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New tech no cure-all for oil industry reality

Digitization for the downturn, but old problems persist

FEATURE *London*—As low prices persist, an outline is emerging of the oil companies of the future. At a conference in Italy this month, executives discussed the innovative ways technology is bringing down the cost of production and improving productivity. However, anyone seeing technology as a cure-all may be disappointed.

- **Technology helps centralize control**
- **Fight to remove engineering complexity**

There was much use at the GE Annual Meeting of buzzwords such as "big data" and "predictive maintenance" — the latter meaning the use of a "virtual twin" for a given piece of equipment that enables prediction of wear and tear, potentially reducing unnecessary maintenance as well as unplanned maintenance.

Citing the aviation sector's comeback after 9/11, GE Chairman Jeffrey Immelt said of oil and gas: "The number one driver of productivity in the future is going to be the digitization of assets."

On a practical level that means, for example, that Total plans to connect all its critical rotating machinery worldwide to its science and technology center at Pau, in France. In similar vein, BP plans to connect all its wells to the Internet, providing access to centralized real-time performance data.

Further ahead, 3D printing of equipment as well as new materials could help "revolutionize" the industry, UK company BG's interim executive vice president for technology, Jon Harris, said.

In some cases technological development is more about adopting gadgets in use elsewhere.

Denmark's Maersk Oil is another company extolling digital technology — its $4.5 billion Culzean North Sea gas project involves connecting all critical equipment wirelessly to shore — but the company is also marking savings by using drones to inspect hard-to-reach parts of offshore installations.

"Big data" need not be the preserve of big companies. In the US shale sector, checks previously conducted by workers traveling long distances between wells at considerable cost may be reduced by the use of sensors connected to the Internet. A common theme

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Saudi, Bahraini Iranian ship ban unlikely to hit crude flows to Asia

Tokyo—Bans imposed by Saudi Arabia and Bahrain on Iranian ships calling at their ports is unlikely to have a major impact on the flow of crude from the Persian Gulf to Asia or Iran's oil product imports, sources and analysts said Friday.

In addition to the bans by the two countries, Bahrain also placed restrictions on vessels that have Iranian ports marked in their last three port entries.

While no official reasons behind the bans have been given, they come after relations between the two Persian Gulf rivals—Iran and Saudi Arabia—have sunk to their lowest in years.

In early January, Riyadh severed its diplomatic ties with Tehran after protesters attacked and burned its consulate following the execution of a prominent Shi'ite cleric, Nimr al-Nimr, on terrorism charges.

Iran has so far not responded to the bans with a reciprocal move to prohibit Saudi or Bahraini tankers and sources in the country are confident the impact will be negligible.

"This ban does not have any impact on Iran's maritime transportation and trade. It's about two years now that our ships haven't had any traffic at the ports of these countries [Saudi Arabia and Bahrain]," an informed source told Iran's Tasnimnews.

"There was basically no need for Iranian ships to call at these ports. With the removal of the sanctions, Iranian ships sail even to European ports...," the source said.

Among crude importers in Asia, Japan does not see any impact on its crude imports from the Persian Gulf, a source at the Japanese Ministry of Economy, Trade and Industry told Platts Friday.

"We do not see any impact on crude imports from the Gulf because Japan does not use Iranian tankers for crude imports," the source said, adding that they understood the ban applied mainly to Iranian-owned and flagged vessels, but not to any tanker calling at Iranian ports.

State-owned Bahrain Petroleum Co. exports

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TOP STORIES

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South Korea's share of Middle East crude falls

Mexican, Russian grades gain market share in 2015

Seoul —South Korea's reliance on Middle Eastern crudes fell in 2015 as refiners turned to Russian and Mexican cargoes because of plentiful availability, but an anticipated rise in purchases from Iran may halt the downslide this year.

The country's four refiners imported 741.78 million barrels from the Middle East in 2015, up 3.1% from 719.3 million barrels in 2014, according to data from state-owned Korea National Oil Corp. compiled by Platts.

Although crude imports from the Middle East rose 3.1%, the market share fell as overall imports grew at a much faster rate of 5.8%, rising to 877.19 million barrels in 2015 from 829.24 million barrels in 2014. As a result, the share of Middle Eastern crudes fell to 84.6% in 2015, from 86.7% in 2014.

"The refiners' reliance on Middle Eastern crudes fell last year as they imported more volumes from Russia and Mexico as part of the efforts to diversify crude supply sources," a KNOC official said.

"The refiners also increased spot crude purchases on the back of abundant global supply, resulting in more volumes from regions other than the Middle East," he said.

The refiners' imports of Russian crude jumped 26.7% to 43.7 million barrels in 2015, from 34.48 million barrels in 2014. South Korea paid an average of $53.90/barrel for Russian crude, lower than the $55.20/b for UAE oil and $56.50/b for Qatari grades, KNOC said.

In addition, South Korean refiners imported 13.89 million barrels of crude from Mexico last year—the first by South Korean refiners since 1992.

The KNOC official said South Korean refiners' reliance on Middle Eastern crude was unlikely to decline sharply in 2016 despite their efforts to diversify supply sources.

"South Korean refiners' facilities are fit for grades from the Middle East, which means refiners cannot significantly reduce their reliance on Middle Eastern crude," the official said.

As South Korean refiners are expected to step up imports from Iran following the lifting of the sanctions, the region's market share would remain relatively high—over 80%—in coming years, the official added.

