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Statoil cuts capex but lifts output target

Two North Sea oil projects hit by delays, cost overruns

London—Norwegian state-controlled Statoil Wednesday delivered strong third quarter results with oil and gas production rising 4% year on year, as it responded to the oil price correction with even deeper spending cuts and delayed the production start at two new fields.

- **Output gets boost from new fields**
- **2015 output to rise 3% versus 2% previously**
- **Capex target in 2015 pared back again**

The group, which has been boosted by new fields coming on stream this year, also upgraded its full year production outlook.

It said output in 2015 was now expected to rise 3%, compared with the previous estimate for a 2% rise.

The company, which last year withheld some gas output from the market due to the poor price environment, has been increasing gas production, helped by swing production from the Troll field, Norway's biggest.

Statoil's Q3 output came in at 1.909 million b/d of oil equivalent, up strongly from production of 1.829 million boe/d for the same period last year.

Natural gas sales volumes amounted to 12.2 billion cu m in Q3, up 9% compared with the same period last year, Statoil said, mainly due to higher Statoil production on the Norwegian shelf.

The Stavanger-based group also cut back further on its spending, it's second successive cut in its spending targets.

Statoil said Wednesday that 2015 total group capital expenditure was now seen at $16.5 billion.

In the Q1 report, it estimated 2015 capex of $18 billion, down 10% from the previous estimate of $20 billion, and with the Q2 results, capex was reduced further to $17.5 billion.

Statoil, by far the biggest operator on the Norwegian shelf, has either canceled or deferred some major projects, was selling off non-core assets and has sought to fund some massive new projects such as the Johan Sverdrup field, which is due to come on stream late 2019.

It announced that it was delaying the start of production from Norway's Aasta Hansteen field and the UK Mariner field from 2017 to the second half of 2018.

Statoil said the updated cost estimate for Aasta Hansteen had been increased by around 9% since the original development plan to

(continued on page 4)

Hess to cut rigs, but keep US shale output steady

Washington—Faced with sustained low prices, Hess plans to halve its Bakken Shale rig in 2016, but expects oil and natural gas production to remain relatively flat even if prices remain low for years to come.

"While it is prudent to plan for continued low oil prices in 2016 we also believe that Hess is well positioned to benefit when oil prices recover," CEO John Hess said during the company's third-quarter earnings call.

Hess will cut its North Dakota Bakken rig count to four in 2016 from the eight it began this year with. But due to well efficiencies, drilling cost reductions and higher well availability, the company expects to average 95,000 b/d to 105,000 b/d of oil equivalent under the four-rig program. This is roughly the same as the 100,000 b/d to 105,000 boe/d production rate Hess expects for the fourth quarter of 2015, when it will have seven rigs operating.

Hess' Bakken drilling costs fell to about $5.3 million/well in the third quarter of this year, compared with $5.6 million/well in the second quarter and $7.2 million/well in the third quarter of 2014, according to Greg Hill, Hess' president for exploration and production.

Wells are more efficient, the company is focusing on drilling in the "sweet spot of the sweet spot" in the Bakken and more NGLs and natural gas are being captured, Hill said.

In 2015, Hess expects to drill 183 new wells in the Bakken, complete 212 and bring 219 online. This will be done with an average of about eight rigs. In 2014, the company drilled 261 wells, completed 230 and brought 238 online. This was done with an average of 17 rigs.

The company expects to bring about 100 new wells online and Hill said the company could maintain about 100,000 boe/d production for "several years" under the drilling program planned for next year.

Hill said Hess will likely increase its rig count and drilling activity if prices increase.

Overall, Hess expects its 2016 oil and gas production to average 330,000-350,000 boe/d, compared with a Q3 average of 380,000 boe/d.

— Brian Scheid

TOP STORIES

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South Korea's jet fuel demand surges

Economic growth, lower airfares lift demand

Seoul—South Korea's appetite for jet fuel posted healthy growth in the third quarter as an improving domestic economy and lower airfares lifted air traffic—a trend government officials expect to continue for the rest of the year.

- **Jet fuel consumption up 14% in third quarter**
- **Buoyant growth supports demand**
- **Uptick set to continue**

Rising jet fuel consumption led a recovery in overall oil products consumption in Q3, a period that saw the country's economic growth rise 1.2% quarter on quarter to a five-year high.

South Korea consumed 9.2 million barrels of jet fuel over July-September, a 14.3% year-on-year jump, calculations based on data from state-run Korea National Oil Corp. showed.

The country's jet fuel demand has risen sharply this year, jumping 10% year on year in Q1 and 7.8% in Q2. Over January-September, jet fuel demand rose 10.7% year on year to 26.3 million barrels.

The number of air passengers rose 8.5% year on year to 65.69 million over January-September, with air cargo up 3.3% year on year at 2.81 million mt

"The rise in jet oil consumption was attributable to an increase in air traffic," said an official at KNOC's domestic market division.

The number of air passengers rose 8.5% year on year to 65.69 million over January-September, with air cargo up 3.3% year on year at 2.81 million mt, according to Ministry of Land, Transport and Infrastructure data.

"Air traffic has jumped, backed by an increase in air travellers and air cargo," said Kim Young-kook, head of the air traffic department at the ministry. "Air traffic slumped in July due to the Middle East Respiratory Syndrome [MERS] scare, but has shown a solid recovery since August," he said.

Spot premiums

Spot premiums for South Korean cargoes have surged since end September to hit a near one-year high of minus 15 cents/b on October 23 to the Mean of Platts Singapore assessment which was at $58.36/b. Some sources said cash differentials were as high as plus 10 cents/b at the end of last week. Spot premiums were last higher on December 24, 2014, at minus 5 cents/b, according to Platts data.

Just a few weeks ago on August 21, FOB Korea premiums were languishing at a multi-year low of minus $1.55/b. They are currently heard to be hovering around minus 20 cents/b.

Kim said South Korea's air traffic growth is expected to remain strong during the rest of the year, keeping domestic demand for jet fuel buoyant.

In addition to recovering air traffic that supported jet fuel, an overall economic recovery in the quarter supported consumption of other oil products, the KNOC official said.

Demand revival

South Korea's overall oil products demand rebounded 3.3% year on year to 211.59 million barrels in Q3, driven by stronger consumption of jet oil and auto fuels.

The country consumed 211.59 million barrels of oil products over July-September, up from 204.78 million barrels the year before.

Oil demand in Q3 was up 4.5% from 202.54 million barrels in Q2. The 3.3% year-on-year growth for Q3 was much greater than the 0.9% expansion in Q2.

"Oil demand that perked up in the first quarter slowed in the second quarter, but rebounded in third quarter on the back of economic recovery and lower pump prices," the KNOC official said.

The country's oil demand in Q1 rose 4.8% year on year to 215.27 million barrels, marking the biggest growth since Q2 2012, then slowed to expand 0.9% to 202.54 million barrels in Q2.

Demand for gasoil jumped 9.1% year on year to 38.96 million barrels in Q3, while gasoline consumption rose 3.5% to 20.02 million barrels.

