) between fiscal 2011-12 and 2014-15 in production-based subsidies to oil marketing companies (OMCs). Under a subsidy-sharing scheme established in 2012, India's upstream NOCs compensate OMCs for losses on fuel sold at subsidised rates.

The report, presented to Parliament last week, said the inclusion of condensate had lost the company 163.32 billion rupees (US$2.45 billion), while the addition of dissolved gas had cost it 22.94 billion rupees (US$343.9 million). The auditor discovered that over-reporting of production in Gujarat and Assam assets had resulted in an additional subsidy burden of 1.61 billion rupees (US$24.1 million). "By including [basic sediment and water] of 3.9%, which has no financial value, off-gas of 1% and recoverable internal consumption of 0.12%, production performance was overstated," the CAG said.

It added that the company had overpaid its staff by 1.6 billion rupees (US$24 million) in performance-related payouts. It said ONGC's employees had received 100% of performance-related pay instead of the 80% that they should have received.

"If the actual crude oil production was reported, the company would not have met its crude oil production targets in any of the years [fiscal 2010-11 to fiscal 2014-15] under review," the auditor said.

ONGC, which produces nearly 70% of India's domestic crude oil, has been struggling to maintain current production levels, owing to ageing assets and the lack of new discoveries. The company has been under pressure from the government to raise output to help curb India's dependence on imports.■

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Indonesia to create new holding companies

ASIA

INDONESIAN President Joko Widodo has approved plans to create holding companies for state firms, including in the oil and gas sector, said Enterprise Minister Rini Soemarno. State-owned Pertamina will be the holding company in the oil and gas sector, while state-run gas distributor Perusahaan Gas Negara (PGN) will be one of its units, local reports said.

"The president hopes the future industrial development will be done by state-owned companies," Soemarno said.

Earlier this month, Pertamina acquired a 24.5% share in French oil company Maurel et Prom from Pacifico and reportedly intends to acquire more of the company in future. The Paris-headquartered company is focused mainly on Africa, with onshore production assets in Gabon and Tanzania as well as a 21% share in local Nigerian operator Seplat Petroleum. The firm also holds upstream asset interests in Namibia, Canada, Colombia, France and Italy, among others.

The move was part of the Indonesian firm's ongoing strategy to bolster its global upstream operations. Pertamina is trying to bolster oil and gas supplies and attract upstream investment to meet expanding energy demand in Indonesia. Indonesia has been a net oil importer for more than a decade. The Southeast Asian country's crude output has fallen steadily since a peak of around 1.7 million bpd in the mid-1990s.

The country's upstream regulator SKK Migas estimates that crude oil production will reach 826,000 bpd this year, less than half its level two decades ago.

Indonesia's net oil deficit widened to 803,000 bpd in 2015, from 761,000 bpd in 2013, according to the BP Statistical Review of World Energy 2016. The 2015 net oil deficit is equivalent to almost half of the country's oil consumption. Despite government efforts to inject some vigour into struggling production, regulatory uncertainty has deterred potential oil and gas investors in the last few decades. The poor reputation of Indonesia's energy administration, which has been accused of corruption and is highly bureaucratic, has also been an obstacle.

A number of foreign majors including ExxonMobil, BP and ConocoPhillips have either relinquished assets in Indonesia or deferred investments.■

Australia launches offshore round

ASIA

AUSTRALIA has launched its latest offshore petroleum exploration release, covering 28 areas across the Bonaparte, Browse, Offshore Canning, Roebuck and Northern Carnarvon basins, the government announced on August 11.

The 2016 Offshore Petroleum Exploration Acreage Release includes 25 areas that are offered for work programme bidding and three areas that are offered for cash bidding; it was launched by Minister for Resources and Northern Australia Matthew Canavan.

The areas are spread across waters offshore the Territory of Ashmore and Cartier Islands and Western Australia.

Prequalification for the three cash bid areas – W16-17, W16-22 and W16-25 – closes on October 20. The auction for prequalified applicants will then end on February 2, 2017.

