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MIDYEAR FORECAST

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REGULAR FEATURES

COVER

In late 2011, *Chevron Australia began construction of the $29 billion Wheatstone Project, located 12 km west of Onslow on the Pilbara coast of Western Australia. The foundation project will consist of two LNG trains with a combined capacity of 8.9 million ton/year, plus a 200 terajoule/day domestic gas plant. The project has approval to expand to 25 million ton/year of LNG, with first cargo expected mid-2017. Oil & Gas Journal's Midyear Forecast special report, starting on p.20, takes a fresh look at this year's supply and demand for oil and gas. Photo from Chevron.*

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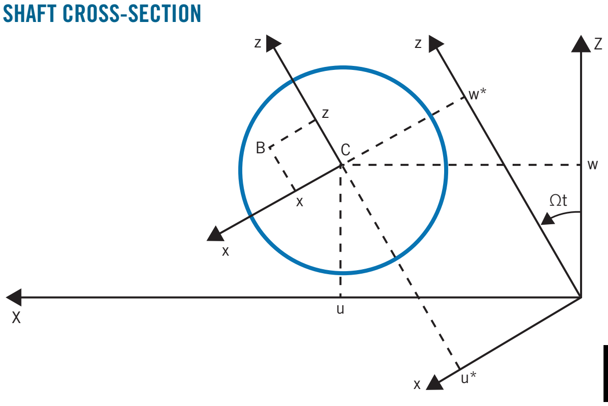
TECHNOLOGY...

SHAFT CROSS-SECTION

FIG. 1



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July 4, 2016

GENERAL INTEREST QUICK TAKES

OGUK: Industry at 'critical juncture' after EU vote

Responding to the UK vote to leave the European Union, Oil & Gas UK said the offshore oil and gas industry is "at a critical juncture." In a statement issued June 24, the trade association said, "We need to ensure the UK Continental Shelf continues to attract investment and be seen as a great place to do business."

OGUK said it had been neutral throughout the referendum campaign and respects the democratic decision of the UK people. "We hope that all those involved will now come together and work constructively to make this transition as smooth as possible and we ask that the UK government clearly outlines the process which will follow to minimize any potential period of uncertainty. We will be consulting closely with our members in the coming weeks and look forward to engaging with all governments to play our part in this process," OGUK said.

Oil, gas penalties lifted to adjust for inflation

The US Bureau of Land Management and Bureau of Safety and Environmental Enforcement separately increased penalties for oil and gas operators to adjust for inflation. BLM's interim final rule more than doubles fines for not taking corrective action and for major violations. BSEE's interim final rule increases the maximum daily civil fine by $2,017 to $42,017.

Both US Department of the Interior agencies acted to comply with the 2015 Federal Civil Penalties Inflation Adjustment Improvements Act. BSEE also made its adjustment for inflation under the 1953 Outer Continental Shelf Lands Act. The changes are effective 30 days after the notices appear in the Federal Register on June 28. Comments will be accepted for 60 days following the publications.

Total awarded 30% interest in Qatar's Al-Shaheen field

Total SA has been awarded 30% interest by Qatar Petroleum (QP) in the concession covering the offshore Al-Shaheen oil field.

The agreement is for a 25-year term beginning July 14, 2017, when the current 25-year production-sharing agreement with operator Maersk Oil AS expires. The concession will be operated by a new company held 70% by QP and 30% by Total.

Located in Qatari waters 80 km north of Ras Laffan, Al-Shaheen began production in 1994 and currently flows 300,000 b/d of oil. The existing development consists of 30 platforms and 300 wells, and production from the field represents about half of Qatar's oil output. QP and Maersk Oil produced the 1 billionth bbl from the field in 2010 (OGJ Online, July 20, 2010).

QP in July 2015 invited several international oil companies to participate in a tender process for future development of Al-Shaheen. Maersk Oil earlier this year submitted its bid in the tender, but the firm says a minority stake in the new joint venture under the terms offered by QP would have created a marginal impact on Maersk Group's earnings in the years ahead.

Total has been present in Qatar since 1936, and currently holds 20% interest in the upstream portion of Qatargas 1, 10% in the Qatargas 1 liquefaction plant JV, 24.5% in Dolphin Energy Ltd., and 16.7% in the Qatargas 2 Train 5 JV. Total's Qatari production averaged 134,000 boe/d in 2015.

Total also is a partner in the Laffan refinery with 10% interest and in the Qapco 20% and Qatofin 48.6% petrochemical plants. Outside the country, the firm's strategic partnership with Qatar extends to Africa, where QP International holds 15% stake in Total E&P Congo (OGJ Online, May 22, 2013). OGJ

EXPLORATION & DEVELOPMENT QUICK TAKES

Egdon, Union Jack sign farmout for UK onshore license

Egdon Resources PLC has farmed out 8.33% of its onshore UK license PEDL182 to Union Jack Oil PLC. The license is in Lincolnshire to the immediate north of PEDL180, where Union Jack farmed into the Wressle-1 exploration well (8.33%).

Under the terms of the farmout, Union Jack will earn 8.33% interest in the remainder of PEDL182 beyond the Wressle discovery in return for covering 12.495% of the cost of a future exploration well to evaluate the Broughton North prospect.

Partners for PEDL180 and PEDL182 include operator Egdon Resources UK Ltd. with 25% interest, Celtique Energie Petroleum Ltd. 33.33%, Europa Oil & Gas Ltd. 33.34%, and Union Jack 8.33%.

Egdon participated in drilling the Keddington-5 sidetrack and the Laughton-1 exploration wells this year, and the operator has plans for two more—Biscathrope and North Kelsey—in PEDL253 and PEDL241, respectively (OGJ Online, Feb. 12, 2016).

Due to the conventional nature of the targeted reservoirs, hydraulic fracturing has not been deployed in the company's com-

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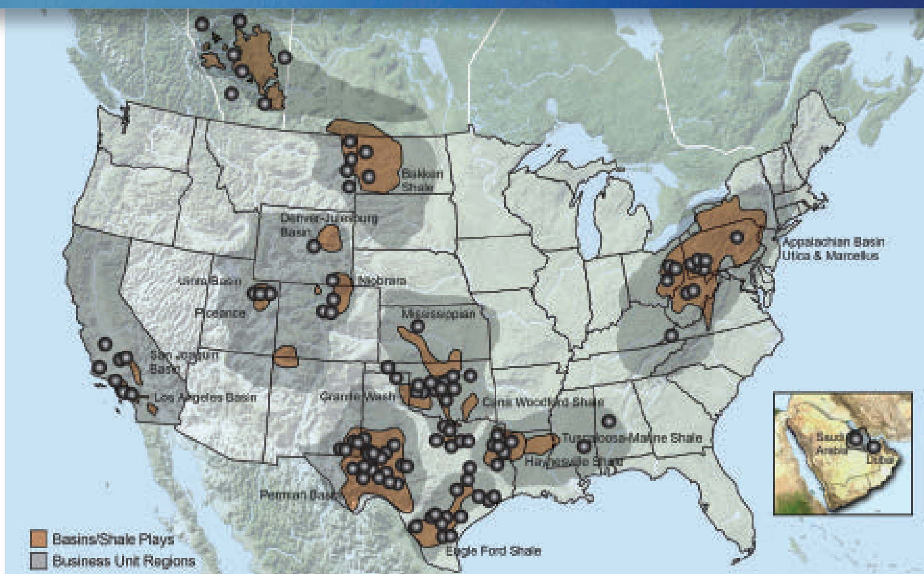

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U.S. ACTIVE RANKING	#2	#1	#1	#2	#1	
SERVICES OFFERED						
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SOUTH TEXAS	✓	✓	✓	✓	✓	✓
MID-CON	✓	✓	✓	✓	✓	✓
ROCKIES	✓	✓	✓	✓	✓	✓
NORTH EAST	✓	✓	✓	✓	✓	✓
CALIFORNIA		✓	✓	✓	✓	✓

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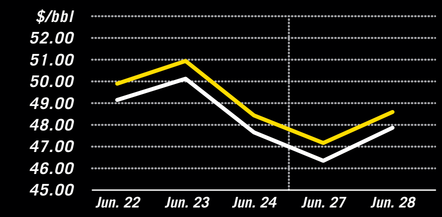
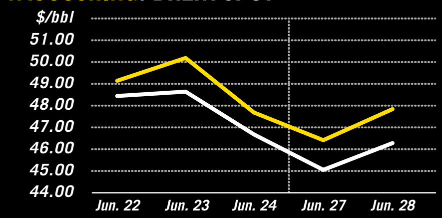
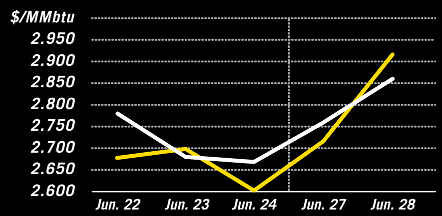
ICE BRENT / NYMEX LIGHT SWEET CRUDE



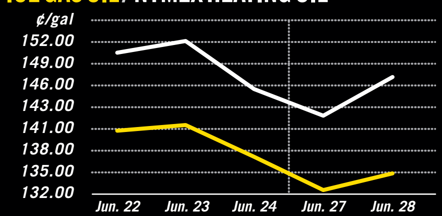
WTI CUSHING / BRENT SPOT



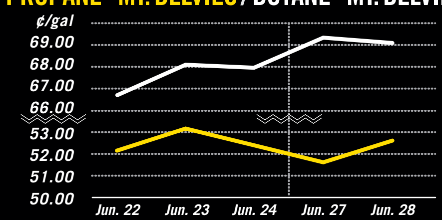
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



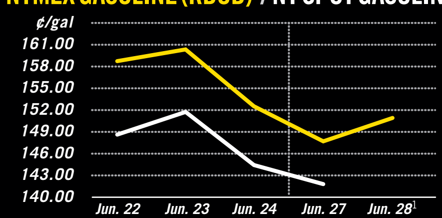
ICE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[2] / NY SPOT GASOLINE[3]



[1]Not available [2]Reformulated gasoline blendstock for oxygen blending
[3]Nonoxygenated regular unleaded

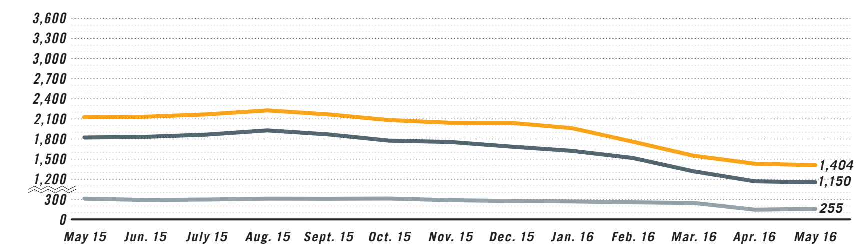
US INDUSTRY SCOREBOARD — 7/4

Latest week 6/17	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Product supplied, 1,000 b/d						
Motor gasoline	9,715	9,352	3.9	9,350	8,985	4.1
Distillate	3,781	3,841	(1.6)	3,746	4,021	(6.8)
Jet fuel	1,668	1,627	2.5	1,580	1,543	2.4
Residual	306	217	41.0	299	208	43.8
Other products	4,776	4,792	(0.3)	4,929	4,806	2.6
TOTAL PRODUCT SUPPLIED	20,246	19,829	2.1	19,904	19,563	1.7
Supply, 1,000 b/d						
Crude production	8,718	9,597	(9.2)	8,981	9,372	(4.2)
NGL production[2]	3,419	3,161	8.2	3,401	3,094	9.9
Crude imports	7,901	6,957	13.6	7,820	7,219	8.3
Product imports	2,273	2,010	13.1	2,114	2,062	2.5
Other supply[2,3]	2,116	1,975	7.1	2,036	2,306	(11.7)
TOTAL SUPPLY	24,427	23,700	3.1	24,352	24,053	1.2
Net product imports	(1,456)	(1,440)	—	(1,780)	(1,557)	—
Refining, 1,000 b/d						
Crude runs to stills	16,361	16,593	(1.4)	16,077	16,003	0.5
Input to crude stills	16,579	16,809	(1.4)	16,279	16,233	0.3
% utilization	90.6	93.4	—	89.4	90.5	—

Latest week 6/17	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	530,626	531,543	(917)	462,993	67,633	14.6
Motor gasoline	237,631	237,004	627	218,494	19,137	8.8
Distillate	152,314	152,163	151	135,428	16,886	12.5
Jet fuel–kerosine	41,388	42,198	(810)	39,731	1,657	4.2
Residual	40,275	40,782	(507)	39,816	459	1.2
Stock cover (days)[4]			Change, %		Change, %	
Crude	32.4	32.6	(0.6)	28.1	15.3	
Motor gasoline	24.5	24.6	(0.4)	23.4	4.7	
Distillate	40.3	39.8	1.3	35.3	14.2	
Propane	81.2	77.1	5.3	88.8	(8.6)	
Futures prices[5] **6/24**			Change		Change	Change,%
Light sweet crude ($/bbl)	49.02	47.91	1.11	59.89	(10.87)	(18.1)
Natural gas, $/MMbtu	2.71	2.60	0.11	2.85	(0.14)	(4.8)

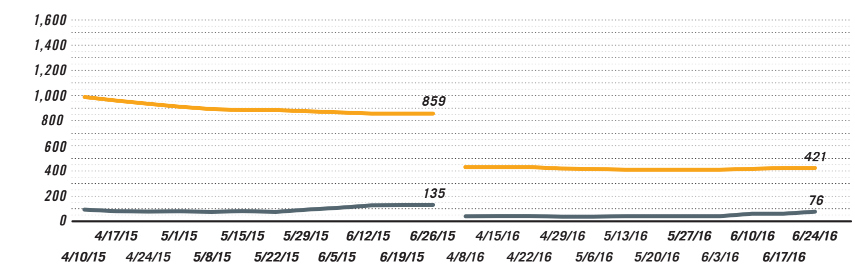
[1]Based on revised figures. [2]OGJ estimates. [3]Includes other liquids, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average of daily closing futures prices.
Source: Energy Information Administration, Wall Street Journal

BAKER HUGHES INTERNATIONAL RIG COUNT: TOTAL WORLD / TOTAL ONSHORE / TOTAL OFFSHORE



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

pletion strategy. Lincolnshire has been associated with UK's shale potential in the Carboniferous Pendleian, which is 2,000 m deep and has been identified as prospective in the nearby Bowland basin in northwest England (OGJ Online, Jan. 16, 2013).

Finder Exploration awarded Timor Sea permit

Finder Exploration Pty. Ltd., Perth, has been awarded a permit in the Vulcan subbasin in the western Timor Sea.

Designated AC/P61, the permit lies in 125-340 m of water and 250 km offshore northwestern Western Australia, 650 km from Darwin. The permit contains the Gem prospect, which has been delineated as a horst block, 190 m of vertical relief, and is a look-alike to the structure that contains the now depleted Jabiru-Challis oil fields to the south.

There are also numerous oil discoveries in the surrounding area, including Tenacious oil field immediately to the west, Audacious oil field to the east, and Oliver oil and gas field to the north. All of these are yet to be developed.

In addition, the Cash-Maple gas field complex lies 30 km west of the new permit.

Finder, which has 100% ownership of AC/P61, plans to reprocess existing 3D seismic data to include the adjacent offset well ties from Oliver, Tenacious, and Audacious fields.

Apart from Gem, other leads in the permit include the Douglad up-dip lead and a potential extension of Tenacious into the permit.

Morocco lets tender for Gharb basin acreage

Morocco's Office National des Hydrocorbures et des Mines (ONHYM) has set an Aug. 19 deadline for acreage in the Gharb Centre area of the greater Gharb basin in the northern portion of the country. The tender includes 1,362 sq km of acreage, excluding three zones where ONHYM fields and infrastructure exist.

Exploration in the region has increased since the early 2000s. ONHYM retains 1,620 km of 2D seismic and 527 sq km of 3D seismic acquired from 18 wells drilled in the area within the last 15 years.

Gulfsands Petroleum PLC completed its Dardara Southeast 1 well in the area in January 2015. The well tested at an average of 7.1 MMcfd through a 32⁄64-in. choke with a stable wellhead pressure of 1,230 psi (OGJ Online, Jan. 12, 2015).

ONHYM will operate its data room July 1-29 and will open sealed bids on prospective acreage on Aug. 25, the company said. OGJ

DRILLING & PRODUCTION QUICK TAKES

IHS: Oil sands output to rise 1 million bbl in 2016-25

Oil sands production is forecast to increase nearly 1 million b/d by 2025, driven primarily by the expansion of existing facilities with more attractive economics, according to IHS. Although that pace is below historical levels, it will keep Canada among the largest sources of global oil supply growth, IHS notes.

Construction of projects that started before the fall in oil prices—and where significant capital has already been invested—will be complete by 2018, after which construction could cease.

The subsequent completion and then ramp up of these facilities will drive growth to 2020. IHS expects more than 75% of future activity to come from the expansion of existing facilities.

"As we saw with tight oil producers, when prices collapsed, they focused their activity on the most productive areas," said Kevin Birn, director for IHS Energy. "We expect a similar experience to play out in the Canadian oil sands. However, given the nature of the long lead times, we expect this will play out over the coming decade."

An additional factor supporting future oil sands growth is the lack of production declines from existing oil sands projects. If oil sands facilities are maintained, their production levels do not decline, which is unique compared with other types of oil production globally. This means that each investment in new oil production results in net growth, IHS says.

Rystad: US DUC inventory dropping by yearend

Rystad Energy expects US unconventional oil well completions to outpace drilling activity during the second half, resulting in 800 fewer drilled but uncompleted (DUC) horizontal wells.

These completions are expected to provide an additional 300,000-350,000 b/d by Dec. 31. The additional output will be more than sufficient to balance the base production decline, Rystad Energy said. The existing inventory of 4,000 DUCs is estimated to hold close to 2 billion bbl of oil reserves.

"Research shows that operators are now starting to complete wells that have previously been put on hold deliberately," said Artem Abramov, Rystad Energy senior analyst and product manager. "This comes as more than 90% of the accumulated oil DUC inventory can be commercially completed at a [West Texas Intermediate price] of $50/bbl."

Pemex lets contract for Abkatun-A2 platform

Pemex Exploracion y Produccion has let a $454-million contract to McDermott International Inc. for the engineering, procurement, construction, and installation of the Abkatun-A2 platform. The platform will be installed in 124 ft of water in the Bay of Campeche and will provide replacement and expansion capabilities to the existing Ku-Maloob-Zaap, Cantarell, and Ayatsil facilities (OGJ Online, Jan. 5, 2015).

McDermott will manufacture the structures at its facility in Altamira, Tamaulipas state, Mexico. Engineering and procurement activities will begin immediately, with fabrication scheduled to begin late this year. Offshore activities are scheduled for 2018, with handover to Pemex in fourth-quarter 2018.

McDermott is expected to use the Derrick Barge 50 and the Intermac 650 float-over installation vessel.

Contract let for third Peregrino platform

South Atlantic Holding, a joint venture of Statoil ASA and Sinochem, is proceeding with the second phase of development of Peregrino heavy oil field offshore Brazil (OGJ Online, Feb.

27, 2015). Working for Kiewit Offshore Services, Wood Group Mustang will provide detailed engineering and design as well as procurement services for Wellhead Platform C, which Statoil estimates will access 250 million boe of reserves.

Wood Group Mustang completed front-end engineering and design for Platform C last year and designed wellhead platforms A and B in the first phase of development.

The field is in about 100 m of water 85 km offshore in the Campos basin. Production began in April 2011 and reached its plateau rate of 100,000 b/d in 2013. The 13° gravity, 1.89 wt % sulfur crude flows into a floating production, storage, and offload vessel.

Greater Enfield oil field development advances

The Woodside Petroleum Ltd.-Mitsui E&P Australia Pty. Ltd. joint venture has given final approval for the $1.9-billion Greater Enfield oil development offshore Western Australia.

Located in the Carnarvon basin about 60 km off Exmouth, the project will involve development of the Laverda Canyon, Norton-over-Laverda, and Cimatti oil accumulations (OGJ Online, Sept. 17, 2015).

The first two are in production licence WA-59-L, while Cimatti lies in WA-28-L.

The oil reserves will be developed and produced via a 31-km subsea tie-back to the Ngujima-Yin floating production, storage, and offloading vessel.

Woodside CEO Peter Coleman said the development has been made possible by recent advances in technology and the use of the existing FPSO infrastructure.

Greater Enfield will comprise six subsea production wells and six water-injection wells, supported by subsea multiphase booster pumps in the Laverda area and gas lift in the Cimatti area. Total 2P reserves in the three accumulations are thought to be 69 million boe. First oil is scheduled for mid-2019.

Woodside has 60% and operatorship of the project, with Mitsui holding the remaining 40%. OGJ

PROCESSING QUICK TAKES

Braskem fully commissions Mexican petchem complex

Braskem Idesa SAPI, a 75-25 joint venture of Braskem SA, Sao Paulo, and Groupo Idesa SA de CV, Mexico City, has fully commissioned its long-planned Etileno XXI petrochemical complex in the Coatzacoalcos-Nanchital region of the Mexican state of Veracruz (OGJ, July 7, 2014, p. 90). The company inaugurated the complex on June 22.

Initially entering precommissioning and testing phases of equipment and systems in early 2015, the $5.2-billion Etileno XXI project features an ethane cracker that now produces a combined 1.05 million tonnes/year of ethylene and polyethylene for clients primarily in Mexico, the US, Europe, Asia, and Central and South America.

Alongside the gas cracker, which uses Technip SA's process technology and receives 66,000 b/d of ethane feedstock under a 20-year supply agreement with state-owned Petroleos Mexicanos, the complex houses the following installations:

- Two high-density polyethylene (HDPE) plants with capacities of 400,000 tpy and 350,000 tpy, respectively, both based on technology from Ineos.
- A 300,000-tpy low-density polyethylene (LDPE) plant that uses technology from LyondellBassell.
- Storage, waste treatment, and utilities.
- A logistics platform for shipment of 1 million tpy of polyethylene via rail, truck, or bagged.
- Administrative, maintenance, control room, and other buildings.

Utility installations at the complex include a 175-Mw combined-cycle power and steam cogeneration plant initially planned as a 150-Mw plant, Braskem said.

Braskem, a subsidiary of Odebrecht SA, said Etileno XXI aligns with the company's strategy to expand operations in the Americas as well as increase its access to more competitively priced North American gas-based feedstock supplies.

Braskem Idesa's full commissioning of the complex follows the start of HDPE production at the site in early April (OGJ Online, Apr. 8, 2016).

Rosneft, Sinopec plan petchem complex for East Siberia

Russia's OJSC Rosneft and China Petrochemical Corp. (Sinopec) have entered a framework agreement to jointly develop a grassroots natural gas processing and petrochemical complex in East Siberia.

Signed on June 25, the agreement furthers a December 2015 memorandum of understanding signed by the companies to cooperate on petrochemical projects, Rosneft said.

Alongside providing for a prefeasibility study on construction and operation of the joint project, the agreement stipulates for selection of processing technology to be used at the complex and for selection of a project management consultant (PMC).

The companies additionally agreed to identify potential competitive challenges as well as a timeframe to address them before moving forward on front-end engineering design, Rosneft said.

Pending favorable results of preliminary activities to be completed as part of the framework agreement, Rosneft and Sinopec will establish a joint venture to advance the project sometime in 2017.

Details regarding selection of technology licensing, PMC, and FEED were not disclosed.

Designed to help meet the growing demand for polyethylene and polypropylene in Russia and China, the proposed complex would have a capacity to process 5 billion cu m/year to produce 3 million tonnes/year of polymers and petrochemical products primarily for Russian and Chinese markets.

To be located in Boguchany district of Russia's Krasnoyarsk Territory, the complex would use feedstock supplied from Rosneft's oil and gas fields in eastern Siberia's Yurubcheno-Takhomsky cluster, Rosneft said.

Under the original MOU for the project, the firms planned to execute a detailed prefeasibility and concept-design study for an integrated 10 billion-cu m/year complex to be built in Boguchany and Angarsk that would produce 3 million tpy of ethylene and about 6 million tpy of polymers and other petrochemicals, according to a Dec. 17, 2015, news release from Rosneft.

Aramco, SABIC plan crude-to-chemicals complex study

Saudi Aramco and Saudi Arabian Basic Industries Corp. plan to conduct a joint feasibility study for development of a fully integrated crude oil-to-chemicals complex in Saudi Arabia.

The proposed plant would use a crude oil-to-chemicals process derived from improved refining technology that mixes configurations with conversion technologies to create a petrochemical complex capable of maximizing chemical yield, transforming and recycling byproducts, driving efficiencies of scale and resource optimization, and diversifying Saudi Arabia's petrochemical feedstock mix, they said.

Pending a positive outcome of the study, Aramco and SABIC plan to establish a joint venture to advance the project, which if approved, would fulfill Saudi Vision 2030 goals for the downstream sector (OGJ Online, June 1, 2016).

The companies did not disclose further details regarding the proposed project.

Announcement of the joint study follows a May 21 joint release from Aramco and SABIC quashing speculative news reports that the companies were planning to merge their petrochemicals businesses.

While the companies clarified they had no intention to pursue a merger, they did confirm they would continue to explore partnership opportunities that would help to expand and diversify Saudi Arabia's economy. OGJ

TRANSPORTATION QUICK TAKES

Energy Transfer declares Williams deal dead

Energy Transfer Equity LP (ETE), Dallas, declared the death of its merger agreement with Williams Cos. Inc., Tulsa, after Williams shareholders approved the deal.

ETE has been trying to cancel the $37.7-billion transaction, announced last September, over continuing objections of the company that once resisted its overtures (OGJ Online, Sept. 28, 2015).

In the announcement of its shareholders' vote on June 27, Williams said it was appealing to the Delaware Supreme Court a June 24 Delaware Court of Chancery opinion upholding ETE's right to escape the deal.

The contested opinion said ETE was contractually entitled to end the merger if its legal advisers couldn't deliver a required tax opinion by June 28. The opinion wasn't delivered.

ETE acknowledged the Williams appeal in its June 29 announce-ment that it was ending the merger agreement, which called for Williams to become part of ETE affiliate Energy Transfer Corp. LP.

Williams rejected ETE's first, unsolicited takeover bid in June 2015, an all-equity transaction valued at $53.1 billion. The later proposal gave Williams shareholders options to receive shares or cash.

Williams issued a statement disputing ETE's right to end the merger, saying it will seek monetary damages. It said ETE breached the agreement "by, among other reasons, failing to cooperate and use necessary efforts to satisfy the conditions to closing." Williams said it "recognizes the practical fact that ETE has refused to close the merger" and will focus on operations.

Obama signs 2016 pipeline safety reauthorization bill

US President Barack Obama signed S. 2276, the 2016 pipeline safety reauthorization bill, on June 21. The bill became law more than a week after the US Senate approved a version with House amendments and sent it to the White House (OGJ Online, June 14, 2016).

The measure requires the US Pipeline & Hazardous Materials Safety Administration to set federal minimum safety standards for underground natural gas storage facilities, and allows states to go above those standards for intrastate requirements.

It also authorizes emergency order authority that is tailored for pipelines, updates regulations for certain LNG facilities to better match changing technology and markets, and increases inspection requirements for certain underwater oil pipelines.

The law also creates a working group of PHMSA, states, industry stakeholders, and safety groups to develop recommendations on how to create an information sharing system to improve safety outcomes, and gives PHMSA authority to study the feasibility of a national integrated pipeline safety database to have a clearer picture of federal and state safety oversight efforts.

Interstate Natural Gas Association of America Pres. Donald F. Santa expressed appreciation for Congress and the administration's work on the new law. "Members of the of the interstate natural gas pipeline industry are already hard at work building on Congress's efforts to enhance the nation's pipeline through an aggressive safety program, anchored with an over-arching goal of zero pipeline incidents," he said.

Riverstone to acquire 50% stake in Utopia project

Riverstone Investment Group LLC will become a 50-50 partner with Kinder Morgan Inc. in the $500-million Utopia pipeline project in Ohio. To acquire its stake, Riverstone agreed to an upfront cash payment reimbursing KMI for its 50% share of prior capital expenditures related to the project. Riverstone also agreed to fund its share of future capital expenditures necessary to complete construction and commissioning.

The common carrier project, supported by a long-term contract with Nova Chemicals Corp., will include 215 miles of 12-in. pipeline constructed entirely within Ohio from Harrison County to Fulton County (OGJ Online, Sept. 4, 2014). The pipeline will connect with an existing KMI pipeline and associated facilities to transport ethane and ethane-propane mixtures to petrochemical companies in Ontario. OGJ

■ *Denotes new listing or a change in previously published information.*

JULY 2016

World Congress on Petroleum & Refinery, Brisbane, web site: petroleum.omicsgroup.com/ **21-23.**

AUGUST 2016

SPE/AAPG/SEG Unconventional Resources Technology Conference (URTeC), San Antonio, web site: www.urtec.org/ **1-3.**

Society of Petroleum Engineers (SPE) Nigeria Annual International Conference & Exhibition, Lagos, web site: connect.spe.org/spenc/naice/naice2016/ **2-4.**

NAPE Expo, Houston, web site: napeexpo.com/shows/about-the-show/houston/ **10-11.**

EnerCom's The Oil & Gas Conference-2016, Denver, web site: www.theoilandgasconference.com/ **14-18.**

4th International Conference on Petroleum Engineering, London, web site: www.petroleumengineering.conferenceseries.com/ **15-17.**

IADC/SPE Asia Pacific Drilling Technology Conference & Exhibition, Singapore, web site: www.spe.org/events/apdt/2016/ **22-24.**

GeoBaikal 2016: Expand Horizons, Irkutsk, Russia, web site: www.eage.org/event/index.php?eventid=1433&Opendivs=s3 **22-26.**

SPE Asia Pacific Hydraulic Fracturing Conference, Beijing, web site: www.spe.org/events/aphf/2016/pages/general/call_for_papers.php **24-26.**

2nd International Congress & Expo on Biofuels & Bioenergy, Sao Paulo, web site: biofuels-bioenergy.conferenceseries.com/ **29-31.**

15th European Conference on the Mathematics of Oil Recovery (ECMOR XV), Amsterdam, web site: www.eage.org/event/index.php?eventid=1416&Opendivs=s3 **Aug. 29-Sept. 1.**

Offshore Northern Seas, Stavanger, web site: www.tofairs.com/expo.php?fair=103366 **Aug. 29-Sept. 1.**

2nd International Congress & Expo on Biofuels & Bioenergy, Sao Paulo, web site: biofuels-bioenergy.conferenceseries.com/ **29-31.**

SEPTEMBER 2016

Second Applied Shallow Marine Geophysics Conference, Barcelona, web site: www. Eage.org/event/index.php?eventid=1421&Opendivs=s3 **4-8.**

EAGE First Conference on Geophysics for Mineral Exploration and Mining, Barcelona, web site: www.eage.org/event/?eventid=1420 **4-8.**

European Association of Geoscientists & Engineers (EAGE) First Conference on Geophysics for Mineral Exploration & Mining, Barcelona, web site: www.eage.org/event/index.php?eventid=1420&Opendivs=s3 **4-8.**

22nd European Meeting of Environmental and Engineering Geophysics, Barcelona, web site: www.eage.org/event/index.php?eventid=1419&Opendivs=s3 **4-8.**

SPE Offshore Europe, Aberdeen, web site: www.offshore-europe.co.uk/ **5-8.**

SPE Intelligent Energy Conference, Aberdeen, web site: www.intelligentenergyevent.com/ **6-8.**

NACE Egypt Corrosion Conference, Cairo, web site: egyptcorrosion.nace.org/ **6-8.**

AAPG SEG International Conference & Exhibition 2016, Cancun, web site: www.aapg.org/publications/blogs/events/article/articleid/23667/increase-your-exposure-exhibition-and-sponsorship-opportunities-available/ **6-9.**

AAPG SEG 2016 International Conference & Exhibition, Cancun, web site: www.aapg.org/events/conferences/ice/announcement/articleid/20311/aapg-seg-2016-international-conference-exhibition-cancun **6-9.**

23rd Annual India Oil & Gas Review Summit & International Exhibition, Mumbai, web site: www.oilgas-events.com/india-oil-gas **9-10.**

International Conference on Chemical Engineering, Phoenix, web site: chemicalengineering.conferenceseries.com/ **12-14.**

Geomodel 2016, Gelendzhik, Russia, web site: www.eage.org/event/index.php?eventid=1448&Opendivs=s3 **12-15.**

ESOPE International Exhibition & Symposium for the Pressure Equipment Industry, Paris, web site: www.esope-paris.com/ **13-15.**

SPE Deepwater Drilling & Completions Conference, Galveston, Tex., web site: www.spe.org/events/ddc/2016/ **14-15.**

2nd Annual IoT in Oil & Gas, Houston, web site: energyconferencenetwork.com/iot-in-oil-and-gas-2016/**14-15.**

Rio Oil & Gas Expo & Conference, Rio de Janeiro, web site: www.whereinfair.com/rio-oil-gas-expo/rio-de-janeiro/2016-Sep/ **14-16.**

Turbomachinery & Pump Users Symposium, Houston, web site: tps.tamu.edu/event-info **15-17.**

Iran International Petroleum Congress (IIPC), Tehran, web site: www.iranpetroleumcongress.com/ **19-21.**

The CWC World LNG & Gas Series: Asia Pacific Summit, Singapore, web site: asiapacific.cwclng.com/ **20-23.**

SPE Liquids-Rich Basins Conference—North America, Midland, Tex., web site: www.spe.org/events/lrbc/2016/ **21-22.**

Eastern Section, American Association

of Petroleum Geologists 2016 Annual Meeting, Lexington, Ky., web site: www.esaapgmtg.org/ **25-27.**

Corrosion Technology Week 2016, Houston, web site: ctw.nace.org/ **25-29**.

SPE Annual Technical Conference & Exhibition (ATCE), Dubai, web site: www.spe.org/atce/2016/ **26-28.**

SPE Annual Technical Conference & Exhibition, Dubai, web site: www.spe.org/events/calendar/ **26-28.**

3rd Annual Unconventional Production & Well Site Facilities Design, Onshore 2016, Houston, web site: www.facilities-design-onshore.com/program/ **28-29.**

Global Oil & Gas South East Europe & Mediterranean Conference, Athens, web site: www.oilgas-events.com/Global-Oil-Gas-Black-Sea-Mediterranean-Conference/ **28-29.**

International Conference on Geophysics, Vancouver, web site: geophysics.conferenceseries.com/ **29-30.**

OCTOBER 2016

ICOGPE 2016: 18th International Conference on Oil, Gas & Petrochemical Engineering, Barcelona, web site: www.waset.org/conference/2016/10/barcelona/ICOGPE **3-4.**

Kazakhstan International Oil & Gas Conference (KIOGE) 2016, Almaty, Kazakhstan, web site: kioge.kz/en/conference/about-conference **5-6.**

USEA 9th Annual Energy Supply Forum, Washington, DC, web site: https://www.usea.org/event/usea-9th-annual-energy-supply-forum **6.**

International Conference on Geosciences, Orlando, web site: geosciences.conferenceseries.com/ **6-7.**

Cyber Security for Critical Assets LATAM, Rio de Janeiro, web site: www.criticalcybersecurity.com/latam/ **6-7.**

23rd World Energy Conference, Istanbul, web site: www.wec2016istanbul.org.tr/ **9-13.**

The 2016 API Tank, Valves, & Piping Conference & Expo, Las Vegas, web site: www.api.org/events-and-training/calendar-of-events/2016/tvp **10-13.**

SEG International Exhibition and 86th Annual Meeting, Dallas, web site: www.seg.org/web/annual-meeting-2016/ **16-21.**

The 8th Saudi Arabia International Oil & Gas Exhibition (SAOGE), Dammam, web site: www.saoge.org/ **17-19.**

SPE Well Construction Fluids 2025 Forum: Meeting the Challenges, Dubai, web site: www.spe.org/events/16fmel/ **17-19.**

2016 Fall Committee on Petroleum Measurement Standards Meeting, Los Angeles, web site: www.api.org/Events-and-Training/Calendar-of-Events/2016/fallcopm **17-21.**

The 37th Oil & Money Conference, London, web site: www.oilandmoney.com/ **18-19.**

Society of Petroleum Engineers (SPE) African Health, Safety, Security, Environment & Social Responsibility Conference & Exhibition, Accra, Ghana, web site: www.spe.org/events/hsea/2016/ **18-20.**

SPE Latin America & Caribbean Heavy Oil & Extra Heavy Oil Conference, Lima, web site: www.spe.org/events/laho/2016/ **19-20.**

Arctic Technology Conference (ATC), St. John's, Newfoundland & Labrador, web site: www.arctictechnologyconference.org/ **24-26.**

SPE Russian Petroleum Technology Conference & Exhibition, Moscow, web site: www.spe.org/events/rpc/2016/ **24-26.**

SPE North America Artificial Lift Conference & Exhibition, The Woodlands, Tex., web site: www.spe.org/events/alce/2016/ **25-27.**

SPE Asia Pacific Oil & Gas Conference & Exhibition (APOGCE), Perth, web site: www.spe.org/events/apogce/2016/ **25-27.**

The 10th Element Oilfield Engineering with Polymers Conference, London, web site: oilfieldpolymers.nace.org/ **25-27.**

Bottom of the Barrel Technology Conference (BBTC) Middle East & Africa 2016, Manama, web site: www.bbtc-mena.biz **26-27.**

Gulf Safety Forum (GSF) 2016, Doha, web site: www.gulfsafetyforum.com/ **30-31.**

23rd Africa Oil Week Africa Upstream Conference 2016, Cape Town, web site: www.oilgas-events.com/Find-an-Event/Africa-Oil-Week/ **Oct 31-Nov 04.**

NOVEMBER 2016

2nd International Conference & Expo on Oil & Gas, Istanbul, web site: oil-gas.omicsgroup.com/ **2-3.**

The Abu Dhabi International Petroleum Exhibition & Conference, (ADIPEC), Abu Dhabi, web site: www.adipec.com/ **7-10.**

RefComm Mumbai 2016, Mumbai, web site: refiningcommunity.com/refcomm-mumbai-2016/ **7-11.**

International Petroleum Technology Conference (IPTC), Bangkok, web site: www.iptcnet.org/pages/about/future-dates.php **14-16.**

4th East Africa Oil & Gas Summit & Exhibition, Nairobi, web site: eaogs.com/**15-17.**

21st Annual Oil & Gas of Turkmenistan (OGT) Conference 2016, Ashgabat, web site: ogt.theenergyexchange.co.uk/ **16-17.**

5th International Conference on Petroleum Geology & Petroleum Industry, Dubai, web site: petroleumgeology.conferenceseries.com/ **24-25.**

Oil & Gas Safety & Health Conference 2016 OSHA Exploration & Production, Houston, web site: www.oshasafetyconference.org/Events/ugm/Osha2016/

default.aspx **29-30.**

Society of Petroleum Engineers (SPE) Middle East Artificial Lift Conference & Exhibition, Manama, Bahrain, web site: www.spe.org/events/meal/2016/ **Nov. 30-Dec. 1.**

DECEMBER 2016

5th World Congress on Petrochemistry & Chemical Engineering, Phoenix, web site: www.petrochemistry.omicsgroup.com/ **5-7.**

Third EAGE Integrated Reservoir Modelling Conference, Kuala Lumpur, web site: www.eage.org/event/index.php?eventid=1477&Opendivs=s3 **5-7.**

OpEx MENA 2016—Operational Excellence in Oil, Gas & Petrochemicals, Abu Dhabi, web site: www.opex.biz **5-7.**

Oil & Gas Supply Chain Procurement, Houston, web site: energyconference.network.com/oil-gas-supply-chain-procurement-2016/ **6-7.**

SPE Heavy Oil Conference & Exhibition, Kuwait City, web site: www.spe.org/events/hoce/2016/ **6-8.**

Green Forum: Oil, Gas & Petrochemicals, Abu Dhabi, web site: www.greenforum.ae **8.**

ICOGPE 2016: 18th International Conference on Oil, Gas & Petrochemical Engineering, Dubai, web site: www.waset.org/conference/2016/12/dubai/ICOGPE/home/ **26-27**.

JANUARY 2017

Global Oil & Gas Middle East & North Africa Conference, Cairo, web site: www.oilgas-events.com/Find-an-Event/Global-Oil-Gas-Middle-East-North-Africa-(1) **24-26.**

SPE Hydraulic Fracturing Technology Conference, The Woodlands, Tex., web site: www.spe.org/events/hftc/2017/ **24-26.**

NACE International Pipeline Coating Technology Conference, Houston, web site: pipelinecoating.nace.org/ **24-26.**

Offshore West Africa, Lagos, web site: www.offshorewestafrica.com/index.html **24-26.**

2017 API Inspection Summit, Galveston, Tex., web site: www.api.org/Events-and-Training/Calendar-of-Events/2017/inspection **Jan. 30-Feb 2.**

FEBRUARY 2017

7th Basra Oil & Gas International Conference & Exhibition, Basra, web site: www.basraoilgas.com/Conference/ **8-11.**

SPE Canada Heavy Oil Technical Conference, Calgary, web site: www.spe.org/events/en/2017/conference/17choc/homepage.html/ **15-16.**

NAPE Summit, Houston, web site: napeexpo.com/shows/about-the-show/summit **15-17.**

19th International Conference on Oil, Gas & Petrochemical Engineering (ICOGPE 2017), Venice, web site: www.waset.org/conference/2017/02/venice/ICOGPE **16-17.**

Society of Petroleum Engineers (SPE) Reservoir Simulation Conference, Montgomery, Tex., web site: www.spe.org/events/rsc/2017/ **20-22.**

Australasian Oil & Gas Exhibition & Conference (AOG), Perth, web site: aogexpo.com.au/ **22-24.**

■ Nigeria Oil & Gas Conference & Exhibition, Abuja, web site: www.cwcnog.com/ **Feb. 27-Mar. 2.**

MARCH 2017

Society of Petroleum Engineers (SPE) 20th Middle East Oil & Gas Show & Conference (MEOS), Manama, Bahrain, web site: meos17.com/ **6-9**.

■ SPE 20th Middle East Oil & Gas Show & Conference (MEOS), Bahrain, web site: meos17.com/ **7-9.**

SPE/IADC Drilling Conference & Exhibition, Dublin, web site: www.spe.org/events/dc/2017/ **7-9.**

15th Global Oil & Gas Turkey, Istanbul, web site: www.global-oilgas.com/Turkey/Home/ **15-16.**

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, Houston, web site: www.spe.org/events/ctwi/2017/ **21-22.**

Corrosion 2017 Conference & Expo, New Orleans, web site: nacecorrosion.org/ **26-30.**

SPE Oklahoma City Oil & Gas Symposium, Oklahoma City, web site: www.speokcsymposium.org/ **27-31.**

APRIL 2017

AAPG 2017 Annual Convention & Exhibition, Houston, web site: www.aapg.org/events/conferences/ace/ **2-5.**

SPE International Conference on Oilfield Chemistry, Montgomery, Tex., web site: www.spe.org/events/en/2017/conference/17occ/homepage.html/ **3-5.**

SPE Asia Pacific Health, Safety, Security, Environment & Social Responsibility Conference, Kuala Lumpur, web site: www.spe.org/events/en/2017/conference/17aphs/homepage.html/ **4-6.**

Gastech Conference & Exhibition, Tokyo, web site: www.gastech-event.com/ **4-7.**

11th Global Oil & Gas Atyrau Conference, Kazakhstan, web site: www.oilgas-events.com/Oiltech-Atyrau-Conference/ **11-12.**

Neftegaz 2017 17th International Exhibition for Equipment & Technologies for Oil & Gas Industries, Moscow, web site: www.neftegaz-expo.ru/en/neftegaz_2017/ **17-20.**

Society of Petroleum Engineers (SPE) Health, Safety, Security, Environment & Social Responsibility Conference–North America, New Orleans, web site: www.spe.org/events/hsse/2017/ **18-20.**

MAY 2017

Colombia Oil & Gas Conference & Exhibition, Cartagena, web site: 10times.com/colombia-oilgas-exhibition **7-9.**

International Oil Spill Conference, Long Beach, Calif., web site: iosc2017.org/ **15-18.**

SPE Latin America & Caribbean Petroleum Engineering Conference, Buenos Aires, web site: www.spe.org/events/en/2017/conference/17lacp/homepage.html/**17-19.**

JUNE 2017

The 16th Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, web site: www.oilandgas-asia.com/home/index.php **11-13.**

Brasil Offshore, Rio de Janeiro, web site: www.brasiloffshore.com/en/Home/ **20-23.**

13th Russian Petroleum & Gas Congress (RPGC), Moscow, web site: www.oilgas-events.com/RPGC-Congress/ **27-29.**

14th Moscow International Oil & Gas Exhibition (MIOGE), Moscow, web site: www.oilgas-events.com/MIOGE-Exhibition **27-30.**

JULY 2017

22nd World Petroleum Congress (WPC), Istanbul, web site: www.22wpc.com/ **9-13.**

The 16th Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, web site: www.oilandgas-asia.com/home/index.php **11-13.**

SEPTEMBER 2017

SPE Offshore Europe Conference & Exhibition, Aberdeen, web site: www.offshore-europe.co.uk/ **5-8.**

Global Oil & Gas Middle East & North Africa Conference, Cairo, web site: www.oilgas-events.com/Find-an-Event/Global-Oil-Gas-Middle-East-North-Africa-%281%29 **17-19**.

