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CONTENTS

Oct. 3, 2016 Volume 114.10

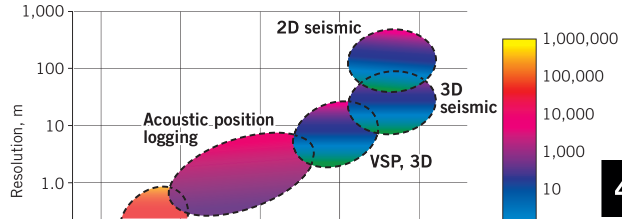
GENERAL INTEREST

COVER

Ocean bottom seismic (OBS) *is providing a passive enhancement to conventional acquisition techniques, which allows better coverage throughout Australia's offshore territory. AuScope Ltd. deployed its fleet of OBS from CGG's Viking Vision for the BART 3D acquisition in 2014-15 offshore Western Australia. Part of the Geophysics Update special report outlines a new project by Advent Energy to investigate nearshore deposits in New South Wales using AuScope's OBS technology (p. 36). Photo from Geoscience Australia.*

EXPLORATION PROPERTIES

FIG. 1



42

SPECIAL REPORT
GEOPHYSICS UPDATE

REGULAR FEATURES

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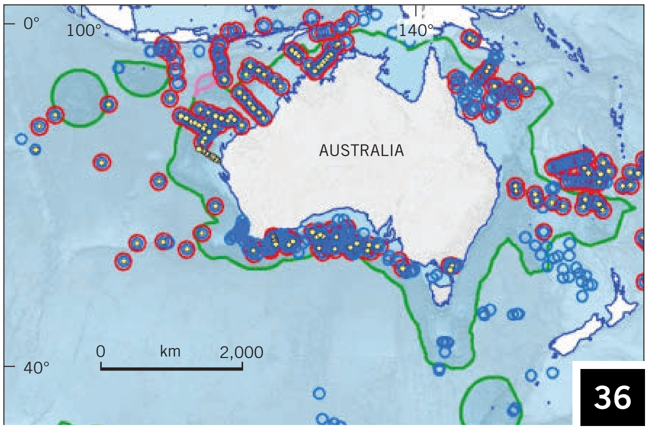
REFRACTION-SEISMIC VELOCITY MEASUREMENTS

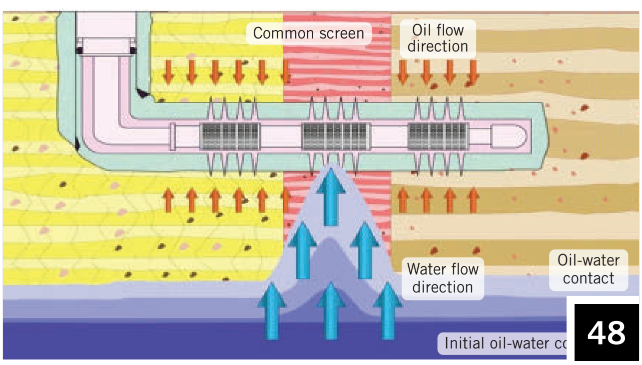
FIG. 1



TECHNOLOGY...

WATER BREAKTHROUGH

FIG. 1



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Oct. 3, 2016

GENERAL INTEREST QUICK TAKES

InterOil shareholders agree to ExxonMobil offer

Shareholders of Singapore-based InterOil Corp. have overwhelmingly voted to approve ExxonMobil Corp.'s $2.5-billion bid for the company at a special meeting on Sept. 19. More than 80% of shareholders voted in favor of the deal.

InterOil Chairman Chris Finlayson thanked shareholders for their support for what he called a value-creating transaction.

Finlayson said the deal will deliver shareholders a material and immediate premium, a potential direct cash payment based on the Elk-Antelope gas-condensate field resource certification in Papua New Guinea, and exposure to future value through ownership of ExxonMobil shares.

The transaction is now expected to be completed by the end of this month.

InterOil intends to seek a final order with respect to the plan of arrangement at a hearing in the Supreme Court of Yukon scheduled for Sept. 27.

InterOil's major asset is Elk-Antelope field in the eastern highlands of Papua New Guinea along with surrounding exploration permits covering about 16,000 sq km.

The gas resources are the potential feedstock for the proposed Papua LNG project, which is operated by Total SA. ExxonMobil now joins Total and its fellow joint venturer Oil Search Ltd. in appraising and planning the development that calls for a pipeline from the fields to an LNG plant at Caution Bay about 20 km from Port Moresby.

The plant is notionally next door to the existing ExxonMobil-operated Papua LNG plant and there will be synergies with the two projects. ExxonMobil and Oil Search are participants in both projects.

Maersk splits oil, transport businesses

A.P. Moller-Maersk AS, Copenhagen, is separating its transportation and oil businesses and starting a 2-year strategic review of the latter. In a press statement the firm said its "main growth focus" will be "delivering best in class transportation and logistics services as an integrated transport and logistics company."

Oil and oil-related services, the statement said, "will require different solutions for future development, including separation of entities individually or in combination from AP Moller-Maersk AS in the form of joint ventures, mergers, or listing."

The company said it "aims to find solutions for the oil and oil-related businesses within 24 months."

A new energy division will comprise Maersk Oil, Maersk Drilling, Maersk Supply Service, and Maersk Tankers.

The statement said Maersk Oil will change strategy to focus "in fewer geographies to gain scale in basins, particularly in the North Sea," and "aim to strengthen its portfolio through acquisitions or mergers."

Maersk Oil now has interests in Algeria, Angola, Brazil, Denmark, Ethiopia, Greenland, Iraqi Kurdistan, Kazakhstan, Kenya, Norway, Qatar, the UAE, the UK, and the US.

The operating company "will mature existing key development projects while keeping exploration activities and expenses at a low level," the statement said. Investments in sanctioned "strategic projects" will continue.

Future investment in Maersk Drilling, Maersk Supply Services, and Maersk Tankers "will be limited," the firm said.

Claus V. Hemmingsen will become chief executive officer of the new energy division and group vice-CEO of A.P. Moller-Maersk. Jakob Thomasen, now CEO of Maersk Oil, will leave the company in November.

OGUK: Fresh investment vital to UKCS

Lack of capital investment and low exploration activity are among the major challenges for the UK oil and gas industry, according to Oil & Gas UK in its Economic Report 2016.

"The UKCS is in urgent need of fresh investment to boost exploration and drive activity, particularly for the supply chain," said Deirdre Michie, OGUK's chief executive. "Exploration has fallen to record lows and little new investment has been approved in 2016, and 2017 looks no better."

In the past 2 years, about 120,000 jobs have been lost, and the supply chain has seen an average 30% fall in revenues.

On the positive side, production was up 10.4% in 2015—the first increase in 15 years. And the cost of extracting oil or gas from the UKCS has dropped 45% since 2014.

"Now it is time for the UK and Scottish governments to reinforce their efforts to promote the UKCS, nationally and internationally, as an attractive investment with world leading capability from front end exploration to late life operations," Michie said. OGJ

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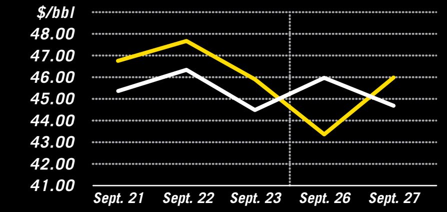
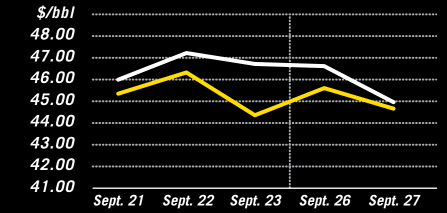
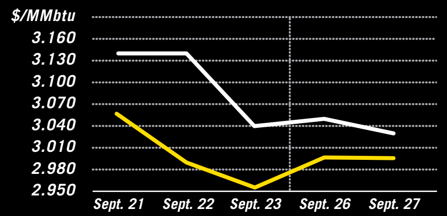


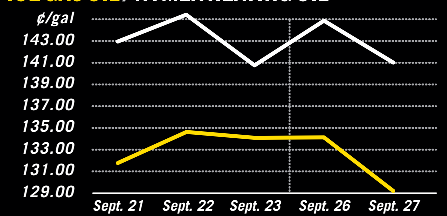
WTI CUSHING / BRENT SPOT



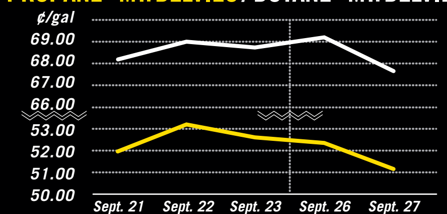
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



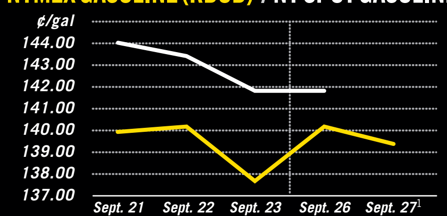
ICE GAS OIL / NYMEX HEATING OIL



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

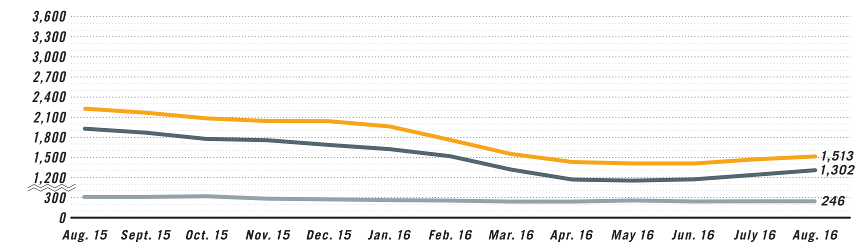
US INDUSTRY SCOREBOARD — 10/3

Latest week 9/16	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	9,541	9,163	4.1	9,466	9,143	3.5
Distillate	3,558	3,783	(5.9)	3,726	3,926	(5.1)
Jet fuel	1,715	1,586	8.1	1,633	1,570	4.0
Residual	430	196	119.4	308	206	49.5
Other products	5,035	4,955	1.6	4,973	4,870	2.1
TOTAL PRODUCT SUPPLIED	20,279	19,683	3.0	20,106	19,715	2.0
Supply, 1,000 b/d						
Crude production	8,488	9,152	(7.3)	8,813	9,373	(6.0)
NGL production[2]	3,612	3,257	10.9	3,457	3,152	9.7
Crude imports	8,089	7,420	9.0	7,955	7,313	8.8
Product imports	2,097	1,909	9.8	2,173	2,093	3.8
Other supply[2 3]	2,183	2,424	(9.9)	2,202	2,333	(5.6)
TOTAL SUPPLY	24,469	24,162	1.3	24,600	24,264	1.4
Net product imports	(2,097)	(1,786)	—	(1,754)	(1,574)	—
Refining, 1,000 b/d						
Crude runs to stills	16,739	16,383	2.2	16,294	16,197	0.6
Input to crude stills	17,088	16,638	2.7	16,533	16,437	0.6
% utilization	93.0	92.0	—	90.5	91.4	—

Latest week 9/16	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	504,598	510,798	(6,200)	453,969	50,629	11.2
Motor gasoline	225,156	228,360	(3,204)	218,756	6,400	2.9
Distillate	164,992	162,754	2,238	151,875	13,117	8.6
Jet fuel–kerosine	42,648	42,749	(101)	41,411	1,237	3.0
Residual	40,655	40,583	72	39,471	1,184	3.0
Stock cover (days)[4]			Change, %		Change, %	
Crude	30.2	30.5	(1.0)	27.8	8.6	
Motor gasoline	23.6	23.9	(1.3)	23.9	(1.3)	
Distillate	46.4	44.6	4.0	40.2	15.4	
Propane	106.3	102.4	3.8	86.3	23.2	
Futures prices[5] **9/23**			Change		Change	Change,%
Light sweet crude ($/bbl)	44.58	44.34	0.24	45.46	(0.88)	(1.9)
Natural gas, $/MMbtu	3.00	2.92	0.08	2.68	0.32	11.8

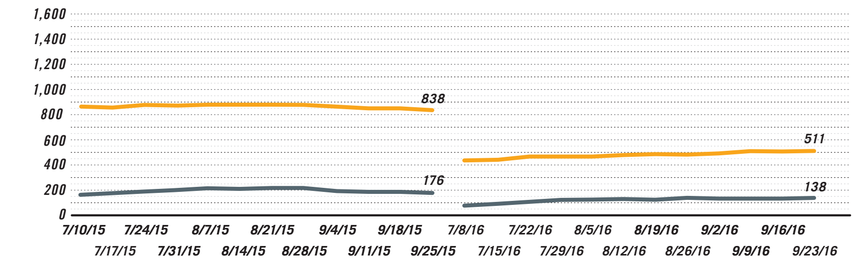
[1]Based on revised figures. [2]OGJ estimates. [3]Includes other liquids, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average of daily closing futures prices.
Source: Energy Information Administration, Wall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

Jordanian firm agrees to buy Leviathan gas

Partners in the Leviathan natural gas project offshore Israel have signed an agreement to supply as much as 45 billion cu m of gas to a Jordanian power company.

The deepwater project recently received development approval of the Petroleum Commissioner of Israel's Ministry of National Infrastructure, Energy, and Water Resources and awaits permitting and a final investment decision (OGJ Online, June 2, 2016).

NBL Jordan Marketing Ltd., a wholly owned subsidiary of the Leviathan partners, will supply the gas at the Jordan-Israel border to National Electric Power Co. of Jordan.

The agreement is for 15 years unless shipments reach the maximum volume earlier.

Delek Group, whose Delek Drilling LP and Avner Oil Exploration LP subsidiaries hold interests in Leviathan, said total revenues under the agreement are estimated at $10 billion. The agreement includes an annual take-or-pay provision. It's subject to approvals of Israeli and Jordanian authorities and the signing of transportation agreements.

Two state-owned Jordanian companies, Arab Potash and Jordan Bromine Co., have agreements to buy gas from Tamar field, which came on stream east of Leviathan in 2013 (OGJ Online, Feb. 20, 2014).

Noble Energy Inc., which operates Leviathan field with a 39.66% interest, recently said it has signed contracts with Israeli buyers for 100 MMcfd of Leviathan gas.

Delek Drilling and Avner Oil Exploration hold 22.67% interests each. Ratio Oil Exploration (1992) LP holds 15%.

Partners see 3 tcf of OGIP at Great Nooros area

The Baltim South West 2X appraisal well, drilled in the Nile Delta, encountered an 86-m net gas column in two sand layers of Messinian age with excellent reservoir characteristics.

The results have prompted partners Eni SPA and BP PLC to upgrade the potential of Baltim South West field to 1 tcf of gas in place. Potential of the Great Nooros area, which encompasses both Baltim South West and Nooros fields, has been lifted to 3 tcf of gas in place.

Eni in June reported the Baltim SW-1 exploration well reached a total depth of 3,750 m, encountering 62 m of net gas pay in high-quality Messinian sandstones (OGJ Online, June 9, 2016). Baltim South West field is 12 km from the Egyptian coastline in 25 m of water.

Eni and BP are reviewing development options for the latest discovery. As for Nooros, the plan is to maximize synergies with existing systems in the area in accordance with Eni's nearfield exploration strategy. Production from Nooros reached 700 MMcfd of gas 13 months after the discovery, Eni and BP said this month. Eni unit IEOC operates Baltim South with 50% interest while BP holds the rest. Operator Petrobel is a joint venture of IEOC and state partner EGPC.

Roc-2 well confirms gas, liquids off W. Australia

The Quadrant Energy Ltd.-operated Roc-2 appraisal well, drilled offshore Western Australia in permit WA-437-P, has recovered condensate-rich gas samples from several zones.

A full suite of wireline logs has been run resulting in the interpretation of a 30-m net reservoir and 60 m of gross gas and condensate charged sands intersected. There also has been excellent quality reservoir of 100-350 md permeability calculated from downhole sampling rates.

Wireline cores are now being acquired, an operation expected to take a week.

Another 10 days will then be required to install tubes and valving preparatory for flow-testing the well.

Quadrant plans to perforate the well across the uppermost 35-m sand interval and open the valves for a controlled test for about a week. Results of the well test are expected in 3 weeks' time.

Overall, Roc-2 has now confirmed the presence of a high-quality reservoir within the Calley formation, which is almost fully saturated with gas and condensate. Porosities of up to 15% were observed, the average being about 9%.

Estimated liquid content within the gas is similar to Roc-1 at about 50-60 bbl of condensate per MMcf of gas. Permeability is also similar to Roc-1.

However pressure data obtained from the wireline logs did not correlate with Roc-1 data and it seems that Roc-1 and Roc-2 are likely to be separate structures in all or at least some of the sands. Nevertheless they are all within the same greater structural closure.

Quadrant has 80% interest with Carnarvon Petroleum Ltd., also of Perth, with 20%.

Production license sought for Galt prospect

Junex Inc. has applied with Quebec's government for a 20-sq-km production lease on its Galt oil prospect in eastern Quebec. The company's application focuses on the central portion of the Galt structure, which was mapped from data in the company's 37-sq-km 3D survey conducted in 2015.

As early as 2012, Junex said its Galt-4 stepout well 20 km west of Gaspe encountered an oil column from 760-1,757 m at a total depth of 2,000 m (OGJ Online, Sep. 25, 2012). The Galt-4 wellsite is 2.5 km west of the Galt-1, 2, and 3 wells. At the time, Junex said the Galt-4 confirmed the extension of the Galt structure, and the well was temporarily suspended in view of drilling horizontally into the hydrothermal breccia encountered in the Devonian Forillon formation.

Junex Pres. and CEO Peter Dorrins said the application for an oil production lease was the first in Quebec's history, to the company's knowledge. The company has held a gas production lease on the 2-sq-km area surrounding its Galt-1 well since 2003 where it operated a pilot project using compressed natural gas transported by truck to local customers.

Netherland, Sewell & Associates Inc. has estimated Galt field to contain 260.2 million bbl of oil in place. OGJ

DRILLING & PRODUCTION QUICK TAKES

RAK brings gas fields on stream off Ivory Coast

RAK Petroleum PLC said Marlin and Manta gas fields offshore the Ivory Coast were brought on stream following completion of a 4-year, $850-million development by operator Foxtrot International LDC, Abidjan, on Block CI-27. Production from the two fields follows installation of a platform in 110 m of water and the drilling of one exploration and seven production wells.

Gas production from Block CI-27 reached an average of 170 MMcfd during August, accounting for more than 75% of the Ivory Coast total gas production. Oil and condensate production averaged 3,000 b/d.

In 2015, gas production from the block averaged 145 MMcfd while liquids production averaged 1,140 b/d.

The block's first platform has operated since 1999 processing gas and liquids from Foxtrot and Mahi gas fields (OGJ Online, Mar. 9, 2015).

Foxtrot International said it has identified significant gas reserves and contingent resources on Block CI-27 across four producing fields, including lower and upper Turonian intervals in Marlin field. A reserves certification study by an independent petroleum engineering firm is expected to be completed shortly, RAK Petroleum said.

RAK Petroleum, through Mondoil Enterprises LLC, holds one-third ownership of Foxtrot International, which in turn operates Block CI-27 with 27.5% interest. Other partners on the block are Ivory Coast state oil company Petroci and Energie de Cote d'Ivoire SA (ENERCI).

Russia's northernmost onshore oil field flowing

OJSC Rosneft reported the startup of production from Vostochno-Messoyakha, Russia's northernmost onshore oil field. The field lies on the Gydan Peninsula in the Taz region of Yamalo-Nenets autonomous district, 340 km north of Novy Urengoy. The nearest settlement, Tazokvsky village, is 150 km away.

The field has 51 active oil wells and a 98-km pipeline to the Zapolyarye-Purpe main pipeline. Rosneft said directional drilling was used for underwater crossings of the Indikyakha and Muduyakha rivers.

Field infrastructure was built within 3 years. Two power stations cover field demand for electricity.

The field is being developed by Messoyakhaneftegas, owned by Rosneft and PJSC Gazprom Neft.

Rosneft said recoverable oil and condensate reserves exceed 340 million tonnes.

Via video linkup, Russian President Vladimir Putin gave the command to start production. Igor Sechin, Rosneft chief executive officer, told Putin that Suzan field, 150 km away, will be ready for startup this month.

PDVSA plans Orinoco drilling, output hike

State-owned Petroleos de Venezuela SA (PDVSA) says it has let contracts for the drilling of 480 wells in a program aimed at raising production in Venezuela's Orinoco heavy oil belt by 250,000 b/d. Investment in the 30-month program, it says, will be $3.2 billion.

"The international companies Schlumberger and Horizontal Well Drillers, as well as Venezuela' Y&V, were selected after a worldwide tender," PDVSA said in a statement. "They will have the support and operational expertise of Halliburton and Baker Hughes for specific project activities; 18 drilling rigs will be available."

Horizontal Well Drillers, Purcell, Okla., confirmed it has a contract to drill as many as 191 shallow, horizontal wells in the Orinoco belt.

The company said Schlumberger's contract is for 80 wells, and Y&V Group's is for 100 wells.

PDVSA said the participating companies will provide $700 million of financing.

The company's joint ventures with international companies—PetroVictoria, PetroCarabobo, and Petroindependencia—will participate in the program, it said. OGJ

PROCESSING QUICK TAKES

Moody's sees another tough refining year

Refiners face another tough year in 2017, predicts Moody's Investors Service.

Citing forecasts by the US Energy Information Administration, the firm says global demand for gasoline and distillate products will grow only modestly and "will continue to lag the anticipated high available supplies."

Across North America, Europe, the Middle East, and Africa, the refining industry's earnings before interest, taxes, depreciation, and amortization (EBITDA) will decline by more than 15% in the next 12-18 months as crack spreads—the differences between crude costs and product values—remain thin, Moody's predicts in a research note.

"Record gasoline produced from 2015 to mid-2016 amid low crude prices, along with excess inventories, has outpaced gasoline and distillate demand growth from consumers and industrial customers in every major world economy," the firm says.

US grant to support IOC's refinery revamp program

The US Trade and Development Agency (USTDA) has awarded a grant to India's public-sector refining firm Indian Oil Corp. Ltd. (IOC) to fund a feasibility study that will recommend technology options for the ongoing modernization of the operator's nine refineries.

The grant comes in support of IOCL's efforts to increase operational efficiency, reduce emissions, and expand production of cleaner fuels at its refineries in order to meets India's more-stringent environmental standards, USTDA said.

The grant award follows IOC's participation in a USTDA reverse-trade mission that brought Indian energy officials to the US for meetings and site visits with US companies focused on refinery modernization solutions, the agency said.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The feasibility study will include a market, technical, economic, and financial analysis of advanced technologies to help IOC identify solutions for converting petcoke byproducts from its refineries into cleaner chemical products and fuels, IOC said.

US firms interested in the opportunity to conduct the USTDA-funded feasibility study are invited to submit proposals to the Federal Business Opportunities' (FBO) web site following FBO's forthcoming formal announcement of the opportunity, USTDA said.

Counting its majority interest in subsidiary Chennai Petroleum Corp. Ltd.'s two refineries, IOC holds a combined 80.7 million tonnes/year of refining capacity with control of 11 of India's 23 refineries, including: Digboi, 650,000 tpy; Guwahati, 1 million tpy; Koyali, 13.7 million tpy; Barauni, 6 million tpy; Haldia, 7.5 million tpy; Mathura, 8 million tpy; Panipat, 15 million tpy; Bongaigaon, 2.35 million tpy; Paradip, 15 million tpy; Chennai, 10.5 million tpy; and Narimanam, 1 million tpy.

Neste advances maintenance at Porvoo refinery

A process upset at Neste Corp.'s 10.5 million-tonne/year Porvoo refinery in the Kilpilahti Industrial Area, about 20 miles east of Helsinki, Finland, has led the operator to advance planned maintenance activities on diesel production line 4 (PL4) ahead of its previously scheduled spring-2017 turnaround.

The decision to expedite the PL4's 6-week turnaround followed a recent process disruption that led to catalyst coking in the production line, the company said.

Neste did not disclose details regarding either the precise nature of the disruption or the scope of work to be executed during the upcoming turnaround.

While the rescheduled maintenance will not impact diesel deliveries to customers, Neste said it does expect the turnaround to reduce its comparable EBIT by about €30 million, most of which will be booked during this year's fourth quarter.

Neste continues to proceed with its €500-million investment plan to improve the competitiveness of its overall refining operations by integrating its 3 million-tpy Naantali refinery with the Porvoo refinery so that the sites will operate as a single Finnish refining system (OGJ Online, Mar. 23, 2015).

In June 2015, Neste completed a 2-month, €100-million planned maintenance turnaround at the Porvoo refinery, which alongside standard 5-year maintenance to ensure safe and reliable operations, also a series of projects related to the refinery's future development, including startup of a 600,000-tpy isomerization unit (OGJ Online, Aug. 5, 2015; Feb. 25, 2014)

Construction also remains under way on a €200-million solvent deasphalting (SDA) feedstock pretreatment unit and asphaltene pelletizer in the area of PL4 at Porvoo, Neste said in its 2015 annual report.

Due for startup in 2017, the SDA unit will enable Porvoo to decrease its output of heavy fuel oil and increase the production of higher-quality fuels such as diesel, among others, by decreasing the content of asphaltenes present in crude feedstock processed at the refinery. OGJ

Atlantic Coast Pipeline hires construction contractor

Atlantic Coast Pipeline LLC, which has proposed a 600-mile, 1.5-bcfd natural gas transmission pipeline to bring Marcellus-Utica shale gas to Virginia and North Carolina, has signed a construction contract with Spring Ridge Constructors LLC, a joint venture of pipeline construction companies Price Gregory International Inc., a Quanta Services Inc. company; US Pipeline Inc.; SMPC LLC; and Rockford Corp., a Primoris Services Corp. company.

Pending approval by the US Federal Energy Regulatory Commission, the Atlantic Coast Pipeline (ACP) would extend from Harrison County, W.Va., southeast through Virginia with a lateral extension to Chesapeake, Va., and then south through eastern North Carolina to Robeson County. If approved, construction is scheduled to begin in fall 2017.

FERC in early August issued a notice of schedule, which established the timeline for the remainder of the project's federal environmental review process. Based on FERC's schedule, ACP expects to receive a FERC certificate in late summer or fall 2017, with construction beginning shortly thereafter. ACP anticipates completing construction and bringing the pipeline into service in late 2019. ACP says it is working with its contractors to evaluate the possibility of bringing on more crews and working on more simultaneous spreads in order to complete construction sooner and expects to finalize this analysis over the next few months.

Atlantic Coast Pipeline LLC consists of four US energy companies: Dominion, Duke Energy, Piedmont Natural Gas Co. Inc., and Southern Co. Gas. The joint venture partners expect the pipeline to cost $4.5-5 billion.

Sunoco Logistics buys Vitol Permian system

Sunoco Logistics Partners LP has bought Vitol Group's Permian basin crude oil system for $760 million plus working capital.

The system includes a crude oil terminal in Midland, a crude gathering and mainline pipeline system, and crude inventories related to Vitol's purchasing and marketing business.

The system includes Vitol's 50% interest in SunVit Pipeline LLC connecting the Midland Terminal with Sunoco Logistics' Permian Express 2 pipeline. Sunoco Logistics now owns all SunVit membership interests.

OMV to sell 49% of Austrian gas unit

OMV AG has agreed to sell a 49% interest in wholly owned Gas Connect Austria GMBH (GCA) to a combine of the European insurance group Allianz and Snam SPA.

Total cash consideration is €601 million, which includes a €147-million adjustment of shareholder debt.

GCA operates a 900-km high-pressure natural gas pipeline network in Austria. Total throughput last year was 152 billion m of gas. OGJ

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

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.**

SPE African Health, Safety, Security, Environment & Social Responsibility Conference & Exhibition, Accra, Ghana, web site: www.spe.org/events/en/2016/conference/16hsea/homepage.html **4-6.**

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

■ Society of Petroleum Resources Economists' Second Annual Conference: SPRE 2017 Oil Prices Outlook, Houston, web site: spreconomists.org/flyers/161006%20Flyer.pdf **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.**

International Conference on Oil Reserves & Energy Management, New York, web Site: www.waset.org/conference/2016/10/newyork/ICOREM **10-11.**

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.**

Natural Gas for High Horsepower Summit, Chicago, web site: www.hhpsummit.com/ **11-13.**

OilComm Conference & Exposition, Houston, web site: www.oil-comm.com/ **11-13.**

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

International Conference on Oil Reserves & Production, London, web site: www.waset.org/conference/2016/10/london/ICORP **17-18.**

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.**

Permian Basin International Oil Show, Odessa, Tex., web site: www.pboilshow.org **18-20.**

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.**

IADC Well Control Europe Conference & Exhibition, Copenhagen, web site: www.iadc.org/event/2016-well-control-europe/ **19-20.**

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

USAEE/IAEE North American Conference, Tulsa, web site: www.usaee.org/usaee2016/ **23-26.**

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.**

Produced Water Quality Recycling & Reuse, Denver, web site: www.produced-water-quality-recycling-reuse-rockies.com/ **26-27.**

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

International Conference & Expo on Oil & Gas, Rome, web site: oil-gas.conferenceseries.com/ **27-28.**

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

SPE Annual Caspian Technical Conference & Exhibition, Astana, Kazakhstan, web site: www.spe.org/events/en/2016/conference/16ctce/homepage.html **1-3.**

4th Iran Europe Oil & Gas Summit, Berlin, web site: www.iran-summit.com/**1-3.**

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

7th Annual Summit Operational Excellence in Oil & Gas, Houston, web site: www.opexinoilandgas.com **7-9.**

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.**

International Conference on Oil, Gas & Petrochemistry, Dubai, web site: www.waset.org/conference/2016/11/dubai/ICOGP **16-17.**

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

Project Financing in Oil & Gas, London, web site: www.smi-online.co.uk/energy/uk/conference/Project-Financing-in-Oil-and-Gas **21-22.**

EIC Connect Oil & Gas Conference & Exhibition, Manchester Central, UK, web site: www.the-eic.com/EIC-Connect/OilGas/About-theEvent.aspx **22-23.**

International Conference on Shale Oil & Gas Engineering, London, web site: www.waset.org/conference/2016/11/london/ICSOGE **24-25.**

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.**

OSEA2016 Exhibition & International Conference, Marina Bay Sands, Singapore, web site: www.osea-asia.com **Nov. 29-Dec. 2.**

SPE Thermal Well Integrity & Design Symposium, Banff, Alta., web site: www.spe.org/events/en/2016/symposium/16twid/homepage.html **Nov. 29-Dec. 1.**

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

International Conference on Oil Reserves & Power Issues, Hong Kong, web site: www.waset.org/conference/2016/12/hongkong/ICORPI **5-6.**

International Conference on Energy Engineering & Oil Reserves, Hong Kong, web site: www.waset.org/conference/2016/12/hongkong/ICEEOR **5-6.**

International Conference on Oil Reserves & Energy Technologies, Hong Kong, web site: www.waset.org/conference/2016/12/hongkong/ICORET **5-6.**

Kurdistan-Iraq Oil & Gas Conference & Exhibition, London, web site: www.cwckiog.com/conference/ **5-7.**

SPE/AAPG Africa Energy & Technology Conference, Nairobi City, Kenya, web site: www.spe.org/events/en/2016/conference/16afrc/homepage.html **5-7.**

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.**

IADC Critical Issues Middle East Conference & Exhibition, Dubai, web site: www.iadc.org/event/critical-issues-me-2016/ **13-14.**

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

Gulf of Mexico Oil Spill & Ecosystem Science Conference, New Orleans, web site: web.iagc.org/events/2017-Gulf-of-Mexico-Oil-Spill-and-Ecosystem-Science-Conference-79/details **6-9.**

■ International Conference on Oil & Gas Projects in Common Fields, Bangkok, web site: www.waset.org/conference/2017/02/bangkok/ICOGPCF **7-8.**

International Conference on Oil & Gas Projects in Common Fields, Amsterdam, web site: www.waset.org/conference/2017/02/amsterdam/ICOGPCF **7-8.**

Cuba Oil & Gas 2017 Summit, Havana, web site: www.cubaoilgas-summit.com/ **7-9.**

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

SPE Canada Unconventional Resources Conference, Calgary, web site: www.spe.org/events/en/2017/conference/17urc/homepage.html **15-16.**

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.**

International Conference on Petroleum & Petrochemical Engineering, London, web site: www.waset.org/conference/2017/02/london/ICPPE **16-17.**

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.**

LNG Summit, Houston, web site: lng-usa.com/ **23-24.**

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

MARCH 2017

International Conference on Oil, Gas & Petrochemical Engineering, Rome, web site: www.waset.org/conference/2017/03/rome/ICOGPE **5-6.**

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.**

SPE Latin American & Caribbean Mature Fields Symposium, Salvador, Bahia, Brazil, web site: www.spe.org/events/en/2017/symposium/17lama/homepage.html **15-16.**

SPE Symposium: Iraq—The Petroleum Potentiality & Future of Energy, Amman, Jordan, web site: www.spe.org/events/en/2017/symposium/16abas/homepage.html **15-16.**

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.**

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, Rio de Janeiro, web site: iadc.org/event/2017-iadcspe-managed-pressure-drilling-underbalanced-operations-conference-exhibition/ **28-29.**

APRIL 2017

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

International Conference on Petroleum Industry & Energy, Brisbane, web site: www.waset.org/conference/2017/04/brisbane/ICPIE **3-4.**

International Conference on Oil, Gas & Petrochemistry, Dubai, web site: petrochemistry.madridge.com/ **3-5.**

SPE Oil & Gas India Conference & Exhibition, Mumbai, web site: www.spe.org/events/en/2017/conference/17ogic/homepage.html **4-6.**

Ocean Business 2017, Southampton, UK, web site: www.ths.org.uk/event_details.asp?v0=512 **4-6.**

Differing orientations

BOB TIPPEE
Editor

Work in the upstream oil and gas industry has more in common with modern politics than might initially seem to be the case.

Both endeavors must accommodate orientations sharply different from one another.

The word "orientations" here means beliefs, assumptions, and thought patterns that give direction to perceptions, ideas, and judgments—not what people think but rather how they do so.

The approach of Oil & Gas Journal's annual Geophysics Update, which appears in this issue, always reminds this editor of the disparate orientations upstream professionals bring to the subsurface.

Differing orientations

Geophysicists perceive a given earth volume as a network of elastic media. Geologists see the same section of the planet as a framework of rock layers. Engineers study the cubic footage as a dynamic system of pressures, temperatures, and potential fluid flows.

Each orientation is important. Even more so is the eventual blend of geophysical, geological, and engineering assessments—along with findings of other disciplines such as petrophysics—into a representation, suitable for decision-making, of realms not viewable.

Achieving that blend isn't easy. The upstream disciplines measure different qualities of or about the subsurface, with varying precision, and vary in their terminology.

Interdisciplinary communication therefore can be troublesome. Even with integrated teams having long ago become the standard organizational unit for upstream work, communication remains, by most accounts, a work in progress.

Politics, of course, grapples with many more orientations, usually engaged in mortal conflict.

Former US Sec. of State Hillary Clinton highlighted a treacherous orientation at a fund-raising event for her presidential campaign Sept. 9 in New York City: the urge to treat political issues of tests of character.

To be sure, neither Clinton nor her political party monopolizes this framework for political thinking. Republicans, including Donald Trump, her main opponent, have the same habit.

But Clinton might have pushed an increasingly corrosive orientation to its unsavory limits.

"You could put half of Trump's supporters into what I call the 'basket of deplorables,'" she said, receiving applause. "Right? The racist, sexist, homophobic, xenophobic, Islamaphobic—you name it."

The offense isn't the name-calling, which is annoying enough and more characteristic of Trump than of Clinton. It's the prejudicial condemnation of people on the basis of nothing more than their opinions, usually misrepresented.

Trump supporters have reasons for their choice in candidates, some sound and defensible and others perhaps less so. The same can be said of Clinton partisans.

Politics is supposed to place reasons to support one candidate in fierce competition with reasons to favor the other.

The contest inevitably encompasses personalities along with ideas and descends to name-calling. That's politics.

Now, though, ideas yield instantly to categorical acrimony—"racist, sexist, homophobic," and so forth. Then acrimony turns vicious: "deplorables."

Clinton partly apologized, saying she regretted aiming her censure at fully half the Trump camp.

But arithmetic isn't the problem; preemptive judgmentalism is. Putting defamation before argument, Clinton betrayed an elitist form of bigotry that spoils too much political discourse nowadays, emanating from everywhere along the political spectrum.

Here's a theory about origins of this degenerate orientation. Social media and the internet provide outlets to any and all opinions. In large and growing numbers, people once consigned to obscurity now vent thoughts in forums open to everyone. And they think exposure means their opinions matter.

Well, not necessarily. Opinions matter only to the extent they're logical, expressed well, and supported by facts. Opinions meeting those standards seldom need name-calling and empty moralizing to attract attention.

A republic oriented to noisy hostility masquerading as discourse now finds itself forced to choose between presidential candidates setting records for popular disapproval. Is this just coincidence?

More civil

The upstream oil and gas industry, of course, is more civil than politics. Geophysicists, geologists, and engineers do not impugn the morals of professionals whose orientations toward the subsurface differ from their own.