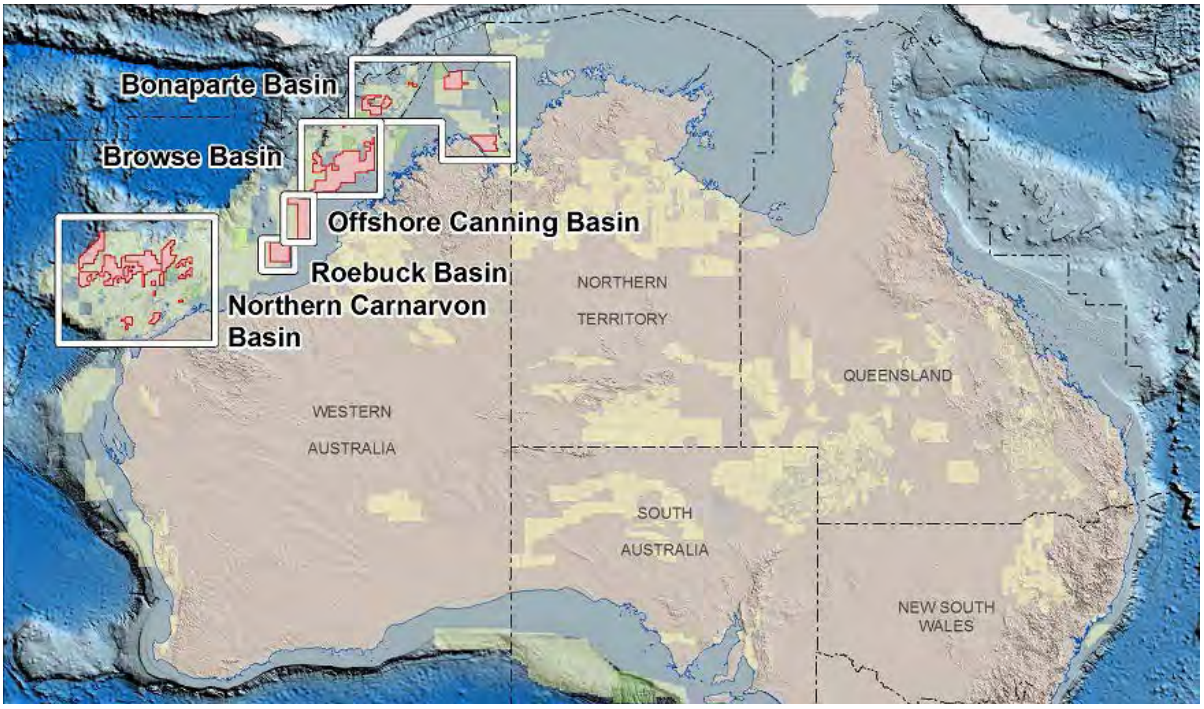
The first round of the work programme release will close on December 8, with round two set to conclude on March 23, 2017.

The areas on offer in round one include AC16-1, AC16-2, W16-1, W16-3, W16-8, W16-10, W16-11, W16-13, W16-15, W16-16, W16-19, W16-20 and W16-21. Round two will then take in AC16-3, AC16-4, W16-2, W16-4, W16-5, W16-6, W16-9, W16-12, W16-14, W16-18, W16-23 and W16-24.

All release areas for 2016 are supported by pre-competitive geological and geophysical data and analysis that was undertaken by Geoscience Australia, according to the Department for Industry, Innovation and Science (DIIS).

Information on other considerations that may have an impact on future petroleum activities in these areas has also been collated and made available in special notices, it said. Geoscience Australia has developed the National Offshore Petroleum Information Management System (NOPIMS) as an online data discovery and delivery system for Australian offshore petroleum wells and seismic surveys.

The bid round comes amid depressed upstream spending in the wake of the oil price crash that began in the second half of 2014. The number of exploration and development wells drilled in Australia slumped from 1,534 in 2014 to 821 in 2015, according to research by EnergyQuest. The consultancy said spending in the final three months of 2015 stood A$446 million (US$344.9 million), adding that this was the lowest level of investment in a decade.■



Senvion buys Kenersys in Indian expansion plans

ASIA

WIND turbine maker Senvion is extending its business interests into Asia by buying the India operations of turbine producer Kenersys.

The purchase includes a 250-MW capacity factory at Baramati in Maharashtra State, as well as wind power generating facilities operated in India by Kenersys India. The financial terms of the deal have not been announced, although India's Economic Times cited sources close to the arrangement who stated that Senvion had paid 2-2.5 billion rupees (US$30-37 million).

In addition, no mention has been made by either company about Kenersys' two turbine production plants at Wismar in Germany with 700 MW of capacity.

Kenersys is also headquartered in Germany, at Münster, but is owned by Indian engineering firm Kalyani Group.

Senvion was previously owned by Indian renewable power firm Suzlon Energy before selling it in 2015 to Centerbridge Partners, an American private equity business.

Senvion said in February that it intended to target India as one of its core markets. It established a research and development centre in Bangalore in 2105, adding that it would tap into the Indian government's target of adding 60,000 MW of wind generating capacity in the country by 2022.