Oil & Gas Indonesia 2017, Jakarta, web site: oilgasindonesia.com/ **20-23.**

3rd Oil & Gas Conference, Houston, web site: oil-gas.omicsgroup.com/ **21-22.**

Argentina Oil & Gas Expo 2017, Buenos

Aires, web site: www.aogexpo.com.ar/en **25-28.**

OCTOBER 2017

Society of Petroleum Engineers Annual Technical Conference & Exhibition, San Antonio, web site: https://www.expocheck.com/en/expos/2378-spe-atce-society-of-petroleum-engineers-annual-technical-conference-and-exhibition **9-11.**

AAPG SEG 2017 International Conference & Exhibition, London, web site: www.aapg.org/events/conferences/ice/announcement/articleid/5666/aapg-seg-2017-international-conference-exhibition-london **15-18.**

Louisiana Gulf Coast Oil Exploration (LAGCOE), Lafayette, La., web site: www.lagcoe.com/ **24-26.**

Offshore Technology Conference Brazil, Rio de Janeiro, web site: www.otcbrasil.org/ **24-26.**

FEBRUARY 2018

ICOGPE 2018: 20th International Conference on Oil, Gas & Petrochemical Engineering, Istanbul, web site: www.waset.org/conference/2018/02/istanbul/ICOGPE **16-17.**

MARCH 2018

ICOGPE 2018: 20th International Conference on Oil, Gas & Petrochemical Engineering, Rome, web site: www.waset.org/conference/2018/03/rome/ICOGPE **5-6.**

Offshore Technology Conference Asia, Kuala Lumpur, web site: 2018.otcasia.org/ **20-23.**

MAY 2018

AAPG 2018 Annual Convention & Exhibition, Salt Lake City, web site: www.aapg.org/events/conferences/ace/ **20-23.**

JUNE 2018

ICOGPE 2018: 20th International Conference on Oil, Gas & Petrochemical Engineering, Copenhagen, web site: waset.org/conference/2018/06/Copenhagen/ICOGPE **11-12.**

World Gas Conference, Washington, DC, web site: wgc2018.org/contact-us/ **25-29.**

JULY 2018

ICOGCT 2018: 20th International Conference on Oil, Gas & Coal Technology, Zurich, web site: www.waset.org/conference/2018/07/zurich/ICOGCT **29-30.**

MARCH 2019

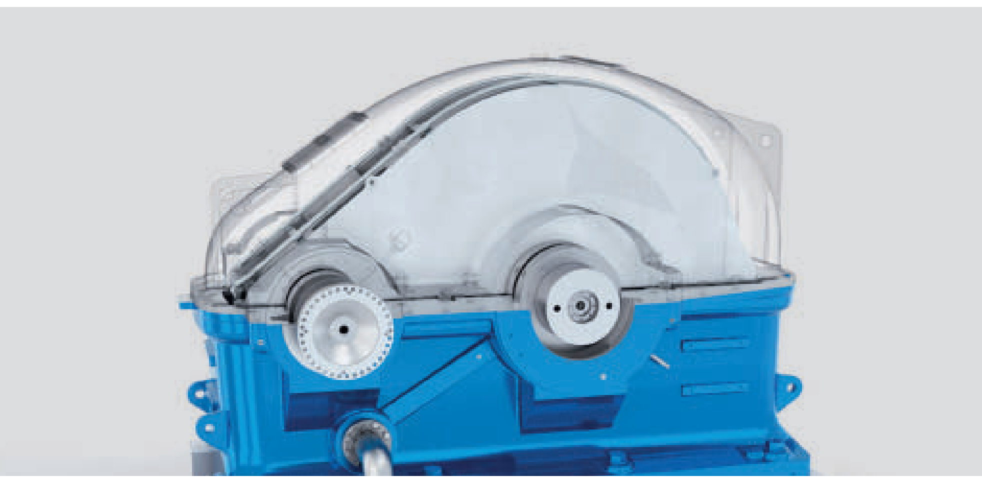
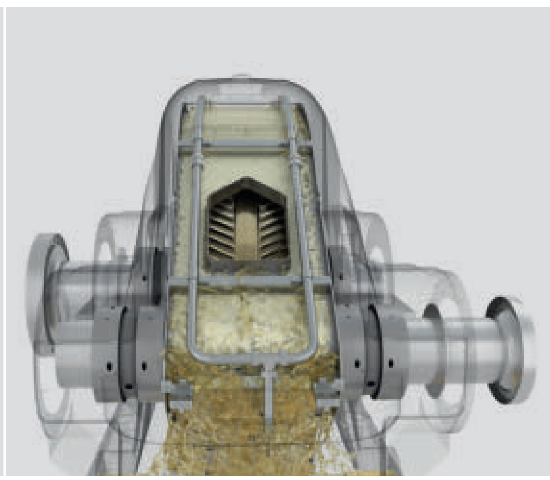
ICOGPE 2019: 21st International Conference on Oil, Gas & Petrochemical Engineering, London, web site: www.waset.org/conference/2019/03/london/ICOGPE **14-15.**

MAY 2019

AAPG 2019 Annual Convention & Exhibition, San Antonio, web site: www.aapg.org/events/conferences/ace/ **19-22.**

APRIL 2020

AAPG 2020 Annual Convention & Exhibition, San Francisco, web site: www.aapg.org/events/conferences/ace/ **5-8.**

Deepwater key to Mexico's reforms

PAULA DITTRICK
Upstream Technology Editor

Industry participants and observers say the overall success of Mexico's Round One likely hinges on its deepwater offerings, which are expected to attract widespread bidding despite current low oil prices.

Ruben Cruz, lead partner of KPMG's energy and natural resources in Mexico, estimated it will take an operator 8-10 years to develop a deepwater discovery, adding KPMG's clients are basing their future project plans using oil price assumptions of $55-65/bbl.

"It's the first time Mexico's deepwater has been open to the private sector, and we expect it will be a very competitive process," Cruz said. Deepwater development could help reverse Mexico's declining production rate. Pemex has lost 1.2 million b/d in 12 years.

"It's likely that the same or more reserves can be found," in Mexico's Gulf of Mexico as in the more widely explored US Gulf of Mexico, Cruz told OGJ in a telephone interview from his Mexico City office.

If international oil companies widely bid on Mexico's Phase 4 Round 1, that likely would serve as an affirmation for smaller industry players still tentative about doing business in Mexico under its emerging energy reforms.

The National Hydrocarbons Commission (CNH) said 31 companies expressed interest with 20 actually accessing the data room. As OGJ went to press last week, CNH was working with a short list of 15 companies.

As of presstime, the list of companies included Atlantic Rim Mexico, BP Exploration, BHP Billiton, Chevron, CNOOC, ExxonMobil, Hess, Inpex, NBL Mexico, Petronas Carigali, Pemex, Ophir Energy, Royal Dutch Shell, Statoil, and Total. Companies making a final list will be invited to bid.

Phase 4 involves 10 exploration blocks—six in the Salina basin and four in the Perdido belt. Phase 4 covers 3,185 sq miles in 1,640-9,842 ft of water.

Contract terms

CNH officials note that changes to contract terms are possible un-til early November. In some previous tenders, clarifications by government have restructured the contract terms. Although Dec. 5 has been published as a final bid date, CNH cautioned deadline date is provisional and subject to change.

Michiel Soeting, KPMG International chairman for global energy and natural resources, told reporters in Houston in May that he believes some Asian national oil companies are apt to participate as financial partners for other Phase 4 bidders.

Mexico requires bidders to have experience with at least one project in 3,280 ft of water during the last 5 years and to have at least $2 billion in capital investments. The contracts will have terms of 35-50 years. Terms are geared to ensure that companies have sufficient financial capacity.

"The investments are huge so only companies with strong balance sheets" are being courted to ensure that they can afford to develop whatever they find, Cruz said.

Another way for companies to explore and develop Mexico oil and gas is through a series of long-delayed farmout agreements. Trion field was the first to be offered.

In a noncompetitive Round Zero during 2014, Pemex kept control of certain properties with the condition that it develop them within a certain period.

Trion field is thought to contain about 485 million bbl of reserves and estimated to cost $11 billion to develop. While the agreement will be in the form of a license, Trion contract details have yet to be released. Companies selected for the Trion farmout are expected to be announced in December. OGJ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THE TYRANNY OF ACTIVISM—3

Assault on democracy

If climate change were the certain danger activists make it out to be, activism wouldn't exist. Energy consumers would respond voluntarily. They would spurn vehicles needing fossil fuels. They'd buy electricity from suppliers specializing in solar and wind. Convinced that failure to reform would yield dire consequences, they'd gratefully change habits and incur extra cost. Markets would accommodate the new behavior.

Not everyone would respond this way, of course. Some consumers never would acknowledge the need. Some wouldn't incur short-term cost for long-term benefit. Some just wouldn't change. Still, certain danger would compel most consumers to follow activists toward expensive precaution.

Unconvinced of the need

This is not happening. A large majority of energy consumers remain unconvinced of the need for radical change. They're not ignorant. They simply know uncertainty when they see it. While most people have heard activists' warnings, relatively few of them demonstrate, through what they buy, preference for high-cost energy options.

Reluctance of people in large numbers to make irrational change is, of course, why activists—in much smaller numbers—fight their battles in courtrooms and bureaucracies. There, focus, persistence, and clever lawyers overcome disadvantages of number. With climate change, manipulation of democratic processes works especially well.

For example, the phrase "carbon pollution" appears everywhere in climate politics yet makes no sense. Carbon is an organic building block. It doesn't pollute. But it's political code for carbon dioxide, the greenhouse gas for which people are most responsible. CO_2, which supports plant life and regulates breathing, doesn't pollute, either. Because it contributes to atmospheric warming, however, clever lawyers persuaded a majority of US Supreme Court justices to sanction regulation of CO_2 under the Clean Air Act. So the naturally occurring gas has fallen subject to the same regulation as very different, more-definitely dangerous substances humanity adds to air. "Carbon pollution" represents a triumph of activist legalism and propaganda over chemistry and biology.

Climate change is hardly the first subject about which courts have made goofy decisions, of course. But the underlying activism projects its manipulations into other branches of government—in the US and elsewhere. It has, for example, turned the US Environmental Protection Agency into a wholly owned subsidiary of environmental pressure groups, eager to impose changes rejected by voters.

The EPA actually came late to the business of making activist wishes come true in defiance of popular will. The European Union institutionalized this function long ago. Eager to lead the world with responses to climate change, the EU sets aggressive targets for CO_2 emission cuts and market shares for renewable energy. Obliging policies in member countries make European energy prices punishingly high, and Europeans can do precious little about it. The costs of energy autocracy help explain why a majority of UK voters opted on June 23 to quit the EU.

In the US, climate activism is testing a new way to sabotage democratic processes. Prodded by archactivist Al Gore, several state attorneys general are conducting criminal investigations of ExxonMobil Corp. and other organizations on record as doubtful about the need to render sacrifice to the climate. They aim to prove the organizations knew long ago that the use of fossil energy threatened humanity and fraudulently shrouded the insight.

This is absurd and unjust. It's absurd because it asserts certainty about climate change that didn't exist long ago and doesn't exist now. It's unjust because it aims to stifle speech and foreclose dissent. It's an assault on democracy.

Undemocratic tactics

Activists employ antidemocratic tactics because they fail to persuade people in large numbers to join an energy revolution as much about control as climate. They fail because their case is weak. Resort to tyranny does nothing to strengthen it.

How should the oil and gas industry respond to activism that distorts science and undermines democracy but succeeds nevertheless? The conclusion of this editorial series will offer suggestions next week. OGJ

Balancing of the oil market to stay on course despite UK exit from EU

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Statistics Editor

Solid movement toward oil-market balance should survive the surprise UK vote on June 23 to withdraw from the European Union.

After falling to a 12-year low of $26.01/bbl on Jan. 20, the Brent crude price had climbed to nearly $51/bbl before the vote on the strength of rising oil demand, falling production outside the Organization of Petroleum Exporting Countries, and unexpected supply disruptions.

But the UK decision contradicted most expectations and threw markets into turmoil. For the oil market, the key question now is whether the UK-EU breakup harms the global economy enough to suppress growth in oil consumption. Unless it becomes the brake on international trade that some observers apparently fear, the answer probably is no.

SPECIAL REPORT

The first-half recovery in oil prices was stronger than most analysts expected. In the first quarter, according to the International Energy Agency, average global oil demand exceeded the year-earlier average by 1.6 million b/d. Initial expectations for first-quarter demand growth were 1.2 million b/d.

In the US, gasoline consumption

WORLDWIDE SUPPLY AND DEMAND — Table 1

	2015 1st Qtr.	2015 2nd Qtr.	2015 3rd Qtr.	2015 4th Qtr.	2015 Year	2016 1st Qtr.	2016 2nd Qtr.	2016 3rd Qtr.	2016 4th Qtr.	2016 Year
	Million b/d									
Demand										
OECD										
North America	24.2	24.1	24.7	24.4	24.4	24.4	24.4	24.8	24.5	24.5
Europe	13.4	13.6	14.1	13.7	13.7	13.6	13.7	13.9	13.6	13.7
Asia/Pacific	8.8	7.7	7.8	8.3	8.1	8.6	7.7	7.8	8.3	8.1
Total OECD	**46.4**	**45.3**	**46.7**	**46.3**	**46.2**	**46.6**	**45.8**	**46.5**	**46.3**	**46.3**
Non-OECD										
FSU	4.6	4.9	5.1	5.0	4.9	4.9	4.9	5.0	5.0	5.0
Europe	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
China	11.2	11.5	11.5	11.6	11.4	11.5	11.6	11.8	12.0	11.7
Other Asia	12.3	12.5	12.3	12.8	12.5	13.0	13.2	12.9	13.4	13.1
Latin America	6.6	6.8	6.9	6.8	6.8	6.5	6.7	6.9	6.8	6.7
Middle East	7.6	8.3	8.6	8.1	8.2	7.8	8.2	8.7	8.3	8.2
Africa	4.1	4.1	4.0	4.2	4.1	4.2	4.3	4.2	4.3	4.3
Total non-OECD	47.2	48.8	49.0	49.2	48.6	48.6	49.7	50.2	50.5	49.7
Total demand	**93.6**	**94.1**	**95.7**	**95.5**	**94.7**	**95.2**	**95.5**	**96.7**	**96.9**	**96.1**
Supply										
OECD										
North America	20.0	19.6	20.1	20.1	19.9	19.9	18.9	19.3	19.5	19.4
Europe	3.4	3.5	3.4	3.6	3.5	3.6	3.4	3.2	3.4	3.4
Asia	0.4	0.4	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Total OECD	**23.8**	**23.5**	**23.9**	**24.2**	**23.9**	**23.9**	**22.7**	**22.9**	**23.3**	**23.2**
Non-OECD										
FSU	14.0	14.0	13.9	14.1	14.0	14.2	14.0	13.9	14.0	14.0
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	4.3	4.4	4.3	4.3	4.3	4.2	4.1	4.1	4.1	4.1
Other Asia	2.8	2.7	2.7	2.7	2.7	2.8	2.7	2.7	2.7	2.7
Latin America	4.6	4.6	4.6	4.6	4.6	4.4	4.4	4.6	4.6	4.5
Middle East	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.2	1.2	1.2
Africa	2.3	2.2	2.2	2.2	2.2	2.2	2.1	2.2	2.2	2.2
Total non-OECD	**29.5**	**29.3**	**29.1**	**29.3**	**29.3**	**29.1**	**28.7**	**28.8**	**29.0**	**28.9**
Processing gain	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3
Other biofuels	1.8	2.4	2.6	2.3	2.3	1.9	2.5	2.7	2.4	2.4
Total non-OPEC	**57.3**	**57.4**	**57.8**	**58.0**	**57.6**	**57.2**	**56.2**	**56.7**	**56.9**	**56.8**
OPEC										
Crude	31.2	32.2	32.4	32.4	32.1	32.6	32.6	32.7	32.6	32.6
NGL	6.6	6.7	6.7	6.7	6.7	6.8	6.8	6.9	6.9	6.9
Total OPEC	**37.7**	**38.9**	**39.1**	**39.1**	**38.7**	**39.3**	**39.4**	**39.6**	**39.5**	**39.5**
Total supply	**95.1**	**96.3**	**97.0**	**97.2**	**96.4**	**96.5**	**95.6**	**96.3**	**96.4**	**96.3**
Stock change	1.5	2.1	1.3	1.7	1.6	1.3	0.1	(0.4)	(0.5)	0.2

Totals may not add due to rounding.
Source: International Energy Agency; OGJ estimates for OPEC 2nd, 3rd and 4th quarter 2016 crude supply.

continues to surge. Despite wobbles among emerging economies, transport-fuel demand is also building in India, China, and Russia.

Although the UK referendum might damp oil demand by suppressing European economic growth, international oil consumption will continue to rise strongly this year as oil prices remain low in comparison with their levels before midyear 2014.

Non-OPEC oil production is slumping, largely driven by changes in US tight oil production. US crude oil production increased in 2015 by 723,000 b/d but will fall by 600,000 b/d this year, OGJ forecasts, unless the price recovery encourages more production than is expected.

In its meeting in Vienna on June 2, OPEC chose not to reinstate an output ceiling, leaving members free to produce at will. OPEC crude oil production is expected to rise modestly this year, with Iran accounting for most of the increase.

Also in the first half, supply disruptions grew, averaging more than 3.6 million b/d in May, a record high. Some disruptions are expected to subside, while others will endure.

In the global gas market, massive new LNG capacity is starting up, while—despite lower prices—demand continues to soften in traditional markets. These trends will keep spot gas prices under pressure and limit trade.

US natural gas supply continues to be robust, despite a drilling slump. Natural gas storage levels remain elevated, suppressing US gas prices.

World economy

The global economy is struggling to regain momentum. In its latest Global Economic Prospects in June, the World Bank lowered its 2016 global growth forecast to 2.4% from 2.9% projected in January.

With risks to growth increasing and inflation persistently below target, the European Central Bank and Bank of Japan are pursuing further policy accommodation, while the US Federal

OGJ FORECAST OF US SUPPLY AND DEMAND

Table 2

	First half 2016 Volume 1,000 b/d	First half 2016 % change from 2015[1]	Year 2016 Volume 1,000 b/d	Year 2016 % change from 2015[1]
DEMAND				
Motor gasoline	9,300	2.9	9,320	1.8
Dist. 1-4	7,701	3.1	7,718	1.8
Dist. 5	1,599	2.1	1,602	1.7
Jet fuel	1,540	2.9	1,550	0.8
Dist. 1-4	1,067	2.5	1,074	0.0
Dist. 5	473	4.0	476	2.6
Distillate	3,920	(3.9)	3,940	(1.0)
Dist. 1-4	3,407	(4.5)	3,425	(0.7)
Dist. 5	513	0.2	515	(2.6)
Residual	300	39.5	260	0.4
Dist. 1-4	173	57.3	150	1.4
Dist. 5	127	22.1	110	0.0
LPG and ethane	2,510	0.5	2,520	2.1
Dist. 1-4	2,494	0.4	2,504	2.2
Dist. 5	16	14.3	16	0.0
Other products	2,030	12.0	2,030	5.5
Dist. 1-4	1,813	10.3	1,813	5.2
Dist. 5	217	29.2	217	8.5
Total domestic demand	19,600	1.7	19,620	1.2
Dist. 1-4	16,662	1.4	16,679	1.2
Dist. 5	2,938	3.3	2,941	1.2
Exports	4,920	5.9	4,950	4.2
Dist. 1-4	4,502	6.3	4,529	4.2
Dist. 5	418	2.0	421	4.2
Total Demand	24,520	2.5	24,570	1.8
Dist. 1-4	21,164	2.4	21,208	1.8
Dist. 5	3,356	3.2	3,362	1.6
SUPPLY				
Domestic production				
Crude & condensate	9,012	(5.0)	8,800	(6.7)
Dist. 1-4	7,991	(4.8)	7,803	(6.7)
Dist. 5	1,021	(6.4)	997	(6.6)
NGL	3,430	7.9	3,500	7.0
Dist. 1-4	3,359	7.9	3,429	7.0
Dist. 5	71	2.9	71	7.6
Total domestic production	12,442	(1.8)	12,300	(3.2)
Dist. 1-4	11,350	(1.4)	11,232	(2.9)
Dist. 5	1,092	(5.9)	1,068	(5.8)
Renewable fuels and oxgyenates	1,110	1.2	1,110	(0.3)
Dist. 1-4	1,086	1.3	1,086	(0.2)
Dist. 5	24	(4.0)	24	0.0
Imports				
Crude oil	7,950	9.4	8,030	9.3
Dist. 1-4	6,737	8.9	6,804	9.3
Dist. 5	1,213	12.4	1,226	9.3
Products & unfinished oils	2,050	(4.9)	2,010	(2.0)
Dist. 1-4	1,798	(5.1)	1,763	(2.0)
Dist. 5	252	(2.7)	247	(2.0)
Total Imports	10,000	6.2	10,040	6.8
Dist. 1-4	8,535	5.6	8,567	6.8
Dist. 5	1,465	9.5	1,473	7.2
Processing gain, loss, etc.	1,070	6.0	1,070	3.2
Dist. 1-4	898	6.8	898	3.2
Dist. 5	172	2.4	172	3.0
Total new supply	24,622	1.8	24,520	1.1
Dist. 1-4	21,869	1.7	21,784	1.1
Dist. 5	2,753	2.4	2,736	1.4
Stock change	102	—	(50)	—
Dist. 1-4	706	—	576	—
Dist. 5	(604)	—	(626)	—
Crude runs to stills	**16,200**	**1.3**	**16,450**	**1.5**
Total Input to stills	**16,430**	**1.2**	**16,700**	**1.6**
Total refining capacity	**18,300**	**2.1**	**18,350**	**1.8**
Refining utilization, %	**89.8**	**(1.3)**	**91.0**	**(0.2)**
Total industry stocks[2]	**1,371**	**9.9**	**1,310**	**2.3**
Refined products	846	9.2	820	1.5
Crude oil	525	11.2	490	3.8
SPR crude oil stocks	695	0.4	695	0.0
IMPORT DEPENDENCY				
Total imports % domestic demand	51.0		51.2	
Net imports % domestic demand	25.9		25.9	

[1]Compared to preliminary EIA figures. [2]Million bbl at end of period.

FIRST QUARTER WORLDWIDE PRODUCTION

Table 3

Country	2016	2016	Change	Change, %
	First quarter 1,000 b/d			
OPEC	**32,581**	**31,287**	**1,294**	**4.1**
Non-OPEC	**45,704**	**45,763**	**(59)**	**(0.1)**
Argentina	519	531	(12)	(2.3)
Brazil	2,321	2,438	(117)	(4.8)
Canada	3,903	3,849	54	1.4
Colombia	980	1,010	(30)	(3.0)
Mexico	2,230	2,301	(71)	(3.1)
United States	9,150	9,396	(246)	(2.6)
Other	3,159	3,223	(64)	(2.0)
Western Hemisphere	22,262	22,748	(486)	(2.1)
Norway	1,645	1,589	56	3.5
United Kingdom	964	852	112	13.1
Other	378	416	(38)	(9.1)
Western Europe	2,987	2,857	130	4.6
FSU	12,980	12,753	227	1.8
Other	165	164	1	0.6
Eastern Europe & FSU	13,145	12,917	228	1.8
Egypt	684	691	(7)	(1.0)
Gabon	260	260	—	—
Other	6,504	6,577	(73)	(1.1)
Africa	7,188	7,268	(80)	(1.1)
Oman	1,017	970	47	4.8
Syria	30	30	—	—
Other	24,141	22,690	1,451	6.4
Middle East	25,188	23,690	1,498	6.3
Australia	300	296	4	1.4
China	4,233	4,254	(21)	(0.5)
India	736	768	(32)	(4.2)
Indonesia	745	794	(49)	(6.2)
Malaysia	619	600	19	3.2
Other	882	858	24	2.8
Asia-Pacific	7,515	7,570	(55)	(0.7)
Total world	**78,285**	**77,050**	**1,235**	**1.6**

Source: Oil & Gas Journal

OPEC PRODUCTION AND CAPACITY

Table 4

Country	Capacity	May 2016 production	Spare capacity
	1,000 b/d		
Algeria	1,120	1,090	30
Angola	1,810	1,750	60
Ecuador	550	540	10
Indonesia	740	740	—
Iran	3,650	3,640	10
Iraq	4,400	4,270	130
Kuwait	2,870	2,850	20
Libya	400	270	130
Nigeria	1,850	1,370	480
Qatar	670	660	10
Saudi Arabia	12,200	10,250	1,950
United Arab Emirates	2,930	2,890	40
Venezuela	2,400	2,290	110
Total OPEC	**35,590**	**32,610**	**2,980**

Source: International Energy Agency

Reserve is extending its program of holding interest rates low.

The US, which represents 20% of global oil demand, remains in an economic expansion. Real gross domestic product (GDP) growth was reported to have been relatively weak early this year, but recent data on retail sales and motor vehicle sales point to higher consumer spending and GDP growth for the second quarter.

As warned by Federal Reserve Chair Janet L. Yellen, headwinds and uncertainties still loom, including weak business investment, weak productivity growth, weak net exports, economic challenges abroad, and the persistently sluggish rate of inflation.

Eurozone real GDP increased 2.2% on an annualized basis in the first quarter of 2016, and the latest data point to more growth in the second quarter, supported by domestic demand and supportive monetary policy. However, the British exit from the EU (Brexit) might threaten trade and investment and, by implication, growth and jobs.

Real GDP in Japan grew just 0.1% year over year in the first quarter, reflecting ongoing weakness of the Japanese economy.

Emerging markets and developing economies face many challenges, including exchange-rate pressures, capital outflows, and subdued global merchandise trade. For countries dependent on commodity production, prices until recently have been low.

The Chinese economy's latest short-term indicators point to sustained economic momentum, with industrial production, fixed-asset investment, and retail sales improving thanks to aggressive monetary and fiscal stimulus. However, China faces considerable challenges as it adjusts its economy to increase domestic demand's contribution to overall growth.

SPECIAL REPORT

World oil demand

Global oil demand outperformed expectations in 2015, with full year growth at 1.8 million b/d. Demand grew by 500,000 b/d among industrialized members of the Organization for Economic Cooperation and Development and by 1.3 million b/d elsewhere. While demand growth in the fourth quarter of 2015 fell, it rose again in the first and second quarters of 2016.

WORLD CRUDE PRICES

Table 5

Country	Type of crude and API gravity	May 2016, $/bbl	Change May 2016–Jan. 2016, %	In effect Jan. 2016, $/bbl	Change May 2016–June 2015, %	In effect June 1, 2015, $/bbl	In effect June 1, 2014, $/bbl	In effect June 1, 2013, $/bbl	In effect June 1, 2012, $/bbl	In effect June 1, 2011, $/bbl
OPEC										
Saudi Arabia	Arabian Light 34	43.48	65.0	26.35	(60.0)	60.94	108.61	101.30	94.51	111.16
Abu Dhabi	Murban 39	47.12	49.3	31.57	(57.4)	64.59	110.74	102.61	96.76	113.33
Algeria	Saharan 44	47.73	52.6	31.28	(57.6)	61.69	112.66	102.07	94.69	116.62
Nigeria	Bonny Light 37	46.85	54.1	30.40	(59.0)	62.19	114.36	106.12	97.19	117.74
Libya	Es Sider 37	45.83	54.1	29.75	(58.8)	60.79	111.31	103.07	96.04	113.72
Indonesia	Minas 34	48.64	57.9	30.80	(56.6)	60.09	112.13	103.19	104.83	120.12
OTHER										
IUK	Brent Blend 38	46.83	52.3	30.75	(56.7)	61.69	108.03	102.92	95.19	115.59
Mexico	Isthmus 33	44.76	49.1	30.03	(58.0)	63.48	106.47	104.08	93.16	109.97
Russia	Urals 32	45.08	54.6	29.15	(58.8)	62.52	109.44	102.74	93.81	113.55

Source: OPEC, for 2012-2016 data; US Energy Information Administration, 2011.

US CRUDE, NATURAL GAS, AND PRODUCTS PRICES

Table 6

Year	Average wellhead crude price, $/bbl	Refiner's acquisition cost of crude, $/bbl	Retail motor gasoline, all types, ¢/gal	On–highway diesel fuel ¢/gal	Jet fuel and kerosine (ex–cluding tax), ¢/gal	Henry Hub natural gas spot price $/MMBTU
1978	9.00	12.46	65.2	NA	38.7	NA
1980	21.59	28.07	122.1	NA	86.8	NA
1985	24.09	26.75	119.6	NA	79.6	NA
1990	20.03	22.22	121.7	NA	76.6	NA
1995	14.62	17.23	120.5	110.9	54.0	NA
1996	18.46	20.71	128.8	NA	65.1	NA
1997	17.23	19.04	129.1	NA	61.3	2.49
1998	10.87	12.52	111.5	NA	45.2	2.09
1999	15.56	17.51	122.1	NA	54.3	2.27
2000	26.72	28.26	156.3	149.1	89.9	4.31
2001	21.84	22.95	153.1	140.1	77.5	3.96
2002	22.51	24.10	144.1	131.9	72.1	3.38
2003	27.56	28.53	163.8	150.9	87.2	5.47
2004	36.77	36.98	192.3	181.0	120.7	5.89
2005	50.28	50.24	233.8	240.2	173.5	8.69
2006	59.69	60.24	263.5	270.5	199.8	6.73
2007	66.52	67.94	284.9	288.5	216.5	6.97
2008	94.04	94.74	331.7	380.3	305.2	8.86
2009	56.35	59.29	240.1	246.7	170.4	3.94
2010	74.71	76.69	283.6	299.2	220.1	4.37
2011	95.73	101.87	357.7	384.0	305.4	4.00
2012	94.52	100.93	369.5	396.8	310.4	2.75
2013	95.99	100.49	358.4	392.2	297.9	3.73
2014	87.39	92.02	342.5	382.5	277.2	4.36
2015	44.39	48.40	251.0	270.7	162.9	2.62
2016*	40.00	44.30	220.0	236.0	136.0	2.20

*OGJ estimate.
Source: US Energy Information Administration, for 1978-2015 data

According to the IEA's June Oil Market Report, global oil demand averaged an estimated 95.4 million b/d in the first half of 2016, up 1.5 million b/d from the first half of the prior year and 400,000 b/d more than predicted in January.

IEA's full-year 2016 global demand estimate stands at 96.1 million b/d, 1.4% higher than the prior year.

For 2016 as a whole, OECD demand is forecast to total 46.3 million b/d, up 0.3% from the year earlier. Demand will be up in South Korea, the US, and Turkey and down in Japan, France, Canada, and Italy.

Demand will grow by 1.1 million b/d in non-OECD countries, with the largest increases in China and other Asia. The non-OECD group will continue to be the main source of demand growth.

Despite economic headwinds, Chinese oil demand rebounded strongly in 2015 on the back of slumping crude prices. Chinese crude oil demand will remain well supported this year against the backdrop of low international oil prices, stockpiling, and refining, according to an analysis from FACTS Global Energy.

Indian demand has been exceptionally strong, propelled by rapid gains in road transport petrochemical. India's demand will grow 400,000 b/d in 2016, likely to be the world's biggest single increment, according to IEA.

India's demand will growth will be 8.3% year-over-year in the second half, while China's 3.3% demand growth will be greater in absolute terms.

Global oil supply

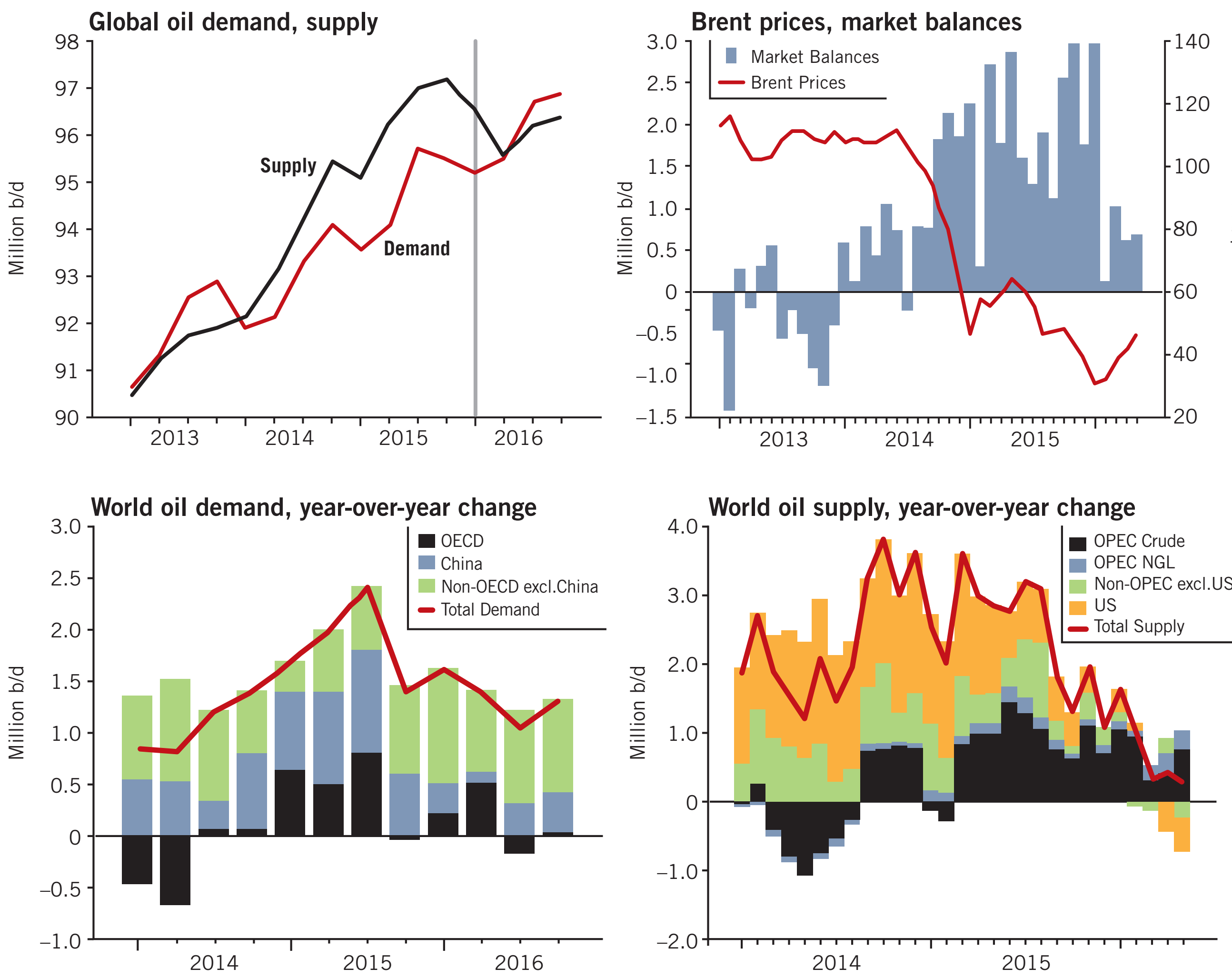
First-half supply disruptions occurred in Canada, Nigeria, Iraq, and Libya.

In Canada, wildfires in Fort McMurray, Alta., reduced oil sands production and led to an average 800,000 b/d supply disruption in May, with a daily disruption peak of more than 1.1 million b/d.

Nigeria's crude oil production fell to an average of 1.4 million b/d in May, its lowest monthly level since the late 1980s, due to militant attacks on oil and natural gas infrastructure. For the first 5 months of 2016, Nigeria's supply disruptions averaged 500,000 b/d, 200,000 b/d more than in 2015. IEA expects Nigeria's disruptions to remain relatively high through 2017.

According to IEA, total OECD supply will average 23.2 million b/d this year, compared with last year's 23.9 million b/d. OECD North American oil output will average 19.4 million b/d, down from last year's 19.9 million b/d.

WORLD OIL MARKET AT A GLANCE



Source: IEA, EIA, OGJ analysis

Average non-OECD oil supply will slip to 28.9 million b/d from 29.3 million b/d last year, led by the decline in China.

Offsetting the Nigerian decline among OPEC members is an increase in supply from Iran, where production increased by 730,000 b/d by May after relaxation of international sanctions.

OGJ expects total production of crude oil by OPEC members to remain at the first-quarter average of 32.6 million b/d. OPEC NGL output will average 6.9 million b/d this year.

Combined with IEA's outlook for demand, total 2016 oil supply of 96.3 million b/d would result in an average stock build of 200,000 b/d, compared with 1.3 million b/d last year. Stock withdrawals are possible in the second half as demand exceeds supply.

Commercial inventories in OECD countries rebounded from March levels by 14.4 million bbl to stand at 3,065 million bbl by end-April, 222 million bbl above the level of 2015.

US energy demand

Total energy demand in the US this year will grow by 0.1%, and energy efficiency will improve to 5.9 Mbtu/$ of GDP from last year's rate of 6.0 Mbtu/$ of GDP.

Oil will still constitute the largest share of the US energy mix: 36.6%. Total energy use will be 35.76 quadrillion btu (quads), an increase of 1.2% from last year.

In light of low prices and rising demand for electric power generation, natural gas demand will reach 28.52 quads, accounting for 29.2% of the energy mix this year. In 2015, US demand for gas totaled 28.32 quads.

SPECIAL REPORT

US ENERGY CONSUMPTION AND EFFICIENCY

Table 7

	GDP (billion 2009 dollars)	Energy consumption (trillion btu)	Energy consumption per GDP, 2009 dollar (Mbtu)	Oil energy consumption (trillion btu)	Oil energy consumption per GDP, 2009 dollar (Mbtu)	Natural gas energy consumption (trillion btu)	Natural gas energy consumption per GDP, 2009 dollar (Mbtu)	Total oil and natural gas energy consumption (trillion btu)	Total oil and gas energy consumption per GDP, 2009 dollar (Mbtu)	Oil and natural gas energy % of total energy
1975	5,385.4	71,965	13.4	32,732	6.1	19,948	3.7	52,680	9.8	73.2
1980	6,450.4	78,067	12.1	34,205	5.3	20,235	3.1	54,440	8.4	69.7
1985	7,593.8	76,392	10.1	30,925	4.1	17,703	2.3	48,628	6.4	63.7
1990	8,955.0	84,485	9.4	33,552	3.7	19,603	2.2	53,155	5.9	62.9
1995	10,174.8	91,032	8.9	34,441	3.4	22,671	2.2	57,112	5.6	62.7
2000	12,559.7	98,819	7.9	38,266	3.0	23,824	1.9	62,090	4.9	62.8
2001	12,682.2	96,172	7.6	38,190	3.0	22,773	1.8	60,963	4.8	63.4
2002	12,908.8	97,647	7.6	38,226	3.0	23,510	1.8	61,736	4.8	63.2
2003	13,271.1	97,921	7.4	38,790	2.9	22,831	1.7	61,621	4.6	62.9
2004	13,773.5	100,094	7.3	40,227	2.9	22,923	1.7	63,150	4.6	63.1
2005	14,234.2	100,193	7.0	40,303	2.8	22,565	1.6	62,868	4.4	62.7
2006	14,613.8	99,492	6.8	39,824	2.7	22,239	1.5	62,063	4.2	62.4
2007	14,873.7	101,027	6.8	39,491	2.7	23,663	1.6	63,154	4.2	62.5
2008	14,830.4	98,906	6.7	36,907	2.5	23,843	1.6	60,750	4.1	61.4
2009	14,418.7	94,138	6.5	34,959	2.4	23,416	1.6	58,375	4.0	62.0
2010	14,783.8	97,480	6.6	35,489	2.4	24,575	1.7	60,064	4.1	61.6
2011	15,020.6	96,902	6.5	34,824	2.3	24,955	1.7	59,779	4.0	61.7
2012	15,354.6	94,487	6.2	34,016	2.2	26,089	1.7	60,105	3.9	63.6
2013	15,583.3	97,238	6.2	34,613	2.2	26,805	1.7	61,418	3.9	63.2
2014	15,961.7	98,505	6.2	34,881	2.2	27,488	1.7	62,369	3.9	63.3
2015	16,348.9	97,527	6.0	35,373	2.2	28,319	1.7	63,692	3.9	65.3
2016*	16,675.9	97,625	5.9	35,762	2.1	28,517	1.7	64,350	3.9	65.9

*OGJ estimate.
Source: US Energy Information Administration

Coal consumption is forecast to decline by 8% in 2016 due to coal-gas switching in power generation, permanent coal-plant retirements, and a warmer-than-normal winter.

US oil consumption

Total US liquid fuels consumption, driven by gasoline, will increase 1.2% to 19.62 million b/d in 2016. US oil consumption increased 1.5% in 2015 to 19.39 million b/d.

Backed by lower retail prices, gasoline consumption increased 2.67% in 2015 to an average of 9.16 million b/d. During this year's first 6 months, estimated gasoline consumption averaged 9.3 million b/d, compared with 9 million b/d for last year's first half, according to EIA data.

Gasoline regular-grade retail prices averaged $2.07/gal in this year's first half, down from $2.55/gal a year earlier, due to increased supply.

This year's gasoline consumption is projected to increase by 160,000 b/d to 9.32 million b/d, the highest annual average gasoline consumption on record. The previous annual average high was 9.29 million b/d in 2007.

Lower jet fuel prices have translated into lower passenger fares and increased flights and routes. Jet fuel consumption jumped 4.7% in 2015 to 1.54 million b/d. OGJ forecasts that jet fuel demand will increase by 0.8% to 1.55 million b/d this year due to improvements in airline fleet fuel economy.

Consumption of distillate fuel fell 1.5% in 2015 to 3.97 million b/d and will continue to fall in 2016 as the result of relatively high winter temperatures, less demand from drilling, and falling coal production. Also, proposed fuel economy and greenhouse gas emission standards would increase fuel economy and reduce diesel consumption in medium and heavy-duty vehicles.

US ENERGY DEMAND

Table 8

	2016	2016*	Change, %	Share, % 2015	Share, % 2016
	Trillion btu				
Oil	35,373	35,762	1.1	36.3	36.6
Gas	28,319	28,517	0.7	29.0	29.2
Coal	15,614	14,365	(8.0)	16.0	14.7
Nuclear	8,338	8,338	—	8.5	8.5
Hydro, NGPL, other renewables	9,675	10,372	7.2	9.9	10.6
Total	**97,527**	**97,625**	**0.1**	**100.0**	**100.0**

*OGJ estimate.
Source: 2015 US Energy Information Administration
Totals may not equal sum of components due to independent rounding

LPG demand will also increase this year, supported by increased ethane consumption due to expansion of the capacity to produce ethylene.

US oil production

US crude and condensate production will decrease to 8.8 million b/d in 2016 from an average of 9.43 million b/d in 2015. In the first half of 2016, estimated US crude and condensate production averaged 9 million b/d. This was andecrease from 9.49 million b/d in 2015's first half. The decline in the Lower 48 onshore is partially offset by higher production in the federal Gulf of Mexico.

In its Drilling Productivity Report, the US Energy Information Administration said oil production from seven major US shale plays fell from 5.45 million b/d in May 2015 to 4.87 million b/d in May 2016. The fall included a 370,000

Model isolates speculative demand in price analysis

Conglin Xu
Senior Editor-Economics

SPECIAL REPORT

Oil demand is often viewed as being determined by the state of the global economy. Given that crude oil is storable, the real price of oil also depends on the demand for storage. But limited attention has been put on the role of inventories in smoothing oil consumption and in providing speculative trading opportunities.

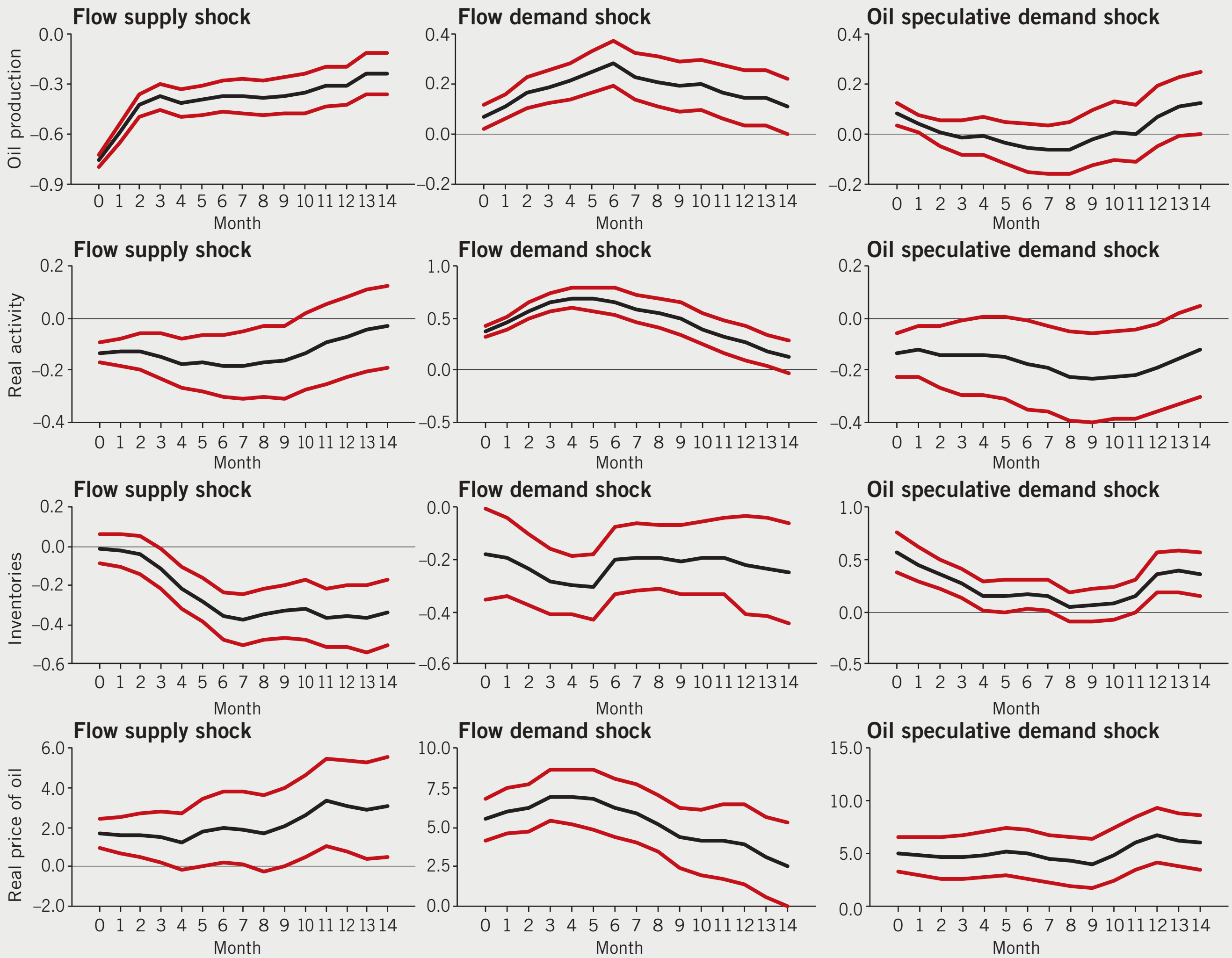
As speculative demand movements cannot be inferred directly from what's observable, an important question in practice is how to distinguish the speculative demand component of real crude oil prices from the normal flow of everyday demand and supply.