Price changes

Pump prices of RON 92 gasoline, which is more popular than RON 95 in South Korea, averaged Won 1,544 ($1.40)/liter in Q3, down from Won 1,838/liter a year earlier, and edging up from Won 1,543/liter in Q2, according to KNOC.

RON 95 gasoline prices averaged Won 1,896/liter in Q3, down from Won 2,176/liter a year earlier and Won 1,904/liter in Q2.

The average pump prices of gasoil fell to Won 1,309/liter in Q3 from Won 1,642/liter a year earlier and Won 1,344/liter in Q2.

The country's LPG demand, which had been sliding, also rebounded, expanding 0.5% year on year to 23.72 million barrels in Q3.

Retail prices of LPG for auto use fell to Won 801/liter in Q3 from Won 1,035/liter a year earlier and Won 821/liter in Q2.

South Korea's LPG demand had been decreasing in recent years due to a decline in its use in the transport sector.

The country's demand for Bunker C fuel oil edged up 0.4% year on year to 6.22 million barrels in Q3, while kerosene demand fell 4.2% to 2.04 million barrels.

Over January-September, South Korea's oil demand rose 3.3% year on year to 629.4 million barrels.— Charles Lee, with Andrew Toh in Singapore

China CEFC delays startup of Yangpu oil storage facility

Singapore—Privately held CEFC China Energy is expected to delay the startup of its oil storage facility at Yangpu in southern China's Hainan province to early next year because of stricter approval procedures following the recent Tianjin explosions, a company source said Tuesday.

The company originally planned to start operations by the end of this year, Platts reported earlier.

Construction work for the facility—with a capacity of 2.8 million cubic meters (17.6 million barrels), comprising 1.8 million cu m for crude oil, 600,000 cu m for fuel oil and 400,000 cu m for clean oil products—finished recently.

"The approval procedure for oil storage facility is stricter and [is taking] longer than our original expectation after explosions at Tianjin port," the source said.

A series of explosions in northern China's Tianjin port area on August 12 killed more than 100 people and injured several hundreds, Platts has reported.

"We are expected to obtain government approval after the Spring Festival, probably in end-February or March," he noted.

CEFC China has signed a preliminary agreement with a Chinese state-owned oil firm to lease out its 18 crude storage tanks with a total capacity of 1.8 million cu m (11.3 million barrels) as commercial petroleum reserve, the source with CEFC said.

"The state-owned company has applied to rent our crude storage tanks as commercial reserves and will pay the rent through financial allocations after they get government approval," he said, but declined to name the company.

A final contract will be signed after both sides receive approval, the source noted, adding that the contract will be for five years.

"The cost of constructing or renting commercial storage facilities will be paid by the government, while the cost of buying oil will be shared by the government and state-owned companies in a ratio of around 30:70," a source said. — Staff reports

Tullow upbeat over Kenyan oil export route

Uganda seen picking northern route despite uncertainty

Cape Town—East Africa's first oil export route from Uganda through Kenya remains the most feasible and cost-effective route, despite recent discussions over a rival route by the Ugandan government, according to officials from Tullow Oil and Africa Oil, which are waiting to developing oil assets in the region.

- **Tanzanian option seen unlikely to stick**
- **Timing of key pipeline still unclear**
- **Security threat casts a shadow in Kenya**

Tullow is confident that the Ugandan government will be able to win public support for the key oil export pipeline through Kenya, COO Paul McDade told Platts, adding that the recent consideration of an alternative route may have had more to do with political expediency than any change of focus.

Ugandan and Kenyan agreed in August on a 1,500 kilometers (930 miles) pipeline that will take the northern route from Hoima in Uganda to Lokichar in Turkana County in Kenya and on to the Kenyan port of Lamu.

But less than two months later Uganda and Tanzania inked a preliminary agreement to explore an alternative line, reopening the long-running debate over the export route.

'(Uganda) will be able to demonstrate that Kenya is the right way,' – Tullow's McDade

McDade, speaking on the sidelines of the African Upstream conference in Cape Town, said this week that the latest move by the government to examine a pipeline from Uganda to Tanzania was because it needed to prove to its citizens that it was taking the most cost-effective decision transparently and publicly.

"I think the look to Tanzania is really all about making sure that, as they politically have to demonstrate to the Ugandans, they have chosen the right route for their pipeline," he said.

"They will be able to demonstrate that Kenya is the right way and the costs through the Kenyan route are very competitive," McDade added.

The route for an export pipeline is important not only to oil-rich Uganda, Kenya and the wider East African region, but also to companies such as Africa Oil, Tullow Oil, Total and CNOOC, which are active in the region.

The pipeline is particularly important to UK-based Tullow, which is developing oil resources in both Uganda and Kenya.

Similarly, the Kenya route is crucial to Africa Oil because the pipeline's northern route would pass through the South Lokichar basin, where it is currently carrying out appraisal work.

'Logical' route

A pipeline from Uganda through Kenya is the "only logical route" for an oil export pipeline through East Africa, Africa Oil President and CEO Keith Hill said Wednesday.

"We like the northern [Kenyan] route because land access is much easier," Hill said at the conference. "The other thing we like about the northern route is that it has a deep water port where we can bring supertankers."

Opponents of the Uganda-Kenya line have cited security concerns in the north, where bandits and militants periodically carry out attacks.

"We feel confident that the government of Kenya can provide security for either of those routes. This is the decision for the governments of Kenya and Uganda to make," Hill said.

"We will abide by the decision made by the two governments and our main concern is to try and get that decision sooner rather than later so we can start monetizing the projects," he added.

Landlocked Uganda has found 6.5 billion barrels of oil in the Lake Albert Rift Basin near the border with the Democratic Republic of Congo, but due to infrastructure, logistical and political constraints, commercial crude production continues to be pushed back due to delays by the government in offering licenses.

Uganda is hoping for first oil in late 2017 or early 2018 set to feed a new domestic refinery shortly afterwards. The country has said it expects the crude export pipeline to be ready by 2019 but many believe the target is overly optimistic.

In Kenya, Tullow and Africa Oil have found 600 million barrels of crude in the onshore South Lokichar basin, with the first discovery made in March 2012. — *Eklavya Gupte*

Nigeria's anti-graft drive to be 'transformational'

Cape Town—Ambitious moves by Nigeria's new government led by President Muhammadu Buhari to stamp out widespread corruption in the oil industry has instilled a lot of excitement and hope and has already led to some positive developments, Olapade Durotoye, CEO of Nigerian energy company Oando, said.

"What we see gives us a lot of hope, that things are going to be addressed in a fundamentally transformational way once and for all," he told the Africa Upstream conference in Cape Town.

Durotoye said security in the Niger Delta was a good example of this, as it had improved drastically in the last few months, leading to a sustained reduction in oil pipeline theft.

The significant reduction in crude losses is the first step that things turn can round, he said. Nigeria loses around 250,000 b/d of its 2 million b/d oil production to theft, according to Buhari.

Durotoye said the appointment of Emmanuel Kachikwu as group managing director of state-owned Nigerian National Petroleum Corp. was a much needed positive step, and that there was already "more transparency with the new NNPC sheriff in town."