The Kenersys acquisition will rapidly shorten Senvion's production-to-sales time frame, Senvion chief executive Jurgen Geissinger said in a statement.

"We can build on a strong base to further align the Kenersys products with our existing Indian R&D organisation and the well-known technical expertise from our Senvion tech centre in Germany," Geissinger said.

Senvion also said that the Kenersys turbine factory at Baramati had the potential to be expanded.

It is not clear when the deal will be finalised but Senvion said it intended to "start its operations with the assets immediately after the closing of the transaction and obtaining the necessary approvals".

India's government, led by modernising Prime Minister Narendra Modi, has ambitious plans to expand grid electricity to all Indians by 2022. Modi's power generating expansion will rely greatly on coal-fuelled plants but also aims to have 60,000 MW of wind capacity and 100,000 MW of solar.

Centerbridge bought Senvion from Suzlon in January 2015 for US$1.2 billion as Suzlon sought to reduce its high debts.■

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Brussels to fund construction of Estonia-Finland pipeline

FSU

THE EC announced last week it had set aside 187.5 million euros (US$210 million) to bankroll the construction of a subsea pipeline linking Estonia and Finland.

Balticconnector, which is listed as an EU project of common interest (PCI), will end the isolation of the Finnish gas grid and help ease northeastern Europe's dependence on Russian gas. EU governments last month signed off on a proposal by the EC to invest 263 million euros (US$294 million) on nine energy infrastructure projects, including the Estonia-Finland link. The funding will be allocated as part of the Connecting Europe programme unveiled by Brussels last year, which aims to provide 5.35 billion euros (US$6 billion) in financial support to PCIs by 2020.

"Diversifying energy sources and routes, and uniting the energy markets, is at the heart of the Energy Union," the commissioner for Climate Action and Energy, Miguel Arias Canete, said in a statement. "This is key to ensuring secure, affordable and sustainable energy for all EU citizens."

The EU will bear 75% of the overall cost of building Balticconnector, representing the maximum level of financial support allowed under current law. For many projects, funding from Brussels is capped at 50%.

The pipeline, which will be built by Finland's Baltic Connector and Estonia's Elering, will traverse 50 km of Estonian territory before reaching the coast of the Gulf of Finland at Paldiski. It will then continue for 80 km under the seabed before making landfall at Inkoo and proceeding a further 22 km onshore Finland.

The Finnish government gave a green light to the project last year, despite state-run gas utility Gasum backing out because of weak domestic demand. Gas accounted for 8% of Finnish energy consumption in 2015, following a 16% fall in demand because of high prices. Finland is entirely dependent on Russian gas supplies and despite the slump in gas consumption, 60% of Finnish energy imports still came from Russia in 2015.

Balticconnector is due to come on stream in December 2017, with an initial bi-directional flow capacity of 7.2 million cubic metres per day (2.63 billion cubic metres per year). The EU-funded Poland-Lithuania interconnector is set for launch at around the same time. This pipeline will be able to pump up to 2.4 bcm per year in the direction of Lithuania and 1 bcm per year in the direction of Poland.

Once Balticconnector is operational, Finland will gain access to Lithuania's Klaipeda LNG terminal, which began receiving shipments in early 2015. The facility can import up to 4 bcm per year of gas, which is just 200 mcm less than the total consumption in the Baltic States in 2015.■

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Nord Stream 2 hits roadblock with withdrawal of Polish JV application

FSU

GAZPROM and its partners in the Nord Stream 2 natural gas pipeline have decided against forming a joint venture to execute the project in light of Poland's anti-trust concerns.

In a joint statement dated August 12, the members of the Nord Stream 2 consortium – Gazprom, Engie (France), OMV (Austria), Royal Dutch Shell (UK-Netherlands), Uniper (Germany) and Wintershall (Germany) – said they had withdrawn their application to form a JV. They explained that they had done so in light of the objections raised to Nord Stream 2 by Poland's anti-monopoly agency UOKiK, which has ruled that the pipeline will inhibit competition by giving Gazprom too much influence over the regional gas market.

Nord Stream 2 was never supposed to pass through Polish territory. Rather, Gazprom was looking to expand its existing Nord Stream system, which runs across the bed of the Baltic Sea to Germany, in order to increase deliveries to Europe. Nevertheless, Warsaw gained influence over the project because Gazprom's partners all have assets in Poland.

Despite the withdrawal of the JV application, the Nord Stream 2 consortium has insisted that the project will go forward. In their statement, the group's members said that recent developments would not affect the implementation schedule or construction work.