At least they don't tweet about it or call one another names on YouTube. OGJ


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Weak on energy

For a debate addressing security, prosperity, and "America's direction," the Sept. 26 contest between major-party presidential candidates made strikingly little time for energy. Americans should be relieved. When Democrat Hillary Clinton and Republican Donald Trump did speak to the subject in Hempstead, NY, they didn't inspire confidence.

Clinton dragged "clean energy" into a discourse about jobs. "We can deploy a half a billion more solar panels," she declared. "We can have enough clean energy to power every home. We can build a new modern electric grid. That's a lot of jobs. That's a lot of new economic activity."

Intolerable burdens

Actually, that's a lot of rubbish. Her program would impose intolerable burdens on energy consumers and the federal treasury. When liberals like her fantasize about energy, they ignore dreadfully much.

Three days before Clinton spoke, the Institute for Energy Research (IER) in Houston estimated the cost of Clinton's plan to install 500 million solar panels by 2020 would start at $205.8 billion. That excludes costs of the Clean Power Plan, the Environmental Protection Agency's judicially challenged program to force states to adopt federal energy choices.

The IER assumes the EPA initiative survives and is implemented, leaving 83 Gw of solar capacity to be installed to meet Clinton's goal. It cites Energy Information Administration estimates that costs of new photovoltaic solar capacity amount to $2.48 billion/Gw. Multiplying those values yields IER's number.

Other costs would arise for peaking capacity needed to compensate for the intermittency of solar energy and for the inefficiency of curtailing cheaper baseload generation when the sun shines. "If the solar build-out occurs in Clinton's plan," IER says, "more and more plants will be used inefficiently in the middle of the day—first turned off and then turned back on quickly as the sun is setting."

Yet the conservative think-tank doubts the country needs half a billion solar panels. According to EIA, it says, the US must add 122 Gw of electrical capacity to replace premature retirements related to the Clean Power Plan and to meet new demand. Utilities already plan to add 51 Gw of capacity fueled by natural gas and renewable energy. "If Hillary Clinton's plan is executed, the nation will be paying for additional capacity that is not needed just to reach a spurious goal," IER says.

Not to be underperformed on energy, Trump repeated his "take the oil" bombast while criticizing Clinton about US policy toward Iraq and the jihadist group Islamic State in Iraq and Syria (ISIS). Trump said ISIS formed partly because of the "vacuum" left after the US withdrew military forces from Iraq while Clinton was secretary of state.

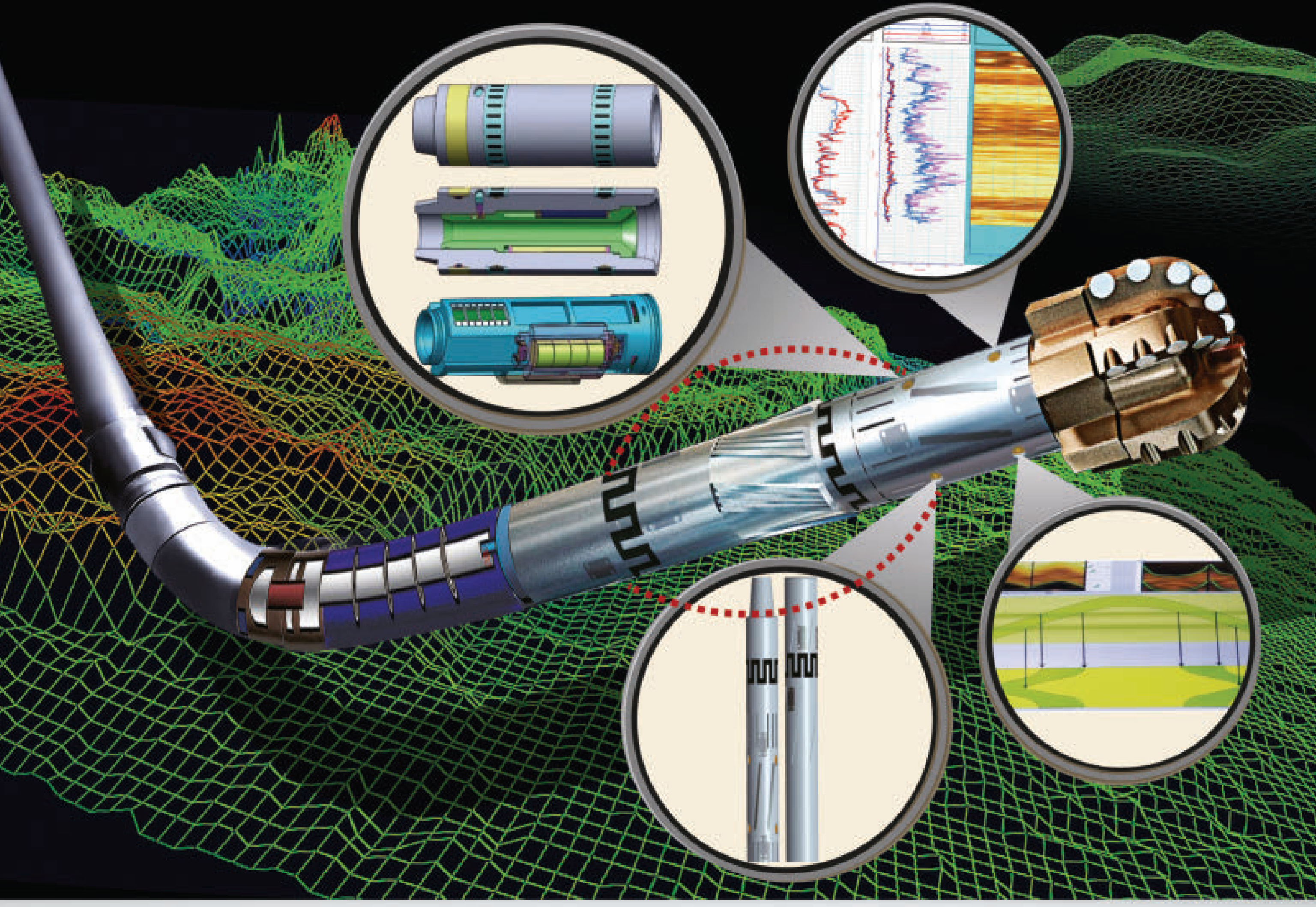
"Had we taken the oil—and we should have taken the oil—ISIS would not have been able to form either because the oil was their primary source of income," he said. "And now they have the oil all over the place, including the oil—a lot of the oil in Libya, which was another one of her disasters."

The best that can be said about this is that the facts are wrong. ISIS oil revenue is known to be down sharply because of a combination of airstrikes, territorial losses, and production declines from fields the group still controls, mostly in Syria. This isn't new. Oil sales had fallen below half of total ISIS revenue by the end of last year.

Recklessness

Worse than ignorance about current affairs is Trump's recklessness with incendiary subjects. Oil not produced can't be "taken" anywhere. It's inseparable from its habitat. Claiming oil thus means claiming land in which it resides. Especially in the Middle East, that means conquest. If that's not what Trump intends, he needs to soften the rhetoric and renounce earlier bluster, which makes him look, not strong, but inept.

Clinton and Trump will debate again Oct. 9 in St. Louis. The hopeful observation is that, on energy, neither of them can do much worse. OGJ



New SEG chief: 'Virtual reality' hones upstream-industry skill

Bob Tippee
Editor

SPECIAL REPORT

How does an industry cutting staffs and budgets hone the geotechnical capabilities it needs to solve increasingly complex problems of the subsurface?

"Learn from virtual reality," suggests William L. (Bill) Abriel, incoming president of the Society of Exploration Geophysicists. His reference is to a series of subsurface models and synthetic data sets developed through cooperative, public research by the SEG Advanced Modeling Corp. (SEAM).

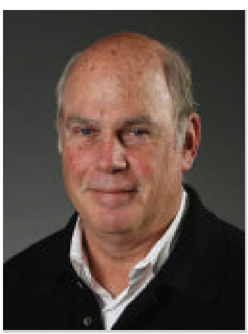
But how does virtual reality apply to real work?

"Imagine you could learn from a reservoir similar to your field—but one that has all the data you ever hoped for and has absolutely no uncertainty," explains Abriel, who worked 36 years as a geophysicist with Chevron Corp. until retiring in May 2015. He helped found SEAM 19 years ago and remains a director. "You could test work flows and procedures for accuracy and efficiency and then use those best practices on your property."

SEAM addresses what Abriel sees as a problem for the upstream oil and gas industry: "Our knowledge management for complex subsurface projects has to improve. A single, smart new computer program is not going to be a solution."

Using SEAM, geophysicists, geologists, and engineers can test theories and transfer what they learn to real subsurface environments. And professionals of all experience levels can use the program for training.

"In the newly restructured industry we need to have valuable crew members," says Abriel, now consulting as principal of Orinda Geophysical in Orinda, Calif. "But I think the question is not 'how many' but 'what type?'"



"Our knowledge management for complex subsurface projects has to improve."
—William L. Abriel

Modern upstream workers must possess "very deep technology roots" in one of the core disciplines as well as the ability to work in integrated teams.

"You've got to have depth, or you can't contribute to the team," he says. "You have to contribute to the team, or depth doesn't count."

To become a top integrated production geophysicist requires perhaps 20 years of work on a variety of subsurface problems with elusive solutions, Abriel says.

"So how do we get people to that position as rapidly and as cheaply as possible?" he asks. "More time in the classroom probably isn't the answer. Working project after project after project so you've collected a lifetime of experience is inefficient, expensive, and risky.

"How do we enable it? The answer is to employ an efficient virtual simulator," analogous to simulators in the aviation industry.

"Flight simulators are very effective tools for rapidly getting experience in complex situations, where the consequences of making a wrong choice are not damaging or expensive," Abriel says.

SEAM development

SEAM projects, in order of their development, cover subsalt imaging in Tertiary basins, core challenges in land seismic, pressure prediction, and "life of field" work flows integrating geology, engineering, and geophysics (see box). The pressure-prediction project focuses on predrill pressure and hazard prediction with surface seismic and electromagnetic data. An offshoot project examines the evolution of pore pressure during production and uses time-lapse (4D) seismic data and reservoir characterization.

Abriel summarizes potential application of SEAM's products by describing the pore-pressure extension project in scientific terms: "We have done the forward problem (generating synthetic data from a managed reservoir) so that people can now do the inverse problem (modeling reservoir dy-

SEG ADVANCED MODELING CORP. (SEAM) PROJECTS

Phase 1: Subsalt Imaging in Tertiary Basins
- Began in March 2007
- Developed numerical earth model representative of a 60-block area of the deepwater Gulf of Mexico
- Simulated 65,000 shot records containing as many as 450,000 traces each for an acoustic data set
- Developed and adopted a data-compression scheme
- Developed multiple classic data subsets for research
- Initiated complementary geophysical simulations (controlled-source electromagnetic, gravity, magnetic, etc.) over the earth model
- Simulated anisotropy and enabled commercial elastic modeling
- Established process for efficient storage and distribution of data and classic data sets

Phase 2: Land Seismic Challenges
- Simulated geophysical data sets for three land challenges:
  Unconventional shale plays (including fractures)
  Arid karst near surface geology
  Foothills overthrust with near-surface topography

Pressure Prediction
- Began in late-2014
- Evaluating and advancing methods for predrill pressure and hazard prediction
- Focuses on deepwater Gulf of Mexico, but findings will be more broadly relevant

Pore Pressure Extension
- Began in fourth-quarter 2015
- Focuses on understanding evolution of pressure, fluids, and geomechanics during production
- Uses time-lapse seismic data, reservoir characterization, reservoir simulation, and geomechanical simulation

Life of Field
- Began late in 2015
- Integrates work flows involving geology, engineering, geomechanics, and geophysics
- Industrial-scale synthetic data set will benchmark full work process for interpretation accuracy and efficiency
- Data can be used to estimate the inverse problem of interpreting reservoir dynamics with only well and geophysical data, yet everything about the underlying reservoir is fully controlled with no uncertainties

namics from simulated field data). We can provide the blind tests for people to take well data and seismic data and try to manage a dynamic reservoir."

Thirty-five oil and service companies have participated in SEAM, which has receives about half its funding from the US government, including the Research Partnership to Secure Energy for America (RPSEA) and National Energy Technology Laboratory. Government involvement accelerated during SEAM's first project.

"We got a certain distance in the subsalt project, and RPSEA came in and said, 'That's great. What more can you do?'" Abriel explains.

SEG patterned SEAM after the Subsalt Multiple Attenuation and Reduction Team (SMAART), a joint venture founded by Abriel and formed in 1998 by BP, BHP Billiton, Chevron, Mobil, and Texaco that operated until 2002.

Abriel says the SMAART JV received credit from Delft University for advancing surface-related multiple elimination (SRME), a standard method of mitigating multiples, or reverberations, in seismic data. The SMAART JV also received the SEG Distinguished Achievement award in 2008 for its work on wide-azimuth and multiazimuth data acquisition, essential in deep water and for complex geology.

Unlike SEAM, SMAART was a private cooperative. But it demonstrated the power of cooperative research among competitors in the oil and gas industry.

"And a fundamental vehicle that enabled results was the power of large-scale, numerical models that represented key challenges," Abriel says.

Appreciation for models

An appreciation for models comes easily to the new SEG president, who used modeling extensively while part of a Chevron team active in early-day application of 3D seismic methods offshore. The team experimented with methods now routine, such as circular and two-boat surveys, ocean-bottom acquisition, and time-lapse (4D) recording.

Led by Robert Wright, Chevron's first development geophysics manager whom Abriel considers a mentor, the team recommended redevelopment rather than divestment of Bay Marchand oil field in the Gulf of Mexico—a 1949 discovery then well into decline. The team acquired, processed, and interpreted 3D seismic data over the field—a risky investment for a mature asset in the mid-1980s—and applied results to development decisions that reversed the production decline (OGJ, Nov. 4, 1991, p. 50).

"Production increased 300%," Abriel recalls, noting the field remains under development.

Abriel then returned from a research-lab assignment to the Gulf of Mexico—thought to have few remaining exploratory targets and disparaged as the "dead sea." The applied research focus, subsalt imaging, became crucial to exploration and development in deep water and opened huge volumes of the subsurface to exploration around the world. The essence of subsalt seismic imaging is model-based processing and analysis.

In that work, and later as geophysical lead on projects elsewhere in North America and in China, Australia, South America, Kazakhstan, Turkey, and Russia, Abriel continued to use models.

Why not have that?

To Abriel, the combined potential of virtual reality and cooperative research should be irresistible to an industry pressured by a slump in commodity prices.

His vision is clear.

"You can conceive of somebody just coming into the business and wanting to be a world-class interpreter. They want to work on carbonates, subbasalt, arctic permafrost, compressional environments, extensional environments, all of the geological environments that are difficult," he says.

"Now picture a library where you check in and check out the training data, say, for carbonates. It comes with instructions that says, 'Welcome to the training library of interpretation. Your job is to interpret this data set. Here are the rules. Here are the basic data parts. Here is the recommended work flow. You don't have to follow this work flow, and if you're creative and you win, congratulations. But if you can't do the recommended work flow then you may have issues becoming a professional interpreter.

"And your reaction would be, 'That's really interesting. I wonder what else I can learn about carbonate interpretation.' Well, here is a bibliography of all the other published examples that relate to this particular type of carbonate. Also, here are other people's answers to this data work flow you just completed.

"It's an open library."

And the "library" is accessible not only by geophysicists but also by geologists and engineers.

"If you have a multitrillion-dollar subsurface management business like oil and gas, why would you not have that?" Abriel asks. "With the proper cooperation, the industry can do this."

Geophysical advance

The new SEG president, who holds a BS in geosciences and MS in geophysics from Pennsylvania State University, won't predict the next major breakthrough in geophysics, saying he can't see beyond about the next 5 years.

Breakthroughs of the past, he says, include digital processing, 3D imaging, and integration of geology with engineering. But the next one is unpredictable.

"If I knew what the next big thing is in geophysics," Abriel says, "I'd make a lot of money."

But he does see an area needing improvement, and it relates—inevitably—to models.

"We don't actually go out every day and dig," he notes. "We sit in our offices and manipulate projects from afar, so we plan and execute with a model. Maps, spreadsheets, and conceptual thinking are definitely models."

Models progress from the conceptual to the illustrative to the functional, Abriel explains.

"Let's assume we've got a project. In the beginning, I've got a mental image of the subsurface, and you've got a mental image. I don't know if my model is the same as yours. I can't tell what's in your head without us illustrating those conceptual models.

"Shockingly, that communicative step is not well handled in our industry. It's not that easy to adequately draw your conception of the subsurface and describe the uncertainties—especially with limited data and a large number of unknowns."

Abriel also sees a problem with operational, numerical models of the subsurface and reservoir: "Once a team gets a complex model built, they are very reluctant to make major changes or rebuild. It's just too time-consuming."

Overall, improvements to integrated subsurface management are crucial to expansion of what Abriel describes as the "social contributions" of his profession.

"Geophysicists are oil finders. We will still do that well into the future," he says.

"But we will also have a greater role in integrated subsurface dynamic management—ground water, CO_2 sequestration, gas storage, oil and gas extraction, hydraulic fracturing, and induced seismicity: We're going to be there." OGJ

SPECIAL REPORT

Global political will did not match gas technology gains, forum told

Nick Snow
Washington Editor

Improvements in technology have increased global natural gas supplies, but delivery problems caused by US and international politics have kept vibrant worldwide markets many people expected 5 years ago from materializing, a senior fellow at the Istituto Affari Internazionali in Rome stated.

"Gas is an easily politicized commodity that producing countries can use to try to influence consuming countries' policies. This helps explain international decision-makers' reluctance to adopt measures to prevent this," Nicolo Sartori said during the US launch of a book, "The Future of Natural Gas: Markets and Geopolitics" at the Atlantic Council on Sept. 22.

The growth of LNG is one positive trend, he said. "It's important not only in Europe, but in China, which has embraced more LNG as a way to reduce its carbon footprint,"

said Sartori, who wrote one of the book's chapters. "Producing countries have had to respond, such as Russia, which has begun to liberalize its internal market.

"But the lack of political will is slowing down the emergence of potential producing regions such as the Eastern Mediterranean and North Africa," he said. "Generally, the book shows how the technological and economic forces to transform the global gas market are there, but the political will has been missing."

Jane Nakano, a senior fellow at the Center for Strategic & International Studies' Energy and National Security Program, who also wrote a chapter for the book, said Japan's response to changing global gas markets has been particularly significant. It has tried to diversify supplies away from Southeast Asia, because they have to move through the South China Sea, and buy more gas at prices that are not linked to crude oil, she noted.

"My chapter also looks at how the so-called US shale revolution could not have happened at a more fortunate time for the Japanese, particularly with changes in their domestic policies," Nakano said.

"Lastly, there's a geopolitical look at Japan's relationship with China and Russia. It comes down to the primacy of Tokyo's relationship with Washington, which constrains the parameters in which it can act."

Limited pipeline options

But Russia also is the only country that has the gas resources that can be shipped to Japan by pipeline, Nakano said. Energy companies in Japan have become much more cautious about this pipeline trade proposal, she said. "When it comes to LNG, I think Japan is more hopeful as Australia has become the major LNG exporter in the region and US supplies are more favorably priced. It wants to make certain that whatever happens between Russia and China, Japan's supply position isn't undermined," she said.

A third participant, Bud Coote, a resident senior fellow at the Atlantic Council's Global Energy Center, said he did not contribute to the book, but had just finished reading it and strongly recommended it. "The future of gas is bright, but it's also a bit smoky. The degree to which governments embrace it as a transitional fuel to move us from dependence on hydrocarbons to fuels which are friendlier to the climate is uncertain," he stated.

The extent to which US and Russian gas compete for European markets is another uncertainty, Coote said. "Currently, low prices in Europe make it difficult for US LNG. Its competitiveness also has been hurt by the recent rise in Henry Hub prices to $3.24/MMbtu from $2[/MMbtu] earlier this year. Sales to Europe would need to be around $5[/MMbtu] to be economic. Russia would like to keep prices below that," he said.

Asked whether Iran could become a bigger force on global gas markets in the next 5 years with its extensive Pars field reserves, the discussion participants said it's uncertain. "Iran's priorities are reinjecting gas into oil fields, improving its petrochemical industry, and satisfying domestic demand," said Coote.

Nakano said, "I understand that Iran might need much of its gas to revitalize its oil production. Asian economies are still interested, but they also want the price to be right, especially with more US exports."

Sartori noted, "The sanction situation still isn't clear, which is discouraging investment. That might be different in 5 more years. Ironically, Iran was expected to supply gas for the Nabucco pipeline in 2003. If you look at where its gas fields are located, it makes more sense for Iran to export its gas as LNG to Asia than to try to build a pipeline to Europe." OGJ

Southern Corridor gas pipelineis on schedule, BP official says

Nick Snow
Washington Editor

The Southern Corridor natural gas pipeline system, which aims to transport gas 2,175 miles from the Caspian Sea to southern Europe, is on schedule and expected to come in under budget, a BP PLC official told an Atlantic Council forum on Sept. 21.

"There still are potential technical delays that remain for this project," said Joe Murphy, Southern Corridor vice-president for BP's Azerbaijan-Georgia-Turkey operations. "This economic environment is different from when the partners signed the contracts, but if we can continue meeting deadlines on time, the project will be economic."

Its three main challenges are getting regional permits in Italy, acquiring land in Greece and Albania, and potential technical delays, he said during a discussion of the project that involves three pipelines:

- The existing South Caucasus Pipeline (SCP), which will be expanded with a parallel pipeline across Azerbaijan and Georgia.
- The Trans Anatolian Pipeline (Tanap), which will transport gas from BP's Shah Deniz field in Azerbaijan across Turkey.
- The Trans Adriatic Pipeline (TAP), which will transport gas across the Adriatic Sea gas through Greece and Albania into Italy.

Initial shipments to Georgia and Turkey are targeted for second-half 2018, with deliveries to Europe expected just over a year after the first gas is produced offshore Azerbaijan, BP said. The first Shah Deniz 2 platform jacket was sent offshore on Sept. 1, it said.

Shah Deniz 2 will be 80% completed by yearend, Murphy said. TAP construction began in Albania and Greece during August and is scheduled to start soon in Italy, where "the key will be on-time, timely approval of permits," he said.

Twenty-five year contracts with companies for Southern Corridor gas give it one advantage over competing projects, Murphy said. Another is its scalability because it permits putting more gas on the market, he told reporters in a post-discussion briefing. "As far as we're concerned, gas supplies are complementary. The more gas we can bring into Europe, the better," he said.

"[State Oil Co. of the Azerbaijan Republic] and Azerbaijan's government have done a fantastic job bringing this public to life, and we really should concentrate on their resources first," Murphy said. "All the others are long-term possibilities—but they're possibilities."

But other participants in the Atlantic Council discussion said that competing projects, emerging alliances, and other potential resources could geopolitically affect the Southern Corridor project.

Big changes since 2011

"[Its] geopolitical significance has changed in the last 5 years as gas prices dropped, the US became a major producer, and more European connections were made," noted Agnia Grigas, a nonresident senior fellow at the council's Dinu Patriciu Eurasia Center. "Particularly, relations between Russia and the West have deteriorated significantly."

While the Southern Corridor project falls within Europe's supply diversification goals, Russia and Gazprom, its gas sales company, want to maintain their markets in southeastern Europe and will continue to fight for them, she said. It's too soon to tell if recent Russian-Turkish rapprochement will mean anything, but initiation of the Turkish Stream project "was a win for Russia," Grigas said.

The US began to support building an East-West energy corridor in the 1990s to make more Caspian Gas available to Europe, said Daniel Stein, a former senior advisor to the Special Envoy for Eurasian Energy at the US Department of State. The Shah Deniz offshore gas discovery changed Azerbaijan's status from a gas transit to producing country in the early 2000s, he said.

"By 2006, Europe began to recognize the need to diversify as more gas became available," Stein said. "If connectors are added, gas will begin to reach countries that now depend on a single supplier. The underlying goal of linking these countries remains."

Murphy said BP feels confident about TAP's technical deliverability, but is more concerned about its getting the necessary permits, particularly in Italy. There's still time to solve that problem before the first deliveries are scheduled to begin there in 2020, he said at the briefing. OGJ

BPTT investment in Trinidad and Tobago could be under threat, executive says

Curtis Williams
OGJ Correspondent

BP Trinidad & Tobago's (BPTT) Pres. Norman Christie has warned the Trinidad and Tobago government that BPTT's $5-billion investment could be under threat if it does not provide clarity on where future natural gas supplies will go and the prices they will attract.

In a blunt speech given Sept. 15, Christie said, "No sensible business person recognizing the context we are in is going to invest approximately $5 billion over the next 3-4 years into natural gas projects without knowing where the gas is going to go, and under what pricing mechanism."

Christie's comments come as the Caribbean twin-island nation and BPTT are expected to negotiate new gas agreements. Negotiations also are due with Atlantic LNG on a new gas-supply contract. BPTT is the second-largest shareholder in Atlantic LNG.

Speaking at the presentation of BP PLC's 2016 Energy Statistical Review, Christie opined that a lack of clarity and investment could lead to more gas shortages in the future, even going so far as to suggest that it could be worse than the country has experienced over the last 2 years.

"Failure to bring clarity to these matters quickly will result in a sharp decline in investments, which will lead to a repeat of the circumstances that have materially contributed to the natural gas supply and demand imbalance that we are currently experiencing—only it will be worse." Christie said.

Trinidad and Tobago has suffered from gas curtailment over the last 4 years and has cost the government hundreds of millions of dollars in taxes. Curtailment also has negatively impacted the country's reputation for reliably supplying its petrochemical customers.

Christie said his comments followed a "longstanding request that the current Gas Master Plan [(GMP)] deliberations must result in clear policy decisions regarding matters such as gas allocation and price and must incentivize upstream investments in an increasingly competitive environment."

Trinidad and Tobago's Energy Minister Nicole Oliverre told the Guardian that the GMP will be going before the Standing Committee on Energy, which is chaired by the country's prime minister, and its findings will then be released to the public.

But Oliverre was clear that the recommendations were based on the findings of the consultants who were hired to develop the plan and also it took into consideration the views of "all the stakeholders."

Asked if that meant the GMP would address the issues raised by Christie, the minister said, "You know that the consultant actually recommended an expanded role for National Gas Co. of Trinidad & Tobago (NGC). The fact is that the NGC provided a secured market for the upstream gas suppliers and a guarantee supply to the downstreamers."

In fact, the role of NGC and ensuring that Atlantic LNG gets its supply of gas appear to be a major point of contention between BPTT and the twin-island's government.

Asked about whether BPTT wanted a review of the role of NGC, Christie admitted this was an issue, saying also it was a key component of getting this right so that there is balance in the risk vs. reward in the business.

Christie said BPTT has worked hard and against significant odds to develop the Juniper and onshore compression projects, which will start production in 2017.

He said, "Beyond these projects though, the next phase of planned major developments starting with Angelin are still not sanctioned and will not be sanctioned unless policy decisions properly recognize the context within which we are operating. We at BPTT have always said that it is not a matter of whether or not the hydrocarbon resources are here in Trinidad, but rather it is matter of how industry and government continue to work together to create an enabling environment to efficiently monetize those resources with fair returns for all stakeholders." OGJ

Deloitte: Survey shows raised optimism among oil executives

A recovery in the oil and gas industry may have already begun or will begin next year, according to more than half (59%) of the oil and gas professionals surveyed recently by Deloitte. This would mean that the industry downturn—now 2 years old—may be drawing to a close, the survey suggests.

The survey—"2016 Oil & Gas Industry Survey: Optimism Emerges in the Aftermath of a Long Downturn"—illustrated renewed confidence driven by expectations of rising commodity prices and increased capital expenditures

"This recovery in many ways mimics the pattern of the recovery from the Great Recession," said John England, vice-chairman, Deloitte LLP and US and Americas oil and gas leader. "If last year was the year of hard decisions, 2017 will be the slow road back. Companies are generally optimistic that prices will rise to a more sustainable level next year; however, they understand that even if we see an uptick in price, the industry likely won't fully recover until 2018 or beyond."

Indicated trends

Deloitte's survey shows that most respondents expect to see an increase in capital expenditures in 2017. In fact, Deloitte says, the upstream side of the business is the most optimistic about a recovery.

Other trends indicated by the survey include:

- A "key threshold" oil price of $60/bbl.
- 71% of those surveyed believe it is possible for the 2016 average price to reach $40-60/bbl—or for prices to at least rise to that range by yearend (61%).
- 28% of respondents foresee crude-oil prices returning to $80-100/bbl for West Texas Intermediate and Brent by 2020.
- For 2017-20, 70% of the respondents expect gas prices to range $2.50-3.50/MMbtu, with one-third anticipating this price band in 2017.
- Survey respondents expect Asian gas prices to be much higher than Henry Hub to the end of 2016-20.
- 81% believe international prices will range from $5-10/MMbtu. However, an increasingly optimistic view (29%) is for prices to be in the $10-15/MMbtu range by 2017 to 2020.

When asked about policy or geopolitical issues affecting their companies, 45% of survey respondents indicated decisions made by the Organization of Petroleum Exporting Countries as having the most impact on the upstream business. Next in line as having an impact on the business were US tax and policy decisions (38%). Environmental and local stakeholder issues were ranked third as concerns at 34%.

Of course, those surveyed see the possibility of "profound energy policy changes" that may be enacted, but the scope and extent of impact of those changes would depend largely on the outcome of the upcoming presidential election. OGJ

Rice Energy to buy Vantage Energy for $2.7 billion

Matt Zborowski
Assistant Editor

Rice Energy Inc., Canonsburg, Pa., has agreed to acquire Englewood, Colo.-based shale gas producer Vantage Energy LLC and Vantage Energy II LLC for $2.7 billion including debt.

Vantage's exploration and production assets include 85,000 net core Marcellus shale acres in Greene County, Pa., with rights to the deeper Utica shale on 52,000 net acres. The firm also has 37,000 net acres in the Barnett shale of North Texas. The assets' combined second-quarter net production was 399 MMcfed, with 65% from Appalachia and 35% from the Barnett.

Its midstream business covers 30 miles of dry gas gathering and compression assets, the entirety of which Rice Energy in turn will sell to affiliate Rice Midstream Partners LP for $600 million. Rice Energy has pledged to dedicate its acquired Pennsylvania acreage to RMP for gas gathering, compression, and water services.

Following completion of the two deals, expected in the fourth quarter, Rice Energy will have 231,000 net acres in the Marcellus and Ohio Utica cores with an inventory of 1,164 drilling locations, and RMP will have a core dry gas Marcellus position covering 199,000 acres in Washington and Greene counties in Pennsylvania.

"Our transaction financings are meant to strengthen Rice Energy's balance sheet even further, including positioning us to capture an additional 20,000-40,000 acres of leasehold adjacent to our existing position," said Daniel J. Rice IV, Rice Energy chief executive officer, upon announcement of the Vantage deal.

Rice Energy has increased its Marcellus drilling and completion capital investments for 2016 by $40 million to reflect ongoing activity on the acquired acreage. In 2017, Rice Energy expects a drilling and completion budget of $950 million–1.125 billion and net production of 1.280–1.355 bcfd of gas equivalent, which is 70% above its increased 2016 estimate based on the midpoint of the guidance.

Vantage in May outbid Rice Energy for Pennsylvania Land Resources LLC, a subsidiary of bankrupt Alpha Natural Resources Inc., in a $339.5-million transaction. The deal comprised leasehold interest in 27,400 net undeveloped Marcellus acres, including rights to the deep Utica on 23,500 net acres, in central Greene County.

Formed in 2006 through investments by private equity firms Quantum Energy Partners, Riverstone Holdings LLC, and Lime Rock Partners, Vantage entered the Barnett in 2007 and Marcellus in 2010. The firm this month filed for an initial public offering with the US Securities and Exchange Commission (SEC) after canceling one 2 years earlier because of falling commodity prices. OGJ

Petrobras slashes 5-year spending plan by 25%

Petroleo Brasileiro SA has set its planned spending for 2017-2021 to $74 billion, down 25% from its 2015-2019 plan, under the direction of new Chief Executive Officer Pedro Parente (OGJ Online, May 20, 2016).

The Brazilian state-owned firm said it hopes to divest $19.5 billion in assets over the next couple of years, pledging to exit biofuel production, LPG distribution, fertilizer production, and investments in petrochemicals. Petrobras has maintained a divestment target of $15.1 billion for 2015-16.

Additional costs savings are expected through increasing strategic partnerships in exploration and production, refining, transportation, logistics, distribution, and sales.

The moves are part of an effort to cut the firm's $125 billion debt load. The financial target determines that the company's net debt be equivalent to 2.5 times its cash generation in 2018. According to Petrobras' 2015 annual balance sheet, this index reached 5.3 times.

Most of the investment under the new 5-year plan, 82%, will be directed toward exploration and production activities, 17% to refining and natural gas, and the remaining 1% to other areas.

Petrobras is targeting 2.8 million b/d in oil and natural gas liquids production by 2021, sustained by operating performance and the application of new technologies. The firm notes the average time to build an offshore well in the Santos basin presalt cluster has been cut to 54 days in 2016 from 152 days in 2010.

Production startups are expected in 2017 from the Tartaruga and Mestica projects in the post-salt Campos basin, Lula Norte and Lula Sul in the Santos basin presalt, and the Libra extended well test. Next year, Berbigao, Lula Extremo Sul, and Buzios 1, 2, and 3, all in the presalt cluster, are expected to come on stream.

Slated to begin flow in 2020 are Buzios 5, the Libra pilot, and the Sepia pilot in the presalt, and Module 1 of the Marlim revitalization project in the Campos basin post-salt area. In 2021, production startup is scheduled for Module 2 of Marlim and the integrated Parque das Baleias project in the Campos basin, as well as Itapu and Libra 2.

"In the next couple years, we will concentrate on recovering Petrobras' financial strength as an integrated energy company that is focused on oil and gas," said Parente. "In the total 5-year horizon this plan encompasses, we propose that the company will have been restructured, that it [has] unquestionable governance and ethical standards in order to support increased, but realistic production, and that it be able to invest and position itself in the transition process the global energy market is going through." OGJ

IHS Markit: Apache's Alpine High discovery in 'historically underperforming area'

Analysis from IHS Markit indicates Apache Corp.'s southern Delaware basin Alpine High oil and gas discovery sits in a "historically underperforming area" where previous well results from other operators have been poor.

Apache has secured more than 300,000 contiguous acres, mainly in Reeves County, Tex., that it says hold an estimated 75 tcf of gas and 3 billion bbl of oil in the Barnett and Woodford shales alone (OGJ Online, Sept. 7, 2016). The firm also sees oil potential in the shallower Pennsylvanian, Bone Springs, and Wolfcamp formations.

"Nearly 10 years ago, several Permian basin specialist companies left the area after drilling a handful of unsuccessful wells," explained Imre Kugler, senior consultant, energy research, at IHS Markit, and lead author of a new report entitled IHS Energy Plays & Basins Analysis—Apache's Alpine High: An Early Look.

"Admittedly, unconventional drilling and completion technology has advanced a good bit since then, but well performance is critical, particularly in the current oil-price environment," Kugler said. "You don't have as much of a cushion or tolerance for failure or poor performance at today's prices as you did at $120[/bbl]."

Kugler said some quality Wolfcamp wells owned by a variety of operators sit within 10 miles of the Apache acreage. However, there are also some poor performing wells nearby, so "it remains to be seen whether Apache's initial success in the play will carry over into the Wolfcamp formation," he said. "It's too early to tell, but more drilling and appraisal will be necessary."

According to the IHS Markit analysis, early economics for the area indicate gas production breaks even near $2.50/Mcf, and oil production breaks even at $55/bbl assuming a constrained 24-hr initial production rate equates to peak-month production and a $5-million well cost, the midrange guidance. If recently published IP rates indicate true 24-hr rates, then breakevens for the play will be closer to $65/bbl and $3/Mcf.

Kugler also noted interest in the Woodford gas play where the ratio of oil at peak is about 15%, but a six-well sample shows a wide variance of 1-19%. The projections only consider Woodford as there is just one Barnett well drilled in the area to date.

Kugler said "to make this part of the play viable, gathering infrastructure will need to be built out," adding that "the play's proximity to the nearby Waha hub helps." He noted that associated gas production has doubled from 0.5 bcfd to nearly 1 bcfd during 2014-16 with Wolfcamp and Bone Spring development. "To fully monetize production from this gas and NGL play, additional takeaway capacity may be required," he said.

Apache is increasing its 2016 capital spending by $200 million, more than 25% of Apache's total capital spending program, to accelerate the delineation and development of Alpine High. OGJ

Climate guidance is not necessarily requirement, CEQ chief testifies

Nick Snow
Washington Editor

Final climate change and greenhouse gas (GHG) emissions guidance that the White House Council on Environmental Quality (CEQ) issued to federal agencies is not necessarily a requirement, CEQ Managing Director Christy Goldfuss told the US House Natural Resources Committee. But several Republican members warned that it is in danger of being interpreted as such.