He said Kachikwu has so far impressed Oando by restructuring NNPC in a way that "will be transformational for the long run."

"We see the new NNPC chief taking a pivotal role in executing some of the government's new strategies ... by changing the structure of NNPC, with a more global perspective," he said.

According to recent reports, NNPC sees a recent multi-year drilling financing package under a joint venture with Chevron changing its funding models.

Durotoye said the alternative funding model was the right way forward. "The government and NNPC have come around to see this is the only way to [boost] the oil industry in Nigeria," he said.

Energy bill changes

Durotoye also said there were clear signs Nigeria's landmark energy legislation, the Petroleum Industry Bill or PIB, which—has been stalled in parliament since 2012—is very likely to be broken up into more palatable bite-size pieces.

Durotoye said new thinking was necessary in the current low oil price environment.

The PIB seeks to change everything from fiscal terms offered to Nigeria's joint venture oil partners to an overhaul of NNPC.

Oil executives have said the prolonged delay in the passage of the bill and the uncertainty it has caused within the industry have held back billions of dollars of investment, especially for capital-intensive deep offshore projects.

Durotoye also said that with the new changes implemented by the NNPC, there would also be increased participation by independent African energy companies and indigenous Nigerian producers like Oando.

Oando had exclusively focused its operations in Nigeria, he said, adding it was beginning to look at operations in Sao Tome and Principe and was looking at making some moves in that area as a precursor towards looking at the wider African continent.

Oando, listed on the Nigerian, Johannesburg and Toronto stock exchanges, has interests in both the upstream and downstream business in Nigeria and elsewhere in West Africa.— *Eklavya Gupte*

Equatorial Guinea braces for oil slowdown

Producer still eying deepwater licensing round in 2016

Cape Town—Activity and interest in Equatorial Guinea's oil and natural gas sector has slowed dramatically as the country has been one of the "first victims" of the sharp drop in oil prices over the past year, energy minister Gabriel Mbega Obiang Lima said.

- **Asia accounts for quarter of exports**
- **To focus on building Bioko oil terminal**

"2016 is definitely going to be a quiet year in Equatorial Guinea," said Lima at the Africa Upstream Conference in Cape Town. "We only have two wells which will be drilled next year. Hopefully, with a continued increase in oil price there could be more interest by companies," he added.

More than 90% of Equatorial Guinea's annual revenue comes from the oil and gas sector.

Lima said new exploration plays in the upstream sector had taken a backseat because of this sustained low oil prices but that there were plans to start a licensing round for some deepwater developments next year.

Focus on Asia

Equatorial Guinea started producing oil in 1995, with production peaking at 425,000 b/d in 2004. Production has since fallen steadily, to 300,000 b/d in 2014, according to energy ministry data. Production in 2015 has averaged 287,370 b/d. The Alba and Zafiro fields account for more than 50% of the country's total output.

Equatorial Guinea has realized the importance of the Asian market as a main growth center for its oil and gas sector, Lima said.

"We have learned that clearly one of our key clients is the Asian market, with more than 26% of our crude exports going to Asia and 92% of our LNG exports," he said.

Of Equatorial Guinea's total crude exports to Asia, 18% is to China, 5% to India, 2.85% to Japan and 0.79% to South Korea, according to the energy ministry.

Due to the significance of Asian demand, Equatorial Guinea has been looking to set up an oil terminal on Bioko Island, the country's oil center, to create a regional hub for oil companies and traders to store crude and refined products.

"What we have learned from our experience in the Asian market is that one of the key constraints is transportation," Lima said. "We are keen to continue with this project because there is a great opportunity to be able to create a hub in which the different traders, companies, producers can actually store their oil and send it to far away markets like Asia.

This was especially relevant in a market where African oil producers are forced to sell their oil because there is no regional storage, he said. — *Eklavya Gupte*

Statoil cuts capex but lifts output target

... from page 1

NOK37 billion ($4.4 billion).

Statoil said for Mariner, the cost increase was slightly above 10% as compared to the original plan.

The high profile Mariner heavy oil field, which is is believed to hold 250 million barrels, is located about 150 km off Shetland.

Oil price impact

The latest quarter displayed how determined energy companies like Statoil are to respond to the new crude price landscape, especially in one of the most expensive places to drill in the world.

But it has also highlighted the extent of the challenge, and the threat posed by the collapse of the oil price late last year. CEO Eldar Saetre said Q3 continued to be affected by low liquids prices.

Statoil reported a Q3 net loss of NOK2.8 billion ($330 million), although lower than the NOK4.7 billion loss for the same period a year ago.

More reflective of the financial pain being felt because of the oil price, Statoil's Q3 net operating income dropped over half to NOK7.3 billion compared with NOK17.0 billion for the third quarter last year.

Statoil said Wednesday that realized average liquids prices in the quarter were down 37% year on year, based on the Norwegian krone.

The company said it was pleased with efficiency measures and cost cuts which began last year and have since gathered momentum, but more could still be done. — *Patrick McLoughlin*

NEWS BRIEFS

EnQuest starts up UK North Sea Alma/Galia oil project

UK independent EnQuest, which specializes in reviving mature assets, said Wednesday it had started production from the Alma/Galia oil project—previously named Argyll and the country's first commercial offshore producer.

EnQuest said the field complex, in the central North Sea, would reach full production rates in early 2016 as it opens additional wells.

It has previously said it expects production to peak at 13,000 b/d of oil equivalent on a net basis, implying 20,000 boe/d in total, and to continue for over a decade. It has put total reserves at 40 million boe. The oil is light, with an API gravity of 38.

EnQuest said only 30% of the complex's original 307 million barrels of "oil in place" had been recovered so far and that "with current technology field life can be extended significantly."

Ineos boosts stake in UK's Clipper South gas field

Switzerland-based petrochemical company Ineos' investment in North Sea gas continues, with an announcement Wednesday that it has purchased a 25% interest in the Clipper South gas field from by Fairfield Energy Holdings.

This will bring Ineos' ownership of the Clipper South to a total interest of 75%. Bayerngas Europe Ltd holds the remaining 25% in Clipper South.

Ineos has in recent years formalized plans to acquire cheap LPG and gas feedstocks, including natural gas, ethane, propane and condensates—for its petrochemical plants, following the prominence of shale gas as a competitive alternative to oil-based naphtha.

The latest purchase comes hot on the heels of its deal to purchase UK North Sea gas fields from Russian-owned LetterOne group.

These included the Breagh and a 50% stake in the Clipper South fields in the Southern North Sea, which represents 8% of UK gas production.

Ineos recently acquired shale gas licenses in England and Scotland and invested a further $1 billion in a project to bring US shale gas to the UK and to its Rafnes facility in Norway.

Republic of Congo to offer 13 blocks in new round

The Republic of Congo launched a licensing round for 13 blocks Wednesday as part of the government's drive to develop offshore and onshore fields to stem declining output, hydrocarbons minister Jean-Marc Thystere Tchicaya said Wednesday.

Speaking at the Africa Upstream conference in Cape Town, the minister said the "renewal" of the Republic of Congo's oil reserves was the major objective of this licensing round.