These speculative demand forces, or shocks, can be identified within the context of structural econometric models. Lutz Kilian and Dan Murphy, two professors at the University of Michigan, developed a four-variable structural vector autoregression (SVAR) model of the global crude oil market using sign restrictions in 2010, which explicitly allows for shocks to the speculative demand for oil as well shocks to flow demand and flow supply.[1]

The speculative component of the real price of oil is identified with the help of data on oil inventories.

IMPULSE RESPONSES TO STRUCTURAL SHOCKS

FIG. 1



Source: Author's calculations based on a structural VAR model identified with sign restrictions and an upper bound on the impact price elasticity of oil supply for the period from Jan. 1993 to Dec. 2015. The middle, the upper and the lower lines are the mean, the 84% quantile and the 16% quantile of the posterior distribution. All shocks have been normalized to imply an increase in the real price of oil.

As elaborated by Kilian and Murphy, the accumulation of inventories is accomplished by a reduction in oil consumption (reflected in lower global real activity) and an increase in oil production, as the real price increases. Both flow demand shocks and speculative demand shocks have an expectational component. The feature that distinguishes flow demand shocks from speculative demand shocks is that positive flow demand shocks necessarily involve an increase in the demand for consumption in the current period, whereas speculative demand shocks do not.

So why not include the oil futures spread? According to Kilian and Murphy, this is because there is an arbitrage condition linking the futures and spot markets for crude oil. To the extent that speculation drives up the futures price, arbitrage will ensure that oil traders buy inventories in the spot market in response. Thus the analysis can focus on quantifying speculation in the spot market with the help of the oil inventory data without loss of generality.

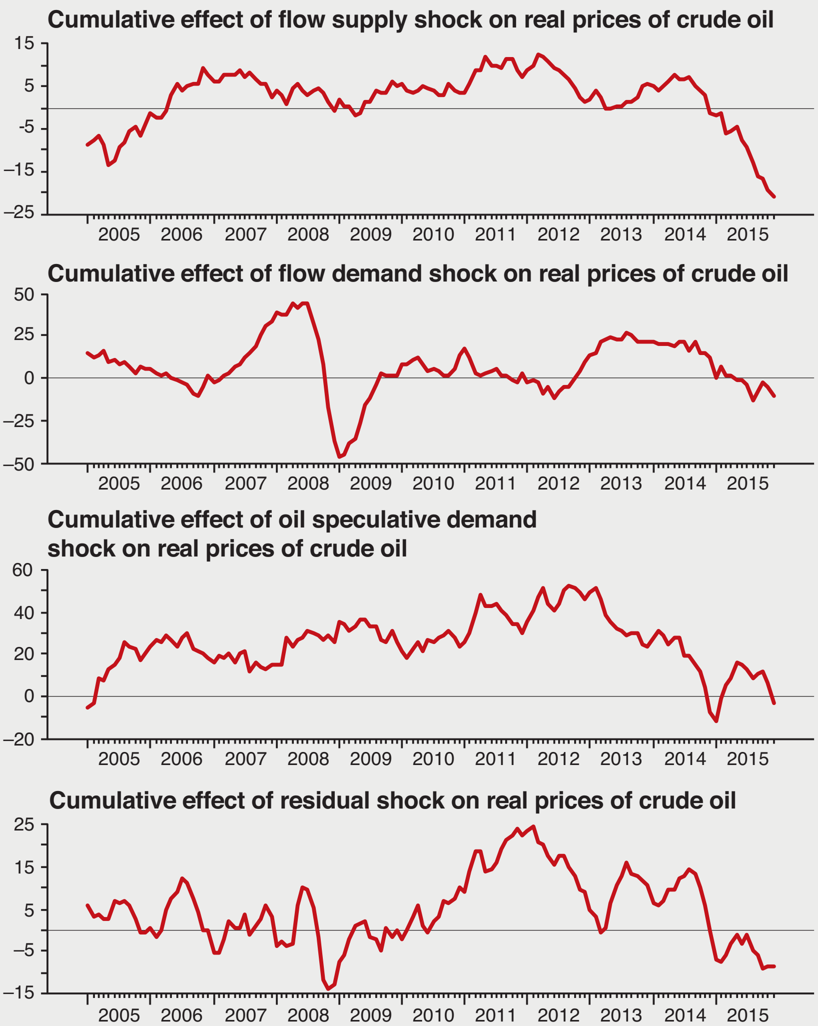
The structural model of the global oil market may be written as

$B_0 y_t = \sum_{i=1}^{n} B_i y_{t-i} + \varepsilon_t$. Let y_t be a 4×1 vector of endogenous variables including the percent change in global crude oil production, a measure of global real activity, the real price of crude oil, and the change in global crude oil inventories above the ground. ε_t is the vector of orthogonal structural innovations, and B_i denotes the coefficient matrices. The vector ε_t consists of four structural shocks: flow supply shock, flow demand shock, speculative demand shock, and a residual shock. Flow demand shock refers to the demand for crude oil and other industrial commodities that is associated with fluctuations in the global business cycle.

Different from traditional short-run

HISTORICAL DECOMPOSITION FOR 2005:01 TO 2015:12

FIG. 2



Source: Author's calculations

restriction methods, the proposed SVAR model is identified by sign restrictions on impact responses and boundaries on the implied price elasticity of oil demand and oil supply. Sign restrictions involve the assumption of impulse responses to structural shocks (Fig. 1).

Prices in 2015

A historical decomposition exercise based on the model (Fig. 2) shows that speculative oil demand once rebounded during 2015 to support real oil prices, after dropping dramatically since mid-2014. This might reflect stockpiling in some oil-importing countries.

The inclusion of oil inventory data to VAR variables can improve forecasting performance, as inventories provide important forward-looking information.

Alquist et al. demonstrate that a VAR model with global oil supply, Kilian's dry cargo shipping rate index (a measure of global real economic activity), and crude oil inventories outperforms the futures forecast and other models for short forecast horizons up to 9 months.[2] This result also holds in real time, as shown by

Model isolates . . . . .(cont'd)

Baumeister and Kilian.[3] These VAR forecasts are found to be robust to various changes in model specification and estimation methods, including Bayesian estimation. Although a study from IMF shows that there could be forecasting instability related to small alternations, it still supports the overall strength of the 4-variable VAR model.4

SPECIAL REPORT

In particular, Baumeister and Kilian provide evidence that, using the four-variable VAR with 24-month lags (Fig. 3c), more than half of the observed decline in the price of oil was predictable in real time as of June 2014.[5] As another experiment, the VAR forecast predicts the pattern of the evolution of the real price of oil from late 2015 to early 2016 (Fig. 3d).

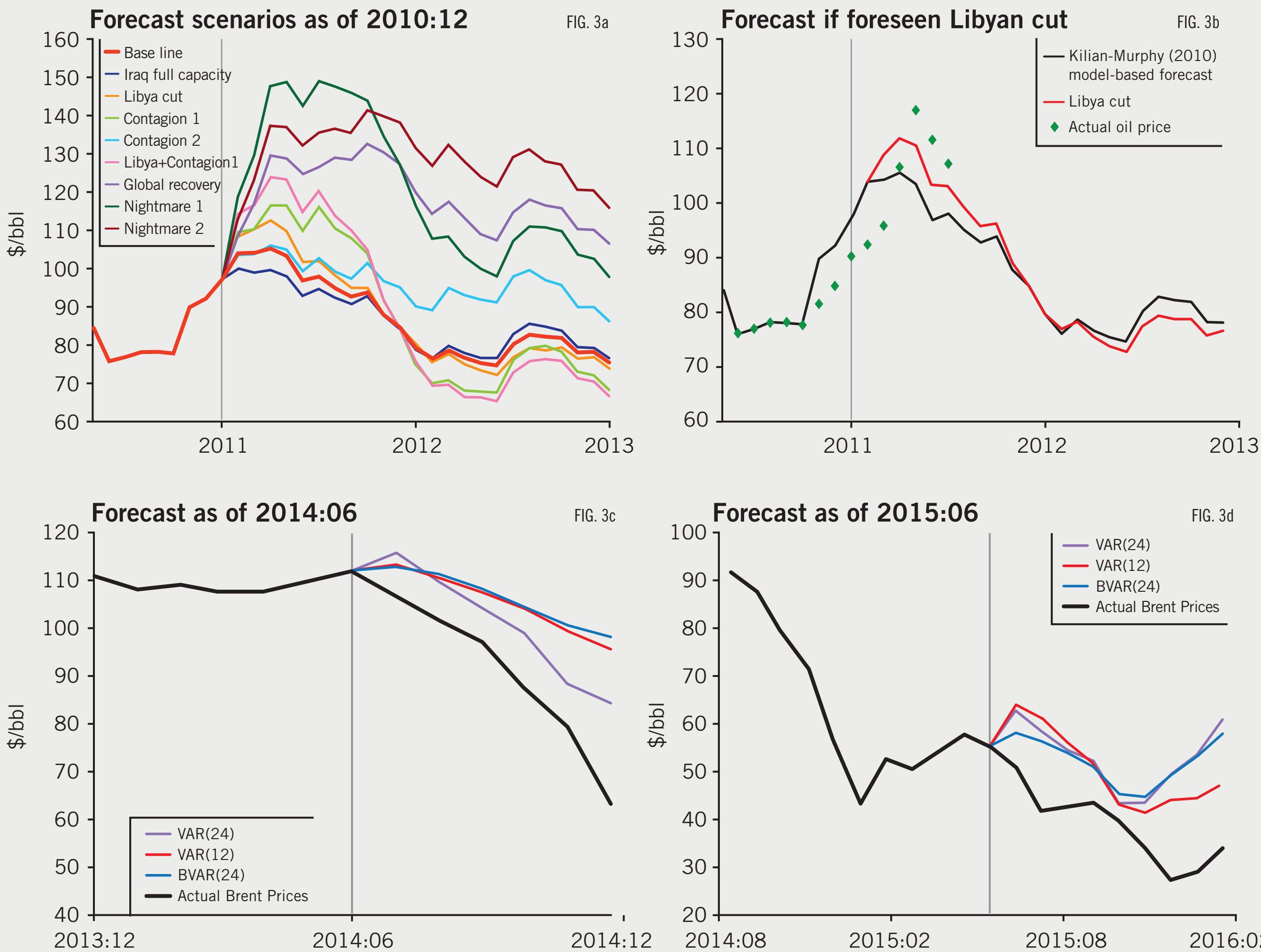
Importantly, the structural VAR model paves the path for conducting scenario forecasts and risk analysis.

Forecast scenarios

The baseline forecast of a reduced-form VAR model corresponds to the expected change in the real price of oil conditional on all future shocks being zero. Departures from this benchmark can be constructed by feeding specified sequences of future structural shocks into the VAR model

FORECASTING THE PRICE OF OIL

FIG. 3



Source: Figure 3a, 3b from Baumeister, C. and L. Kilian (2014). Chart 3c from Baumeister,C. and L. Kilian (2015). Chart 3d from author's calculation. BVAR stands for Bayesian VAR.

and projecting the dependent variable into the future.

Baumeister and Kilian illustrated the use of these tools through an application to real-time data for December 2010.3 Forecast scenarios as of December 2010 involve the unexpected return of Iraqi oil, Libyan production shortfall, global economic recovery, and a couple of others (Fig. 3a). They show how alternative forecast scenarios could have generated very different outcomes. Correct judgments can improve forecast accuracy (Fig. 3b).

Risk analysis

These forecast scenarios can be weighted by their respective probabilities, allowing the construction of a probability-weighted predictive density for the real price of oil.

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US NATURAL GAS SUPPLY AND DEMAND

Table 9

	2013	2014	2015	% change, 2015/2014	2016, bcf	% change, 2016/2015
		bcf				
Production						
Texas	7,634	7,953	7,872	(1.0)	7,550	(4.1)
Pennsylvania	3,259	4,215	4,769	13.1	5,200	9.0
Federal Gulf of Mexico	1,309	1,255	1,331	6.1	1,240	(6.8)
Other states	13,360	13,914	14,780	6.2	15,100	2.2
Total production	**25,562**	**27,337**	**28,752**	**5.2**	**29,100**	**1.2**
Imports						
Canada	2,785	2,635	2,625	(0.4)	2,630	0.2
Mexico	1	1	1	0.0	1	0.0
LNG	97	59	92	55.9	90	(2.2)
Total imports	**2,883**	**2,695**	**2,718**	**0.9**	**2,721**	**0.1**
Supplemental gas	55	60	60	0.0	60	0.0
Losses, etc.*	(1,319)	(1,627)	(1,738)	6.8	(1,747)	0.5
Total new supply	**27,181**	**28,465**	**29,792**	**4.7**	**30,122**	**1.1**
Supply from storage	546	(253)	(539)	113.0	(299)	(44.5)
Total supply	**27,727**	**28,212**	**29,253**	**3.7**	**29,823**	**1.9**
Exports						
LNG	3	16	28	75.0	193	589.3
Pipeline	1,569	1,498	1,755	17.2	1,980	12.8
Total exports	**1,572**	**1,514**	**1,784**	**17.8**	**2,173**	**21.8**
Total consumption	**26,155**	**26,698**	**27,470**	**2.9**	**27,650**	**0.7**

*Extraction losses and unaccounted for gas.
Source: 2012–2015 EIA; 2016 OGJ estimate

b/d, or 22%, drop in the Eagle Ford to 1.27 million and a 158,000 b/d, or 13%, drop in the Bakken to 1.07 million b/d. Production in the Permian area increased 126,000 b/d over the same period.

The number of oil-directed drilling rigs operating in the US for the week of June 24 was 330, according to Baker Hughes Inc. This is down from 628 rigs a year earlier.

As oil prices reach $50/bbl, operators have started to complete wells previously suspended after drilling.

Rystad Energy, an independent oil and gas consulting firm, estimated that more than 90% of wells drilled but uncompleted (DUC) can be commercially completed at a West Texas Intermediate crude price of $50/bbl. The firm expects horizontal oil completion activity in US shale plays to outpace drilling by 30% in the second half of 2016, resulting in the contraction of the DUC inventory by 800 wells. These completions will add 300,000-350,000 b/d to yearend production rate.

Wood Mackenzie projects WTI to reach $60/bbl in 2017 and suggests a rig recovery could start to gain momentum toward the end of 2016 and into 2017.

FIRST HALF US CRUDE PRODUCTION

Table 10

	First half [1]2016	First half [2]2015	Change, %
	— 1,000 b/d —		
PAD District 1	43	54	(20.4)
Pennsylvania	18	21	(14.3)
West Virginia	20	26	(23.1)
Others	5	7	(28.6)
PAD District 2	1,735	1,901	(8.7)
Illinois	25	26	(3.8)
Kansas	109	129	(15.5)
Michigan	16	18	(11.1)
North Dakota .1,	140	1,181	(3.5)
Ohio	70	65	7.7
Oklahoma	351	453	(22.5)
Others	24	29	(17.2)
PAD District 3	5,458	5,687	(4.0)
Alabama	23	27	(14.8)
Arkansas	17	19	(10.5)
Louisiana	1,315	1,352	(2.7)
Mississippi	58	72	(19.4)
New Mexico	380	414	(8.2)
Texas	3,665	3,802	(3.6)
PAD District 4	710	756	(6.1)
Colorado	320	319	0.3
Montana	72	83	(13.3)
Utah	88	108	(18.5)
Wyoming	230	247	(6.9)
PAD District 5	1,066	1,091	(2.3)
Alaska	515	487	5.7
California	550	603	(8.8)
Others	1	1	—
Total	**9,012**	**9,488**	**(5.0)**

[1]OGJ estimate. [2]Preliminary.
Source: Energy Information Administration

IEA also stated that, following the recovery in oil prices to $50/bbl and a market closer to balance next year, a slight uptick in completions is expected through 2016 and into 2017.

US REFINERY UTILIZATION Table 11

	Crude runs	Input to distillation units	Operable capacity	Utilization rate, %
	1,000 b/d			
1987	12,854	13,003	15,642	83.1
1988	13,246	13,447	15,927	84.4
1989	13,401	13,551	15,701	86.3
1990	13,409	13,610	15,623	87.1
1991	13,301	13,508	15,707	86.0
1992	13,411	13,600	15,460	87.9
1993	13,613	13,851	15,143	91.5
1994	13,866	14,032	15,150	92.6
1995	13,973	14,119	15,346	92.0
1996	14,195	14,337	15,239	94.1
1997	14,662	14,838	15,594	95.2
1998	14,889	15,113	15,802	95.6
1999	14,804	15,080	16,282	92.6
2000	15,067	15,299	16,525	92.6
2001	15,128	15,352	16,582	92.6
2002	14,947	15,180	16,744	90.7
2003	15,304	15,508	16,748	92.6
2004	15,475	15,783	16,974	93.0
2005	15,220	15,578	17,196	90.6
2006	15,242	15,602	17,385	89.7
2007	15,156	15,450	17,450	88.5
2008	14,648	15,027	17,607	85.3
2009	14,336	14,659	17,678	82.9
2010	14,724	15,177	17,575	86.4
2011	14,806	15,289	17,736	86.2
2012	14,999	15,373	17,328	88.7
2013	15,312	15,724	17,818	88.3
2014	15,848	16,156	17,873	90.4
2015	16,207	16,433	18,026	91.2
2016*	16,450	16,700	18,350	91.0
1990-2016 change				
Volume	3,041	3,190	2,827	—
Percent	22.7	23.4	18.1	—
2015-16 change				
Volume	243	367	424	—
Percent	1.5	2.2	2.4	—

*OGJ estimate. Source: US Energy Information Administration

Natural gas liquids and liquefied refinery gases output will increase to 3.5 million b/d this year from last year's 3.27 million b/d. Most of this growth is expected to come from additional ethane and propane production following increases in demand for petrochemical feedstock in the US and abroad.

Imports, exports

US imported an estimated 7.9 million b/d of crude during this year's first half, up from an average of 7.35 million b/d last year, reversing a years-long decline. For the full year, oil imports will remain elevated and average 8 million b/d, OGJ forecasts.

Crude imports are trending up due to falling US oil production, higher demand from refineries, and the relative price strength of WTI and Louisiana Light Sweet crudes relative to Brent.

During this year's first quarter, the leading source of US crude imports was Canada, which supplied 3.43 million b/d, 43.6% of the total. Next was Saudi Arabia at 1.11 million b/d then Venezuela, at 716,000 b/d, and Mexico, 566,000 b/d.

Total US crude imports from OPEC increased 12.6% in the first quarter, compared with a contraction of 10.8% last year. Imports from Nigeria surged to 269,000 b/d in March, compared with an average of 57,000 for all of 2015. Imports from Saudi Arabia also surged to 1.26 million b/d in March from January's 1.05 million b/d.

Crude imports from non-OPEC countries averaged 4.85 million b/d for the first 3 months of 2016, compared to an average of 4.67 million b/d for full year 2015.

High US output of oil products and full inventories dampen product imports. According to the American Petroleum Institute, gasoline imports declined to 584,000 b/d in this year's first 5 months from 647,000 b/d over the same period last year.

US exports of petroleum products continue to increase, while crude exports decline. Total exports will increase 4.2% to 4.9 million b/d this year following a 13.7% increase last year.

Currently, about 50% of product exports move to South America and Latin America, with Europe, Asia-Pacific, and Canada receiving about 13% each (OGJ Mar. 7, 2016).

The share of domestic demand met by net imports will be 25.9%, compared with 23.9% in 2015, 26.7% in 2014, and 32.9% in 2013.

US inventories

US industry stocks of crude at midyear stood at 530 million bbl, up from 469 million in the first half of 2015 and well above the 5-year average. Crude in the Strategic Petroleum Reserve (SPR) remains at 695 million bbl.

EIA data show that US crude oil storage capacity utilization rises even as storage capacity grows. Weekly commercial crude oil inventories have increased by more than 71 million bbl, or 15%, since the end of September last year, pushing crude oil storage capacity utilization to a near record high of 73% for the week ending June 10.

From September 2015 to March 2016, the US added 34 million bbl—6%—of working crude storage capacity, the largest expansion of commercial crude oil storage capacity since EIA began tracking such data in 2011. The largest commercial crude oil storage capacity expansions since September were in the Midwest and Gulf Coast, which added 19 million bbl and 13 million bbl, respectively.

SPECIAL REPORT

Inventories of gasoline and distillate have been above the 5-year historical range for most of 2016.

At the close of the first half of 2016, gasoline stocks were up 6.5% from a year earlier at 235.5 million bbl, while distillate stocks were up almost 10% from a year earlier at 153 million bbl, OGJ estimates.

Refining

Refinery utilization will average 91% this year on operable capacity of 18.35 million b/d, OGJ forecasts. Last year, refineries ran at 91.2% of capacity on average.

During this year's first half, refinery utilization averaged 89.8% on operable capacity of 18.3 million b/d, compared with utilization 90.5% on operable capacity of 17.93 million b/d during last year's first half.

Refineries were running at maximum levels in the Gulf Coast, with several refineries back from maintenance. This compensates for lower levels in other areas, possibly reflecting diminished supplies of Canadian crude.

According to Simmons & Co., declining US onshore light oil production and transportation infrastructure development have narrowed inland light crude differentials. Medium and heavy crude production has been more resilient with the exception of temporary outages caused by one-time events such as Canadian wildfires. High-complexity refineries are expected to benefit from continued healthy medium and heavy crude oil discounts.

Gasoline crack spreads are under pressure due to higher production and elevated inventories. Distillate margins remain weak.

According to Muse, Stancil & Co., for the first 5 months of this year the Gulf Coast and Midwest cash refining margins averaged $10.03/bbl and $9.82/bbl, down respectively from $11.81/bbl and $15.94/bbl a year earlier. East Coast and West Coast margins averaged $3.17/bbl and $13.11/bbl, compared with $5.87/bbl and $22.88/bbl during the first 5 months of last year.

US IMPORTS

Table 12

Country	Share of total 2016 %	First quarter average 2016, 1,000 b/d	Change 2016-15, %	Annual average 2015, 1,000 b/d	Change 2015-14, %	Annual average 2014, 1,000 b/d
Sources of crude imports*						
Angola	1.9	149	20.2	124	(10.8)	139
Ecuador	3.6	282	32.4	213	(5.3)	225
Indonesia	0.6	44	29.4	34	70.0	20
Nigeria	2.6	205	259.6	57	(1.7)	58
Saudi Arabia	14.1	1,111	5.7	1,051	(9.3)	1,159
Venezuela	9.1	716	(8.1)	779	6.3	733
Other OPEC	6.5	510	21.1	421	(37.3)	671
Total OPEC	**38.3**	**3,017**	**12.6**	**2,679**	**(10.8)**	**3,005**
China	—	—	—	—	—	1
Canada	43.6	3,432	8.3	3,169	10.0	2,882
China	—	—	—	—	—	—
Colombia	6.2	485	31.1	370	25.9	294
Gabon	—	—	—	7	(56.3)	16
Mexico	7.2	566	(17.7)	688	(11.9)	781
Norway	0.5	41	355.6	9	—	9
Trinidad and Tobago	0.1	4	(42.9)	7	40.0	5
UK	0.2	17	54.5	11	10.0	10
Other Non-OPEC	4.0	313	(23.8)	411	20.2	342
Total imports	**100.0**	**7,875**	**7.1**	**7,351**	**0.1**	**7,344**
Sources of refined product imports						
Algeria	6.4	130	23.8	105	1.0	104
Saudi Arabia	0.8	16	128.6	7	0.0	7
Venezuela	2.8	58	13.7	51	(8.9)	56
Other OPEC	2.9	60	5.3	57	(12.3)	65
Total OPEC	**12.9**	**264**	**20.0**	**220**	**(5.2)**	**232**
Canada	30.9	630	7.7	585	15.8	505
Colombia	—	41	--	22	(4.3)	23
Italy	0.7	14	16.7	12	(25.0)	16
Mexico	3.5	71	1.4	70	14.8	61
Netherlands Antilles	—	—	—	—	—	—
Other Non-OPEC	50.0	1,022	(10.4)	1,141	7.6	1,060
Total imports	**100.0**	**2,042**	**(0.4)**	**2,050**	**8.1**	**1,897**

*Includes imports for the Strategic Petroleum Reserve.
Source: US Energy Information Administration

FIRST HALF CRUDE AND PRODUCTS STOCK

Table 13

	[1]2016, 1,000 bbl	Change 2016-15 %	[1]2015, 1,000 bbl	Change 2015-14, %	[1]2014, 1,000 bbl
Motor gasoline	235,500	6.5	221,028	1.0	218,830
Jet fuel	42,100	(3.7)	43,703	20.4	36,293
Distillate fuel oil	153,000	9.7	139,437	14.6	121,674
Residual fuel oil	40,600	(2.8)	41,753	13.9	36,657
Unfinished oils	89,000	3.4	86,035	(1.5)	87,325
Other	279,800	1.4	275,858	15.9	238,037
Total products stocks	**840,000**	**4.0**	**807,814**	**9.3**	**738,816**
Crude stocks[2]	530,000	12.9	469,539	22.3	383,886
Total	**1,370,000**	**7.3**	**1,277,353**	**13.8**	**1,122,702**

[1]At end of June. [2]Excludes Strategic Petroleum Reserve.
Source: US Energy Information Administration, 2014-2015. 2016, OGJ estimate.

Natural gas market

Front-month futures prices for gas averaged about $2.01/MMbtu in this year's first half, compared with $2.77/MMbtu for last year's first half.

Gas drilling is down in response to lower gas prices. The number of gas-directed drilling rigs operating in the US for the week of June 24 was 90, according to Baker Hughes. This is down from 228 rigs a year earlier. The number of gas-directed drilling rigs in the Gulf of Mexico fell to 4 from 8 for the same period.

Despite reduced drilling, natural gas supply in the US remains strong. Over the first 5 months, marketed gas production averaged 79.35 bcfd, compared with 78.18 bcfd over the same period last year, according to EIA.

Production trends diverge across regions. Gross production in Texas, the largest gas-producing state, averaged 21.7 bcfd for the first 4 months of 2016, down 10% from the same period a year earlier, according to the Railroad Commission of Texas. Meanwhile, total marketed gas production in the Marcellus region averaged 17.5 bcfd for this year's first half, up from 16.2 bcfd a year earlier, according to EIA.

Several factors contribute to strong gas supply, including strong production from newly completed "legacy" offshore wells, strong production from shale gas plays as DUC wells come online, increased production efficiency, and improved takeaway capacity in the form of pipelines and processing plants in emerging areas such as the Marcellus shale.

Gas demand is projected to grow 0.7% this year following a 2.9% increase last year, OGJ forecasts.

This year's increases in total gas consumption are mainly attributable to increases in use for power generation, led by a combination of coal-to gas switching and permanent coal retirements. But a warmer-than-normal winter in the first quarter of the year reduced overall electricity generation.

According to the National Oceanic and Atmospheric Administration, the continental US summer on average will be 3% cooler than last summer but 8% warmer than the 30-year average. Compared summer-over-summer, the total number of cooling degree days is nearly identical to 2015.

Natural gas inventories in March ended at 2.5 tcf, the highest end-of-withdrawal-season level on record.

For the past several weeks, injections have been somewhat lower than the previous 5-year average. Despite lower-than-average injections, the record-high starting point of the injection season allows for a projected end-of-October record high.

The US continues to be a net gas importer. During 2015, it imported 7.4 bcfd of gas, mostly from Canada by pipeline, and exported 4.9 bcfd, mostly to Mexico by pipeline. Gross imports represented nearly 10% of total supply in 2015.

Imports from Canada have fallen steadily since 2007. This year, due to a warm winter and record gas storage, the AECO Hub price in Alberta sank to a big discount against the US benchmark. This may encourage more gas imports from Canada.

SPECIAL REPORT

Deliveries from LNG regasification terminals in the US Northeast area have jumped. The crude price, used as a benchmark in many LNG contracts, fell, making imports competitive in the eastern US, where a lack of adequate pipeline capacity keeps local price high.

US exports to Mexico increased to a record 1.054 tcf in 2015 to meet increasing demand from new power plants. Higher production of gas from the US Gulf Coast and the Eagle Ford shale in southern Texas as well as new pipeline capacity contributed to the increase. Pipeline projects still under way in the US and Mexico will help to bring US pipeline exports to Mexico to record levels.

US LNG exports will increase substantially this year with the start up of Cheniere's Sabine Pass LNG liquefaction plant in Louisiana, which sent out its first cargo in February.

Sustained E&P spending cuts may lead to underinvestment, report warns

Nick Snow
Washington Editor

Competing cash priorities during depressed oil and gas prices could increase the risk of long-term underinvestment, a recent Deloitte Center for Energy Solutions report warns.

"When prices are depressed, the No. 1 move in most companies' playbooks is to cut capital expenditures. We may see a huge capital migration out of the industry," said John W. England, vice-chairman and US oil and gas leader at Deloitte LLP.

Simply keeping reserve levels flat takes 80% of a company's production budget, England told reporters on June 21 during Deloitte's 2016 Washington Energy Conference. "Companies will prioritize, so the emphasis will be on developing their established reserves and less on finding new resources," he said.

Maintaining sufficient oil and gas reserves is a good strategy for exploration and production companies, but a lot of development capital will need to be spent to bring them into production, England said. "So many projects have been deferred or canceled in this low-price environment that there's a potential for tighter supplies around 2018," he said.

Emphasizing development over exploration could result in other long-term consequences, another Deloitte official cautioned. "If a capital-constrained sector focuses on spending more on development for too long, major potential resources off Brazil and elsewhere will be kicked to the back of the queue," said Andrew Slaughter, who is the Center for Energy Solutions' executive director.

E&P companies have reduced their spending drastically already, the report noted. "In fact, after reducing capex by about 25% in 2015, the global upstream industry, excluding the Middle East and North Africa, has announced further cuts of 27% in 2016," it said. "These cuts have reduced spending to below the minimum required levels to offset resource depletion, let alone meet any expected growth."

England said, "We think about $600 million/year will be needed for the next 5 years to reach the necessary $3 trillion the global E&P industry needs to ensure its long-term sustainability. Companies are expected to budget about $2 trillion. The rest will need to come from additional debt. There will be other calls on cash flow, such as dividend payouts, which could increase their deficits."

Oil and gas issues unsettled after UK vote to leave EU

Bob Tippee
Editor

Policies affecting oil and natural gas join myriad issues thrown into question by the UK's vote on June 23 to withdraw from the European Union.

An immediate question is the status of Scotland and its crucial role in operations on the UK Continental Shelf. Scottish voters strongly supported retaining membership in the EU. Leaders of the Scottish government were reported to be seeking ways to maintain ties to the EU, possibly in conjunction with Gibraltar and Northern Ireland, where voters also supported staying in the union.

The UK vote also revived speculation about Scottish independence, although First Minister Nicola Sturgeon called a new referendum on that issue "highly unlikely." An independence initiative failed in 2014.

Also of obvious concern is the flexibility of oil and gas workers to move between the UK and other EU members, now unrestricted. Immigration issues will be subject to negotiations that will begin once the UK provides formal notice of its intention to withdraw. Those talks are supposed to be completed within 2 years unless the parties agree to an extension.

Energy, environmental measures

Negotiations also will have to resolve the British relationship with a host of EU energy and environmental measures, many of which the UK has enacted into law.

The UK's status in the Energy Union, for example, is now unclear.

That project seeks to harmonize efforts of EU members toward supply security, a fully integrated internal energy market, energy efficiency, climate action and emissions reduction, and research and innovation on climate.

As a supporter of energy liberalization, the UK government can be expected to want to stay connected with the effort, if welcome. But it will need terms of participation as an EU nonmember.

Related to the Energy Union is the EU's Third Energy Package, which legislates liberalization of electricity and natural gas transmission through unbundling of supply and transportation. Another part of the package encourages cross-border cooperation between transmission system operators.

The UK has gas-pipeline connections with three EU members, Belgium, the Netherlands, and Ireland.

Existing EU directives and regulations directly affecting oil and gas cover matters such as obligatory oil and gas inventories, offshore safety, information-sharing, and price transparency.

Climate initiatives

More generally, the EU has aggressive programs for climate-change mitigation and decarbonization of energy supply. In many cases, the UK has parallel programs of its own.

The EU, for example, has set targets for reducing emissions of greenhouse gases (GHGs) by at least 20% from 1990 levels by 2020. By that year, it wants 20% of energy supply to come from renewable sources and energy efficiency to improve by 20%.

For 2050, the EU seeks cuts in GHG emissions of 80-95%.

The UK has set a target for GHG emission cuts in 2050 of 80% and a renewable-energy market share in 2020 of 15%. Its climate-change legislation includes 5-year "carbon budgets" and covers adaptation measures.

The UK participates in the EU's Emissions Trading Scheme (ETS) and had a cap-and-trade system of its own before the European version began operation.

If the breakaway country stays on course with climate mitigation, it probably will want to remain part of the ETS.

But even that is uncertain after the resignation of Prime Minister David Cameron, a supporter the country's climate policies who wanted his country to remain in the EU and called for the vote that contradicted his wishes. OGJ

CAPP: Oil pipelines urgently needed

Oil pipelines are "urgently needed" in Canada, the Canadian Association of Petroleum Producers said in its 2016 Crude Oil Forecast, Markets, and Transportation report.

"Canada's energy future relies on our ability to get Canadian oil and gas to the people who need it," said Tim McMillan, CAPP president and chief executive officer. "We need the infrastructure to connect Canadian energy to the global economy."

The CAPP report noted that Canada's oil supply will soon greatly exceed its current pipeline capacity. The pipeline network can move about 4 million b/d, which "closely matched" the 2015 average supply of 3.981 million b/d.

But CAPP said more than 850,000 b/d of additional oil sands supply will be available by 2021. Between 2021 and 2030, supply from Canada's oil sands is forecast to increase more than 700,000 b/d, requiring additional transportation systems.

CAPP said current delays in startup dates for several oil pipeline projects mean railways will continue to complement pipeline transportation.

CANADIAN CRUDE OIL SUPPLY Table 1

	2015	2020	2025	2030
	Million b/d			
Eastern Canada	0.18	0.24	0.17	0.09
Western Canada				
Light	1.44	1.36	1.39	1.46
Heavy	2.54	3.21	3.48	3.99
Western Canada	3.98	4.57	4.87	5.45
Total Canada*	**4.16**	**4.81**	**5.04**	**5.54**

*Totals may not add up due to rounding.
Source: Canadian Association of Petroleum Producers

CANADIAN CRUDE OIL PRODUCTION Table 2

	2015	2020	2025	2030
	Million b/d			
Eastern Canada	0.18	0.24	0.17	0.09
Western Canada Conventional				
(including C5+/condensate)	1.31	1.09	1.11	1.17
Oil sands	2.37	3.06	3.28	3.67
Western Canada	3.68	4.15	4.39	4.83
Total Canada*	**3.85**	**4.39**	**4.56**	**4.93**

*Totals may not add up due to rounding.
Source: Canadian Association of Petroleum Producers

Supply—the total volume after imported diluent is added to production—is expected to increase 37% over the next 15 years to 5.5 million b/d by 2030. "Due to the increase in total volume, all forms of transportation are needed to get Canadian oil to new and existing markets," CAPP said.

Oil sands remain the primary driver for growth in Canadian crude oil production, with 3.7 million b/d expected by 2030. CAPP's forecast a year ago for 2030 was 4 million b/d (OGJ Online, June 11, 2015).

Conventional oil production in western Canada, including condensates, drops from 1.3 million b/d in 2015 to 1.1 million b/d by 2018, and is expected to remain relatively stable to 2030.

Canada, the sixth largest producer in the world in 2015, spent $17 billion in 2015 importing oil from countries such as the US, Saudi Arabia, Algeria, Angola, and Nigeria. About 600,000 b/d was imported to meet refinery needs in Quebec and Atlantic Canada. OGJ

Production of Canadian oil—the total volume of oil before imported diluent is added—will increase 28% over the next 15 years to 4.9 million b/d by 2030, compared with 3.8 million b/d in 2015.

Analysis: Panama Canal expansion will first benefit US LPG exports

Christopher E. Smith
Managing Editor-Technology

The opening of a new, third set of locks on the Panama Canal will cut the distance between the US and Far East by more than one-third for vessels that can now transit the waterway but hadn't been able to before. A voyage from the US Gulf Coast to the Far East around the Cape of Good Hope typically takes 45 days vs. the 25-30 taken by passage through the canal.

Old Panamax vessels could measure up to 965 ft long, with a 106-ft beam and 39.5 ft draft. Neopanamax ships can measure 1,200 ft by 160 ft by 50 ft, boosting capacity to 400,000-600,000 bbl from 300,000-500,000 bbl.

This increase will allow passage of the very large gas carriers typically used to carry propane and other LPG and products tankers but falls short of the scale needed to accommodate fully loaded very large and ultra-large crude carriers, the vessels that haul the majority of crude shipments. VLGC passage will be far more efficient than the ship-to-ship transfers required until now to move LPG across the isthmus.

Distillate and gasoline led Atlantic-to-Pacific petroleum traffic through the canal last year, with a respective 9.5 million and 9.1 million long tons, according to the US Energy Information Administration. But net US length in these markets doesn't compare to that in ethane and propane, for which the ability to move more volume more quickly will be a welcome relief. The continued strength of demand for refined products in western South America also is questionable.

China is already the biggest single customer for US propane and second-biggest for LPG and the ability to move these volumes more efficiently will likely only increase that flow. EIA data show trade to both China and Japan having already accelerated before the canal expansion's opening. LPG shipments to Japan more than tripled to 166,000 b/d in the first 3 months of 2016 from 49,000 b/d for the same period last year. Shipments to China jumped to 161,000 b/d from 66,000 b/d in the same window.

The first VLGC to pass through the new locks will be the Lycaste Peace, carrying propane from Enterprise Products Partners for discharge in Tokyo Bay in Japan. By 2018 US exports of LPG will likely equal those of Qatar and the United Arab Emirates combined (OGJ, June 6, 2016, p. 28).

The expansion will also shorten the journey for future US LNG exports. All LNG carriers except the Q-Flex and Q-Max ships, limited by their excessive beams, will now be able to pass through the Panama Canal compared with only a small portion of the fleet that could before. Stagnant LNG demand, however, will likely limit the shipment of US-sourced LNG through the canal for the time being, particularly given the proximity of new Australian liquefaction capacity to Asian markets. OGJ

Washington state DNR opposes Vancouver rail-to-marine oil terminal

Nick Snow
Washington Editor

A proposed Vancouver, Wash., rail-to-marine crude oil terminal poses such serious fire, landslide, and spill risks that the state's Energy Facility Site Evaluation Council (EFSEC) should not certify it without more safety and environmental safeguards, Washington's Department of Natural Resources said.

"Based on the evidence as a whole, DNR asserts that EFSEC cannot meet its obligations to assure the public that the proposal contains adequate safeguards for public welfare and protection, and to ensure the proposal will have minimal adverse environmental consequences," DNR said in a June 20 filing prior to EFSEC's scheduled June 27 adjudication hearing on the proposed project.

"Accordingly, EFSEC should deny the application to certify the proposal," DNR's filing recommended.

The joint venture of Tesoro Refining & Marketing Co. LLC and Savage Cos. would receive crude by rail and load it onto ships bound for US West Coast refineries, its sponsors say. No oil would be refined there and it would not increase transportation fuel use in the area, they note. The facility was expected to handle an average 360,000 b/d of light crude and cost $75-100 million when it was announced in 2013.

EFSEC's previously scheduled hearing will occur weeks after a Union Pacific train hauling crude derailed across the Columbia River and farther upstream in Mosier, Ore. About 1,000 bbl of Bakken crude spilled from overturned tank cars. The town was briefly evacuated and water use restrictions were imposed for several days. The spilled crude did not ignite and no one was injured (OGJ Online, June 8, 2016).

DNR's filing outlined concerns about possible wildfires, for which the department's firefighting crews would be available only during the summer fire season, while the terminal would operate year round. "In addition, response to a crude oil fire requires specialized training, materials, and equipment that DNR wildland firefighters do not possess," it said.

Fire's estimated cost

The filing noted that Vancouver's fire expert, Robert Blackburn, has estimated that a derailment and fire within the city limits could cost $5-6 billion. "As noted by Mr. Blackburn, commercial insurance is not available for such catastrophic losses, and even the largest railroad would be unable to cover them," it said.

Landslide risks to train travel along the rail corridor also have not been addressed, the filing continued. "A landslide hitting a train would create an obvious potential source of derailment. Without hitting trains, however, landslides can also indirectly lead to derailments by forcing trains to stop suddenly and by damaging tracks," it said.

The Columbia River Gorge, which contains a significant part of the rail line associated with the proposal, has been among the most landslide-prone areas in the state in the recent past, according to the filing.

Another estimate found that damages associated with a worst-case spill into the Columbia River would exceed $84 million, and associated ecosystems would take nearly 9 years to recover.

Noting that a 2013 crude-by-rail accident in Lac Megantic, Que., killed 47 people and destroyed the city's downtown, DNR's filing said that dollar figures associated with a catastrophic oil train derailment and fire do not provide "an adequate measure of the true human cost of a worst-case disaster involving shipment of crude by rail (OGJ Online, July 8, 2013). OGJ

FRA: Failure to maintain track led to Oregon oil train accident

Nick Snow
Washington Editor

Union Pacific's failure to maintain track and equipment led to the June 3 derailment of a crude oil train, a fire, and a 1,100-bbl spill near the town of Mosier, Ore., the Federal Railway Administration (FRA) said in a June 23 preliminary finding (OGJ Online, June 8, 2016).

A preliminary investigation determined that broken lag bolts, leading to wide track gauge, caused the derailment, the US Department of Transportation's FRA said. The loosened tie plates allowed the rails to be pushed outward as trains moved across them, eventually resulting in a wide gauge area that made the train derail, it explained.

"Broken and sheared lag bolts, while difficult to detect by high-rail, are more detectable by walking inspection combined with indications of movement in the rail or track structure and/or uneven rail wear, and are critically important to resolve quickly," it added.

FRA said that following the derailment, it:

- Conducted walking inspections of all the curves in the Columbia River Gorge to inspect for additional track, fastener, or bolt issues.
- Conducted similar inspections of Burlington Norther Santa Fe track on the Washington side of the Columbia River.
- Searched its databases for tie fastener trends across the rail industry.
- Commissioned Volpe, one of DOT's research centers, to test the broken bolts' metallurgy.
- Ran a geometry car with a Gage Restraint Measurement System on UP track to rule out wide gauge on the railroad's Portland, Ayer, and Spokane subdivisions.
- Confirmed that nine UP temporary speed restrictions remain in place in the railroad's Portland subdivision, including a 10-mph speed restriction in Mosier.
- Evaluated potential enforcement actions, including violations, and other actions to ensure UP's compliance with applicable safety regulations.

FRA said the train originated in New Town, ND, and was bound for Tacoma, Wash. It consisted of two head-end locomotives, one distributed power locomotive at the rear, two buffer cars, and 94 tank cars loaded with Bakken crude oil. The train was operating with conventional air brakes. Dakota Plains, which loaded the crude, said it had a 9.2 psi vapor pressure at the North Dakota loading facility.

"During the derailment, a coupler struck one tank car, mechanically puncturing it," FRA said. "This puncture allowed crude oil to come into contact with an ignition source, leading to a fire that burned for approximately 14 hr. Four cars were eventually involved in the fire."

The four tank cars involved in the fire were the punctured car and three additional tank cars—two that had their bottom outlet valves sheared off in the derailment, and one car with the gasket melted out from under the manway cover, it said.

Oregon's Department of Transportation asked its federal counterpart to temporarily halt movement of trains carrying crude oil in the state until ways are found to prevent a track bolt failure that led to the derailment and crude oil spill near Mosier (OGJ Online, June 17, 2016). OGJ

TAEP: Upstream job losses in Texas eclipse 100,000 despite rising oil prices

An increase in crude oil prices in Texas to $43.38/bbl in May from $27.08/bbl in February couldn't prevent the tally of upstream job losses from surpassing 100,000, according to the Texas Alliance of Energy Producers' latest Texas Petro Index (TPI).

Total upstream jobs in the state during May averaged 205,100, down 21.2% from the May 2015 average and 33% from the estimated high of 306,020 in December 2014. Estimates from the TPI show the trough in upstream employment before December 2014 was 184,640 in October 2009. During the previous growth cycle, industry employment peaked at 225,965 in October 2008.

"The last time industry employment was this low was in late 2010, as the [most recent] expansion of upstream oil and gas activity in Texas was just beginning to take off," noted Karr Ingham, economist and creator of the TPI.

A composite index based on a comprehensive group of upstream economic indicators, the TPI in May was 159.9, down 39.7% year-over-year. Before the current economic downturn, the TPI peaked at a record 313.3 in October and November 2014, which marked the zenith of an economic expansion that began in December 2009 when the TPI stood at 187.4.

Other TPI indicators revealed the upstream economy in Texas continued to deteriorate in May. The number of drilling permits granted by the Texas Railroad Commission totaled 606, the fewest for the month in the history of the TPI, which dates back to 1995. The number of permits issued year-to-date through May totaled 2,883, the fewest in the first 5 months of the year since 1999.

The Baker Hughes Inc. count of active drilling rigs in Texas during May averaged 182, down by just more than half year-over-year. However, the count for the week ended June 24 rose for the fourth consecutive week, gaining 21 units during that time (OGJ Online, June 24, 2016).

"Dramatically lower demand for drilling, oil-field services, and even labor appear to have driven down costs enough that some operators calculate they can develop some properties profitably with oil prices at current levels," said Ingham. "But there still is a lot of work to do to bring global oil supply and demand into line with one another."

Crude oil production in Texas during May totaled an estimated 103.7 million bbl, down 5.1% compared with the May 2015 total. The value of Texas-produced crude totaled nearly $4.5 billion, falling 26.4% year-over-year.

Estimated Texas natural gas output was 721.4 bcf, a year-over-year monthly decline of 3.1%. With natural gas prices in May averaging $1.76/Mcf, the value of Texas-produced gas fell 37.5% to $1.27 billion. OGJ

Tesoro acquires North Dakota refinery

Robert Brelsford
Downstream Technology Editor

Tesoro Corp. affiliate Tesoro Refining & Marketing Co. LLC has completed a deal with WBI Energy Inc., a subsidiary of MDU Resources Group Inc., Bismarck, ND, to become 100% owner of Dakota Prairie Refining LLC (DPR), the former MDU Resources-Calumet Specialty Products Partners LP joint venture that operates a 20,000-b/d diesel refinery near Dickinson, ND (OGJ Online, Feb. 7, 2013).