Similarly, a spokesperson for Nord Stream 2 stressed last week that the pipeline was not being abandoned. The consortium's members "still support the project and believe that it has a crucial importance for the European energy system," she told RIA Novosti on August 12. The shareholders are now looking into alternative strategies for building the link, she added.

For the moment, though, Gazprom's hands appear to be tied – even though UOKiK is not in a position to enforce its ruling for a pipeline that will not cross Polish territory.

The Russian company could in theory proceed alone. In practice, though, it would have a difficult time doing so, as it needs the funds pledged by the five European companies to cover the projected 8 billion euro (US$9 billion) cost of building the pipeline.

It also cannot afford the time and resources that would have to be devoted to fighting the lawsuits that might be filed if Engie, OMV, Shell, Uniper and Wintershall ignored Polish anti-trust concerns.

The proposed JV would have divided equity in Nord Stream 2 as follows: 50% to Gazprom and 10% each to the other five companies.

The partners have said they want to build a link that will supplement the existing Nord Stream network, which is capable of pumping 55 billion cubic metres per year of Russian gas to Germany for delivery to other destinations.■

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Rotenberg launches new gas company

FSU

RUSSIAN oligarch Arkady Rotenberg and his business partner Artem Obolensky have founded the National Gas Group, according to the SPARK-Interfax database.

The main functions of the new company will be to serve as an investment fund, produce natural gas and gas condensate, engage in retail trade and to provide bookkeeping, auditing and consulting services.

Rotenberg holds a 51% stake in the new company, which will also manage Rusgazdobycha, an upstream unit 99% owned by Rotenberg through a Cyprus-based holding company, Olpon Investments. Obolensky owns the remaining 1% of Rusgazdobycha.

In June, Gazprom and Rusgazdobycha signed an agreement to develop the Parusovoye, Severo-Parusovoye and Semakovskoye natural gas deposits in Yamalo-Nenets Autonomous Okrug. Gazprom is aiming to produce up to 12 billion cubic metres of gas per year at the Parusovoe and Severo-Parusovoe deposits, which are due for launch in 2017. The gas giant also expects to flow 18 bcm per year from the Semakovskoye and Antipayutinskoye fields, which will begin production in 2023.

The deposits are located near Gazprom's Yamburgskoye gas condensate deposit, where complete infrastructure is in place. As the sole owner of Stroygazmontazh, one of Gazprom's three main contractors, Rotenberg has extensive experience in construction for the gas industry. But the deal with Rusgazdobycha is the billionaire's first production project with the company. Analysts say the appearance of a new production company is unexpected – "almost a revolution in the distribution and balance of forces on the gas market," Urus Advisory's Moscow director Alexei Panin told Vedomosti. National Chemical Group, which also belongs to Rotenberg's Olpon Investments, may be the consumer of the gas produced at the deposits where Rusgazdobycha will be active, a source told RBC.

National Chemical Group entered into a contract with Gazprom last year for the delivery of 3.15 bcm of gas per year for two decades. The company is now building a gas-processing plant in the Russian Far East that should be competed in 2019. The creation of the National Gas Group could simplify the supply chain, analysts say. They also note that Rotenberg could use the new company to consolidate a number of smaller assets.■

Gazprom's Serbian unit sees profit slump

FSU

SERBIAN oil company Naftna Industrija Srbije (NIS), majority-owned by Russian energy giant Gazprom, reported a slump in first-half consolidated net profits last week as a result of weak oil prices and a growing tax burden.

NIS's net income in the period fell by 38% year on year to 3.1 billion dinars (US$28.3 million), while EBITDA declined 37% to 13.2 billion dinars (US$121 million). NIS also noted that its direct and indirect tax liabilities amounted to 76.3 billion dinars (US$697 million), up 13% compared to the same period in 2015.

Still, the company said that total turnover of petroleum products rose 6% year on year to 1.55 million tonnes, while its retail market share in Serbia inched up 1 percentage point to 43%. At the same time, total volume of oil refining and semi-finished products climbed by 16% to 1.75 million tonnes.

According to NIS CEO Kirill Kravchenko, the extended crisis in the global oil and gas industry prompted the company to continue implementing measures aimed at boosting operational efficiency in all business segments. These measures had a positive financial impact of 4.4 billion (US$40.2 million) dinars in the first six months of the year, he said.

NIS also said it had not abandoned any key investment projects despite bearish market conditions.

"In the first six months of 2016, the value of our investments is threefold the amount of our net profit, i.e. a total of 9.1 billion dinars (US$83.1 million)", Kravchenko said.