The minister said he expects the production sharing contracts for this round to be finalized by May 31, with bids to be submitted by March 31.

The oil industry remains the country's main revenue generator, with more than 80% of its revenue coming from this sector.

Canada's oil sands output to grow 22%

Forecast comes on heels of Shell suspending Alberta project

Calgary—Raw bitumen production in Canada's Alberta province is still expected to grow 22% to 2.845 million b/d by fiscal 2017-2018, a provincial government forecast said late Tuesday.

The optimistic view came on the same day that Shell opted not to move ahead with its bitumen project in the province.

"After several years of large scale investments in the oil sands, new projects will add over 500,000 b/d of production over the next three years," Alberta's finance ministry said in a submission to the Legislative Assembly during its annual budget presentation.

Raw bitumen output—currently put at 2.330 million b/d—will rise to 2.473 million b/d in fiscal 2015-2016, 2.647 million b/d the following fiscal year, before reaching 2.845 million b/d in 2017-201818, it said.

The projected growth is based on a price assumption of a WTI crude price of $50/b in fiscal 2015-2016, followed by $61/b in 2016-2017 and $68/b in 2017-2018.

"Bitumen production will continue to grow as projects currently under construction will be completed," the ministry said without elaborating.

But Shell Canada announced late Tuesday it would not move ahead with its planned 80,000 b/d Carmon Creek in-situ bitumen extraction project in Alberta.

Shell said in a statement it made its decision after reviewing design options, updated costs and the company's capital priorities. It cited "current uncertainties," including the lack of infrastructure to transport Canadian crude to global markets.

The company sanctioned the project in 2013 and was expected to have first oil from Carmon Creek in 2017. The company will hold onto the Carmen Creek property, which has 418 billion barrels of proven oil reserves.

The growth projects

The additional oil sands output of some 500,000 b/d will primarily come from:

- Suncor Energy that is targeting to produce 180,000 b/d from its flagship Fort Hills project.
- Canadian Natural Resources that will add 125,000 b/d to its Horizon oil sands output.
- Cenovus Energy, which plans to add 100,000 b/d of output from the next phases of its Foster Creek and Christina Lake facilities.
- ConocoPhillips, which will add another 110,000 b/d output under its Surmont Phase 2 expansion.

A further reduction in operating costs and seeking greater market access will be two key issues that producers will keep in mind as they increase output, said Justin Bouchard, co-head of energy research with Desjardins Securities.

"Enbridge has added this summer 300,000 b/d of Western Canadian crude throughput on its Alberta Clipper line, while another 300,000 b/d will also be offered when the Line 9 reversal project is completed this year end," Bouchard said.

The Alberta Clipper line runs from Alberta to the US Midcontinent, while Line 9 runs from Sarnia in Ontario to Montreal.

Despite new takeaway capacities for Alberta's producers that reduce transport costs compared to rail, the province's finance ministry is forecasting a "volatile" differential between WTI and Western Canadian Select.

The WCS ex-Hardisty, Alberta, price by pipeline on Tuesday was at a $14.5/b discount to the WTI calendar month average, according to Platts data.

With production ramping up, access to Texas refineries or coastal ports in the US for export is anticipated to remain insufficient and will impact differentials, the finance ministry said, noting Alberta's producers will have to rely on the "more costly" rail transportation rather than pipelines that offer a lower tariff.

Conventional crude output

Conventional crude oil output—that turned corners in 2011 and started rising, primarily driven by hydraulic fracking—will decline 12% to 518,000 b/d by fiscal 2017-2018 compared with the current output of 586,000 b/d, the finance ministry said.

A prime reason for such a scenario will be the decrease in drilling activity, the ministry said.

The number of active drilling rigs in Alberta in September was 113, a 55% decrease over the same month in 2014, the province's energy department said last week.

Access to capital by a majority of the conventional producers is also another stumbling block, said Gary Leach, president of the Explorers and Producers Association of Canada. — *Ashok Dutta*

Anadarko grows US crude output despite low prices

Houston—Anadarko Petroleum grew its US crude production over the past year despite persistently low oil prices and a continuing question mark over the timing of pricing improvement.

Based on stellar results in its its showcase Wattenberg field in Colorado and the emerging Delaware Basin in West Texas and New Mexico, Anadarko weighed in with 224,000 b/d of crude oil production in the US in the third quarter, up 11,000 b/d from the same year-ago period, CEO Al Walker said during a quarterly conference call.

Total Q3 production, including declining natural gas and natural gas liquids production, was 787,000 b/d of oil equivalent, down from 849,000 boe/d in the same period in 2014.

Year to date, the company has sold $2.2 billion of assets, including Bossier play natural gas assets in East Texas and northwest Louisiana and enhanced oil recovery assets in Wyoming.

Even though pressed by analysts for clues to Anadarko's 2016 capital budget, Walker declined specific guidance other than to say he expects to spend within cash flows, similar to this year.

That is something most upstream operators have also been forced to do as oil prices at $50/b oil or below have lingered for the better part of 2015.

On Wednesday, NYMEX December crude settled $2.74 higher at $45.94/b.

Anadarko expects $5.5 billion this year in capital spending, $100 million less than initial projections as it has shaved off well costs in key operating areas.

"Given the uncertainty around sustainably higher oil prices, you can see us investing [next year] in a higher percentage of longer-cycle opportunities such as exploration" where offshore Colombia wells have had "encouraging" initial results, Walker said.

Looking for value over growth

Also, the company's third appraisal well at the Shenandoah field, in the US Gulf of Mexico, encountered 622 feet of net pay. Anadarko officials earlier called the field a "potentially giant project" after a 2013 appraisal well found 1,000 net feet of pay.

"We will continue to invest fewer dollars in short-cycle US onshore activities," Walker said. "This approach reflects our conviction that growth will not be rewarded in this environment and that ... building value is more appropriate at this time."

As an example of building value, the company has driven costs down. The CEO said efficiency gains in the Wattenberg field the company have reduced its cost per drilled foot by nearly 15% sequentially in Q3, and reduced its cost by nearly $70/foot on each well. That amounts to nearly $1 million saved per well stemming from an enhanced wellbore design, Walker said.

And in the Delaware Basin--the western part of the greater Permian Basin--Anadarko has reduced per-well costs by $4 million to $7.5 million this year even though the company is not in development mode there. It could shave as much as $2 million/well further off wells when it elects to pursue growth on its 650,000 gross acre position in the basin, Walker said.

In addition, Bob Daniels, Anadarko executive vice president for deepwater and international operations, said that offshore wildcats next year will include "several" wells in the Gulf of Mexico, and also wells in Colombia and Cote d'Ivoire.

"Beyond that, we're still working the planning," Daniels said. — *Starr Spencer*

Valero sees lower Q4 refinery throughput

Heavy turnaround expected to keep West Coast market tight

New York —US refiner Valero Energy expects to see total system throughput of 2.685 million b/d-2.795 million b/d in the fourth quarter on a "fairly heavy turnaround" schedule, CEO Joe Gorder said Wednesday.