To execute the transaction, WBI acquired Calumet's 50% membership interests in DPR on June 27, the same day on which it completed its sale to Tesoro, MDU Resources said in a filing to the US Securities & Exchange Commission.

As consideration for the purchase, Tesoro is ensuring continued servicing of DPR's existing $66-million term-loan debt as well as contributing about $10 million toward working capital, the San Antonio-based independent operator said.

With the sale of the refinery, MDU Resources said it expects an aftertax impairment in the range of $150-160 million in this year's second quarter, subject to customary closing adjustments, as a result of its discontinued refining operations.

Despite the plant's strong and smooth operations, MDU Resources decided to shed the Dickinson refinery as a result of its poor financial performance due to low commodity prices, according to David L. Goodin, MDU Resources president and chief executive officer.

Alongside reducing exposure to commodity prices, the refinery sale will enable MDU Resources to focus on other growth opportunities, which include a $1.5-billion, 5-year capital investment plan at its regulated utility businesses as well as a $50-million potential natural gas pipeline expansion project in North Dakota, Goodin said.

The first US refinery to be commissioned in nearly 40 years upon its startup in May 2015, the Dickinson refinery processes nearby Bakken crude feedstock to produce about 8,000-b/d of ultralow-sulfur diesel (ULSD), naphtha, and atmospheric tower bottoms.

Last year and as recently as early 2016, MDU Resources was evaluating operational improvements to the refinery that could increase its daily processing capacity and profitability.

In its 2015 annual report to investors issued in February, however, MDU Resources warned that increased crude feedstock costs as well as weaker demand for diesel and naphtha amid ongoing reduced oil field activity in the region likely would continue to negatively impact the refinery's profitability.

Tesoro Refining & Marketing Co. LLC, an affiliate of Tesoro Corp., has completed a deal with MDU Resources Group Inc. subsidiary WBI Energy Inc. to become 100% owner of Dakota Prairie Refining LLC, the former MDU Resources-Calumet Specialty Products Partners LP joint venture that operates a 20,000-b/d diesel refinery near Dickinson, ND. Photo from Tesoro.

New life

For Tesoro, which operates its 74,000-b/d Mandan refinery about 100 miles east of the Dickinson refinery, the recent acquisition presents new opportunities for continued growth in the region.

"We have already identified plans to drive substantial improvements [at the refinery], and we are prepared to execute on these plans in 2016," said Greg Goff, Tesoro chairman, president, and chief executive officer.

Proposed improvements include system-wide commercial and feedstock optimization, increased efficiencies in distribution, and reduced transportation and refining costs.

Even if currently weaker economic conditions persist, Tesoro expects its improvement plan for the Dickinson refinery will help generate more than $20 million in annual operating income from the business, Goff added.

Tesoro, which plans to utilize naphtha and resid produced by the refinery in its integrated refining system, said it will continue to market ULSD produced at the plant to local customers. OGJ

ExxonMobil breaks ground on Rotterdam hydrocracker expansion

Robert Brelsford
Downstream Technology Editor

ExxonMobil Corp. has started construction on the planned expansion of hydrocracking operations at subsidiary Esso Nederland BV's 191,000-b/d refinery in Rotterdam, Zuid-Holland, Netherlands.

The company broke ground on construction for the project on June 15, the Port of Rotterdam said.

Valued at an investment of more than $1 billion, ExxonMobil's Rotterdam expansion will include the following:

• Construction of a hydrocracking unit based on Exx-

Construction on the Esso Refinery Rotterdam began in 1958 and, in May 1960, the refinery was officially opened. The plant has been regularly modernized throughout its life with the last major modernization occurring in the mid-1980s. Photo from ExxonMobil Corp.

onMobil's proprietary hydrocracking technology that will enable increased production of ultralow-sulfur fuels (diesel, kerosine) and base oils from semifinished, high-sulfur feedstock.

- Minor modifications to the refinery's existing hydrocracker that will add reactors as well as a vacuum distillation section to increase processing capacity to 415 tonnes/hr from its current capacity of 330 tonnes/hr.
- Construction of six tanks that will boost storage capacity at the refinery by 140,000 cu m.

First announced in October 2015, the hydrocracking expansion at Rotterdam comes as part ExxonMobil's plan to increase the refinery's capability to upgrade heavier byproducts into high-quality lubricating oils, greases, and ULS ultralow-sulfur diesel to meet growing market demand for those products (OGJ Online, Oct. 29, 2015).

While the project will not alter the refinery's nameplate crude processing capacity of 191,000 b/d, it will increase capacity to process an existing heavy vacuum gas oil stream (HVGO) as feedstock for the hydrocracker rather than being sold to market, eliminating altogether the plant's output of HVGO and hydrocrackate.

Following the expansion, the Rotterdam refinery will become the first in Europe able to produce ExxonMobil's EHC Group II base stocks, which are designed to help lubricant blenders meet evolving industry requirements by enabling greater formulation flexibility and simplifying global qualification testing.

The project, which also will improve energy efficiency at the refinery by 5%, remains on schedule for startup in 2018, according to the Port of Rotterdam.

The Rotterdam project follows a series of previously announced expansions by ExxonMobil to boost production of more profitable products at its Baytown, Tex., Antwerp, Belgium, and Jurong Island, Singapore, manufacturing sites (OGJ Online, Aug. 12, 2015). OGJ

Voters back more oil, gas development, API-commissioned poll finds

Nick Snow
Washington Editor

A majority of registered US voters support more US oil and gas development and are more likely to back a candidate who shares that view, a survey commissioned by the American Petroleum Institute found. "This makes clear that the American people want a national energy policy that expands the gains we've made in the last few years," API Pres. Jack N. Gerard said at a June 21 event where the poll's results were released.

Harris Poll conducted the telephone survey of 1,001 voters May 10-15. Of the respondents, 47% were men and 53% were women. By political party, 31% said they voted Republican, 31% said Democrat, 24% said Independent, 9% said other, 2% were not sure, and 3% declined to answer. Results were weighted to be representative of registered voters nationwide.

Of the respondents, 69% said they were more likely to vote for a candidate who supports developing more oil and gas; and 73% (79% of the Democrats and 69% of the Republicans) back a national energy policy that assures a secure supply of abundant, affordable, and available energy developed and produced in an environmentally responsible manner.

"We're increasing our energy production in a growing, albeit slowly, economy while reducing our carbon emissions. It's a national position that's unique in the world," Gerard said.

The survey's results also showed that:

- 80% (including 75% of the Democrats, 91% of the Republicans, and 81% of the Independents) said increased access to US oil and gas resources could help reduce consumers' energy costs.
- 73% (including 63% of Democrats, 80% of Republicans, and 78% of Independents) believe federal regulations can contribute to increased retail gasoline costs.
- 77% support more US oil and gas production.
- 77% think it is important that the US is doing better than all of the other major economies when it comes to reducing greenhouse gas emissions, and 70% support natural gas's role in this reduction.
- 82% supported increased development of the country's energy infrastructure.
- On the federal Renewable Fuel Standard, 77% were concerned about government requirements that would increase the amount of ethanol in gasoline, given the fact most motor vehicle manufacturers don't warrant their products against potential damages from higher ethanol concentrations.
- 71% oppose legislation that could increase the cost of oil and gas operations, potentially driving up energy costs for consumers.
- 64% oppose higher taxes that could decrease investment in energy production and reduce energy development.

"The test that any proposed energy policy or imposed government regulation should satisfy is: will it make energy more affordable for the con-sumer; is it better for the environment; does it grow our economy; and will it enhance our national security?" Gerard said. "If not, then it clearly isn't what's best for our nation, our environment or America's energy future." OGJ

Regional reserves growth shows decline in annual rate of increase

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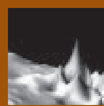


EXPLORATION & DEVELOPMENT

Recoverable reserves of hydrocarbon liquids will grow 614 billion bbl from 2014 to 2044. Natural gas reserves will increase 87 trillion cu m (tcm) in the same 30-year period. This estimate results from a new region-specific model for assessing global reserve growth.

The model reflects regional conditions and resource characteristics in estimating reserve growth by using a new method called "segment-accumulation multiplier." This methodology can forecast reserve growth more accurately than previous means, given its focus on region-specific factors.

Already discovered fields provide the majority of reserves growth, as continued exploration and development expand their resource bases.

Previous assessment

In 2000 the US Geological Survey (USGS) modeled reserves growth based on historical data of recoverable reserves in the US and 128 geological provinces discovered before 1996 outside the US (Fig. 1). The model predicted oil reserves to reach 612 billion bbl with 93.5 tcm of natural gas by 2030. The USGS cross-referenced its assessment in 2012 with IHS's database to validate its 1996-2003 forecast. The findings verified a forecast average oil reserve growth of 28%, suggesting that the USGS's statistical method was reliable.[1]

Reserve growth comprises added resources in existing fields and new discoveries once they enter development.[2] Increases are refined during the field's life cycle. Studies in geology and engineering achieve reserve growth by several means:

- In known accumulations, improved recovery efficiency increases reserves and provides updated parameters for reserves computation.
- Continued exploration and appraisal expand reserves.
- Development drilling adds new discoveries, i.e. new pools and reservoirs.[3]

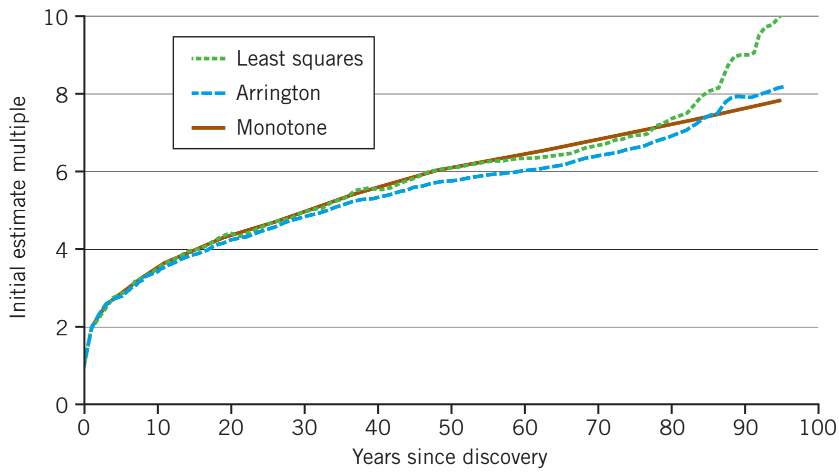
Techniques such as infill drilling, well stimulation, completions of bypassed zones, and recompletions are crucial to reserves growth. Quantitative evidence shows that a complete assessment of global resources requires a forecast of future reserve growth potential.

Reserves increases for countries or specific regions are quantified by a combination of the previous year's reserves, adding reserve growth, and new discoveries. Based on the study presented in this article, reserve growth volume has been higher than new discoveries' volume for the past 10 years.

Geological conditions and recovery efficiencies differ across regions. A precise forecast cannot rely on one reserve growth model. Our 2010 assessment studied factors influencing reserve growth in different regions of the world (Table 1). The petroleum re-

ESTIMATED RESERVES, CUMULATIVE CHANGE

FIG. 1



source-management system developed individual models for each of the dominant regions:

- North America.
- Former Soviet Union (Commonwealth of independent states or CIS).
- Northern Europe.
- Oceania.

The Oceania model assesses reserves growth of Australia, New Zealand, and Papua New Guinea (Fig. 2). The models provided a refined forecast of reserves growth when compared with the USGS 2000 report.[4]

Analogous assessment

The USGS reserve growth forecast with individual accumulation analysis in 2012 included considerations for recoverability and uncertainty in its assessment (Fig. 3).[2] Resulting reserve growth is represented by total production plus remaining and recoverable reserves.

The forecast presented in this article is based on the US reserve growth assessment. The method used generates probability distribution of reserves recoverability based on 68 US oil accumulations. It then applies this sampling distribution to oil accumulations outside the US, yielding a reserve growth of 665 billion bbl of oil, 40 tcm of natural gas, and 16 billion bbl of natural gas liquids.[5]

Geological conditions and reservoir engineering differ across regions. A direct application of the US assessment method will lead to biased results for reserve growth in other countries. More importantly, the USGS model does not consider time aspects in its forecast, which limits its usefulness in making reserve growth estimates for the next 10-30 years.

In the US, 70% of potential reserve growth is found in 68 assessed individual oil accumulations.[6] Globally, giant fields (>500 MMboe) in 2014 numbered 1,186 and made up 74% of the world's recoverable 2P conventional reserves. This distinction highlights the importance of regionally focused reserve growth.

New assessment

The reserves growth assessment presented in this article classifies global oil and gas accumulations into eight regions:

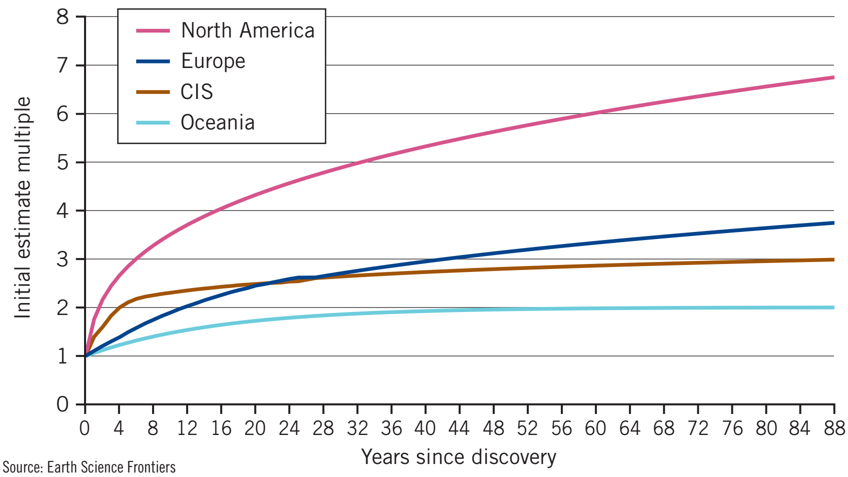
- CIS.
- North America
- Europe
- Latin America
- Middle East
- Africa
- Asia
- Oceania

Our research applied a statistical method to build reserve growth models for each region and forecast growth to 30 years.

The study applied USGS's model to North America and the segment-accumulation multiple to build reserve growth models based on changes in recoverable reserves for giant fields in the remaining regions. These new models provide predictive rates of increase on a regional basis, making forecast results more credible.

RESERVES GROWTH, 2010

FIG. 2



Source: Earth Science Frontiers

GLOBAL RESERVE-GROWTH FORECAST

Table 1

Region	Recoverable reserves 2008	Recoverable reserves 2030	Reserve growth	Increase, %
	million bbl			
Middle East	1,103,105	1,262,119	159,014	14.40
CIS	362,253	388,105	25,852	7.10
Latin America	422,720	521,485	98,765	23.40
Europe	93,800	114,022	20,222	21.60
Africa	254,672	331,346	76,674	30.10
Asia Pacific				
South Asia	92,713	103,012	10,299	11.10
Oceania	11,099	12,355	1,256	11.30
Rest of Asia	70,518	91,154	20,636	29.30
Global	2,410,880	2,823,599	412,719	17.10

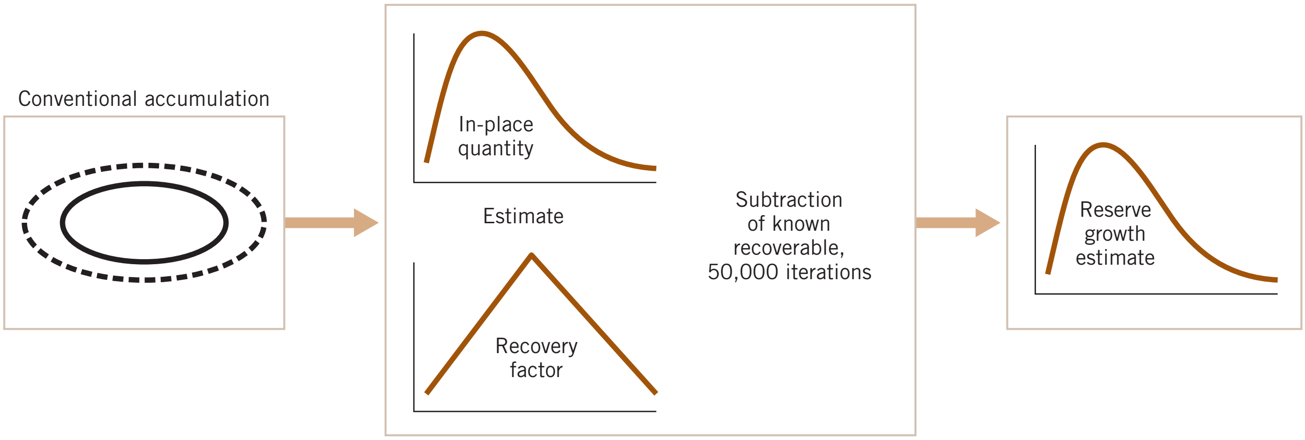
EQUATIONS

$$CGF_{12,47} = MGF_{17,23} \times MGF_{24,29} \times MGF_{30,35} \times MGF_{36,40} \times MGF_{41,45} \times MGF_{46,47} \quad (1)$$

$$CGF = \alpha (YSD)^{\beta} \quad (2)$$

USGS APPLIED METHOD, 2012*

FIG. 3



*Recoverable quantities subtracted from the ultimate recoverable resources provide estimates of potential reserve growth.

RESERVES REGRESSION PARAMETERS*

Table 2

	North America	Middle East	Africa	Latin America	Asia	Oceania	CIS	Europe
α	1.7575	1.2738	0.800	0.7492	0.8984	1.0549	1.6474	1.0713
β	0.3005	0.3245	0.265	0.3600	0.4041	0.1540	0.1358	0.2790
R^2	0.9930	0.9120	0.921	0.9480	0.8920	0.9410	0.9780	0.9800

*The values of α and β in each region represent the regression of cumulative growth factors.

RESERVES GROWTH TO 2044*

Table 3

	Recoverable reserves				Reserves growth, 30-year	
	2014		2044			
Region	Liquid, billion bbl	Gas, tcm	Liquid, billion bbl	Gas, tcm	Liquid, billion bbl	Gas, tcm
Middle East	1,245	106	1,453	134	208	28
Africa	260	29	325	40	65	11
Latin America	606	24	787	34	181	10
Asia	171	36	235	55	64	20
Oceania	16	10	18	12	2	2
CIS	382	99	413	109	32	10
Europe	106	21	132	25	26	5
North America	65	5	98	7	33	2
World	2,851	330	3,461	416	610	87

*North America's assessment includes federal waters and Alaska but excludes onshore fields in the Lower 48 states due to no available field data.

Applied method

The segment-accumulation multiple method overcomes shortages and discontinuity of data inherent to historical reserves, especially in giant fields. The process begins with selection of a giant field with relatively abundant reserve history; i.e. data from IHS, Carbonates and Clastics Reservoirs Co., and the American Association of Petroleum Geologists. For each region our method:

- Built a database using available information.[7-10]
- Calculated the age of each accumulation by years since discovery.
- Summed the recoverable reserve from each year's report.

Because reserve data is often sparse, we segmented computations of reserve growth factors in different stages for each oil and gas accumulation in the database. This process yielded a primary reserve growth factor (PGF). The weighted reserve growth factor (WGF) was computed from the summary statistics of PGF for oil and gas accumulations of similar age. Outliers were tossed out in summary statistics. We then used the cumulative multiple of WGF in consecutive segments to obtain the cumulative growth factors (CGF).

For example, as shown in Equation 1 (see box), the Halfaya oilfield in the Middle East is 17 years old, and its reserve growth in 30 years CGF (i, i+30) is the multiple of 6 consecutive WGFs.[2]

We applied regression analysis on CGF to build reserve growth models for large petroleum accumulations in each region (Fig. 4). The regression curves use the form described by Equation 2 as the curve with the best fitness results, where YSD is the number of years since discovery.[1] Table 2 summarizes Equation 2's regression parameters.

Assessing 30-year growth

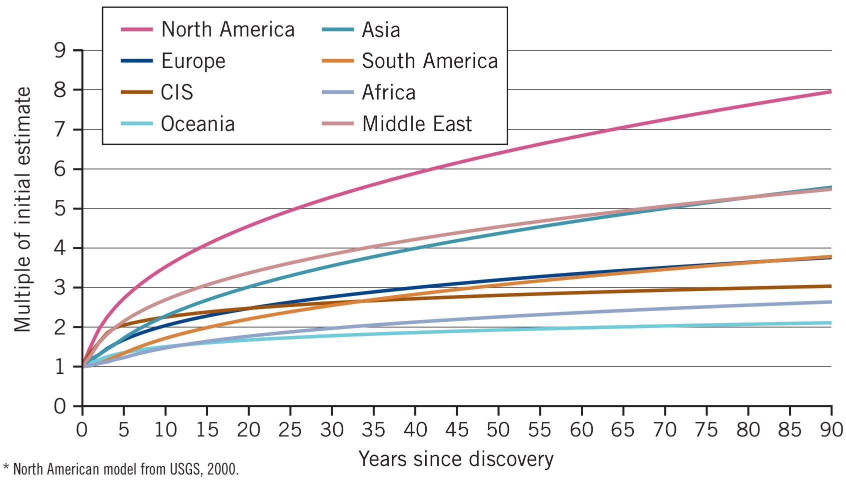
IHS has 28,660 oil and gas fields in its database. By applying power functions (Equation 2) as a projection model to these fields in their corresponding region, we obtained the multiple of initial estimate of each field in the predicting year.

For example, a field was discovered in 2000 with recoverable reserve of 160 million bbl of oil reported in 2013. We calculated the ages of the field in 2013 by subtracting the year of discovery, i.e. 2013-2000=13, and continued this process through 2044. We then input these ages into a projection model for their corresponding region, which forecast multiples of initial estimates from 2014 to 2044 (factors of 2.2-3.6), generating reserve growth estimates for the next 30 years.

We then calculated recoverable reserves in 2014 (160 × 2.4/2.2=174.5 million bbl), and with the same method 2044 reserves equaled 261.8 million bbl. For the field in this example, 30-year reserves growth is 87.3 million bbl (difference of 261.8-174.5). As a final step, we summarized growth for each oil and gas accumulation within each region and then globally (Table 3).

RESERVES GROWTH MODEL, GIANT FIELDS*

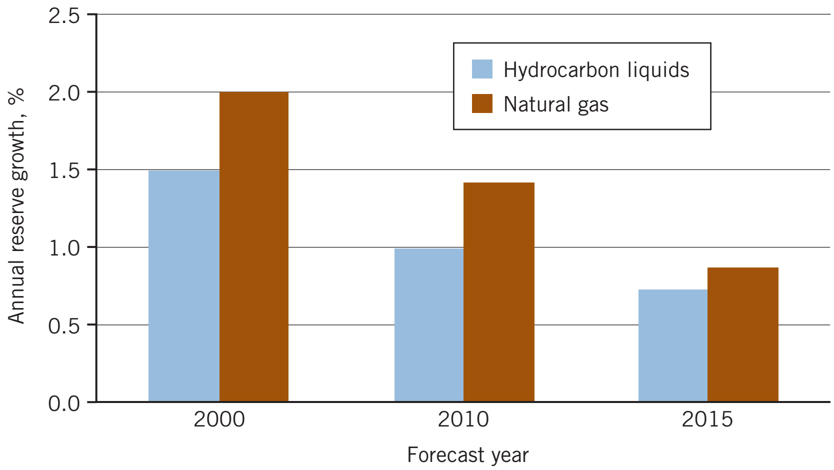
FIG. 4



* North American model from USGS, 2000.

FORECAST COMPARISONS, 2000-15

FIG. 5



North American reserves include only Alaska and US Federal Waters in this assessment. The conterminous states were excluded due to limited field data.

Based on our most recent assessment, recoverable reserves of hydrocarbon liquids equaled 2,851 billion bbl in 2014 and will increase to 3,461 billion bbl by 2044, a 21% increase. The Middle East will provide the largest increase, with 208 billion bbl added throughout the period. Latin America follows with growth of 181 billion bbl.

For natural gas, recoverable reserves equaled 329.9 tcm in 2014 with a 30-year forecast of 416.4 tcm, an increase of 86.5 tcm.

Forecast differences

Comparison among three forecasts—the USGS 2000 report, our previous 2010 forecast, and this current assessment—shows that world reserves' annual rate of increase is slowing.

The USGS estimated in 2000 a reserve growth of 654 billion bbl for oil and natural gas liquid in the next 30 years, based on 1993 recoverable reserves of 1,466 billion bbl, and an annual growth rate of 1.49%. Our 2010 assessment estimated an annual rate of 0.99%. The current assessment shows an annual growth rate of 0.71% (Fig. 5).

Similar results occur for natural gas, with the USGS estimating an annual growth rate of 2% in 2000, our 2010 assessment growth of 1.41%, and the current assessment's growth rate, 0.87%.

We also compared our result with the results of USGS's 2012 assessment. This report covered reserve growth for fields' entire life cycle, while our research estimated growth for the next 30 years. The USGS estimated reserve growth to be 723 billion bbl. Our current assessment estimates reserve growth to be 610 billion bbl, 16% lower than USGS's 2012 estimate.

Results analysis

Future reserve growth modeling will incorporate specific factors such as geological conditions and recovery technologies. As reserve growth models become more refined by regions representing different growth rates, the average rate of reserve growth will continue to decrease.

In addition, the rate of decrease will be more obvious for natural gas, suggesting reserve growth is lower for regions outside the US. Reserve volumes and the rate of increase in recent years may not provide the same stable growth as in earlier years. Reserve growth models will continue to be tested against known and developing fields and future investments in oil and gas exploration.

Acknowledgment

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Sustained low oil price subdues deepwater spend 2016-20

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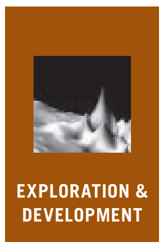
Low oil prices will continue to impact deepwater capital expenditure (capex) over the next 5 years. Industry headlines have been dominated for the past 12 months by implications of the sustained downturn and operators have responded by announcing widespread redundancies, reducing budgets, and deferring new projects. Capex reductions were already a focus for operators before the oil price collapse, but have risen in importance in recent months. The market downturn has prompted the industry to rethink development processes with an increased focus on subsea equipment standardization, supply chain efficiency, and project simplification.

Despite near-term concerns, the long-term fundamentals for deepwater activity remain strong. As production from mature onshore and shallow-water basins declines, development of deepwater reserves becomes more important. The need to offset declining production from matured basins, as well as the ability of international oil companies (IOC) to access larger reserves with the use of new exploration and production technology, will continue to drive deepwater expenditure.



Despite the extended nature of the current downturn, Douglas-Westwood (DW) has identified increased deepwater expenditure in basins away from the traditional areas of West Africa, Brazil, and the US Gulf. Fast-track development plans for large deepwater discoveries such as Eni's Zohr gas field offshore Egypt and ExxonMobil's Liza discovery offshore Guyana show that some capital intensive projects will be sanctioned in the current weak price environment. Development plans, however, will be implemented in phases.

DW forecasts deepwater capex, excluding floating productions systems (FPS) spend, to plummet from 2014's record levels until 2018, with a gentle upswing in 2019-20 (Fig. 1). The upswing will be driven by development of deepwater prospects in Brazil and the beginning of offshore activity in the East Africa gas basin.

The FPS market will see a similar drop in spend, but this will be most evident in the latter years of the forecast period. In 2015, the industry experienced the lowest number of deepwater FPS units ordered since 1996. Unit orders are expected to remain minimal for 2016. The longer lead times associated with FPS projects have insulated the market to date, as most 2017-18 installations were ordered in 2013-14.

Global market

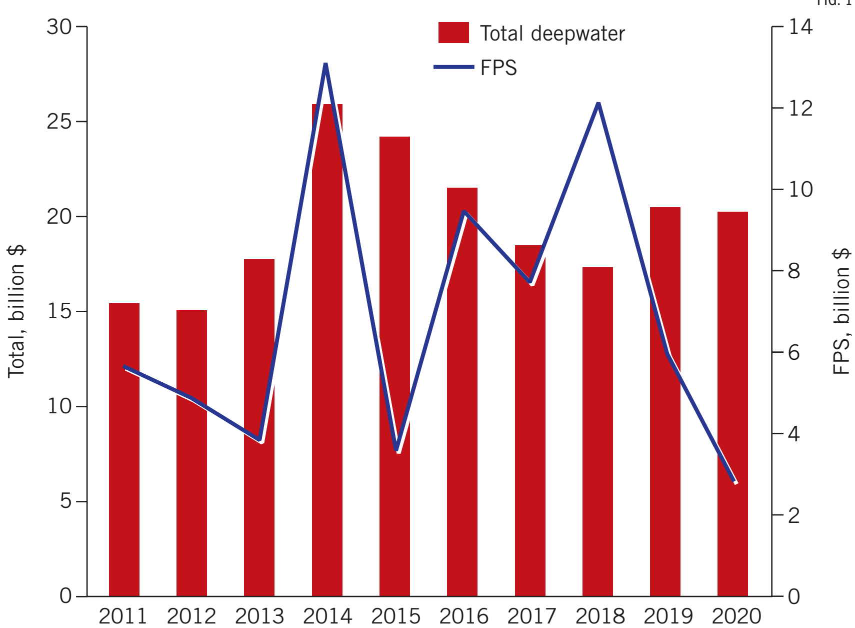
Deepwater expenditure will decline at -6% compound annual growth rate (CAGR) 2016-20. Total expenditure of $137 billion for the period, however, will still be a 5% increase on the previous five-year period ($129.6 billion). Project delays have resulted in a slower growth profile than was expected a year ago.

In addition to low oil prices, reduced rig demand will impact capex growth over the forecast period. Before the downturn, record deepwater rig demand resulted in an unprecedented level of rig orders, creating a supply-demand imbalance. Drilling contractors now face plummeting day rates due to a combination of oversupply and reduced demand, with day rate suppression triggering delays and cancellations for new rigs and widespread stacking of deepwater rigs.

The market downturn has negatively impacted

GLOBAL DEEPWATER CAPEX, 2011-20

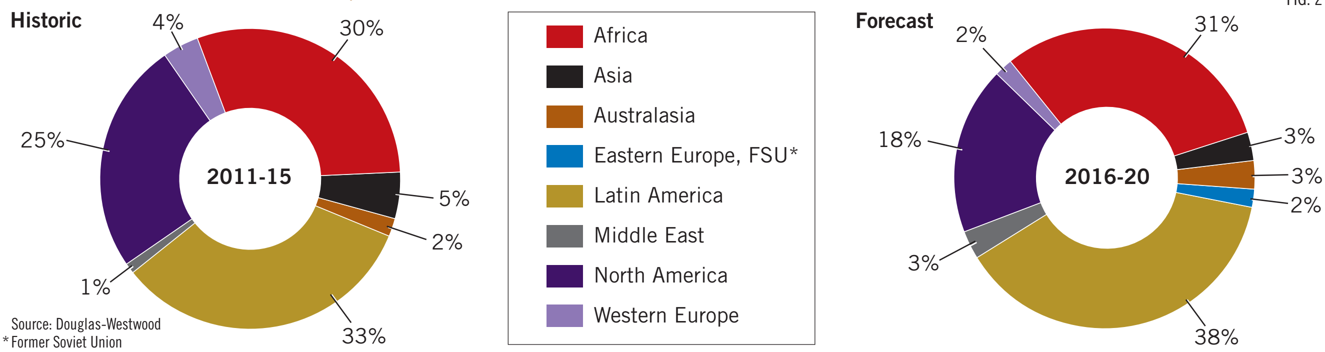
FIG. 1



Source: Douglas-Westwood

DEEPWATER REGIONAL SPEND, 2011-20

FIG. 2



Source: Douglas-Westwood
*Former Soviet Union

all regions, but the degree to which this is true varies based on ongoing and prospective projects. Through 2020, Africa and the Americas will account for 87% of total deepwater expenditure (Fig. 2).

Latin America

Spending in Latin America will make up 38% of total offshore capex, driven by the number of FPS units expected to be installed over the forecast period. Petroleo Brasileiro SA's (Petrobras) financial problems, however, are likely to result in constrained future expenditure on new units.

Mexico showed much initial promise after reform of its energy sector to allow foreign upstream participants, but recent interest in licensing rounds has been tempered by the prolonged low oil prices and widespread exploration activity is unlikely in the near term.

Petroleos Mexicanos (Pemex) expected production from its Lakach deepwater development in 2018, but this project has been suspended for at least 1 year due to budget cuts.

East Africa

East Africa will be the next key deepwater hub, with offshore installation activities in Tanzania and Mozambique commencing during the forecast period. Development of these gas basins is highly likely, as planning for these projects is well developed.

Anadarko has awarded onshore LNG contracts that will process gas reserves in Mozambique. The potential recovery of oil prices may also boost LNG-spot prices.

Other regions

Beyond Africa and the Americas, minimal deepwater activity is forecast. The majority of other capex is driven by a small number of projects such as Statoil SA's Aasta Hansteen (OGJ Online, Aug. 26, 2014) and Chevron Corp.'s Rosebank (OGJ Online, July 9, 2012). Cancellations and delays to individual projects within smaller regions can have a substantial impact on market outlook. For example, expenditure within the UK is highly dependent on Rosebank, but there have been numerous changes to contractual terms associated with the project, leading to uncertainty regarding development timelines. Additional delays to the project timeline will further impact deepwater spend, creating a large potential downside to total UK capex.

Over the forecast period, the fastest growth in capex is expected in Australasia (37% CAGR); although, the region will remain a comparatively small deepwater market.

North America will account for 18% of total capex through 2020. Spend in the region will decline by 24% compared to the preceding 5 years due to both prolonged delays in project final investment decisions and outright cancellations. Notable projects affected include BP PLC's Hopkins discovery and Murphy Oil Corp.'s Thunder Bird (OGJ Online, Dec. 3, 2015).

Offshore components

Drilling and completion is the largest segment of the deepwater market, with expenditure totaling $53 billion to 2020, an incremental increase from 2011-15. The majority of spend in this category is associated with subsea well completion. Africa will have the most (38%) deepwater subsea well completions over the next 5 years. Latin America, however, will account for the largest capex in this segment (40%) due to lengthier drilling and completion times.

FPS account for the second largest segment of expenditure, 28% of total capex. This sector is dominated by Brazil, which accounts for 52% of total spend. Floating production, storage, and offloading (FPSO) vessels make up almost 81% of forecast FPS spend.

Out of forecast FPSO installations 2016-20, 82% have already been sanctioned. These projects will prevent a total collapse of the FPS market in the near term, but low oil prices are causing operators to reevaluate the use of FPS in development plans. A clear example is Leviathan field in the Eastern Mediterranean; Noble Energy has abandoned its proposed FPS unit for a subsea tieback to a shallow-water fixed platform in a bid to further reduce development cost (OGJ Online, June 2, 2016).

Subsea equipment, including production hardware and subsea umbilicals, risers, and flowlines (SURF), jointly account for 27% of global expenditure through 2020. Subsea production hardware spend is driven by the number of development wells drilled. Africa is the largest market for subsea production hardware over the forecast period, both in terms of the number of units installed and capex. SURF expenditure will total $17 billion through the next 5 years.

Pipeline capex will account for 6% of spend over the forecast period, a 2% decline from the previous 5 years. Political disagreements between Russia and Turkey regarding Syria prompted cancellation of the Turkish Stream pipeline (OGJ Online, June 25, 2015), which had been expected to boost expenditure over the forecast period. Spending later in the forecast period will benefit from projects such as Sur de Texas-Tuxpan gas pipeline.

Near-term outlook

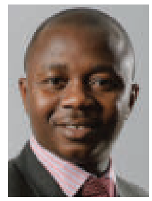
Original equipment manufacturers, vessel owners, and drilling contractors are likely to find the next few years difficult as project delays continue. Operators are expected to reengineer and reevaluate development plans of various projects to improve their economic viability. Lower drilling and equipment costs have so far provided limited upsides for project sanctioning.

In addition to low oil prices, the corruption scandal and financial difficulties experienced by Petrobras will restrict the state-owned company's spending plans for the foreseeable future. Deepwater capex growth offshore Brazil will be impacted beyond the forecast period.

In Africa, the breakup of the Nigerian National Petroleum Corp. (NNPC) highlights continued efforts to overhaul the country's oil and gas sector, however, the future of the country's long-awaited Petroleum Industry Bill remains unclear. Prolonged uncertainty and various regulatory bottlenecks between the state and IOCs have created a lull in Nigeria's oil development. Delays and low prices are also impacting several major deepwater projects in the region, such as Royal Dutch Shell PLC's Bonga SW-Aparo and Chevron's Nsiko.

The North American outlook is largely negative through 2020. Several deepwater projects have either been cancelled or delayed by reengineering. In contrast to other regions, however, North America is well positioned for recovery by the end of the forecast period due to existing infrastructure. Subsea-well tiebacks will likely be the preferred system for future developments. Project reengineering and various cost reduction exercises in North America will also allow for rapid response to future oil price recovery. OGJ

The author



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Well-kill model forecasts pressure for deepwater horizontal well

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DRILLING & PRODUCTION

Well-control operations using the wait-and-weight method (W&W) in a deepwater horizontal well are harder to implement than in a vertical well. Simulations of well-killing procedures for future projects provide guidance to drilling engineers.

Choke-pressure variations grow more complicated as a function of time in horizontal wells. China plans to drill a deepwater horizontal well in 2017. A few deepwater horizontal wells exist worldwide but detailed information about them remains proprietary.

The authors devised a mathematical model using the W&W method for a South China Sea deepwater horizontal well. It calculates standpipe pressure (SPP), choke pressure (CP), and choke-line pressure loss (CLPL) by simulating pressure schedules under different parameters.

The model can be applied to vertical wells and directional wells by changing the coefficient of conversion from a curved borehole segment depth to vertical depth.

Well-control simulations enable drilling crews to better respond in case of kicks. Many computer models have been developed to analyze kicks. A kick simulator can forecast pressure and volume behavior of kick fluids as a function of time (OGJ, Dec. 2, 1996, p. 68).

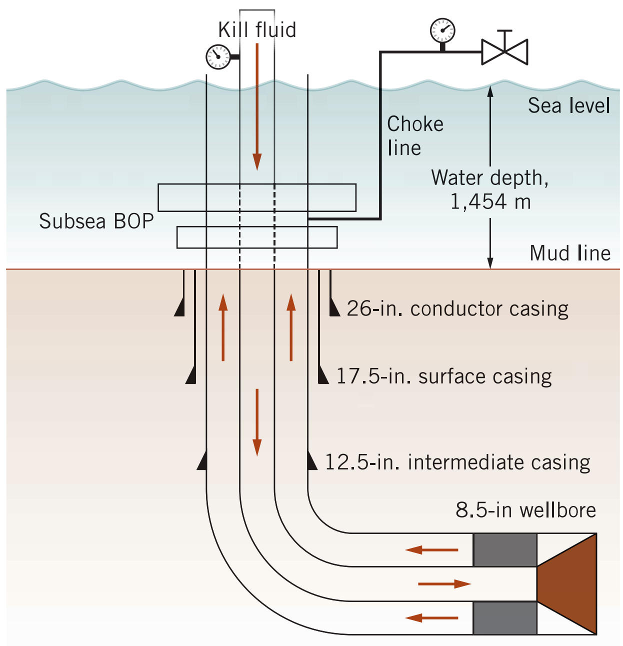
The W&W method uses one circulation to both pump mud and kill the well. Drill-pipe pressure control is critical during this procedure.

SPP and CP schedules are more complex for a deepwater horizontal well than a vertical well. Water depth, kill rate, kick size, lateral length, and pipe size affect total well-kill time and the risk of formation fracture.

Actual kick statistics from Yun-6, a vertical well that operator China National Offshore Oil Corp. (CNOOC) drilled in 1,035 m of water in Baiyun Sag east of the South China Sea during 2008, allowed verification of simulation accuracy.

Yun-6 experienced a gas kick at 4,070 m. The crew reported a pit gain of 1.65 cu m, shut-in SPP of 4.1 MPa, and shut-in CP of 3.5 MPa. Engineers used the W&W method with water-based mud weighing 1.4 g/cu cm.

KILL-FLUID PATH, WELL LW002 FIG. 1



YUN-6 PRESSURE SCHEDULES

	Simulation, MPa	Field, MPa	Relative error, %
SPP, 0 min	7.05	6.93	1.70
SPP, 110 min	3.55	3.48	1.97
CP, 0 min	5.61	5.49	2.14
CP, 110 min	6.42	6.29	2.03

EQUATIONS

SPP model

$$P_d(t) = P_{sp} - (G_k - G_m) \cdot \frac{Q_k t}{S_d} + \Delta P_{dk} \frac{Q_k t}{S_d} + \Delta P_{dm}\left(L_t - \frac{Q_k t}{S_d}\right) + \Delta P_{am}(L_w) + \Delta P_{dk}(H_{sea}) + \Delta P_{bit} \quad (1)$$

$$P_d(t) = P_{sp} - (G_k - G_m) \cdot \left[H_{kop} + \frac{Q_k(t - t_{01})}{S_d} \cdot R\right] + \Delta P_{dk}(Q_k t) + \Delta P_{dm}(L_t - Q_k t) + \Delta P_{dm}(L_w) + \Delta P_{clm}(H_{sea}) + \Delta P_{bit} \quad (2)$$

$$P_d(t) = \Delta P_{dk}(Q_k t) + \Delta P_{dm}(L_t - Q_k t) + \Delta P_{am}(L_w) \Delta P_{clm}(H_{sea}) + \Delta P_{bit} \quad (3)$$

$$P_d(t) = \Delta P_{dk}(L_t) + \Delta P_{bit} + \Delta P_{am}\left(L_w - \frac{Q_k(t - t_{03})}{S_a}\right) + \Delta P_{ak}\left(\frac{Q_k(t - t_{03})}{S_a}\right) + \Delta P_{clm}(H_{sea}) \quad (4)$$

$$P_d(t) = \Delta P_{dk}(L_t) + \Delta P_{bit} + \Delta P_{ak}(L_w) + \Delta P_{clk}\left(\frac{Q_k(t - t_{04})}{S_k}\right) + \Delta P_{clm}\left(H_{sea} - \frac{Q_k(t - t_{04})}{S_k}\right) \quad (5)$$

$$P_d(t) = \Delta P_{dk}(L_t) + \Delta P_{bit} + \Delta P_{ak}(L_w) + \Delta P_{clk}(H_{sea}) \quad (6)$$

CP model

$$P_a(t) = P_b - H_t \cdot G_m - \Delta P_{am}\left(L_w - \frac{V_g(t)}{S_a}\right) - \Delta P_{clm}(H_{sea}) \quad (7)$$

$$P_a(t) = P_b - \left[H_t - \frac{V_g(t) - (V_h - Q_k t)}{S_a} \cdot R\right] \cdot G_m - \Delta P_{am}\left(L_w - \frac{V_g(t)}{S_a}\right) - \Delta P_{clm}(H_{sea}) \quad (8)$$

$$P_a(t) = P_b - \left(H_t - \frac{V_g(t)}{S_a} \cdot R\right) \cdot G_m - \Delta P_{am}\left(L_w - \frac{V_g(t)}{S_a}\right) - \Delta P_{clm}(H_{sea}) \quad (9)$$

$$P_a(t) = P_b - \left[H_t \frac{V_{kop} - Q_k t}{S_a} \cdot R - \frac{V_g(t) - (V_{kop} - Q_k t)}{S_a}\right] \cdot G_m - \Delta P_{am}\left(L_w - \frac{V_g(t)}{S_a}\right) - \Delta P_{clm}(H_{sea}) \quad (10)$$

$$P_a(t) = P_b - \left(H_t - \frac{V_g(t)}{S_a}\right) \cdot G_m - \Delta P_{am}\left(L_w - \frac{V_g(t)}{S_a}\right) - \Delta P_{clm}(H_{sea}) \quad (11)$$

$$P_a(t) = P_b - \left(H_t - \frac{V_g(t)}{S_a}\right) \cdot G_m - \Delta P_{ak}\left(\frac{Q_k(t - t_5)}{S_a}\right) - \Delta P_{am}\left(L_w - \frac{Q_k(t - t_5)}{S_a} - \frac{V_g(t)}{S_a}\right) - \Delta P_{clm}(H_{sea}) \quad (12)$$

$$P_a(t) = P_b - \frac{Q_k(t - t_6) \cdot R}{S_a} \cdot (G_k - G_m) - \left(H_t - \frac{V_g(t)}{S_a}\right) \cdot G_m - \Delta P_{ak}\left(\frac{Q_k(t - t_5)}{S_a}\right) - \Delta P_{am}\left(L_w - \frac{Q_k(t - t_5) + V_g(t)}{S_a}\right) - \Delta P_{clm}(H_{sea}) \quad (13)$$

$$P_a(t) = P_b - \left[H_t - H_{kop} \frac{Q_k(t - t_7)}{S_a}\right] \cdot G_k - \left[H_{kop} \frac{V_g(t)}{S_a} - \frac{Q_k(t - t_7)}{S_a}\right] \cdot G_m - \Delta P_{ak}\left(\frac{Q_k(t - t_5)}{S_a}\right) - \Delta P_{am}\left(L_w - \frac{Q_k(t - t_5) + V_g(t)}{S_a}\right) - \Delta P_{clm}(H_{sea}) \quad (14)$$

$$P_a(t) = P_b - \left[H_t - H_{kop} \frac{Q_k(t - t_7)}{S_a}\right] \cdot G_k - \left[H_{kop} - \frac{V_a - Q_k t}{S_a} \frac{V_g(t) - (V_a - Q_k t) -}{S_k} - \frac{Q_k(t - t_7)}{S_a}\right] \cdot G_m - \Delta P_{ak}\left(\frac{Q_k(t - t_5)}{S_a}\right) - \Delta P_{am}\left(L_w - \frac{Q_k(t - t_5)}{S_a} - \frac{V_a - Q_k t}{S_a}\right) - \Delta P_{clm}\left(H_{sea} - \frac{V_g(t) - (V_a - Q_k t)}{S_k}\right) \quad (15)$$

$$P_a(t) = P_b - \left[H_t - H_{kop} + \frac{Q_k(t - t_7)}{S_a}\right] \cdot G_k - \left[H_{kop} - \frac{V_g(t)}{S_k} - \frac{Q_k(t - t_7)}{S_a}\right] \cdot G_k - \Delta P_{ak} \frac{Q_k(t - t_5)}{S_a} - \Delta P_{am}\left(L_w - \frac{Q_k(t - t_5)}{S_a}\right) - \Delta P_{clm}\left(H_{sea} - \frac{V_g(t)}{S_k}\right) \quad (16)$$

$$P_a(t) = P_b - \left[H_t - H_{kop} + \frac{Q_k(t - t_7)}{S_a}\right] \cdot G_k - \left[L_w - \frac{Q_k(t - t_5)}{S_a} + \left(\frac{Q_k(t - t_9)}{S_k}\right)\right] \cdot G_m - \Delta P_{ak}\left(\frac{Q_k(t - t_5)}{S_a}\right) - \Delta P_{am}\left(L_w - \frac{Q_k(t - t_5)}{S_a}\right) - \Delta P_{clm}\left(\frac{Q_k(t - t_9)}{S_k}\right) \quad (17)$$

$$P_a(t) = P_b - \left[H_t - H_{kop} + \frac{Q_k(t - t_7)}{S_a}\right] \cdot G_k - \left[L_w - \frac{Q_k(t - t_5)}{S_a}\right] \cdot G_m - \Delta P_{ak}\left(\frac{Q_k(t - t_5)}{S_a}\right) - \Delta P_{am}\left(L_w - \frac{Q_k(t - t_5)}{S_a}\right) - \Delta P_{clm}(H_{sea}) \quad (18)$$

$$P_a(t) = P_b - \left[H_t - H_{sea} + \frac{Q_k(t - t_{12})}{S_k}\right] \cdot G_k - \left[H_{sea} - \frac{Q_k(t - t_{12})}{S_a}\right] \cdot G_m - \Delta P_{ak}(L_w) - \Delta P_{clk}\left(\frac{Q_k(t - t_{12})}{S_k}\right) - \Delta P_{am}\left(H_{sea} - \frac{Q_k(t - t_{12})}{S_k}\right) \quad (19)$$

$$P_a(t) = P_b - H_t \cdot G_k - \Delta P_{ak}(L_w) - \Delta P_{clk}(H_{sea}) \quad (20)$$

Nomenclature

$P_d(t)$ = SPP measured as a function of time, Pa
$P_a(t)$ = CP measured as a function of time, Pa
ΔP_{dm} = friction loss of the original drilling fluid in the drill stem measured as a function of length, Pa
ΔP_{dk} = friction loss of the weighted drilling fluid in the drill stem measured as a function of length, Pa
ΔP_{am} = friction loss of the original drilling fluid in the annulus measured as a function of length, Pa
ΔP_{ak} = friction loss of the weighted drilling fluid in the annulus measured as a function of length, Pa
ΔP_{clm} = friction loss of the original drilling fluid in the choke line measured as a function of length, Pa
ΔP_{clk} = friction loss of the weighted drilling fluid in the choke line measured as a function of length, Pa
ΔP_{bit} = friction loss of the drill bit, Pa
P_{SP} = shut in drill pipe pressure, Pa
P_p = bottomhole pressure, Pa
Q_k = killing flow rate, cu m/sec
G_k = pressure gradient of the weighted drilling fluid, Pa/m
G_m = pressure gradient of the original drilling fluid, Pa/m
S_a = cross-sectional area of the annulus, sq m
S_k = cross-sectional area of the choke line, sq m
S_d = cross-sectional area of the drill stem, sq m
H_t = total vertical depth, m
H_{sea} = choke line length, m
H_{kop} = depth of the KOP, m
L_t = total depth of the well, m
L_h = depth of the landing point of the well, m
L_w = wellbore length below the mud line, m
R = coefficient of conversion from the depth of the curved borehole segment to the vertical depth
V_h = volume of lateral segment, cu m
$V_g(t)$ = volume of gas column measured as a function of killing time, cu m
V_{kop} = volume of annulus below KOP, cu m
V_a = volume of annulus below mud line, cu m

A key kick indicator is pit gain, an increased drilling mud level in the surface mud pit. This results from the kick displacing mud in the well bore. Delta flow, the difference between the mud flow into the drill pipe and that returning from the annulus, also indicates a kick.