"The guidance fits in [the National Environmental Policy Act's] regulatory framework, which requires agencies to look at the consequences of their actions," Goldfuss said during the committee's Sept. 21 hearing on the final guidance that CEQ issued in August (OGJ Online, Aug. 3, 2016). "It says that when it comes to climate change, it recommends using the tools that are available. If those tools are not, the agencies are advised to note this."

CEQ has taken pains to explain that the guidance is not a requirement because it has no enforcement authority, she told the committee. "We urge agencies to look at the reasonably foreseeable impacts of the decisions they are making. That is what NEPA requires," Goldfuss said.

But committee chairman Rob Bishop (R-Utah) said that Wildearth Guardians could cite the guidance when its Aug. 25 lawsuit to keep the US Department of the Interior and the US Bureau of Land Management from issuing oil and gas leases on onshore federal land comes to trial in US District Court for the District of Columbia.

"If a court uses your voluntary guidance as something an agency should do, doesn't it become a de facto responsibility? This is a dangerous and difficult area," Bishop said.

Goldfuss emphasized that the climate impact guidance has limitations. It specifically does not require that carbon emissions' social costs be addressed, that specific economic impacts be considered, that determinations include life cycle analysis, or that agencies conduct additional analyses, she said.

"Today, taking into account climate change in environmental impact assessment processes has become a standard practice that has been adopted by federal agencies, state agencies, international bodies, and public and private organizations around the world," she said.

"The final CEQ guidance is built on this record of experience to help ensure that NEPA analysis provides the public and federal agencies with a clear picture of how many types of federal actions can [affect] climate change issues and identify opportunities to build climate resilience," Goldfuss said.

Improving climate impact resilience is essential, she said. The White House Office of Management and Budget, in its fiscal 2017 budget request, noted that the nation has spent $257 billion already on climate change's direct costs, Goldfuss said. "It makes sense to consider these pieces of information when designing a bridge, highway, or other infrastructure project. We recommend, where it's appropriate, for agencies to consider how these projects will be affected by a changed environment," she said.

"As someone who worked in an agency, I can tell you that nothing delays things more than uncertainty," Goldfuss said. "This guidance allows agencies to move beyond the debate and do analysis. It encourages them to use the tools that are available, and when the tools aren't available, to move on." OGJ

US refiners complete MSAT II-compliance projects

Robert Brelsford
Downstream Technology Editor

Placid Refining Co. LLC has commissioned a grassroots dividing wall column (DWC) reformate splitter as part of a project to comply with US regulatory requirements for benzene content of finished gasoline at its 75,000-b/d refinery in Port Allen, La.

Equipped with KBR Inc.'s proprietary Distill-Max DWC technology, the reformate splitter column is designed to remove benzene from gasoline streams to ensure the finished product complies with limitations under the US Environmental Protection Agency's Mobile Source Air Toxics Phase II (MSAT II) final rule, KBR said.

Use of Distill-Max DWC technology—which combines two distillation columns within a single shell to enable three or more products to be separated from a feed stream—has resulted in a minimum energy savings of 20% for the Port Allen refinery since startup of the new reformate splitter, according to the service provider.

Alongside technology licensing, KBR said its scope of work on the project included delivery of basic column design, supply of column trays and internals, as well as commissioning support.

First announced in February 2013 and approved in September 2013, the Port Allen project was to involve necessary modifications and additions to existing processing units so that the refinery could effectively comply with MSAT II, which finalized by EPA on Feb. 26, 2007, limits the annual average of benzene content in gasoline to 0.62 vol % by refiner and to 1.3 vol % by refinery, Placid said in filings to the Louisiana Department of Environmental Quality (LDEQ).

The new DWC reformate splitter allows the refinery to pro-

Placid Refining Co. LLC has commissioned a grassroots DWC reformate splitter as part of a project to comply with US regulatory requirements for benzene content of finished gasoline at its 75,000-b/d refinery in Port Allen, La. Photo from Placid Refining.

duce a benzene-lean MSAT reformate stream and a benzene-rich MSAT benzene stream, the latter of which is loaded off site for sale via barges, according to LDEQ.

HollyFrontier Corp., Dallas, also has completed a MSAT II compliance project involving two DWCs equipped with KBR's Distill-Max technology at its 135,000 b/sd refinery in El Dorado, Kan., KBR said.

As part of HollyFrontier's naphtha fractionation project (OGJ Online, Sept. 8, 2015), KBR delivered a grassroots four-product DWC, which is the first DWC of its kind ever to be implemented at a refinery.

Outfitted with Distill-Max Plus, the four-product DWC (vs. a conventional column design) for the naphtha fractionator has resulted in a 25% reduction of the column area as well as a 30% energy savings for the refinery, according to KBR.

The service provider also delivered a revamp of an existing DWC in the overhead section of a crude unit that, alongside improving separation efficiency, has reduced the energy required to remove butanes from straight-run naphtha by 25% vs. use of a conventional three-product column.

Along with technology licensing, KBR's scope of work on the new and repurposed DWCs at El Dorado included basic column design as well as supply of column trays and internals, the provider said. OGJ

More discussion of energy needed in 2016 elections, API's Gerard says

Nick Snow
Washington Editor

American Petroleum Institute Pres. Jack N. Gerard expressed hope that more US political candidates—from Hillary Clinton and Donald J. Trump on down—would mention energy more prominently in their 2016 election campaigns because it has contributed so much to the US economic recovery since the end of 2008.

Voters have consistently identified energy and economic growth as their main concerns this year in surveys, Gerard told reporters during a Sept. 26 teleconference hours before the two leading presidential nominees' first debate. "We believe you can't have a conversation about any election topic without including energy and, in particular, oil and gas because of its significantly lower prices," he said.

"Many of the income equality and poverty questions are being addressed by lower energy costs," Gerard said. "If

President Obama's campaign message in 2008 was 'Yes, We Can,' the oil and gas industry's in 2016 is 'Yes, We Did.'"

There's a growing recognition now that energy is a key part of the US economy, although issues vary across the country from production in some areas to transportation in others and consumption elsewhere, he said.

"This election is a good time to discuss the various visions," Gerard said. "There's an opportunity to recognize differences between professional agitators and people who genuinely want to help run the country."

The API leader saw a potentially disturbing precedent for candidates to consider, referring to the US Departments of Interior, Justice, and the Army joint action to withdraw an issued permit for the proposed Dakota Access crude oil pipeline in response to growing protests by Indian tribes and other groups hours after a federal judge in Washington rejected a request that the permit be stayed (OGJ Online, Sept. 12, 2016).

"It's important that a project is allowed to go forward when the government has approved it and a court upholds that approval," Gerard said. "Otherwise, there's a chilling effect when companies grow uncertain that government decisions might be reversed arbitrarily." OGJ

BHI: US rig count up 5 to 511

Matt Zborowski
Assistant Editor

The overall US drilling rig count gained 5 units to 511 rigs working during the week ended Sept. 23, according to Baker Hughes Inc. data. Three gas-directed and 2 oil-directed units began operations.

Up in 14 of the last 17 weeks, the overall count has now added 107 units since the week ended May 27. Compared with the week ended Dec. 5, 2014, after which began a steep dive in US drilling activity, the count is still down 1,409 units.

The recent drilling rebound has been characterized by steady increases devoid of major rig and equipment constraints. With the overall count expected to continue to rise over the next 2 years, however, analysts at financial services firm Raymond James & Associates Inc. foresee "meaningful bottlenecks" emerging due to low spending on oil field infrastructure during the downturn.

The primary culprit is expected to be the beleaguered pressure pumping industry, whose readily workable US frac fleet is forecast to be down 35-50% by 2017 compared with 2014 levels, the analysts said in an industry brief this week. Some 3-4 million hp has been removed permanently during the downturn while another 3-4 million hp will require major investment to be refurbished into working condition.

"With modest attrition on the nearly 2,000 rigs running in 2014, the market should be able to supply additional drilling rigs—of varying qualities—beyond 1,000 active rigs," they said. "The problem will be, if wells cannot be completed, why drill them?"

RJA believes the industry's initial bottleneck point will be reached next year at 800 rigs working. The average overall US rig count for 2017 is also expected at 800 units, rising to 1,100 in 2018, even though the firm projects industry cash flows will likely justify higher counts.

Oil-rig streak holds steady

US oil-directed rigs have now risen in 15 of the last 17 weeks, adding 102 units over that time to total 418 rigs working, down 1,191 units since their peak on Oct. 10, 2014. Gas-directed rigs now total 92, and have stayed within a range of 81-97 units since the beginning of March.

The overall increase comprised onshore units, which are up 6 to 488. Rigs engaged in horizontal drilling gained 8 units to 402, a rise of 88 units since May 27 but down 970 since their peak on Nov. 21, 2014. Directional drilling rigs edged up a unit to 49.

Several of the major oil-and gas-producing states made either a modest increase or modest decrease. Texas and Oklahoma led the way in increases, each gaining 2 units to 246 and 67, respectively. Texas is now up 65 units since May 13 but down 712 since a peak on Aug. 29, 2008.

The Cana Woodford and Mississippian each added a unit to hit respective totals of 33 and 3. The Eagle Ford was down a unit, settling at 37. Down 1 unit to 201, the Permian declined for just the second time in 19 weeks.

In news of yet another firm banking on the West Texas and southeastern New Mexico basin, Calgary-based Encana Corp. this week completed a public offering to raise $1 billion, a portion of which will go toward boosting its Permian rig count and doubling its number of producing wells in the play during 2017 vs. the 2016 total.

North Dakota, Pennsylvania, Alaska, and California each rose a unit to 28, 22, 6, and 6, respectively. As with its home state, the Williston was up 1 to 28, while the Marcellus also increased a unit to reach 30.

Louisiana, New Mexico, and West Virginia each lost a unit to respective totals of 40, 27, and 9.

One rig drilling in inland waters was idled, bringing that tally to 3. The tally of active offshore rigs was static at 20.

Canada topped the US with a 6-rig rise to 138, up 102 units since May 6. Gas-directed units increased 5 to 61 while oil-directed units gained 2 to 77, up 69 since Apr. 8. OGJ

Aramco chief calls for chemical expansion

Saudi Aramco wants to become "a top-three player in ethylene, paraxylene, and benzene" and is increasing the integration of its refining and petrochemical industries to pursue that goal, says Pres. and Chief Executive Officer Amin H. Nasser.

The company is researching cracking technologies able to increase the petrochemical yields of crude oil, Nasser said Sept. 26 at a conference in Bahrain, encouraging neighboring countries to do the same.

"More liquids cracking for petrochemicals would lock in larger oil sales volumes for our region's producers over the long term," he said.

Aramco also envisions "the elimination of the entire refining step in the process so that we can introduce crude oil directly into the petrochemicals manufacturing process," he said.

He mentioned Aramco's plan to conduct a joint feasibility with Saudi Arabian Basic Industries Corp. of a fully integrated crude-to-petrochemicals plant (OGJ Online, June 28, 2016).

Aramco's goal to become a top producer of basic olefins and aromatics fits the first of four strategies Hasser described for increasing Persian Gulf producers' share of global chemical markets:

- Enhancing value chains "by producing more differentiated, higher-value commodity petrochemicals, along with their derivatives."
- Converting commodity petrochemicals into higher-value products.
- Increasing the manufacture of higher-value products by expanding from commodities to specialty chemicals.
- Deriving "even more value from those specialty chemicals by building higher-value downstream manufacturing and conversion industries." OGJ

Alberta approves 95,000 b/d in oil sands projects

Matt Zborowski
Assistant Editor

The Alberta government has approved three oil sands projects representing 95,000 b/d of oil production and $4 billion (Can.) of potential investment.

Blackpearl Resources Inc.'s Blackrod steam-assisted gravity drainage (SAGD) development, Surmont Energy Ltd.'s Wildwood SAGD development, and Husky Energy Inc.'s Saleski development now await final investment decisions, the timetables of which are uncertain given lower crude oil prices.

Although oil sands production costs are falling, an IHS report late last year estimated that SAGD projects required a West Texas Intermediate price of $55-65/bbl to breakeven in 2015.

The 80,000-b/d Blackrod project is 200 km southwest of Fort McMur-ray in the Athabasca region. As of Dec. 31, 2015, the firm's independent reserves evaluator assigned 180 million bbl of proved plus probable bitumen reserves to its Blackrod leases and an additional 453 million bbl of contingent resource, representing a production life of more than 20 years.

"In addition to extensive delineation drilling and seismic coverage over the application area, we have run a successful SAGD pilot at Blackrod during the last 4 years that validated the SAGD process on our lease," said John Festival, Black-Pearl president and chief executive officer. The pilot averaged 550 b/d of oil over the last 16 months with an oil-steam ratio of 2.8.

The 12,000-b/d Wildwood project is 65 km south of Fort McMurray, immediately west of ConocoPhillips Canada's Surmont oil sands project. The SAGD project comprises 800-m long horizontal well pairs drilled at depths of 485 m.

Surmont Energy says Wildwood's design incorporates comprehensive measures to minimize environmental impacts, including a low surface footprint, no surface water use, recycling up to 97% of water produced by the bitumen extraction process, utilization of natural gas to fuel steam generation and electricity cogeneration, and progressive surface reclamation throughout the life of the project.

The firm assesses production from the Wildwood leases to be capable of expanding to 30,000 b/d assuming required additional regulatory approvals.

The 3,000-b/d Saleski project is 100 km to the west of Fort McMurray. Husky holds the oil sands rights in the bitumous Grosmont, Ireton, and Nisku formations, covering more than 241,000 acres.

The proposed developments by the Calgary-based firms will fall under the new 100-megatonne greenhouse gas emissions limit for oil sands projects, announced with Alberta's Climate Leadership Plan late last year. The Alberta government says the three projects combined represent about 2.5 megatonnes of GHG emissions. OGJ

Canada expands review of proposed BC grassroots refinery project

Robert Brelsford
Downstream Technology Editor

The Canadian government has called for the creation of an independent review panel to evaluate the environmental assessment (EA) for Kitimat Clean Ltd.'s Kitimat Clean Refinery Project (KCRP), a proposed grassroots facility to be built about 13 km north of Kitimat, BC (OGJ Online, Aug. 16, 2016).

Canada's ministry of environment and climate change (MECC), decided on Sept. 9 to refer KCRP's EA to a review panel after considering public concerns regarding the project's potential to cause significant adverse environmental effects, the office of the MECC and the Canadian Environmental Assessment Agency (CEAA) said in a joint release.

Alongside MECC's decision, CEAA said it also will make funding available to assist eligible individuals of the public and indigenous groups to participate in the review panel's environmental assessment in several ways, including reviewing and providing comments on the review panel terms of reference and the environmental impact statement; preparing for and participating in future public hearings; and commenting on potential conditions that would be required if KCRP is allowed to proceed.

Funding also would be allocated to enable indigenous groups to participate in consultation activities following the submission of the panel's report, CEAA said.

Catherine McKenna, minister of MECC, has set timelines for the project's environmental assessment as follows:

- Prepanel phase, or the timeline for establishing the review panel: 90 days from the project referral date.
- Panel phase, or the timeline for the review panel to submit its report to MECC: 480 days from the date of the review panel's establishment.
- Post-panel phase, or the timeline for the minister of MECC to issue a decision statement on the review panel's report: 150 days from the date of the review panel report's submission.

The above timelines do not include the time it takes Kitimat Clean to complete its work or gather information required for the environmental assessment, CEAA added.

Under its current proposal, Kitimat Clean plans to build and subsequently decommission the following KCRP components upon conclusion of the project's 50-year lifespan:

- A grassroots refinery capable of processing 400,000 b/d of bitumen to produce 460,000 b/d of finished fuels.
- A bitumen-receiving facility, including a rail yard and bitumen offloading site.
- A tank farm containing 54 tanks of various capacity.
- A 23-km fuel-delivery pipeline corridor consisting of three 18-in. pipelines.
- A marine terminal facility for loading refined products on very large crude carrier tankers for export.

While Kitimat Clean anticipated bringing KCRP on stream in 2024, MECC's recent requirement for the 16-month review panel process likely will delay project startup by at least as many months. OGJ

Ocean-bottom seismographs improve data resolution offshore Australia

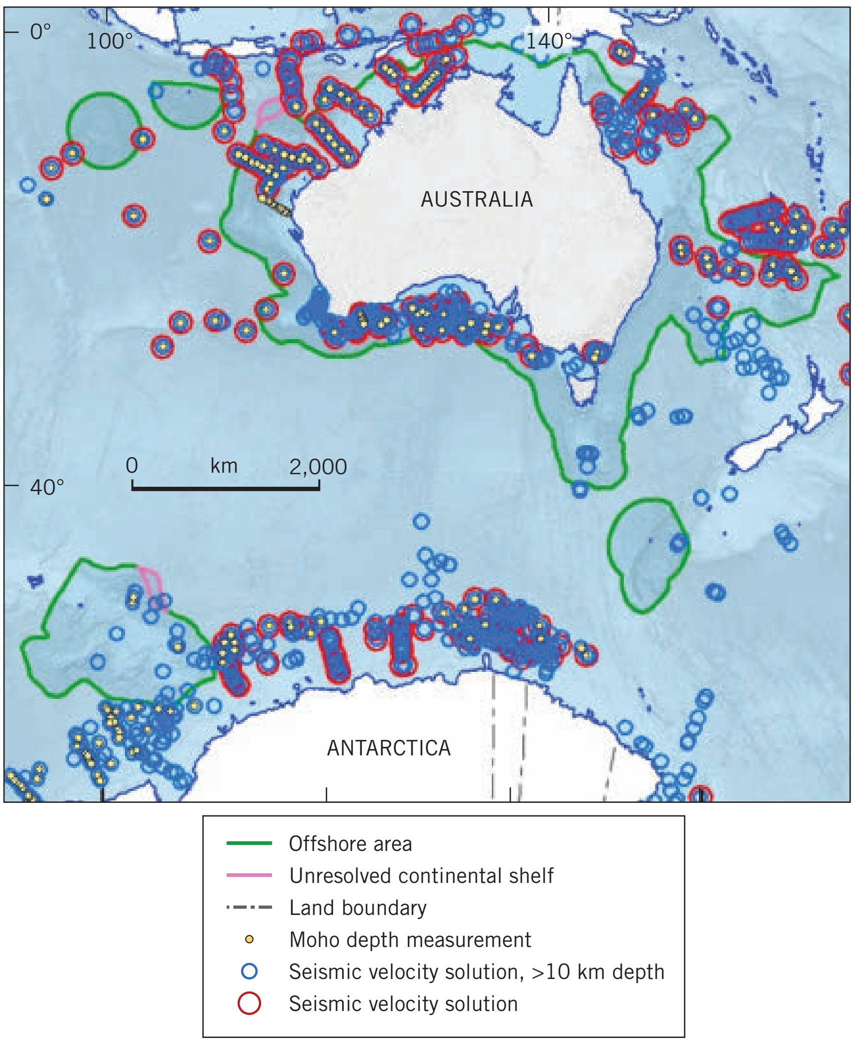
Tayvis Dunnahoe
Exploration Editor

Ocean-bottom seismic (OBS) has emerged in recent years as a mainstream offshore exploration technique. Operators have benefitted from supplementing conventional surveys with OBS data. AuScope Ltd. invested in a fleet of ocean-bottom seismographs (OBSs) that are maintained by Australia's national geological survey to aid in mapping its offshore territories.

A project is planned to investigate nearshore gas deposits off New South Wales on Australia's East Coast using OBS as a cost-effective method for supplementing conventional seismic acquisition in a shallow water environment.

REFRACTION-SEISMIC VELOCITY MEASUREMENTS

FIG. 1



Fleet response

The Australian marine jurisdiction is the third largest in the world and nearly twice the size of the continent's land mass. "Existing refraction seismic studies have poor coverage over Australia's marine jurisdiction, and some parts of the Australian Antarctic Territory are better covered than the mainland by such measurements," said Alexey Goncharov, principal scientist at Geoscience Australia (Fig. 1).

EXPLORATION & DEVELOPMENT

SPECIAL REPORT

Refraction seismic studies require seismic signals be recorded at much larger shot-receiver offsets than are conventionally used in reflection (streamer) surveys. The Australian National OBS Fleet was created to improve seismic velocity coverage in deep-crust settings. Constraining subsidence and hydrocarbon maturation modeling both require crustal thickness measurements and petrological composition information, which are difficult to obtain from reflection data.

BOWEN BASIN ANALOG

FIG. 2

Fig. 2a

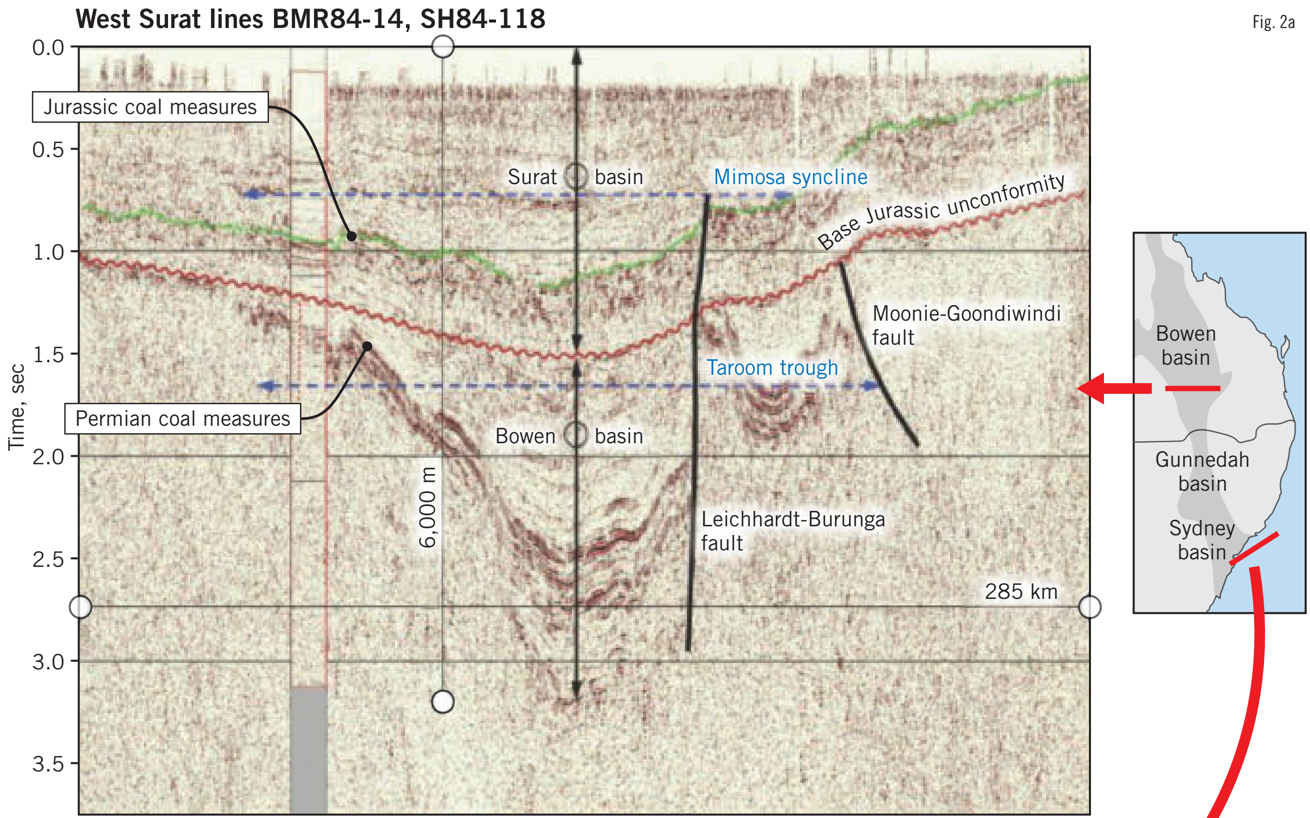
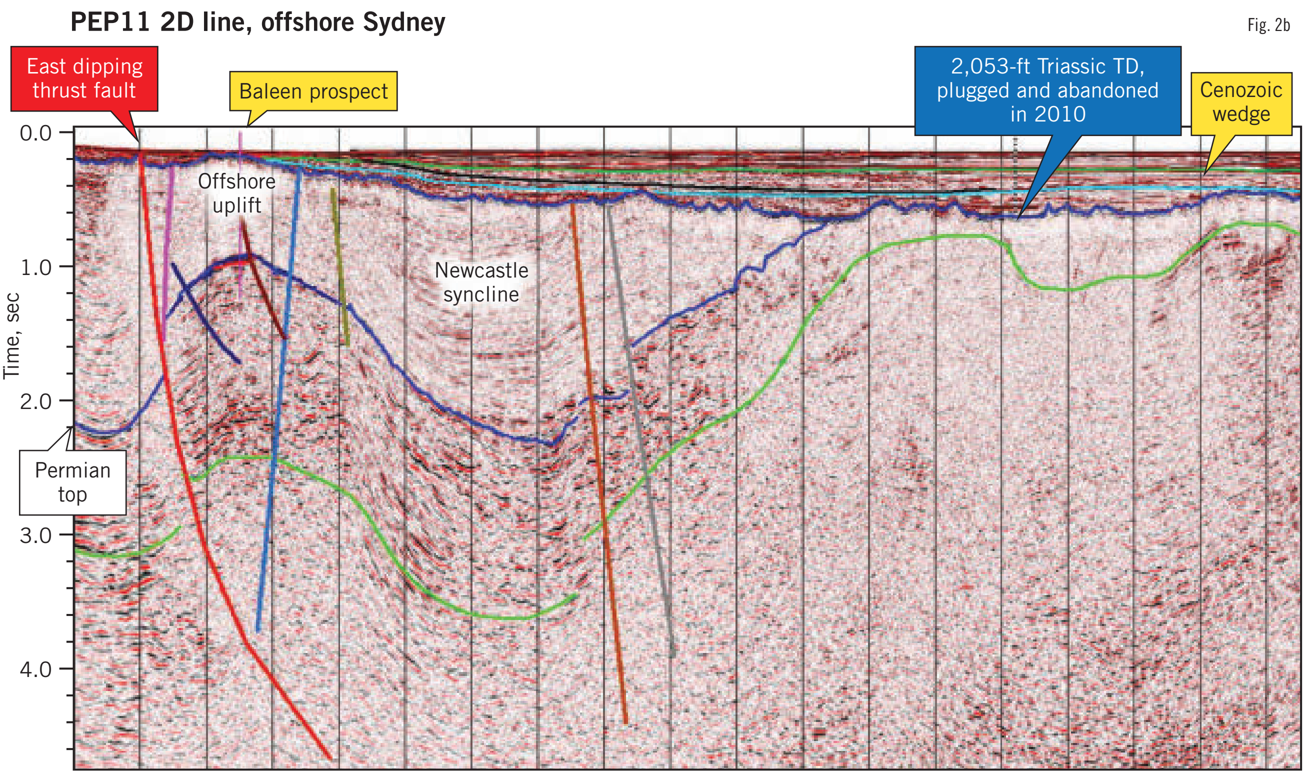
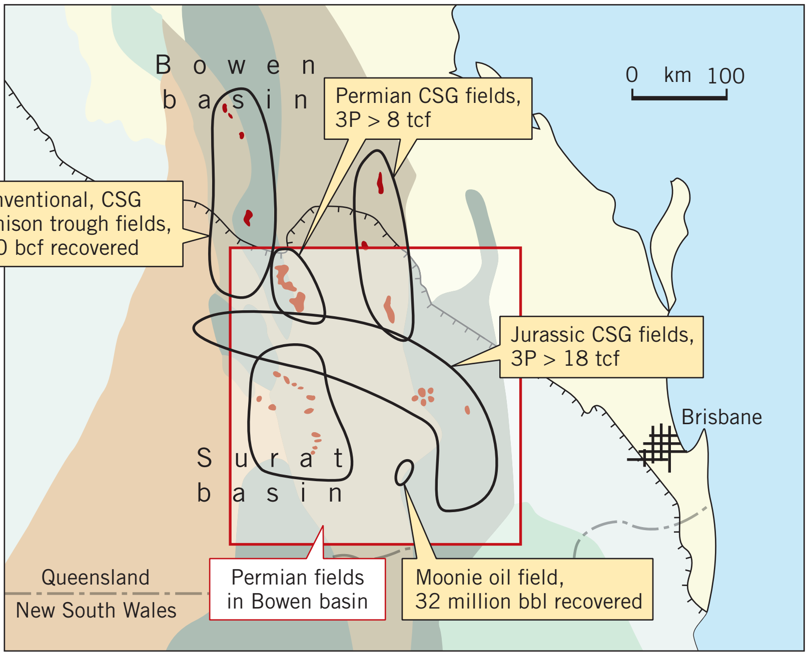


Fig. 2b



BOWEN BASIN PRODUCTION

FIG. 3



The more commonly used OBSs, so called short-period instruments, have frequency-pass bands starting at 4.5 hz. Geoscience Australia's first experiments with BBOBSs proved that broadband airgun arrays with moderate (by refraction seismic standards) volumes of 4,630 cu in. were sufficiently strong to generate recordable signals at large (tens of km) offsets.

OBS data collected during commercial seismic surveys in Australian territorial waters in 2014-15 proved it is possible to comprehensively image crust and upper-mantle velocity distributions from analysis of reflected and refracted phases generated by an industry-standard broadband airgun array. "This means that valuable pre-competitive information on a regional scale can be obtained as a by-product of commercial seismic surveys," Goncharov said.

Better seismic velocities than those derived from conventional streamers are also needed for both prestack depth migration and depth conversion of reflection data, particularly in the deeper crust. "These drivers motivated our industry partners to support the establishment of the fleet," Goncharov said.

The Australian National OBS Fleet is part of AuScope's Australian Geophysical Observing System (AGOS), an initiative of the Australian government funded through the Education Investment Fund. Instruments were delivered by the manufacturer, Guralp Systems Ltd. (UK), in late 2013. Shell Australia and Woodside funded the OBS acceptance trials and inaugural deployments in 2014-15.

Parameters, capabilities

The OBS units can withstand depths to 6,000 m. Each has four-channel recording with a maximum 1,000-samples/sec (sps) frequency and on-board flash memory capable of up to 12-month continuous recording.

AuScope OBSs have a broadband flat frequency response from 0.0167 hz to 100 hz. According to Goncharov, only five or six institutions globally have broadband OBSs (BBOBS). The broadband capability allows the instruments to record both passive-source (earthquakes, ambient noise) and active -source (airgun-generated) seismic data.

"This broadband capability has come at the right time, as the petroleum industry and geophysical companies are more commonly using broadband airgun arrays as sources of seismic energy to improve resolution of subsurface reflection seismic imagery," said Goncharov.

At a rate of 100 sps, data can be recorded by the AuScope OBSs continuously for 12 months. After that the battery powering the digitizer will be exhausted. "There is no sense in leaving an instrument on the seafloor for a long period of time after that," Goncharov explained. "However, if the logistics of the experiment preclude recovery immediately after the exhaustion of the digitizer battery, the instrument can stay on the seafloor longer." The release mechanism is powered by a different battery than the digitizer.

OBSs are pinged from several directions immediately after they have settled on the seafloor to define the exact location at which data will be recorded. That location generally differs from the deployment location on the sea surface, particularly if ocean currents are strong. The instrument descends to the sea floor at a rate of about 40 m/min. "At a depth of 2,400 m—our deepest commercial survey deployment so far—it takes approximately 1 hr for an instrument to reach the sea floor," Goncharov said.

OBSs can record data simultaneously with conventional seismic acquisition, in either 2D or 3D. The ability to eavesdrop on conventional shoots is an efficient and cost effective way to supplement conventional seismic acquisition. This process can also radically increase the data recording aperture from a maximum of several kilometers on streamers to possibly in excess of 100 km, depending on airgun array volume and configuration.

OBSs can also be used on stand-alone deployments for passive data recording, including monitoring microseismicity induced by reservoir depletion.

Conventional comparison

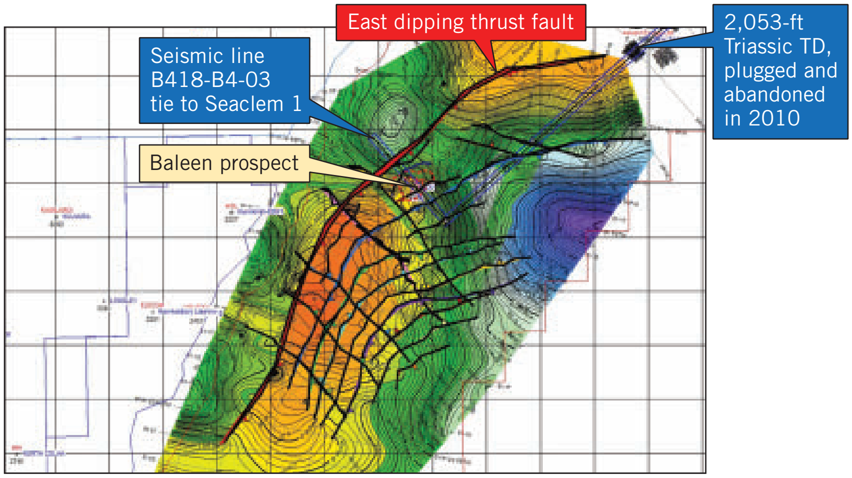
Conventional hydrophones in streamers towed behind a seismic vessel are pressure sensors. "They are omnidirectional, which means they cannot detect the direction from which seismic energy arrives," Goncharov explained. AuScope's broadband OBSs have a 3-component seismometer as well as a hydrophone (flat frequency response from 2 hz to 30 khz).

Multicomponent recording of the seismic signal detects the direction of the seismic energy arrival. On the vertical component of the seismometer, the down-going wave field displays differently than the up-going wave field. "Summing the pressure [hydrophone data] and vertical geophone data means we can reduce the effects of ghosts and water column reverberations in seismic data acquired on the seafloor," said Goncharov.

Methods based on the separation of up-going and down-going elastic wave fields from the geophone and hydrophone data can provide efficient noise rejection and amplitude preservation in the summed data. These directly translate into higher resolution of seismic data, which is essential for future exploration.

NEAR SHORE IMAGING SHOWS PERMIAN-TOP, NARABEEN TRIASSIC BASE

FIG. 4



S-wave detection

Compressional waves (P-waves) recorded during conventional marine surveys by hydrophones in streamers towed behind seismic vessels are mechanical waves that propagate through the interior of the material as pressure fluctuations. A characteristic of longitudinal waves, according to Goncharov, is that the motion of the particles goes back and forth in the same direction the wave travels. Three types of mechanical waves will propagate through solid material:

- Shear waves.
- Rayleigh waves.
- Love waves.

Similar to compressional waves, shear waves (S-waves) travel through the interior of the material; both are known as body waves. Rayleigh and Love waves travel along the surface of a solid material.

Shear waves depend on elastic deformation of the medium in a direction that is perpendicular to propagation. "Although most reflection surveys are based on analysis of pressure waves, seismic sources generate all types of waves in the seabed," Goncharov said. The various wave types are separated by their differences in propagation velocity. "Fluids, such as water, cannot sustain a shear deformation," he added. Only compressional waves propagate through air or water."

At the water-solid interface, however, new wave types will be generated through energy conversion, and both shear and surface waves will be present in marine seismic surveys. "But these cannot be recorded on a streamer towed in water," Goncharov said. OBS that is coupled with the seafloor will record them on all three components of the seismometer. "This is the fundamental difference between OBS recording on the seafloor and a hydrophone recording on streamer near the water surface."

Goncharov added, "Derivative shear waves, or to be more precise, SP-conversions that originate at the seafloor on the way back to streamer receivers, are present in the streamer data but are unlikely to be identifiable." But converted-wave seismic exploration based on multicomponent seismic recording captures these data and is increasing in its application.