Top refiners

The country's top refiner SK Energy imported 204.72 million barrels from the Middle East in 2015, up 10.5% from 185.24 million barrels in 2014.

But its share of the total imports fell to 75.8% in 2015 from 77.5% in 2014 as its total crude imports rose 13% to 269.94 million barrels, from 238.91 million barrels in 2014.

SK Energy's imports from Iran dropped 38.4% to 18.83 million barrels last year, from 30.59 million barrels in 2014. SK Energy officials said the refiner would seek to lift imports from Iran following the lifting of the sanctions.

The refiner's crude imports from Iraq soared more than three times to 30.86 million barrels in 2015 from 10.16 million barrels in 2014 on lower prices. South Korean importers paid an average of $49.40/b for Iraqi crude, lower than $53.70/b for Saudi Arabia and $50.70/b for Kuwaiti grades.

Its imports from the UK also rose 161% to 13.18 million barrels last year, from 5.05 million barrels in 2014 as it increased spot purchases of North Sea Forties crude, according to the KNOC official. SK Energy also imported 3.95 million barrels of Mexican crude last year, compared with none in 2014.

But its imports from Africa declined 10.4% to 9.28 million barrels in 2015, from 10.39 million barrels in the previous year. Imports of Asian crudes also fell 23.9% to 13.38 million barrels in 2015, from 17.58 million barrels a year earlier.

The second-biggest refiner GS Caltex imported 221.95 million barrels of Middle Eastern crude oil last year, up 7.7% from 206.08 million barrels in 2014. But the share of Middle Eastern crudes declined to 82.3% in 2015 from 83.8% in 2014.

Its imports of Iraqi crude jumped 54.1% to 77.82 million barrels in 2015, from 50.5 million barrels in 2014. GS Caltex's imports of Russian crude rose 6.9% to 14.8 million barrels from 13.84 million barrels in the previous year.

Hyundai Oilbank

Hyundai Oilbank imported 101.63 million barrels of Middle Eastern crude in 2015, down 5.6% from 107.62 million barrels in the previous year. Its share also fell to 81.8% last year, from 89.1% in 2014.

The refiner's crude imports from Iran increased 8.1% to 15.49 million barrels in 2015, from 14.33 million barrels in 2014, while those from Iraq more than doubled to 17.55 million barrels from 8.16 million barrels in 2014.

Hyundai Oilbank imported 3.46 million barrels of Russian crude last year, compared with none in 2014, while its crude imports from the Americas more than doubled to 14.67 million barrels last year, from 6.21 million barrels in 2014, driven by 9.93 million barrels from Mexico.

S-Oil Corp. imported 213.48 million barrels of Middle Eastern crude in 2015, down 3.1% from 220.37 million barrels in the previous year. S-Oil, which is 63.4% owned by Aramco Overseas Co., a subsidiary of Saudi Aramco, imports most of its crude oil from Saudi Arabia and only small volumes from Qatar.

SK Innovation's petrochemical subsidiary, SK Global Chemical, as well as Hanwha Total Petrochemical, also imported small volumes of crude oil, but the exact volumes were not available. —*Charles Lee*

Saudi, Bahraini Iranian ship ban unlikely to hit crude flows to Asia

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its Banoco Arab Medium crude from Saudi Arabia's Ras Tanura as part of shared production from the 300,000 b/d offshore Abu Safah offshore field. This is also unlikely to be affected by the latest development.

"Japanese charterers do take BAPCO cargoes, although loaded from Ras Tanura," a VLCC broker based in Tokyo said. "Since Saudi Arabia did not ban [vessels marked with] Iran in their last three port entries, like Bahrain, it wouldn't cause much of a problem."

South Korea, which also imports crude from Iran using Iranian tankers, similarly does not also see any immediate impact, refiner and government sources said.

South Korea's two refiners which import Iranian crude—SK Energy and Hyundai Oilbank—have been importing Iranian crude on Iranian tankers and using Iranian shipping insurance cover.

"We don't co-load Iranian crude with others because we have used Iranian vessels. So there is no immediate impact," a South Korean refiner source said.

Another South Korean trader said: "Korean refiners normally purchase Iranian crudes [and condensates] on a delivered basis, like DES and CFR. In other words, the South Koreans hardly ever co-load Iranian crude with other Middle Eastern grades."

India and China are two other major Asian consumers which buy Iranian crude using Iranian tankers, as well as crude from Saudi Arabia.

Iran's product imports

Iran's oil products imports, using its five to six clean tankers mainly from the United Arab Emirates, would also not be affected by the latest developments, according to a market source.

But Tushar Bansal, Head of Oil, East of Suez, at Facts Global Energy said its oil products shipping costs could rise.

"Iran's product import costs will rise—this will mainly affect gasoline," Bansal said. "On other products that Iran exports, the higher shipping costs will result in marginally lower netbacks for Iran. Overall, [there will be] a financial impact on Iran but not a huge one."

Iran imported an average of 33,400 b/d of gasoline over January-October 2015, according to data from the Riyadh-based Joint Organizations Data Initiative. —*Staff reports*

Nigeria urged to overhaul onshore JVs

PSCs could stem output decline, ease funding crunch

INTERVIEW *London*—Nigeria needs to urgently revise the contracts governing its onshore oil blocks if it wants to stem the decline of production in a low oil price environment, the head of Oando, Nigeria's biggest independent oil company said Thursday.