NIS has seen earnings slide for the past two years amid plunging global oil prices and the strengthening of major currencies against the Serbian dinar. The company ended 2015 with a net profit of 14.6 billion dinars (US$133 million), down from 27.8 billion dinars (US$254 million) in 2014 and 48.4 billion dinars (US$442 million) in 2013.

Gazprom owns a 56.15% stake in NIS, while the government in Belgrade has a 29.87% holding. The rest of the capital is in the hands of small shareholders. The Moscow-based company acquired NIS as part of a 2009 oil and gas pact that also called on Russia to route the South Steam gas pipeline through Serbia. The project was abandoned in 2014, however, because of EU pressure.■

Gas Natural Fenosa capitalises on gas sector growth

Growing demand for gas across is driving the company's strong performance

LATIN AMERICA

SPANISH gas and power giant Gas Natural Fenosa (GNF) continued its penetration into Latin America's gas markets in the first half of 2016.

The group reported buoyant results from its wide and diversified portfolio in the region, despite being hit by foreign exchange rates. First-half earnings before interest and tax (EBITDA) for GNF's Latin American gas distribution business fell to 377 million euros (US$422 million) from 412 million euros (US$461 million) in the same period last year.

The sharp decline in the values of local currencies, especially the Colombian peso and the Brazilian real, had an adverse effect on the company's profits, while performance across different sectors was varied.

GNF has a gas sale and distribution presence in numerous Latin American countries, most notably Brazil. But it was the latter that saw the biggest slide in activity levels, with sales falling from 53,417 GWh in H1 2015 to 35,622 GWh in the first six months of this year.

The downward shift was a result of reduced demand from gas-fired power thermal power plants (TPPs) in Brazil as hydroelectric power generation rates recovered during the period. Brazil had to raise sharply its use of gas for power generation after a severe drought affected hydro output in 2014-15. The 33% slide in Brazilian gas sales offset growth in all of the other markets that GNF serves in the region.

The best results came from Colombia, where GNF enjoyed gas sales growth of 10.4% to 14,019 GWh, and Chile, where sales were 11.1% higher, at 23,420 GWh. There were also positive results in Argentina, where gas sales rose by 2.9% to 32,584 GWh, and Mexico, with 3% growth to 25,304 GWh. Overall, GNF's Latin American gas sales saw a reduction of 8.7%.

New connections

Rates of growth for new connections achieved by GNF, a good indicator of future use of gas and potential demand, rose strongly in H1 2016 (+4.3%), with the fastest rates seen in Brazil. This suggests gas sales will recover there, with similar trends seen in Mexico.

The other markets also uniformly delivered growth, demonstrating GNF's dedication to the whole region, and its well-diversified income stream. This growth was despite a slight reduction in net investment in gas distribution assets to 112 million euros (US$125 million), although the exchange rate volatility clearly has some influence upon euro-denominated results. Investment in gas networks is focused most extensively upon Mexico, Chile and Colombia.

GNF has also adopted a more strategic attitude towards LNG assets. It sold a 20% stake in the Chilean Quintero LNG import terminal to Spanish rival Enagas for 200 million euros (US$224 million) in July, which will realise a net capital gain of 32 million euros (US$36 million) in H2 2016.

This was motivated by the need to free up financial resources. GNF has maintained rights to use the facility, which provides it with access to the Chilean gas market, one of its key growth targets.

GNF is now the leader in the gas distribution sectors of four out of the five Latin American countries it operates in. It has a market share of 87% in Chile, in which it only began activities in 2014, a 60% share in Mexico, 36% share in Colombia and a 33% share in Brazil.

The company is the second largest distributor in Argentina, where it has a 19% market share. Next steps will include the evaluation of gas potential in power markets in which GNF is active, such as the Dominican Republic, Peru, Panama and others.

Underlying the projected future growth of GNF's gas portfolio is the general growth in energy demand across

▸▸

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Latin America, which is estimated at 3.2% per year since 1993. The share of gas within this upward curve is growing, as coal and oil-fired power generation declines.

Room to grow

GNF also believes there is more space to create value in Latin American gas markets compared to those in Europe owing to key structural issues.

More mature gas markets like Europe are often characterised by higher expenses, with GNF saying in its 2016-20 strategy document that it would have to cut costs in such markets.

By contrast, the cost of building new infrastructure in emerging gas markets, including LNG, is becoming more competitive. Moreover, the regulatory environment in these markets could start to ease as governments see the benefits of increased gas use.