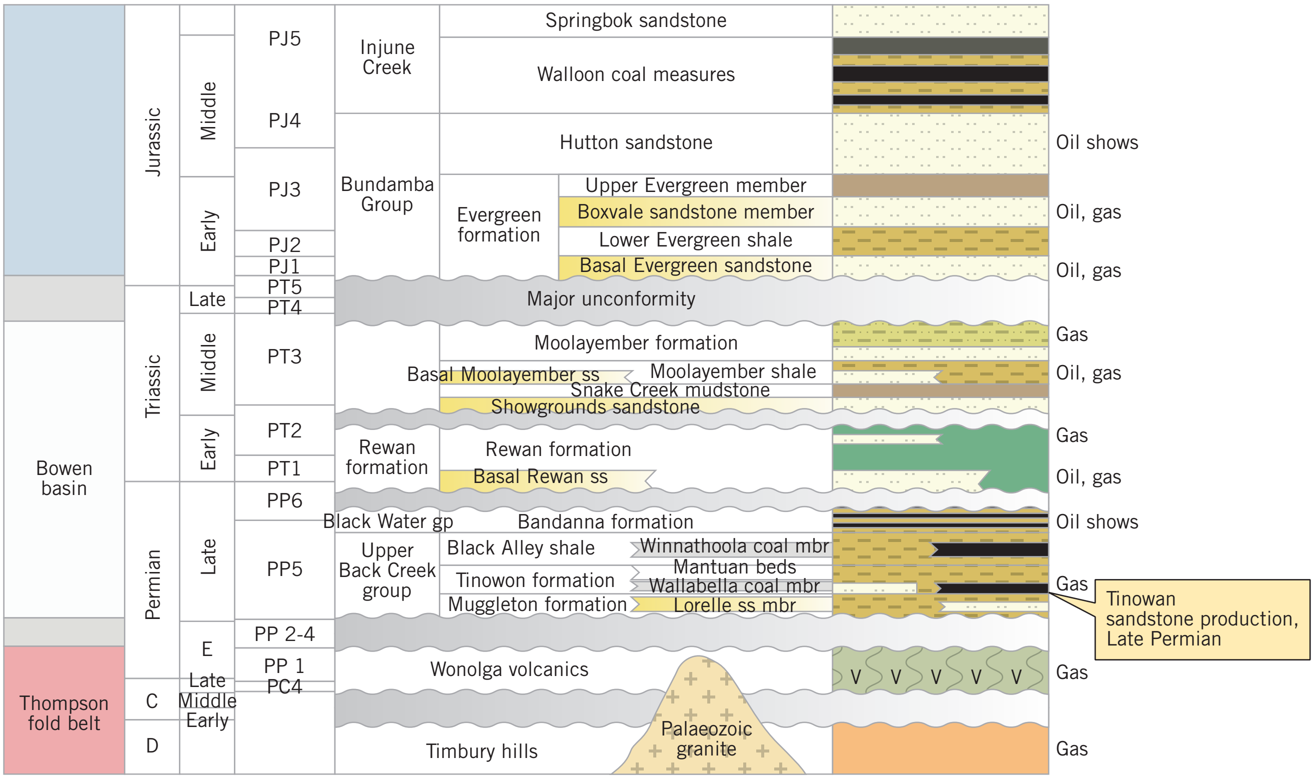
"S-wave analysis makes it easier to identify the elastic moduli of the rock, fluid type, and degree of saturation, all of which are important for the oil and gas industry," he said. Interpretations using only P-waves do not always adequately image a reservoir or describe its properties. Rocks differing in saturants can have a similar P-wave response or some interfaces may have low P-wave contrast. "S-wave properties may vary more, and along with the P-wave properties, can help characterize the rock structure, type, and fluids within," Goncharov said.

Project planning

On the East Coast of Australia, soaring gas prices due to a cold snap and rising demand from Queensland LNG projects triggered a winter energy crisis. "Wholesale gas prices in Sydney in early July 2016 reached almost $29 per gigajoule, which was almost 60% higher than their [previous] peak in 2012," said David Breeze, executive director at Advent Energy Ltd. Domestic industrial gas buyers were pay-

MYALL CREEK LITHOLOGY

FIG. 5



ing more than three times as much as Japan was paying for imported LNG.

"OBSs have come to our attention recently in Australia as potentially providing a reduced-noise seismic signal," Breeze said. The operator is investigating the application of OBS in conjunction with surface-towed seismic over its Baleen prospect.

The Baleen prospect in PEP11 is in 125 m of water in the offshore Sydney basin 30 km south-southeast of Newcastle. Initial reserves estimates by previous permit holders identified 1 tcf of gas. "This was at a time when the cheap prevalence of coal in the region limited the viability of offshore gas exploration," Breeze said.

Recent interpretation of all available data has demonstrated that the Baleen prospect exhibits numerous analogies with producing fields onshore in the Bowen-Sydney superbasin (Fig. 2 and 3) and is ideally situated adjacent to the Newcastle syncline sedimentary sink-source kitchen.

New Seaclem-1 is the only well drilled in the offshore Sydney basin. It targeted Tertiary sand above the regional Cainozoic unconformity. The well slightly penetrated the pre-Cainozoic unconformity Permian-Triassic sequence. "The offshore Sydney basin suffers from complex geophysical conditions, including a hard seabed and an eastward dipping and rugose Cainozoic unconformity approaching the surface in the west of PEP11," Breeze said.

These features result in rapid signal degradation and a severe problem with multiples. OBS deployment in conjunction with surface-towed streamers is expected to allow geohazard determination for drilling safety. Advent Energy also hopes to:

- Improve velocity models for the offshore Sydney basin.
- Image immediately below the regional unconformity.
- Identify 3D imaging of direct or indirect hydrocarbon indicators.
- Possibly image deeper structures.

The OBS component of the seismic program is still in the planning phase, though Advent Energy believes its project will be a novel application of the technology. "Application may include shallow geological and geophysical investigation for overburden integrity analysis—via multichannel analysis of surface waves—and shallow gas hazard identification," Breeze said.

The primary target at Baleen is 2,150 m below the seafloor. Two-dimensional seismic data show that the Permian-aged section of the onshore Bowen basin has conventional gas fields at similar time and depth to PEP11 at the Triassic-Permian age boundary with a similar seismic amplitude strength on regional 2D to PEP11 (Fig. 4 and 5).

Final project design has yet to occur. But if the outcome is successful it could demonstrate the viability of OBS applications in untested regions. "If we are successful in identifying any or all of the objectives outlined above, then geotechnical derisking, improved drilling tolerances, and heightened prospectivity may be achieved," Breeze said.

Once the company has concluded acquisition and interpretation, it plans to evaluate securing a suitable rig to take advantage of the current market conditions.

Advanced acquisition

To date AuScope's OBS fleet has recorded high-quailty data at each of its deployment sites, often including offsets sufficiently large to detect possible Pn phases, refractions from the upper mantle. Such information allows determining both crustal thickness and seismic velocity distribution to the Moho discontinuity, providing important constraints for subsidence and hydrocarbon maturation modeling.

The Moho, or Mohorovicic, discontinuity is a seismic boundary where velocity of seismic waves exceeds approximately 8 km/sec. In most cases it is rather easy to map from refraction seismic data recorded at large (several tens of kilometers) source-receiver offsets. Sometimes, however, this discontinuity is difficult to identify using "conventional reflection data because often there are a number of competing strong and discontinuous reflections in the lower crust that can be interpreted as the Moho," Goncharov said. Conventional reflection technology struggles to get good seismic velocity resolution in the deep crust.

The Moho is generally interpreted as the boundary between crustal felsic-mafic rocks and upper mantle ultramafic peridotites. "It is fair to say that the Moho is becoming widely recognized by the petroleum industry as one of the key parameters that define heat flow affecting hydrocarbon maturation in sedimentary basins," Goncharov said.

Geoscience Australia has also undertaken research examining the interaction between anthropogenic signals (airgun source, vessel noise) and the natural environment. Earthquake data have been recorded by AuScope OBSs during marine seismic surveys. "Surprisingly, the earthquake energy appears to make a noticeable addition to airgun generated energy not only near the microseismic peak frequencies generated by the ocean (~0.15 hz or less), but also up to frequencies as high as 50-60 hz," Goncharov said.

These frequencies are in the middle of the passband for conventional petroleum-oriented marine reflection surveys. As a result, there may be some distortion in attribute analysis and other refined techniques used for oil and gas seismic data interpretation. "OBS data suggest that not all recordings that come to the streamer on a marine reflection survey come from airguns," Goncharov said.

"The biggest advantage of using earthquake events as a passive source in offshore seismic exploration at this stage is that these techniques are a less expensive method to obtain certain seismic information, such as the crustal thickness discussed above," Goncharov said. He added that passive source techniques like receiver-function analysis need further work, and benchmarking against active-source techniques, to be accepted as valid tools for oil and gas exploration. "We have already begun recording earthquake and airgun signals at fixed locations, and this opens up a range of possibilities for calibration and comparison of those signal strengths and spectral compositions."

The OBS Access Committee received an application to use AuScope instruments for a 12-month deployment in the Roebuck basin on the Australian NW Margin starting in 2017. The project is targeted at passive recording (earthquake energy, ambient noise). "If the petroleum company or geophysical contractor shoots an airgun line over the instruments while they are deployed on that survey, this would be an excellent opportunity to benchmark results of passive source recording against those derived from active source data," Goncharov said.

Future potential

OBS technology presents advantages in a number of areas. AuScope OBSs are broadband instruments and allow passive and active source data recording at the same, or proximal locations, which is finding appeal for calibration-benchmarking of results. "The first results of such combined experiments undertaken in 2014-15 are already available to researchers through Geoscience Australia," Goncharov said. He adds that recording active-source seismic reflection, wide-angle/refraction, and passive data at coincident or proximal locations should be a long-term goal.

OBS time-lapse (4D) monitor surveys are already a reality, with the Gulf of Mexico's Atlantis field as one example. While the logistics of such experiments are complicated, potential remains for recording and processing horizontal component seismometer data in such surveys in addition to vertical component data, significantly improving information on fluid saturation of the rock, according to Goncharov.

Combined onshore-offshore experiments with signals from sources on land recorded on the seafloor, supplemented by marine airgun signals recorded by land stations, have occured in the Gulf of Mexico and the Arctic Coast of East Siberia. "Such acquisition design allows seismic ray coverage through the coastal transition zone in both directions, and all the powers of reciprocal analysis become available," Goncharov said.

Broader OBS technology applications relative to 2D and 3D reflection surveys are generated by the large source-receiver offsets inherent to OBS recording. Refracted and reflected phases can be recorded and analyzed in OBS data rather than just reflected in streamer surveys. Multicomponent OBS data also display and make available for analysis more types of recorded seismic energy, such as shear waves and converted waves. OGJ

Ultrasonic test redesigns sample geometries, identifies high-resolution anisotropy in shale

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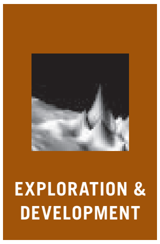
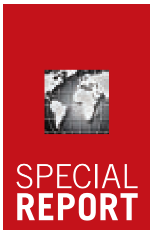
A new ultrasonic test method can acquire high-resolution shale data in the lab by using new geometries for sample testing with specialized equipment suited for measuring shale formations at reservoir conditions. The ultrasonic ⅓-slab test alleviates problems associated with sampling and fills gaps that often result in poor data resolution found with other technologies in field-scale applications.

Octagonal and dodecagonal methods allow ultrasonic testing to measure acoustic anisotropy and heterogeneity with improved precision at 45° and 30° increments, respectively. Integrated analysis and interpretation resulting from the acoustic tests can calibrate well logs, improve reservoir characterization, and enhance completion designs.



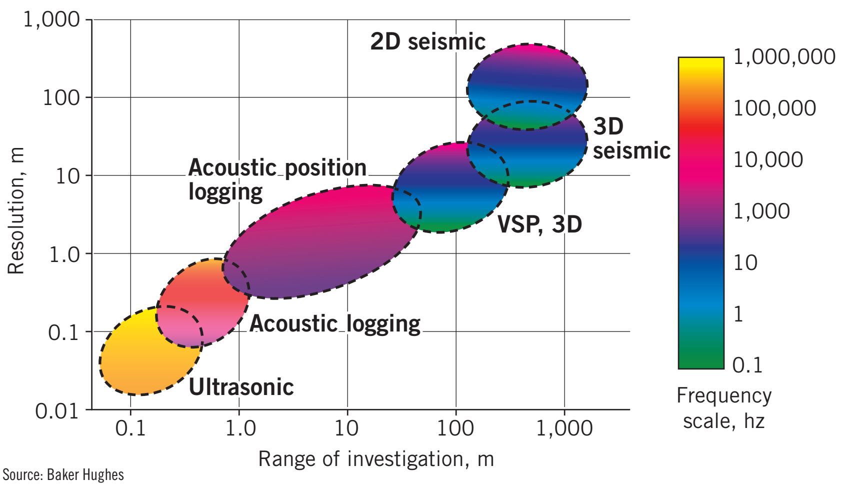


Shale formations make up a large portion of the world's sedimentary basins. Shale has a great deal of mechanical anisotropy. Proper sampling dimensions in laminated shale cores can be difficult to obtain.

Oil and natural gas exploration employs a variety of acoustic investigations to identify specific locations and accurate reserves estimates of commercial hydrocarbon deposits. Seismic surveys are important tools for exploring reservoirs and evaluating formations, but their wide data resolution

EXPLORATION PROPERTIES

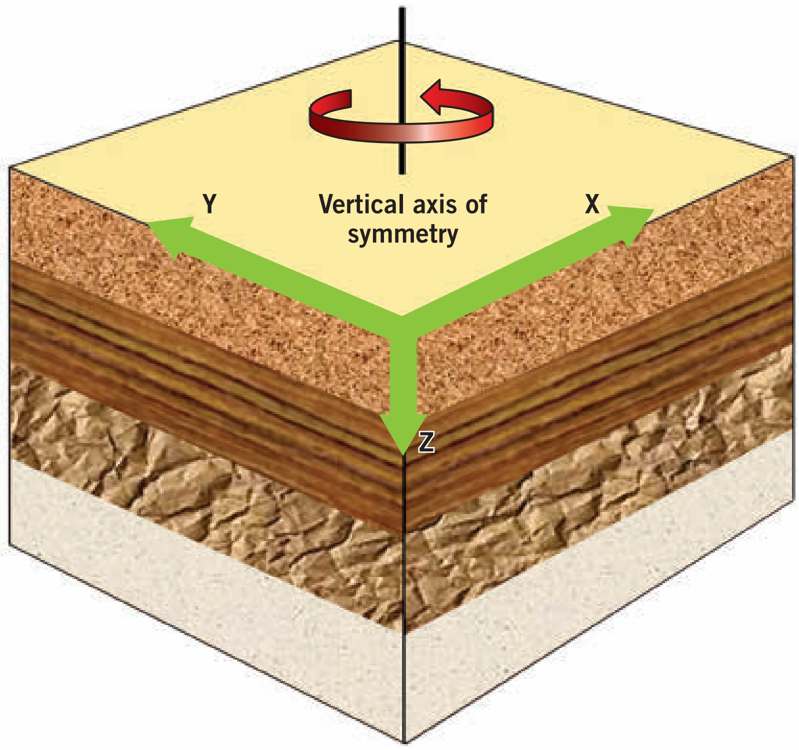
FIG. 1



Source: Baker Hughes

VERTICALLY TRANSVERSE ISOTROPY

FIG. 2



can often skip important geophysical and petrophysical features. Acoustic logs provide reservoir information at wellbore scales with moderate frequency and data resolution.

Other methods include vertical seismic profiles (VSP) and ultrasonic tests. Depending on the coverage desired and the level of investigation, operators tailor tools and applications to fit specific needs. Seismic and VSP are viable for exploring a wide range of fields both horizontally and vertically through multiple formations, but also provide poor data resolution. Ultrasonic tests measure small specimens at laboratory-scale using low frequencies and often provide higher data resolution (Fig. 1).

Elastic properties variation

Anisotropy is the directionally dependent variation of physical and mechanical properties.[1,2] Acoustic anisotropy is a directional variation in velocities within a spatial sequence of bedding planes, fractures, laminations, grains, and pore structures. Waves will propagate differently parallel or perpendicular to bedding and fastest in the stiffest direction.[3-6] Acoustic anisotropy is a key parameter for seismic data processing because it strongly influences interpretations of seismic surveys, formation evaluations, pore pressure predictions, and microseismic monitoring.[6-9]

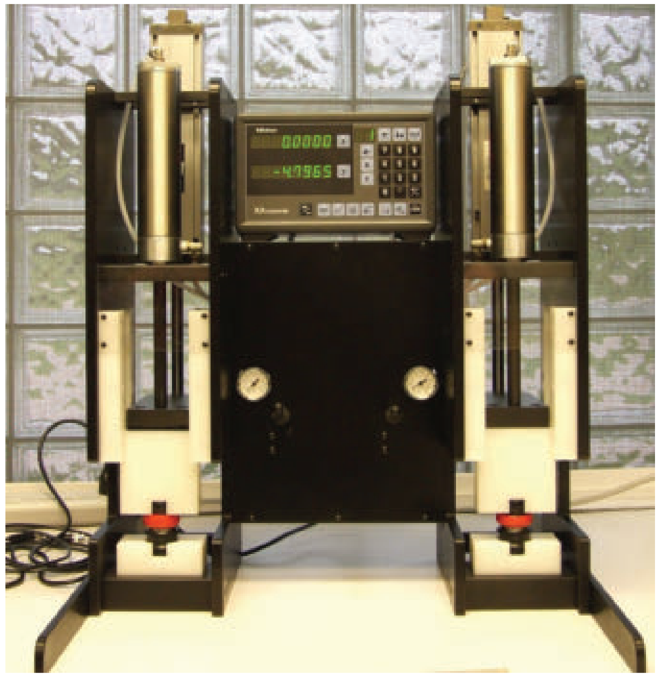
Shale exhibits a high degree of intrinsic and mechanical anisotropy due to platy clay particles, kerogen, and laminations aligned parallel to the bedding.[10-13] This combination creates vertically transverse isotropy (Fig. 2).[14,15]

Ultrasonic testing

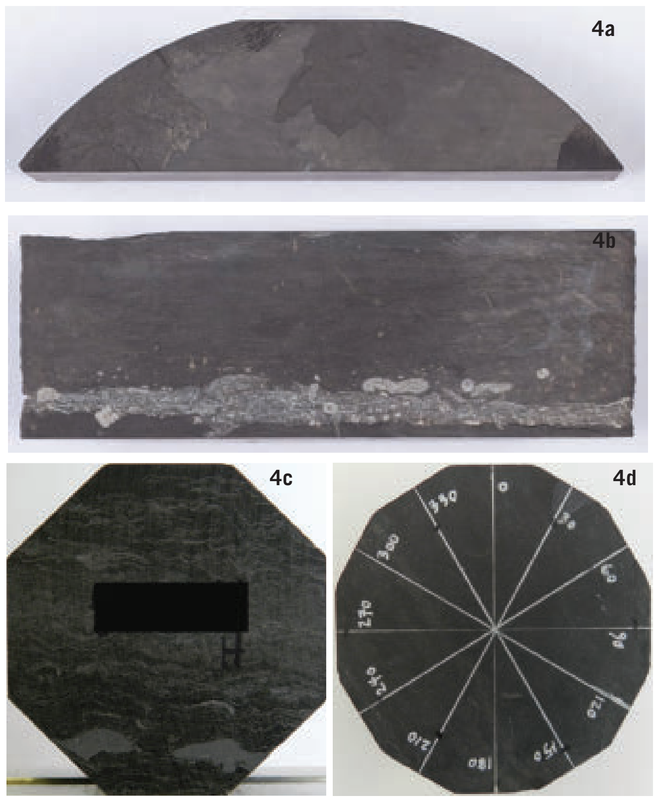
One difficulty in laboratory testing of rock mechanics is obtaining properly dimensioned samples in laminated shale cores. Through modification and specialized equipment, Chesapeake Energy Corp.'s Reservoir Technology Center created a new ultrasonic test system designed to measure wave velocities and elastic properties of unconventional rocks (Fig. 3). Shale cores possess intervals with tightly spaced horizontal laminations. Typical laboratory tests require 2-in. vertical plugs, but the nature of shale core samples makes obtaining these plugs difficult if not impossible.[16-18] Chesapeake's new ultrasonic test trims samples to 1-in. to alleviate problems associated with larger samples.

Each pneumatic ram applies a contact force of about 100 lbs, with 120 psi of axial stress, based on the surface area of the specimen. This process expels air or gas captured in pores, laminations, and pre-existing cracks and fractures in shale samples.

The test measures wave velocities in as-is (or as-received) cores and converts them to elastic properties as close as possible to reservoir conditions. To preserve formation gas, oil, and any fluids, the ⅔-butt section cores are wrapped with plastic following the cutting process. The ⅓-slab section cores are exposed to ambient conditions, allowing moisture and some light hydrocarbon captured in specimens to dry



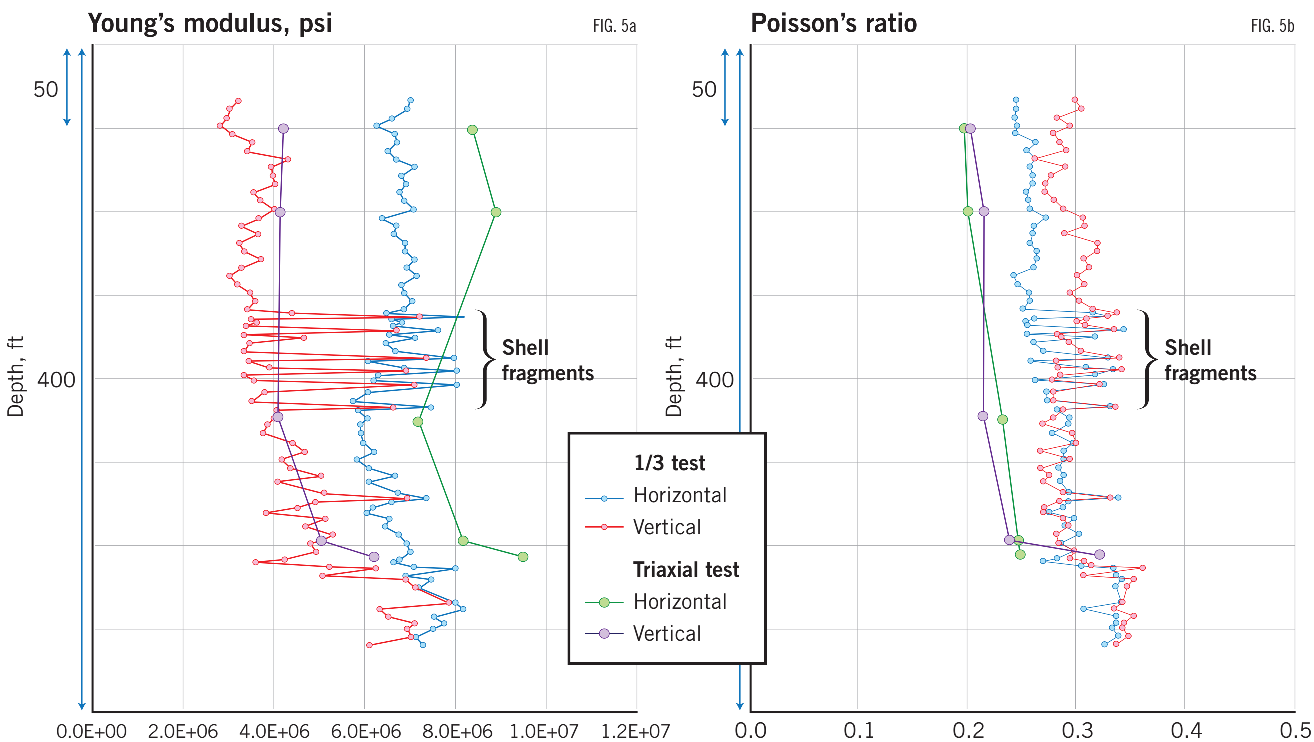
Chesapeake designed this ultrasonic test apparatus for unconventional rocks. The unit stands 30-in. tall and 24 by 12-in. wide (Fig. 3).



The ⅓-slab sample measures 3.25-in. in diameter by 1-in. thick (Figs. 4a and 4b). Chesapeake's new acoustic anisotropy and heterogeneity test devised new sample geometries from the ⅔-butt section (octagonal) and a dodecagonal specimen from the whole core section (Figs. 4c and 4d).

SHALE SAMPLES' ELASTIC PROPERTIES

FIG. 5



over time.

This study saturated the 1/3-slab specimens in 5% potassium chloride for 2 days. Saturation is necessary due to the low axial stress applied during testing. Wave velocities are more affected by saturation in shale samples than in porous sandstones. Partial drying limited detection through Young's modulus without saturation or high axial stress, but the data maintained reasonable ranges. Invalid results were clearer in Poisson's ratio, as data were expressed in low or negative values. Typical field-level ultrasonic testing is not an efficient approach in laboratory experiments.[19-22]

Sample geometry

Fig. 4a represents the ⅓-slab specimen used to measure ultrasonic wave velocities in vertical and horizontal directions. These types of specimens provide greater data resolution at every inch when measuring acoustic anisotropy in vertical and horizontal orientations, as long as the ⅓-core samples are sound. Sample preparation can be limited if fractured zones are too tight, such as with "poker-chip" type fractures, when there are rubblized zones, or when cores have vertically broken parts due to drilling-induced fractures.

Usually, ⅓-slab specimens are prepared at every 1-2 in. depending on the intent of the experiment or sample lithology. Anisotropic or heterogeneous core sections employ sampling every 1 in. For rocks that contain similar lithology, such as a clean sandstone section with a uniform particle-size distribution or fewer pre-existing microfractures, sampling occurs every 2 in. Octagonal specimens allow for anisotropy measurements at every 45° (Fig. 4b).

Samples are prepared in a vertical direction using the ⅔-butt sections harvested with a 2-in. coring bit. After coring, the 1-in. thick sample is cut and ground at every 45°.

Most acoustic anisotropy experiments measure wave velocities at only three directions: vertical, 45°, and horizontal. The measurements are provided with an assumption that each opposite direction must generate the same velocities. But natural rocks include different minerals, particle sizes, pore sizes, and heterogeneous mineral elongations. These assorted features also lead to different wave velocities, but these heterogeneity-based differences are smaller than the anisotropic differences.

This study introduces a new dodecagonal sampling technique to measure heterogeneous characteristics at every 30° (Fig. 4c). The sample is extracted along a horizontal direction, not vertically, through the 4-in. diameter core section.

Anisotropy measurement

Fig. 5 compares anisotropy in elastic properties measured by dynamic triaxial compressive tests and ultrasonic ⅓-slab tests. Triaxial compressive tests require discrete samples because of high cost, long experiment time, and limited sampling. Researchers therefore select a small plug (1-in. width, 2-in. length) for rock mechanics tests, but it is impossible to extract samples with these dimensions in highly laminated cores. One-third slab samples by comparison are flexible, fast, and inexpensive to prepare.

This study conducted five triaxial compressive tests and 80 ultrasonic ⅓-slab tests to investigate elastic properties in reservoir formations (Fig. 5). The triaxial compressive tests applied 3,000 psi confining stress and the ultrasonic ⅓-slab tests were conducted with no confinement.

The different magnitudes in elastic properties from both tests are based on their different confining stress conditions. Dominant data spikes occur in the zone of shell fragments detected by the ultrasonic ⅓-slab test (Fig. 5), unlike the triaxial compressive tests which skipped this specific feature.

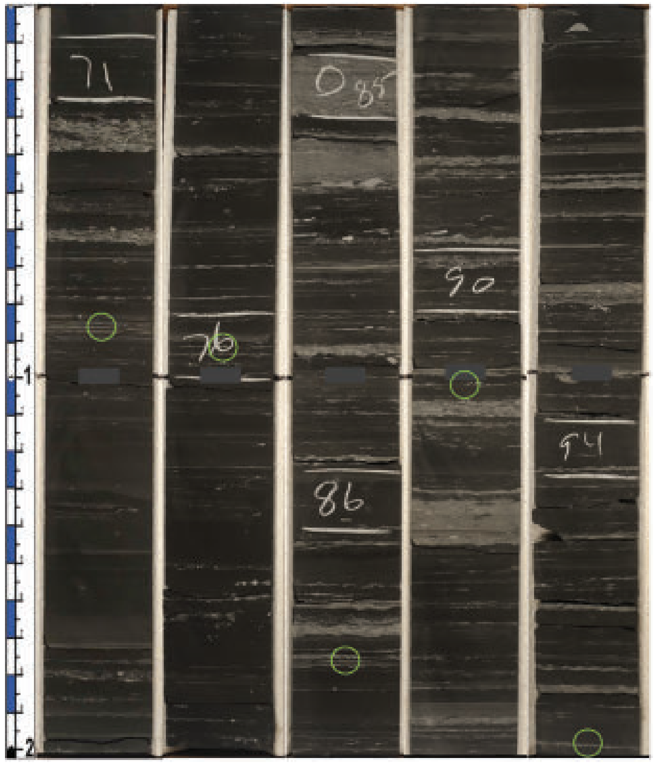
This shell-fragment example shows the circumstances in which seismic, VSP, or acoustic well logs may bypass lithological variations mostly seen in unconventional formations. This high-frequency laboratory experiment, however, conducted on small specimens with high sampling rates, can cover and interpolate intervals missing from larger, lower frequency field-scale exploration techniques.

The grey-colored areas in Fig. 6 consist of bioclastic shell debris. Accumulations of shell debris range from disseminated fragments to thin beds. The length of this column is 2 ft. Each data point is designated by a circular mark on the photo. All sampling spots show horizontally layered shell fragments composed of calcite.

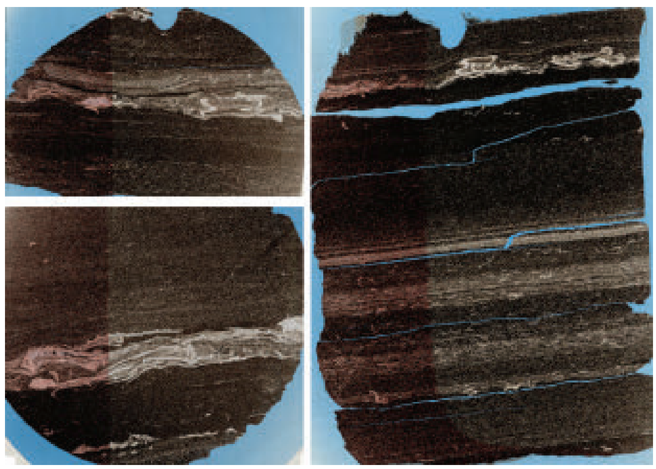
The test measured anisotropy in elastic properties in 10 octagonal specimens at every vertical 45° angle (Fig. 8). Young's moduli are higher along the horizontal direction. In contrast, Poisson's ratios are lower in the opposite trend.

This mechanical anisotropy comes from the horizontally layered shell fragments. The results infer that the samples are stiffer horizontally and identically match the ultrasonic ⅓-slab test results showing high spikes in Young's moduli in Fig. 5.

Heterogeneity in elastic properties was measured using three dodecagonal specimens at every horizontal 30° angle (Fig. 9). Young's moduli are slightly different in the specimens. For example, Sample 2 shows a higher Young's modulus along 60°–120° (Fig. 9a). For Poisson's ratio, Sample 1 shows the relatively higher value along 60°–90° (Fig. 9b). Overall, the degree of variance in elastic properties due to heterogeneity is not as dominant as that due to anisotropy (Fig. 8). The scale of anisotropy with bedding planes, fractures, and laminations is greater than heterogeneity in platy clay samples. OGJ



The green circles indicate sampling locations from the ⅓-slab section cores including shell fragments (Fig. 6).



Thin-section images of shell fragments and microfossils are layered parallel to bedding planes. These play a major role in causing anisotropy in wave velocities, elastic properties, strength, and fracture toughness (Fig. 7).

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OCTAGONAL ACOUSTIC ANISOTROPY

FIG. 8

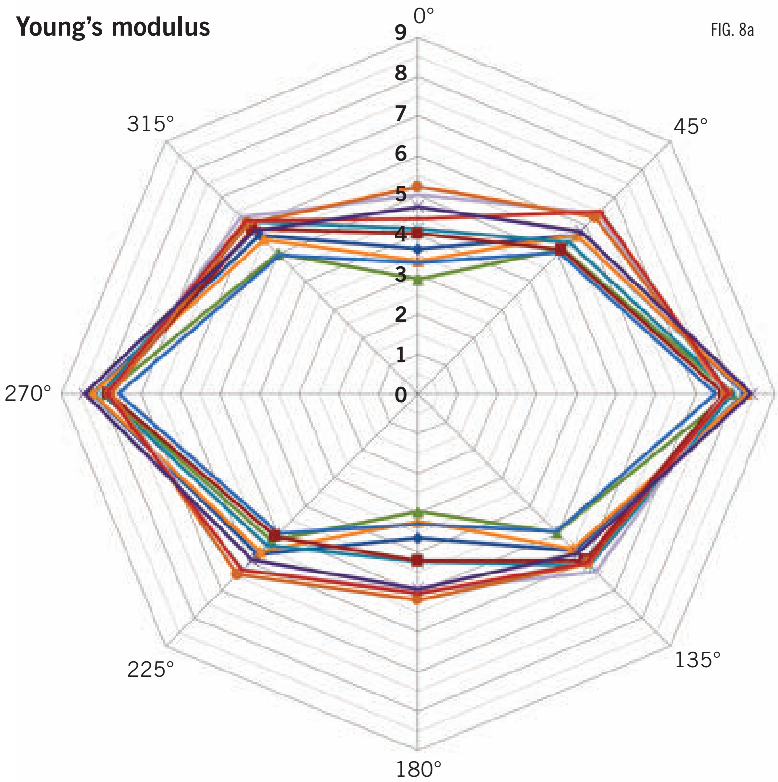

FIG. 8a

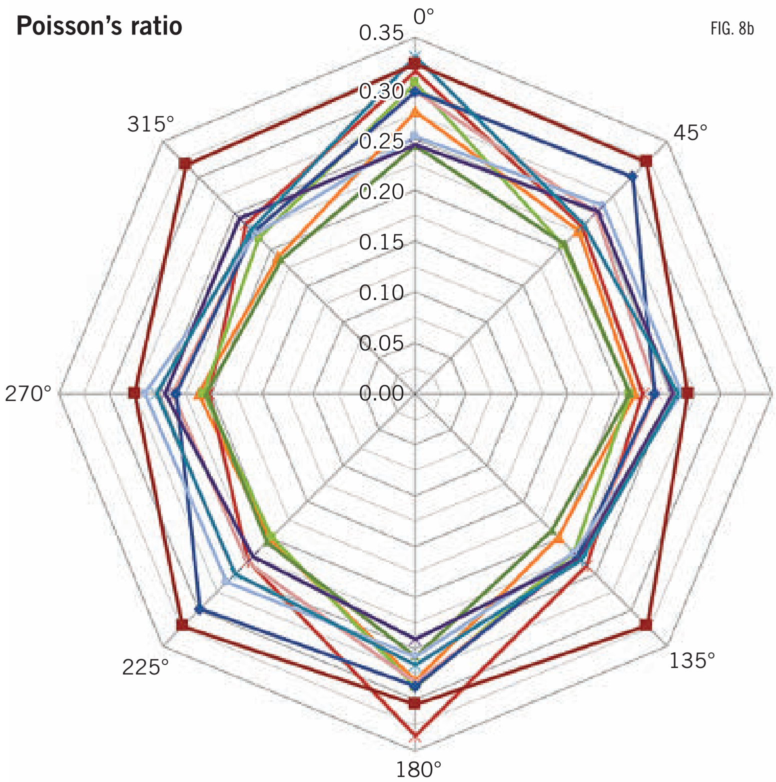

FIG. 8b

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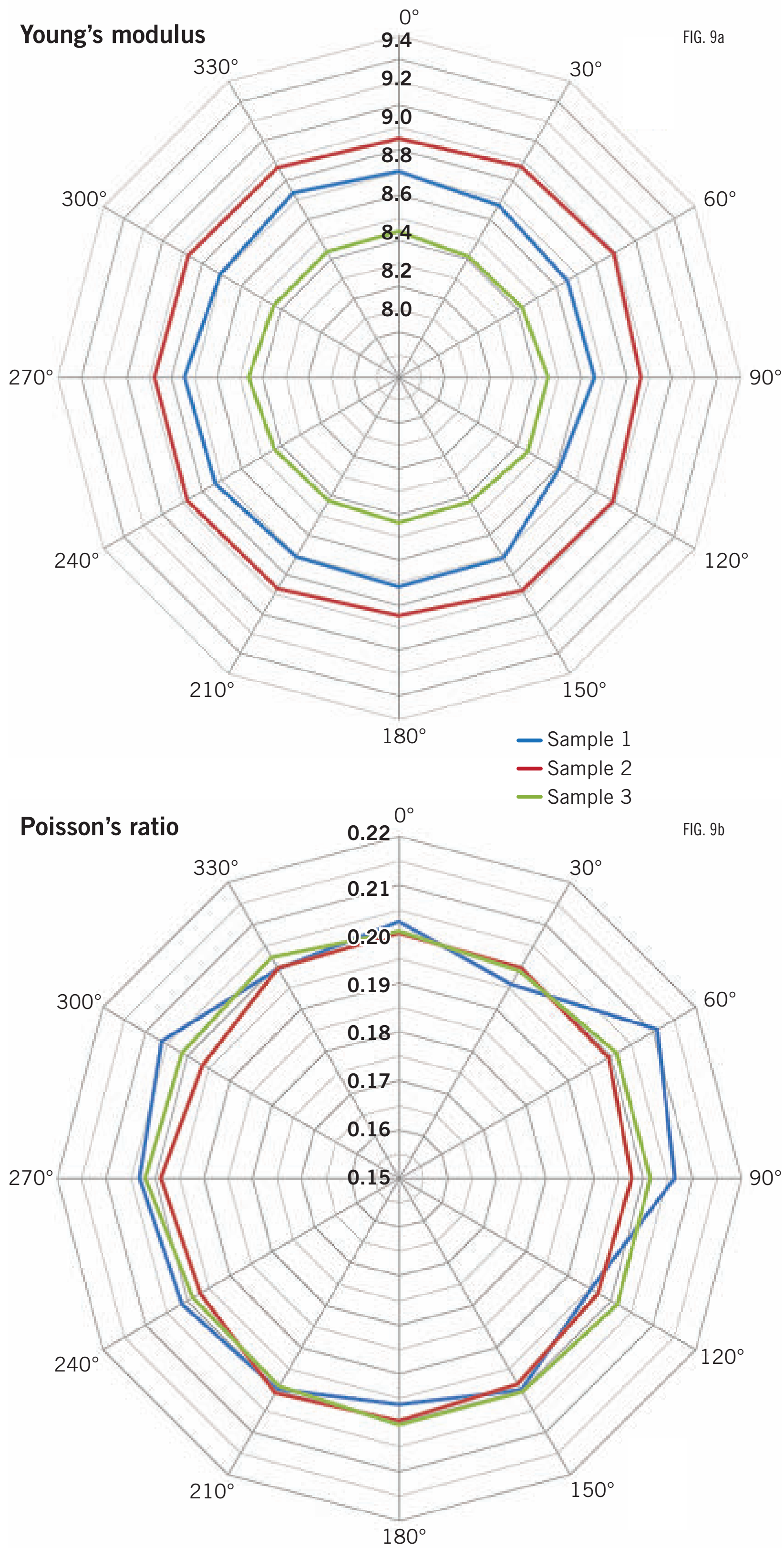
DODECAGONAL ACOUSTIC HETEROGENEITY

FIG. 9



ICD-packer completion reduces water in China's Jidong oil field

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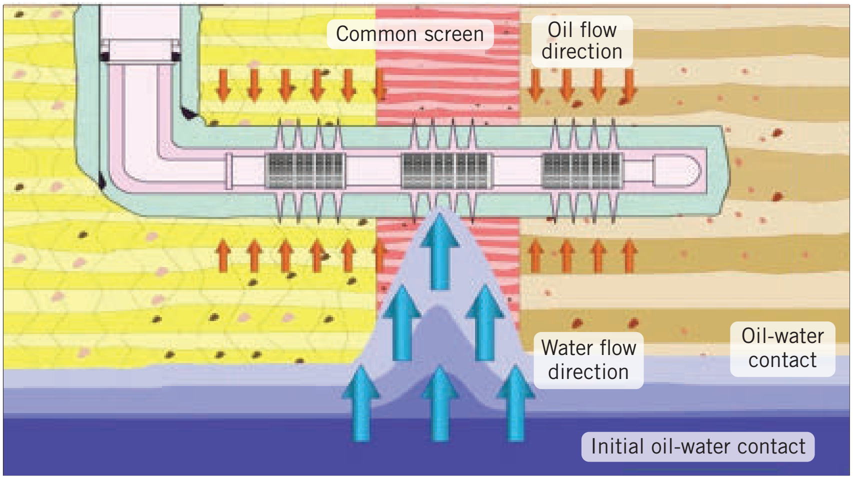
DRILLING & PRODUCTION

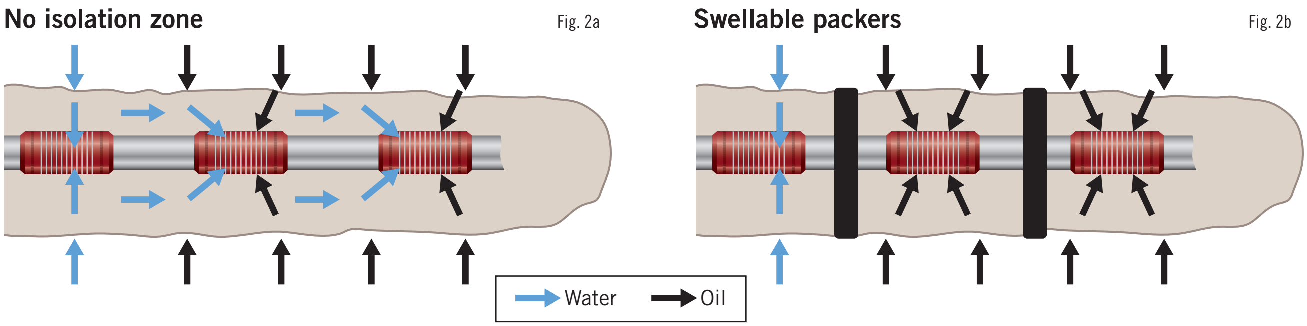
Inflow control devices (ICDs) paired with oil-swellable packers often perform water control during well completions in unconsolidated reservoirs, but ICD-packer systems offer effective zonal isolation for only about 90 days.