- **Onshore output stymied by cash**
- **Oando focused on upstream growth**
- **Local refineries must be improved**

Nigeria's state-owned NNPC, which manages the Nigerian government's average 57% equity interest in joint venture oil businesses with foreign companies including Shell, ExxonMobil, Chevron, Total and Eni, has struggled in recent years to fund its share of operations.

Nigeria is now struggling to meet monthly cash call obligations for joint venture oil and gas projects due to low global oil prices, which have slashed Nigeria's oil earnings, NNPC said last week.

"There has been a reduction in the cash available to finance the NNPC share of our joint ventures, thus leading into us mortgaging production, reducing capacity, reducing our ability to generate reserves, reducing our production," Adewale Tinubu told Platts on the sidelines of the International Petroleum Week conference in London.

Funding shortfall

A wave of divestments by foreign oil companies of onshore assets has seen indigenous producers increase their output in the last few years and Oando has been one of the companies at the forefront of the trend.

But Tinubu said the government needs to look at converting its onshore assets into production sharing contracts which were widely used for offshore projects.

Under PSCs, NNPC holds the concessions while the oil companies fund development of the mostly deepwater offshore blocks and recover their costs from the production after royalty payments.

"This will relieve the government of the pressure of providing capital expenditure and can focus on earning royalties and its own share of production and its own share of profit," he said.

Tinubu noted the PSC model has worked for offshore production—which currently is over 1 million b/d—and the template needs to be applied to its onshore assets.

"It seems like an obvious choice for us to make. We do need speed and a timeline towards actualizing that. That is my fundamental request for a reform," he said.

Nigeria first introduced the PSCs, a form of operating arrangement with foreign oil companies, in 1993 to help solve NNPC's inability to fund its share in joint venture oil operations. But the contracts terms have recently come under fire for being too generous and NNPC last year said it was looking to renegotiate the PSC terms with foreign producers to help stem the impact of the oil price slump on government revenues.

Nigerian oil output has stagnated at around 2 million b/d even though the country has the capacity to produce up to 3.2 million b/d, largely because of underinvestment in exploration and also due to oil theft, pipeline sabotage, and corruption.

Shifting focus upstream

Oando has significantly grown its upstream business in the past few years and Tinubu said this was part of transforming Oando into an integrated oil company.

Oando acquired four onshore oil blocks—OMLs 60, 61, 62, 63—as well as two offshore blocks—OMLs 131 and 145—in 2014 from ConocoPhillips for a total of $1.65 billion.

The acquisitions bolstered Oando's oil production to 53,169 b/d in third-quarter 2015 from 35,307 b/d in the year-ago period. The Q3 average is, however, down slightly from Q2, when it produced 56,917 b/d. The company is expected to release its 2015 results next month.

"We wanted to balance our portfolio to have a substantial export presence and that is what upstream provides for us," he said.

"It is a powerful tool to have to be in the export market because you do have your own dollar supply which provides substantial support for your downstream infrastructure investments. That was a priority for us," he said.

Oando, listed on the Nigerian, Johannesburg and Toronto stock exchanges, said last year it had a five-year production target of 100,000 b/d.

Downstream sector

Oando, which is also Nigeria's largest fuel retailer, sees the priority for the Nigerian downstream sector is to first "revamp and improve" the state's existing refineries, then expand refining capacity by new investments, Tinubu said.

He said Nigeria's reliance on oil product imports was not such a bad idea in the short term due to the low oil prices and also because of the excess refining capacity in Europe.

"Clearly we need to use this lag time toward revamping our refineries and increasing the refining capacity we have ... we do have aspirations to participate in that ... but no immediate plans," he said.

Nigeria's four refineries, which have a combined nameplate capacity of 445,000 b/d of crude, were shut for seven months in 2015 and the utilization rate was 4.88%, making it very reliant on imports.

The poor performance of the refineries, caused mainly by mismanagement and years of neglect, has forced Nigeria to import almost all its domestic fuel needs, estimated at more than 1.2 million mt/month.

He said that according to the new pricing template issued by the government it was paying no subsidies on gasoline as the landing costs had fallen due to the low oil prices which was providing some cushion to the country. — *Eklavya Gupte*

Surgutneftegaz sees oil output slipping this year

Moscow—Russia's third-largest crude producer Surgutneftegaz expects its 2016 crude production to drop by 0.4% year on year, erasing last year's growth, as new fields set for launch this year will not compensate for natural declines in West Siberia.

The company said in its fourth-quarter 2015 results Friday that it plans to produce 61.4 million mt, or 1.233 million b/d, of crude this year.

The latest 2016 forecast is above the estimate the company's CEO Vladimir Bogdanov gave in early September, when he said Surgutneftegaz's 2015 output would drop 0.3% on the year to 61.2 million mt, and stay at a similar level in 2016.

Instead, the company increased production to 61.6 million mt last year.

The estimate returns the company's crude output to the 2014 level as production growth at the company's greenfields in Russia's new oil province, East Siberia, is expected to slow.

Crude production in East Siberia is expected to grow by 2% year-on-year to 8.6 million mt in 2016, after a 9% increase in 2015, according to the company's data.

The 2016 plan involves developing new hydrocarbons reserves, exploration drilling, well optimization, and raising recovery rates, the company said in Friday's report.

"The development of East Siberian fields plays a significant role in maintaining the company's output volume," the company said in the report, adding the region accounted for 13.7% of its total Q4 production of 15.6 million mt.