GNF remains aware of the risks, however, acknowledging that lower commodity prices could have an impact on returns from gas activity, and that currency volatility could continue to affect results. The company also notes that there is a need for rapid infrastructure development to meet growing demand for gas.

At a macroeconomic level, the volatility of the region remains a risk, though the potential return on investment means it will remain a key target area for GNF.■

Petrobras records first profit in three quarters

LATIN AMERICA

BRAZIL'S Petrobras made a net profit for the first time in three quarters as it benefited from higher exports and an improvement in oil prices.

In a statement released on August 11, the state-owned oil company said it had made 370 million reais (US$118 million) net profit in the second quarter of 2016, up from the 1.25 billion reais (US$390 million) loss reported for the first quarter.

Crude oil and oil product exports climbed by 14% on the first quarter of 2016, which aided performance. But the results still represented a 30% decline on net profits from the same period last year and operating profits were down 25% on the first quarter of 2016. In the same quarter last year, the company made a 531 million reais (US$169 million) profit, whilst this year it made 370 million reais (US$118 million).

The drop in operating profits from 8.1 billion reais (US$2.57 billion) to 7.2 billion reais (US$2.28 billion) can be accounted for, in part, by a 1.12 billion reais (US$350 million) impairment charge suffered at the Comperj refinery.

The revaluation of the troubled Comperj natural gas processing unit comes after this was postponed last year, being over-budget and significantly delayed. The opening of the refinery will be put back until at least 2023 as Petrobras looks for a partner for the project.

The latest quarter is seen as a transitional one for Petrobras and with the Comperj impairment charges now out of the way the company is expected to post stronger results in the remaining two quarters of 2016. The company is still fighting the effects of low oil prices and the ever-widening corruption scandal that has rocked it and Brazilian politics.

In the statement Petrobras also announced a 7% rise in oil and gas production compared to the first quarter of 2016, with an average daily output of 2.89 million barrels of oil equivalent per day.

Some 93% of that output was in projects based in Brazil as the company scales back its activities abroad. The opening of the Lula Central project in the pre-salt Santos Basin in July also helped the growth in output, with the company's monthly record for pre-salt output broken in July with a total of 1.32 million boepd produced.

Petrobras also announced that its total debt, the largest in the oil industry, had fallen slightly. It is now 2% lower than it was at the end of 2015 at US$123.9 billion. In an effort to reduce its debt pile, Petrobras has committed to a two-year US$15 billion divestment programme. In July it sold a 66% stake in the Carcara offshore licence for US$2.5 billion to Norwegian oil company Statoil in its biggest ever oilfield sale.

This followed the company's scaling back of its operations in Argentina and Chile, with US$1.4 billion of assets sold off in May.

The results are the first under new market-friendly CEO Pedro Parente, who became Petrobras's CEO in June. He has said that the company's debt reduction programme will continue to focus on the sale of non-core assets.■

Bahrain a difficult sell to investors

MIDDLE EAST

WITH a fiscal breakeven oil price of at least US$106 per barrel this year and a stock market that is one of thinnest and least traded in the region, Bahrain is running out of funding options.

Like many of its neighbours, Manama continues to look to international bond issues to boost government coffers but this heavy supply merely serves to worsen the prospects for future issues out of Manama, which has its own blend of major problems to contend with.

The backdrop for a planned US dollar-denominated benchmark debt issue – usually 5 years plus and at least US$500 million – from the island after the summer look less than favourable. This is even with global banking heavyweights JPMorgan Chase, Credit Suisse, BNP Paribas, and Standard Chartered having been lined up to manage the sale, Energy Finance Week understands, along with ABC Bahrain.

"Bahrain was particularly ill-placed to confront a prolonged period of low oil prices, with the government having begun to run a budget deficit since 2009 – even when oil prices were above US$100 per barrel. We estimate that the shortfall widened to more than 13% of GDP in 2015," Jason Tuvey, senior Middle East analyst for global independent economics research consultancy, Capital Economics, told EFW.

"The government has sought to finance this shortfall through a combination of debt issuance and drawing down savings but with public debt now standing at 63% of GDP, and expected to rise further in the coming years, this form of funding is less sustainable than in the rest of the Gulf, particularly given the slow pace at which the authorities have so far tightened fiscal policy," he added.

Falling short

Indeed, according to Rachida Talal-Azimi, economist for Rabobank, Bahrain can only finance two years of its budget deficit with its sovereign wealth fund (Mumtalakat Holding Co.), while the UAE and Qatar, for example, could cover about 30 years of their deficit with their reserves.