Model assumptions

Operator CNOOC and partner Husky Energy plan to drill deepwater horizontal well LW002 in the Pearl River Mouth basin of the South China Sea. Preparations included simulations based on statistics from vertical well LW001.

LW001 and the planned LW002 are in LW3-1 gas field in 1,454 m of water. The vertical depth for LW002 is expected to be 3,715 m, the same as LW001. Both LW001 and LW002 target the LW gas reservoir.

Operator CNOOC drilled LW001, the first LW development well, in 2012 about 310 km southeast of Hong Kong. Although LW001 did not experience a kick, LW002 planners used LW001 information as the basis for well-killing simulations.

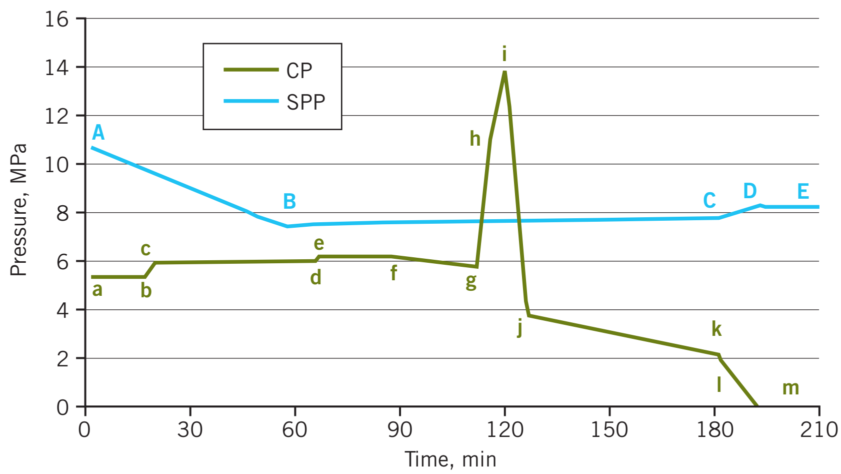
Specific formulas established the SPP and the CP schedules, which change during stages of the simulated well-kill operation (Equations 1-20). Fig. 1 shows the kill fluid's flow path.

Model development assumed:

- A kick occurs at bottomhole, forming a gas column that migrates up. Rig workers ignore both friction pressure losses and a gravitational pressure drop in the gas-column zone.[1]
- Workers ignore gas solubility in the kill fluid.
- The borehole has a round cross section and is concen-

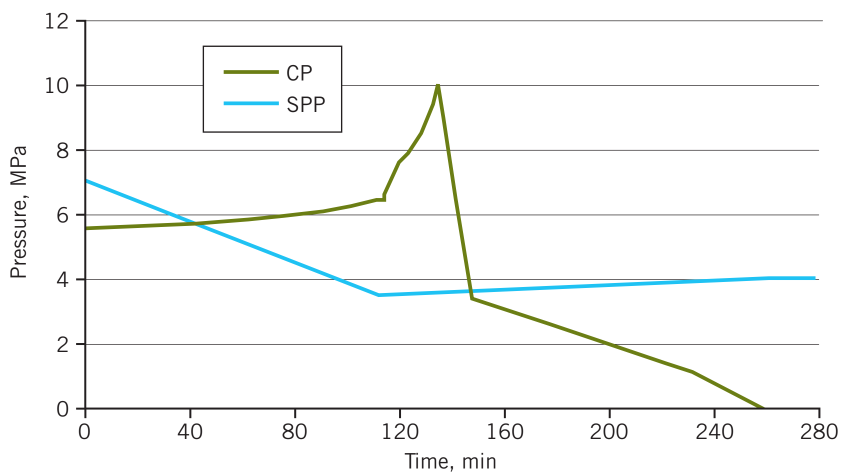
TYPICAL SPP, CP SCHEDULES

FIG. 2



WAIT-AND-WEIGHT WELL KILL, YUN-6

FIG. 3



tric with the drill stem.

• Power-law patterns describe the kill fluid's rheological behavior.

• Researchers used a turbulent regime to correct for the friction factor in anticipation of frictional pressure losses.[2]

• Drillstring pipe volumes are larger than the annular volume below the kickoff point but smaller than the annular volume below the mud line.

Authors used wellbore heat analysis[3] to compute a transient temperature profile simulation.

In the model simulations, LW002 experienced a kick when the 215.9-mm borehole reached 4,349 m. Crews used the W&W method to kill the well with the following parameters:

• Shut-in drill pipe pressure = 4 MPa.
• Kill rate = 10 l./sec.
• Original mud density = 1.17 g/cu cm
• Weighted mud density = 1.28 cu cm.

Both SPP and the CP change as a function of the kill process using the W&W method. The goal is to hold bottomhole pressure (BHP) constant with, or slightly above, formation pressure. Multiple pipe diameters complicate the SPP schedule.

BHP pressure cannot be held constant during W&W unless drilling engineers correctly calculate the SPP and CP schedules.

SPP decreases linearly when original drilling fluid in the drill string is replaced with weighted drilling fluid. Point B in Fig. 2 shows the fluid's condition at bottomhole.

After the fluid enters the annulus, SPP increases slightly. Point C represents the point at which the fluid reaches the mud line.

Once the fluid enters the choke line, SPP increases rapidly. Point D represents the condition under which the circulated fluid reaches the rig floor. SPP stays constant after that.

CP is constant before the kick. CP builds after the kick as the gas column enters the curved borehole (Fig. 2, Points b to c). CP increases slowly while the gas column expands and rises in the curved borehole (Fig. 2, Points c to d). But CP accelerates more quickly once the gas column flows into the vertical borehole segment (Fig. 2, Points d to e).

As the gas column rises in the vertical borehole, the CP increase slows (Fig. 2, Points e to f). CP decreases gradually when the weighted drilling fluid flows into the annulus (Fig. 2, Points f to g) and rapidly increases when the gas column flows into the choke line because the cross-sectional area of the choke line is small (Fig. 2, Points g to h).

When the gas column expands and rises in the choke line, the CP increase slows. CP reaches its maximum when the gas column reaches the rig floor (Fig. 2, Point i) but decreases rapidly with fluid being continuously pumped (Fig. 2, Points i to j).

CP decreases linearly when the weighted fluid flows upward to the mud line (Fig. 2, Points j to k) with a rapid decrease when the fluid enters the choke line's small inner diameter (Fig. 2, Points k to l). CP is close to 0 when the circulated fluid reaches the rig floor and remains 0 as circulation continues (Fig. 2, Points l to m).

SPP, CP schedules

SPP and CP simulations forecast effects of choke-line length, kill rate, kick size, and lateral length.

Both pressure schedules change over time during the kill depending on choke-line length. SPP and CP peak values and total well-kill time increase with water depth. During the kill, choke-line friction pressure must be monitored to maintain constant-bottomhole pressure.

CLPL increases with the choke-line length. SPP increases with a longer choke line because gas expansion lasts longer, making a larger gas volume when the column reaches the choke valve.

A longer choke line will produce a higher CP peak value. Kill fluid flows through the choke line such that the kill takes 6 min longer in 1,500 m of water than in 1,000 m of water.

CLPL reaches maximum value when the weighted kill fluid fills the choke line. Using the W&W method, the casing-shoe pressure is 1.76 MPa greater in 1,500 m of water than in 1,000 m of water.[4]

Well-control crews should monitor kill rate in deeper water to avoid a built in casing-shoe pressure capable of fracturing the rock formation. Too high a pressure might damage the formation.

CP and SPP schedules change during well kills using 10-l./sec and 15-l./sec flow rates while other parameters remain constant. A higher kill flow rate resulted in a higher SPP rate and shorter kill time.

Kill rate has little effect on CP peak value. Circulation-pressure loss increases with kill rate, raising SPP as well. Kill rate also has little influence on gas expansion, resulting in almost no difference between the CP peak values when choke line lengths and kick sizes are equal.

Simulations showed kill efficiency could be improved with higher kill rates. CLPL also increases with kill rate. When the weighted kill fluid fills the choke line, the calculated casing-shoe pressure with a 15-l./sec kill rate is 1.65 MPa greater than with a 10-l./sec kill rate. Allowable casing-shoe pressure can restrict kill rate.

Kick size influences CP more than it does SPP. A larger kick size causes a higher CP peak but has little effect on SPP and total kill time.

SPP curves closely track at kick sizes of 1.5 cu m and 3 cu m because kick size has little influence on circulation pressure loss. Gas volume in the choke line, however, increases greatly with kick size. CP peak value is much greater with a kick size of 3 cu m than with a kick size of 1.5 cu m. The pressure difference reaches 5.3 MPa.

Lateral length also makes a difference. SPP and kill time are higher with a 1,000-m lateral than a 500-m lateral, but the effect on CP's peak value is small.

Longer laterals produce larger circulation-pressure losses, increasing SPP. Total well-kill time grows 26 min for a 500-m lateral increase, showing that kill time is influenced more by annular space below the mud line than by water depth. Gas volume builds in the choke line with a longer lateral.

Available information from the Yun-6 W&W-method well kill enabled SPP and CP calculations (Fig. 3).

Crews used weighted mud for the kill. The accompanying table outlines simulation calculations and field data, showing relative errors of less than 5% and confirming the simulation's reliability.

Acknowledgments

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Texas Supreme Court rules on post-production costs, royalty payments

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Producers calculate oil and gas royalties using a relatively straight-forward formula, but litigation can still arise from any of its variables. The royalty payment equals the royalty owner's net interest multiplied by the total value of production from a well minus the royalty owner's share of post-production expenses. It is becoming more common in Texas for royalty owners to contest post-production expenses.

Royalty owners specifically are claiming that operators improperly categorize an expense as post-production when it is a production expense. Royalty owners might also claim a lease or other agreement provides that royalty interest is free of post-production expenses.

Texas is among the highest producing oil and natural gas states (Figs. 1-2). Post-production expenses involve millions of dollars in allocations between working-interest holders and royalty owners.

Operators must ensure that post-production expenses comply with Texas laws and lease terms. This article provides an overview of general Texas law regarding royalties and the allocation of production and post-production expenses. It will discuss the Texas Supreme Court's opinion in French vs. Occidental Permian Ltd., in which the issue was whether carbon dioxide extraction from casinghead gas during a tertiary recovery operation was a production or post-production expense.

It will also discuss the Texas Supreme Court's opinion in Chesapeake Exploration LLC vs. Hyder, in which the court analyzed post-production expense allocations for a "cost-free (except only its portion of production taxes) overriding royalty."

Texas courts define a royalty as a share of production free of production expenses but subject to post-production costs. Overriding royalties are carved out of the working interest and are generally free of production expenses. But overriding royalty owners are subject to proportional post-production costs. The parties, however, may agree to alter these general definitions.

Texas courts apply a plain-terms analysis to oil and gas leases. An oil and gas lease is interpreted as any other contract. In construing an unambiguous lease, courts seek the parties' intent. Courts apply plain, grammatical meaning to lease language unless doing so clearly defeats the parties' intentions.

One problem with analyzing post-production expenses in Texas is the terminology. Industry and Texas law generally categorize expenses borne solely by the working interest as production expenses. Post-production expenses are expenses shared between the working-interest holders and royalty owners.

Royalty provisions for decades stated that royalties were to be paid at the well where production ended. Many leases, however, now provide that royalties will be paid on oil or gas delivered into tanks or pipelines, at a plant's tailgate, at the point of sale, or other locations.

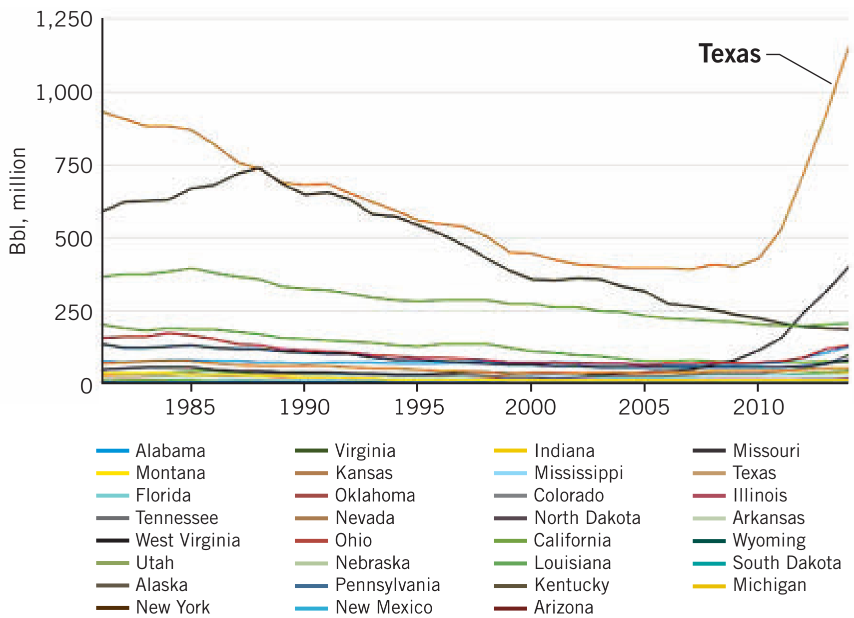
DRILLING & PRODUCTION

Texas law uses the designated delivery point in the parties' lease to determine the allocation of expenses between the working and royalty interests. Lease language is more important than the fact that production ends at the wellhead.

The working interest holder is solely responsible for the cost of getting oil or gas to the delivery point, whether it's the wellhead, the tank, the pipe-

CRUDE OIL PRODUCTION

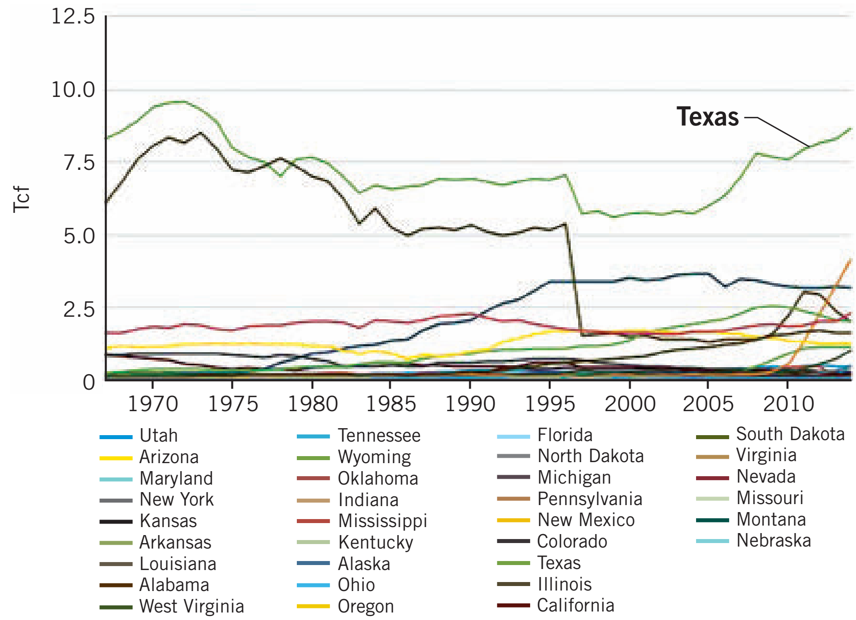
FIG. 1



Source: US Energy Information Administration

NATURAL GAS PRODUCTION

FIG. 2



Source: US Energy Information Administration

line, the tailgate of a plant, the point of sale to a nonaffiliated third party, or some other point.

Subsequent expenses adding value to the production can be shared proportionally between the working and royalty interests. An expense can occur post-production from an operational standpoint but be treated as a production expense from a royalty-accounting standpoint.

This article used production and post-production terminology for categorizing expenses that might or might not be shared with the royalty interest because those are the words industry and the Texas courts use.

It's impossible to broadly state what costs always are borne solely by the working interest or always may be shared between the working and royalty interests. Terms of a lease, the nature of the expense in question, and the precise character of the royalty provide case-by-case answers.

Working-interest holders generally pay all production costs, defined as the expenses incurred in exploring for hydrocarbons and bringing them to the surface. These costs include:

- Geophysical surveys.
- Drilling.
- Tangible and intangible costs incurred in testing, completing, or reworking a well.
- Secondary or tertiary recovery.

Production is defined as extracting oil or gas from the well for storing or selling, meaning production ends at the wellhead.

It would follow that post-production begins after the wellhead. Post-production costs, which generally are shared proportionally between the working and royalty interests, include:

- Gross production and severance taxes.
- Gathering.
- Transportation.
- Treatment required to make the hydrocarbon fit to be sold, such as dehydration, the removal of CO_2 and hydrogen sulfide (H_2S), compression to make gas deliverable into a pipeline, and manufacturing costs incurred in extracting liquids from gas or casinghead gas.

But the line between production and post-production is not always clear, particularly during tertiary recovery operations.

French vs. Occidental Permian

The issue in French vs. Occidental Permian Ltd. was whether the expense to remove CO_2 from casinghead gas during a tertiary recovery operation was a production expense or a post-production expense.

Oxy operated the Cogdell Canyon Reef Unit (CCRU) in Scurry and Kent counties, Tex. CCRU casinghead gas contained less than 2% CO_2.

The Fuller gasoline plant processed casinghead gas to remove H_2S and nitrogen, both contaminants, and to extract natural gas liquids (NGLs).

In 2001, Oxy began injecting CO_2 into the CCRU. Oil production rose to 5,800 b/d compared with 1,500 b/d during the late 1990s. Without the CO_2 flood, production would have declined to 200 b/d and become uneconomical, stranding more than half of the oil in place.

After CO_2 injection began, CCRU casinghead gas contained 85% CO_2. That percentage was too high to be processed at the Fuller gasoline plant so Oxy hired Kinder Morgan Co. (KM), which removed at least 90% of the CO_2 and most of the H_2S from the casinghead gas for reinjection.

KM extracted 66% of total NGLs for sale. KM contracted with Torch Energy Marketing to remove the remaining CO_2 and H_2S at the Snyder gasoline plant. Remaining NGLs also were extracted.

Oxy paid KM a monthly fee of $0.33/Mcf delivered to KM's plant plus 30% of the total NGLs in-kind and 100% of the residual gas at the Snyder gasoline plant tailgate. In calculating royalties on casinghead gas, Oxy considered 70% of the NGLs provided by KM.

Oxy did not pay royalties on the remaining NGLs or any of the residual gas paid to KM. Oxy, however, did not charge royalty interest on any part of the $0.33/Mcf fee.

Oxy treated 30% of the NGLs and 100% of the residual gas as a post-production expense to prepare casinghead gas for sale. Oxy allocated that expense between working and royalty interests. The monthly $0.33/Mcf fee on gas delivered was considered a production expense and paid solely by Oxy, the working-interest owner.

The royalty owners sued Oxy for underpayment of royalties, alleging "the transportation of the casinghead gas from its gathering point to the [KM] plant some 15 miles away, the processing at the [KM] plant, the transportation of the partially processed streams of NGLs and gas to the Snyder [gasoline plant], the removal of CO_2 there, and the transportation of…CO_2 and H_2S from both plants back to the injection wells," were production expenses.

Royalty owners said any NGLs that KM extracted were incidental byproducts of removing the CO_2 and part of the production process. They wanted the royalty to be based on the value of 100% of the NGLs net extraction expenses and removing H_2S, plus the value of 100% of residue gas.

Oxy maintained that CO_2 removal was necessary to sell the casinghead gas so it was a post-production expense that royalty owners should help pay. The producer also described 30% of the NGLs and 100% of residual gas paid KM as compensation for post-production activities, for which no royalty was due because the royalty interest must bear its proportionate share.

The Texas Supreme Court ultimately ruled that the cost to separate injected CO_2 from casinghead gas was a post-production expense that could be charged proportionately to royalty owners.

The court initially recognized that royalty provisions were based on market value at the well and the proceeds from the sale of casinghead-gas products net of post-production expenses. But instead of analyzing these common and well-understood royalty clauses, the court undertook a fact-specific analysis, ruling that CO_2 separation was a post-production expense because:

- Unlike separation of oil from water for the water flood, CO_2 separation from the casinghead gas was not critical to continued oil production.
- The entire casinghead gas stream could have been reinjected into the formation without any processing. That stream was 85% CO_2 and included NGLs and residual gas.
- The CCRU agreement stated no royalties would be due on casinghead gas reinjected into the formation.
- Agreement terms gave Oxy sole discretion on whether to reinject or process the casinghead gas.
- The royalty owners benefited from Oxy's decision to process the casinghead gas.

The royalty owners must share the cost of CO_2 removal in these circumstances because the royalty interest owners gave Oxy the right and discretion to decide whether to reinject or process the casinghead gas and because they benefitted from Oxy's decision to process and sell the gas.

The court said the cost of separating injected CO_2 from the casinghead gas was a post-production expense to be paid proportionately by the working-interest holders and royalty owners. But this ruling was fact specific, leaving working-interest owners susceptible to royalty owner claims that the cost of separating injected CO_2 is a production expense to be borne solely by the working-interest holders.

Chesapeake Exploration vs. Hyder

An overriding royalty on oil and gas production is free of production costs but must bear its share of post-production costs unless the parties agree otherwise. The issue in Chesapeake Exploration LLC vs. Hyder was whether the lessee agreed to pay for all post-production expenses relating to an overriding royalty.

The overriding royalty provision provided for "a perpetual, cost-free (except only its proportion of production taxes) overriding royalty of 5% of gross production obtained" from directional wells drilled on the lease, but reaching TD on nearby land.

The lease provided each lessor the "continuing right and option to take its royalty share in kind," although no lessor exercised that right. The parties did not dispute that the royalty can be paid in cash.

Chesapeake drilled seven directional wells on the leased premises that produced from land not subject to the lease. Chesapeake paid royalties on production from those wells after deducting gathering, transportation, and a 3% marketing fee as post-production costs.

The royalty owners argued that the cost-free language in the overriding royalty provision constituted an agreement that Chesapeake would pay all post-production expenses, including any gathering, transportation, or marketing fees.

But Chesapeake asserted that cost-free language merely emphasized that the overriding royalty was free of production costs and did not relate to the allocation of post-production expenses.

The Texas Supreme Court sided with the royalty owners, ruling that the cost-free language frees the overriding royalty from post-production expenses. The court concluded a production-taxes exception indicated that cost-free language applied to post-production expenses. Taxes are considered a post-production expense.

"It would make no sense to state that the royalty is free of production costs, except for post-production taxes (no dogs allowed, except for cats)," the court said, asking Chesapeake to show why cost-free language cannot refer to post-production costs. Chesapeake argued that a royalty paid on gross production must be measured at the wellhead and, therefore, is the same as a royalty paid at the well, which bears post-production costs. The court said a requirement to measure wellhead volumes does not indicate whether the overriding royalty must bear post-production costs.

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Abadan Oil Refining Co., a subsidiary of state-owned National Iranian Oil Refining and Distribution Co. (NIORDC), operates a 400,000-b/d refinery in Abadan City, Khoozestan province, Iran. Photo from NIORDC.

Post-sanctions Iran advances refinery modernization, expansion program

Robert Brelsford
Downstream Technology Editor

PROCESSING

Iran's state-owned National Iranian Oil Refining and Distribution Co. (NIORDC), a subsidiary of the country's Ministry of Petroleum (MOP), is seeking international investors to help complete a long-planned program to increase crude oil and condensate processing capacities and improve the quality of production at the country's refineries.

Alongside an estimated $14 billion in rehabilitation, modernization, and expansion projects at five of its existing refineries, Iran's downstream program involves construction of five new processing plants, Abbas Kazemi, NIORDC's managing director and MOP deputy petroleum minister, said in a June release from NIORDC.

The call for increased capital investment to help revitalize the country's refining sector comes in the wake of sanctions relief that began in mid-January following the July 2015 agreement Iran reached on its nuclear program with international negotiators (OGJ Online, Feb. 23, 2016; Nov. 12, 2015; July 22, 2015).

Primarily intended to reduce Iran's dependence on foreign fuel imports, the refining optimization also aims to reduce fuel oil output to expand the nation's market share as an exporter of fuels such as jet fuel, low-sulfur gasoline, and diesel grades.

Background

Through its wholly owned and partly privatized subsidiaries, NIORDC operates nine major refineries in Iran that have a combined crude processing capacity of 1.86 million b/d (Table 1).

The refineries' historical production of predominantly heavier, low-value products (i.e., fuel oil) and mounting energy costs stemming from their inefficient original configurations (Table 2) initiated a series of proposals over the past 10 years aimed at up-

NIORDC'S REFINERIES IN IRAN — Table 1

Subsidiary	Location	Capacity, b/d	Crude feedstock quality: API gravity	Crude feedstock quality: Sulfur, wt%
AORC	Abadan City	400,000	25.78	1.52
BAORC	Bandar Abbas	330,000	30.21	1.90
EORC	Esfahan City	375,000	33.00	1.10
IKORC	Arak	250,000	31.42	1.71
KORC	Kermanshah City	22,000	37.48	1.47
LORC	Lavan Island	60,000	33.96	1.23
SORC	Shiraz City	60,000	28.50	1.30
TBZORC	Tabriz City	110,000	32.24	1.60
TORC	Tehran City	250,000	32.17	1.84

Source: NIORDC, October 2015

PROCESS UNITS AT INDIVIDUAL IRANIAN REFINERIES

Table 2

Process	Abadan	Bandar Abbas	Esfahan	Shazand	Imam Khomeini Kermanshah	Lavan	Tehran	Shiraz	Tabriz
Atmospheric distillation	•	•	•	•	•	•	•	•	•
Vacuum distillation	•	•	•	•	—	•	•	•	•
Visbreaking	•	•	•	•	—	•	•	•	•
LPG recovery	•	•	•	•	•	•	•	•	•
Alkylation	•	—	—	—	—	—	—	—	—
Isomerization	•	—	•	•	—	•	•	—	—
FCC	•	—	—	—	—	—	—	—	—
Catalytic reforming	•	•	•	•	•	•	•	•	•
Propylene recovery	•	—	—	•	—	—	—	—	—
Gasoline hydrotreating	•	—	—	•	—	•	•	—	—
Naphtha hydrotreating	•	—	—	•	•	•	•	•	•
Kerosine hydrotreating	—	—	—	•	•	•	•	—	•
H_2 production	—	—	—	•	—	—	•	•	•
Tail gas treating	—	—	—	•	—	—	•	—	—
Hydrocracking	—	—	—	•	—	—	•	•	•
Sulfur recovery	•	—	—	•	—	—	•	•	•
Residue FCC	—	—	—	•	—	—	—	—	—
Reduced crude desulfurization (RCD)	—	—	—	•	—	—	—	—	—
n-Pentane production	—	—	—	—	•	—	—	—	—
Lube fractionation	—	—	—	—	—	—	•	—	—
Kerosine treating	—	—	—	—	—	—	—	•	—
Benzene extraction	—	—	—	—	—	—	—	—	•

grading and renewing Iran's refining sector to address rising and subsidized demand for imported gasoline.

The Iranian government allocated $15 billion to expand capacity and increase efficiency in 2010 at NIORDC's refineries at Tehran, Lavan Island, Abadan, Arak, and Esfahan, as well as build seven new refineries to ensure the country's energy security amid ongoing international sanctions, according to a June 14, 2010, release from NIORDC.

While NIORDC undertook several of those projects, a combination of escalated sanctions, financing problems following the drop in global crude oil prices, and sector-specific management issues resulted in delays for many of them.

But a renewed focus on reforming the country's oil and gas sector after the 2013 election of current President Hassan Rouhani, a May-2015 cut in government subsidies supporting domestic consumption of refined petroleum products, and the subsequent lifting of international sanctions against the country's oil industry led NIORDC to accelerate its timeline for refinery optimization. The company now plans to add up to 3.2 million b/d in new plant capacity by 2020, according to recent media reports from the region.

Revamps, modernizations

NIORDC's proposed $14-billion modernization plan for existing operations includes a combination of projects at the following five refineries:

- Abadan Oil Refining Co.'s (AORC) 400,000-b/d refinery in Abadan City, Khoozestan province.
- Bandar Abbas Oil Refining Co.'s (BAORC) 330,000-b/d refinery in Bandar Abbas, Hormozgan province.
- Esfahan Oil Refining Co.'s (EORC) 375,000-b/d refinery in Esfahan City, Esfahan province.
- Imam Khomeini Shazand Oil Refining Co.'s (IKORC) 250,000-b/d refinery in Arak, Markazi province.
- Tehran Oil Refining Co.'s (TORC) 250,000-b/d refinery in Tehran City, Tehran province.

AORC, PROPOSED UNIT ADDITIONS

Table 3

Unit	Capacity
Crude distillation, b/d	210,000
Vacuum distillation, b/d	110,000
LPG recovery 1, tonnes/day	713
LPG recovery 2, tonnes/day	679
Naphtha hydrotreating, b/d	71,500
Continuous catalytic reforming, b/d	51,700
Kerosine hydrotreating, b/d	45,000
Gasoline hydrotreating, b/d	90,000
Hydrocracking, b/d	42,000
Isomerization, b/d	20,000
H_2 production, MMcfd	75
Sour water stripping, tonnes/day	24,000
Sulfur recovery, tonnes/day	460

Source: NIORDC, October 2015

At AORC's refinery in Abadan, NIORDC has proposed a suite of projects to increase crude processing, expand clean-fuels production and residue upgrading, and improve overall efficiency and environmental performance at the plant (Table 3), according to an October 2015 presentation by Kazemi.

A new 210,000-b/d crude distillation unit, replacing three of the plant's aging units, will allow production of Euro 5-quality fuels and is targeted for startup in 2019.

As part of its ongoing revitalization of the plant, NIORDC between 2012-13 completed a series of upgrades and capacity enhancements, including installation of:

- Fluid catalytic cracking (FCC), 45,000 b/d.
- Alkylation, 12,000 b/d.
- Isomerization, 10,000 b/d.
- Sulfrex, 10,000 b/d.
- Gas amine treating, 330 tonnes/day.
- Sulfuric acid recovery (SARP), 267 tonnes/day.
- Sulfur recovery (SRU), 80 tonnes/day.
- Gasoline post-treatment (GPTU), 25,666 b/d.
- Propylene recovery, 330 tonnes/day.

EORC, PROPOSED UNIT ADDITIONS Table 4

Unit	Capacity
Crude distillation, b/d	120,000
Kerosine hydrodesulfurization, b/d	27,000
Gas oil hydrodesulfurization, b/d	99,370
Hyvahl, b/d	81,000
RFCC, b/d	91,290
RFCC gasoline treating, b/d	51,477
LPG, b/d	9,819
LPG Merox, b/d	23,728
Propylene recovery, b/d	23,728
H_2 production 1, tonne/day	429
H_2 production 2, tonne/day	429
SRU, tonne/day	650

Source: NIORDC, October 2015

IKORC, PROPOSED UNIT ADDITIONS Table 5

Unit	Capacity
Crude distillation	80,000
Naphtha hydrotreating	33,000
Octanizing	20,000
RFCC	94,387
LPG Merox	28,105
RCD	69,180
Kerosine hydrotreating	31,500
Gas oil hydrotreating	53,000
FCC gasoline treating	50,500
Isomerization	8,500
Propylene recovery	28,105

Source: NIORDC, October 2015

At its Bandar Abbas refinery, NIORDC already has 96.7% completed a project to expand production and improve the quality of finished fuels, the company said in a June 9 release.

In addition to a 500-tonne/day sour water stripper and 120-tonne/day SRU, the Bandar Abbas project will add the following units by yearend:

- Heavy naphtha treating, 25,000 b/d.
- Continuous catalytic reforming (CCR), 25,000 b/d.
- Light naphtha treating, 21,000 b/d.
- Isomerization, 16,000 b/d.
- Gasoil hydrodesulfurization, 50,000 b/d.
- Amine treating, 230 tonnes/day.
- Sulfur solidification, 250 tonnes/day.

The Abadan modernization program, which Iran's government has agreed to finance, and the ongoing revamp at Bandar Abbas financed by China are each projected to cost between $1.7-1.8 billion, NIORDC said in releases posted to its website on Apr. 18 and May 17.

While NIORDC recently completed a series of capacity additions aimed at boosting the quantity and quality of fuel output at its Esfahan refinery that include a 62,000-b/d naphtha treater, a 32,000-b/d continuous catalytic reformer (CCR), and 27,000-b/d isomerization unit, the state-owned company's future plans at the plant include another round of projects to further expand capacities for crude processing as well as clean fuels production (Table 4).

At TORC's Tehran refinery, NIORDC plans to complete a clean fuels project that previously involved installing an 18,000-b/d naphtha treater and 18,000-b/d isomerization unit along with the following:

- Kerosine hydrodesulfurization, 31,500 b/d.
- Gas oil hydrodesulfurization, 53,500 b/d.
- H_2 production, 42 MMcfd
- SRU, 110 tonnes/day.

In addition to units added as part of an ongoing residue upgrading and optimization project at IKORC's refinery in Arak (Table 5), NIORDC plans to add a 341-MMcfd H_2 recovery plant and 640-tonne/day SRU.

New capacity, plants

Iran also is advancing construction and commissioning activities for five new processing plants to accommodate the country's rising condensate and natural gas supplies.

Already under construction in Bandar Abbas, the Persian Gulf Star Refinery, tentatively due for startup in 2016-17, will have capacity to process 360,000 b/d of condensate from Iran's South Pars gas field to produce the following:

- LPG, 24,000 b/sd.
- Gasoline, 230,000 b/sd.
- Jet fuel, 21,000 b/sd.
- ULSD, 84,000 b/sd.

NIORDC is also building a 480,000-b/d gas condensate refinery in Siraf, at Assaluyeh in Booshehr province, to process stabilized gas condensate feedstock from different phases of South Pars.

The Siraf complex will consist of eight processing trains, each configured with the following capacities:

- Condensate fractionation, 60,000 b/sd.
- LPG recovery, 3,100 b/sd.
- LPG treatment, 3,100 b/sd.
- Naphtha hydrotreating, 34,450 b/sd.
- Kerosine treatment, 3,700 b/sd.

According to NIORDC, the Siraf complex, once completed, will be able to produce 25,000 b/sd of LPG, 276,000 b/sd of treated naphtha, 30,000 b/sd of jet fuel, and 148,000 b/sd of gas oil.

Iran is also building the following refineries:

- Hormoz Oil Refining Co.'s 300,000-b/d Bahman Geno refinery at Bandar Abbas, which will process Iranian heavy and extra-heavy export crudes.
- NIORDC subsidiary Anahita Oil Refining Co.'s 150,000-b/d refinery in Kermanshah City, which will process 125,000 b/sd of Iran's North Desfull (26.35° API), 10,000 b/sd of NaftShahr (42.43° API), and 15,000 b/sd of SarkanMalehkuh (42.66° API) crudes.
- NIORDC's 120,000-b/d Pars condensate refinery in Shiraz, scheduled for startup in 2025, according to earlier company reports OGJ.

GUIDE TO WORLD CRUDES

BP issues assay for Basrah Heavy

BP Oil International Ltd., a subsidiary of BP PLC, has published an assay for Basrah Heavy crude oil based on a sample taken June 4, 2015.

Issuance of the new assay follows a 2015 decision by Iraq's Ministry of Oil to split crude oil production from its southern fields into separate light and heavy streams for marketing purposes beginning in May 2015.

Creation of the separate Basrah Heavy stream came amid customer complaints of quality deterioration in Basrah Light supplies as increased Iraqi production resulted in a heavier crude mix.

BP, which leads Rumaila Operating Organization (ROO) on behalf of partners PetroChina Co. Ltd., South Oil Co., and Iraq's State Oil Marketing Organization (SOMO), produces Basrah Heavy from Rumaila field, 50 km west of Basra in southern Iraq (OGJ Online, Dec. 17, 2015).

Currently producing at 1.35 million b/d, total Rumaila output averaged 1.31 million b/d in 2015, said ROO.

With a lower gravity and higher sulfur content than its lighter counterpart, Basrah Heavy ships via pipeline from southern production fields to load for export at the Al Basra and Khor al-Amaya oil terminals, according to ExxonMobil Corp., which also produces the grade as lead operator of the West Qurna 1 rehabilitation.

Whole crude

API gravity at 60/60° F.: 23.7
Density at 15° C., kg/l.: 0.9111
Total sulfur, wt %: 4.120
Mercaptan sulfur, ppm (wt): 26
Total nitrogen, ppm (wt): 2,000.0
Basic nitrogen, ppm (wt): 566
Acidity, mg KOH/g: 0.300
Vis. at 20° C., cst: 59.06
Vis. at 30° C., cst: 37.55
Vis. at 40° C., cst: 25.320
Vis. at 50° C., cst: 17.930
Pour point, °C.: –51
Wax, wt %: 3.0
Carbon residue, wt %: 9.80
Asphaltenes, wt %: 5.9
Vanadium, ppm (wt): 93
Nickel, ppm (wt): 24
Iron, ppm (wt): 50
Ethane, wt %: 0.01
Propane, wt %: 0.16
Isobutane, wt %: 0.12
n-Butane, wt %: 0.59
Isopentane, wt %: 0.56
n-Pentane, wt %: 0.85
Cyclopentane, wt %: 0.04

PROCESSING

As lead of the Rumaila Operating Organization (ROO), BP PLC produces Basrah Heavy crude on behalf of partners PetroChina Co. Ltd., South Oil Co., and Iraq's State Oil Marketing Organization (SOMO) from Rumaila field, 50 km west of Basra, Iraq. Photo from ROO.

C_6 paraffins, wt %: 1.91
C_6 naphthenes, wt %: 0.33
Benzene, wt %: 0.06

Light naphtha, C5 to 95° C.

Yield on crude, wt %: 4.89
Yield on crude, vol %: 6.64
Density at 15° C., kg/l.: 0.6702
Total sulfur, wt %: 0.012
Mercaptan sulfur, ppm (wt): 99
Acidity, mg KOH/g: 0.022
Paraffins, wt %: 86.14
Naphthenes, wt %: 12.64
Aromatics, wt %: 1.22
n-Paraffins, wt %: 36.94
Research octane no.: 64

Heavy naphtha, 95-149° C.

Yield on crude, wt %: 5.88
Yield on crude, vol %: 7.20
Density at 15° C., kg/l.: 0.7430
Total sulfur, wt %: 0.075
Mercaptan sulfur, ppm (wt): 76
Acidity, mg KOH/g: 0.082
Paraffins, wt %: 60.75
Naphthenes, wt %: 26.17
Aromatics, wt %: 13.08
n-Paraffins, wt %: 29.31
Research octane no.: 44

149-175° C.

Yield on crude, wt %: 3.39
Yield on crude, vol %: 4.03
Density at 15° C., kg/l.: 0.7652
Total sulfur, wt %: 0.233
Mercaptan sulfur, ppm (wt): 85
Total nitrogen, ppm (wt): 0.1
Acidity, mg KOH/g: 0.147
Paraffins, wt %: 65.13
Naphthenes, wt %: 18.24
Aromatics, wt %: 16.63
n-Paraffins, wt %: 33.51
Research octane no.: 22

Kerosine, 175-232° C.

Yield on crude, wt %: 7.58
Yield on crude, vol %: 8.64
Density at 15° C., kg/l.: 0.7975
Total sulfur, wt %: 0.417
Mercaptan sulfur, ppm (wt): 25
Total nitrogen, ppm (wt): 0.5
Acidity, mg KOH/g: 0.097
Vis. at 40° C., cst: 1.273
Vis. at 60° C., cst: 0.9936
Smoke point, mm: 25.5
Aromatics, vol %: 18.4
Naphthalenes, wt %: 0.57
Freezing point, °C.: –49.5
Cetane index (ASTM D4737-90): 47.2
Refractive index at 70° C.: 1.4239

Light gas oil, 232-342° C.

Yield on crude, wt %: 15.32
Yield on crude, vol %: 16.25
Density at 15° C., kg/l.: 0.8567
Total sulfur, wt %: 2.070
Mercaptan sulfur, ppm (wt): 25
Total nitrogen, ppm (wt): 46.0
Basic nitrogen, ppm (wt): 26
Acidity, mg KOH/g: 0.240
Vis. at 50° C., cst: 2.860
Vis. at 100° C., cst: 1.330
Aromatics, wt %: 30.50
Smoke point, mm: 16.1
Aromatics, vol %: 27.1
Naphthalenes, wt %: 8.60
Pour point, °C.: –18
Cloud point, °C.: –18
Freezing point, °C.: –15.0
Cetane index (ASTM D4737-90): 49.5
Refractive index at 70° C.: 1.4583
Wax, wt %: 1.6

Heavy gas oil, 342-369° C.

Yield on crude, wt %: 4.32
Yield on crude, vol %: 4.34
Density at 15° C., kg/l.: 0.9058
Total sulfur, wt %: 3.630
Total nitrogen, ppm (wt): 300.0
Basic nitrogen, ppm (wt): 105
Acidity, mg KOH/g: 0.720
Vis. at 50° C., cst: 8.346
Vis. at 100° C., cst: 2.654
Pour point, °C.: 3
Cloud point, °C.: 4
Cetane index (ASTM D4737-90): 48.9
Refractive index at 70° C.: 1.4822
Aniline point, °C.: 64.9
Wax, wt %: 5.6

Light vacuum gas oil, 369-509° C.

Yield on crude, wt %: 21.78
Yield on crude, vol %: 20.88
Density at 15° C., kg/l.: 0.9482
Total sulfur, wt %: 4.210
Total nitrogen, ppm (wt): 1,000.0
Basic nitrogen, ppm (wt): 325
Acidity, mg KOH/g: 0.260
Vis. at 60° C., cst: 37.0800
Vis. at 100° C., cst: 9.029
Pour point, °C.: 24
Refractive index at 70° C.: 1.5078
Aniline point, °C.: 68.9
Wax, wt %: 7.1
Carbon residue, wt %: 0.31

Heavy vacuum gas oil, 509-550° C.

Yield on crude, wt %: 5.87
Yield on crude, vol %: 5.42
Density at 15° C., kg/l.: 0.9862
Total sulfur, wt %: 5.360
Total nitrogen, ppm (wt): 2,200.0
Basic nitrogen, ppm (wt): 610
Acidity, mg KOH/g: 0.270
Vis. at 60° C., cst: 553.9000
Vis. at 100° C., cst: 58.030
Refractive index at 70° C.: 1.5348
Aniline point, °C.: 73.0
Wax, wt %: 5.5
Carbon residue, wt %: 3.77

550-585° C.