While low oil prices have forced some oil producers to revise investment programs this year and focus efforts on existing assets, Surgutneftegaz has pledged to maintain investment in exploration at Rb16 billion ($200 million) through 2018 "with no cuts or significant changes," its chief geologist Vyacheslav Chirikov said in November. — *Nastassia Astrasheuskaya*

OMV heads for Turkish fuel business exit

Price controls seen as source of industry discontent

Istanbul—Austria's OMV said Friday it plans to sell its wholly owned Turkish fuels division, Petrol Ofisi, amid signs of a potential exodus from the country by international oil companies.

- **Petro Ofisi is Turkey's biggest retailer**
- **Speculation over Socar interest**

Petrol Ofisi includes Turkey's largest network of retail fuel stations and a storage and logistics business with over 1 million cubic meters of storage capacity. With total fuel sales last year of around 10 million mt, it is also Turkey's largest lubricants distributor.

OMV said it was in the process of selecting advisers to help it proceed with the sale.

OMV's announcement is bound to reignite speculation both regarding potential buyers for Petrol Ofisi and regarding the possible exit of other international companies from the Turkish retail sector.

OMV said the move is "aimed at optimizing OMV's integrated portfolio in a challenging market environment". Previously, however, the company has repeatedly complained of "regulatory uncertainty in Turkey", and the announcement comes in a week when Turkish officials indicated that they plan to re-impose a controversial price ceiling on retail fuel sales.

That ceiling was first introduced last year, with the Turkish government alleging that retailers were failing to reduce their prices in line with falling crude oil prices.

The move came only months ahead of general elections held in June, prompting speculation that it was a populist gesture aimed at increasing support at the polls.

It was not the first time that Turkey's populist Islamist government has clashed with retailers. At the time, five of the top seven retailers—accounting for over 80% of retail sales—were wholly or partly owned by international majors, with a sixth belonging to a Turkish group with which the government has often clashed, making them an easy target.

Although short-lived the price ceiling sparked a spate of media reports that international operators were planning to exit the Turkish market.

Total did pull out, announcing in September that it was selling its Turkish retail fuel network and other downstream assets to the country's Demiroren group for Eur325 million ($356 million), ostensibly in an effort to cut costs and streamline its portfolio.

However, local analysts and industry sources suggest that the sale may have been more closely connected to the difficulties faced by fuel retailers in the Turkish market.

"Why would you continue to invest in a country where you can't earn back the cost of your capital?" one industry source said Friday, pointing out that profit levels in the Turkish fuel retail sector are currently so low that distributors could generate a higher return selling their assets and putting the money in a bank.

Buyer speculation

Founded as Turkey's state petroleum distribution monopoly, Petrol Ofisi was privatized in 2000.

OMV bought a majority stake in Petrol Ofisi in 2010 and has since increased its stake. At the time of its purchase of Petrol Ofisi, OMV described the deal as a basis for further expansion in Turkey on perceptions that the country had greater growth prospects than much of Europe.

However, the collapse in 2013 of plans by the OMV-led Nabucco consortium to develop a 31 billion cubic meter/year pipeline to carry Caspian and other regional gas to Europe led to intense speculation about OMV's position in Turkey. This was heightened last year when the company sold its last remaining upstream assets in the region, in Iraqi Kurdistan.

The past three years has seen OMV issue several denials that it was in talks with potential buyers including Shell and Azeri state oil company Socar. Socar—which is currently building the 214,000 b/d STAR refinery on Turkey's Aegean coast, slated to begin operations at the end of next year—has long been regarded as the obvious buyer. — *David O'Bryne, with Nick Coleman in London*

New tech no cure-all for oil industry reality

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among companies is the need for greater simplicity, which may mean big companies learning from nimbler counterparts in the US shale industry.

Shell projects and technology director Harry Brekelmans says the major has learned from its involvement in shale—which is not generally seen as a success—and is applying those lessons in the Gulf of Mexico at projects such as Stones, which is due on stream this year.

Similarly, standardization and simplification of wells at the Mars and Ursa fields saved $95 million last year, he says.

For Stones, "we fundamentally redesigned our wells recently using practices developed in our onshore unconventional business," Brekelmans said. "In the process we reduced the capital cost of the wells by more than 30% — we used less materials, reduced the installation cost, we also reduced the overall risk of delivering, given that they are now much simpler and much easier to drill and complete," he added.

Ways of executing

Brekelmans says it is working practices, ways of thinking and standardization that will rescue the industry as much as technology.

"Ever-accumulating specifications [and] individual engineering preferences have resulted in a proliferation of company-specific requirements," Brekelmans said. Some companies are trying to adopt common standards for items such as valves through the International Association of Oil and Gas Producers.

Similarly, Maersk Chief Executive Jakob Thomasen emphasizes the importance of disciplined operations, highlighting the Dumbarton cluster of fields in the North Sea, a legacy asset inherited from BP.

Output from the fields more than doubled to 26,000 b/d in 2014-2015 and operating costs more than halved, to $13/b, "through reduction of unplanned [downtime], better execution of maintenance programs...adding a little bit of equipment, mining all the data that we get and making sure we understand our equipment and really own it and run it optimally," Thomasen said.

Skills shortages, particularly in remote or politically challenging locations, are part of what is driving automation. BP's head of global operations, Fawaz Bitar, also said that "wrench time" across the industry — the amount of time actually worked — was often just four or five hours out of a 12-hour shift.

Bitar said BP's creation of a central logistics team as part of its post-Macondo revamp had helped reduce the number of boats it uses by 40% and the number of helicopters by 20%. "Our industry is only scratching the surface in operational areas such as maintenance, workforce productivity and logistics," Bitar said.