Moreover, the sovereign's central bank foreign exchange reserves are very thin, relative to Middle East standards, believed to stand at around US$5.3 billion, down from US$5.8 billion at the end of 2014. The funding situation is not helped by the increasing strain on Bahrain's financial sector – the second largest contributor to GDP (15% of the total), which has suffered from the country's ongoing social and political unrest, she said.

"This turmoil stems from the longstanding issues related to the dominance of a minority Sunni ruling class in a Shia majority country and, additionally, the steadily increasing competition of other rising financial centres in the region, such as Dubai and Qatar, which are relatively politically and socially stable, are also a challenge for Bahrain's financial sector," she concluded.

This combination of toxic factors has not gone unnoticed by the 'Big Two' global credit ratings agencies – Standard & Poor's (S&P) and Moody's – either, with the former downgrading Bahrain in February to its 'junk' status (BB), the first Gulf sovereign to receive the non-investment grade rating since they were unrated deserts, with Moody's doing the same in March (Ba1) and once again in May (Ba2).

Aside from the enduringly low oil price, the key rationale for Moody's second downgrade was a reflection of the government's willingness and ability to adjust spending and introduce revenue enhancement measures that could affect its debt trajectory. In this respect, the government had announced a range of plans, including cuts to expenditure, tax reforms which would broaden the tax base and measures to increase efficiency in the public sector, but progress has been decidedly mixed.

Given no substantive policy response across all of these areas, depressed oil prices for the coming years would imply a reduction of 25% in government revenues in 2016 and only a gradual recovery in the following years, said Moody's.

"With fiscal deficits expected to average 15% of GDP between 2016 and 2018, this would imply a rise of 40 percentage points in Bahrain's debt burden until 2018, bringing it close to 100% of GDP, and that would shift Moody's assessment of the strength of the government's balance sheet to 'Very Low' from 'Moderate'," said senior sovereign risk analyst, Steffen Dyck.

These downgrades may prove potentially devastating to Bahrain's bond-issuance plans both in the very short term and for the foreseeable future as well, Christopher Cruden, CEO of hedge fund, Insch Capital Management, told EFW.

"Going into junk ratings territory immediately takes a country off the radar of the big international pension and insurance funds that are very conservative in approach and are often not allowed in their portfolio mandates to invest in any asset with a rating that is less than investment grade, it's as clear cut as that," he said.

"That leaves the funds that invest in countries listed in the benchmark emerging markets indices, but Bahrain is not included in the key indices there, and then funds that look at the next tier down – the frontier markets – but these funds tend to be much smaller, and in any event they do tend to mitigate the higher risks involved by

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placing a larger weight on the transparency of information from a sovereign as a minimum investment criterion," he added.

Not as advertised

In this context, even on the figures that are known, there is every reason to suspect that if Bahrain's economic trajectory continues in the direction that the ratings agencies consider possible, the country's ability to even meet repayments on its outstanding bonds going forward would be highly questionable.

The further knowledge that figures from the Middle East are broadly highly unreliable at best, and extremely misleading at worst, will do little to encourage foreign investors taking big packages of paper originating from Middle Eastern hydrocarbons-centric countries going forward.

EFW understands that such distrust has been exacerbated by the recent figures coming out of Saudi Arabia. A senior oil and gas industry source in Dubai, said: "There is always a huge time lag on figures relating to anything of real importance from these countries, and then even when figures are produced they are often shown to be completely inaccurate when they are subsequently revised – always to the downside in market terms – at a much later date," said the source.

A recent major case in point came when Saudi Arabia's government statistics office released data showing that GDP grew by 3.6% in the fourth quarter of 2015 from a year earlier, the same as third-quarter growth, implying that the economy was coping well with cheap oil.

In June, though, the same office posted new data revising the figure down to just 1.8%, a figure which itself has been widely regarded as an overly optimistic representation of the real performance over the quarter. Although many countries do revise their figures, such a massive revision is virtually unheard of. A 2015 OECD study found that revisions to year-on-year GDP growth rates by 18 member countries rarely exceeded 0.3% within the following five months.

Moreover, Saudi is not the only culprit of failing to provide accurate and/or timely data, with many of its Middle East neighbours still not having provided their current, fiscal and national accounts data for 2015. Bahrain itself has not published monthly monetary statistics – including for its foreign reserves – since June 2015.