Yield on crude, wt %: 4.58
Yield on crude, vol %: 4.11
Density at 15° C., kg/l.: 1.0120
Total sulfur, wt %: 5.870
Total nitrogen, ppm (wt): 2,900.0
Basic nitrogen, ppm (wt): 770
Acidity, mg KOH/g: 0.300
Vis. at 60° C., cst: 1,967.0000
Vis. at 100° C., cst: 158.000
Aniline point, °C.: 74.5
Wax, wt %: 4.3
Carbon residue, wt %: 7.64

Atmospheric residue (369°-FBP)

Yield on crude, wt %: 57.71
Yield on crude, vol %: 51.44
Density at 15° C., kg/l.: 1.0201
Total sulfur, wt %: 6.240
Total nitrogen, ppm (wt): 3,500.0
Basic nitrogen, ppm (wt): 966
Acidity, mg KOH/g: 0.190
Vis. at 60° C., cst: 3,354.0000
Vis. at 100° C., cst: 243.400
Vis. at 120° C., cst: 98.32

Pour point, °C.: 27
Wax, wt %: 4.7
Carbon residue, wt %: 16.90
Asphaltenes, wt %: 10.1
Vanadium, ppm (wt): 162
Nickel, ppm (wt): 41
Iron, ppm (wt): 87

Vacuum residue, 509º-FBP

Yield on crude, wt %: 35.93
Yield on crude, vol %: 30.56
Density at 15° C., kg/l.: 1.0692
Total sulfur, wt %: 7.470
Total nitrogen, ppm (wt): 5,000.0
Basic nitrogen, ppm (wt): 1,353
Acidity, mg KOH/g: 0.150
Vis. at 100° C., cst: 21,610.000
Vis. at 120° C., cst: 4,302.00
Vis. at 150° C., cst: 682.2
Pour point, °C.: 93
Wax, wt %: 3.2
Carbon residue, wt %: 27.00
Asphaltenes, wt %: 16.2
Vanadium, ppm (wt): 259
Nickel, ppm (wt): 66
Iron, ppm (wt): 140

550º-FBP

Yield on crude, wt %: 30.06
Yield on crude, vol %: 25.14
Density at 15° C., kg/l.: 1.0871
Total sulfur, wt %: 7.880
Total nitrogen, ppm (wt): 5,500.0
Basic nitrogen, ppm (wt): 1,499
Acidity, mg KOH/g: 0.120
Vis. at 100° C., cst: 164,000.000
Vis. at 120° C., cst: 23,390.00
Vis. at 150° C., cst: 2,541.0
Pour point, °C.: 108
Wax, wt %: 2.7
Carbon residue, wt %: 31.50
Asphaltenes, wt %: 19.1
Vanadium, ppm (wt): 310
Nickel, ppm (wt): 79
Iron, ppm (wt): 167

585º-FBP

Yield on crude, wt %: 25.48
Yield on crude, vol %: 21.03
Density at 15° C., kg/l.: 1.1017
Total sulfur, wt %: 8.250
Total nitrogen, ppm (wt): 6,000.0
Basic nitrogen, ppm (wt): 1,630
Acidity, mg KOH/g: 0.090
Vis. at 100° C., cst: 1,991,000.000
Vis. at 120° C., cst: 188,600.00
Vis. at 150° C., cst: 12,870.0
Pour point, °C.: 117
Wax, wt %: 2.5
Carbon residue, wt %: 35.80
Asphaltenes, wt %: 21.8
Vanadium, ppm (wt): 364
Nickel, ppm (wt): 93
Iron, ppm (wt): 196 OGJ

NELSON-FARRAR COST INDEXES[1]

Refinery construction (1946 basis)
Explained in OGJ, Dec. 30, 1985, p. 145.

	1962	1980	2013	2014	2015	Mar. 2015	Feb. 2016	Mar. 2016
Pumps, compressors, etc.	222.5	777.3	2,221.1	2,271.9	2,313.6	2,309.5	2,334.1	2,336.9
Electrical machinery	189.5	394.7	516.7	515.8	516.5	516.8	513.2	513.2
Internal-comb. engines	183.4	512.6	1,046.8	1,052.9	1,062.3	1,058.4	1,034.4	1,035.7
Instruments	214.8	587.3	1,509.9	1,533.6	1,554.4	1,536.4	1,583.5	1,581.2
Heat exchangers	183.6	618.7	1,293.3	1,305.0	1,305.0	1,305.0	1,221.2	1,221.2
Misc. equip. average	198.8	578.1	1,317.5	1,335.8	1,350.3	1,345.2	1,337.3	1,337.6
Materials component	205.9	629.2	1,538.7	1,571.8	1,434.9	1,469.9	1,342.2	1,353.6
Labor component	258.8	951.9	3,123.4	3,210.7	3,293.8	3,260.1	3,347.6	3,370.8
Refinery (inflation) index	237.6	822.8	2,489.5	2,555.2	2,550.2	2,544.1	2,545.4	2,563.9

Refinery operating (1956 basis)
Explained in OGJ, Dec. 30, 1985, p. 145.

	1962	1980	2013	2014	2015	Mar. 2015	Feb. 2016	Mar. 2016
Fuel cost	100.9	810.5	1,123.7	1,264.8	915.9	954.2	837.2	748.0
Labor cost	93.9	200.5	308.3	312.8	319.2	297.0	361.5	350.4
Wages	123.9	439.9	1,506.4	1,541.3	1,584.4	1,609.6	1,661.6	1,646.5
Productivity	131.8	226.3	489.1	493.1	497.1	542.0	459.7	469.9
Invest., maint., etc.	121.7	324.8	905.3	939.4	948.0	945.7	918.9	925.6
Chemical costs	96.7	229.2	502.6	472.3	434.6	442.1	402.1	398.5
Operating indexes[2]								
Refinery	103.7	312.7	661.8	688.5	660.0	654.7	653.2	643.6
Process units	103.6	457.5	802.6	865.3	748.1	754.1	723.1	690.9

[1]These indexes are published in the first of each month and are compiled by Gary Farrar, OGJ Contributing Editor.
[2]Add separate index(es) for chemicals, if any are used. Indexes of selected individual items of equipment and materials are also published on the Quarterly Costimating page in first issues for January, April, July, and October.

Indexes for most finished steels weaken during 2012-15

Gary Farrar
Contributing Editor

Nelson-Farrar indexes for finished steels changed drastically during 2012-15, but alloy steels showed less movement than carbon steel products.

Alloy bars started the period with an index value of 1,425.9 and ended at 1,382.9. Alloy sheets fell to an index value of 815.1 by yearend 2015 from 1,058.6 in early 2012.

The index value for cold-rolled sheets fell to 1,567.4 in fourth-quarter 2015 from 2,035.5 during the first quarter of 2012. During the same 4-yr period, structural plates tumbled to a low of 1,776.7 in fourth-quarter 2015 from an index value of 2,334.1 in first-quarter 2012.

The composite index for steel products began with an index value of 1,919.5 in first-quarter 2012 but had fallen to 1,448.5 by yearend 2015. The composite category includes all steel-mill products.

This analysis shows a large fluctuation in the cost of finished steels over the 2012-15 period. OGJ

INDEXES FOR FINISHED STEELS

Quarter	Composite	Alloy bars	Cold-rolled sheets	Alloy sheets	Structural plates	Welded carbon tubing
2012						
1st	1,919.5	1,425.9	2,035.5	1,058.6	2,334.1	3,446.4
2nd	1,906.2	1,398.2	2,037.3	1,059.5	2,297.8	3,368.8
3rd	1,782.3	1,373.4	1,947.0	1,012.7	2,137.3	3,199.3
4th	1,742.4	1,353.3	1,916.9	996.9	2,075.1	3,066.2
Total	**1,837.6**	**1,387.7**	**1,984.2**	**1,031.9**	**2,211.1**	**3,270.2**
2013						
1st	1,741.6	1,361.0	1,893.1	984.6	2,077.2	3,001.1
2nd	1,720.3	1,349.5	1,866.7	971.0	2,093.8	2,911.1
3rd	1,715.9	1,361.0	1,877.6	976.7	2,054.4	2,932.2
4th	1,733.6	1,353.3	1,918.7	997.8	2,069.9	2,941.7
Total	**1,727.8**	**1,356.2**	**1,889.0**	**982.5**	**2,073.8**	**2,946.5**
2014						
1st	1,771.7	1,386.8	1,941.5	1,009.6	2,143.5	2,957.1
2nd	1,769.0	1,409.7	1,968.9	1,024.0	2,127.9	2,937.9
3rd	1,786.7	1,435.5	1,999.0	1,039.8	2,164.2	2,917.8
4th	1,776.1	1,445.0	1,969.8	1,024.5	2,178.7	2,922.6
Total	**1,775.9**	**1,419.2**	**1,969.8**	**1,024.5**	**2,153.6**	**2,933.8**
2015						
1st	1,699.1	1,426.9	1,847.5	961.0	2,018.1	2,892.0
2nd	1,577.8	1,413.5	1,698.8	883.4	1,951.8	2,669.8
3rd	1,536.2	1,408.7	1,666.9	866.8	1,911.4	2,611.4
4th	1,448.5	1,382.9	1,567.4	815.1	1,776.7	2,499.3
Total	**1,565.4**	**1,408.0**	**1,695.2**	**881.6**	**1,914.5**	**2,668.1**

ITEMIZED REFINING COST INDEXES

The cost indexes may be used to convert prices at any date to prices at other dates by ratios to the cost indexes of the same date. Item indexes are published each quarter (first week issue of January, April, July, and October). In addition the Nelson Construction and Operating Cost Indexes are published in the first issue of each month of Oil & Gas Journal.

Operating cost (based on 1956 = 100.)	1954	1972	2013	2014	2015	Feb. 2016	*References	Index for earlier year in Costimating and Questions on Technology issues
Power, industrial electrical	98.5	131.2	1,008.5	1,077.8	1,098.1	1,015.4	Code 0543	No. 13, May 19, 1958, p. 181
Fuel, refinery price	85.5	152.0	1,064.2	1,211.5	857.4	796.7	OGJ	No. 4, Mar. 17, 1958, p. 190
Gulf cargoes	85.0	130.4	3,403.2	3,403.2	3,403.2	3,403.2	OGJ	No. 4, Mar. 17, 1958, p. 190
NY barges	82.6	169.6	3,460.4	3,460.4	3,460.4	3,460.4	OGJ	No. 4, Mar. 17, 1958, p. 190
Chicago low sulfur	—	—	3,238.2	3,238.2	3,238.2	3,238.2	OGJ	July 7, 1975, p. 72
Western US	84.3	168.1	4,176.7	4,176.7	4,176.7	4,176.7	OGJ	No. 4, Mar. 17, 1958, p. 190
Central US	60.2	128.1	3,368.3	3,368.3	3,368.3	3,368.3	OGJ	No. 4, Mar. 17, 1958, p. 190
Natural gas at wellhead	83.5	190.3	3,189.3	3,912.8	2,173.2	1,875.4	Code 531-10-1	No. 4, Mar. 17, 1958, p. 190
Inorganic chemicals	96.0	123.1	1,138.7	1,083.7	1,089.2	1,028.3	Code 613	Oct. 5, 1964, p. 149
Acid, hydrofluoric	95.5	144.4	414.9	414.9	414.9	414.9	Code 613-0222	Apr. 1, 1963, p. 119
Acid, sulfuric	100.0	140.7	439.1	439.1	439.1	439.1	Code 613-0281	No. 94, May 15, 1961, p. 138
Platinum	92.9	121.1	1,153.0	1,098.4	978.4	899.0	Code 1022-02-73	July 5, 1965, p. 117
Sodium carbonate	90.9	119.4	750.3	714.0	717.6	677.6	Code 613-01-03	No. 58, Oct. 12, 1959, p. 186
Sodium hydroxide	95.5	136.2	1,028.4	978.6	983.6	928.6	Code 613-01-04	No. 94, May 15, 1961, p. 138
Sodium phosphate	97.4	107.0	844.2	844.2	844.2	844.2	Code 613-0267	No. 58, Oct. 12, 1959, p. 186
Organic chemicals	100.0	87.4	1,037.0	1,002.4	796.1	729.2	Code 614	Oct. 5, 1964, p. 149
Furfural	94.5	137.5	1,496.5	1,446.5	1,148.8	1,049.9	Chemical Marketing	No. 58, Oct. 12, 1959, p. 186
MEK, tank-car lots	82.6	87.5	625.0	625.0	625.0	625.0	Reporter	
Phenol	90.4	47.1	500.3	500.3	500.3	500.3	Code 614-0241	No. 58, Oct. 12, 1959, p. 186

ITEMIZED REFINING COST INDEXES

Operating cost (based on 1956 = 100.)	1954	1972	2013	2014	2015	Feb 2016	*References	Index for earlier year in Costimating and Questions on Technology issues
Operating labor cost (1956 = 100)								
Wages and benefits	88.7	210.0	1,506.4	1,541.3	1,584.4	1,661.6	Employ & Earn	No. 41, Feb. 16, 1969
Productivity	97.2	197.0	489.1	493.1	497.1	459.7	Employ & Earn	No. 41, Feb. 16, 1969
Construction labor cost (1946 = 100)								
Skilled const.	174.6	499.9	2,796.5	2,866.3	2,943.9	2,991.1	Eng. News Record	No. 55, Nov. 3, 1949
Common labor	192.1	630.6	3,732.8	3,848.5	3,933.2	4,009.7	Eng. News Record	No. 55, Nov. 3, 1949
Refinery cost	183.3	545.9	3,123.4	3,210.7	3,293.8	3,347.6	OGJ	May 15, 1967, p. 97
Equipment or materials (1946 = 100)								
Bubble tray	161.4	324.4	1,780.7	1,827.1	1,773.1	1,721.7	Computed	July 8, 1962, p. 113
Building materials (nonmetallic)	143.6	212.4	1,169.8	1,204.8	1,233.6	1,251.3	Code 13	No. 61, Dec. 15, 1949
Brick—building	144.7	252.5	1,342.5	1,375.6	1,398.5	1,401.8	Code 1342	No. 20, Mar. 3, 1949
Brick—fireclay	193.1	322.8	2,072.6	2,077.9	2,112.7	2,127.1	Code 135	May 30, 1955, p. 104
Castings, iron	188.1	274.9	1,728.2	1,743.1	1,730.9	1,720.3	Code 1015	Apr. 1, 1963, p. 119
Clay products (structural, etc.)	159.1	342.0	952.5	963.2	984.1	992.2	Code 134	No. 20, Mar. 3, 1949
Concrete ingredients	141.1	218.4	1,305.4	1,360.7	1,418.0	1,467.7	Code 132	No. 22, Mar. 17, 1949
Concrete products	138.5	199.6	1,046.5	1,086.9	1,130.9	1,151.6	Code 133	Oct. 2, 1967, p. 112
Electrical machinery	159.9	216.3	516.7	515.8	516.5	513.2	Code 117	May 2, 1955, p. 104
Motors and generators	157.7	211.0	1,107.4	1,125.3	1,124.5	1,104.6	Code 1173	May 2, 1955, p. 104
Switchgear	171.2	271.0	1,395.8	1,400.6	1,402.7	1,403.5	Code 1175	May 2, 1955, p. 104
Transformers	161.9	149.3	798.0	798.2	757.2	730.8	Code 1174	No. 31, May 19, 1949
Engines (combustion)	150.5	233.3	1,046.8	1,052.9	1,062.3	1,034.4	Code 1194	No. 36, June 23, 1949
Exchangers (composite)	171.7	274.3	1,293.3	1,305.0	1,305.0	1,221.2	Manufacturer	Mar. 16, 1964, p. 154
Copper base	190.7	266.7	1,171.5	1,178.5	1,178.5	1,150.4	Manufacturer	Mar. 16, 1964, p. 154
Carbon steel	156.8	281.9	1,310.4	1,320.9	1,320.9	1,237.0	Manufacturer	Mar. 16, 1964, p. 154
Stainless steel (304)	—	—	1,294.2	1,312.7	1,312.7	1,201.2	Manufacturer	July 1, 1991, p. 58
Fractionating towers	151.0	278.5	1,421.5	1,457.9	1,449.5	1,435.8	Computed	June 8, 1963, p. 133
Hand tools	173.8	346.5	2,080.4	2,099.7	2,099.4	2,101.0	Code 1042	June 27, 1955
Instruments (composite)	154.6	328.4	1,509.9	1,533.6	1,554.4	1,583.5	Computed	No. 34, June 9, 1949
Insulation (composite)	198.5	272.4	1,951.1	2,014.9	2,072.6	2,130.9	Manufacturer	July 4, 1988, p. 193
Lumber (composite)	197.8	353.4	1,379.9	1,489.7	1,380.7	1,340.6	Code 81	No. 7, Dec. 2, 1948
Southern pine	181.2	303.9	999.5	1,025.0	966.4	932.3	Code 81102	No. 7, Dec. 2, 1948
Redwood, all heart	238.0	310.6	2,059.5	2,112.1	1,992.0	1,921.1	Code 811-0332	July 5, 1965, p. 117
Machinery								
General purpose	159.9	278.5	1,510.6	1,540.5	1,562.1	1,572.7	Code 114	Feb. 17, 1949
Construction	165.9	324.4	1,871.3	1,899.9	1,925.9	1,936.7	Code 112	Apr. 1, 1968, p. 184
Oil field	161.9	269.1	1,983.2	2,017.8	2,020.1	2,009.4	Code 1191	Oct. 10, 1955, p. 267
Paints—prepared	159.0	231.8	1,410.4	1,424.6	1,411.3	1,401.4	Code 621	May 16, 1955, p. 117
Pipe								
Gray iron pressure	195.0	346.9	3,363.2	3,392.1	3,369.5	3,347.4	Code 1015-0239	Jan. 3, 1983, p. 76
Standard carbon	182.7	319.9	2,907.9	2,895.4	2,633.2	2,420.9	Code 1017-0611	Jan. 3, 1983, p. 76
Pumps, compressors, etc.	166.5	337.5	2,221.1	2,271.9	2,313.6	2,334.1	Code 1141	No. 29, May 5, 1949
Steel-mill products	187.1	330.6	1,727.8	1,775.9	1,565.4	1,390.9	Code 1017	Jan. 3, 1983, p. 73
Alloy bars	198.7	349.4	1,356.2	1,419.2	1,408.0	1,411.6	Code 1017-0831	Apr. 1, 1963, p. 119
Cold-rolled sheets	187.0	365.5	1,889.0	1,969.8	1,695.2	1,468.9	Code 1017-0711	Jan. 3, 1983, p. 73
Alloy sheets	177.0	225.9	982.5	1,024.5	881.6	763.9	Code 1017-0733	Jan. 3, 1983, p. 73
Stainless strip	169.0	221.2	1,049.0	1,093.8	941.5	815.6	Code 1017-0755	Jan. 3, 1983, p. 73
Structural carbon, plates	193.4	386.7	2,073.8	2,153.6	1,914.5	1,688.7	Code 1017-0400	Jan. 3, 1983, p. 73
Welded carbon tubing.	180.0	265.5	2,946.5	2,933.8	2,668.1	2,453.4	Code 1017-0622	Jan. 3, 1983, p. 73
Tanks and pressure vessels	147.3	246.4	1,152.3	1,181.8	1,179.3	1,171.7	Code 1072	No. 5, Nov. 18, 1949
Tube stills	123.0	125.3	674.4	692.8	642.6	599.7	Computed	Oct. 1, 1962, p. 85
Valves and fittings	197.0	350.9	2,384.3	2,445.5	2,467.2	2,473.1	Code 1149	No. 46, Sept. 1, 1940
Nelson-Farrar Refinery (Inflation Index)								
(1946)	179.8	438.5	2,489.5	2,555.2	2,550.2	2,545.4	OGJ	May 15, 1969
Nelson-Farrar Refinery Operation								
(1956)	88.7	118.5	661.8	688.5	660.0	653.2	OGJ	No. 2, Mar. 3, 1958, p. 167
Nelson-Farrar Refinery Process Operation								
(1956)	88.4	147.0	802.6	865.3	748.1	723.1	OGJ	No. 2, Mar. 3, 1958, p. 167

*Code refers to the index number of the Bureau of Statistics, US Department of Labor, "Wholesale Prices" Itemized Cost Indexes, Oil & Gas Journal.

Rotor vibration dynamic analysis helps detect compressor defects

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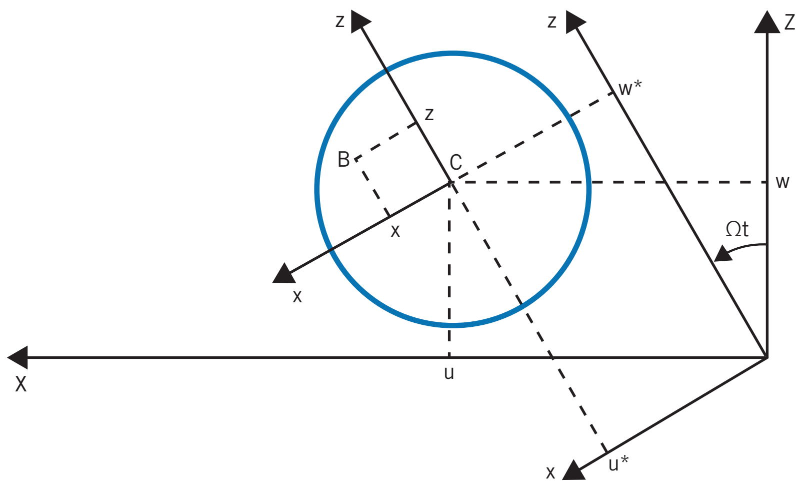
Applying vibration modelling in gas turbines to fault monitoring of the same equipment can assist maintenance planning and extend system life. Bearings are responsible for vibratory phenomena in gas turbines (OGJ, Mar. 2, 2015, pp. 98-100).[1-10] But vibrations in turn cause bearings' rapid deterioration.

This article proposes analyzing the dynamic behavior of a gas turbine's rotor vibration for purposes of modeling the frequencies characterized by bearing defects. Spectral analysis of vibration signals for defect detection allows diagnosis of in-service gas turbines. It will also allow timely intervention if defects are detected (unbalance, misalignment, fracture, cracking, or lubrication) and minimize repair times, creating a reliable and easily implemented diagnostic strategy.

Turbine dynamic-behavior analysis consists of studying vibration characteristics of the gas turbine rotor. Determining the rotor's energy allows analysis of dynamic behavior at nominal rotational speed within a limited range of several frequencies. Research sought to determine rotor response to dynamic excitation. Disturbances

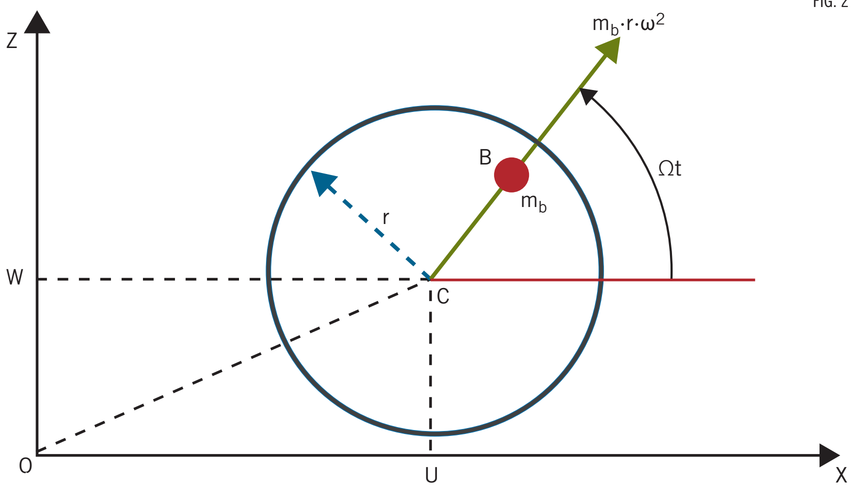
SHAFT CROSS-SECTION

FIG. 1



UNBALANCE-GENERATED CENTRIFUGAL FORCE

FIG. 2



Measurements taken on the rotor of gas turbine MS5002b, in service at Sonatrach's TRC Timzhert CC1 compressor station on the southern side of Hassi R'mel, Algeria, provided the data for this article (Fig. 3).

in mechanics are generated by vibrations either from outside systems such as adjacent machines, or from the gas turbine itself, such as residual unbalance, lack of lineage, or bearing degradation.

Shaft

The expression of the shaft's kinetic energy is an extension of the expression of the disk's kinetic energy. For an element with length, L, Equation 1 calculates kinetic energy.[11] Shaft deformation energy is calculated via deformation of a point on the shaft's straight section (Fig. 1) as expressed in Equation 2.

Equation 3 expresses the deformation,[12] while Equation 4 calculates deformation energy.

Unbalance response

Unbalance is characterized by its kinetic energy, when mass m_b is at point B in the disk's plane at distance d from its geometric center C. Equations 5 and 6 provide the unbalance coordinates in fixed coordinate system *oxyz* (Fig. 2). Equation 7 calculates unbalance kinetic energy. The term $\Omega^2 d^2/2$ is constant and will not intervene in the equations. The mass of the unbalance is negligible relative to the rotor mass and kinetic energy can be approximated as shown in Equation 8 by introducing generalized coordinates (Equation 9).

Bearings guide the rotating shaft in a stationary turbocharger. Radial load is weak and caused primarily by the unbalance, which may be reduced if necessary. A few major factors contribute to ball bearing damage:[13-18]

- Superficial material fatigue resulting from the constraints-concentration effect produces flaking and cracking. This superficial fatigue can be aggravated by such other factors as insufficient lubrication, surface conditions, and shock.
- Contact wear, which can be compounded by oil contamination, bearing load, speed, and vibration,
- Contact corrosion.
- Heating, seizure.

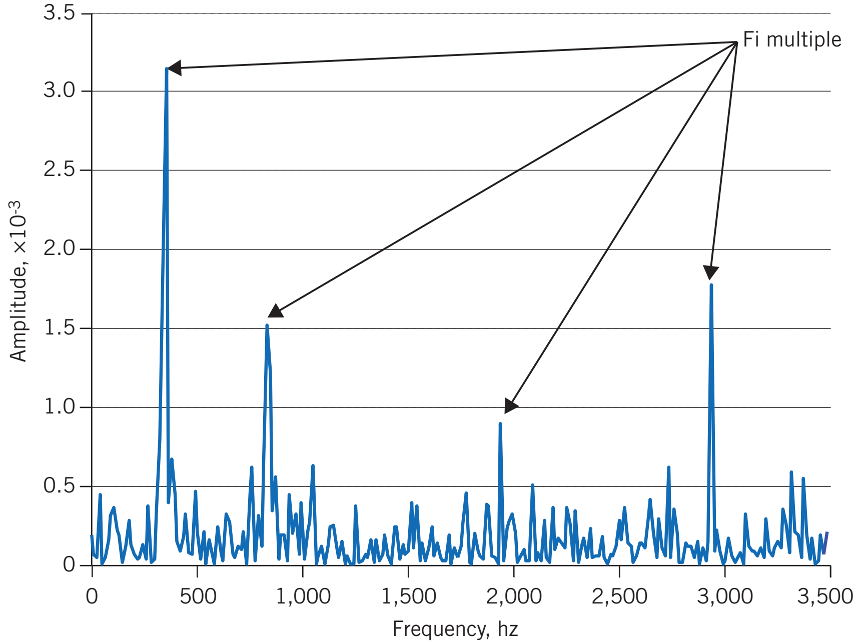
Equations frequency

For a ball bearing with n_b number of balls, rotating at shaft-rotation frequency f, a default such as stripe, flat, etc., differentiates the various rotating elements, the frequencies of which are defined in Equations 10-15, where *d* is the ball diameter, and φ the contact angle between the ball and raceway.

Equation 10 defines the frequencies related to default on each of the rotating elements for a defined unbalance.

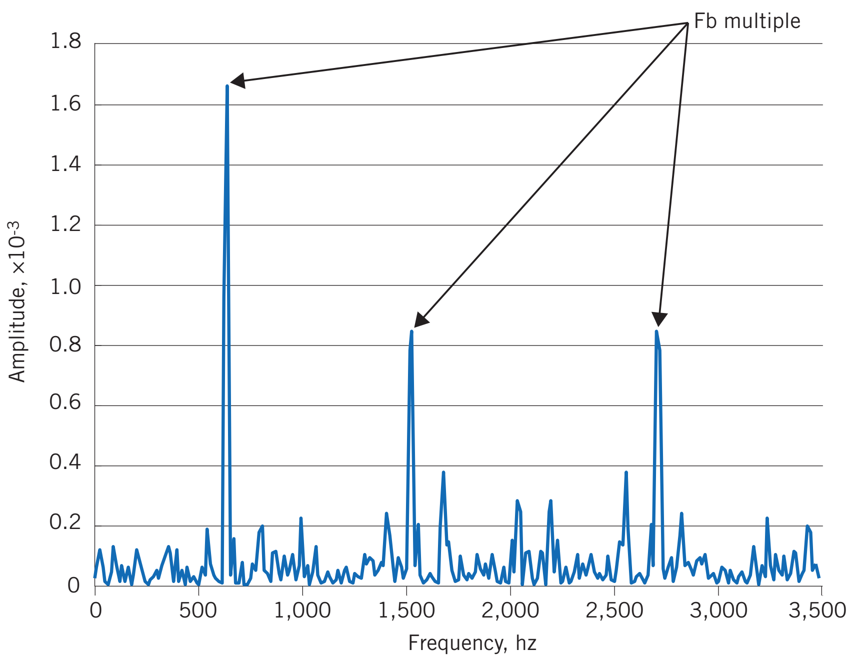
INNER-RING DEFECT VIBRATION SIGNAL

FIG. 4



BALL-DEFECT VIBRATION SIGNAL

FIG. 5



EQUATIONS

$$T_s = \frac{\rho S}{2}\int_0^L (\dot{u}^2 + \dot{w}^2)dy + \frac{\rho I}{2}\int_0^L \left(\dot{\psi}^2 + \dot{\theta}^2\right)dy + \rho IL\Omega^2 + 2\rho I\Omega^2 \int_0^L \dot{\psi}^2\theta\, dy \quad (1)$$

$$\int_0^L (\dot{u}^2 + \dot{w}^2)dy = \text{the translation}$$

$$2\rho I\Omega \int_0^L \dot{\psi}^2\theta dy \text{ gyroscopic effect} \star$$

$$\frac{\rho I}{2}\int_0^L \left(\dot{\psi}^2 + \dot{\theta}^2\right)dy = \text{rotation}$$

$$\rho IL\Omega^2 = \text{a constant term}$$

$$U_s = \frac{1}{2}\int_r \varepsilon' \sigma\, d\, \tau \quad (2)$$

Where:

$\sigma = E\varepsilon$ and $E =$ Yong module

ε, σ - deformation constraints along shaft axis

$$\varepsilon = -\chi\frac{\partial^2 u^*}{\partial y^2} - z\frac{\partial^2 w^*}{\partial y^2} + \frac{1}{2}\left(\frac{\partial u^*}{\partial y}\right)^2 + \frac{1}{2}\left(\frac{\partial w^*}{\partial y}\right)^2 \quad (3)$$

$$U_s = \frac{EI}{2}\int_0^L \left[\left(\frac{\partial^2 u^*}{\partial y^2}\right) + \left(\frac{\partial^2 w}{\partial y^2}\right)^2\right]dy + \frac{F_0}{2}\int_0^L \left[\left(\frac{\partial u}{\partial y}\right)^2 + \left(\frac{\partial u}{\partial y}\right)^2\right]dy \quad (4)$$

$$\chi(t) = u_B + d\cos\Omega t \; \frac{d\chi(t)}{dt} = u_B - d\Omega\sin\Omega t \quad (5)$$

$$\Longrightarrow$$

$$z(t) = \omega_B + d\sin\Omega t \; \frac{dz(t)}{dt} = \omega_B + d\Omega\cos\Omega t \quad (6)$$

$$T_{Bal} = \frac{1}{2}m_b\left((\dot{u}_B^2 + \dot{w}_B^2) + \Omega^2 d^2 + 2\Omega d\dot{u}_B\sin\Omega t - 2\Omega d\dot{w}_B\cos\Omega t\right) \quad (7)$$

$$T_{Bal} \approx m_d d\Omega(\dot{u}_B\sin\Omega t - \dot{w}_B\cos\Omega t) \quad (8)$$

$$T_{Bal} \approx m_b d\Omega\begin{bmatrix}(\dot{A}_u\dot{Y}_B^3 + \dot{B}_u\dot{Y}_B^2 + \dot{C}_u\dot{Y}_B^2 + \dot{D}_u)\sin\Omega t - \\ (\dot{A}_w\dot{Y}_B^3 + \dot{B}_w\dot{Y}_B^2 + \dot{C}_w\dot{Y}_B^2 + \dot{D}_u)\cos\Omega t\end{bmatrix} \quad (9)$$

$$f_{be} = \frac{f_r n_b}{2}\left(1 - \frac{d}{D}\cos(\varphi)\right) \quad (10)$$

$$f_{bi} = \frac{f_r n_b}{2}\left(1 + \frac{d}{D}\cos(\varphi)\right) \quad (11)$$

$$f_{be} = \frac{f_r n_b}{2}\left(1 + -\frac{d}{D}\cos(\varphi)\right) \pm f_c \quad (12)$$

$$f_B = \frac{f_r n_b}{2}\left(1 - \left(\frac{d}{D}\cos(\varphi\right)^2\right) \quad (13)$$

$$f_{bi} = \frac{f_r n_b}{2}\left(1 + \frac{d}{D}\cos(\varphi)\right) \pm f_c \quad (14)$$

$$f_c = \frac{f_r}{2}\left(1 - \left(\frac{d}{D}\cos(\varphi)\right)\right) \quad (15)$$

$$f_r = \frac{V(tr/min)}{60(S)} = \frac{4530}{60} = 75 - 5Hz \quad (16)$$

Where:

$V =$ shaft rotation speed

$(n_b = 20) =$ number of balls

Equation 11 provides defects on the inner ring. Equation 12 accounts for modulation of the signal by frequency f_c on inner-ring defects.

Equation 13 yields defects on the ball, with Equation 14 accounting for modulation of the signal by frequency.

Equation 15 provides fundamental cage frequency. Construction imperfections, assembly problems, or rotor operations lead to signal modulation.

Application results

Experimental results came from measurements taken on the rotor of gas turbine MS5002b, in service at Sonatrach's TRC Timzhert CC1 compressor station on the southern side of Hassi R'mel, Algeria. Researches gathered data from Bearing #1 and #4 in a vertical orientation and shaft rotation speed, ω, of 4,530 rpm.

The lack of information on the contact angle of the ball requires using equations based on testing more than 2,000 different types of bearings. Equations 10, 12, 14, and 15 give the frequencies for different bearing components. Equation 16 calculates shaft rotation frequency.

The measured values of the turbine at Bearings 1 and 4 present vibration defects in a vertical direction over 0-3,500 hz and 0-6,000 hz, respectively. Figs. 4-5 present the amplitude of the vibration signal as a function of its frequency. Fig. 4 shows an inner-ring bearing fault and Fig. 5 the vibration signal as a bearing failure due to a defect of the ball itself. Fig. 6 shows the vibration signal without a fault

These obtained results under actual conditions are presented to show the amplitude of the signal versus its frequency. The lifespan of the bearings depends on the load applied to the shaft, the rotational speed, and the force action point.

This kind of component appears when the shaft of the turbine operates under a bearing default explained by the presence of oscillations in the torque load and keeps the machine operating stably. These fluctuations occur at the same characteristic frequency of the defect.

Figs. 7-8 show the envelope spectrum calculated for the different cases of operation in misalignment. The frequency signal of a misalignment defect appears as a peak amplitude with 2 or 3 times the rotor's rotation frequency. Fig. 7 shows the spectrum at the rotation frequency without defects. Figs. 8-9 show the spectrum at the rotation frequency with misalignment.

Figs 7-8 show spectral structure evolution successively when a fault is added. At 4,530 rpm and 75.5 hz, in a frequency range of 0-6,000 hz, a peak appears at the shaft rotation frequency characterizing the misalignment fault seen in Figs. 8-9.

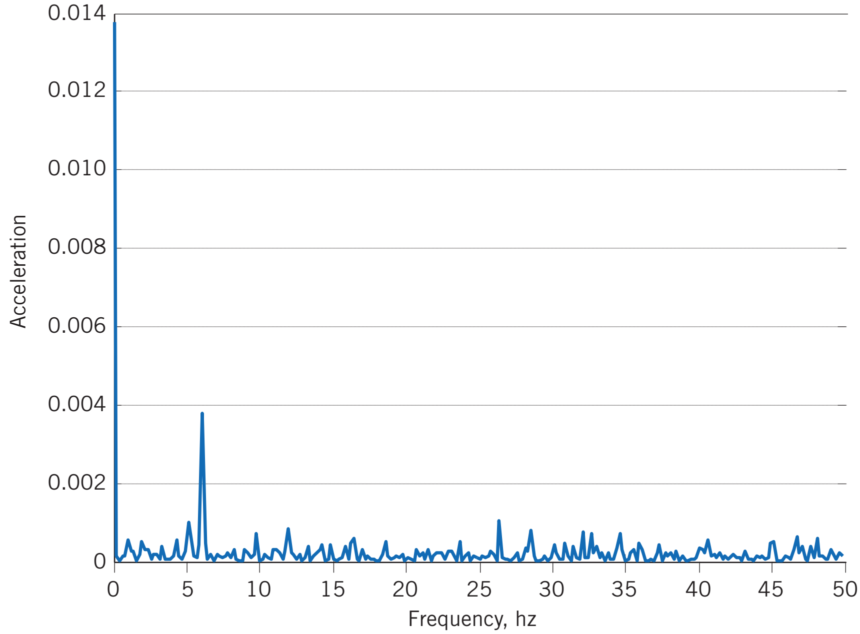
Balancing processing compensates for this poor distribution by adding or removing known masses at specific rotor locations. Additional work checked the system's capacity to address strong unbalances. Fig. 9 presents a test with two balancing speeds, designed to reduce all vibration levels at all rotor speeds. Displacement amplitude is increased in speed without balancing.

Fig. 10 shows rotational speed, including a peak at frequency F1 of 20 μm and a harmonic at (2 × F1 = F2) 35 hz, with an amplitude of 20 μm indicating an imbalance in the shaft.

Maximum amplitude identifies critical speed, with rotor displacements characteristic of sensitivity to a dominant unbalance mode. Fig. 11 shows the balancing rotational speeds' portion of vibration amplitude measured on the rotor as it accelerated toward critical speed OGJ

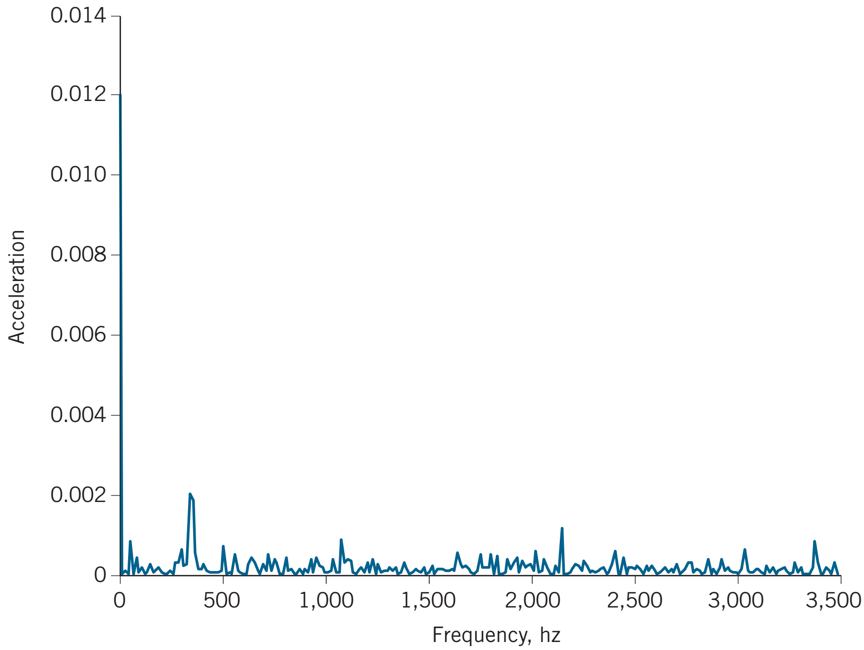
VIBRATION SIGNAL WITHOUT DEFECTS

FIG. 6



SPECTRUM FREQUENCY WITHOUT DEFECTS

FIG.7



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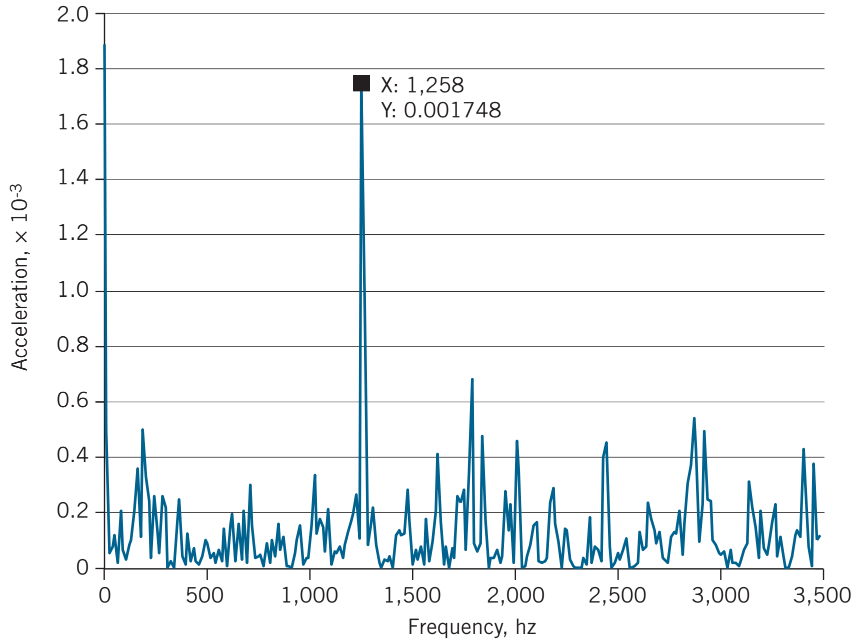
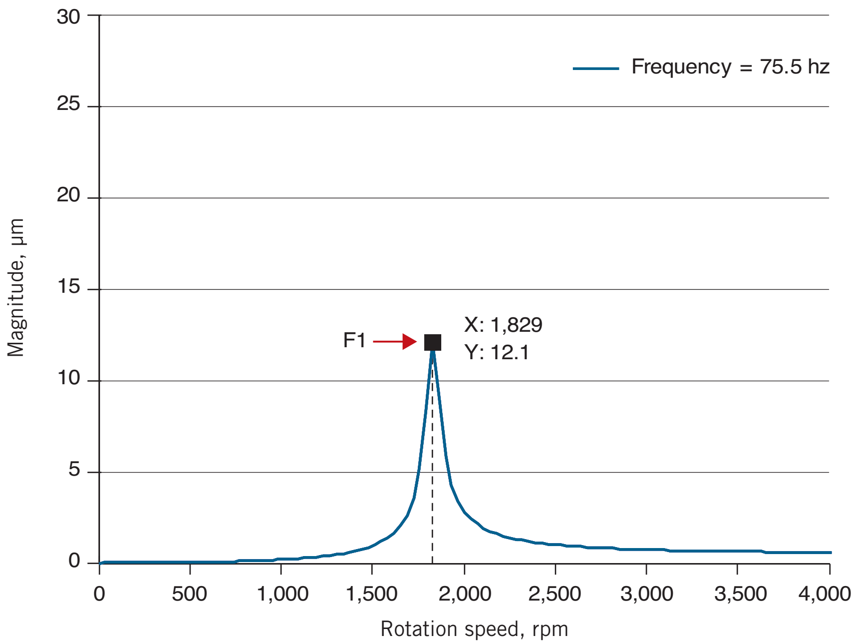
SPECTRUM FREQUENCY WITH MISALIGNMENT

FIG. 8



RESPONSE TO UNBALANCE F1

FIG. 9



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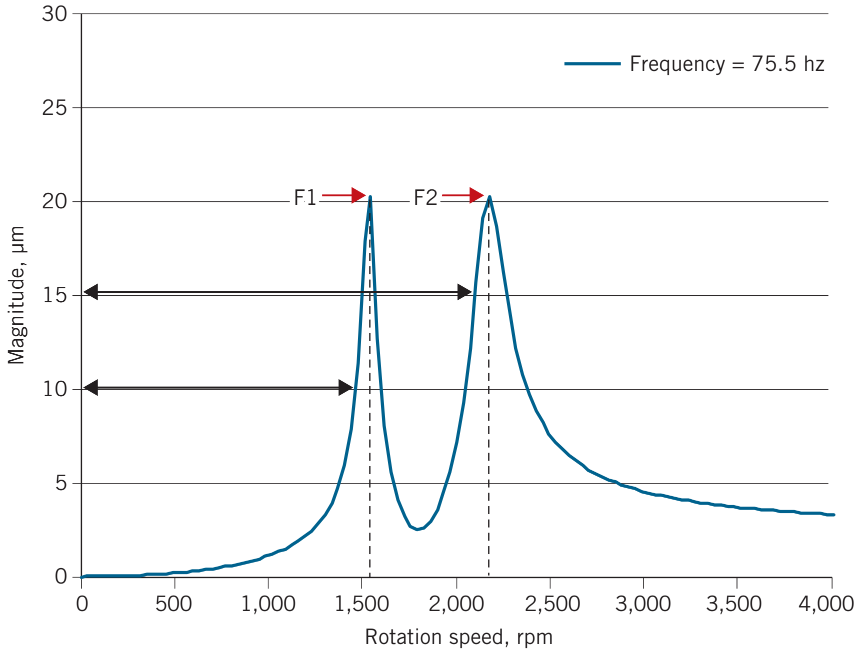
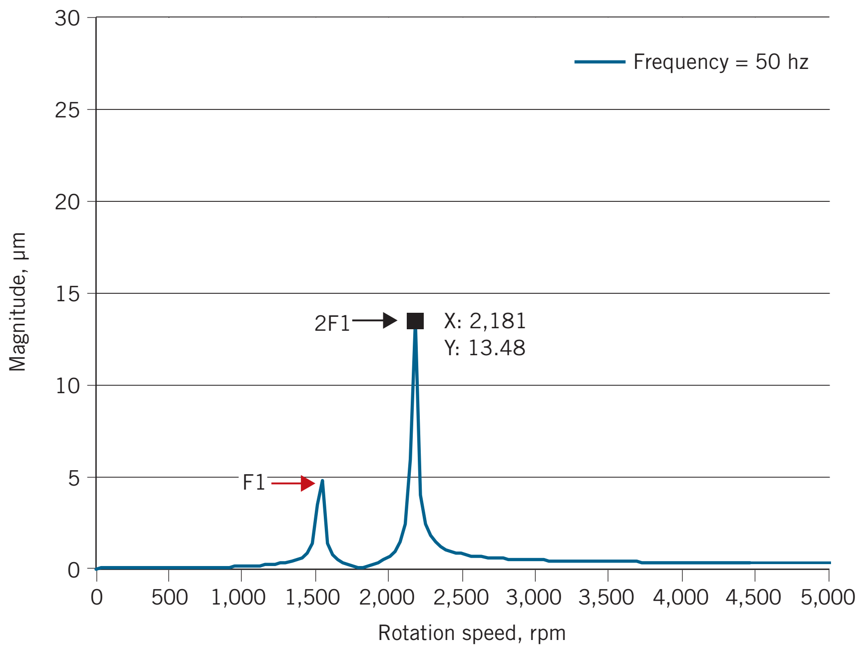
RESPONSE TO UNBALANCES F1, F2

FIG. 10



FAULT-UNBALANCE VIBRATORY SIGNAL

FIG. 11



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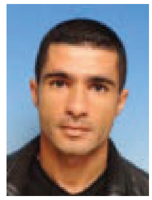

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TRANSPORTATION

Oil tanker freight-rate volatility increases

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Factors that can either increase demand for tankers or lead to excess supply will clash for the balance of 2016, leading to great fluctuations in oil tanker freight rates. Crude oil prices plummeted in July 2014, leading to job cuts, declining margins, and depleted cash reserves for both upstream operators and their suppliers. Low oil prices, however, initially had the opposite effect on crude tanker rates, which had surged to 8-year highs by December 2015.