Neither Gorder nor Gary Simmons, Valero's Vice President of Marketing and Supply, gave any specific turnaround details on refineries, units, and timeframes for work in Q4 during the company's Q3 earnings webcast. Valero is the largest US independent refinery, owning 14 refineries with total throughput capacity of 2.935 million b/d and crude throughput capacity of 2.388 b/d.

Total refinery throughput was 2.832 million b/d in Q3 2015 and 2.814 million b/d in the Q4 2014.

During Q3, Valero ran a record high 1.307 million b/d of light, sweet crude through its refineries. But in Q4, it expects to run more sour grades due the seasonal switch to distillates. Also, falling gasoline prices have cut into profit margins, which could lead to lower rates at gasoline-making FCC units, although the lower prices have opened up the arb for gasoline exports.

Valero exported 89,000 b/d of gasoline in Q3, mostly to Mexico and Latin America. Distillate exports were 241,000 b/d, with about 65% going to Latin America and 35% going to Europe. Including kerosene exports, total distillate exports for Q3 totaled 285,000 b/d.

More medium sour on the USGC

In Q4, Valero plans to run heavier, more sour crude, particularly medium sours, where its high complexity USGC refineries are able to run most grades of crude.

"It is certainly to our advantage" in the USGC to run heavier crudes, said Gorder, noting the medium sour barrel will be the barrel to compete with in the USGC.

So far in Q4, the medium sour Mars USGC coking netback margin averaged $10.79/b, while heavier Western Canada Select averaged $8.28/b, according to Platts data.

Platts margin data reflects the difference between a crude's netback and its spot price. Netbacks are based on crude yields, which are calculated by applying Platts product price assessments to yield formulas designed by Turner, Mason & Co.

Valero expects Q4 2015 throughput at its six USGC refineries to range between 1.55 million b/d and 1.6 million b/d. Valero processed 1.571 million b/d in Q3 2015 and 1.613 b/d in Q4 2014. The company has 1.66 million b/d of throughput capacity in the region, of which 1.284 million b/d is crude capacity.

In the Midwest, Valero plans to run between 420,000 b/d and 440,000 b/d in Q4, up from Q3 2015 throughput of 470,000 b/d and 469,000 b/d Q4 2014 throughput. Valero has three Midwestern refineries with total throughput capacity of 465,000 b/d and crude throughput capacity of 434,000 b/d.

Diamond Pipeline options

The company is mulling whether to exercise its option to buy 50% of the 200,000 b/d Diamond Pipeline, which will carry crude from Cushing, Oklahoma, to Valero's 180,000 b/d Memphis, Tennessee, refinery where it will also connect with Valero Energy Partners' Collierville pipeline. The Diamond pipeline is being built by Plains All American and will be completed in 2017.

The Memphis refinery currently receives crude from the Capline, which runs north from the USGC, but shifting crude production flows have the reversal of the 1.2 million b/d line under discussion.

Along the West Coast, Valero expects to run between 235,000 b/d and 255,000 b/d in Q4, below Q3 2015 and Q4 2014 actual throughputs of 275,000 b/d and 265,000 b/d respectively. Valero's total West Coast throughput capacity is 305,000 b/d, with crude throughput capacity of 230,000 b/d.

Heavy turnaround activity currently underway on the West Coast is expected to "keep the West Coast market fairly tight," according to Lane Riggs, Valero's executive vice president of refining.

The company will soon benefit from cheaper crude at its 235,000 b/d Quebec City refinery as Enbridge's Line 9B begins service.

"It will start showing up in Montreal in December," said Simmons, about crude coming off Line 9B. Valero will receive Bakken, MSW, and Syncrude on the line, and while the economics may not be as strong as planned, they are better than shipping crude from the USGC to Canada. — Janet McGurty

NEWS BRIEFS

CN Rail's crude shipments drop 32% in Q3

Canadian National Rail handled nearly 23,300 car loads of crude in the third quarter this year, a 32% decrease compared with the same period of 2014.

With WTI prices averaging $45/b compared with $95/b last year, crude has been a very competitive category for the railroad and the expectation is this will continue in 2016, COO Jim Vena said during an earnings webcast.

"We also see a shift from manifest to unit trains for crude-by-rail movements," he said, without elaborating.

Crude price dynamics and rising pipeline capacity for oil will challenge rail operators to find ways to stay competitive, CN executives said

"If the crude spread [between WTI and Western Canadian Select] continues this way, CBR volume nominations for the last quarter of 2015 will be increasingly transitional and short-term in nature," Jean-Jacques Ruest, CN's chief marketing officer, said during the webcast.

Moving crude by rail will come under increasing pressure in the near term, as new pipeline takeaway capacity is being offered from Western Canada to refineries in US and Canada, Ruest said.

US SPR sales would raise $5.05 billion: CBO

A plan to sell 58 million barrels of crude from the US Strategic Petroleum Reserve to partially fund a two-year budget agreement will raise $5.05 billion over eight years, the Congressional Budget Office said Wednesday.

The plan, included in the Bipartisan Budget Act of 2015, calls for crude to be sold from the SPR in various increments for eight years beginning in fiscal 2018.

According to the CBO's estimates, the sales would raise $350 million in 2018 and $400 million each year from fiscal 2019 through 2021 when 5 million barrels would be sold each year.

Crude prices would average $70/b in 2018 and stay at $80/b over the next three years, according to the CBO's calculations.

In its latest Annual Energy Outlook, the US Energy Information Administration forecast WTI spot prices would average $70.06/b in 2018 and climb steadily to $75.10/b in 2021.

The CBO also estimates that the planned sale of 8 million barrels of SPR crude in fiscal 2022 would generate $700 million, or $87.50/b. EIA projects WTI will average $77.48/b in 2022.

The planned sales of 10 million barrels each year in fiscal 2023, 2024 and 2025 would raise $900 million, $950 million and $950 million, according to the CBO's calculations.

US grants Mexico request for 75,000 b/d crude swap

The US has granted Mexico's Pemex license to import 75,000 b/d of light crude for a year beginning this month, Pemex said in a statement Wednesday.

The move was proposed by Pemex as an exchange for heavy Mexican crude, which US refineries are better able to process than those in Mexico.

Pemex said the swap "offers Mexico an opportunity to benefit from current conditions in North America as a region within the world energy context."

Pemex in August said the swaps would allow up to 100,000 b/d of light crude and condensate from the US.

Oil complex rebounds on stock draw

Product inventory decrease trumps crude stock build

New York—Oil futures surged Wednesday after data showed demand was strong enough to pull US stocks of distillates and gasoline lower last week, even as refineries ramped up production.

- **Implied distillate demand rises**
- **Gulf Coast diesel exports steady**
- **Refinery rate up 1.2 percentage points**

NYMEX December crude settled $2.74 higher at $45.94/b. ICE December Brent settled up $2.24 at $49.05/b.

NYMEX November ULSD settled up 5.95 cents at $1.4839/gal. NYMEX November RBOB settled 6.29 cents higher at $1.3501/gal.

US distillate stocks decreased 2.951 million barrels to 142.057 million barrels in the week ended October 23, Energy Information Administration data showed Wednesday.