Field studies demonstrate acceptable produced water volumes upon initial production of horizontal wells in China's Jidong oil field, but the water cut increased rapidly after 3 months while oil production decreased. Pressure-distribution analysis during laboratory simulations of water-control techniques in unconsolidated sands showed that pressure differences be-

WATER BREAKTHROUGH FIG. 1



OPEN COMPLETION FIG. 2



tween the ends of a packer contributed to channeling.

A horizontal well completed with an ICD-packer system provides several isolated flow units. Water entering a producing wellbore causes different flow pressures between oil and water units outside the ICD.

The differential pressure drives water into the adjacent oil unit through the unconsolidated sandstone outside the swellable packers. Unconsolidated sandstone will channel with time, rendering swellable packers inefficient for water control.

This article outlines how experimental simulation can forecast water breakthrough in a producing oil well.

Reservoir modeling can determine the critical pressure gradient that forms channeling in unconsolidated sand. Crucial differential pressure was evaluated to determine if ICDs and packers offer a feasible solution. A laboratory experiment resulted in a water-cut trend forecast that proved consistent with well-production data.

Jidong horizontal wells

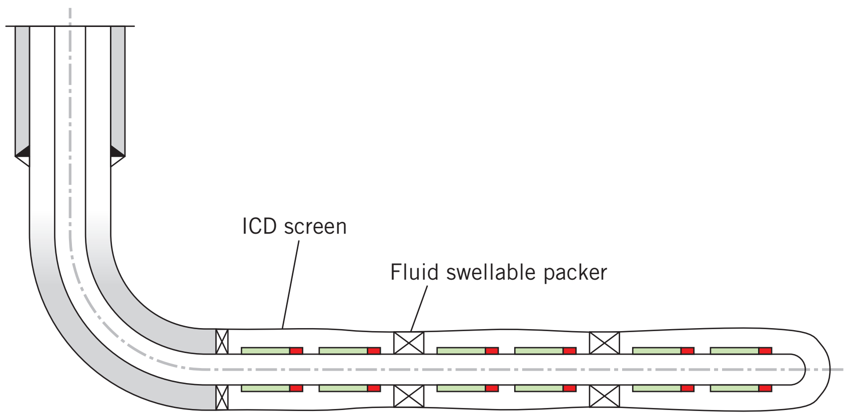
Horizontal wells in various reservoir types commonly include ICD open-hole well completions and oil-swellable packers. Little long-term information exists on production after an ICD-packer completion.

Operators since 2004 have drilled horizontal wells in Jidong oil field in Hebei Province. Some wells were shut in within 1 year because of high water cuts.

Jidong operators started using ICD and oil-swellable packers in 2006, but water or gas early breakthrough remains a problem. Horizontal wells in homogeneous formations feature a heel-toe effect that causes unequal inflow, leading to water breakthrough at the heel. This occurs more commonly in heterogeneous reservoirs.

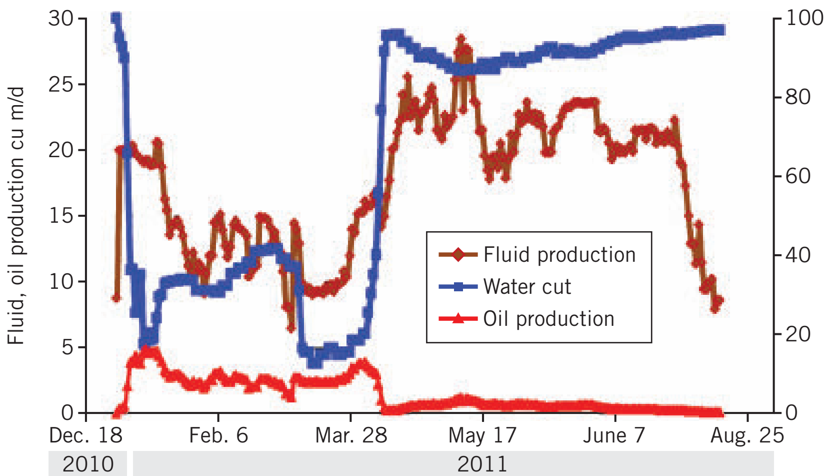
ICD-PACKER COMPLETION

FIG. 3



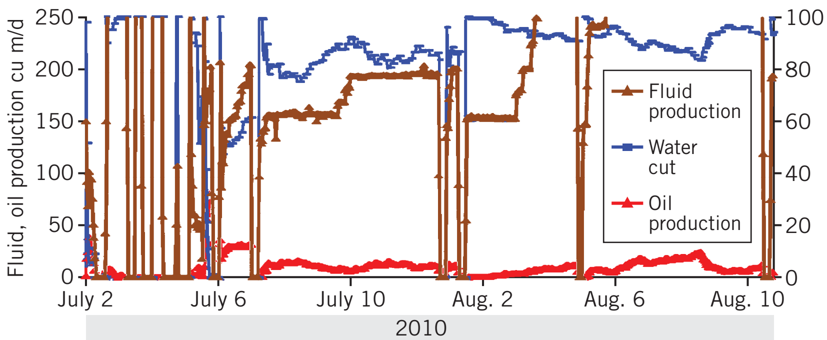
STUDY WELL

FIG. 4



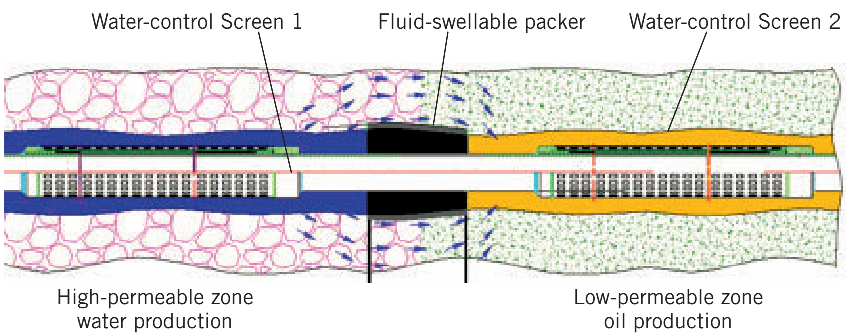
WELL WITHOUT ICD

FIG. 5



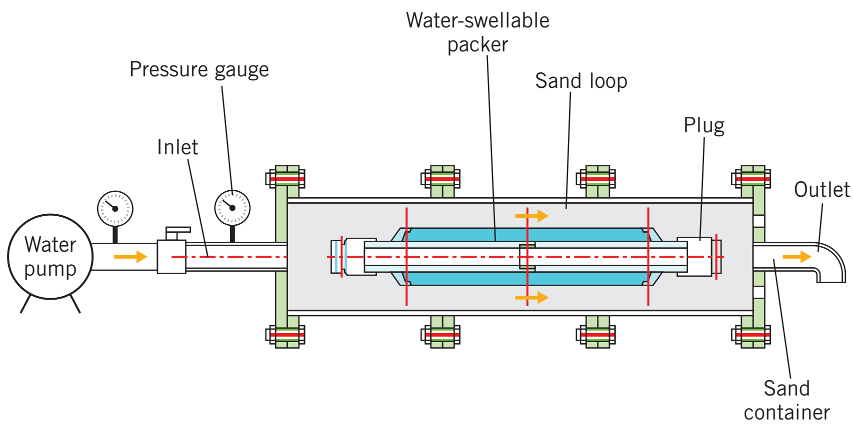
PRESSURE DISTRIBUTION IN WATER, OIL ZONES

FIG. 6



EXPERIMENTAL DEVICE

FIG. 7



A horizontal well produces oil from stratum layers having different permeabilities (Fig 1). Viscosity differences between water and oil increase fluid influx unbalance, resulting in early water breakthrough.

ICDs can delay water breakthrough while oil-swellable packers create isolated zones and prevent fluid from flowing across them (Fig. 2). The ICD-packer combination can create a dependable fluid rate with a manageable pressure drop. The combination offsets tubing friction loss and other variables.

The onshore study well lies on Block G104-5 of Jidong oil field on the northeastern China coast. Jidong field covers 6,300 sq km, extending from the southern foot of Yanshan Mountain to the north to 1.5 km offshore into Bohai Bay.

Jidong's exploration and development area includes 3,600 sq km of land and 2,700 sq km of shallow sea. Block G104-5 mainly is composed of anticlinal and unconsolidated sandstone reservoirs.

The reservoir lithology consists primarily of fine and medium-grained sandstone, including part anisometric, pebbly sandstones and part sandy conglomerate. Quartz accounts for 41-56% of the reservoir. Feldspar is secondary.

Clay dominates cements in the reservoir. Carbonate is the subordinate cement mineral. Cement content is 5-20%. The reservoir has high porosity (~31%) and permeability (0.1-8,956 md), but also great heterogeneity.

The hydrocarbon viscosity of the reservoir is about 300 cp.

The operator started using the ICD-packers technique in 2009 to control water on two wells from Block G104-5. Results were very similar so this article only outlines details from one of those wells.

The swellable-packer isolating design addressed the well's 100-m horizontal production length. Three isolated production units were created using two oil-swellable packers.

The distance between each unit was about 30 m. Fig. 3 shows the well configuration with ICD-packers.

The ICD specification and model are the same in each flow unit. A 7-in. ICD screen (OD 210 mm) was installed in the 9⅝-in. open bore hole (ID 241.33 mm). A 15.6-mm gap exists between the ICD screen and open hole.

The study well initially showed relatively stable production. The water cut slowly rose to 40% from 20% before surging to 90% where it remained after 3 months (Fig. 4).

A separate well near the study well used traditional screen completion without an ICD. Fig. 5 shows its production performance. The water cut increased rapidly to more than 80% and remained high.

Two swellable packers divided the well bore into three isolated flow units from heel to toe. The first unit produced water with high permeability. The adjacent one produced oil with low permeability.

Pressure dropped greatly in the ICD of the water unit upon water breakthrough because flow accelerated. The oil-production unit exhibited a smaller pressure drop in its ICD.

The packer maintained differential pressure between the two units, with the pressure drop smaller than the production differential pressure (Fig. 6).

The pressure difference between the ends of the oil-swellable packer drove the water flow from the water unit to the oil unit. Water flow caused a collapse in the unconsolidated sand outside the packer to the annulus.

Channeling formed in the unconsolidated sand, making packer isolation inefficient. Once the isolation zones failed, water production increased quickly.

Pressure increased outside the oil unit's ICD screen. Formation pressure dropped, reducing oil production as the water cut accelerated.

Experiment logistics

Researchers designed this experiment to simulate differential pressure conditions that cause channeling in unconsolidated sands during oil production. The results can help an operator forecast pressure and decide if an ICD-packer combination should be used in a horizontal well.

The lab experimental device includes a water pump, packer, formation sand, and sand container. A 5½-in. casing (ID 150 mm) served as a sand-filling tube to simulate the well hole.

The experiment's water-swellable packer (OD 102 mm, length 300 mm) models the performance of an actual well's 7-in. oil-swellable packer (OD 210 mm, length 6 m).

Retaining collars sealed the experimental packer ends. Fluid was allowed to flow through the unconsolidated sand when the swollen packer had a differential pressure.

The fluid used to trigger swelling differs in oil vs. water packers. Researchers used a water-swellable packer, which had no effect on the experiment's final results.

They filled the annulus between the packer and experimental well wall with sand from the field-study well. Researchers calculated particle-size distribution of formation sand in the experiment.

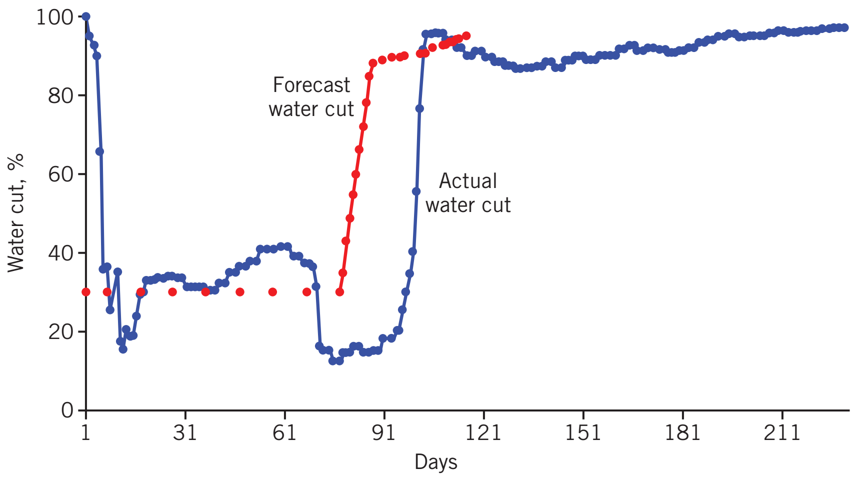
The experiment used sand particles with a 24-mm gap vs. the actual well's 15.6 mm. Water injection into the sand tube ensured the water-swellable packer filled and isolated sufficiently. The packer compacted surrounding sand tightly against the well wall.

A water pump provided high pressure to the inlet packer end, which simulated the well bore's differential pressure and flow. Two holes allowed sand and water to flow out of the experimental device, which modeled sand collapsing in the well bore.

Researchers sought to create the same 0.67-MPa/m pressure gradient as in the actual reservoir. The packer length in the actual well bore is 6 m, so the differential pressure between packer ends was 4 MPa.

ACTUAL, FORECAST WATER CUT

FIG. 8



Researchers concluded 0.2 MPa was the required differential pressure from the pump.

They placed a packer in the middle of the sand-filling tube. The gap between packer and sand-filling tube was filled and compacted with sand from the field-study well. Water filled the pores in the sand-filling tube.

The experimental device stood for 12 days to allow the water-swellable packer to isolate sufficiently. Researchers injected water from the inlet under 0.2-MPa pump pressure to model the flow process caused by the differential pressure between the two ends of the packer.

They observed and recorded the water and sand's outflow values. Initial inlet pressure was 0.2 MPa and the flow rate 0.1 l./min.

This status lasted 94 hr until the pressure suddenly dropped to 0 and the flow rate jumped to 12 l./min. Researchers found irregular flow channeling in the sand outside the packer upon opening the experimental device.

The pressure gradient of fluid flow in the unconsolidated sand was the same as with the experimental well bore. The time to form the channeling was directly proportional to the axial length of the unconsolidated sand outside of packer.

Fig. 8 shows the forecast and actual well water cuts. The water cut increased rapidly in a consistent, predictable trend in both the lab and the field.

The water cut rose suddenly in the experiment 2.5 months after initial production. The field study's water cut increased suddenly after 3 months, about 20% later than the forecast.

Water breakthrough in the actual well took longer than forecast because the sandstone in the field study increased flow resistance and delayed channeling. Sand compaction in the reservoir also was stronger than the experimental condition.

DRILLING & PRODUCTION

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DRILLING & PRODUCTION

Researchers test mud formulas for Turkey's Dadas shale

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Istanbul

Two water-based mud (WBM) and one potassium-based mud (PBM) drilling fluid systems emerged as alternatives to non-aqueous based fluids (NAFs) in testing at the Silurian Dadas shale of southeast Turkey.

Laboratory results show WBM and PBM drilling fluids can be deployed for shales elsewhere having properties similar to the Silurian Dadas. These include the Vaca Muerta shale in Argentina and three US plays: the Eagle Ford and Barnett in Texas, and the Niobrara in Colorado.

Silurian Dadas operators initially considered NAFs, but their use poses environmental issues and is expensive. Operators instead sought customized alternate drilling fluids involving a combined water-based mud and salt-based mud.

Turkish National Oil Co. and Viking Services Co. provided shale samples for laboratory testing of three different mud systems.

Researchers studied the systems for rheology and water-loss properties in temperatures up to 250° F.

Drilling-fluid selection depends on a specific shale play's morphology and lithology, drilling requirements, and other reservoir-specific variables.

Unconventional natural gas shale formations vary considerably, especially regarding well bottom-hole temperature (BHT). NAFs offer good shale stabilization, lubricity, and contamination tolerance. But water-based muds (WBM) commonly offer more options at lower cost. WBM is more sensitive than NAFs to changes in temperature, salinity, pH, and contaminants.

A shale's reactive clay content and high BHT is crucial to its WBM design. PBM can be modified more easily than WBM to handle reactive clays and BHT. Operators use PBM to limit chemical modifications in shale formations.

Different clays offer different mud characteristics. Potassium ions fit closer into a clay lattice structure then do calcium ions. In the presence of montmorillonite, potassium replaces sodium and calcium to produce a stable, less hydrating structure.

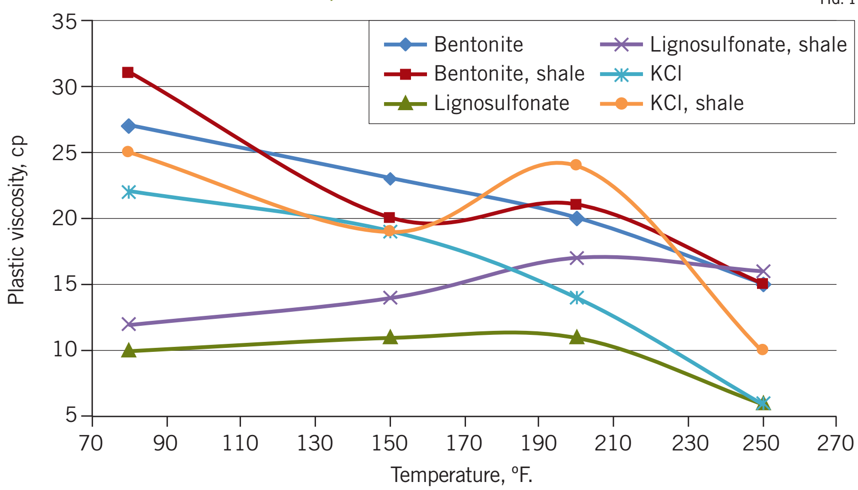
Potassium substitutes for exchangeable impurities in the structure when illites are present. Potassium cations stabilize shales containing a large percentage of illite or illite-smectite layer combinations.

If the potassium level drops, clays and shales can hydrate, leading to borehole instability and mud loss problems.

A well-known PBM is potassium

DRILLING FLUIDS RESPONSE, DADAS SHALE

FIG. 1



XRD DATA FOR DADAS SHALE

Table 1

Component	%
Quartz	17
Feldspar	<5
Dolomite	20
Calcite	<5
Caolinite	35
Illite	15
Smectite	<5

WBM FORMULATIONS FOR DADAS SHALE Table 2

Substance	Bentonite mud	Lignosulfonate mud
Caustic, g	0.06	0.06
Soda ash, g	0.1	0.1
Bentonite, g	20	20
Thinner, ml	2	—
Chrome-free lignosulfonate, g	—	3
Filtration-control polymer 1, g	—	3
Filtration control polymer 2, g	2	—
XCD polymer, g	2	—

chloride mud (KCl), developed to provide wellbore stability and reduce cuttings dispersion. KCl used in water-sensitive formations provides low-formation damage and high-return permeability. A low-polymer concentration allows cuttings dispersion, resulting in increased viscosity.

Siluarian Dadas shale

The Silurian Dadas shale covers an estimated 480,000 acres in southeast Turkey. Latest assessments show the shale holding a potential 110 million bbl of oil (OGJ, July 1, 2013, p. 46).

The Dadas formation is deltaic. Sandstone and shale are found in outcrop in the Dadas and Zenala areas of North Diyarbakir and Mardin High. The formation's age ranges from Late Silurian to Early Devonian.

Table 1 shows X-ray diffraction (XRD) analysis of Dadas shale cuttings and core samples. Dadas shale consists of clay, dolomite, and quartz. The clay is almost exclusively caolinite and illite.

Potassium replaces sodium in illitic clay's lattice structure, making it less prone to swelling than in smectite clays.

XRD analysis showed the feasibility of WBM and PBM formulas for Dadas shale. Researchers added thinners and deflocculants to control drilling-fluid water loss.

Table 2 shows WBMs thermal stability. KCl mud was designed to handle contamination caused by the shale play (Table 3).

The entry of solids and fluids from the formation into the drilling mud contaminates it. Shale as a contaminant was studied to determine how its entry might deteriorate key properties of specific drilling fluids.

Researchers ground shale samples into particles smaller than 75 microns. They added 30 g of particles to the drilling fluids being tested.

Each sample of contaminated and uncontaminated mud stood for 16 hrs at four different temperatures: 80°, 150°, 200°, and 250° F.

A rotational viscometer determined rheological properties. Researchers used a filter press to measure filtration properties at 80° F. under 100 psi and used a high-temperature, high-pressure filter press for tests at under 100 psi pressure difference, 200 psi with back-pressure applied, and 300 psi. The filter presses were API certified.

Testers also noted mud-cake thickness and the pH of mud and filtrate. Researchers tracked conformance with API's Recommended Practice RP13 throughout the study. Each experiment was repeated at least three times.

Shale contamination

Contamination from the shale itself caused an increase in the viscometer and rheometer readings, indicating an increase in the fluid's viscosity. Dial readings were taken at six different rpm: 600, 300, 200, 100, 6, and 3.

Fig. 1 shows plastic viscosity, contamination, and temperature variables of the three mud systems. Plastic viscosity values changed slightly with higher temperature.

Fluid-loss properties varied with contamination and temperature (Fig. 2). Results are shown at room temperature for the bentonite mud. Bentonite's rheology stabilized at high temperature in spite of clay contamination.

Contamination and increased temperature caused a slight increase of water loss up to 200° F., and water loss rates increased more above 200° F.

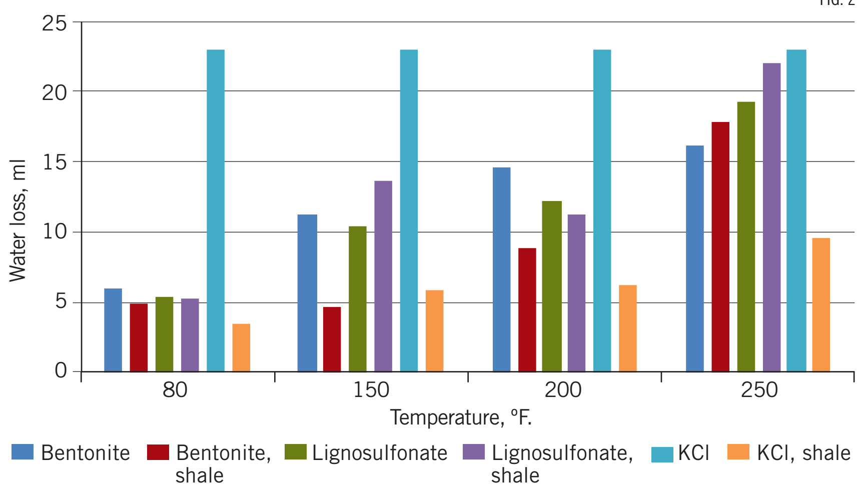
Filtration values were 15 ml or less (API standards require filtration of less than 15 ml) even in different temperatures. Bentonite samples tolerated shale entry up to 250° F.

Shale contamination caused a slight increase at room

KCl formulation for Dadas shale Table 3

Substance	KCl mud
Caustic, g	0.06
Soda ash, g	0.1
PHPA, g	1
PAC-LV, g	5
KCl	< 5% by weight
NaCl	< 20% by weight
XCD polymer, g	0.25

DRILLING FLUID FILTRATION PROPERTIES FIG. 2



temperature in dial reading and plastic viscosity values for lignosulfonate mud samples.

The plastic viscosity of the uncontaminated lignosulfonate mud samples decreased with higher temperature (Fig. 2). The lignosulfonate mud sample's viscosity, however, improved and did not decrease even at higher temperatures. Results revealed that the developed lignosulfonate mud samples' rheology was unaffected by shale contamination.

Contamination and increased temperature caused a slight increase in water loss up to 200° F. Water loss rates increased at 250° F. Filtration values were below 15 ml up to 200° F. Filtration values equaled 22 ml at 250° F. Although this value is above the API recommendation, it is still acceptable for field application.

Lignosulfonate mud samples also tolerated shale entry without measured changes in rheological and filtration properties. KCl mud's rheological properties were similar to bentonite mud. Shale contamination increased dial readings and caused higher plastic viscosity values for KCl mud samples at room temperature.

Plastic viscosity values measured more than 19 cp up to 200° F., but then decreased. Even so, they remained higher than those of the uncontaminated mud sample.

KCl mud was designed to provide good filtration properties in case of contamination. Fig. 2 shows that uncontaminated KCl mud's filtration was too high (>50 ml). When contaminated, however, filtrate volumes were very low even at higher temperatures. The water-loss values were all below 10 ml, in adherence with the API-recommended sub-15 ml recommendation. OGJ

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AFPM Q&A—3

Refiners discuss FCC reliability issues, catalyst selection

This is the final of three articles presenting selections from the 2015 American Fuel and Petrochemical Manufacturers Q&A and Technology Forum (Oct. 4-7, New Orleans). It highlights fluid catalytic cracking (FCC) processes, including issues related to reliability, additives and catalysts, and unit slowdowns.

The first installment, based on edited transcripts from the 2015 event (OGJ, Aug. 3, 2015, p. 52), addressed hydroprocessing operations, with an extended focus on safety, phosphorous poisoning, and meeting the US Environmental Protection Agency's more stringent Tier 3 gasoline standards taking effect Jan. 1, 2017. The second installment (OGJ, Sept. 5, p. 71, 2016) highlighted discussion of processes associated with crude and vacuum distillation, coking, and refiners' experiences with desalting and wastewater treatment.

The forum included six industry-expert panelists from refining companies and other technology specialists responding to selected questions and then engaging attendees in discussion of the relevant issues (see accompanying box).

The only disclaimer for panelists and attendees was that they discuss their own experiences, their own views, and the views of their companies. What has worked for them in their plants or refineries might not be applicable to every situation, but it can provide sound guidelines for what would work to address specific issues or challenges encountered in other plants.

The panel

Bart De Graaf, head of FCC research and development, Johnson Matthey Process Technologies
Todd Foshee, FCC licensing and design, Shell Global Solutions US
Nik Larsen, cat cracker technologist, Marathon Petroleum Corp.
Mark Reynolds, FCC process engineer—Billings, Wash., refinery, Phillips 66
Rich Russeff, operations superintendent—Wynnewood, Okla., CVR Refining LP
Sanjiv Singh, director of refineries, Indian Oil Corp. Ltd.

The respondents

Melissa Clough, BASF Corp.
Neil Dahlberg, Hamon Research-Cottrell Inc.
Emerson Fry, Delek Refining Ltd.
Ziad Jawad, Technip Stone & Webster, Process Technology
Roger Lanouette, Monroe Energy LLC
Warren Letzsch, Technip USA
Robert Ludolph, Shell Global Solutions (US) Inc.
Rik Miller, Phillips 66
Rama Rao Marri, CB&I Lummus Technology
Kevin Proops, Koch Industries Inc.
James Prorok, Husky Energy Inc.
W. Lee Wells, LyondellBasell Industries NV
J.W. Wilson, BP Products North America Inc.

Reliability

The industry continues to experience process safety incidents associated with FCC electrostatic precipitators. What are you doing to prevent these incidents?

Reynolds Phillips 66 has six electrostatic precipitators (ESPs). We have not been immune to serious incidents on our ESPs. In 1994 we had an ESP explode, which actually led to a fatality. In order to minimize the likelihood of these kinds of incidents happening again, the company has a standard that outlines features of an FCC emergency shutdown system all refineries must follow. It lays out how the safety system is supposed to be configured and which features it is supposed to have. Adherence to the standard by each refinery is tracked at the corporate level, and refineries that do not meet the standard must have plans to close the gaps. We actually have one wet ESP at the Billings refinery that is downstream of the scrubber, and it must meet the compliance requirements just like regular ESPs.

One of the standard's requirements is that the ESP shall shut down if the main FCC safety system engages or trips, regardless of the cause. There are several other features as well. If the inlet carbon monoxide (CO) level exceeds the standard's prescribed limit for CO of no greater than 5,000 ppm, the safety system engages. Also, if the air preheater has a safety system on it which then trips, the ESP is required to trip along with it.

The ESP must have its own separate shutdown button.

The CO is used basically as a surrogate for other combustible material. CO is combustible itself, but if you are having poor combustion in your regenerator, you are likely to be generating CO as well. One of the more important features is that the ESP cannot have the ability to reenergize itself after it trips.

So the highest potential for operating on ESP and explosive composition in your flue gases during startups comes from the use of torch oil along with air preheaters, which can lead to poor combustion. Our recommended practice is to keep the ESP down during startup until the unit is stable. Stability is defined as feed in the unit, stable pressure balance, CO within limit, and nothing bypassed in the safety system. For certain locations, you may not be able to have the luxury of starting up without ESPs, in which case the standard recommends that you have an air-preheater safety system as well.

The standard also includes some recommendations: for instance, minimizing the personnel around the ESP during startup, shutdown, or if an upset occurs. It also recommends using the methane analyzer in conjunction with the CO analyzer. For the sites that do start up with an ESP online, having a methane analyzer—in addition to a CO analyzer—is strongly recommended.

The standard additionally includes some scenarios you must consider whenever you do a process hazard analysis (PHA), such as the loss of combustion air, any kind of upset in the regenerator, upset in the stripper, low-riser outlet temperature, and pressure reversals. A lot of this information also can be found in a presentation Phillips 66's own Mike Wardinsky gave at the 2009 AFPM Q&A Principles & Practices session.

Larsen Within Marathon, we have two units with ESPs on them. Our setup is very similar to what Mark described with Phillips. Any activation of the normal FCC safety instrumented system (SIS) will deenergize the ESP. Our trip point for CO is 1,500 ppm, which is a little more conservative. Also, we will trip the ESP if excess oxygen is less than 0.1%. Either of those inputs will act to deenergize the ESP. For safety purposes, we only run our ESPs energized during stable, normal operations, not during the times of hot standby or startup, etc.

Proops Mark and Nik, thank you for your comments. I had the misfortune of visiting the unit Mark mentioned about a week after that catastrophe happened. I want to add a couple of comments to what you described during the startup, when that explosion occurred. Natural gas backed in from the fractionator, through the reactor, and got all the way to the regenerator. I believe that there would not have been any significant CO at that time. Oxygen was high.

So panel members and the audience, if you are worried about ESPs on startup, recognize that they can be very abnormal to what you are used to seeing. I believe the incident investigation also found that the ESP had been in a deenergized state, but it still exploded. So you have to watch out for potentially explosive mixtures of oxygen and methane at higher temperatures.

Lanouette I am curious about the shutdown system. Our analyzer people are telling us that there is interference with CO and methane in doing the analysis, as well as calibration difficulties. Is there a specific analyzer that you have come across that is better for this kind of service? The second part of this question is: Is this a safety integrated level (SIL)-rated shutdown system?

Larsen I know a lot of folks are turning to the tunable diode laser (TDL) technology. I can meet with you after the session to go over the specific analyzer we use with good success.

Fry Does anyone have any experience or insight as to whether or not this would be important to have in a partial-burn unit with a CO boiler on the backend? Is that at any greater or lesser risk than a full-burn unit?

Wilson Just to add another question about it, is there greater risk with an ESP and CO boiler, or is the risk the same? I think it is at least the same, and I certainly think the standards will be the same on our units. I imagine other people who have standards will probably apply the same standards.

Miller I will address two issues. One is the analyzer. As Nik said, the Phillips 66's standard also calls for TDL analyzers because they are very fast-responding and very accurate and sensitive for CO. You can also get a TDL for methane. Some of our units have that as well.

As Kevin pointed out, the incident that Mark mentioned would not have been stopped by one of these analyzers. The explosive mixture was fuel gas, and the ESP was not energized at the time. What that site and about half of our other FCCs have done since then is install these overhead blinding devices between the reactor overhead and the main fractionator. Those are reusable devices that can seal off the reactor from the main fractionator so you avoid getting migration of fuel gas or other hydrocarbons during periods when you are down or starting up. Those are very effective, and we recommend them strongly in our system.

Ludolph I would like to open up the ESP safety question to include any ESP manufacturer respresentatives who may be in the audience. What are the ESP manufacturers doing to help improve the safety and operation of their equipment, and, in turn, the overall safety of the refineries?

Dahlberg Hamon Research Cottrell has supplied a large number of precipitators to US refineries during the last

Indian Oil Corp. Ltd. (IOCL) started the 4.27-million tonne/year (tpy) INDMAX fluid catalytic cracking (FCC) unit to produce a high-yield of light olefins and high-octane gasoline from an array of petroleum fractions at its recently commissioned 15-million tpy, full-conversion refinery at Paradip in India's state of Odisha, on the country's northeastern coast (OGJ Online, Apr. 22, 2016). Photo from IOCL.

PROCESSING

15 years. Many of these suggestions are implemented in our design, and we participate in a hazard and operability (HAZOP) study at the beginning of each design process. An additional level of protection would be to limit the power to the operating transformer and rectifiers at startup to stay below the threshold of sparking, which will eliminate a source of sparking in the precipitator and a potential source of ignition of combustible gases.