The market for crude tankers looked strong through at least 2017 as last year closed. Declining crude prices increased oil trade, with countries like China importing huge quantities to build up their strategic reserves. And with the Organization of Petroleum Exporting Countries (OPEC), North America, and Russia showing no signs of decreasing production, prices are not expected to rise radically over the next 2 years.

But daily rates for benchmark Saudi Arabia-Japan very large crude carrier (VLCC) cargoes crashed almost 50% in January. There was also a slump in Middle East spot cargo availabilities. Both events were in stark contradiction to the expected market trend. This article will examine if the oil-tanker market boom is already over or if the recent decrease in rates is seasonal and the market is still going to be strong.

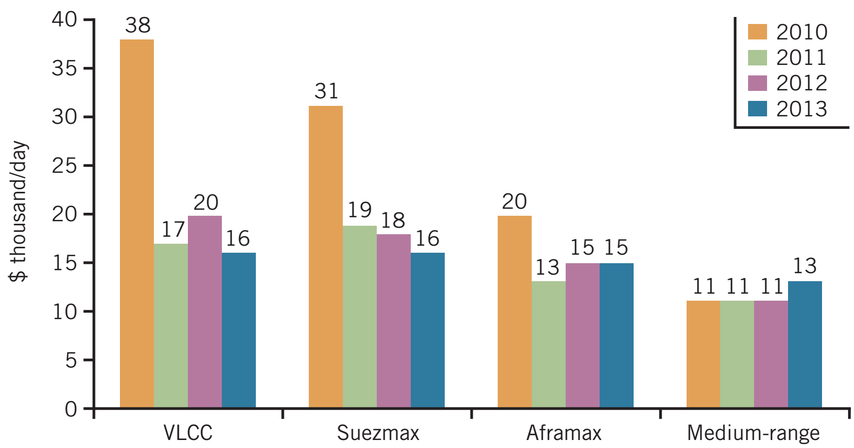
Assessments

The Average Freight Rate Assessment system is a classification system used by the global crude oil and refining tanker fleet to establish shipping costs, standardize contract terms, and determine the ability of a ship to pass through certain channels and straits.

Classification occurs on a dwt basis, a measure of how much mass a

OIL TANKER RATES

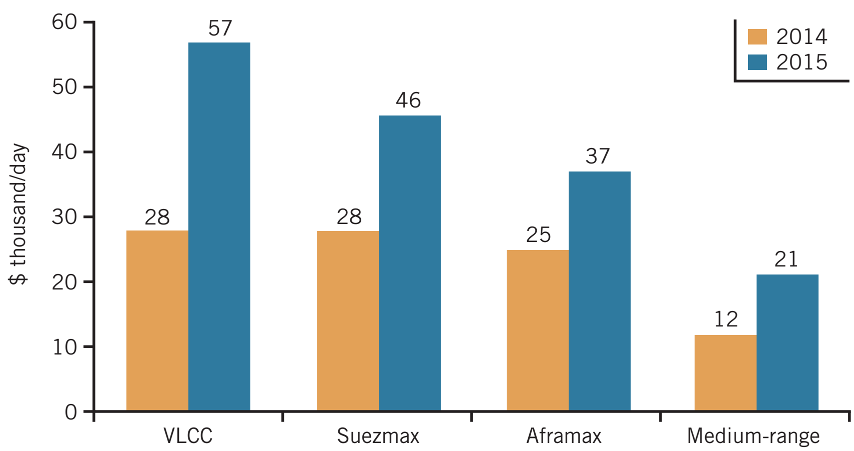
FIG. 1



Source: Clarksons, Credit Suisse, MAREX

RATES, 2014-15

FIG. 2

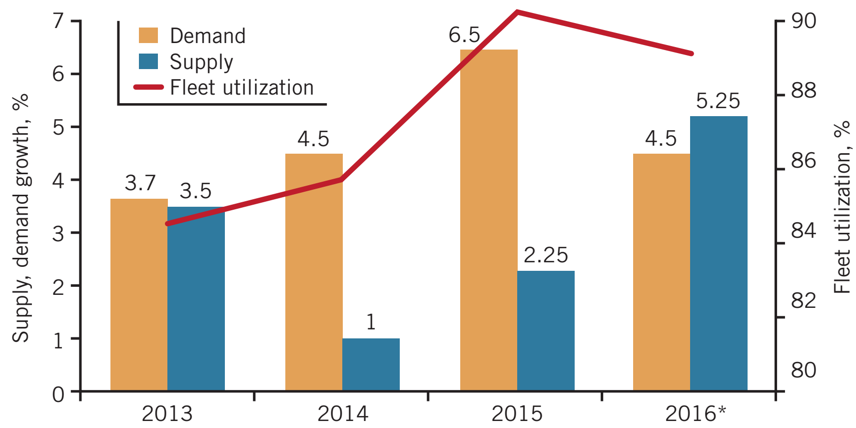


Source: Clarksons, Credit Suisse, MAREX

ship is carrying or can safely carry (Table 1). To calculate the barrels of oil that a ship can carry, 90% of the ship's dwt is multiplied using a bbl/tonne conversion factor specific to the type of petroleum product or crude oil being transported.

OIL TANKERS

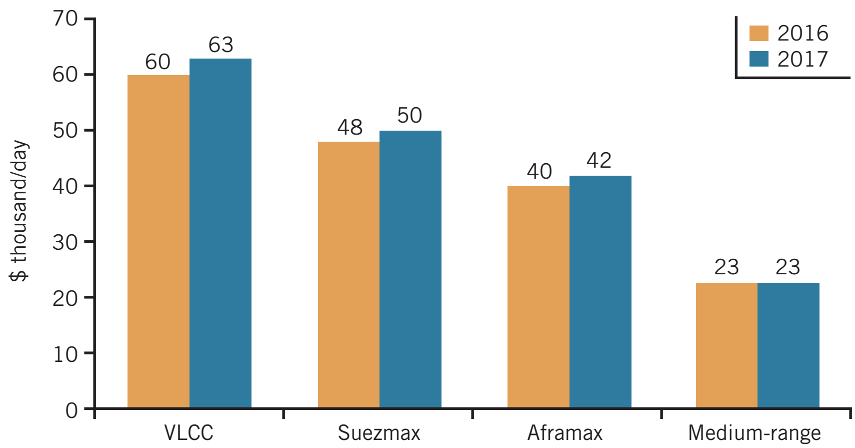
FIG. 3



*Estimate
Source: Teekay Tankers 4Q 2015 investors presentation, Beroe analysis.

ESTIMATED RATES

FIG. 4



Source: Clarksons, Credit Suisse, MAREX

Historical trend

The oil tanker market had been sluggish since the economic downturn of 2008. High crude oil prices had dampened international trade and led to rate stagnation apart from the usual seasonal increase towards the end of each year due to heating oil demand, (Fig. 1).

Tanker rates 2009-13 were well below the long-term average (Table 2). The oil tanker industry suffered huge losses, with day rates often significantly below operating costs.

Revival

Crude production surpluses measured 0.85 million b/d worldwide in 2014 and 1.7 million b/d in 2015, according to the International Energy Agency. North America and OPEC were producing record volumes around January 2015, and with Iran sanctions soon to be lifted crude prices fell even further than had been expected. The lower commodity prices, however, helped spot tanker rates hit 7-year highs of $64,000/day in May 2015.

Improvement in time-charter rates was slow compared to the spot freight rates, getting stronger only towards end-2014. Time-charter prices were then relatively stable for first-quarter 2015. After further crude price declines and spot rate increases, time-charter rates started rising again, reaching $56,250/day their highest level since the start of the financial crisis in 2008.

2015 trends

Lowered crude oil costs improved refinery margins, resulting directly in more oil-products trade. One example was the 22% increase in China's export of oil products in 2015 as compared with 2014 reported by jodidata.org and trademap.org.

Floating storage also has been in increased demand, with commodity trading firms storing oil at sea to earn profits from longer-dated futures contracts. This practice has further reduced available shipping capacity.

OIL TANKERS

Table 1

Cargo type	Vessel class	Capacity, thousand dwt
Refined products	General purpose, GP	10-25
	Medium range, MR	25-45
Refined products, crude oil	Long range 1, LR 1	45-80
	Aframax	80-120
	Long range 2, LR 2	80-160
	Seuzmax	~160
Crude oil	Very large crude carrier, VLCC	160-320
	Ultra large crude carrier, ULCC	320-550

Demolition activity has subsided, however, with most fleet operators instead running their vessels at maximum speeds to achieve as much benefit as possible from the increased demand.

Shipping companies ordered 66 new VLCCs in 2015, adding about 35 million dwt to the fleet..

SPOT TANKER RATES

Table 2

Tanker type	2013 Day rate, $	2009-2013 average	Long-term average
Suezmax	16,000	18,500	38,700
Aframax	15,000	13,000	28,500

Source: Teekay Tankers

2016 expectations, reality

A 2015 in which the market witnessed the highest freight rates in years and rapid increase in demand prompted expectations that strength in the oil tanker industry would continue in 2016.

- Oil tanker net earnings were expected to increase 5-10% in 2016 compared with 2015.
- The existing fleet of crude oil tankers was projected to grow by 4.3% in 2016, with total fleet growth expected to be around 5-6%.
- With VLCC utilization rising to 95% towards end-2015, freight rates were expected rise beyond $100,000/day.

The oil tanker industry expected another profitable year in 2016 and freight rates were expected to remain elevated for most of the year. But following winter's seasonal hike, freight rates started declining. Asian VLCC rates (Persian Gulf-Japan route) dropped 44% in January 2016, losing 11 worldscale points to trade at W53.25. Worldscale prices represent a percentage of the nominal value of shipping the cargo in question. Day rates for Saudi Arabia-Japan VLCC rates fell nearly 50%, reaching $50,955/day in January after briefly reaching the expected $100,000/day mark just one month earlier.

Heightened competition between owners keen to avoid lengthy waiting periods for vessels heading to the Middle East was the main reason for the decline. At one point more than 10 vessel offers were made on a single eastbound Persian Gulf cargo. The increased competition stemmed from abundant vessel supply, including newly built VLCCs, older tonnage, and ships just out of dry dock. Freight rates remained low in February, with the key Persian Gulf-Japan route assessed at W59.5 early in the month.

Rates started rising again, however, at the start of March. Persian Gulf-Japan prices jumped more than 33% to eclipse 100 worldscale points for the first time since Jan. 8. Spot market rates rose to about $60,000/day, driven in large part by delays in discharging ships in northern China. An increase in short-term VLCC charters also tightened the market.

The future

Improved March vessel demand helped shrink the tanker oversupply. But the industry expects to take delivery of about 130 total VLCCs and Suezmaxes in 2016 and first-half 2017, further depressing freight rates.

With the global oil market flooded, most countries and refineries have been stockpiling crude for future use. Once stockpiling ends and refiners start running down inventories, tanker demand will take a serious hit.

Vessel-demand growth for 2015 was significantly higher than supply growth, one of the primary reasons for high freight costs. The opposite, however, is expected to hold true this year. And the total number of scrapped tankers will not be enough to offest the high number of new tankers entering the market. The rate at which US and Iranian crude exports enter the market will help determine the severity of downward pressure on freight rates.

Strategy

Oil tanker suppliers should be cautious. Entering into a 3-year time charter can shield them against market volatility. Current 3-year charter rates stands at $44,000/day vs. $58,250/day for a 1-year charter. Considering the possibility of both vessel oversupply and decreased demand, rates could go much lower than $44,000/day.

Suppliers with diverse fleets can enter into long-term crude charters on their Suezmax or smaller vessels, and use the VLCCs for 1-year business, taking advantage of any short-term upticks while hedging against risk as well. Similarly suppliers with both crude and product carriers can go into long-term charters on their crude carriers and rely on market conditions for the products fleet. Refined products trade will likely increase as low crude prices improve refining margins. OGJ

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Texas Supreme Court rules

cont'd from pg. 55

DRILLING & PRODUCTION

The royalty-pricing mechanism drove post-production expenses, judges said. For example, the oil royalty in the same lease bore its share of post-production expenses because it priced oil based on market value at the well, not because the oil volume was measured at the wellhead.

Similarly, the gas royalty in the same lease was free from the burden of post-production expenses because it priced gas based on the price received by Chesapeake's affiliate after post-production costs were paid, not because the gas volume was measured away from the wellhead.

Chesapeake argued overriding royalty value should be equal whether the royalty is paid in cash or in kind, assuming that royalty owners incur post-production costs if the gas was taken in kind. The court countered that royalty owners taking gas in kind does not suggest the overriding royalty must be subject to those costs when taken in cash. Consequently, the court said cost-free language in the overriding royalty provision includes post-production expenses.

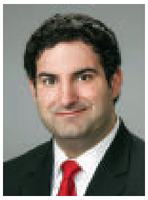
Practical implications

In French and Hyder, the Texas Supreme Court left working interest-holders vulnerable to future underpayment of royalty claims based on post-production expense allocations. Companies assessing expenses to extract CO_2 from casinghead gas might:

- Review how CO_2 extraction fits within overall enhanced oil recovery operations. Is the CO_2 separation from the casinghead-gas stream necessary for production?
    - Review whether, under the applicable leases and unit agreement, the operator can reinject the entire casinghead gas stream without paying royalties.
    - Review whether, operationally, the casinghead-gas stream can be 100% reinjected without processing.
- Compare the cost allocated to the royalty interest for separating CO_2 from casinghead gas to the gas-sales benefit royalty owners receive.

Working-interest owners should review lease royalty provisions and overriding royalty terms to assess liability for any cost-free language. Producers should review how post-production expenses have been allocated and whether that complies with the Hyder ruling. OGJ

The author



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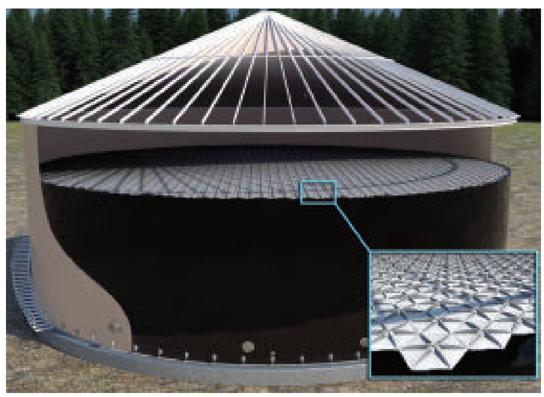

Hexa-Covers Floating Covers are newly introduced to reduce oil and gas-related volatile organic liquids evaporation as well as VOC and hydrocarbon emissions. These 8-inch-diameter hexagonal-shaped tiles are placed within fixed-roof aboveground storage tanks to form a flexible, interlocking floating blanket.

Two designs are available. **Oil & Gas Duty Hexa-Covers** comprise low-density DuPont Zytel 612 nylon resin which is chemically compatible with oil, bitumen, diluents, condensates, gasoline, refined products, organic chemicals and water. It is classified "static dissipative' by ASTM and resists thermal shock and weight gain. The oil and gas configurations cover nearly the entire surface area of a liquid to reduce volatile organic liquids evaporation, odor emissions, VOCs, and water vapor.

Water version Hexa-Cover R114 is specifically designed for use in frac water impoundments. It delivers up to 99.9% coverage of liquid surface; up to 95% reduction of evaporation from water surface; up to 95% stable, constant emissions reduction; up to 90% stable, constant odor reduction; and up to 74% reduction of heat loss from heated water. Complete Hexa-Covers specifics are yours free for the asking.

Greatario Covers: Calgary

For FREE Information, select #2 at ogpe.hotims.com

NEW PRODUCTS & SERVICES

AC-powered torque multipliers operate over 100 - 4,500 lb-ft, are ±3% accurate

EvoTorque 2 alternating-current-powered torque multiplier are newly announced to provide outstanding accuracy, versatility, and easy operation.

The new generation tools are factory calibrated and certified to ±3% accuracy regardless of fluctuating voltages. They operate over 100 to 4,500 lb-ft.

Models measure in torque, torque and angle, and torque audit mode for pretightened bolts. Both 110-v ac or 230-v ac versions are offered.

The 23-lb tools' communication is via USB and Bluetooth 4.0 data transfer (Bluetooth Smart). Up to 3,000 readings can be stored in EvoTorque 2's internal memory, with time and date stamping. EvoLog PC software manages data and tool configuration.

The new wrenches handle a broad range of bolting applications from factory to field — for fabrication, installation, verification, and maintenance declares the manufacturer.

Besides this new-gen multiplier, the company offers a full line of torque tightening and calibration tools for "nearly every bolting application," for 0.221 to 221,268 lb-ft. The entire range is supported by the maker's electronic torque measurement program.

Norbar Torque Tools Incorporated: Willoughby OH

For FREE Information, select #4 at ogpe.hotims.com

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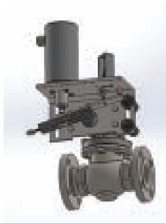
Shock, vibration MIL-certified solenoid-operated rotary valves



Several of this manufacturer's **solenoid-operated rotary valves** are now shock and vibration certified per MIL-STD-901D and MIL-STD-167-1.

Certification specifics include A shock grade, 1 equipment class, A lightweight shock test type, and hull mounted equipment mounting location aboard ship.

For 1/2 to 6-in. pipe sizes, the direct-operated and pilot-operated solenoid rotary valves are fast acting. They are configurable with various wetted materials, voltages, position indicator switches, end connections and come in both manually open and closed designs.

Clark Cooper Division, Magnatrol Valve Corporation: Roebling NJ

For FREE Information, select #5 at ogpe.hotims.com

Free 68-page utility work boots catalog

American-built KEEN utility work boots are described, shown, and specified in this free 68-page catalog.

Its five sections showcase more than 75 individual mens heavy, medium, and light duty boots plus womens industrial designs, and service foot wear styles.

Among important work boot features emphasized are Million Step Comfort midsoles which are shock absorbing plus resist breakdown and compression.

CLEANSPORT NXT odor removal is fully explained as an advantage along with non-continuous welt construction. Work boot sizes ragne from 7 to 17 for men; 5 to 12 for women.

KEEN Incorporated: Portland OR

For FREE Literature, select #250 at ogpe.hotims.com

Drilling fluids emulsifiers formulated for oil-based muds, variety of system conditions

EnvaMul emulsifiers are introduced for oil-based muds in drilling applications. They are formulated to perform well in regard to fluid loss, rheology, electrical stability, and solids control in a variety of mud systems. Based on fatty acid chemistry, EnvaMul is cited for effective use "where cost is the primary driver." Complete emulsifiers specifics are yours free for the asking.

Ingevity Corporation: North Charleston SC

For FREE Information, select #6 at ogpe.hotims.com

By any measure, AMETEK knows your process.

TRULY PORTABLE BTU ANALYZER FOR NATURAL GAS IN PRODUCTION AND AT CUSTODY TRANSFER

The new AMETEK Chandler Engineering Model 292B portable natural gas chromatograph is compact and light weight, yet it includes fully integrated sample handling and onboard storage for up to 1,000 sample runs. A 5″ full-color display shows sample results, raw and calibration data, analytical reports and real-time chromatograms. Advanced software accurately calculates heating value, relative density, and compressibility using industry standard methods. Precise monitoring and control yields exceptional sensitivity and peak performance. Connectivity includes USB and Ethernet, plus compatibility with HP printers. AMETEK Chandler Engineering. Tel: 412-828-9040. **www.ametekpi.com**

#403 at ogpe.hotims.com

THE SMARTEST ALTERNATIVE IN TOTAL TANK LEVEL MEASUREMENT

AMETEK Drexelbrook's new total tank level system (TLS) uses the latest in magnetostrictive technology to provide unparalleled accuracy when measuring total tank level, interface tank level and temperature. Made of durable polymer and stainless steel, this rugged tank probe offers total and interface level sensors, five temperature sensors, in lengths up to 50 feet. It is ideal for oil, oil/water, condensate or petrochemical applications. The TLS meets FM and FMc Class I Div 1 standards and is the most accurate (±1mm), cost-effective alternative to flexible stainless steel cable probes. And where needed, a rigid 316SS probe is available. AMETEK Drexelbrook. Tel: 800-334-2748 or 215-674-1234. **www.drexelbrook.com**

#404 at ogpe.hotims.com

MODEL 5100 GAS ANALYZER MEASURES MOISTURE IN BULK GAS, HYDROCARBON STREAMS

Using tunable diode laser absorption spectroscopy (TDLAS), this unit offers high specificity, sensitivity and fast response speeds. The 5100 Portable's application-specific gas cells are available in a wide range of path lengths, and a reference cell for laser line-lock eliminates measurement errors caused by laser wavelength shifting as ambient temperature varies. Gas sampling accessories allow customization, the back lit LCD displays four 20-character lines of data, and a membrane keypad makes parameter input and display selection easy. The unit weighs only 11 lb., has a battery life of eight hours, and a USB 2.0 interface. The 5100 is factory calibrated and calibration is NIST traceable. AMETEK Process Instruments. Tel: 412-828-9040. **www.ametekpi.com**

#405 at ogpe.hotims.com

NEW WAVE GUIDE OPTION ELIMINATES SIGNAL INTERFERENCE FROM TANK NOZZLES

Impulse® wave-guided radar level systems from AMETEK Drexelbrook generate total level, distance or volumetric outputs, unaffected by variations in process material electrical characteristics. Adding the Wave Guide option eliminates nozzle interference, making tank nozzle configuration immaterial and negating the need for more expensive coaxial probe systems. Reliable and accurate to ±3 mm, Impulse series transmitters provide continuous level measurement of liquids to ranges up to 50 ft. (15 m) at operating temperatures ranging from –40° to 392°F (-40° to 200°C) and pressures up to 580 psig (40 bar). Five different sensor types are available, constructed of Type 316SS or Hastelloy C for Class I, Div 1 hazardous environments requiring either intrinsically safe or explosionproof installation. AMETEK Drexelbrook. Tel: 800-334-2748 or 215-674-1234. **www.drexelbrook.com**

#406 at ogpe.hotims.com

INTRINSICALLY SAFE PRESSURE TRANSMITTER OPERATES IN HAZARDOUS LOCATIONS

AMETEK PMT Model IDT intrinsically safe pressure transmitters offer superior accuracy (±0.2% full-scale) for critical applications, and all meet FM US, FM Canada, ATEX and IECEx standards for worldwide acceptance. Pressure ranges are available from vacuum to 5,000 psi, including exclusive 0–1, 0–3 and 0–6 psi units. Factory calibration eliminates the need for field calibration for plug-and-play reliability, and EN61326-1 RFI/EMI protection enables the Model IDT's use in high-noise environments. Standard units include Type 316SS housing and all wetted materials. Hastelloy and Monel diaphragms are available as options. Yet, in spite of their many advantages, PMT Model IDT intrinsically safe transmitters remain surprisingly economical. AMETEK PMT Products. **ww.ametekpmt.com**

#407 at ogpe.hotims.com

THE NEW THERMOX® WDG-V COMBUSTION ANALYZER OFFERS IMPROVED CONTROL PLUS UNPARALLELED PROCESS SAFETY

The WDG-V measures excess oxygen, hydrocarbons and combustibles in flue gas, to help improve burner efficiency and operating safety. Logs of historical operating data can help operators decide when preventive maintenance is needed, significantly reducing operating costs. Specifically designed for wet, dirty gas applications, probes are available at lengths up to 108″ (274cm) at temperatures to 1875°F (1024°C), and to 72″ (152cm) for temperatures to 3000°F (1760°C). The WDG-V also features automatic calibration, analog outputs, multiple alarms, self-diagnostics, and local or remote interface as well as a variety of network communications protocols. AMETEK Thermox. Tel: 412-828-9040. **www.ametekpi.com**

#408 at ogpe.hotims.com

AMETEK®

ALL-WELDED PROCESS GAUGE & SEAL FOR ECONOMY, RELIABILITY

AMETEK U.S. Gauge all-welded process gauge with integrated seal offers lower cost than gauges and seals purchased separately. In addition, the combination unit reduces the number of potential leak paths, increasing field reliability. The rugged Model XR-81 gauge with PET case, Type 316L SS socket and seamless Bourdon tube is mounted and welded onto an M&G diaphragm seal, available with either Type 316L SS or Hastelloy® C wetted parts. Offered in 15 ranges, from 0–30″ Hg vac. to 0–5000 psi. AMETEK U.S. Gauge. Tel: 215-293-4100. **www.ametekusg.com**

#409 at ogpe.hotims.com

NEW VAPOR PRESSURE TESTER IDEAL FOR MOBILE LABS

The Grabner® MINIVAP VP Vision portable vapor pressure tester works on gasoline, jet fuel, crude oil, liquefied petroleum gas and solvents, without the need for a pressure regulator. The VP Vision is certified to function in cold climates as well as hot, humid climates, withstands vibrations and heavy shock loads from any direction, and provides an extended pressure range of 0–2000 kPa with repeatability of ±0.2 kPa. Its combination of rugged design and precision make it ideal for mobile labs as well as military applications. AMETEK Grabner Instruments. Tel: +43 1 282 16 27-0. **www.grabner-instruments.com**

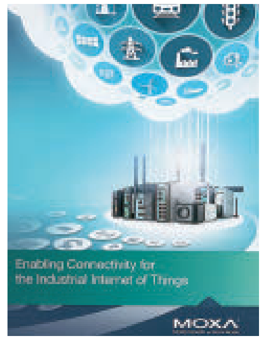
#410 at ogpe.hotims.com

IPS-4 DUAL UV/VIS AND NIR PROCESS SPECTROPHOTOMETER

New IPS-4 spectrophotometer detects and quantifies thousands of chemical species, up to eight at once, to verify feedstock, intermediate, and final product quality. It includes 22-key keypad, analog output, web-based queries, alarm contacts, Ethernet, RS232, RS485, and three digital signal ports, plus multilingual interface. UV/VIS and NIR versions have fully integrated sampling systems. Tel: 412-828-9040. **www.ametekpi.com**

#411 at ogpe.hotims.com

Free literature: Enabling Connectivity for the Industrial Internet of Things



From a company with over 25 years industry experience and which has connected more than 35-million devices worldwide: this free **Enabling Connectivity for the Industrial Internet of Things** brochure.

It illustrates and summaries "delivery of fast and reliable communication between people, systems, and processes to achieve all forms of automation and collaboration for increased productivity and faster response to market opportunities in industrial environments."

Among connectivity highlights: serial/Fieldbus, I/O, and video in combination with industrial computers, Ethernet, wireless, and routers — with complete management.

MOXA: Brea CA For FREE Literature, select #252 at ogpe.hotims.com

Standardized produced water treatment packages developed, offer CAPEX savings

"Substantial CAPEX savings" are declared to be realized with newly developed **standardized produced water treatment packages**.

They typically reduce oil-in-water content from 2000 down to 20 ppmv. Included are hydrocyclones for bulk oil removal followed by a compact flotation unit to remove remaining small oil droplets. Packages are expandable with a desanding module to process water suitable for reinjection.

The cited cost reduction is achieved via package modular design, small footprint, and low weight combined with minimum engineering and site work.

Frames: Alphen aan den Rijn The Netherlands

For FREE Information, select #8 at ogpe.hotims.com

Reaction style torque transfer standards calibrate nonrotating production torquemeters

Series 2300DV Reaction Style Torque Transfer Standards perform as a complete, ultra-precise torque transfer standard without mV/V calibrator or other external device.

The high torsional stiffness and low deflection sensors are very accurate and particularly suited for nonrotating field calibration of production torquemeters. They allow field calibration of installed torquemeters without removal/transfer to a remote torque calibration lab.

S. Himmelstein and Company: Hoffman Estates IL

For FREE Information, select #9 at ogpe.hotims.com

Density compensation now offered in-line water cut monitors

Universal IV In-Line Water Cut Monitors are now offered with a **Density Compensation Module**. It automatically compensates for density changes that may occur in products composition and reduces calibration requirements due to those changes.

As CM achieves high-accuracy water-in-oil measurement, DCM allows it to maintain stated accuracy with variations in density up to 10 API. This ensures measuring accuracy from load to load regardless of product composition changes.

AMETEK Drexelbrook: Horsham PA For FREE Information, select #10 at ogpe.hotims.com

Worldwide-approved warning signals overview literature

Hazardous area, fire and industrial, and wide area signalling specialties of this manufacturer are showcased and illustrated in its free 12-page company overview.

It highlights such established worldwide approved brands as BEx, GNEx, IS Range, E2x, D2x, STEx, and D1x for broad oil and gas hazardous area signalling along with AlertAlight and SpectraAlarm, AlertAlarm, M Range, Appello X, and Hootronic fire and industrial signaling. Wide area signal highlights include A141, A131, and A151.

E2S Warning Signals: London & Houston

For FREE Literature, select #254 at ogpe.hotims.com

New foam-lined, anti-fog eyewear now on market

StarLite FOAMPRO eyewear is available to keeps dust and debris out of your eyes.

The new safety glasses are lined with soft, closed-cell foam and are anti-fogging.

OptiFit foam technology is of tapered design to provide a more tailored fit and improved seal around the eyes. Venting channels along the foam lining help with air circulation behind the lens.

FOAMPRO also comes in 1.5 and 2.0 bifocial MAG version.

Gateway Safety Incorporated: Cleveland OH

For FREE Information, select #12 at ogpe.hotims.com

Green in-line density measurement tech for cementing slurry

RM5 in-line continuous density meters for applications including oil well cementing slurry, measure direct mass over a known volume within a flow tube. By directly calculating density rather than inferring or estimating — RM5's technology improves accuracy and environmental viability of sensor and mass flow systems.

The meters are designed to be safer and more cost effective than nuclear techniques or inefficient auto-sampling within slurry processing operations, declares the manufacturer.

Red Meters: Orlando FL

For FREE Information, select #13 at ogpe.hotims.com

Company's electronic field ticketing mobile app is free

A free version of **OpenTicket mobile electronic field ticketing application** is available.

It allows service companies to replace paper-based field tickets to enhance field workflow, improve information accuracy, and decrease customer payment cycle.

OpenTicket module is fully mobile and works in both online and offline modes. It includes a live dashboard to track completed, in-progress, and invoiced jobs. Management teams are provided with full visibility of each job to follow every step in real time. The module can be used standalone or combined with its maker's software modules, depending on your needs and challenges.

Phoenix DAS: Houston

For FREE Information, select #14 at ogpe.hotims.com

Three new Class I Div. II rugged computers

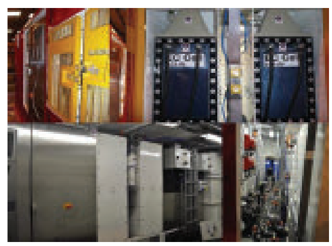
Rugged tablets, laptops, and smart flat panel LCD displays are newly introduced for offshore, wireline, fracing, seismic imaging, MWD/LWD, refining, and field data acquisition.

The three new products are 11.6-in., 13.3-in., and 15-in. respectively. All are American made and built to excel in extreme oil and gas environments.

Systel Incorporated: Sugar Land TX

For FREE Information, select #15 at ogpe.hotims.com

Electrocoagulation-based wastewater, effluent treatment



A new generation of **electrocoagulation-based wastewater and effluent treating** is announced to help companies proactively and cost effectively achieve compliance with stringent regulations in a broad variety of environments.

Systems are easy to operate and maintain, offer full automation and continuous monitoring, scalability, plus continuity.

Global Advantech: Aberdeenshire UK

For FREE Information, select #16 at ogpe.hotims.com

*Free Information or Literature — **Click the link***

Intelligent active heave compensation

HeaveMate intelligent active heave compensation module is newly introduced as easy-to-integrate on such new or existing offshore and subsea equipment as winches, cranes, or LARS systems.

It can be delivered as an OEM package with such essentials as black box controller with sensors and software, or as part of a complete turn-key system including mechanical and hydraulic hardware.

Seatools B.V.: Numansdorp The Netherlands

For FREE Information, select #17 at ogpe.hotims.com

API 2000-compliant pressure and vacuum relief valves unveiled

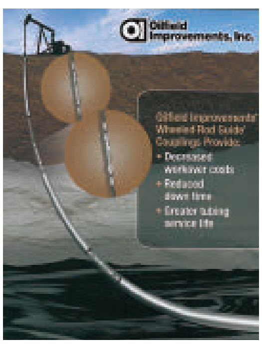
New **Anderson Greenwood 4000 Series pressure and vacuum relief valves** comply with the latest API 2000 standard.

The high-capacity full lift designs are designed to provide increased flow capacities and will fully open at 10% overpressure. This helps protect tanks from physical damage caused by internal pressure fluctuations. Thus, 4000 Series can be set more closely to storage tank MAWP or MAWV so you more quickly fill and empty tanks plus operate them at higher pressures. Complete pressure and vacuum relief valve data are free.

Pentair Valves & Controls: Dubai

For FREE Information, select #18 at ogpe.hotims.com

Wheeled Rod Guide couplings cited for thousands of uses since 1982



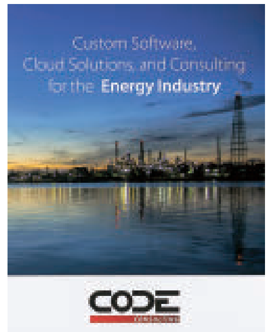
This free **Wheeled Rod Guide couplings brochure** reviews and illustrates how the products have been successfully field-employed since 1982 — and their benefits.

Presented is how they centralize the sucker rod string in the tubing. Rolling action of the wheels inside the tubing walls during stroking reduces friction and wear caused by sucker rods slapping or rubbing the tubing. Wheels are set vertically and at 45° angles to each other along the axis of the coupling body. This assures the centralizing effect wherever Wheeled Rod Guide couplings replace regular types. Numerous features/advantages are emphasized.

Oilfield Improvements Incorporated: Broken Arrow OK

For FREE Literature, select #255 at ogpe.hotims.com

Energy industry custom software cloud solutions, consulting



Cutting-edge **energy industry software** is this company's specialty and subject of its free six-page brochure.

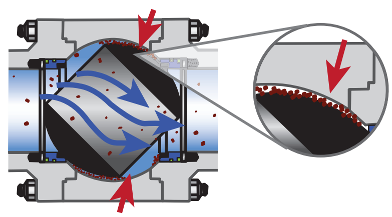
The literature declares "we will help you build better software with expert developers, a repeatable process, and a solid infrastructure."

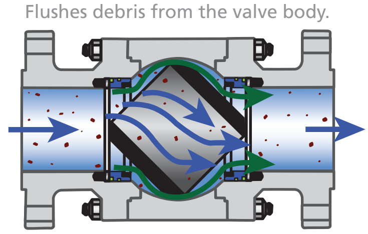
Custom software on any scale, from small applications to multi-year start-to-finish systems is available. Development, mentoring, project management, and architectural know-how are available using a variety of such tools and technologies as .NET, iOS, Android, web, cloud, services, and various databases. The company's software consulting and IT staffing are also presented.

Teams of experts will help you determine if you should be running your software in the cloud. They will guide you through the numerous considerations.

CODE: Spring TX

For FREE Literature, select #256 at ogpe.hotims.com

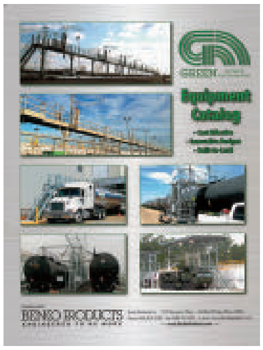




Oil & Gas Journal & OG&PE recently exhibited at and covered **International Liquid Terminals Association's Annual Tradeshow** in Houston.

Here are highlights representing **equipment manufacturer and service provider exhibitors** on which we gathered information. **To request free information or literature** on items of interest — simply go to **OGPE.com — Click "Product Info" (white typeface) at top.** Select by number or click the company name to visit their website. You can also click the items right here on the pages if you receive OG&PE digitally within the pages of Oil & Gas Journal.

36-page brochure: Safe tank truck, railcar access products



GREEN Access & Fall Protection products are described, illustrated, diagrammed, and specified in this free 36-page brochure. They deliver **safe access in both tank truck and railcar** applications.

Major product categories are flat ramp, telescoping ramp, and self-leveling stair gangways plus safety cages and 'slide-track' mounts.

A full line of railcar access platforms and tank truck loading racks are likewise showcased.

GREEN Access & Fall Protection, Benko Products: Sheffield Village OH

For FREE Literature, select #258 at ogpe.hotims.com

U-pin-designed coupler = disassembly, access in seconds

LYNX coupler is on the market to enable coupler disassembly in seconds.

Its U-pin design shortens coupler service cycles. With a simple pull, operators gain access to internal components for maintenance and can quickly put the unit back in service. The U-Pin does not require special tools. Quickly take LYNX apart with a flat-head screwdriver.

OPW Engineered Systems: Lebanon OH

For FREE Information, select #20 at ogpe.hotims.com

Product recovery pigging

"Don't waste it. Pig it" is how this free brochure illustrates and describes **product recovery pigging systems** to "recover product, save money, and protect the environment."

Systems cited to require no tools to perform routine pig maintenance — with safe pig access in less than 15 sec.

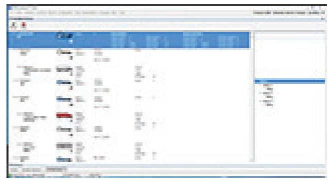
They feature a patented LQC access cap with pressure locking safety feature while reduced product changeover time and inventory are also delivered.

Pigg Solutions: Springfield MO

For FREE Literature, select #259 at ogpe.hotims.com

Terminal automation update offers centralized inventory, demand control

DTN Guardian 3 terminal automation system is newly updated to deliver "powerful centralized control over inventory and demand." It helps terminals anticipate shortages, adjust product allocations, and maximize profits.



Among updated features: software now available in multiple languages plus customizable user interface, fully compliant with TSA TWIC biometric identification proposed regulations, and auxiliary programs set up to run as services for the system.

Schneider Electric: Omaha NE

For FREE Information, select #21 at ogpe.hotims.com

H_2S gas sweetening, process water ammonia removal, tank services bulletins

Three free **application bulletins** highlight this company's proven field, refinery, and tank capabilities/solutions.

Vapor Lock Sugar Daddy Sweetening Units combine the firm's hydraulic amalgamation process with "the best scavenging chemicals." **Process water ammonia removal** is a patent-pending turnkey system to reduce levels of undesired constituents. **Services for tank vent emissions/nuisance odors and degassing** at sites including petrochemical tanks farms, are presented to eliminate NOx and SOx emissions.

Vapor Point: La Porte TX

For FREE Literature, select #260 at ogpe.hotims.com

Loading terminal ground system unveiled

LOGIC Terminal Ground Systems are newly developed as "the first all-in-one systems for loading terminals."

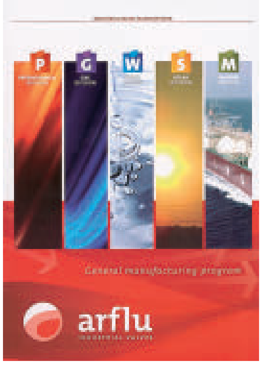
The controller provides multiple truck and railcar grounding options — all in one enclosure. It monitors potential overfill and loading arm position as it enables dead-man control plus the ability to log such external environmental conditions as temperature and humidity.

Besides real-time wireless communications, it also features simple visual interface so operators or terminal managers immediately see operational issues and activities via preset menu.

SixAxis LLC, SmartTech LLC: Andrews SC

For FREE Information, select #22 at ogpe.hotims.com

Industrial valves serve petrochem, gas, water, desalination, marine, solar



"Absolute regulation of fluids" is declared delivered by this manufacturer's **industrial valves** designed to serve multiple applications including petrochemical and gas.

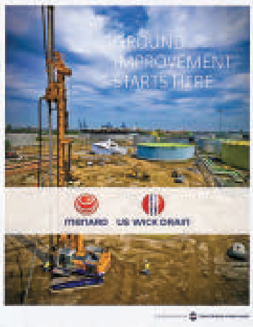
This free eight-page brochure presents petrochem and energy valves manufactured according to API, NACE, ASA, ANSI, ASTM, ASME, DIN, and MSS. Gate, globe, swing check, lift check, wafer lift check, wafer duo check, ball, plug, and dual expanding plug valves are showcased in a broad range of sizes, materials, actuators, and pressure capabilities.

Ball, top entry ball, plug, wafer duo check, and globe valves for gas operations are also presented.

ARFLU, S.A.: Sopela (Bizkaia) Spain & Houston

For FREE Literature, select #261 at ogpe.hotims.com

Soil, structural, geotechnical engineering solutions information



"Geotechnical Problem Solvers" are how these soil, structural, and nuclear engineering" companies describe themselves in free literature.

Menard and US Wick Drain are design-build specialty geotechnical contractors. The former for ground improvement on sites with poor soil; the latter offering practical sustainable solutions for ground improvement, specializing in wick drain installation.

Menard USA & US Wick Drain: Carnegie PA & Leland NC

For FREE Literature, select #262 at ogpe.hotims.com

Safety transmitter pressure, temperature transmitter-switch data

One Series Safety Transmitters are illustrated, described, and specified in this free brochure to monitor pressure or temperature and meet SIL 2 requirements for random integrity.

Their design is based on "a powerful microprocessor that provides an extremely fast response time for emergency shutdown situations."

One Series features are cited to include digital process display, programmable setpoint and deadband, self-diagnostic solid-state digital electronics, plus adjustable nuisance trip dampening.

United Electric Controls: Watertown MA

For FREE Literature, select #263 at ogpe.hotims.com

Aluminum geodesic domes design, manufacture, construct

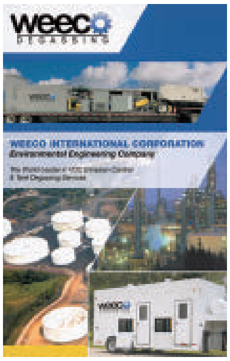
Liquid and dry bulk storage are accommodated by a complete line of **aluminum geodesic domes and services** declares this free brochure.

Besides batten bar, panel, and beam section details as well as node designs, the literature cites numerous dome advantages. These include all-aluminum construction benefits, corrosion resistance, freedom from maintenance, strong space frame design, clear span design, water tight construction — with reduced vapor losses on internal and external floaters.

Tank Connection LLC: Parsons KS

For FREE Literature, select #264 at ogpe.hotims.com

Free VOC emission control and tank degassing services data



Six specific **VOC emission control and tank degassing services** are highlighted as available in this pamphlet.

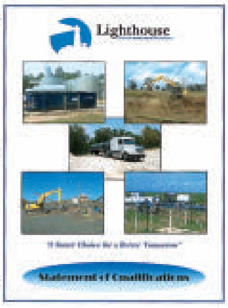
Drawings depict tank degassing or barge/tank degassing — before, during and after tank cleaning or during tank refilling.

The company also offers tank degassing during tank refill, VOC control during turnarounds, backup incinerator service during plant maintenance, as well as complete engineering and consulting services.

WEECO International Corporation: Houston

For FREE Literature, select #265 at ogpe.hotims.com

Construction remediation services for midstream refining



Twenty one specific **environmental services** are cited as available for midstream in this free notebook.

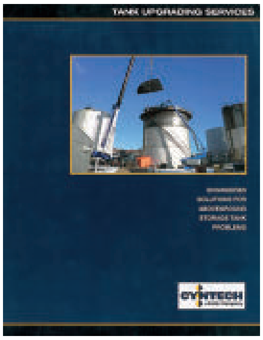
The provider's focus is on cost effective waste management and a complete range of remediation services. Among construction remediation experience and capabilities are in-situ and ex-situ bioremediation, in-sit chemical treatment using high pressure injection technology, groundwater treatment and product recovery, plus groundwater extraction and treatment.

Additional capabilities are cited to include oil/water separation and filtration, activated carbon, excavation and disposal, dewatering, plus thermal desorption and incineration.

Lighthouse Environmental Services Incorporated: Houston

For FREE Literature, select #266 at ogpe.hotims.com

Aboveground storage tank upgrading services, solutions



Energy and petrochemical **storage tank upgrading services** are presented in this free brochure.