At the end of the day, it is not simply technology that will differentiate successful companies, but a host of economic factors, from taxation to materials costs to the ability of management to decide on the appropriate size and focus of their asset portfolio. "It is obvious that what you call digital will be part of the new way of implementing projects. Will it save the industry? I don't know," Total Chief Financial Officer Patrick de la Chevardiere told Platts this week.

Total's own record in cutting costs last year is proof of the slack that exists in the system, he says. "The industry has to adjust to a new oil price environment — it will be difficult for some of our contractors, but they have to do it. There is a lot of fat in our industry." — *Nick Coleman*

US producers continue to whittle down rigs

But analysts say more rigs must be idled before recovery can start

Houston—US rig counts concluded a second week of free-fall on Friday, Baker Hughes data showed, as crude prices continued to teeter below the landmark $30/b mark and industry peered at new government data hoping for some clue to long-awaited production declines.

- **Oil rig count drops by 28**
- **Permian idled 8 rigs last week**
- **Industry hoping rig count bottoms soon**

The oil rig count dropped 28 to 439, the eighth week of continuous declines and down from 1,056 a year ago. That is off a peak of 1,609 oil rigs in October 2014.

"January has been terrible for the industry and new budgets have come into effect," Evercore ISI analyst James West said in an e-mail. "Probably another 75 [oil rigs would have to come off] from today's levels" to begin having a meaningful effect on production.

Among major US oil plays, the Permian Basin of West Texas and New Mexico, lost the most rigs last week, eight, leaving 169 rigs. That is less than half the 365 rigs working in the same week of 2015 and less than a third of the 562 in November 2014. The Permian has been the most active US basin for several years.

On Friday, NYMEX front month crude settled up $3.23 to $29.44/b.

Oil prices have held around the $30/b level for about a month, down from the roughly $40-$50/b range last year.

Horizontal rigs working in the US last week fell to 49, down by four to the lowest level in at least 25 years of Baker Hughes data. Horizontal rigs are key to the shale revolution since they effectively allow operators to eke out larger hydrocarbon volumes from unconventional reservoirs.

The total US rig count on Friday was 541, down 30, from 1,358 in the same week a year ago and down from a recent peak of 1,931 in September 2014.

"Wish we could say this is the bottom," Seaport Global analyst Mark Brown said in an investor note last week, quoting managers of giant land driller Helmerich & Payne who met recently with analysts.

Industry widely points to reduced capital budgets and dropping rig counts as key to price recovery. Oil companies in the last couple of weeks have begun unveiling 2016 capex plans that are in many cases 50% to 60% lower than last year. Yet many operators say they expect flat or nearly flat production this year compared to 2015.

"You're seeing operators laying down rigs and saying they will only pick them back up if oil prices recover an appreciable amount," Edward Jones analyst Rob Desai said. "This is the quarter I think where we're starting to get the message from companies themselves, and not the other way around where others are saying rigs have to come off."

Desai said he believes the rig count could see "double-digit decline weeks for a couple of months."

"We're hearing companies talk about going down to one to two rigs" in prolific plays such as the Bakken Shale, where just a couple of years ago some operators each had 10 or 12 rigs working, he said.

For example, Hess is down to just two rigs in the Bakken, located in the Williston Basin of North Dakota and Montana, Desai said. That is down from 17 in mid-2014.

Besides the Permian, other large US oil basins have seen their rig counts reduced to a fraction of 2014 peaks. On Friday, Baker Hughes data show the Williston lost three oil rigs for a total 39, down from 127 during the same week a year ago and 198 in October 2014.

And, the Eagle Ford Shale in South Texas dropped another two rigs to 53 last week, compared with 145 the same week a year ago and 210 in July 2014.

In a recovery, both the Permian and the Eagle Ford will be the first to add rigs, UBS analyst Angie Sedita said in an investor note this week.

Meanwhile, the US Energy Information Administration, in releasing its February Short-Term Energy Outlook this week, projected a year-on-year drop in oil production in 2016 that is 40,000 b/d greater than it had a month earlier. — *Starr Spencer*

US RIG COUNT FALLS BY 30

Houston-The US rig count was 541 for the week ended February 12, down by 30 from the prior week, according to Baker Hughes.

The latest count includes 516 land and 25 offshore, with 102 assigned to gas, 439 to oil and 0 to miscellaneous drilling. The rigs were drilling 59 vertical, 49 directional and 433 horizontal wells.

Here are Baker Hughes' latest figures for the total number of active rigs in the US (with selected states) and Canada, plus comparable figures for a week ago and a year ago:

	2/12/16	2/5/16	2/13/15
US	541	571	1,358
Alaska	13	13	10
California	8	7	16
Colorado	20	22	49
Kansas	8	9	18
Louisiana	47	46	108
New Mexico	22	26	66
North Dakota	39	42	123
Oklahoma	76	80	171
Texas	248	262	598
Wyoming	11	13	39
Canada	222	242	382

Precision retires rigs, cuts capex on drilling activity rout

Calgary—Canada's Precision Drilling retired 79 legacy rigs in the fourth quarter 2015 and has slashed its capital spending 56% for the current year, Chief Financial Officer Rob McNally said Thursday.

The company's budget in 2016 will be C$202 million ($145 million), compared with C$459 million last year, in line with a 51% decrease in drilling in Canada and the continued low oil prices, McNally said on an earnings webcast.

Last year, 5,241 oil and gas wells were drilled in Canada, compared with 10,942 wells in 2014, McNally said.