Catalysts

Under what conditions do gasoline-sulfur reduction additives and catalysts reduce sulfur in gasoline, and by how much? What is the lowest gasoline-sulfur level for which the gasoline-sulfur reduction products are effective? At this gasoline-sulfur level, please quantify the gasoline-sulfur reduction and the amount of additive-catalyst required.

Larsen That is a very long breath of a question. I will summarize some of Marathon's findings on gasoline-sulfur reduction additives. We have done a lot of testing in our pilot plant in the past. Some of that has already been presented. You can reference Jeff Sexton's response to Question 46 of the 2009 AFPM Q&A FCC session if you want to see a little more data.

In general, we already mentioned our pre and post-treat scenarios and went over how gasoline-sulfur reduction additives work. I will hit on the mechanism of how we believe they work, some of the variables that would impact their performance, and then some of our more recent testing and applicability at already low gasoline-sulfur levels.

In terms of the mechanism, in our pilot-plant testing, we have seen that recombinant reactions play a large role. So no matter what feed-sulfur species end up entering the pilot plant, we get the same gasoline-sulfur species coming out the backend, thereby emphasizing that recombinant reactions in the riser play a large, dominating role in generating gasoline-sulfur species. The additives we tested, for the most part, will crack the gasoline-sulfur species into H_2S. I believe there is other technology that will move the sulfur down into coke.

Several variables can cause an effect. Bart already identified vanadium as one of them. Vanadium's impact on the gasoline sulfur-to-feed sulfur ratio in one of our units with operation at low and high-vanadium levels is very significant.

We also have done testing with nitrogen and noticed big effects in the gasoline sulfur. In general, we have tried many types of gasoline-sulfur reduction catalysts and found two that worked well for us. It is important to recognize the importance of balancing the ability of the gasoline-sulfur reduction catalyst to reduce sulfur without having any adverse yield impacts.

We have done economic modeling and confirmed the pilot-plant testing with actual unit post-audits to find additives that work best for us, and we have then gone on to do some of our testing recently at already low gasoline-sulfur levels.

The gasoline sulfur we are starting at is 20 ppm. This is full-range gasoline-sulfur concentration. We have experienced about the same reduction in gasoline sulfur that previously occurred when starting with higher levels of gasoline sulfur. It appears, then, that the additives we have tested worked in about the same range, even when starting with lower gasoline-sulfur levels or reloads.

De Graaf Additives can help to reduce gasoline sulfur 20-

35%, but they cannot perform miracles. Their performance depends on how much hydrogen transfer is already present in the system. There are various contributing factors to the success of this reduction.

I visited a refinery in China that had two different FCC units. They processed the same feed and used the same base catalyst. One FCC, however, had a sort of fluid bed in the unit, while the other was more of a typical side-by-side FCC unit. At similar conversion level, the unit with the sort of fluid bed in the riser had 35% less sulfur in gasoline due to the huge spent-catalyst recycle caused by the fluid bed.

The base catalyst contributes to hydrogen transfer as well. You can optimize the amount of rare earth. The more rare earth you put in the catalyst, the higher the acid-site density in the zeolite, which will result in more hydrogen transfer. A high-alumina catalyst helps reduce sulfur; and as I mentioned before, high vanadium levels also help to reduce gasoline sulfur.

Another factor is how much hydrogen the feed brings in itself. If there is a lot of hydrogen transfer from the feed, the performance of the gasoline-sulfur additive will be affected. It will be more of an uphill battle vs. feed that presents a low amount of hydrogen transfer.

Mercaptans, thiophenes, or hydrothiophenes are easier to remove than benzothiophenes. Typically, you would use about 10- 20% of gasoline-sulfur additive in one inventory, but we have seen that gasoline-sulfur additives are effective over a very wide range of applications.

Clough I will just add a couple of comments. Both Nik and Bart did a good job talking about a number of key aspects, including speciation. It is important to understand how or what kind of game plan you need in terms of gasoline-sulfur reduction additives. Use of the additive, like Bart said, is about 10-20%. Another point to consider is preblending in order to avoid diluting the base catalyst.

Regarding the use and effectiveness of gasoline-sulfur additives in an instance where you already have low sulfur in the gasoline, I want to share another story from the refinery experience side. Some of our customers in Japan running very low-sulfur feeds are using gasoline-sulfur reduction additives and are still seeing around 20% reduction. So even at already low gasoline-sulfur levels, further reductions are possible.

Reliability

What operating practices or technology upgrades are you using to manage coking in the reactor overhead line at the main fractionator inlet?

Singh Feedstock, catalyst, and reactor hardware all play a very major role in vapor-line coking. Coking of the reactor overhead line is a major concern, particularly when we are processing resids. Catalyst formulations designed for higher hydrogen-transfer reactions, coupled with high-aromatic feed, tend to produce higher-boiling point polynuclear aromatics (PNAs), which have a tendency to condense and form coke in the vapor line. Design and configuration of the vapor line is also a very important factor.

There are different reasons that are all extremely unit-specific for vapor-line coking, and they can predominantly be classified into two categories. The first includes factors leading to the presence of components that tend to produce coke at the reactor outlet. These factors include heavier feeds, aromatic feeds, improper atomization, post-riser cracking, high residence time in the reactor, low activity of the catalyst, comparatively more thermal cracking, etc. The second involves factors related to the configuration and design of the reactor vapor line, which influences condensation and coking. The phenomena of vapor-line coking gets aggravated by cold spots in the reactor vapor line, improper insulation, damaged insulation, low velocities, improper slope, cool patches in the vapor line, etc.

We have experience operating both hot and cold-walled vapor lines, as well as a variety of feed injectors, including old-designed shower heads used for vacuum gas oil (VGO), and modern injectors with resid feed. Our experience has been that, even with the old design of feed injectors, the extent of vapor-line coking was much less while processing VGO vs. processing resid feed with modern atomizers, indicating the significance of feed type on vapor-line coking.

In one of the units, configuration of the vapor line was such that it had too many cold spots. It had the worst slope, and while the unit did have a modern feed-injection system, we had the tremendous problem of vapor-line coking. After correcting the problems related to the vapor line's configuration, to a very large extent, the problem was eliminated. The type of feed you're using and the configuration of your vapor line, then, are very important factors to consider when encountering vapor-line coking.

Here are some suggestions to avoid coking of the vapor line:

- Start with the best feed vaporization. Avoid mixing slurry with feed. While using slurry filters, we find it better to use feed as the backwash medium in lieu of heavy cycle oil (HCO) to avoid having the once-cracked material going back to the riser.
- Avoid cold spots in the vapor line and, based on the design, insulate the vapor line well. During insulation, special attention should be paid to supports, manways, fittings, and flanges.
- Avoid cooling the vapor line with cool-purge streams. In one of our units, we had to provide some steam purges in the vapor line that significantly enhanced coking within the line. Some old designs might be having some purges or bypasses going in the vapor line which, again, should be avoided.

Reynolds I will just reemphasize one point. Yes, you want to make sure you minimize all of the heat sinks on the overhead line. I recommend you do regular infrared scans or thermography and look for hotspots. Do that annually, quarterly, or some other frequency, which is especially important after a turnaround. Make sure you get a high-quality baseline infrared scan so you have a baseline of where you started. I think the dew point in the overhead vapor lines is also 600-700° F., or so. You want to make sure you stay well above that temperature.

Jawad There are a lot of technology options available to help you minimize coking. It is really difficult to measure pressure drop across the vapor line. Typically, you are limited to instrumentation measuring single pressures, and you then have to subtract those pressure measurements. Obviously, you can take pressure at the top of the plenum, but on the main fractionator, you may not have a spot. So you might want to think about having some dedicated tubing, if it is not short, to have an actual differential pressure (DP) at the top of the level bridle to get a downstream pressure.

Wells The actual question stated that the main fractionator inlet was the concern. I did not write the question, but we have a similar concern. It is not on the line itself; it is only right where it goes into the fractionator, in the dead spot. The line comes in from the side and elbows into the main fractionator. On the inside of that sweep, there is a dead spot that tends to build up coke, which breaks off and fills up the bottom of the main fractionator.

Does anyone have an answer as to why that occurs? Also, has anyone else seen coke buildup in the same location? Obviously, someone else submitted this question.

PROCESSING

Letzsch It is not uncommon to actually get a donut around the inlet to your main fractionator. In our old units I have seen areas where we have built up a 5-lb pressure drop across the donut. I think it has a lot to do with the velocity going into the main fractionator—whether it is too low or too high, or if it is sloped properly—and the insulation around it. Frankly, that has been addressed in old AFPM (formerly National Petrochemical and Refiners Association) transcripts.

I will just tell you about one even more interesting situation. You know, when you guys get your FCC units, you go to the licensor. He gives you a process design package, and then you go to the detailed-engineering company. You think the detailed-engineering company personnel are experienced and know what they are doing. Here is your reactor coming out with the main overhead vapor line, and you thought it would go into the main fractionator. But, oh, no! This guy from the detailed-engineering company was really clever. He brings the vapor line out, down, and around to the pipe rack. It went around and then came all the way back around to the back of the fractionator, and you ended up with about a 300-ft vapor line. And the guy was complaining about finding coke in it! These situations really do happen.

Russeff I have seen a similar phenomenon right at the blind flange location on the tower where the coke tends to build up and then streak into the tower building, creating a good pressure drop. We had that same issue, which we ended up solving with a combination of steam rings and insulation to try and eliminate that particular spot during normal operations. It was quite a bit to chisel out, however. It was very oddly shaped because it had started at the flange and then worked its way into the tower, making horizontal stalactites on its way into the tower. Is that the same situation you saw?

Wells We do not have a flange in that location, and we do not see stalactites.

Ludolph We have seen a variety of coke formations pinching the main fractionator inlet, creating pressure drop between the top of the reactor and the top of the main fractionator. Shell did a review of what might have been contributing to the coke growth and concluded that velocity was a player. The ranking of the process parameters suspected as coke growth contributors, however, is quite site-specific. We have conducted computational fluid dynamics (CFD) analysis to better understand what might be occurring, but we are not satisfied with the results. Suspected locations and causes of pressure-drop increases are, many times, unconfirmed when entering the equipment during turnaround. Remediation and prevention of main fractionator-inlet coking remains a big area of learning for us.

Marri The question also asks about some technology practices, as Warren and Sanjiv already discussed. I want to add a couple of thoughts. We recommend that the velocity be somewhere about 120-150 fps toward the coking in the reactor because that also relates to residence time. Secondly, many of these units do not normally have the capability to measure the change in DP (ΔP), as was already mentioned.

So you could look at this as a prevention measure. When you clean the unit and power it up, it would be better to take a single-gauge pressure survey and monitor the present profile across the whole reactor and up to the fractionator, or over to the wall. That helps us keep track of the ΔP across the column and across the vapor line. So typically, there is 1-2.5 psi ΔP across the reactor vapor line, which establishes a guideline. If something in the process changes, such as the hydraulics of the main fractionator, you could monitor and prevent the coking tendencies.

Unit slowdowns

What are your top three causes of unit slowdowns, and what is the loss in on-stream factor for each? Please provide the same information for your top three causes of unit shutdowns.

Russeff I get the fun one! For us, it has been the main-column bottoms exchanger cleaning. We've been achieving some new recoveries at a residual oil supercritical extraction (ROSE) unit located upstream of the FCC that have resulted in high asphaltenes in our feed and slurry. Slowdowns are the result of the combination of that and PNA formation. Some people get excited over 15% asphaltenes in their slurry. When the ROSE unit is not online, we go from about 3% up to as high as 40%, which is very discouraging. A typical turndown for replacing a bundle in that service is about 75% max capacity. We have a spare steam generator online, so we could switch back and forth between the two units.

Another contributor to unit slowdowns is feed availability. The FCC at our Wynnewood refinery does have to compete with other units for feed, depending upon market conditions, whereas the FCC at our Coffeyville doesn't necessarily have a competitor for feed within the refinery itself. We have changed some operations, however, as a result of positioning and some of the prices we have seen in terms of premium gasoline and diesel. We try to make up for that price fluctuation in other areas of the gasoline crack. We have also been able to locate opportunity feed from some external sources. We have good synergy between the two refineries, and since they're relatively close to one another, when Coffeyville was going into turnaround this year, we managed to turn through a lot of its gas and oil at Wynnewood. So the answer on feed availability during turnaround is: It varies, depending upon the market.

Limitations on our wet-gas machine also can contribute to slowdowns. We have a dry-screw machine in wet-gas service. This is a first for me and has been a painful process. We've had a couple of outages as a result of problems with the dry-screw machine in wet-gas service, and we also have a current rebuilding going on that has led to some efficiency losses. We do have a reciprocating compressor as a backup machine, but we have a considerable turndown, basically down to 50%. As for upstream-unit recoveries such as the ROSE I mentioned earlier, we are turning up the knob on recoveries and the asphaltenes. Conradson carbon residue (CCR) leads to metals taking up capacity in the wet-gas machine with a higher hydrogen-to-methane ratio, which we've been addressing by aggressively flushing the additional metals in the catalyst. I've also switched over to a nickel trap catalyst, which is working well.

Given the lack of condensing and cooling capacities our Oklahoma and Kansas refineries have during the summertime, the loss in capacity is really directly dependent on ambient conditions. So that turndown I mentioned earlier also depends on how hot it is outside at each moment.

As far as causes for our top three shutdowns, we don't typically have full shutdowns of the units. But I have to say that rotating-equipment reliability, especially with the dry-screw machine, has been challenging. We have a reciprocating wet-gas machine as a spare machine, but it just doesn't have the capacity. You would think that some of the parts on that dry-screw machine were made of fresh panda blood because it is very difficult to get parts for it.

We've also had some other problems during a rigorous pump-rebuild program that's under way as part of our goal to start a new benchmark in terms of reliability. We've had to send pumps out for complete rebuilds, which does take more time. Pump availability for the spares has not been there during this revamp of our reliability program, so we have had some issues there.

Finally, the other main contributor to slowdowns or shutdowns is probably the catalyst. This is a very sensitive subject, but it is a catalyst issue. We had an opportunity to run what I'll call opportunity equilibrium catalyst (e-cat). Right now, I want to say that we are really happy with our long-time catalyst vendor, and running that opportunity e-cat from another vendor didn't turn out to be such a good opportunity after all, as it resulted in a unit shutdown. Alongside proving to us that our long-time catalyst vendors really are probably the best out there, that shutdown gave us a chance to truly understand the critical importance of paying attention to your e-cat, no matter from whom you get it. You have to pay attention to your e-cat's additives, activity, metals, particulate size, yield projections, and required addition rates.

Singh Cat crackers are one of the major secondary units for all of our refineries. Irrespective of demand and market condition, our units are always required to operate at high capacities. All of our refineries have been participating in Solomon Associates Inc.'s Comparative Performance Analysis benchmarking studies, which show clients where their operations stand vs. their competition. Results of these studies in 2014, which are based on more than 300 cat crackers worldwide, show the percentage of slowdowns for Indian Oil's (IOCL) eight cat crackers is much lower compared with their global competition, consistent with our refineries' focus on consistently high-capacity performance of FCC units.

There is no single reason for unplanned outages of FCC units at IOCL's refineries. Our youngest unit is 13 years old, with most of the units between 17-32 years old. All eight units have been revamped to operate at rates more than 25% to as much as 50% higher than their original design capacities.

During the past 5 years, IOCL's FCC units collectively have experienced 41 interruptions. Out of these 41 incidents, however, not a single cause has been predominant. About 15% resulted from power and utilities interruptions at our captive power plants, while 19% were caused by catalyst-loss issues attributable to aging reactor-regenerator internals. About 24% were a result of rotary equipment issues stemming from wet-gas compressor (WGC) failures, as none of our refineries are equipped with a spare WGC. Static and instrumentation issues, respectively, have resulted in 27% and 15% of our total FCC outages during the 5-year period.

Note that these statistics include all interruptions, irrespective of the duration. Any incident that led to a feed outage also has been accounted for in the evaluation.

Larsen I tracked internal problems associated with our FCCs and the reliability impact of these for all of our Marathon FCCs. I'll highlight two incidents that occurred in 2014 and one that took place in 2015.

In 2014, a flue-gas steam generator leak led to a slowdown that resulted in a 0.7% loss in our overall FCC mechanical reliability. The incident basically stemmed from the presence of older cyclones at this particular site. We chose to operate the unit at higher velocities than our normal operating guidelines, which caused higher catalyst losses and impacted the flue-gas steam generator.

The second slowdown, also in 2014, involved the waste-heat boiler situation I previously mentioned, where older CO boilers were converted to just normal waste heat boilers. An improper quench design where the boiler-feed water was injected too close to a geometry change in the flue-gas line resulted in significant erosion and corrosion problems. This slowdown resulted in a 3% loss in our total FCC mechanical liability for that year. To correct this, we'll be installing new waste-heat boilers on this unit in the future.

The last slowdown occurred in 2015 and was an unforced error that resulted from a blast steam that was left open on the guides of the spent slide valves, which caused a loss of control on the reactor level. This slowdown led to a 1.3% loss in our overall FCC mechanical reliability.

In terms of slowdowns, I just want to add one interesting example. We have one unit that experiences main-column coking as a result of high vapor velocity and slurry entrainment. It requires us to reduce throughput to manage the coking until getting to the next turnaround where we can properly swap some of the fractionation beds. This unit has high inlet velocities to the fractionator, high slurry entrainment, and a fractionation section located right above the slurry section, which combined, leads to low-liquid rates contributing to the coking problem. To eliminate that concern, we'll ultimately swap the beds around in the fractionator.

Prorok You again mention waste-heat boilers as a factor that sometimes contributes to reduced reliability. On our unit, the mud drum hangs on the bottom of the tubes inside the flue-gas duct, so you cannot get to it very easily. We had manway gaskets on the mud drum. You could tell it was leaking by the water balance on the boiler. So yes, when you do maintenance of your unit and have startup and shutdown, the thermal cycling of the system may cause the gaskets to leak. It may have stretched bolts and leaked where the gaskets were crushed and then cooled, ending in failure. OGJ

NELSON-FARRAR COST INDEXES[1]

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

	1962	1980	2013	2014	2015	June 2015	May 2016	June 2016
Pumps, compressors, etc.	222.5	777.3	2,221.1	2,271.9	2,313.6	2,316.2	2,336.0	2,336.9
Electrical machinery	189.5	394.7	516.7	515.8	516.5	517.3	513.7	513.2
Internal-comb. engines	183.4	512.6	1,046.8	1,052.9	1,062.3	1,061.5	1,036.3	1,036.3
Instruments	214.8	587.3	1,509.9	1,533.6	1,554.4	1,554.3	1,597.3	1,635.4
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	1,350.9	1,340.9	1,348.6
Materials component	205.9	629.2	1,538.7	1,571.8	1,434.9	1,454.5	1,432.6	1,427.6
Labor component	258.8	951.9	3,123.4	3,210.7	3,293.8	3,290.0	3,392.8	3,398.7
Refinery (inflation) index	237.6	822.8	2,489.5	2,555.2	2,550.2	2,555.8	2,608.7	2,610.3

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

	1962	1980	2013	2014	2015	June 2015	May 2016	June 2016
Fuel cost	100.9	810.5	1,123.7	1,264.8	915.9	943.4	784.0	783.6
Labor cost	93.9	200.5	308.3	312.8	319.2	308.1	348.6	327.5
Wages	123.9	439.9	1,506.4	1,541.3	1,584.4	1,568.4	1,627.0	1,581.7
Productivity	131.8	226.3	489.1	493.1	497.1	509.1	466.8	482.9
Invest., maint., etc.	121.7	324.8	905.3	939.4	948.0	950.1	941.8	942.3
Chemical costs	96.7	229.2	502.6	472.3	434.6	435.7	406.5	410.5
Operating indexes[2]								
Refinery	103.7	312.7	661.8	688.5	660.0	659.2	654.0	646.6
Process units	103.6	457.5	802.6	865.3	748.1	755.2	708.6	702.3

[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.

Weaker demand outlook, heightened regulations create uncertainty for Chinese refiners

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PROCESSING

Rising oil and gas production and processing capacity over the past decade has been strongly influenced by China's rapidly growing economy. Many forecasts using the country's recent industrialization and urbanization plans as well as its annual gross domestic product (GDP) growth-rate data to gauge future demand suggest an uncertain future for the country's refining sector.

On Nov. 10, 2015, the International Energy Agency (IEA) published its World Energy Outlook 2015 (WEO-2015),[1] which provided projections for China's future energy consumption through 2040. While informed by preliminary Chinese statistical data for 2014 and a draft version of the 13th Five-Year Development Plan (FYP) for 2016-20, these predictions relied mostly on statistical data for 2013 and the 12th FYP for 2011-15.

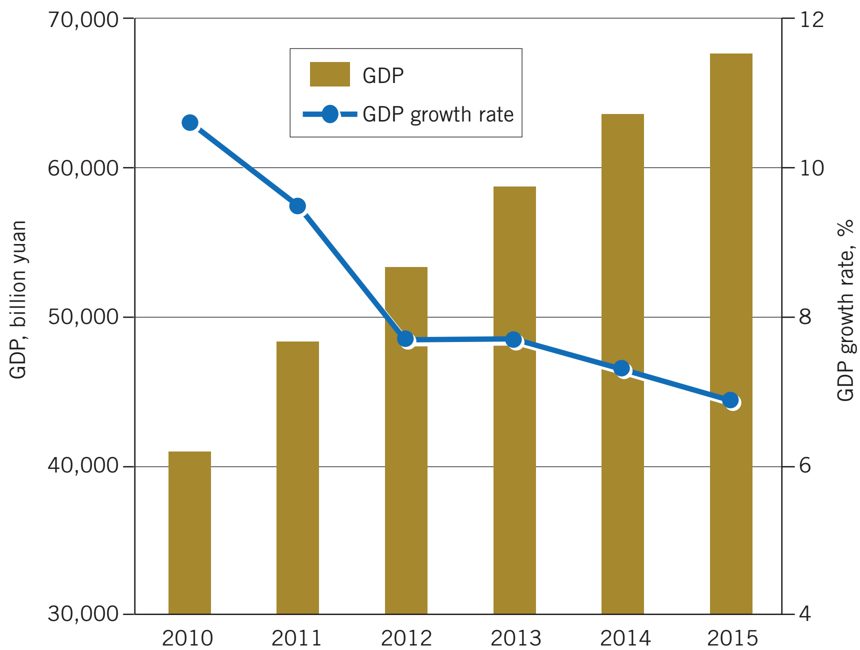
Subsequent revisions to preliminary data by the National Bureau of Statistics of China and additional clarifications regarding economic development plans, improved energy efficiency policies, and aggressive environmental targets under the 13th FYP following its official ratification by China's National People's Congress in March 2016, however, left many in the country's petroleum processing sector seeking a revised outlook for China's future oil and gas demand.

Using a bottom-up accounting framework, the authors of this article ran a long-range energy alternatives planning (LEAP) model[2] based on China's revised statistical data for 2015[3] and recently announced economic and environmental targets under the 13th FYP to provide an updated oil-and-gas demand outlook and its corresponding implications for the nation's refining industry.

Though tracking similar trends as WEO-2015's outlook, results of the authors' analysis show China's actual oil and gas consumption through 2030 may not be as robust as that predicted by WEO-2015, pointing to a future of increasingly stringent regulations on Chinese refiners to reduce capacity in line with the country's softer demand and government targets for lowering emis-sions.

CHINA'S GDP

FIG. 1



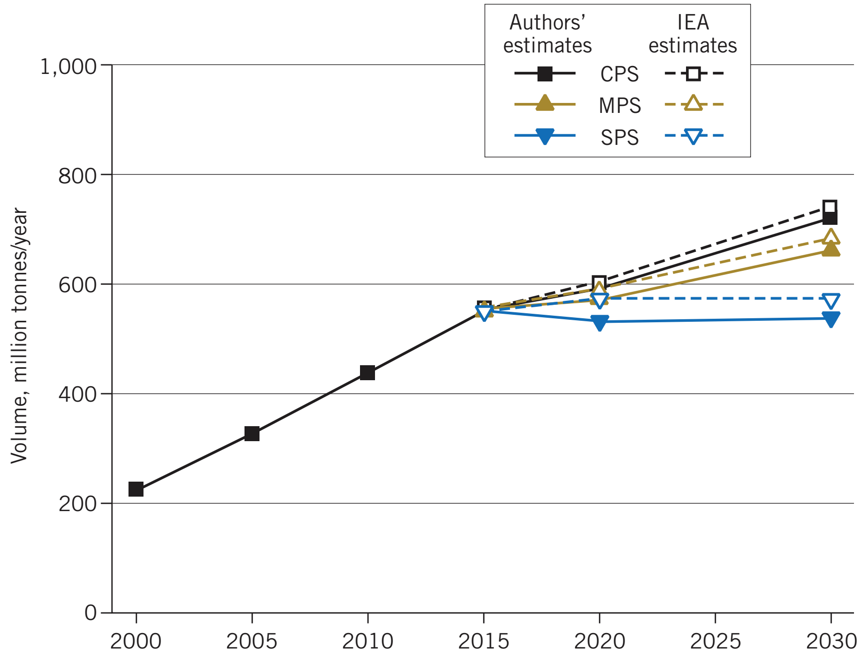
Background

Since the Economic Reform Program initiated in 1978, China has experienced tremendous social transformation and rapid economic growth, with energy consumption becoming an essential component of the country's objectives for social and economic development.

In 1978, China consumed 91 million tonnes of oil primarily for agricultural and industrial applications. By 2015, however, oil consumption had risen to 550 million tonnes, 61% of which was imported to supply energy demands of the transportation and manufacturing sectors in an effort to

CHINA'S OIL DEMAND

FIG. 2



COMPARISON OF OUTLOOK ASSUMPTIONS

Table 1

Scenario	This article	WEO-2015
CPS	Reduce energy intensity 5% from 2015 level by 2020. Reduce CO_2 emissions 60-65%/GDP unit from 2005 level by 2030. Increase nonfossil fuels used in primary energy consumption to 19% by 2030.	Reduce energy intensity 16% from 2010 level by 2015.* Reduce CO_2 emissions 17%/GDP unit from 2010 level by 2015.* Increase nonfossil fuels used in energy consumption primary to 15% by 2020.
MPS	Reduce energy intensity 10% from 2015 level by 2020. Reduce CO_2 emissions 65-70%/GDP unit from 2005 level by 2030. Increase nonfossil fuels used in primary energy consumption to 24% by 2030.	Reduce CO_2 emissions 60-65%/GDP unit from 2005 levels by 2030. Increase nonfossil fuels used in primary energy consumption to 20% by 2030.
SPS	Reduce energy intensity 15% from 2015 level by 2020. Reduce CO_2 emissions 70-75%/GDP unit from 2005 level by 2030. Increase nonfossil fuels used in primary energy consumption to 30% by 2030.	Reduce SO_2 emissions 8% and NO_x emissions 10% from 2010 level by 2015.* Implement CO_2 emissions trading scheme for power, industrial sectors.

*Targets of 12th FYP.

stimulate employment opportunities for the country's quickly growing middle-class population.

Like many developing countries, China has accelerated its replacement of coal with natural gas as a source of power generation. The gradual shift comes despite higher costs for using natural gas relative to those associated with using the country's abundant coal supplies. In 2015, China's natural gas consumption rose to 205 billion cu m from 31 billion cu m in 2001, an average annual growth rate of 13.4%.

While China's annual GDP increased to 67,670 billion yuan in 2015 vs. 40,890 billion yuan in 2010, its annual GDP growth rate fell to 6.9% from 10.6% during the same period.

Fig. 1 shows China's annual GDP and GDP growth rate between 2010-15.

Prediction variations

WEO-2015 provided China's energy consumption outlook for the next two decades under three scenarios: the current-policies scenario (CPS), a moderate-policies scenario (MPS), and a strong-policies scenario (SPS).

While WEO-2015's predictions for Chinese future oil and gas consumption under the various scenarios were in line with those presented in this article, our predictions using the latest data resulted in lower values for all three scenarios. The discrepancies between the authors' and WEO-2015's predictions can be attributed the following:

- WEO-2015's predictions relied heavily on the 12th FYP, which underestimated the rigorous measures undertaken in 2015 by the Chinese government for improving energy efficiency and reducing environmental impacts.
- China, while an association country, is not one of IEA's official 28-member countries. Data sources for WEO-2015 likely came from third parties and may not have reflected China's most up-to-date data.
- Alongside this article's use of China's 2015 energy consumption as a baseline vs. WEO-2015's use of a 2013 baseline, assumptions used for calculations in this study differ from those used by IEA under the three scenarios (Table 1).

Oil, gas demand

Based on the most currently available data, China's oil demand by 2030 will continue to increase under CPS and MPS to 722 million tonnes and 661 million tonnes, respectively, vs. a 2015 demand of 550 million tonnes.

Under SPS, however, Chinese oil demand will remain relatively constant to the 2015 level, dropping only slightly to 538 million tonnes by 2030. The possible decline results from potentially rigorous implementation of alternative energies (gas, renewables, and nuclear) as replacements for oil to achieve the government's ambitious target for reducing greenhouse gas emissions.

Fig. 2 shows predictions by the authors and WEO-2015 for Chinese oil demand by 2030 under the three scenarios.

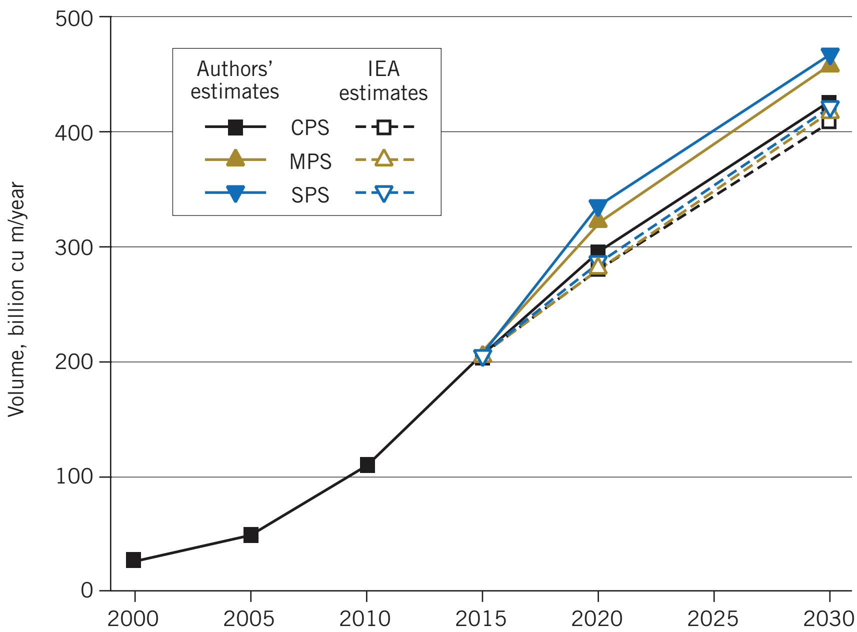
This article's revised outlook indicates China's gas demand also will continue to rise by 2030 from a level of 205 billion cu m in 2015 under all three scenarios. Under the CPS scenario, gas demand will climb to 426 billion cu m, with demand under the MPS scenario predicted to be 457 billion cu m. Under the SPS scenario of high-energy efficiency, China's gas demand will rise to its highest level of all three scenarios at 468 billion cu m.

In addition to previously mentioned factors contributing to discrepancies between the authors' and WEO-2015's demand predictions, our outlook for rising gas demand under SPS considers the increased substitution of oil with gas in certain applications as a route to meeting regulatory targets for high-energy efficiency.[4]

Fig. 3 shows our and WEO-2015's predictions for gas demands in China by 2030 for the various scenarios.

CHINA'S GAS DEMAND

FIG. 3



13TH FYP OBJECTIVES FOR REFINERS

Table 2

Sector element	Objective
Refining capacity	Phase out obsolete, inefficient, and small to medium-sized refineries in preference of optimizing large and advanced petrochemical projects. Halt development of new petrochemical projects during first 3 years of 13th FYP.
Structure adjustment	Restructure, transform, and optimize refineries into integrated refining-petrochemical operations that leave limited environmental footprints.
Market competition	Encourage more private investment in the refining industry. Loosen restrictions on exports and pricing of refined products.
Energy savings	Implement Euro 5-grade transportation fuels in all Chinese cities by January 2017. Improve energy efficiency and upgrade processing technologies.
Belt and Road Initiative	Strengthen oil and gas investment and cooperation with countries along the Silk Road Economic Belt.

Refining sector

Between 2005-14, China's refining industry undertook an aggressive expansion of crude processing capacities to meet sharply rising demand for transportation fuels and petrochemical products. The spike in capacity occurred largely as a result of state-owned enterprises (SOE) such as PetroChina Co. Ltd. and China Petrochemical Corp. (Sinopec) executing massive upgrading programs at most of their existing plants, as well as building several new and highly complex refineries. By 2014, China's overall processing capacity reached 721 million tonnes.

In 2015, however, China initiated a series of steps aimed at reforming its refining sector, particularly with the introduction of cleanfuel specifications as well as a loosening of restrictions on the country's smaller, non-SOE teapot refineries.[5]

The government's mandate for implementation of Euro 5-grade transportation fuels in major cities in early 2015 forced some poorly equipped refineries to shut down or operate at reduced rates. By yearend 2015, China's overall refining capacity had fallen to 710 million tonnes, a combined 74% of which belongs to SOEs and the remaining 26% to independent teapot refiners.

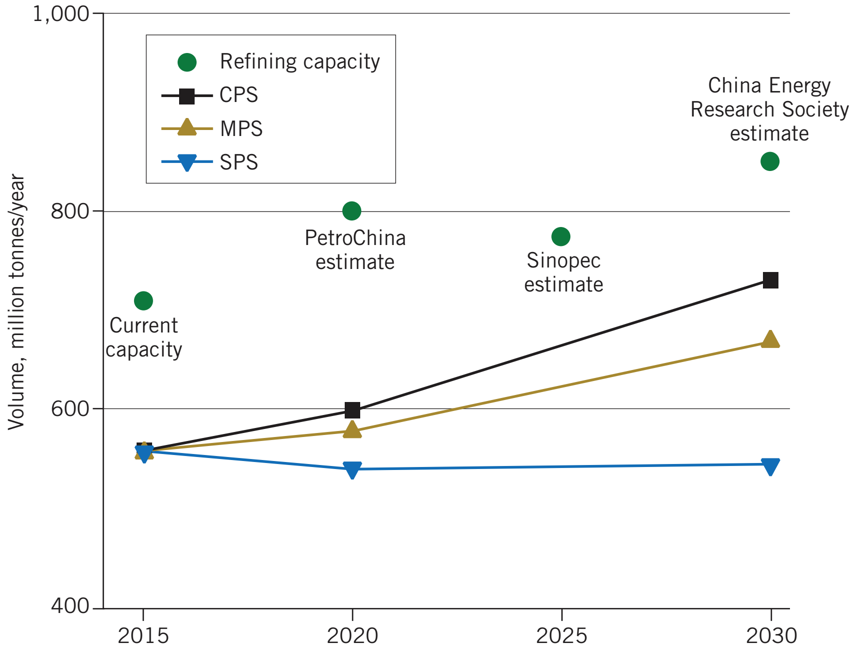
At the same time, however, the government's relaxed restrictions on teapots (including granting some teapots licenses to import crude and export refined products) have encouraged some teapots to revamp and upgrade their aging refineries to produce high-quality fuels.

Whereas SOEs struggle to compete with each other for market share amid reduced national demand and processing restrictions, teapot refiners have increased capacity utilization as well as their market share of refined product sales. This is especially true in Shandong Province, where 89% of China's teapot refineries are located.

While it has contributed to a rise in crude imports into China, this surge in capacity utilization at teapot refineries is likely to be short-lived, as many of these independent refin-

CHINA'S OIL DEMAND, REFINING CAPACITY

FIG. 4



ers are not financially equipped to retool to produce Euro 5-grade transportation fuels that will be required across the country by 2017. Recently launched investigations by Chinese government agencies into allegations of tax fraud committed by these smaller refiners will further limit their ability to compete with SOEs.

Despite China's heightened regulations, China's future refining capacity is poised to increase slightly to 800-850 million tonnes, according to data from several petrochemical information agencies.[6]

Fig. 4 shows predictions for future Chinese oil demand and refining capacity.

In 2030, under our high (720 million tonnes) and low- (540 million tonnes) demand scenarios, China's refining capacity utilization will be 85% and 64%, respectively.

The low-demand scenario, along with its implication for low-capacity utilization, has created a great deal of uncertainty for Chinese refiners, which already are facing heightened government intervention with the introduction of policies and corrective efforts designed to address the nation's overcapacity.