Since 1981, this company has delivered complete turnkey service packages for all aspects of AST inspection, engineering, and construction for any modifications.

Among 13 specific services showcased: API 650/653 inspection, tank lifting and levelling, concrete and gravel foundation reconstruction, release prevention barriers with leak detection systems, as well as floor or shell course repair and replacement.

Cyntech, A Keller Company: Calgary

For FREE Literature, select #268 at ogpe.hotims.com

Eco-friendly C6 chemistry Class B firefighting foams

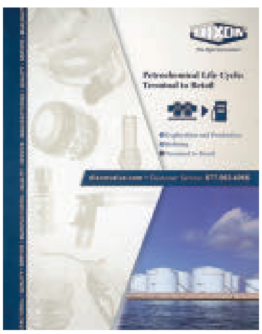
Phos-Chek, a leader in Class A foam concentrates, gels, and fire retardants — is entering the **Class B firefighting foams** market.

Of eco-friendly C6 chemistry, **PHOS-CHEK Class B fire control and extinguishing products** will include aqueous film forming, alcohol resistant, medium and high expansion foams, training foams, and wetting gels — complemented with training and consulting.

ICL Performance Products: Rancho Cucamonga CA

For FREE Information, select #24 at ogpe.hotims.com

Transfer products for exploration, production, refining, petrochemical



"Petrochemical Life Cycle: Terminal to Retail" is this free 24-page brochure on a broad range of **transfer products**.

Five sections describe and illustrate dry disconnects, loading arm components, crude loading (bottom) and unloading specialties and accessories. These include API fittings, dry disconnect couplings, cam and groove dry disconnects, as well as bayonet style dry disconnect couplings.

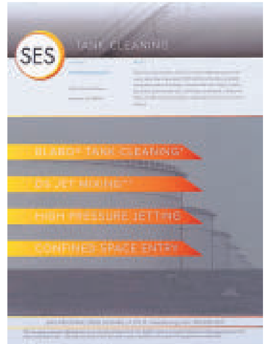
Loading arm swivel joints, vapor recovery adapters, vapor recovery couplers, low pressure swivels, and safety breakaway couplings are also presented.

Railcar unloading products along with components for custom assemblies are likewise shown and detailed.

Dixon Specialty Products: Chestertown MD

For FREE Literature, select #269 at ogpe.hotims.com

Custom tailored tank cleaning data



"The best available equipment and technologies are coupled with highly trained personnel" to deliver **custom-tailored tank cleaning**, declares this free datasheet.

Emphasis is upon the company's ability to to clean oil and mixed service storage tanks.

It offers BLABO tank cleaning, DS jet mixing, high pressure jetting, and confined space entry.

Sweat Energy Services: Geismar LA

For FREE Literature, select #270 at ogpe.hotims.com

Asset, non-asset transport, pipeline & terminal services

This **pipeline and terminal services company's** datasheet cites **general maintenance and environmental availabilities** for natural gas, natural gas liquids, refined products, and crude oil facilities.

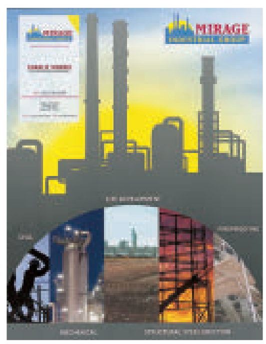
Upstream, midstream and downstream services are cited to include dehydration tower maintenance, confined space services, filtration system cleaning and maintenance, or crude oil and product tank cleaning.

The datasheet also declares "as an asset and non-asset services provider, we transport the most hazardous, heaviest, and largest products. We clean up the dirtiest plants, messiest spills, and nastiest environmental sites — the harder the better."

Action Environmental: Birmingham AL

For FREE Literature, select #271 at ogpe.hotims.com

Concrete construction, management for oil and gas, process, manufacturing



This **concrete construction contractor's** brochure cites capabilities, services plus related management.

Light commercial to heavy industrial projects are handled, including oil and gas for concrete placement and finishing, site prep, plus underground utilities and piping.

Also emphasized are capabilities to install terminal/tank farm foundations of widely varying types and sizes. These include AST ringwalls, tank slabs, or tank pile caps as well as concrete tank floors with anchor channels, plus elevated concrete slabs, or grade band foundations.

Mirage Industrial Group: Lolita TX

For FREE Literature, select #272 at ogpe.hotims.com

June "Advertiser Product & Service Followup"

Companies featured here advertised their equipment, products, or services in **June 6 Oil & Gas Journal's OG&PE products section**. These summaries give you an opportunity to receive **free information or literature** on leading manufacturers' and service providers' oil and gas specialties. **Go to OGPE.com — Click "Product Info" (white typeface) at top.** You will receive prompt, complete response from these valued OG&PE media partners.

FLOWSIC600-XT: the perfect match for intelligent ultrasonic gas flow measuring

With its **FLOWSIC600-XT**, the market leader for reliable, maximum precision ultrasonic gas flow measuring devices offers a product family which can meet any application requirement as a standalone or system solution — and deliver best possible measuring performance at the same time.

Along with ground breaking design, FLOWSIC600-XT impresses with innovative intrinsics while PowerIn Technology continues to take measurements for up to three weeks should main voltage fail. Designs deliver combined maximum measurement accuracy, long-term stability, and unrivaled operational safety.

SICK AG: Waldkirch Germany Sick.com/FLOWSIC600-xt

For FREE Information, select #26 at ogpe.hotims.com

Field-proven, rugged solenoid valves for oil, gas, petrochemical operations

Magnatrol two-way stainless steel and bronze valves control the flow of oil/fuel oil, biofuel, natural gas, solvents, hot liquids and gases, corrosive fluids, water, steam and other sediment-free fluids.

Models with flanged ends or NPT threads from 3/8 to 3 in. handle up to 400°F. and up to 500 psig. They feature continuous duty coils for all AC/DC voltages, are fully tested and customer-service-supported, and come with a number of options.

Magnatrol Valve Corporation: Hawthorne NJ
Magnatrol.com

For FREE Information, select #27 at ogpe.hotims.com

Want to stay ahead of the Industrial Internet of Things curve? MOXA

As an operations manager or engineer — **to stay ahead of the IIoT curve** — one of your first challenges: Getting all your devices connected to the internet. MOXA has collected and offers some great resources to guide you.

Among topics covered at the url below are how to calculate payback on your investment, address cyber security concerns, achieve device interoperability, and connect industrial devices to the internet.

Because you cannot afford to miss IIoT opportunities — and the huge revenue potential — check the useful information on trends and insights, download resources to help get you connected to the IoT, plus have access to check tips, tricks, and best practices.

MOXA: Brea CA Pages.MOXA.com/IIoT

For FREE Information, select #28 at ogpe.hotims.com

Seismic safety switches engineered for up to SIL-2 in oil and gas applications

High integrity, low-noise piezoelectric **Sensonics SA-3 Seismic Switches** are designed for oil and gas.

With unique self-testing, models are seismically qualified, robust, and in weatherproof steel enclosures. The seismometers are designed for safety applications up to SIL-2 explosionproof versions for hazardous petroleum duties.

SENSONICS LTD.: Berkhamsted, Hertfordshire UK
Sensonics.co.uk

For FREE Information, select #20 at ogpe.hotims.com

Field-installed centralizers / paraffin scrapers = full-circle Tubing ID wiping

ULTRA-FLOW centralizers / paraffin scrapers are field-installed to deliver full-circle wiping of tubing inside diameter.

Among ULTRA-FLOW benefits and advantages: more gripping force on sucker rods, more fluid flow-by volume, longer useful life from longer vanes and bearing surfaces, plus positive wear indicators.

Oilfield Improvements Incorporated.: Broken Arrow OK
RodGuides.com

For FREE Information, select #30 at ogpe.hotims.com

Coming in August:

- **PRIME MOVERS** for upstream, midstream, downstream: **Pumps, Compressors, Engines, Turbines, Motors**
- Bonus Conference & Exhibition Distribution: **Turbomachinery & Pump Symposia**, Houston; **NAPE South,** Houston; **POWER-GEN Natural Gas,** Columbus Ohio, **Offshore Northern Seas,** Stavanger; **SPE Intelligent Energy,** Aberdeen

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All Products — All The Time:
Oil & Gas Journal's Product Section

FRANK'S INTERNATIONAL N.V.

Frank's International N.V. deployed its patented 1,250-ton Buoyancy Module Spider along with ExPert Landing String Solutions' Drill Pipe Buoyancy Modules to help Anadarko achieve a nearly 250,000-pound reduction in total weight. It was the industry's first run of this ground-breaking weight reduction system, which saves time and money and improves safety.

Working closely with Anadarko and ExPert to deliver a customized solution, Frank's completed the job safely and successfully aboard the Diamond Ocean BlackHawk drillship positioned on the Walker Ridge Block 51 Shenandoah V Well. The job also involved using Frank's 1,250-ton Slip-Type Elevator and Split Bushing Spider to install 19,821 feet of casing and the Company's new 1,250-ton BM Spider and 1,500-ton Drill Pipe Elevator to install 5,929 feet of landing string.

The original expected buoyed string weight of casing and drill pipe was approaching the rig's weight capacity. Anadarko achieved a 10 percent reduction in string weight by running ExPert's Drill Pipe Buoyancy Modules and applying Frank's BM Spider, the only technology that can clean the modules during removal and accommodate their large outer diameter.

Frank's International N.V. is a global oil services company that provides a broad and comprehensive range of highly engineered tubular services to leading exploration and production companies in both offshore and onshore environments, with a focus on complex and technically demanding wells.

WEATHERFORD LABS

Weatherford Labs and Enthought announced that they are participating in the study of a 2,725-ft (830-m) core recovered from the central area of the Chicxulub Crater. The crater, located in the Gulf of Mexico beneath the Yucatán Peninsula, is believed to have been caused by the same asteroid that led to a mass extinction event 66 million years ago.

Dual-energy CT scanning of the core at Weatherford Labs began the week of June 13, 2016. CT scanning entails the use of medical-grade computerized tomography scanners adapted for specialized use — generally, for analyzing cores drilled as part of oil and gas exploration. Data from the scanners is presented as images and animations of the core slices are provided to enable rapid qualitative analysis.

Enthought's Virtual Core software will be used to analyze the CT scan data and create a three-dimensional digital 'fingerprint' of the core. The software provides machine learning feature detection intelligence and visualization capabilities for detailed insight into the composition and structure of the core, which is critical data needed to understand the processes that occurred during the impact. This digital representation of the core's features will also preserve the data for future exploration.

The project is led by scientists at The University of Texas at Austin and Imperial College London, and is funded by the International Ocean Discovery Program, European Consortium for Ocean Research Drilling, and International Continental Scientific Drilling Project.

BAKER HUGHES

Baker Hughes announced the commercial release of its WellLink™ Performance service, designed to help operators reduce invisible lost time by transforming the complex data buried within legacy applications, drilling reporting systems and data streams into real-time information that is instantly accessible and actionable. Using this information, operators can improve drilling economics by quickly identifying, investigating and mitigating common performance issues associated with drilling processes such as connection procedures, circulating times and tripping speed – inefficiencies which can account for as much as 30% of normal uptime activities.

Delivered via a software-as-a-service model, the WellLink Performance service enables drilling teams to identify these inefficiencies immediately by analyzing historic and real-time wellsite data and comparing those data to planned, benchmark and offset data. The teams also can seamlessly identify and investigate ILT root causes on a degree much more granular than with common manual methods by reviewing charts that compare depth versus days drilled and activity analysis graphs and reports in real time. Key performance indicator alarms and dashboards help operators take proactive actions to improve ILT-related issues and monitor these actions in real time for continuous improvement across operations.

The service also is compatible with the company's SIGNALS™ Drilling Advisory service, which combines the WellLink software with remotely-located Baker Hughes personnel, who are available 24-7 to critically analyze and interpret the data sets. Through this analysis, the experts can identify opportunities to further reduce ILT during the drilling process.

WOOD GROUP

Wood Group has acquired the trade and assets of Enterprise Engineering Service Limited's Aberdeen based fabrication and manufacturing business; following the announcement on 26th May, 2016 that EESL had appointed administrators.

The acquisition further enhances Wood Group's asset integrity management capabilities, adding fabrication to its services, which focus on driving efficiencies and extending the life of upstream and midstream assets in the UK oil and gas sector.

The employees of EESL's Aberdeen based fabrication business as at the date of the acquisition will transfer to Wood Group and will remain at their existing 4,000sq m fabrication facility located on Craigshaw Road, Aberdeen.

Dave Stewart, Wood Group PSN's CEO said: "Wood Group's relentless focus is on enhancing value and driving cost efficiencies in the technical solutions we provide to our clients. The acquisition of Enterprise Engineering Service Ltd.'s fabrication and manufacturing business broadens our repair order capabilities, enabling us to offer a fully integrated, end to end service that supports our clients in assuring the integrity of their assets.

HONEYWELL UOP

Honeywell UOP opened a new production line at its catalyst manufacturing facility in Shreveport, La. The $150 million investment will enable Honeywell UOP to produce a new range of catalysts for the oil refining industry at the facility, which employs 290 people.

The new production line will manufacture catalysts for hydroprocessing, which removes impurities from fractionated crude oil and also makes transportation fuels.

Construction of the new production line began late in 2014, coinciding with several other investments, including expansion of the facility's third production line, and installation of a new kiln and water clarification system.

As a result of these investments, the Shreveport plant now will be able to produce catalysts in less time while keeping inventories lower. Most of the plant's production is for export to other countries.

Honeywell UOP established the Shreveport plant in 1950 to manufacture its own proprietary catalyst designs. Today, the company also manufactures catalyst and adsorbent products in Baton Rouge, La., Mobile, Ala., McCook, Ill., Reggio de Calabria, Italy, Shanghai and Zhangjiagang, China, and through its Nikki-Universal and Union Showa K.K. joint ventures in Hiratsuka and Yakkaichi, Japan, respectively.

The Shreveport facility manufactures catalysts that can be used in Honeywell UOP's Oleflex™, isomerization and hydroprocessing processes, and for processing naphtha.

Catalysts are proprietary structures made of silica, alumina and other elements that aid in the production of specific chemical intermediates from naphtha and distillate. As pellets or powders, they are used in refineries and petrochemical plants and as part of proprietary processes to make a wide range of transportation fuels and petrochemicals.

GE OIL & GAS

GE Oil & Gas and Technip have signed a Memorandum of Understanding for a joint project to explore areas to co-develop digital solutions for the LNG industry, with a particular focus on the design and build phase of new Liquefied Natural Gas (LNG) projects.

The two companies will work together to evaluate the application of digital solutions to the engineering, construction, commissioning, startup and operation of LNG facilities. All solutions under consideration would encompass Technip and GE Oil & Gas expertise in digital tools and be powered by Predix, the world's first and only cloud-based operating system built exclusively for industry by GE.

This is the first digital collaboration between the world's first digital industrial company and a leading integrated services and equipment company to explore areas to develop Predix-based solutions. GE has a strong track record in providing equipment reliability solutions for a number of LNG facilities around the world, through sensors, advanced analytics and diagnostic expertise. Technip brings its unique expertise in the engineering, procurement and construction (EPC) phases of LNG and LNG new frontier projects.

LNG is an important growth space for the oil and gas sector. As global gas demand rises, and stretches into new markets, the volume of liquefied natural gas traded globally. Additionally, digital solutions will continue to play an increasingly critical role for oil and gas as the industry prioritizes the optimization of their equipment and operations to improve productivity and cost-efficiencies.

T.D. WILLIAMSON

In a deal that is expected to strengthen gas leak detection and other services to the energy industry, ECOTEC International Holdings, LLC, Jackson, WY, has acquired GAZOMAT S.A.R.L., a subsidiary of T.D. Williamson, Tulsa, OK.

Based in Strasbourg, France, GAZOMAT manufactures high-performance portable gas leak detection instruments, leak detection services, and first-responder environmental safety equipment.

ECOTEC and GAZOMAT use similar core technologies and serve complementary markets. As a result, the acquisition represents an opportunity to expand capabilities and geographic reach.

FORUM ENERGY TECHNOLOGIES

Subsea technology provider Forum Energy Technologies Limited has unveiled a deep water test facility and received industry accreditation for the calibration laboratory at its new European Operational Centre in Aberdeen.

The indoor test tank is one of the largest in the North-east of Scotland and is dedicated to testing subsea tooling and survey sensors as well as work-class remotely operated vehicles (ROVs).

Staffed by dedicated personnel, the test tank and laboratory have a primary purpose to provide full control, certification and faster turnaround in preparing Forum's rental inventory for hire. In addition, the firm will also offer a full test and calibration service to customers.

The large fresh water tank, measuring 5 meters x 6m x 4.5m, is fitted with overhead 10T crane, lighting, cameras and a viewing platform.

The calibration laboratory has been accredited by Valeport Ltd and conforms to traceable procedures for the recalibration of Valeport CTDs (conductivity, temperature and density) and Sound Velocity sensors and parameters fitted on current meters, tide gauges, wave recorders and loggers.

In addition, seven of Forum Subsea Rentals' (FSR) engineers have undergone extensive training at Valeport on all aspects of the calibration of CTD and Sound Velocity parameters.

Forum's test tank and lab builds on the company's industry-leading subsea facilities across the UK. The company operates one of Europe's largest hyperbaric testing vessels at Moffat, Northumbria. The service is rated to 241bar

(2400m depth) and is 2.4m in diameter with a length of 9.7m.

In North Yorkshire, Forum's ROV manufacturing facility has a dedicated System Integration Test (SIT) facility. This includes an 11m x 9m x 6m tank which is capable of fully submerging and flying multiple ROV systems or complete trenchers.

All Forum UK's facilities are accredited with ISO 9001 and are available for hire along with the technical support required to operate them.

Forum Energy Technologies is a global oilfield products company, serving the subsea, drilling, completion, production and infrastructure sectors of the oil and natural gas industry. The company's products include highly engineered capital equipment as well as products that are consumed in the drilling, well construction, production and transportation of oil and natural gas. Forum is headquartered in Houston, TX with manufacturing and distribution facilities strategically located around the globe.

ONESUBSEA

OneSubsea, a Schlumberger company, has been awarded an engineering, procurement and construction contract totaling more than $170 million from Belayim Petroleum Company. OneSubsea will supply the subsea production systems for the first stage of the Zohr gas field, located in the Shorouk Concession, offshore Egypt.

The award follows an accelerated FEED study by OneSubsea in which a multidisciplinary team collaborated with Eni and Petrobel to develop the subsea equipment architecture and control system to validate handling of high gas volumes, considering reservoir characteristics and subsea equipment specifications.

The scope of contract includes six horizontal SpoolTree* subsea trees, intervention and workover control systems, landing string, tie-in, high-integrity pressure protection system, topside and subsea controls and distribution, water detection and salinity monitoring provided by the AquaWatcher* water analysis sensor, and installation and commissioning services. The FasTrac program comprises a strategic inventory capability with the flexibility to configure the system to the customer needs and deliver on a fast turnaround.

FUGRO

Following successful delivery of recent cable-lay and trenching projects for the renewables sector, Fugro has secured three contracts for its trenching services for oil and gas clients. The contracts will see its high performance Q1400 trenching systems deployed in the North Sea over the next 12 months.

At the Wintershall-owned Maria development in the Norwegian sector of the North Sea, Fugro will deploy the Q1400 trenching system under a contract with Subsea 7. At Det Norske's Ivar Aasen development, the system will be deployed for EMAS CHIYODA Subsea in June. For both projects the trencher will operate in jetting mode for burial of pipelines, power cables and umbilicals.

In the UK sector, a contract with Bibby Offshore will see Fugro's Q1400 trencher operating in both jetting and cutting modes to bury a new umbilical at the BP ETAP redevelopment.

INTERMOOR

InterMoor, an Acteon company, has successfully completed the final tensioning and chain cutting operations on the FPSO Turritella for the Shell Stones project, located in the Walker Ridge protraction area in the Gulf of Mexico.

The FPSO Turritella will connect to subsea infrastructure located beneath approximately 9500 ft. (2896 m) of water, breaking the existing water depth record for an oil and gas production facility. This ultra-deep water project marks the first FPSO for Shell in the GoM, and the second FPSO in the GoM.

Having arrived in January 2016, the Turritella is a disconnectable turret moored FPSO with nine mooring lines consisting of chain and polyester, arrayed in three bundles of three. The mooring lines were attached to a dis-connectable Buoyant Turret Mooring buoy in field, awaiting the FPSO's arrival. Each mooring leg has an in-line mooring connector tensioning system, located approximately 900 ft. below the surface, which was pre-tensioned after connection to the BTM. Once the Turritella arrived, and the BTM was recovered by the FPSO. InterMoor's work scope consisted of chain final tension adjustments through the ILMC system, subsequent cut and removal of excess chain, and riser pull-in rope stretching and transfer to the FPSO.

InterMoor used the Seacor Keith Cowan anchor-handling vessel (AHV) to perform the first phase of the operations and later moved to a larger construction vessel already on charter and on standby.

Acteon sister companies worked alongside InterMoor on the project, with UTEC providing the positioning survey for the AHV, and Mirage custom-designing and fabricating the diamond wire cutting saw and clamping system.

CORTEC

CORTEC, a manufacturer of high quality API compact ball valves and manifolds, has expanded its CORTEC Manifold Systems Lafayette manufacturing facility and relocated to new premises in Port Allen, Louisiana.

According to Stephen Corte, vice president of CORTEC, the move was necessitated to support the company's growth initiatives and increase in customer demand. The facility now supports a full range of CORTEC's service operations, including: sales, engineering, quality, machining, product assembly and testing, inventory and coating.

The 55,000 square-foot facility is equipped with specialized machinery capable of manufacturing high pressure metal-seated ball valves and testing equipment designed for severe service applications. The location has capacity for 35 employees, but additional acreage and building plans are in place to expand and accommodate four times that number, which will support continued growth and expansion over the next several years.

IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4 6-17 2016	Districts 1-4 6-10 2016	District 5 6-17 2016	District 5 6-10 2016	Total US 6-17 2016	Total US 6-10 2016	Total US 6-19* 2015
	1,000 b/d						
Total motor gasoline	833	727	44	22	877	749	897
Mo. gas. blending comp.	732	516	37	13	769	529	873
Distillate	50	54	96	69	146	123	129
Residual	170	249	44	21	214	270	208
Jet fuel-kerosine	41	62	39	101	80	163	109
Propane-propylene	119	55	14	25	133	80	83
Other	829	759	3	283	832	1,041	674
Total products	**2,042**	**1,906**	**240**	**521**	**2,282**	**2,426**	**2,100**
Total crude	**7,082**	**6,477**	**1,357**	**1,145**	**8,439**	**7,622**	**6,765**
Total imports	**9,124**	**8,383**	**1,597**	**1,666**	**10,721**	**10,049**	**8,865**

*Revised.
Source: US Energy Information Administration
Data available at PennEnergy Research Center.

EXPORTS OF CRUDE AND PRODUCTS

	Total US 6-17-16	Total US 6-10-16	Total US *6-19-15
	1,000 b/d		
Finished motor gasoline	374	374	366
Jet fuel-kerosine	152	152	144
Distillate	1,178	1,178	1,228
Residual	366	366	390
Propane/propylene	649	649	600
Other oils	1,010	1,010	1,013
Total products	**3,729**	**3,729**	**3,741**
Total crude	**489**	**489**	**571**
Total exports	**4,218**	**4,218**	**4,312**
NET IMPORTS			
Total	6,503	5,830	4,553
Products	(1,447)	(1,303)	(1,641)
Crude	7,950	7,133	6,194

*Revised.
Source: Oil & Gas Journal
Data available at PennEnergy Research Center.

Additional analysis of market trends is available through **OGJ Online**, *Oil & Gas Journal's* electronic information source, at http://www.ogj.com.

OIL&GAS JOURNAL online research center. PennEnergy research

OGJ CRACK SPREAD

	6-24-16*	6-26-15*	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	61.37	79.25	(17.89)	(22.57)
Brent crude	48.12	60.84	(12.72)	(20.90)
Crack spread	13.25	18.41	(5.16)	(28.05)
FUTURES MARKET PRICES				
One month				
Product value	65.68	83.17	(17.49)	(21.03)
Light sweet crude	49.51	60.06	(10.55)	(17.56)
Crack spread	16.16	23.11	(6.95)	(30.07)
Six month				
Product value	62.17	76.61	(14.44)	(18.85)
Light sweet crude	51.49	61.76	(10.27)	(16.64)
Crack spread	10.68	14.85	(4.17)	(28.07)

*Average for week ending.
Source: Oil & Gas Journal
Data available at PennEnergy Research Center.

CRUDE AND PRODUCT STOCKS

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 bbl						
PADD 1	17,785	68,624	63,687	11,599	57,834	10,370	3,671
PADD 2	153,672	53,118	46,832	6,610	30,266	1,422	22,988
PADD 3	272,857	79,602	70,380	14,117	47,630	23,314	50,387
PADD 4	24,118	7,601	5,485	608	3,355	201	[1] 2,515
PADD 5	62,195	28,687	26,231	8,454	13,230	4,968	—
June 17, 2016	**530,627**	**237,632**	**212,615**	**41,388**	**152,315**	**40,275**	**79,561**
June 10, 2016	**531,544**	**237,004**	**213,436**	**42,199**	**152,163**	**40,783**	**78,352**
June 19, 2015[2]	**462,993**	**218,494**	**192,615**	**39,732**	**135,428**	**39,817**	**81,968**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available at PennEnergy Research Center.

REFINERY REPORT—JUNE 17, 2016

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Refinery output Jet fuel, kerosine	Refinery output Fuel oils Distillate	Refinery output Fuel oils Residual	Refinery output Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,175	1,104	3,303	88	387	42	157
PADD 2	3,673	3,670	2,616	237	1,029	41	406
PADD 3	8,700	8,706	2,068	850	2,808	194	938
PADD 4	661	658	327	33	194	10	[1] 199
PADD 5	2,509	2,367	1,719	425	539	84	—
June 17, 2016	**16,718**	**16,505**	**10,033**	**1,633**	**4,957**	**371**	**1,700**
June 10, 2016	**16,509**	**16,317**	**10,002**	**1,562**	**4,984**	**388**	**1,739**
June 19, 2015[2]	**16,794**	**16,533**	**9,754**	**1,672**	**4,970**	**380**	**1,632**
	18,307 Operable capacity		**91.3 utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available at PennEnergy Research Center.

OGJ GASOLINE PRICES

	Price ex tax 6-22-16	Pump price* 6-22-16	Pump price 6-24-15
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	164.4	213.8	262.3
Baltimore	175.8	226.8	265.8
Boston	172.9	217.8	268.8
Buffalo	166.8	227.9	279.3
Miami	161.9	216.9	272.3
Newark	172.0	204.9	257.3
New York	189.8	250.8	295.9
Norfolk	207.1	247.8	245.9
Philadelphia	157.0	225.8	289.9
Pittsburgh	175.0	243.8	286.9
Wash., DC	199.0	240.9	276.9
PAD I avg	176.5	228.8	272.8
Chicago	245.0	293.6	310.3
Cleveland	193.5	239.9	278.7
Des Moines	193.8	244.2	280.7
Detroit	193.1	242.0	278.7
Indianapolis	195.3	243.6	269.7
Kansas City	194.7	230.4	259.7
Louisville	194.0	238.4	299.7
Memphis	200.4	240.2	261.7
Milwaukee	179.8	231.1	285.7
Minn.-St. Paul	186.5	233.5	278.7
Oklahoma City	183.8	219.2	262.7
Omaha	188.5	234.6	263.4
St. Louis	187.6	223.3	278.7
Tulsa	184.8	220.2	259.7
Wichita	185.4	227.8	261.7
PAD II avg	193.7	237.5	275.3
Albuquerque	169.0	206.3	262.7
Birmingham	175.3	214.6	253.8
Dallas-Fort Worth	173.1	211.5	262.5
Houston	177.1	215.5	254.5
Little Rock	172.5	212.7	259.3
New Orleans	169.9	208.3	258.2
San Antonio	173.4	211.8	253.7
PAD III avg	172.9	211.5	257.8
Cheyenne	183.5	225.9	260.8
Denver	195.4	235.8	265.8
Salt Lake City	190.0	237.8	295.3
PAD IV avg	189.6	233.2	274.0
Los Angeles	254.9	313.9	384.5
Phoenix	191.2	228.6	278.7
Portland	188.0	237.5	294.2
San Diego	228.5	287.5	371.7
San Francisco	234.7	293.7	384.5
Seattle	207.6	270.5	266.2
PAD V avg	217.5	272.0	330.0
Week's avg.	**188.9**	**235.5**	**279.5**
May avg...	**176.1**	**222.8**	**276.9**
Apr. avg.	**161.9**	**208.6**	**267.0**
2016 to date	**156.4**	**203.1**	—
2015 to date	**195.3**	**242.6**	—

*Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes.
Source: Oil & Gas Journal.
Data available at PennEnergy Research Center.

BAKER HUGHES RIG COUNT

	6-24-16	6-26-15
Alabama	1	—
Alaska	9	10
Arkansas	—	5
California	5	11
Land	5	11
Offshore	—	—
Colorado	17	38
Florida	—	1
Illinois	2	2
Indiana	—	—
Kansas	2	13
Kentucky	1	1
Louisiana	41	75
N. Land	15	27
S. Inland waters	3	7
S. Land	3	13
Offshore	20	28
Maryland	—	—
Michigan	—	—
Mississippi	1	3
Montana	—	—
Nebraska	—	2
New Mexico	20	44
New York	—	—
North Dakota	26	74
Ohio	12	17
Oklahoma	54	105
Pennsylvania	13	47
South Dakota	—	—
Texas	194	361
Offshore	—	—
Inland waters	—	—
Dist. 1	15	50
Dist. 2	14	39
Dist. 3	4	18
Dist. 4	7	22
Dist. 5	1	5
Dist. 6	11	19
Dist. 7B	5	2
Dist. 7C	19	33
Dist. 8	103	144
Dist. 8A	7	12
Dist. 9	4	2
Dist. 10	4	15
Utah	4	8
West Virginia	11	20
Wyoming	7	21
Others HI-1	1	1
Total US	**421**	**859**
Total Canada	**76**	**135**
Grand total	**497**	**994**
US oil rigs	330	628
US gas rigs	90	228
Total US offshore	21	28
Total US cum. avg. YTD	**492**	**1,155**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 46.
Source: Baker Hughes Inc.
Data available at PennEnergy Research Center.

OGJ PRODUCTION REPORT

	[1]6-24-16	[2]6-25-15
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	27
Alaska	515	447
California	547	564
Colorado	304	327
Florida	6	7
Illinois	19	26
Kansas	96	125
Louisiana	1,306	1,323
Michigan	13	18
Mississippi	52	69
Montana	58	79
New Mexico	355	421
North Dakota	1,050	1,201
Ohio	68	69
Oklahoma	343	432
Pennsylvania	15	21
Texas	3,565	3,717
Utah	83	103
West Virginia	18	24
Wyoming	200	240
Other states	49	75
Total	**8,681**	**9,315**

[1]OGJ estimate. [2]Revised. Source: Oil & Gas Journal.
Data available at PennEnergy Research Center.

US CRUDE PRICES

	6-24-16 $/bbl*
Alaska-North Slope 27°	24.29
Light Louisiana Sweet	43.01
California-Midway Sunset 13°	37.00
California Buena Vista Hills 26°	44.89
Wyoming Sweet	43.89
East Texas Sweet	42.50
West Texas Sour 34°	39.50
West Texas Intermediate	44.50
Oklahoma Sweet	44.50
Texas Upper Gulf Coast	38.25
Michigan Sour	36.50
Kansas Common	43.25
North Dakota Sweet	37.25

*Current major refiner's posted prices except N. Slope lags 2 months. 40° gravity crude unless differing gravity is shown. Source: Oil & Gas Journal. Data available at PennEnergy Research Center.

WORLD CRUDE PRICES

		$/bbl
OPEC reference basket	Wkly. avg. 6-24-16	45.95
	Mo. avg., $/bbl	
	Apr.-16	May-16
OPEC reference basket	37.86	43.21
Arab light-Saudi Arabia	38.22	43.48
Basrah light-Iraq	36.62	42.05
Bonny light 37°-Nigeria	41.51	46.85
Es Sider-Libya	40.48	45.83
Girassol-Angola	41.25	46.58
Iran heavy-Iran	36.65	41.67
Kuwait export-Kuwait	36.33	41.60
Marine-Qatar	38.97	44.13
Merey-Venezuela	28.84	34.28
Minas 34°-Indonesia	38.52	48.64
Murban-UAE	42.47	47.12
Oriente-Ecuador	35.04	41.96
Saharan blend 44°-Algeria	42.33	47.73
Other crudes		
Fateh 32°-Dubai	39.00	44.29
Isthmus 33°-Mexico	38.14	44.76
Brent 38°-UK	41.48	46.83
Urals-Russia	39.89	45.08
Differentials		
WTI/Brent	(0.53)	0.01
Brent/Dubai	2.48	2.54

Source: OPEC Monthly Oil Market Report.
Data available at PennEnergy Research Center.

REFINED PRODUCT PRICES

Spot market product prices

	6-17-16 ¢/gal
Motor gasoline (Conventional-regular)	
New York Harbor	144.30
Gulf Coast	143.30
Motor gasoline (RBOB-regular)	
New York Harbor	165.10
No. 2 heating oil	
New York Harbor	137.40
No. 2 Distillate Low sulfur diesel fuel	
New York Harbor	148.10
Gulf Coast	144.60
Los Angeles	152.60
Kerosine jet fuel	
Gulf Coast	136.60
Propane	
Mont Belvieu	49.30

Source: EIA Weekly Petroleum Status Report.
Data available at PennEnergy Research Center.

IHS PETRODATA RIG COUNT

JUNE 24, 2016

	Total supply of rigs	Marketed supply of rigs	Marketed contracted	Marketed utilization rate (%)
US Gulf of Mexico	112	62	41	66.1
South America	58	54	43	79.6
Northwest Europe	107	88	71	80.7
West Africa	66	55	30	54.6
Middle East	166	157	124	79.0
Southeast Asia	93	79	35	44.3
Worldwide	833	706	502	71.1

Source: IHS Petrodata
Data available in PennEnergy Research Center

US NATURAL GAS STORAGE[1]

	6-17-16	6-10-16	6-17-15	Change, %
	bcf			
East	612	585	517	18.4
Midwest	724	703	510	42.0
Mountain	194	188	149	30.2
Pacific	318	312	331	(3.9)
South Central	1,255	1,253	978	28.3
Salt	366	368	295	24.1
Nonsalt	890	885	685	29.9
Total US	**3,103**	**3,041**	**2,485**	**24.9**
	Mar.-16	Mar.-15	Change, %	
Total US[2]	**2,492**	**1,483**	**68.0**	

[1]Working gas. [2]At end of period.
Source: Energy Information Administration
Data available at PennEnergy Research Center.

PACE REFINING MARGINS

	Apr. 2016	May 2016	June 2016	June 2015	Change	Change, %
	$/bbl					
US Gulf Coast						
Composite US Gulf Refinery	11.48	11.11	11.32	15.87	(4.55)	(28.7)
Mars (Coking)	12.86	12.09	12.22	16.74	(4.52)	(27.0)
Mars (Cracking)	8.99	8.29	8.40	13.55	(5.15)	(38.0)
Bonny Light	6.83	7.63	7.71	13.68	(5.97)	(43.6)
US PADD II						
Chicago (WTI)	14.59	15.89	19.05	19.84	(0.79)	(4.0)
US East Coast						
Brass River	8.36	9.22	11.31	17.62	(6.30)	(35.8)
East Coast Comp	10.04	11.03	14.90	21.63	(6.73)	(31.1)
US West Coast						
Los Angeles (ANS)	14.59	10.81	14.21	16.46	(2.25)	(13.7)
NW Europe						
Rotterdam (Brent)	3.14	1.76	2.45	5.79	(3.35)	(57.7)
Mediterranean						
Italy (Urals)	4.30	4.06	4.37	6.64	(2.27)	(34.2)
Far East						
Singapore (Dubai)	3.07	2.49	2.52	5.67	(3.16)	(55.6)

Source: Jacobs Consultancy Inc.
Data available at PennEnergy Research Center.

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Mar. 2016	Feb. 2016	Mar. 2015	July 2016–2015 change	Total YTD 2016	Total YTD 2015	YTD 2016–2015 change
	bcf						
DEMAND							
Consumption	2,375	2,697	2,617	(242)	8,201	8,699	(498)
Addition to storage	215	111	182	33	392	314	78
Exports	196	164	164	32	530	454	76
Canada	81	62	90	(9)	213	240	(27)
Mexico	105	99	74	31	304	208	96
LNG	10	3	—	10	13	6	7
Total demand	**2,786**	**2,972**	**2,963**	**(177)**	**9,123**	**9,467**	**(344)**
SUPPLY							
Production (dry gas)	2,294	2,183	2,291	3	6,773	6,607	166
Supplemental gas	5	5	5	—	16	16	—
Storage withdrawal	274	515	376	(102)	1,583	1,974	(391)
Imports	240	251	258	(18)	763	790	(27)
Canada	231	241	243	(12)	733	752	(19)
Mexico	—	—	—	—	—	—	—
LNG	9	10	15	(6)	30	38	(8)
Total supply	**2,813**	**2,954**	**2,930**	**(117)**	**9,135**	**9,387**	**(252)**

NATURAL GAS IN UNDERGROUND STORAGE

	Mar. 2016	Feb. 2016	Jan. 2016	Mar. 2015	Change
	bcf				
Base gas	4,354	4,361	4,361	4,360	2,477
Working gas	2,492	2,544	2,948	1,483	1,009
Total gas	**6,846**	**6,905**	**7,309**	**5,843**	**3,486**

Source: DOE Monthly Energy Review.
Data available at PennEnergy Research Center. **NOTE: No new data at press time.**

WORLDWIDE NGL PRODUCTION

	Mar. 2016	Feb. 2015	3 month average production 2016	3 month average production 2015	Change vs. previous year Volume	Change vs. previous year %
	1,000 b/d					
Brazil	93	89	91	107	(16)	(14.9)
Canada	799	840	814	710	104	14.7
Mexico	290	301	303	346	(42)	(12.2)
United States	3,509	3,329	3,380	3,087	293	9.5
Venezuela	206	206	206	213	(7)	(3.3)
Other Western Hemisphere	229	220	212	242	(30)	(12.4)
Western Hemisphere	**5,126**	**4,985**	**5,007**	**4,705**	**302**	**6.4**
Norway	382	395	385	349	36	10.2
United Kingdom	76	76	74	53	21	40.7
Other Western Europe	13	13	13	12	1	5.4
Western Europe	**471**	**484**	**472**	**414**	**58**	**14.0**
Russia	849	849	850	705	145	20.5
Other FSU	170	170	170	156	14	9.2
Other Eastern Europe	15	15	15	16	(1)	(4.3)
Eastern Europe	**1,034**	**1,034**	**1,035**	**876**	**158**	**18.1**
Algeria	521	521	521	523	(2)	(0.4)
Egypt	202	202	202	201	1	0.7
Libya	50	50	50	50	—	—
Other Africa	144	144	145	126	19	15.1
Africa	**917**	**917**	**918**	**900**	**18**	**2.0**
Saudi Arabia	1,820	1,820	1,820	1,810	10	0.6
United Arab Emirates	641	641	641	641	—	—
Other Middle East	694	694	694	690	4	0.5
Middle East	**3,155**	**3,155**	**3,155**	**3,141**	**14**	**0.4**
Australia	51	51	52	48	3	6.9
China	12	12	12	12	—	—
India	122	122	122	102	20	19.2
Other Asia–Pacific	324	324	323	323	—	0.1
Asia–Pacific	**509**	**509**	**509**	**485**	**23**	**4.8**
TOTAL WORLD	**11,212**	**11,084**	**11,096**	**10,522**	**573**	**5.4**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available at PennEnergy Research Center.

OXYGENATES

	Mar. 2016	Feb. 2016	Change	YTD 2016	YTD 2015	Change
	1,000 bbl					
Fuel ethanol						
Production	30,812	28,678	2,134	89,809	86,032	3,777
Stocks	22,301	23,004	(703)	22,301	20,865	1,436
MTBE						
Production	1,649	1,196	453	4,145	2,340	1,805
Stocks	1,183	1,213	(30)	1,183	889	294

Source: DOE Petroleum Supply Monthly.
Data available at PennEnergy Research Center. **NOTE: No new data at press time.**

US HEATING DEGREE–DAYS

	Mar. 2016	Feb. 2016	Mar. 2015	% change	Total degree days YTD 2016	Total degree days YTD 2015	% change
New England	755	956	1,103	(31.6)	2,839	3,853	(26.3)
Middle Atlantic	648	900	1,001	(35.3)	2,665	3,581	(25.6)
East North Central	670	956	951	(29.5)	2,865	3,690	(22.4)
West North Central	652	935	802	(18.7)	2,890	3,374	(14.3)
South Atlantic	241	483	359	(32.9)	1,385	1,671	(17.1)
East South Central	323	574	445	(27.4)	1,756	2,145	(18.1)
West South Central	180	310	277	(35.0)	1,055	1,400	(24.6)
Mountain	542	617	481	12.7	2,072	1,898	9.2
Pacific	390	342	283	37.8	1,298	1,083	19.9
US average*	**450**	**627**	**583**	**(22.8)**	**1,947**	**2,340**	**(16.8)**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
Data available at PennEnergy Research Center.

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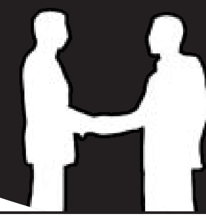

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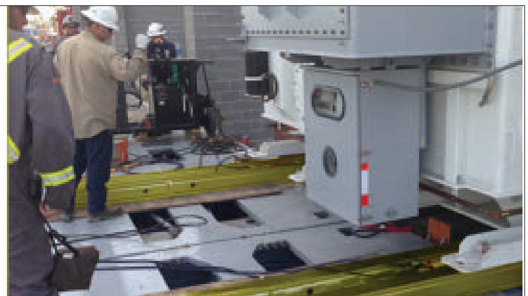

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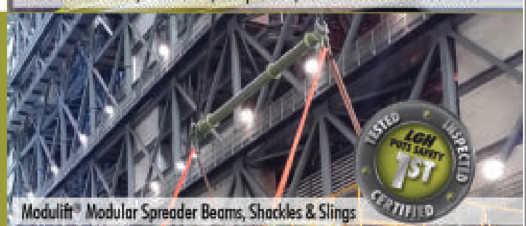

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THE EDITOR'S PERSPECTIVE

US courts reassert limits on power of Executive Branch

by **Bob Tippee**, Editor

Executive power in the US encountered limits—of all things—during the third full week of June.

First a federal district court judge in Wyoming ruled the Bureau of Land Management lacks authority to regulate hydraulic fracturing on federal and Indian land.

Then the Supreme Court let stand a lower-court rule blocking President Barack Obama's program to shield millions of undocumented immigrations from deportation.

It was a good week for separation of powers.

Obama overworks executive action. He says Congress forces him to rely on the infamous pen and phone because it won't do his bidding.

Someone should remind the former constitutional professor that Congress wasn't designed to bow to presidential will.

In the frac-case ruling, Dist. Judge Scott Skavdahl wrote, "Regulation of an activity must be by congressional authority, not administrative fiat."

The issue, he said, was whether Congress gave the Department of the Interior, of which BLM is part, authority to regulate hydraulic fracturing.

"It has not," Skavdahl ruled.

In the immigration case, the Supreme Court upheld an appeals-court ruling with an evenly split decision.

The program in question deferred action on deportation of immigrants illegally in the US who are parents of American citizens or of lawful permanent residents.

Twenty-six states challenged the plan. The appeals court had affirmed a ruling that the administration violated notice requirements and added a broader ruling that it exceeded statutory authority.

House Speaker Paul Ryan said the Supreme Court "vindicated" Article I of the Constitution, which reserves to Congress all legislative powers.

"The president is not permitted to write laws," Ryan said. "Only Congress is."

The imperious Obama won't be chastened, of course. But his presidency is almost over.

Because tests of Executive Branch authority aren't likely to subside when Obama leaves office, a stiffening of the judicial spine is welcome.

Both leading presidential contenders seem to share Obama's dangerously expansionist tendencies with powers of the office.

So their honors have provided a needed reminder: The Constitution still applies.

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WATCHING GOVERNMENT

Nick Snow
Washington Editor

Will oil and gas matter in 2016?

The question was inevitable. The American Petroleum Institute had just released results on June 21 of the latest telephone survey it commissioned, which found most US voters support more US oil and gas development and are more likely to back a candidate who shares that view.

So it was only logical that a panel of four political campaign experts, who were on the event's program as a follow-up, were asked why issues important to the oil and gas industry had not become part of the 2016 election contests.

The experts were momentarily stumped. Then, slowly, they agreed that personalities had dominated the campaigns so far, and the two major parties' presumptive nominees at least had not yet discussed any issues so far. That makes this a better time for oil and gas industry advocates to educate voters and candidates than when they are angry because prices are high. "Now is when the industry should be working hardest," one of the experts said.

"We should be looking at what this energy renaissance can do for the public as a whole," API Pres. Jack N. Gerard said. "It could be capable of addressing poverty and other issues more broadly, and not just jobs."

It's clearly in the industry's long-term interest to emphasize careers as much as jobs. Professionals capable of finding, producing, and transporting oil and gas will need to be especially resourceful as pressure increases to change the ground rules because of growing climate concerns. Minimizing impacts also matters more as activity moves increasingly from sparsely populated rural areas to sites near commuter communities close to population centers.

Candidates farther down the ballot from Hillary Clinton and Donald J. Trump also should be cultivated. Governors and state legislators, along with local leaders, matter too. If they can be convinced that facilitating more oil and gas activity provides broader economic benefits that translate into votes, many would be less likely to cave in to environmental activists' demands to "leave it in the ground."

Where sides coexist

There are some signs that energy and environmental interests are coming together. Many states' oil and gas divisions now are part of environmental protection departments. Several larger universities' petroleum studies departments have become parts of more comprehensive energy, environment, and climate schools.

The biggest challenge this election could be addressing the needs of people who feel they have been left behind. There were enough to vote Great Britain out of the European Union. There may be enough of them to affect final results in the US in November. The oil and gas industry would be the big winner if its positive messages won their support. OGJ