Distillate stocks have fallen the last six weeks a total of 12 million barrels. Last week's decline was the largest seen during that stretch.

One key question facing the market is whether distillate demand will prove strong as attention shifts toward winter heating.

Implied distillate demand jumped 442,000 b/d last week to 4.261 million b/d. The four-week moving average equaled 3.972 million b/d, a 10% surplus to the same period a year-ago.

On the Gulf Coast, combined low and ultra low sulfur diesel stocks fell 1.872 million barrels, to 34.641 million barrels, 3.6% below the five-year average for the same period.

The decline in USGC distillate stocks is at least partly attributable to steady exports.

A total of 1.74 million mt of distillates have been tracked leaving the US Gulf Coast bound for October arrival in Europe, according to Platts trade flow software cFlow.

This compares with a total of 1.59 million mt of distillates tracked on the same route over September and 1.73 million mt over August.

Platts data shows USGC ULSD delivered into Northwest Europe has held a $5.20/mt discount to CIF NWE cargoes over a 30-day moving average. The arbitrage appears open to the Mediterranean as well, with USGC ULSD holding a $3.19/mt discount to CIF Med cargoes.

USAC diesel glut eases

On the Atlantic Coast, home to the New York Harbor-delivered NYMEX ULSD futures contract, combined stocks were down for only the third time in the last 12 weeks.

USAC combined stocks fell 1.079 million barrels to 51.049 million barrels, but were still 84.6% above the five-year average for the same period.

Large storage levels on the Atlantic Coast have impacted NYMEX ULSD timespreads.

An abundance of supply has meant the prompt-month contract has been trading at a discount compared with deferred delivery. At this time of year rising seasonal demand usually translates into a premium paid for prompt-delivery.

The front-month/second-month spread averaged minus 2.59 cents/gal last week, compared with plus 1.41 cents/gal a year ago.

US gasoline stocks decreased 1.137 million barrels last week to 218.647 million barrels, matching analysts' expectation of a 1.1 million-barrel draw.

Implied gasoline demand increased 186,000 b/d last week to 9.343 million b/d, exceeding the year-ago level by 5.3%.

Last week represented the highest level of implied demand since the week ended August 28, when summer driving was in full swing.

The four-week moving average moved to 9.149 million b/d, compared with 8.848 million b/d a year ago.

Crude stocks build

Crude stocks at Cushing, Oklahoma, delivery point for the NYMEX crude contract, dropped 785,000 barrels to 53.334 million barrels.

Other aspects of the EIA report offered a different outlook, including a sizable increase in US crude oil stocks and higher estimate of domestic production.

"I didn't read the EIA report to be bullish at all," Tradition Energy senior analyst Gene McGillian said.

Technical factors could have also played a role in Wednesday's rally, as "selling pressure eased up and the market turned on short-covering," he said.

NYMEX prompt crude had been sliding of late, and settled Tuesday at its lowest level since August 11.

US commercial crude oil stocks built 3.376 million barrels to 479.963 million barrels.

The build occurred despite imports falling 439,000 b/d to 7.032 million b/d, the lowest level since mid-June.

Imports were down even though the ICE Brent/WTI spread narrowed, and has mostly been in the $2-$3/b range since mid-September.

Another factor limiting the size of last week's build was refinery crude runs, which rose 271,000 b/d to 15.616 million b/d.

The refinery utilization rate increased 1.2 percentage points to 87.6% of operable capacity. Analysts were looking for a 0.1 percentage point increase.

The utilization rate has increased the last two reporting periods, suggesting the depths of the autumn maintenance season may be over.
— *Geoffrey Craig, with James Bambino*

DOE WEEKLY STOCKS SUMMARY

(numbers in million barrels)

	10/23/15	10/16/15	10/24/14
District 1			
Crude	15.315	17.614	11.931
Conventional Mogas	6.807	7.070	5.713
Blend Components	55.612	54.706	45.034
Kero Jet	8.945	10.035	10.130
Dist >500 ppm	7.658	8.380	6.954
Dist <15 ppm	46.088	47.677	30.111
Dist >15<500 ppm	4.961	4.451	4.221
Distillate	58.707	60.508	41.287
Resid	10.082	10.434	7.876
District 2			
Crude	138.502	137.920	96.000
Conventional Mogas	6.084	6.420	6.785
Blend Components	39.091	40.579	38.216
Kero Jet	6.126	5.795	6.820
Dist >500 ppm	0.360	0.410	0.430
Dist <15 ppm	26.448	26.357	25.719
Dist >15<500 ppm	14.302	14.824	15.008
Distillate	27.267	27.165	26.608
Resid	1.302	1.206	1.409
District 3			
Crude	250.611	247.241	194.782
Conventional Mogas	11.092	10.406	8.755
Blend Components	64.858	65.115	64.882
Kero Jet	14.168	13.661	11.120
Dist >500 ppm	5.220	4.927	6.485
Dist <15 ppm	33.340	35.548	28.877
Dist >15<500	1.301	0.965	1.811
Distillate	39.861	41.440	37.173
Resid	24.262	23.633	21.388
District 4			
Crude	22.880	22.547	20.403
Conventional Mogas	1.938	2.120	2.331
Blend Components	4.855	4.950	4.306
Kero Jet	0.613	0.667	0.813
Dist >500 ppm	0.083	0.062	0.151
Dist <15 ppm	3.051	3.144	3.142
Dist >15<500 ppm	0.209	0.203	0.144
Distillate	3.343	3.409	3.437
Resid	0.209	0.256	0.107
District 5			
Crude	52.654	51.264	56.629
Conventional Mogas	2.056	2.150	2.647
Blend Components	26.220	26.229	24.426
Kero Jet	8.911	9.092	8.769
Dist >500 ppm	0.981	1.046	0.988
Dist <15 ppm	11.411	10.911	10.696
Dist >15<500 ppm	0.487	0.530	0.187
Distillate	12.879	12.486	11.872
Resid	6.052	5.782	4.756
Total US			
Crude	479.963	476.587	379.745
Conventional Mogas	27.978	28.165	26.231
Blend Components	190.636	191.579	176.865
Kero Jet	38.763	39.249	37.651
Dist >500 ppm	14.302	14.824	15.008
Dist <15 ppm	120.338	123.636	98.546
Dist >15<500 ppm	7.417	6.548	6.823
Distillate	142.057	145.008	120.377
Resid	41.908	41.311	35.536

US crude storage and capacity tracker

Houston—The rapid crude stock growth in the US slowed in the week that ended October 23 as imports fell and refinery input grew, Energy Information Administration data showed Wednesday.

Stocks were up 3.38 million barrels to 479.96 million barrels that week, after ascending for an average of 7.79 million barrels each of the prior two weeks, according to the data. That puts the growth much closer to the fourth-quarter-to-date average of 3.06 million barrels higher each week.

Imports fell 439,000 b/d to 7.03 million b/d, while refinery runs climbed 271,000 b/d to 15.62 million b/d, offsetting the balance between supply and demand by 710,000 b/d. Production held mostly steady, climbing by 16,000 b/d to 9.11 million b/d.