"If the current price uncertainty persists, our visibility in Q2 will be murky," he said, adding Precision owns a fleet of 236 Tier-1 rigs capable of multi well-pad drilling and spares no efforts to "dominate the North American market."

The company has 57 rigs operating in Canada, 32 in the US and nine globally with a majority of those rigs placed under term contracts, CEO Kevin Neveu said on the same webcast, without indicating the timeline for the contracts.

"Our margins are holding well due to this [term contracts]," Neveu said. "But in a market where incremental opportunities are limited, day rates for rigs trend lower."

Precision's average revenue on a daily basis from its rig in Canada in Q4 last year was C$25,589, up from C$22,648 in the year-earlier quarter. In the US, the average daily revenue was C$24,498 in Q4 last year, compared with C$24,118 in the last quarter of 2014.

For first quarter 2016, Precision has term contracts for 36 rigs in Canada, 25 in the US and nine globally, Neveu said.

In Canada, the term contracts generate 250 drilling days—due to the seasonal nature of well access sites—while in the US and globally term contracts imply 365 drilling days, Neveu said.

Demand for natural gas and NGL drilling in the deep gas basin in the WCSB [Western Canadian Sedimentary Basin] remains strong and we expect that to continue," Neveu said. "But conventional oil drilling in the Viking, Cardium and Canadian Bakken remains challenged."

Western Canadian conventional crude producers have been cutting on their drilling budget in the shallow plays in Alberta and Saskatchewan. However, the liquids content particularly NGL, is spurring drilling activity in the WCSB, Neveu said. — *Ashok Dutta*

TAPPING THE BARREL

Highlights from the Platts Barrel blog

US enters the brave new world of LNG exports

Next month, the US is set to export its first cargo of LNG from the continental US.

Cheniere Energy, the company that won the highly-contentious race to be the first exporter out of the gate, will have some advantages over its US peers, but the global LNG landscape has changed significantly since the company first proposed to build its LNG export terminal over a half-decade ago.

Between 2001 and 2008, the forecast for US natural gas went from gas shortages to gas gluts. Showing off a sparkling new, state of the art LNG import facility, Cheniere was literally trying to sell natural gas into a sufficiently supplied market.

Cheniere then set out to do the complete opposite of what they planned to do a decade ago: export LNG. In September 2010, Cheniere was the first company to apply with the US Department of Energy for a permit to export LNG.

By late 2011, Charif Souki, Cheniere's CEO at the time, managed to work out a deal for Cheniere to sell $8 billion of LNG over 20 years to BG Group, which is now owned by Shell.

In a nutshell, Souki's pitch was this: US natural gas prices are forecast to stay low because of the abundance of newly-accessible shale gas resources, while natural gas and LNG prices are expected to remain high in Asia.

Why was Cheniere so confident that LNG prices were going to stay high in Asia? At the time, nearly all LNG prices in Asia were linked to oil.

This value proposition was successful, as Cheniere has been able to sell 80% of their LNG export capacity at Sabine Pass under take-or-pay contracts.

Fast-forward to 2016. Cheniere is expected to export its first cargo of LNG out of Sabine Pass this March. As Cheniere, along with other hopeful LNG exporters, know all too well, market dynamics never stay constant and volatility is the name of the game. Commodities are cyclical. When Cheniere and other companies decided to build multi-billion dollar LNG export terminals, there was a large price difference between gas prices in the US and Asia.

For example, the average price for a spot cargo of gas in Asia in 2011, using the Japan-Korea Marker, JKM, was $14.02/MMBtu. A key reason prices spiked was the Fukushima nuclear disaster, which occurred in March 2011, leading Japan to shut 47.5 GW of nuclear generation capacity.—*Chris Pedersen in Houston*

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FUEL FOR THOUGHT

Ecuador's refinery dream seems more of a fantasy

It was supposed to be the biggest investment ever in Ecuador: $12 billion for a 300,000 b/d refinery and the kick-start to industrialization with a major petrochemical complex.

After $1.2 billion and eight years of broken promises, the Eloy Alfaro Refinery of the Pacific near Manta on the Pacific Coast is a vast empty lot cut from tropical dry forest. Soon the area will be at the receiving end of a 93-kilometer aqueduct that might supply potable water to nearby cities, but the refinery is a fast vanishing dream despite recent overtures with Iran.

Goaded into planning the mega-project by deceased Venezuelan President Hugo Chávez, his Ecuadorean peer, Rafael Correa, is once again touting the imminent closing of funding for the project. Last week, an Ecuadorean delegation talked with Iran about crude supplies and to participate in the refinery.

While Iran is happy to sell its fellow OPEC partner oil, it remains to be seen if the country will invest in Correa's refinery plan. Particularly since Iran has many suitors from all corners of the world looking for potential refinery tie-ups.

It's been quixotic quest to fund the refinery. Initially, Ecuador expected PDVSA to help put up the cash, which never happened, and for the plant to go online in 2013. In 2009, Ecuador hired French investment bank Lazard. A year later, it was Japanese bank Mizuho. And the next year, an unnamed German investment bank.

The government finally signed a memorandum of understanding with CNPC and the Industrial and Commercial Bank of China in 2012 to seek funding. A year later, CNPC was to take a minority stake in the refinery, but that also never happened. CNPC pulled out, and even though Ecuador slashed the planned output by a third to 200,000 b/d, the $12 billion price tag remained the same.