"Given this type of reporting, and this specific set of problems for Bahrain, it is highly unlikely that the country will find a big appetite from Western investors for any bonds it offers for the foreseeable future, and even if it finds a Western buyer for any part of an offering then it will have to pay a very big premium on the paper, which, of course, it can't really afford to do," the source concluded. ■

Kurdish July exports fall, Gulf Keystone in flux

MIDDLE EAST

EXPORTS and revenues from the oilfields in northern Iraq controlled by the Kurdistan Regional Government (KRG) slumped in July, according to a report from the Ministry of Natural Resources (MNR), published in early August.

Additional negative news came in the form of unusually late payment for June exports to the international oil companies (IOCs) managing the territory's largest field – exacerbating the threat to Erbil's hard-won and newfound reputation for financial reliability posed by three months of staggered monthly disbursements and thus endangering the renewed investment pledged by the three main foreign producers, conditional on continued regular reimbursement.

Meanwhile, the ultimate fate of one of the trio – London-listed Gulf Keystone Petroleum (GKP), operator of the Shaikan field – remained in flux, as the board rebuffed a takeover offer from fellow Kurdistan producer DNO International of Norway and received approval for a restructuring that leaves the struggling firm in the hands of its creditors.

According to the MNR report, net exports through the Kirkuk-Ceyhan pipeline fell to 457,000 barrels per day in July from 500,000 bpd the previous month – compounding a dip in the average sales price from US$36.43 to US$32.53 per barrel to reduce revenues by 18% month-on-month to US$461 million.

While the declines would be expected to curtail roughly commensurately the next payment to the major IOC producers, the disparity between their monthly allocations as laid out in the MNR reports appears disproportionate for unknown reasons. The amount said in the July report to have been "allocated to main producers according to their [production-sharing contract] entitlements" is put at US$24.9 million, compared to

US$81.4 million in June.

Such a substantial reduction in eventual payments appears unlikely. Since September 2015 the KRG has maintained regular monthly remuneration despite huge fiscal strains and, since February, has been calculating the sums according to a fixed formula. The development has been effusively welcomed by the three key firms – GKP, DNO and Anglo-Turkish Genel Energy – and has yielded the desired resumption of investment by the latter two.

On general form before this month, the next disbursements would be expected around the end of August but the Norwegian company only reported receipt of the second and final payment for June's exports from the Tawke field – Kurdistan's largest – on August 8. Meanwhile, GKP's first June instalment was acknowledged three days later, reflecting a gradual slippage in the timing. For the past three months, Erbil has also dispensed the monthly payments in two instalments.

The payment for Tawke's June exports to DNO and junior partner Genel – which operates the second-largest Taq Taq field – fell to US$38.4 million from US$39.3 million in May, on the back not only of lower prices but also a slight decline in volumes. Production at the key field fell to 114,000 bpd from 117,000 bpd.

The figures for July output and exports from individual fields have yet to be released but a positive note in the MNR's latest report was a marginal increase in overall production to 572,000 bpd in July from 567,000 bpd in June – with the lower net export figure augmented by barrels lifted against money received at the end of June, barrels added to storage at Ceyhan, and volumes sent to the local Bazian and Kalak refineries.

Both DNO and Genel have outlined plans to resume development spending at Tawke and Taq Taq respectively this year to arrest and reverse production declines that set in during the second half of last year, before the onset of regular payments.

The Norwegian firm has been especially emphatic on its intention to accelerate work at the territory's main field while also alluding to inorganic growth plans: presenting first-quarter results, executive chairman Bijan Mossavar-Rahmani mentioned a desire to expand within "our footprint area" while chief financial officer Haakon Sandborg spoke of "actively looking for new assets to grow the business".

Such ambitions were evident in DNO's unsolicited offer on July 29 of US$300 million to take over GKP – comprising a cash payment of US$120 million and 170 million DNO shares. The price represented a 20% premium to that on July 14, when the terms of the proposed restructuring were announced. "We understand Shaikan's challenges and opportunities and we are well positioned to focus financial, technical, commercial and logistical support to maintain and then grow production at this field to the benefit of both Kurdistan and our investors," Mossavar-Rahmani said in support of the deal.

However, GKP – which has been talking to DNO and numerous other suitors in recent months – provisionally rejected the offer in order to concentrate on implementing the restructuring. "The board has concluded that completion of the restructuring best serves our stakeholders and we will not engage in any additional process that causes the company to be distracted from that objective," the firm said in a statement.

The restructuring agreed by a 95% majority at a special general meeting on August 5 will see US$500 million of the company's roughly US$600 million debt converted to equity, leaving GKP majority-owned by lenders and bondholders while diluting existing shareholders' stake to around 5% – potentially to be increased to just under 15% through an open offer of additional shares being staged in order to raise up to US$25 million for further investment at Shaikan.■

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