"A 700,000 b/d swing in the supply-demand balance, yet we still built over 3.3 million barrels," said Anthony Starkey, energy analysis manager at Platts unit Bentek Energy. "This is largely due to the fact that the adjustment factor remains quite elevated."

The adjustment factor, or crude oil that has not been accounted for in the EIA data, was 7,000 b/d higher at 458,000 b/d. That represents nearly half a million barrels of understated supply or overstated demand each day.

Crude stocks in the Midwest climbed for the fourth consecutive week, up 582,000 b/d to 138.5 million b/d as refinery utilization stayed below 80%. The growth and low utilization were both less extreme than in previous weeks, though, with refineries running 6.1 percentage points higher at 79.6% and stock growth much lower than the 2.87 million barrel average increase from the prior two weeks.

Atlantic Coast crude stocks lost most of the ground gained in the prior week's build, shedding 2.3 million barrels to 15.31 million barrels. That region, which does not have direct pipeline access to crude oil, depends on imports and crude-by-rail for its supply. With imports to the region down 288,000 b/d to 595,000 b/d and refining margins on railed Bakken crude averaging negative for the third straight week limiting supply, stocks felt the pressure from refinery utilization at 89.8%, just above the national average of 87.6%. — Joshua Mann

US CRUDE INVENTORIES AND STORAGE CAPACITY

Region	Inventories (Million barrels) 23-Oct-15	Shell capacity Mar-15	Shell capacity Utilized	Working capacity Mar-15	Working capacity Utilized
PADD I	15.32	25.64	60%	19.5	79%
PADD II	138.50	173.78	80%	140.24	99%
Cushing, Oklahoma	53.33	86.3	62%	71.41	75%
PADD III	250.61	359.68	70%	297.46	84%
PADD IV	22.88	23.17	99%	19.18	119%
PADD V	51.65	76.94	67%	64.19	80%
US	479.96	659.21	73%	540.57	89%

Source: US Energy Information Administration

Note: Shell capacity includes tank bottoms, which may include water and sediment, and contingency space. Working storage capacity excludes tank bottoms and contingency space

US CRUDE INVENTORIES AND ADJUSTED STORAGE CAPACITY

Region	Inventories (Million barrels) 23-Oct-15	Adjusted Shell capacity Mar-15	Adjusted Shell capacity Utilized	Adjusted Working capacity Mar-15	Adjusted Working capacity Utilized
PADD I	15.32	26.13	59%	19.99	77%
PADD II	138.50	209.88	66%	176.35	79%
Cushing, Oklahoma	53.33	87.65	61%	72.76	73%
PADD III	250.61	414.21	61%	351.99	71%
PADD IV	22.88	34.63	66%	30.65	75%
PADD V	51.65	94.35	55%	81.6	63%
US	479.96	779.21	62%	660.57	73%

Source: US Energy Information Administration, Platts

Note: The above table shows capacity adjusted higher to reflect pipeline capacity and oil in transit. The EIA's weekly inventory numbers include barrels that are in pipeline, "oil that has been produced but not put in the supply chain," and oil in transit from Alaska. The capacity for these figures is not included in the EIA's capacity numbers. According to the EIA, those volumes total around 120 million barrels.

US SUPPLY/DEMAND BALANCE - FOUR WEEK MOVING AVERAGE (MILLION B/D)

	Crude Production+Imports	Crude Stock Change	Total Supply	Crude Runs	Crude Exports	Total Demand
25-Sep-15	16.45	0.089	16.36	16.20	0.49	16.69
2-Oct-15	16.38	0.107	16.27	16.06	0.50	16.56
9-Oct-15	16.40	0.452	15.95	15.75	0.51	16.26
16-Oct-15	16.47	0.808	15.66	15.53	0.53	16.06
23-Oct-15	16.34	0.787	15.55	15.45	0.52	15.97

Source: US Energy Information Administration

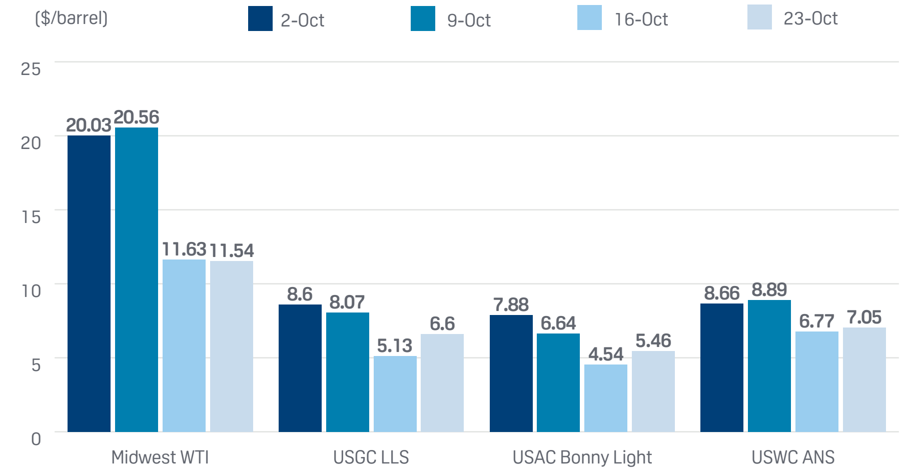
PLATTS PRICESCORE

Week ending		Oct 23	Oct 16
Crude oil ($/b):			
Dated Brent	($/b)	46.95	49.17
Dubai (First month)	($/b)	44.63	47.10
WTI (Cushing)			
(First month)	($/b)	45.09	46.91
ANS (California)	($/b)	46.95	49.21
Mars (MOC)	($/b)	41.14	42.53
Products:			
NWE (CIF cargoes)			
Naphtha (physical)	($/MT)	411.90	436.95
Diesel 10PPM NWE	($/MT)	449.55	461.20
Diesel 10ppm UK	($/MT)	451.05	462.70
Fuel Oil 3.5%	($/MT)	203.30	211.80
Jet Kerosene	($/MT)	466.00	474.80
Singapore (FOB cargoes)			
Kerosene			
(physical)	($/b)	57.96	59.62
Kerosene (paper)	($/b)	58.60	60.30
Gasoil 0.5%	($/b)	58.07	59.70
HSFO 180cst	($/MT)	237.83	246.53
LSWR			
mixed/cracked	($/b)	40.40	41.81*
C&F Japan			
Naphtha (physical)	($/MT)	445.65	465.30
US Atlantic Coast (Barge)			
RBOB 87	(cts/gal)	129.30	131.81
No. 6 1.0%			
(Cargo)	($/b)	35.17	36.09
Ethanol			
US Gulf (Pipeline)			
Unleaded 87	(cts/gal)	123.38	125.60
No. 2	(cts/gal)	134.13	136.05
US Gulf (Waterborne)			
No. 6 3.0%	($/b)	33.46	34.76
Average settlement prices:			
NY Mercantile Exchange			
Light Sweet Crude	($/b)	45.70	47.06
No. 2 oil	(cts/gal)	146.04	149.77
RBOB	(cts/gal)	128.75	133.24
Natural Gas	($/MMBtu)	24.17	25.02
IntercontinentalExchange			
Gasoil	($/MT)	446.65	461.90
Brent	($/b)	48.53	49.87