In the near term, China's refiners must focus on a strategy to meet the government's recently announced policies, which—while likely to expand further in scope—presently include the following:

- Align refining capacity with oil demand by 2025. This will phase out obsolete, inefficient, and small-to-medium sized refineries in preference of optimizing large and advanced petrochemical projects. Newer and more advanced technologies will be required to improve processing efficiency as well as quality of refined products to comply with targets of the 13th FYP, particularly those related to emissions reductions (Table 2).
- Integrate the refining industry into China's Belt and Road Initiative for foreign policy, which allows export of refined products and will help alleviate the need for excess processing capacity as a pathway to accelerate modernization of domestic refineries in preparation for increased competition abroad. This will impact future refinery development in China as well as planned investments in developing refineries across the Asia-Pacific region.
- Impose stringent environmental regulations on the domestic refining industry. Alongside improving the quality of refined products, this will result in increased energy efficiency and reduced emissions at Chinese refineries.
- Restructure and transform the refining sector into a green manufacturing industry in the sense that it operates with little impact to the environment as a result of limiting its use of natural resources, recycling and reusing water and other produced forms of energy from processing activities, and limiting its emissions. This aims to spur domestic refiners into adopting innovative technologies that will lead to efficient operations of large petrochemical complexes. OGJ

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Equipment costs rise moderately

Gary Farrar
Contributing Editor

While costs for the five equipment items which make up the Nelson-Farrar miscellaneous equipment cost index were mixed during 2014-15, the overall index ended the period stronger at 1,355.5 in December 2015 vs. 1,337.6 in January 2014.

Of the components included in the equipment average, pumps & compressors experienced the greatest increase, rising to 2,323.7 in December 2015 from 2,251.9 in January 2014.

Electrical machinery ended the timeframe slightly weaker, falling to 515.0 in December 2015 from 516.4 in January 2014.

Engines rose across the period to 1,064.7 from 1,047.7, while heat exchangers remained steady during 2014-15 at 1,305.0.

After dropping to 1,532.3 in December 2014 from 1,567.0 in January 2014, the index average for instruments rebounded to end December 2015 stronger at 1,569.2. OGJ

VARIATION OF NELSON-FARRAR MISCELLANEOUS EQUIPMENT INDEX

Year and month	Code 1141 Pumps compressors	Code 117 Electrical machinery	Code 1194 Engines	Instru-ments	Heat exchangers	Misc. equipment average
2014						
Jan.	2,251.9	516.4	1,047.7	1,567.0	1,305.0	1,337.6
Feb.	2,260.4	516.4	1,049.6	1,521.8	1,305.0	1,330.6
Mar.	2,264.2	515.5	1,051.4	1,520.6	1,305.0	1,331.4
Apr.	2,267.0	515.5	1,050.8	1,532.2	1,305.0	1,334.1
May	2,272.7	515.0	1,050.8	1,528.6	1,305.0	1,334.4
June	2,272.7	515.5	1,050.8	1,528.3	1,305.0	1,334.5
July	2,268.0	515.5	1,054.6	1,547.8	1,305.0	1,338.2
Aug.	2,269.9	515.5	1,055.9	1,538.7	1,305.0	1,337.0
Sept.	2,276.5	515.9	1,055.9	1,536.1	1,305.0	1,337.9
Oct.	2,282.1	515.9	1,055.9	1,525.7	1,305.0	1,336.9
Nov.	2,284.0	515.9	1,055.9	1,523.9	1,305.0	1,336.9
Dec.	2,293.5	516.4	1,055.2	1,532.3	1,305.0	1,340.5
Year	**2,271.9**	**515.8**	**1,052.9**	**1,533.6**	**1,305.0**	**1,335.8**
2015						
Jan.	2,305.8	517.7	1,060.9	1,529.3	1,305.0	1,343.8
Feb.	2,306.7	516.8	1,060.3	1,528.4	1,305.0	1,343.5
Mar.	2,309.5	516.8	1,058.4	1,536.4	1,305.0	1,345.2
Apr.	2,313.3	516.8	1,064.1	1,553.2	1,305.0	1,350.5
May	2,313.3	517.7	1,062.2	1,565.9	1,305.0	1,352.8
June	2,316.2	517.3	1,061.5	1,554.3	1,305.0	1,350.9
July	2,307.7	517.3	1,061.5	1,555.9	1,305.0	1,349.5
Aug.	2,316.2	516.4	1,063.4	1,561.1	1,305.0	1,352.4
Sept.	2,315.2	515.5	1,062.8	1,563.8	1,305.0	1,352.5
Oct.	2,317.1	515.0	1,064.1	1,561.2	1,305.0	1,352.5
Nov.	2,318.0	515.0	1,064.1	1,573.5	1,305.0	1,355.1
Dec.	2,323.7	515.0	1,064.7	1,569.2	1,305.0	1,355.5
Year	**2,313.6**	**516.5**	**1,062.3**	**1,554.4**	**1,305.0**	**1,350.3**

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	May 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	1,021.8	Code 0543	No. 13, May 19, 1958, p. 181
Fuel, refinery price	85.5	152.0	1,064.2	1,211.5	857.4	746.2	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	1,627.0	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	1,024.3	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	936.8	Code 1022-02-73	July 5, 1965, p. 117
Sodium carbonate	90.9	119.4	750.3	714.0	717.6	675.0	Code 613-01-03	No. 58, Oct. 12, 1959, p. 186
Sodium hydroxide	95.5	136.2	1,028.4	978.6	983.6	925.0	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	743.1	Code 614	Oct. 5, 1964, p. 149
Furfural	94.5	137.5	1,496.5	1,446.5	1,148.8	1,072.3	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	May 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	1,627.0	Employ & Earn	No. 41, Feb. 16, 1969
Productivity	97.2	197.0	489.1	493.1	497.1	466.8	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	3,028.9	Eng. News Record	No. 55, Nov. 3, 1949
Common labor	192.1	630.6	3,732.8	3,848.5	3,933.2	4,068.7	Eng. News Record	No. 55, Nov. 3, 1949
Refinery cost	183.3	545.9	3,123.4	3,210.7	3,293.8	3,392.8	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	1,776.5	Computed	July 8, 1962, p. 113
Building materials (nonmetallic)	143.6	212.4	1,169.8	1,204.8	1,233.6	1,256.7	Code 13	No. 61, Dec. 15, 1949
Brick—building	144.7	252.5	1,342.5	1,375.6	1,398.5	1,405.5	Code 1342	No. 20, Mar. 3, 1949
Brick—fireclay	193.1	322.8	2,072.6	2,077.9	2,112.7	2,127.9	Code 135	May 30, 1955, p. 104
Castings, iron	188.1	274.9	1,728.2	1,743.1	1,730.9	1,716.2	Code 1015	Apr. 1, 1963, p. 119
Clay products (structural, etc.)	159.1	342.0	952.5	963.2	984.1	997.1	Code 134	No. 20, Mar. 3, 1949
Concrete ingredients	141.1	218.4	1,305.4	1,360.7	1,418.0	1,488.0	Code 132	No. 22, Mar. 17, 1949
Concrete products	138.5	199.6	1,046.5	1,086.9	1,130.9	1,166.8	Code 133	Oct. 2, 1967, p. 112
Electrical machinery	159.9	216.3	516.7	515.8	516.5	513.7	Code 117	May 2, 1955, p. 104
Motors and generators	157.7	211.0	1,107.4	1,125.3	1,124.5	1,111.5	Code 1173	May 2, 1955, p. 104
Switchgear	171.2	271.0	1,395.8	1,400.6	1,402.7	1,411.8	Code 1175	May 2, 1955, p. 104
Transformers	161.9	149.3	798.0	798.2	757.2	738.3	Code 1174	No. 31, May 19, 1949
Engines (combustion)	150.5	233.3	1,046.8	1,052.9	1,062.3	1,036.3	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	1,454.9	Computed	June 8, 1963, p. 133
Hand tools	173.8	346.5	2,080.4	2,099.7	2,099.4	2,112.0	Code 1042	June 27, 1955
Instruments (composite)	154.6	328.4	1,509.9	1,533.6	1,554.4	1,597.3	Computed	No. 34, June 9, 1949
Insulation (composite)	198.5	272.4	1,951.1	2,014.9	2,072.6	2,155.2	Manufacturer	July 4, 1988, p. 193
Lumber (composite)	197.8	353.4	1,379.9	1,489.7	1,380.7	1,398.0	Code 81	No. 7, Dec. 2, 1948
Southern pine	181.2	303.9	999.5	1,025.0	966.4	1,006.2	Code 81102	No. 7, Dec. 2, 1948
Redwood, all heart	238.0	310.6	2,059.5	2,112.1	1,992.0	2,073.7	Code 811-0332	July 5, 1965, p. 117
Machinery								
General purpose	159.9	278.5	1,510.6	1,540.5	1,562.1	1,576.8	Code 114	Feb. 17, 1949
Construction	165.9	324.4	1,871.3	1,899.9	1,925.9	1,943.8	Code 112	Apr. 1, 1968, p. 184
Oil field	161.9	269.1	1,983.2	2,017.8	2,020.1	2,001.1	Code 1191	Oct. 10, 1955, p. 267
Paints—prepared	159.0	231.8	1,410.4	1,424.6	1,411.3	1,389.0	Code 621	May 16, 1955, p. 117
Pipe								
Gray iron pressure	195.0	346.9	3,363.2	3,392.1	3,369.5	3,340.1	Code 1015-0239	Jan. 3, 1983, p. 76
Standard carbon	182.7	319.9	2,907.9	2,895.4	2,633.2	2,543.6	Code 1017-0611	Jan. 3, 1983, p. 76
Pumps, compressors, etc.	166.5	337.5	2,221.1	2,271.9	2,313.6	2,336.0	Code 1141	No. 29, May 5, 1949
Steel-mill products	187.1	330.6	1,727.8	1,775.9	1,565.4	1,491.0	Code 1017	Jan. 3, 1983, p. 73
Alloy bars	198.7	349.4	1,356.2	1,419.2	1,408.0	1,450.7	Code 1017-0831	Apr. 1, 1963, p. 119
Cold-rolled sheets	187.0	365.5	1,889.0	1,969.8	1,695.2	1,623.1	Code 1017-0711	Jan. 3, 1983, p. 73
Alloy sheets	177.0	225.9	982.5	1,024.5	881.6	844.0	Code 1017-0733	Jan. 3, 1983, p. 73
Stainless strip	169.0	221.2	1,049.0	1,093.8	941.5	899.7	Code 1017-0755	Jan. 3, 1983, p. 73
Structural carbon, plates	193.4	386.7	2,073.8	2,153.6	1,914.5	1,755.0	Code 1017-0400	Jan. 3, 1983, p. 73
Welded carbon tubing.	180.0	265.5	2,946.5	2,933.8	2,668.1	2,576.9	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	1,172.9	Code 1072	No. 5, Nov. 18, 1949
Tube stills	123.0	125.3	674.4	692.8	642.6	628.7	Computed	Oct. 1, 1962, p. 85
Valves and fittings	197.0	350.9	2,384.3	2,445.5	2,467.2	2,496.5	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	2,608.7	OGJ	May 15, 1969
Nelson-Farrar Refinery Operation								
(1956)	88.7	118.5	661.8	688.5	660.0	654.0	OGJ	No. 2, Mar. 3, 1958, p. 167
Nelson-Farrar Refinery Process Operation								
(1956)	88.4	147.0	802.6	865.3	748.1	708.6	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.

Method yields more conservative estimates of DRA effectiveness

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Drag-reducing additives (DRA) alone are not enough to meet increased flow demand given pipeline codes and operational constraints, despite being a very practical means of resolving bottleneck situations in pipeline operations, such as increasing pipeline flow capacity to meet peak demand or mitigating potential surges (OGJ, April 4, 2016, pp. 76-78).

A simple method is proposed to estimate DRA-induced flow increase in liquid pipelines from either a field test or the vendor's DRA performance curve. The proposed method requires knowledge of only three operational parameters—average flow rate, pipeline inlet pressure, and pipeline outlet pressure—and could give more conservative results than the vendor's claimed results.

Background

Drag-reducing additives or drag-reducing agents (DRA) are long-chain polymers of very high molecular weight made of alpha olefins.[1] Recent developments in DRA synthesis and trials show promising results in terms of reducing frictional losses and improving flow in both multiphase[2] flows and gas pipelines, joining DRA's well-established effects in single liquid-phase flows such as stabilized crude or refined products.

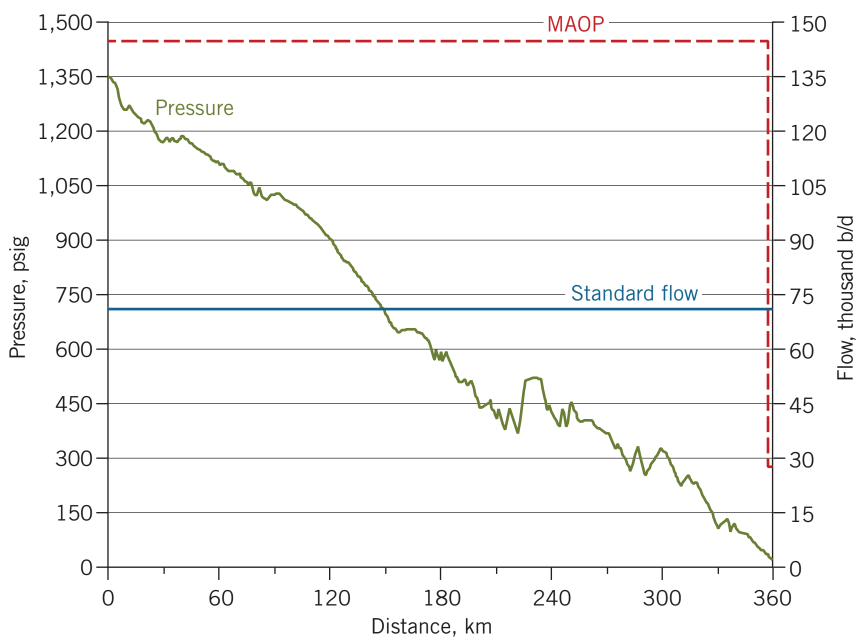
DRA manufacturers and vendors present a performance curve with each of their DRA products in a specific application to show its performance in, for instance, oil-service pipelines or other hydrocarbon-service pipelines (e.g., diesel or gasoline).[3] Such curves are generated from either laboratory and research tests or from actual field trials in operating pipelines.

These performance curves, however, cannot be generalized to every pipeline, even those in the same type of service. Actual DRA performance curves depend not only on the properties of the DRA and of the fluid into which it is injected, but also on the pipeline's profile and operating conditions.

In most DRA field tests, however, flow rate during normal operation is almost constant and cannot be increased due to operational constraints or demand limitations, despite the desire to measure the percentage flow increase caused by the DRA. DRA performance monitoring measures a pipeline's pressure differential before and after DRA injection. Drag reduction percentages are calculated from these measurements and plotted against DRA concentrations (ppm), generating the actual performance curve of that specific DRA in that specific pipeline and application.

Jet-fuel pipelines cannot use DRA and it is injected only with extreme care into multi-products pipelines shipping batches of jet along with other refined products. Another limitation is the maximum DRA concentration set by the end-user. Some pipeline operating companies set a maximum of 15 ppm of DRA in gasoline to avoid probable plugging of engines' injector nozzles.

FLOW CHARACTERISTICS WITHOUT DRA FIG. 1



EQUATIONS

$Q = K\sqrt{(\Delta P)}$ (1)

or

$Q^2 = K^2\Delta P$ (2)

Where

K = a constant that involves the valve coefficient

$nQ^2 = K^2[(P_i - P_2) + (P_2 - P_3) + (P_3 - P_4) + (P_n - P_o)] = K^2(P_i - P_o)$ (3)

or

$Q^2 = (K^2/n)(P_i - P_o) = C^2\Delta P$ (4)

Where

C = a constant, since n is, implying

$Q = C\sqrt{(\Delta P)} = C[\sqrt{(P_i - P_o)}]$ (5)

Where

ΔP = pressure drop across the pipe with P_i = pipe inlet pressure and P_o = pipe outlet pressure

P_{ib} = pipeline inlet pressure before DRA injection

P_{ia} = pipeline inlet pressure after DRA injection

$(\Delta P)_b = P_{ib} - P_o$ = pressure drop in pipeline before DRA injection

$(\Delta P)_a = P_{ia} - P_o$ = pressure drop in pipeline after DRA injection

$Q = C_b\sqrt{(\Delta P)_b}$ (6)

Where

Constant C_b = the proportionality constant before DRA injection

$Q = C_a\sqrt{(\Delta P)_a}$ (7)

$C_a = Q/[\sqrt{(\Delta P)_a}]$ (8)

$xQ = [\sqrt{(\Delta P)_b}]Q/[\sqrt{(\Delta P)_a}]$ (9)

Where

$x > 1$

$x = [\sqrt{(\Delta P)_b}]/[\sqrt{(\Delta P)_a}]$ (10)

$(x - 1)(100\%) = [\{\sqrt{(\Delta P)_b}/\sqrt{(\Delta P)a}\} - 1](100\%)$ (11)

$D = [(\Delta P)_b - (\Delta P)_a]/(\Delta P)_b$ (12)

$(\Delta P)_a/(\Delta P)_b = 1 - D$ (13)

$x = \sqrt{[1/(1 - D)]}$ (14)

$xQ = Q/[1/(1 - D)]$ (15)

$(x - 1)(100\%) = [\sqrt{\{1/1(1D)\}} - 1](100\%)$ (16)

$Q^2/Q^2d = \Delta P\sqrt{\Delta P_d}$ (17)

From which

$\Delta P_c = (Q/Q_d)^2(\Delta P_d)$ (18)

$D = [(\Delta P)_b - (\Delta P)_c]/(\Delta P)_b$ (19)

$(Q_1/Q_2)^n = \Delta P_1/\Delta P_2$ (20)

From which

$n = \log(\Delta P_1/\Delta P_2)/\log(Q_1/Q_2)$ (21)

Other limitations may come from the pipeline itself, such as multiple fittings, which sharply degrade the DRA and limit its effect. Such degradation could be compensated for by increasing DRA doses, but these are capped both by users' policies and by DRA's own pressure reduction limits.

Increase estimation

Equations 1 and 2 supply the general flow (Q) and pressure drop (ΔP) relation across a valve.[4] Pipeline topography and fittings (such as elbows) can be substituted for with equivalent lengths, resulting in a horizontal pipe of more or less the actual pipe length between pipe inlet and pipe outlet. Considering this pipe as if it is composed of n-adjacent similar valves of the same size and valve coefficient and applying Equation 2 yields:

- $Q^2=K^2(\Delta P)_1$; $(\Delta P)_1=P_i-P_2$, where P_i is pipe inlet pressure.
- $Q^2=K^2(\Delta P)_2$; $(\Delta P)_2=P_2-P_3$, where P_2 is upstream pressure of the second (next) valve
- $Q^2=K^2(\Delta P)_3$; $(\Delta P)_3=P_3-P_4$, where P_3 is upstream pressure of the third valve

Continue until the last (nth) hypothesized valve. $Q^2=K^2(\Delta P)_n$; $(\Delta P)_n=P_n-P_o$, where P_n is upstream pressure of the nth (last) valve and P_o is the pipe outlet pressure, the downstream pressure of the nth valve at the pipeline outlet.

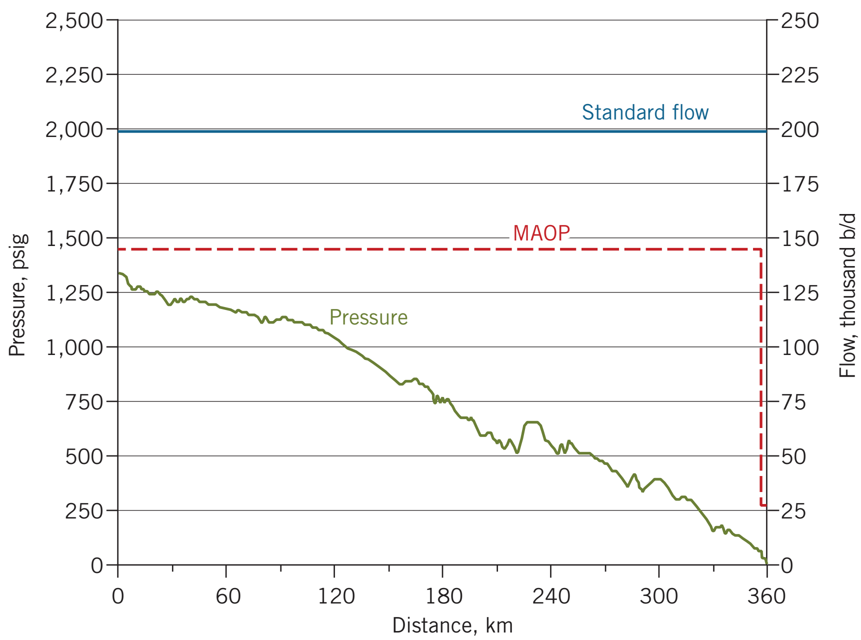
Completing these equations yields Equations 3-5

Substituting into Equation 5 produces Equation 6.

The required pipeline inlet pressure after DRA injection

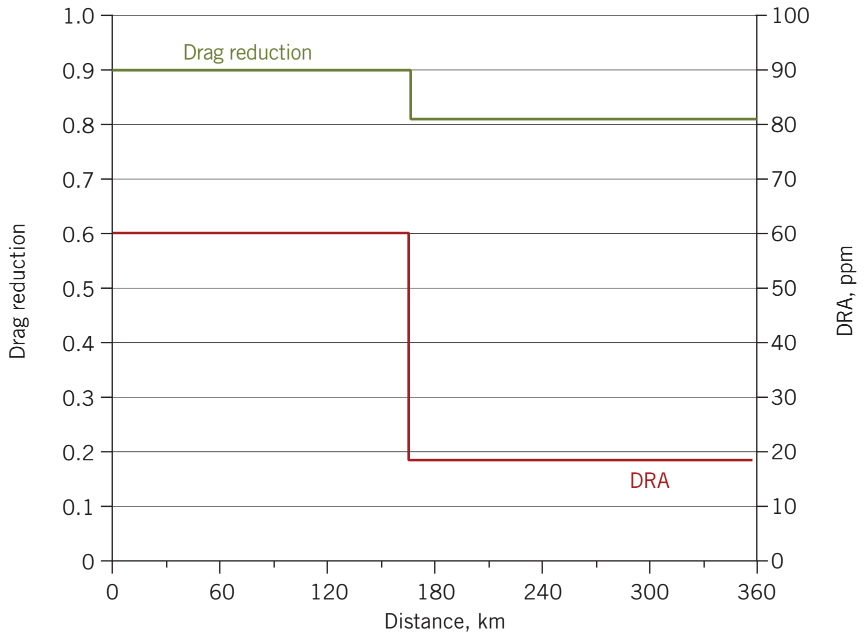
FLOW CHARACTERISTICS, DRA AT SOURCE ONLY

FIG. 2



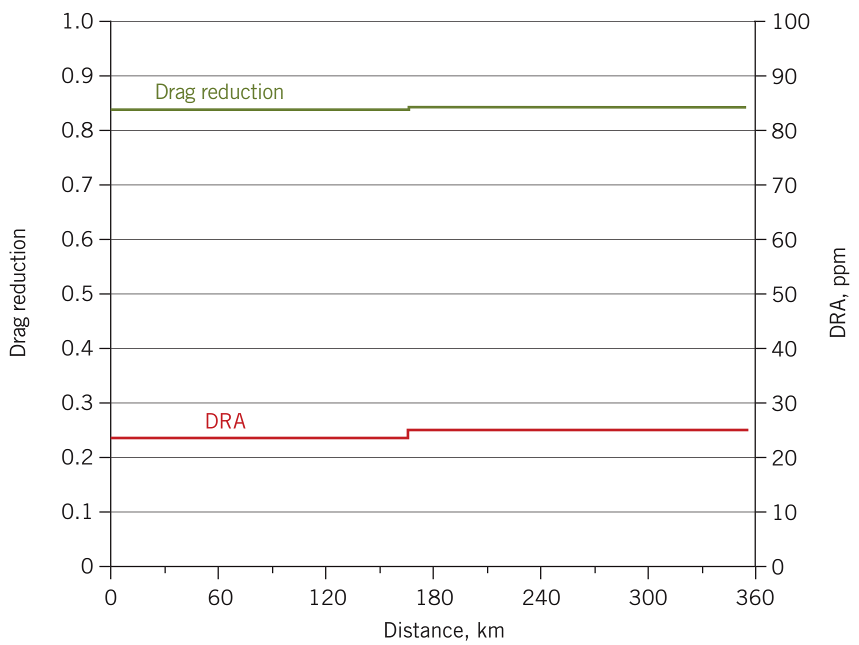
DRA PERFORMANCE, INJECTED AT INLET ONLY

FIG. 3



DRA PERFORMANCE; INJECTED AT INLET, KM-160

FIG. 4



(P_{ia}) will be less than the required pressure before DRA injection (P_{ib}) to pump the same flow rate. That is: $P_{ia}<P_{ib}$ or $(\Delta P)_a<(\Delta P)_b$. After DRA injection, Equation 6 becomes Equation 7.

Q is the same during the test before and after DRA injection, while $(\Delta P)_a<(\Delta P)_b$, so the proportionality constant after DRA injection C_a must be bigger than C_b, as if we have the same flow going through a bigger valve (Equation 8).

To actually increase the flow rate, we would use DRA with the original available pipeline inlet pressure P_{ib}. That is, we would have to apply the proportionality constant given by Equation 8 into Equation 6, where the new flow rate with DRA would then be as derived by Equation 9, which in turn yields Equation 10.

The predicted flow rate as a result of using DRA would be xQ, where x is calculated from Equation 10 and Q is the original flow rate of the test. Equation 11 shows the percentage of flow increase stemming from DRA use.

The customer can also estimate the flow increase from the drag reduction corresponding to a specific DRA concentration and injection flow rate by letting D equal the fraction of drag reduction resulting from use of DRA (Equation 12). Equation 12 can be converted to Equation 13.

Using Equation 13, Equation 10 becomes Equation 14. The predicted new increased flow rate after using DRA therefore can be estimated from the vendor-provided drag reduction (Equation 15). Similarly, the percentage of flow increase in terms of drag reduction is defined by Equation 16.

During field tests a variable such as the flow rate or pipeline outlet pressure might be hard to keep fixed at a constant value and would fluctuate around an average value during a reasonably stable operation. This average is the datum to apply in the preceding equations.

The DRA performance curve is constructed against a specific fixed flow rate, Q, which can be taken as the average operationally stable flow rate during DRA field testing. If during the development of the DRA curve the flow rate deviated significantly from Q to a new flow rate, Q_d, after DRA injection, with a corresponding differential pressure (ΔPd), then ΔPd will have to be corrected (to ΔP_c) to correspond with Q, not Q_d. This can be done as shown in Equations 17-18 given shared pipeline size and fluid properties.[5]

Substituting ΔP_c into Equation 12 calculates drag as shown in Equation 19. Some DRA testers assume $\Delta P_c=(Q/Q_d)^n(\Delta P_d)$, where n is a positive real value (does not have to be an integer) that will have to empirically be calculated from two different recorded flow rates, say Q_1 and Q_2, with their corresponding differential pressures (frictional pressure drops) ΔP_1 and ΔP_2 (Equations 20-21).

The n found in Equation 21 must equal 2 for Equation 18 to be good for any liquid fluid, with pipeline size and liquid properties assumed constant throughout the test.

DRA limitations

The following case study demonstrates DRA limitations in increasing pipeline flow rate as well as providing examples of flow increase estimations using the suggested formulas.

A 16-in. OD ANSI 600 class pipeline transports 70,000 b/d of diesel 360 km to a storage without DRA. A sharp increase in demand required raising the flow rate to 200,000 b/d by some combination of DRA and a new intermediate pump station under the operational constraint that pipeline inlet pressure must not exceed 1,350 psig.

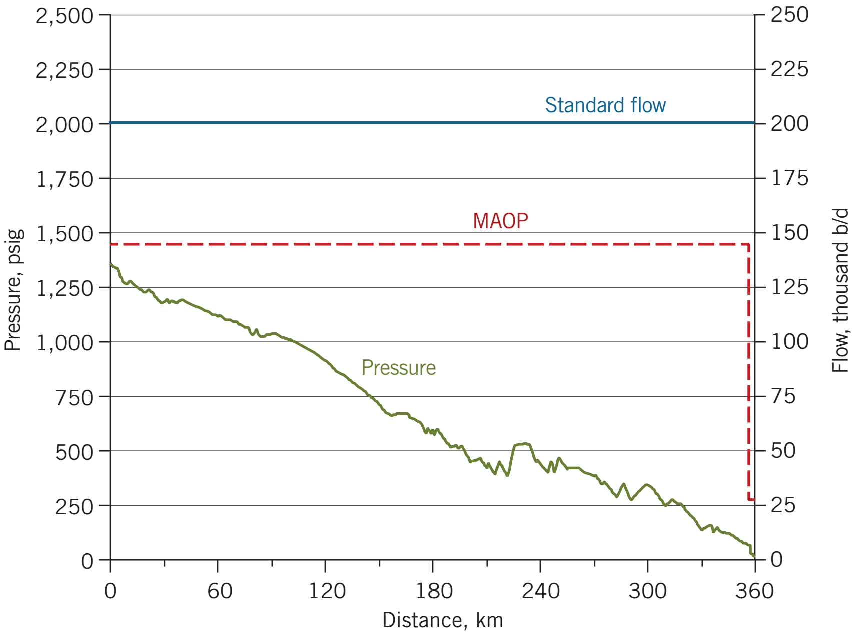
Fig. 1 shows the pipeline profile at 71,000 b/d without DRA and limited to 1,350 psig. The following options were considered to determine the best alternative.

- ***Source-only DRA.*** *Applying Equation 15, 200=70/√[1/(1–D)], or D=0.8775.* This value is very close to the 0.90 value obtained from simulation (Fig. 2). This option requires a very high DRA dosage—500 gal/d, or almost 60 ppm DRA solution or 15.6 ppm DRA polymer—and drag reduction of almost 90%.

Though this is theoretically achievable according to the DRA performance curve, it is not viable due to the roughly 70% drag degradation the DRA will have suffered by KM-160 due to pipe fittings and sharp turns at this location. This situation suggests either installing another DRA injection point downstream of KM-160 or building an intermediate pump station (IPS) at KM-160.

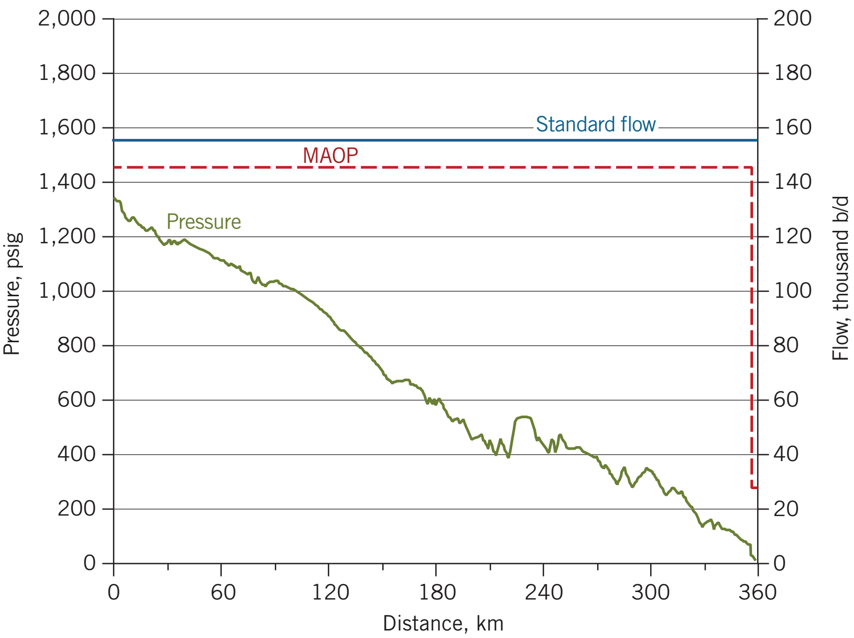
FLOW CHARACTERISTICS; DRA INJECTED AT INLET, KM-160

FIG. 5



FLOW CHARACTERISTICS, TWO INJECTION SITES*

FIG. 6

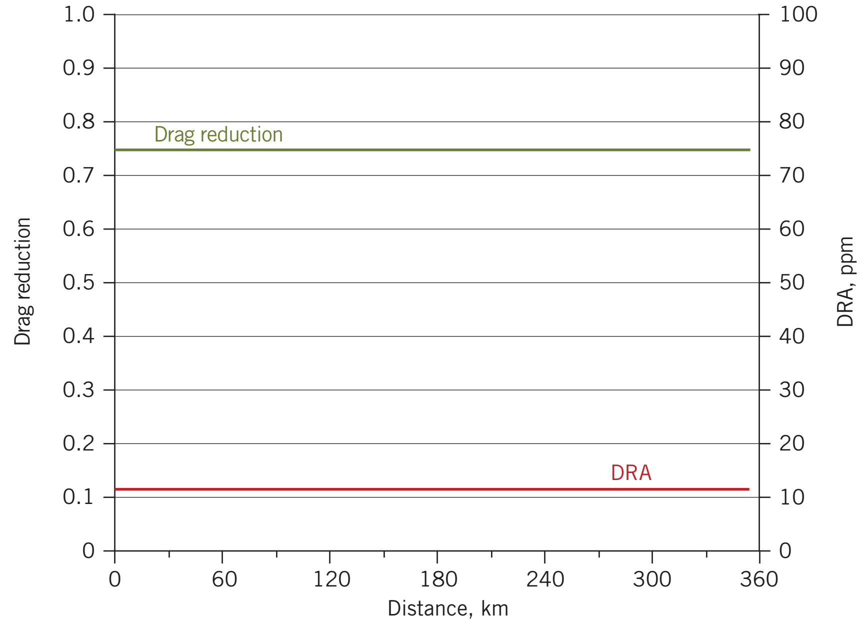


*Inlet, KM-160; maximum drag reduction = 75%.

- ***DRA at source and KM-160.*** Figs. 3-5 show the pipeline flow-pressure profile at 200,000 b/d and DRA concentration-drag reduction as a result of injecting 200 gal/d of DRA at the source and 150 gal/d at KM-160, downstream of valves and fittings causing the 70% drag degradation. DRA dosage at the two locations totals 350 gal/d (50 ppm, about

DRA PERFORMANCE, TWO INJECTION SITES*

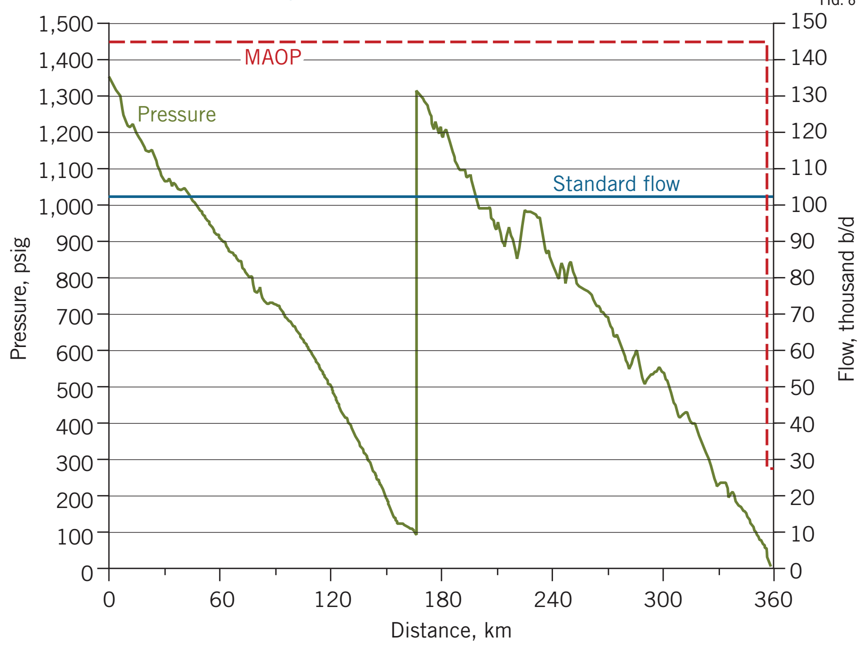
FIG. 7



*Inlet, KM-160; maximum drag reduction = 75%.:

FLOW CHARACTERISTICS, TWO INJECTION SITES*

FIG. 8



25 ppm at each location), less than the amount used when injecting at just the source.

But the DRA-required drag reduction remains very high at almost 85%, which is both hard to achieve practically and very close to the 0.8775 theoretically predicted drag calculated using Equation 13.

If DRA is injected at these two locations and limited by a maximum drag reduction of 75%, then the maximum achievable flow rate would be 156,000 b/d (Fig. 6-7). The DRA consumption in this case would be 75 gal/d at the source and 53 gal/d at KM-160, a total daily consumption of 128 gal/d (23 ppm).

Substituting the drag value of 75% (i.e. D = 0.75) into Equation 13 predicts a flow rate (xQ, where Q=70,000 b/d) of 140,000 b/d, more conservative than the 156,000-b/d flow rate predicted by simulation based on the vendor's DRA-performance curve.

Neither this nor the preceding option, therefore, can achieve the target flow rate of 200,000 b/d, suggesting the need for an intermediate pump station (IPS) at KM-160, downstream of the bottleneck area.

- ***IPS at KM-160 without DRA.*** The maximum achievable flow rate using and IPS but no DRA is 102,000 b/d (Fig. 8), suggesting the need to use both.