By point of comparison, all of PDVSA's Citgo refining assets in the US were valued at $12 billion, with 750,000 b/d capacity.

Now, hope is set on a Chinese-South Korean industrial consortium, Sinomach plus Hyundai, for a financial deal sometime this year.

Will Iran come to the rescue?

This is not the first time Correa has courted Iran. His administration pursued a number of financial deals in 2009, primarily for the funding of hydroelectric plants, which also never materialized.

"It's not just a mega-project in Ecuador, but on a global level," said Rafael Poveda, minister for strategic sectors, during a trip to Manta last month, making it sound as if the project were still alive.

Right now, however, it's more notable as an invisible white elephant. Given the history of failure with the project, and Correa pledging not to seek reelection, it's hard to see who might want to sink money into a project of this scale under the current circumstances.

An opposition government would also likely pull the plug on the plan since country's balance sheet is in tatters following the crash of oil prices.

Even some of the most basic issues for the project have never been resolved, although critics have raised these issues from the very beginning in 2008.

Other than political—the province of Manabí surrounding Manta is Ecuador's third most populous, hence home to an attractive number of voters—the location for the Refinery of the Pacific was never an obvious choice.

It will require either a port for oil tankers to bring crude to the plant or a pipeline of some 250 kilometers in length to link up with the OCP heavy crude pipeline, which transports oil from the Amazon oilfields.

But supply from the pipeline is questionable as the pipeline is only transporting about a third of its 450,000 b/d capacity (according to the most recent data from Ecuador's government hydrocarbons regulator, which stopped uploading pipeline data in July 2013).

This brings up the question whether Ecuador would have enough oil to ensure there would be enough to refine over the lifetime of the plant.

As of December, the country exported 71.8% of the 533,000 b/d it extracts. The remaining 150,300 b/d goes to its existing refineries at Esmeraldas (110,000 b/d), La Libertad (45,000 b/d), and Shushufindi (20,000 b/d).

At least on paper, Ecuador looks as if it already has some overcapacity in refining, since it tops domestic consumption by 30,000 b/d, but it doesn't necessarily demand the fuels it's able to refine. The recently finished restoration of Esmeraldas to 110,000 b/d, at a staggering $1.2 billion, still leaves that refinery with about 50% residue.

Iran may have the crude available to support a new refinery, but the daunting financial task ahead makes the Refinery of the Pacific looks as remote now as it ever has. —*Stephan Kueffner in Quito*

OPEC output grows by 150,000 b/d

Saudi, Iraqi gains fuel January production rise: survey

London—OPEC crude output climbed to 32.43 million b/d in January, a 150,000 b/d month-on-month increase that was attributable largely to Saudi Arabia and Iraq, a Platts survey of OPEC and oil industry officials and analysts showed Friday.

- **OPEC pumping 32.43 million b/d**
- **Iranian oil flows now growing**

Powerhouse producer Saudi Arabia, after a dip in December, boosted output by 100,000 b/d to 10.2 million b/d, the survey showed. Iraq, now OPEC's second biggest producer after the kingdom and buoyed by record exports from its southern terminals in January, saw an 80,000 b/d increase to 4.33 million b/d from 4.25 million b/d in December.

Smaller increases came from Indonesia, which has rejoined the oil producer group, Iran and Kuwait.

Newly freed from sanctions, Iran is starting to make inroads into the European markets from which it was excluded for several years, with deals already agreed to supply a total of more than 300,000 b/d to France's Total, Italian companies Eni and Saras, and Greek refiner Hellenic Petroleum.

Restrictions on Iran's international oil sales were removed in mid-January when the International Atomic Energy Agency verified Tehran's compliance with a nuclear pact struck with six world powers last July. The country is now working to double oil sales, which the tightened sanctions had kept at around 1 million b/d since 2012. Before 2012, Iranian crude exports had been in the region of 2.2 million to 2.3 million b/d.

In the run-up to the removal of sanctions on January 16, Iranian oil minister Bijan Zanganeh had flagged an immediate post-sanctions supply boost of 500,000 b/d and a further increase of 500,000 b/d over the following six months. However, he acknowledged earlier this week that some obstacles related to shipping insurance and banking remained, but said he expected these to be resolved shortly.

The only dips came from Angola, Nigeria and Libya. Angolan oil output in January fell to 1.74 million b/d, down 60,000 b/d from December, amid reduced loadings of some key grades, including Dalia, Kissanje, Sangos and Gimboa.

This is somewhat below Angola's 1.8 million b/d output target for 2016. Oil minister Jose Maria Botelho de Vasconcelos said in December that the country's oil-dependent economy remained fragile due to the significant fall in crude prices, with the 2016 budget based on an oil price of $45/b. This is considerably higher than current price of around $32/barrel for North Sea Brent crude.

Nigerian output was estimated at 1.85 million b/d, down 10,000 b/d from December, following recent unrest in the key Niger Delta producing area and amid ongoing loading delays related to operational issues for a number of crude grades.

After a few years of relative calm, there are signs that militant attacks in the Delta are gradually picking up and affecting Nigerian total crude production.

In mid-January, militants bombed two key oil and gas pipelines, disrupting crude supplies from Chevron-operated fields to the 110,000 b/d Kaduna refinery and the two refineries at Port Harcourt, which have combined capacity of 210,000 b/d, forcing them to be shut down.

In late January, attacks on pipelines in Bayelsa State affected 16,000 b/d oil equivalent of Eni production, according to a company official.