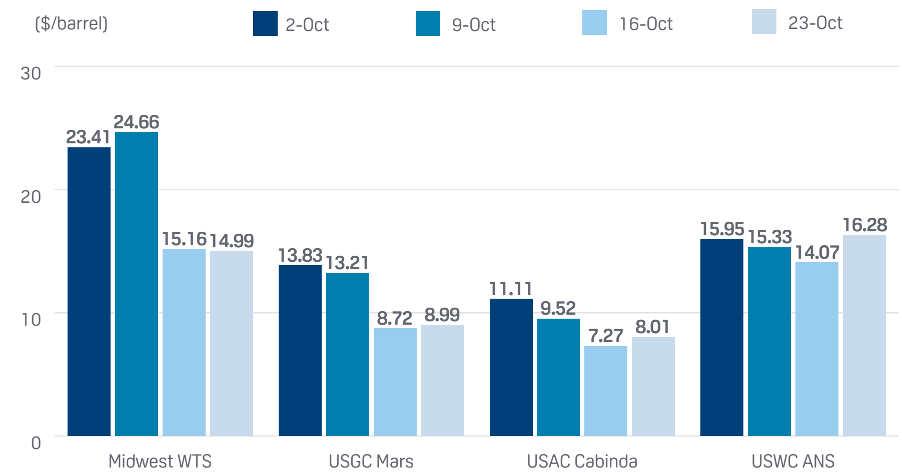
The averages in this table are the mean of Platts low and high daily quotations, or exchange settlements, calculated on a 5-day week basis, Monday through Friday. Saturdays and Sundays are excluded; *LSWR assessment is FOB Indonesia.

WEEKLY REFINERY MARGINS

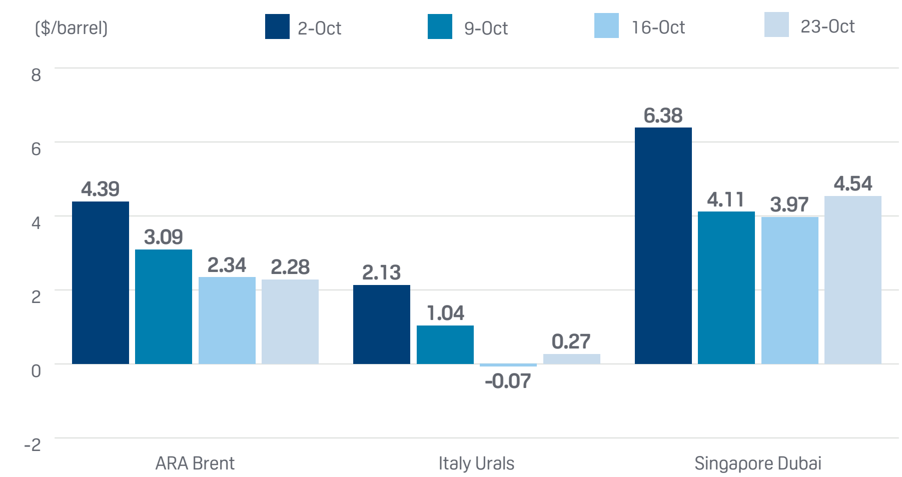
US CRACKING MARGINS



US COKING MARGINS



INTERNATIONAL CRACKING MARGINS



Refinery margins are derived from a weekly average of Platts daily spot assessments, and coking and cracking netbacks. For additional details, please contact Jeff Mower at jeff_mower@platts.com.

Source: Platts; Turner, Mason & Company

Occidental to pare down focus on Middle East

Houston—Occidental Petroleum is re-evaluating its operations in parts of the Middle East and North Africa, while it has agreed to sell its Williston Basin operation.

Oxy, a long-time player in the Middle East and North Africa, is mulling how to minimize its exposure to Bahrain, Yemen, Iraq, Libya and Yemen, Vicki Hollub, Vicki Hollub, Oxy's senior executive vice president, said during a quarterly conference call.

"We will comply with contract terms as we reduce our exposure [there] and expect capital investments to decline in 2016," Hollub said. "These actions will improve profitability and cash flow of our Middle East operations as we focus on Qatar, Abu Dhabi and Oman."

Oxy Chief Financial Officer Chris Stavros said the company took a $760 million non-cash charge on Iraq in the third quarter for reduced exposure to that non-core area.

Paring down or eventually even exiting some of those areas "will create a more focused domestic oil and gas organization, while minimizing exposure to areas we deem as having high political risk," Stavros said.

Middle East/North Africa production was 330,000 b/d of equivalent oil in the third quarter, an increase of 10% versus the previous quarter.

In addition, Oxy CEO Steve Chazen confirmed recent news reports that the company was selling its Bakken Shale operation. News reports claimed the buyer was private equity fund Lime Rock Partners.

The company's CEO, Steve Chazen, said the agreed-upon price was actually $600 million, not $500 million as reported in media reports.

"We just can't see a situation where we'd invest in it, given what we have in the Permian," he said in response to an analyst question on why company was selling the Williston Basin asset, which contains the giant Bakken Shale which is one of the US' premiere oil basins.

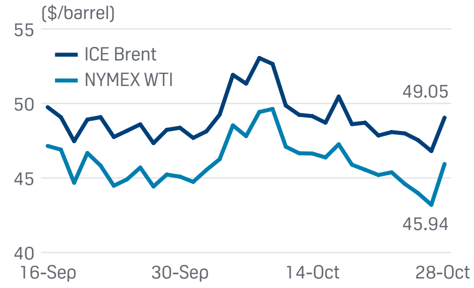
The sale is expected to close during the fourth quarter, Hollub said. Due to curtailed spending, Oxy's Williston production was reduced about 25% on an annual basis, she said.

"We expected [a production decline], given our limited capital investments in the basin," Hollub said. "Acreage in North Dakota, whether the acreage was Tier 1, 2 or 3, could not compete with Permian."

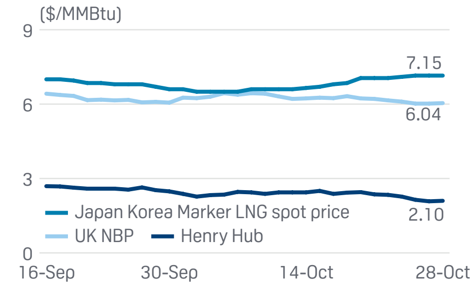
On the other hand, the Permian is profitable at oil prices under $60/b, she said. For example, in the western part of the Permian, the company has driven well costs down to $6.3 million from an average $10.9 million 2014, while drilling days have dropped to 19 per well in the third quarter from 43 days in 2014.

Chazen also said Oxy's Bakken Shale production, which yielded about 17,000 b/d of oil equivalent in the third quarter, would produce around 13,000 b/d a year from now. — *Starr Spencer*

NYMEX WTI, ICE BRENT CRUDE OIL FRONT MONTH DAILY SETTLES



GLOBAL GAS PRICE COMPARISON



Source: Platts, prices are rounded

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