Non-OPEC cooperation

Libyan production fell slightly in January to 370,000 b/d, as terrorists from the so-called Islamic State attacked some oil infrastructure in the east of the country, including facilities at key ports Es Sider and Ras Lanuf. The presence in Libya of militants linked to IS has intensified the pressure on the country's fragile oil sector.

Mustafa Sanalla, chairman of the state-owned National Oil Corporation, told Platts in an interview in January that output could be doubled almost immediately if the Sharara and Elephant fields in the southwest of the country were brought back online. But Sanalla said it would take "years" for Libya to restore production to 1.6 million b/d, the level Libya was producing before the 2011 uprising and which was briefly achieved in May 2012.

Speculation about possible talks involving OPEC and key non-OPEC producers reached fever pitch late last month after oil prices fell to a new multi-year low of $27.10/b for Brent.

Russian energy minister Alexander Novak said OPEC was talking to some independent producers about a February meeting to discuss potential options for cutting into the supply glut. Russia was ready to attend such talks, Novak said at the time. —*Margaret McQuaile*

OPEC CRUDE OUTPUT IN JANUARY

(million b/d)

	Jan-16	Change	Dec-15	Nov-15
Algeria	1.1	0	1.1	1.1
Angola	1.74	-0.06	1.8	1.80
Ecuador	0.54	0	0.54	0.54
Indonesia	0.71	0.01	0.7	0.70
Iran	2.91	0.02	2.89	2.88
Iraq	4.33	0.08	4.25	4.30
Kuwait	2.77	0.02	2.75	2.75
Libya	0.37	-0.01	0.38	0.38
Nigeria	1.85	-0.01	1.86	1.90
Qatar	0.66	0	0.66	0.66
Saudi Arabia	10.2	0.1	10.1	10.15
UAE	2.9	0	2.9	2.90
Venezuela	2.35	0	2.35	2.35
Total	32.43	0.15	32.28	32.41

Note: Indonesia reactivated its membership of OPEC at the December meeting. The estimate for Iraq includes volumes from semi-autonomous Iraqi Kurdistan.

Oil futures rally on UAE minister comments about OPEC cut

New York—The oil complex strengthened Friday on comments by the UAE energy minister that OPEC might consider a production cut.

NYMEX March crude settled $3.23 higher at $29.44/b. ICE April Brent settled up $3.30 at $33.36/b.

NYMEX March ULSD settled 9.02 cents higher at $1.0693/gal, while NYMEX March RBOB settled up 10.15 cents at $1.0432/gal.

UAE energy minister Suhail al-Mazrouei was quoted by the *Wall Street Journal* Wednesday as telling broadcaster Sky News Arabia in an interview that OPEC members were "ready to cooperate" on a production cut.

Speculation around a possible OPEC intervention arrested the slide in prices that had pushed NYMEX crude to its lowest level in nearly 13 years.

NYMEX March crude's settlement Thursday—$26.21/b—was the lowest for the front-month contract since May 2003.

Despite the price reaction, there was still doubt the UAE minister's comments signaled a meaningful shift in OPEC policy.

"As a general rule, the UAE agree on their oil policy with Saudi Arabia," Commerzbank said in a note. "Nonetheless, we remain skeptical about whether any agreement on coordinated production cuts will be reached," it said.

One reason for analysts' skepticism is that Saudi Arabia has not publicly backed efforts by certain OPEC members, like Venezuela, for a coordinated output reduction.

Just this past weekend, Saudi Arabia's oil minister, Ali Naimi, met with Venezuelan Oil Minister Eulogio del Pino in Riyadh, but gave no indication of support for production cuts.

In fact, production by key Middle Eastern OPEC members has been growing.

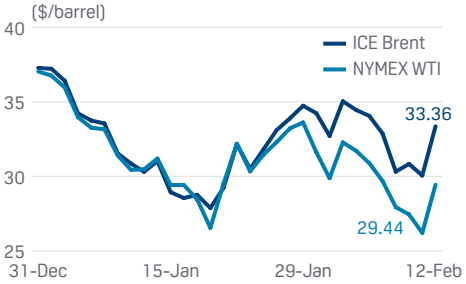
Saudi Arabia has been pumping oil at record levels above 10 million b/d for nearly a year. In January, Saudi Arabia boosted output by 100,000 b/d to 10.2 million b/d, a Platts survey of OPEC and oil industry officials and analysts showed Friday.

Iraq raised production 80,000 b/d to 4.33 million b/d in January, the survey showed. And Iranian oil officials have said they want to boost output this year following the removal of international sanctions.

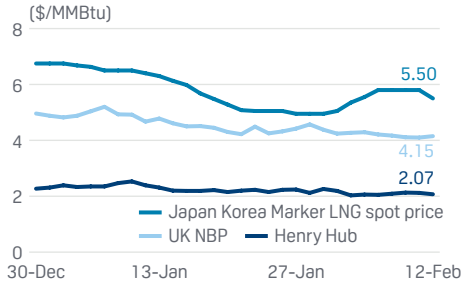
OPEC is likely to stay the current course because its tactics have been working, ClipperData director of research Matt Smith said in a note.

"The US oil patch is debilitating at a rapid pace. Oil firms are maxing out credit lines, as shrinking revenues from lower oil prices mean cash flow is not enough to service debt obligations," he said. —*Geoffrey Craig*

NYMEX WTI, ICE BRENT CRUDE OIL FRONT MONTH DAILY SETTLES



GLOBAL GAS PRICE COMPARISON



Source: Platts, prices are rounded

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