- ***DRA at both sites, IPS at KM-160.*** Installing an IPS at KM-160 and injecting DRA both at the source and downstream of the IPS can achieve the target flow rate of 200,000 b/d without exceeding 75% drag reduction. The required DRA consumption in this case would be 75 gal/d (9 ppm) at each site. Figs. 9 and 10 respectively show the pipeline flow-pressure profile at 200,000 b/d and DRA ppm-drag. Drag reduction is about 71%.

The predicted drag of 71% (0.71) is very close to the theoretically calculated drag from Equation 13, where xQ=200,000 b/d and Q=102,000 b/d, from which D=0.74 (74%). OGJ

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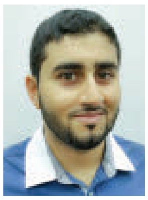

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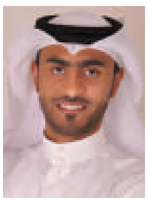

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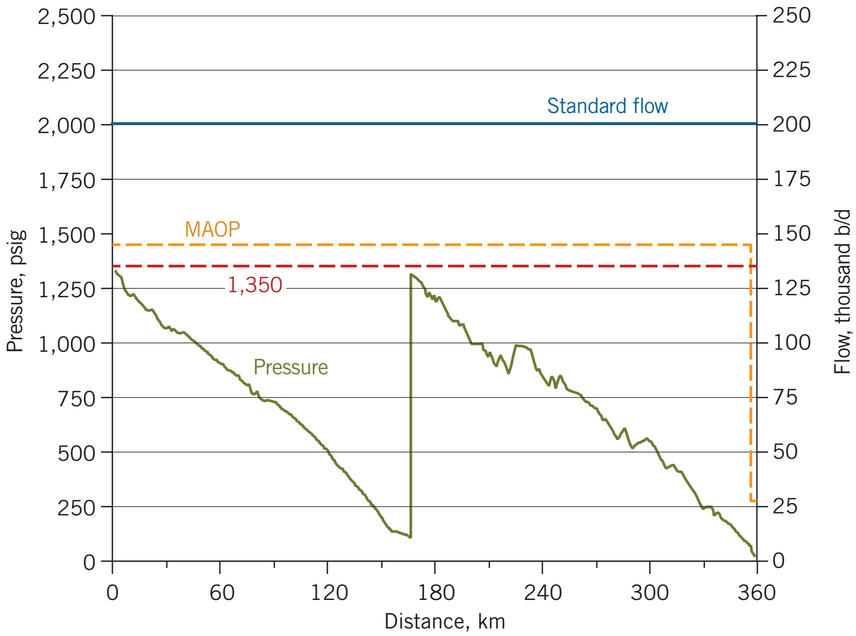
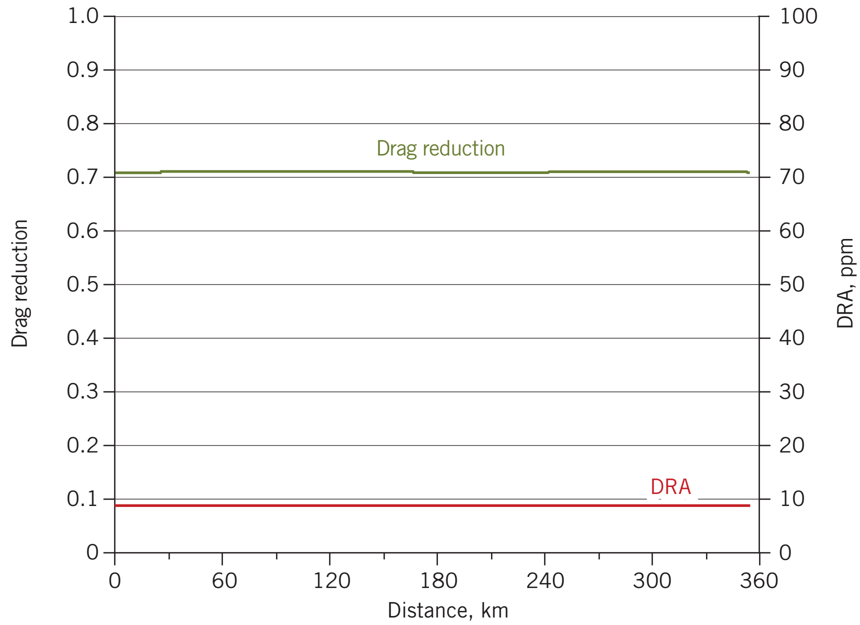
FLOW CHARACTERISTICS, DRA AT INLET, IPS

FIG. 9



DRA PERFORMANCE, 200,000 B/D*

FIG. 10



*Maximum drag reduction = 71%, DRA injected at two locations, with IPS

TRANSPORTATION

India advancing LNG projects to bridge gas-supply gap

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On May 5, 2016, Indian Petroleum Minister Dharmendra Pradhan hinted that the country seeks to further increase natural gas's share of India's energy basket by both increasing domestic production and importing LNG at competitive prices.

India is already the fourth largest importer in the world, taking 5.7% of global volumes in 2014. It has signed long-term contracts with suppliers and also plans to help set up an LNG liquefaction plant at Chabahar, Iran, to ship natural gas back to India.

This article assesses India's drive to increase its LNG imports and scrutinizes its current LNG infrastructure and the need for expansion in light of the projected increase in domestic natural gas demand. The authors will offer policy recommendations for the government to ensure sustained LNG imports, with an ultimate objective of closing the country's natural gas demand-supply gap and ensuring its energy security.

Global LNG supply

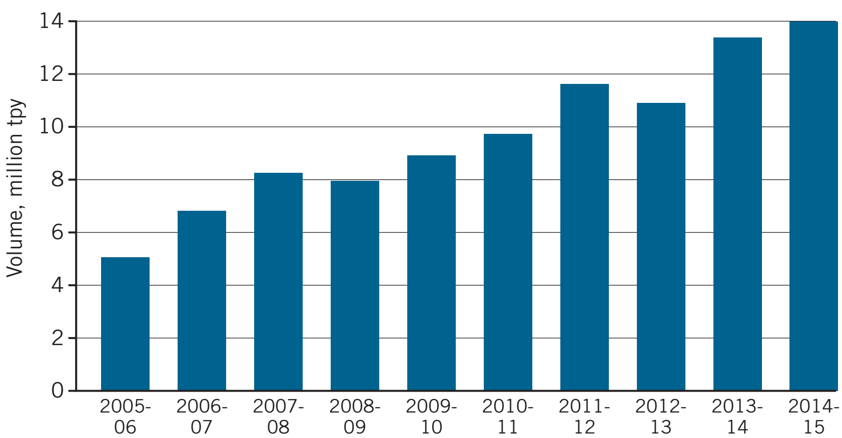
Global liquefaction capacity measured 308 million tonnes/year (tpy) at end-2015, compared with regasification capacity of 777 million tpy.[1] But pending liquefaction additions in the US and Australia will change global LNG supply dynamics in the near future.

LNG pricing is gradually moving from crude oil indexation to gas-hub linked prices, but two-thirds of LNG is still sold at prices linked to crude oil.

India's LNG demand

LNG IMPORTS, INDIA

FIG. 1



Source: Petroleum Planning and Analysis Cell, Government of India

Fig. 1 shows India's LNG imports growing from about 5 million tpy in 2005-06 to about 14 million tpy in 2014-15. LNG imports jumped another 15% during 2015-16. The biggest increases occurred in February and March 2016, up 63%[2] and 58%[3] respectively from the corresponding months a year earlier.

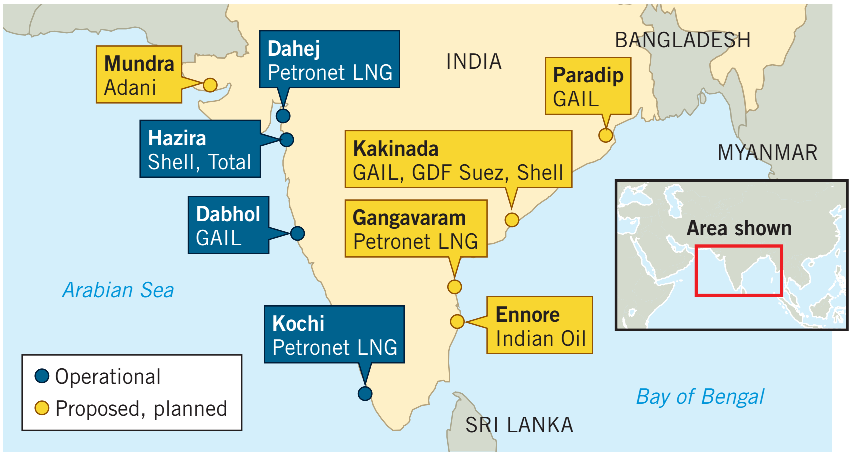
Policy interventions by the government aimed at improving utilization of stranded power plants[4] and pooling domestic gas[5] with regasified LNG (R-LNG) to produce urea have combined with lower crude oil prices to boost India's demand.

Grid-connected gas-fueled power generation capacity in India is 24,150 Mw, out of which 14,305 Mw lacks access to domestic gas.[6] On Mar. 20, 2016, nine stranded power plants with an installed capacity of 5,942 Mw were allocated 7.62 million standard cu m/day (MMscmd) of R-LNG via an e-auction. Power produced from these plants was sold at or below Rs 4.70/unit to local distribution companies for resale to end users from Apr. 1, 2016, to Sept. 30, 2016, via a reverse auction process that was expected to be renewed at the time of writing.

The price of power produced from gas plants typically varies in India depending on the gas source. Power produced from LNG would cost Rs. 7-9/unit depending on gas price and plant load factor. The lower price was an effort by the government to extend the benefits of lower gas costs to end users.

LNG TERMINALS, INDIA

FIG. 2



Source: Interfax

LNG sourcing

The Middle East and Africa dominated LNG shipments to India in 2015, with Qatar supplying 61% of the total, followed by Nigeria (14.7%), and 11 other countries dividing the remaining 24.3%.[7]

Long-term contracts with fixed-destination clauses dominated LNG trade for years, but changing trade patterns stemming from the accident at Japan's Fukushima nuclear power plant and the US shale-gas boom have allowed growth of shorter-term and gas-price based LNG trade. Depressed spot prices have motivated many LNG buyers to renegotiate supply contracts.

Petronet LNG Ltd. (PLL) renegotiated its 2004-2029 contract with RasGas for sourcing 7.5 million tpy to $6.50-7.00/MMbtu FOB from $12.50/MMbtu FOB (calculated at $96/bbl), effective Jan. 1, 2016.[8] According to India's Petroleum Minister, the current applicable LNG price under this contract is less than $5.00/MMbtu FOB.[9] A new agreement for an additional 1 million tpy from January 2016 to January 2028 was similarly based on market prices. RasGas and Petronet also agreed to reschedule the LNG not taken by the latter during 2015 to a future period, with RasGas waiving the contract's take-or-pay liability.

GAIL (India) Ltd. has signed long-term agreements with both Cheniere Energy Partners and Dominion Resources to source LNG from the US. The deal with Cheniere is for 3.5 million tpy from Sabine Pass Liquefaction (OGJ Online, Dec. 12, 2011), while the one with Dominion is for 2.3 million tpy (OGJ Online, Sept. 23, 2013). Supplies from these two deals will start in 2018.[10] GAIL expects to swap 1-2 million tpy of the Cheniere supplies to save transportation costs.[10]

GAIL has also agreed to buy 2.5 million tpy from Gazprom for 20 years beginning 2018-2020.[11] Gazprom wants to increase supplies to 3.5 million tpy and the agreement's duration to 25 years.[12]

The US contracts are priced on a Henry Hub basis. The EIA's Short-Term Energy Outlook predicts the Henry Hub spot price will rise from $2.00/MMbtu during first-quarter 2016 to $3.22/MMbtu in fourth-quarter 2017, potentially escalating GAIL's LNG import costs when the contracts come into play in 2018.

The LNG market is moving toward increased spot liquidity. Cargoes initially sold under long-term contracts now move into the spot market with renegotiated prices and without take-or-pay clauses so that LNG traders can get the best possible price for each cargo.

In March 2016 the delivered price of LNG into Japan was $6.80/MMbtu,[13] 62.8% lower than the $18.30/MMbtu paid in March 2014. Additional production from Australia, the US Gulf, and Angola is expected to drive spot prices down further,[14] which would benefit Asian buyers including India.

LNG infrastructure

India has a total of four operational LNG terminals in Dahej, Hazira, Kochi, and Dabhol, with regasification capacity of 25 million tpy but currently running at 58%. A lack of supporting infrastructure,[15] subdued R-LNG demand as a result of higher prices, and minimal pipeline connectivity between terminals and demand centers account for the low capacity utilization.

To meet future demand for natural gas, more than 65 million tpy of new regasification is planned (both brownfield and greenfield) by 2030, including both land-based LNG terminals and floating storage and regasification units (FSRU).

LNG TERMINALS; EXISTING, PLANNED

Table 1

Location	Principals[1]	Capacity, million tpy	Onshore-FSRU[2]	Start-up	Capacity utilization, %[3]
Dahej, Gujarat	PLL	10, to be increased to 15 this year	Onshore	Operating	108.9
Hazira, Gujarat	Hazira LNG Pvt. Ltd.	5	Onshore	Operating	67
Dabhol, Maharashtra	RGPPL (GAIL-National Thermal Power Corp. Ltd. jv)	1.24 in Phase 1, to be increased to 5	Onshore	Operating	75
Kochi, Kerala	PLL	5	Onshore	Operating	3.4
Kakinada East Godavari, Andhra Pradesh	GAIL, Andhra Pradesh government	3.5	FSRU	2018	—
Ennore, Tamil Nadu	IOCL	5 in Phase 1 to be increased to 10	Onshore	2019	—
Mangalore, Karnataka	ONGC, BPCL	2.5	Onshore	2018	—
Mundra, Gujarat	Adani, GSPC	5	Onshore	2017	—
Gangavaram, Andhra Pradesh	PLL	5	Onshore	2018	—
Pipavav, Gujarat	Swan Energy Ltd.	5	FSRU	2018	—
Haldia, West Bengal	Hiranandani Group	4	FSRU	2019	—
Mumbai Port Trus, Maharashtra	India Gas Solution (BP-Reliance Industries jv)	5	FSRU	2020	—
Digha, West Bengal	H-Energy Pvt. Ltd., Excelerate Energy	4	FSRU	2019	—
Jaigarh, Maharashtra	H-Energy, Gateway Pvt. Ltd.	8	Onshore	2018	—
Chhara, Gujarat	SP Ports (Shapoorji Pallonji Group unit)	5	Onshore	2018	—
Dhamra, Odhisha	Dhamra LNG Terminal Pvt. Ltd.	5	Onshore	—	—

[1]RGPPL-Ratnagiri Gas and Power Pvt. Ltd., GAIL–Gas Authority of India Ltd., IOCL–Indian Oil Corp. Ltd., ONGC–Oil and Natural Gas Corp. Ltd., BPCL–Bharat Petroleum Corp. Ltd., GSPC–Gujarat State Petroleum Corp.[2] Floating storage and regasification unit.[3] April-September, 2015-16.
Source: LNG operating companies, Ministry of Petroleum & Natural Gas, GAIL

• Petronet signed a firm and binding term sheet for developing a land-based, 5-million tpy LNG terminal at Gangavaram port, Andhra Pradesh, on India's east coast with Gangavaram Port Ltd. (GPL).

• The upcoming LNG terminal in Ennore with an initial capacity of 5 million tpy and expandable to 10 million tpy could supply R-LNG to power plants and fertilizer units, other industrial customers, consumer end-users, and transportation buyers in Tamil Nadu.

• H-Energy Gateway Private Ltd. (HEGPL), an affiliate of H-Energy, is setting up an 8-million tpy onshore regasification terminal at Jaigarh, Ratnagiri district, Maharashtra, which would supply 29 MMscmd of regasified LNG to downstream markets.[16]

The accompanying table lists these and other upcoming LNG regasification terminals and FSRU.

Limiting factors

Ensuring cost-effective and reliable sourcing of LNG from sources relatively close to regasification terminals remains critically important to India. The Middle East and North Africa (MENA) region has historically been India's preferred LNG sources. But post-Fukushima (2011-14), India started to look beyond MENA. The sourcing destinations which emerged as alternatives were Australia, the US, and Russia.

In 2015 Australia exported 30.4 million tonnes of LNG and is expanding liquefaction capacity to 85 million tpy, expected to come on stream by 2020. Commercial production of shale gas changed the US natural gas supply-demand balance, prompting development of about 50 million tpy[17] of LNG capacity expected to enter service by 2019.

The India-Australia LNG Sub-Working Group for Collaboration, supported by representatives of National Thermal Power Corp., GAIL, Petronet, and shipping companies, came together to take advantage of new opportunities to move Australian-sourced LNG to India.[18] It remains to be seen, however, if this group can meet the challenge of developing mutually agreeable long-term fixed price contracts between suppliers and end users.

India's LNG ship-building sector is at a nascent stage of its development and needs domestic and foreign investment to mature. A fully developed LNG shipping sector in India would not only help meet domestic requirements but also would serve global markets.

GAIL initially postponed a nine-vessel $7-billion LNG ship tender by 1 month. Each vessel would carry 150,000-180,000 cu m of LNG to India, primarily from Sabine Pass and Cove Point in the US.[19] The delay was largely due to changed market dynamics stemming from the fall in the gas prices. Top Japanese fleet owners and one non-Japanese company, GasLog, ended up filling the tender, with three ships to be built at local Indian yards.[20]

Domestic shipbuilders Cochin Shipyard Ltd. and Pipavav Offshore Engineering showed interest in teaming up with international ship builders like Samsung Heavy Industries and Daewoo Shipbuilding & Marine Engineering to build LNG carriers in India. But Cochin was the only Indian yard that met the eligibility criteria set by GAIL for building the

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Learn more about World of Watson at ibm.com/wow ships locally. State-run Shipping Corp. of India Ltd. (SCI) and GAIL have a step-in right to take 26% and 10% stakes respectively in each of the nine LNG carriers hired by GAIL.

India's LNG value chain lacks a sufficient gas pipeline network connecting terminals with customers in demand centers. Underutilization of Kochi LNG terminal is a good example of this underutilization due to lack of pipeline connectivity.

Future investment

Investing in foreign oil and gas, especially gas assets in Russia, Iran, and Mozambique, could be critical to meeting domestic Indian demand. The same is true regarding investment in overseas liquefaction projects. Japanese and Chinese companies have already invested in liquefaction plants in Australia.

Indian companies should continue to proactively invest in liquefaction in countries like the US, Australia, Iran, Mozambique, Nigeria, and Algeria. India's existing natural gas infrastructure also needs expansion and upgrade. OGJ

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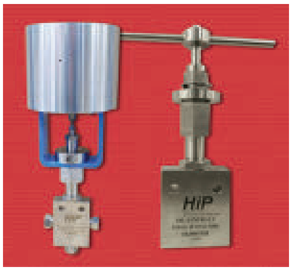

A newly developed line of **custom and standard extreme temperature valves and fittings** are specifically designed for cryogenic and extreme heat environments.

An extended stuffing box with fins provided around the packing area move packing away from cold or hot zones and dissipate heat or cold for safe, reliable operation.

Standard and custom valves are available in manual or air-operated configurations for 10,000 to 30,000 psi. They use coned-and-threaded connections and are come in such special materials as Monel and Hastelloy.

High Pressure Equipment Company: Erie PA

For FREE Information, select #5 at ogpe.hotims.com

AD INDEX OCTOBER 2016

OG&PE

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Handheld XRF analyzers = accurate elemental ID

Vanta handheld X-ray fluorescence analyzer delivers fast, accurate elemental analysis and quantification for a wide variety of materials — in as little as 1 to 2 sec.

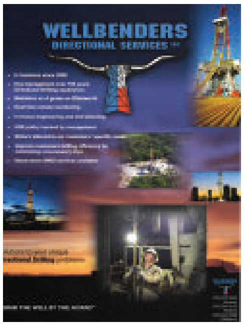
Instruments combine with new Axon technology, XRF signal processing that utilizes ultra-low-noise electronics to provide higher X-ray counts/second and fast results.

Vanta is IP 65 rated for dust and water protection, and drop-tested to military standards.

Olympus Scientific Solutions Americas: Waltham MA

For FREE Information, select #6 at ogpe.hotims.com

Directional drilling services



Directional drilling solutions are presented in this free datasheet.

With primary West Texas, South Texas, and Oklahoma operational areas, the 10-year-old firm offers key management with 100+ years directional drilling experience. Some 24 specific plays are listed in its management experience.

Real-time remote monitoring, motors tailored to your specific needs, stand-alone MWD services, plus in-house engineering and well planning are available.

WellBenders Directional Services LLC: Conroe TX

For FREE Literature, select #250 at ogpe.hotims.com

Portable, improved usability gas analyzers

"Improved usability and attractive features as standard" are how this manufacturer announces enhancements to its new **Lancom 4 Portable Gas Analyzer**.

Now available as a free download, Lancom 4's Insight data acquisition software is powerful so you can interface your analyzer with a PC for remote control and datalogging. Insight offers graphing and analysis tools for data visualization and reporting plus provides easier access to data. Wake and Sleep functions are also now standard.

AMETEK Land: Sheffield UK

For FREE Information, select #7 at ogpe.hotims.com

Transloaders aid propane, NGL railcar transfer safety, efficiency

Transloaders / portable rail towers, are "constructed for maximized safety and efficiency when transferring propane and other natural gas liquids between railcars and tanker trucks."

Built to U.S. Dept. of Transportation requirements, the NFPA 58 and NFPA 70 compliant models are custom-manufactured for specific applications to deliver dependable product transfer into truck transport containers in 45 min or less.

Superior Energy Systems Ltd.: Columbia Station OH

For FREE Information, select #8 at ogpe.hotims.com

OG&PE recently exhibited at, was media sponsored and Texas A&M's Turbomachinery & Pump Users Tradeshows 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: Go to OGPE.com — **Click "Product Info" (white typeface) at top.** Select by number or click the company name to visit their website. Click the items right here on the pages if you receive OG&PE digitally as Oil & Gas Journal's products section.

Intelligent, energy saving pumping equipment solutions

This company wants to partner with you for **intelligent, energy-saving pumping applications,** declares its 14-page brochure.

It describes and illustrates, Machine-Struxure intuitive solution for pump system automation to provide all features and functions needed to build pump equipment. Key oil and gas, water/wastewater, and mining markets, solutions include those specific to rod pump control and dewatering. Thirteen pumping solutions are shown and summarized to aid selection.

Schneider Electric USA Incorporated: Knightdale NC

For FREE Literature, select #252 at ogpe.hotims.com

For FREE Information, select #402 at ogpe.hotims.com

Lube oil systems built-to-specs/requirements

How **600 Series Lube Oil Systems** reduce lubrication piping and facilitate pump maintenance are summarized and shown in this free datasheet.

The dual pump design for non-shaft-driven applications is built to customer specifications and requirements and configured for easy maintenance. Fourteen lube oil system features are called out including Ful-flo pump protection and system pressure control valves along with top entry heating element.

Momentum Engineered Systems Incorporated: Houston

For FREE Literature, select #253 at ogpe.hotims.com

Multi screw pumps, systems

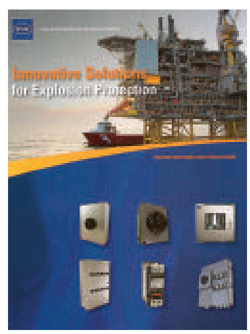
NOTOS multiple screw pumps series is illustrated and described in this free eight-page brochure. They serve broad applications which include asphalt refining, lubricant oil, and marine.

Two series offer up to 440 and 2,700-gpm at up to 1,160 and 360 psi over 570°F. respectively. Both are cited to deliver high efficiency, easy maintenance, light weight, small footprint, and low pulsation with no metal contact on 4NS models.

NETZSCH Pumps North America LLC: Exton PA

For FREE Literature, select #254 at ogpe.hotims.com

40 pages: Power distribution with explosion protection



This explosion protected electrical products manufacturer offers its free **power distribution brochure**.

Its 40 pages describe, illustrate, and specify a broad range of specialties including disconnect switches, hazardous classified breaker panelboards, external handle breaker panels, enclosed circuit breakers, ground fault or arc fault interrupters, and fusible distribution panels. They are engineered to serve oil and gas with light weight, easy installation, outstanding corrosion resistance and such global certifications as NEC, CEC, ATEX, IECEx, CU-TR, and INMETRO.

R. STAHL: Stafford TX & Calgary

For FREE Literature, select #255 at ogpe.hotims.com

Refinery-yield-improving electrostatic separators

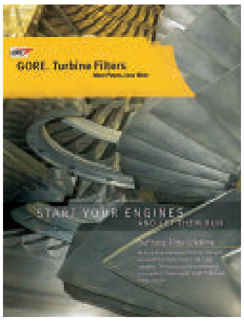
Gulftronic electrostatic separators are showcased in this free four-page brochure to help refineries improve yields. They convert low-grade byproducts into higher value commodities "creating new opportunities to market and increase revenue from upgraded clarified oil."

Described and illustrated as a more efficient alternative to mechanical filtration, Gulftronic captures and removes all solids from a process stream.

General Atomic Electromagnetics: San Diego CA

For FREE Literature, select #256 at ogpe.hotims.com

How long will filters last in a turbine?



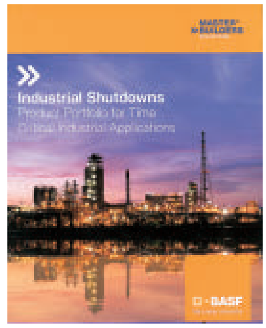
How long will **GORE filters last in my turbine?** is answered and illustrated in this free brochure.

Presenting influences affecting filter longevity, the literature helps define your application as to inlet filters, overall airflow and flow/filter element, then cites five major GORE Turbine Filter benefits. These include how they reduce turbine wear, optimize power output, increase turbine availability, and reduce corrosion.

W.L. Gore & Associates: Elkton MD

For FREE Literature, select #257 at ogpe.hotims.com

Industrial shutdown products, solutions



Because downtime is critical in shutdown applications, this free brochure highlights **industrial shutdown products for time-critical situations**.

Grouts, corrosion inhibitors, CP anodes, bonding agents, concrete repair, composite strengthening systems, epoxy coatings, plus sealants for adhesive and crack repair are among portfolio highlights.

BASF Construction Chemicals: Shakopee MN

For FREE Literature, select #258 at ogpe.hotims.com

Proximity system smart driver

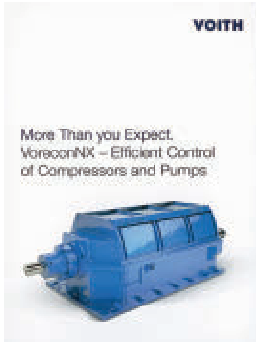
New **Metrix Proximity System Smart Driver** is presented in this free datasheet as "a highly reliable and accurate three-wire dynamic voltage output device . . . allows users the flexibility to completely configure their proximity transducer systems in the field to include custom "OK/Not OK" limits indicated by a case mounted LED."

A single smart drive can reduce the number of spare parts needed to monitor machines as it handles different shaft materials, variable system lengths, linearity in tight situations, as well as other manufacturer's probes and cables.

Metrix: Houston

For FREE Literature, select #259 at ogpe.hotims.com

Compressor, pump variable speed drives



VoreconNX speed controllers are illustrated and described in this brochure for efficient compressor and pump control.

The new variable speed drives are presented as "an advanced development of hydrodynamic power transmission in combination with a planetary gear." Adjustable pump guide vanes in the torque converter offer up to 8% efficiency improvement at part load.

VoreconNX is cited for FPSO, offshore platforms, gas transport, refineries, petrochemical complexes, oil and gas production, and gas treatment.

Voith Turbo: Crailsheim Germany, York PA, Houston

For FREE Literature, select #260 at ogpe.hotims.com

Oil and gas pumping systems

Offshore and onshore **oil and gas pumping systems** are described, illustrated and specified in this free 44-page publication.

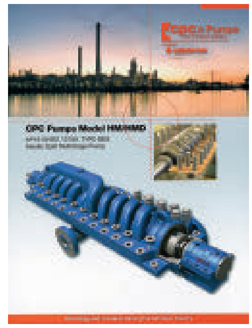
Firewater pumps, sea water lift pumps, water injection pumps, and designs for underground storage are presented. Literature sections include information on floating production, fixed installations, service, support, training, and testing.

At the manufacturer's plant for oil and gas products, it declares it is "putting the newest technologies in the hands of a skilled workforce producing pumps systems of highest quality."

Framo AS: Florvåg Norway

For FREE Literature, select #261 at ogpe.hotims.com

API 610 axially split multistage pumps



HM/HMD BB3 axially split multistage pumps are described and illustrated in this free brochure.

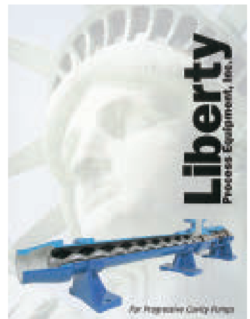
With full cutaway and callouts plus operation/features summaries, the API 610 / ISO 13709 designs deliver in excess of 4,400 USgpm, up to 5,600-ft differential heads in up to 400°F. at standard 2,250 psig.

Models offer wide hydraulic coverage and application tailored hydraulic selections. A number of options are also available to include high pressure special casing design.

CPC Pumps International: Burlington Ontario Canada

For FREE Literature, select #262 at ogpe.hotims.com

Progressive cavity pumps



American, Liberty, Millennium, Justice, Freedom, and Victory Series progressive cavity pumps are shown and summarized in this free four-page brochure.

Engineered packages are offered along with spare parts for difficult pumping applications.

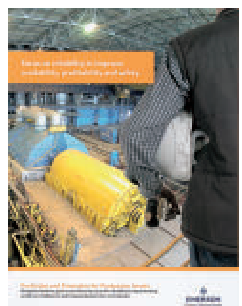
The seven-pump series handles broad applications including flows from a fraction of a gallon for polymer dosing or chemical feed up through large designs for heavy-duty uses.

Pump ranges are cited over 53 to 875 gpm and from 150 to 450 psi with a variety of features including 'wobble stator,' pin joint, and gear joint designs plus high-viscosity capabilities.

Liberty Process Equipment Incorporated:
Arlington Heights IL

For FREE Literature, select #263 at ogpe.hotims.com

Plant production assets condition monitoring offer broad range of improvements



Devices, instruments, technologies, systems, sensors, and support services are described and illustrated in this brochure, to help focus on reliability to improve plant availability, profitability, and safety.

Highlights include **AMS Device Manager** real-time online access to intelligent instrument and valve diagnostics and alerts.

Vibration data collection technology via PeakVue technology cuts through the complexity of machinery analysis and provides a simple reliable indication of equipment health.

Emerson protection systems help confidently determine when critical assets can be allowed to continue running safely.

A full line of **specialized sensors** are offered to complement prediction and protection systems.

Guardian Support services optimize reliability and performance of machinery health products.

Emerson Process Management: Knoxville TN

For FREE Literature, select #264 at ogpe.hotims.com

*Free Information or literature — **Click the link***

September "Advertiser Product & Service Followup"

Companies featured here advertised their equipment, products, or services in **September 5 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 — and/or be directed to their websites.

Functional safety dual input smart HART temp transmitters: the right safety choice

Have confidence in your Safety Instrumented System's instruments with the **FS Functional Safety Series**.

It includes new **STZ dual Input Smart HART Temperature Transmitters** — designed and built from the ground up to strict IEC 61508 standards — to ensure safe, reliable function — particularly in possible hazardous or emergency situations.

Moore Industries-International Incorporated: North Hills CA
miinet.com/safetyseries
For FREE Information, select #12 at ogpe.hotims.com

By any measure — AMETEK knows your petroleum process product needs

AMETEK Chandler Engineering Model 292B portable natural gas chromatographs are compact and lightweight yet include fully integrated sample handling and onboard storage for up to 1,000 sample runs.

Drexelbrook's new total tank level system (TLS) uses the latest magnetostrictive technology to provide unparalleled accuracy when measuring total tank level, interface tank level, and temperature.

AMETEK Process Instruments Model 5100 Gas Analyzers measure moisture in bulk gas or hydrocarbon streams via Tunable Diode Laser Absorption Spectroscopy.

Drexelbrook Impulse wave-guided radar level systems generate total level, distance or volumetric outputs — unaffected by variations in process material electrical characteristics.

AMETEK PMT IDT intrinsically safe pressure transmitters deliver ±0.2% full-scale accuracy for critical applications plus meet FM, ATEX, and IECEx.

AMETEK Thermox WDG-V Combustion Analyzers offer improved control and process safety as they measure excess oxygen, hydrocarbon, and combustibles in flue gas.

AMETEK U.S. Gauge all-welded process gauges comprise integrated seal for lower cost than gauges and seals purchased separately.

AMETEK Grabner MINIVAP ON-LINE process analyzers automatically monitor vapor pressure of gasoline, crude oil, and liquefied or natural petroleum gas.

AMETEK Process Instruments new IPS-4 Spectrophotometers detect and quantify thousands of chemical species — up to eight at once — to verify feedstock, intermediate, and final product quality.

AMETEK: Berwyn PA **AMETEK.com**
For FREE Information, select #13 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 #14 at ogpe.hotims.com

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 #15 at ogpe.hotims.com

Metal versus NYLACAST polymers: benefits in broad oil and gas applications

NYLACAST Polymers, compared to metal — deliver cost savings, corrosion resistance, wear resistance, maintenance, and light weight advantages.

The engineered plastic solutions weigh 1/7 that of steel, deliver 25-times the life of phosphor bronze, and eliminate cathodic protection requirements.

Polymer properties especially suit them for use in salt water. Additional benefits include self lubrication, low coefficient friction, material integration with metal inserts and coatings, as well as exceptional wear and abrasion resistance.

Products in which NYLACAST polymers are integral and effective: sheaves, winch and spooling shells, bigfoot crane outrigger pads, warehouse trailer plates, and dock bumpers.

A video at this provider's website depicts performance, efficiency, and safety across the oil and gas industry.

NYLACAST Ltd.: Leicester UK **Nylacast.com/offshore**
For FREE Information, select #16 at ogpe.hotims.com

Reduced rod-pump, ESP wells chemical treatment costs via batch pressure-balancing alternative

Ayre-Flo chemical injection systems are designed to reduce chemical treatment costs on rod-pumped or ESP wells.

As an alternative to batch treatment and continuous injection pumps — systems utilize a pressure-balancing technique to precisely apply chemical into wells using virtually no moving parts. Ayre-Flo pulses small packets of chemical into wells throughout the day. It eliminates the need for chemical pumps and treater trucks.

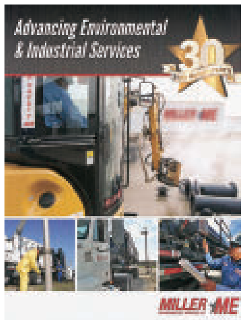
The compressed-nitrogen-powered design supplies a sealed power source which acts like a mechanical spring to inject chemical into wells. When the chemical is restocked, the nitrogen gas charge is automatically recompressed to its original value.

Ayre-Flo is fully contained. It requires no outside gas supply or power output. Its nonvented, nitrogen blanketed chemical delivery is said to significantly reduce possibilities of chemical exposure or injury to workers as well chemical loss or contamination to environmentally sensitive areas.

Pro-Ject Chemicals LLC: The Woodlands TX

For FREE Information, select #10 at ogpe.hotims.com

Environmental and industrial services



12 categories of **environmental and industrial services** are available from this company and presented in its free four-page brochure.

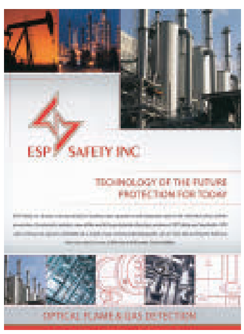
Patented vapor control, spill response, automated hydroblasting, hydro excavation, vacuum services, robotic tank cleaning, and chemical cleaning are among capabilities.

Also highlighted: **ecoTrack waste information management system** which collects and organizes all your waste stream data in a cloud-based storage system. It's designed to provide everything needed to track, manage, report, and file via readily accessible easy-to-use online interface.

Miller Environmental Services LLC: Corpus Christi TX

For FREE Literature, select #266 at ogpe.hotims.com

Safety and fire prevention equipment, integrated systems



Six series of **gas and flame detection equipment and integrated systems** are highlighted in this free four-page brochure.

For global oil and gas, categories of combustible or toxic and combustible gas detectors are presented. Three infrared, infrared and ultraviolet, or ultraviolet flame detectors are also showcased. This company designs, manufactures, installs and commissions it turnkey solutions.

ESP Safety Incorporated: San Jose CA, Houston

For FREE Literature, select #267 at ogpe.hotims.com

Remote production monitoring

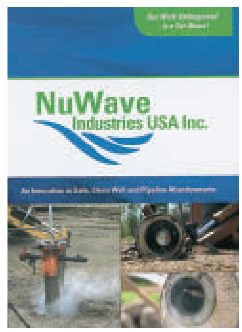
The WELLKEEPER remote monitoring system in this free literature is complete and flexible for oil and gas production.

Operators cost-effectively access field and production data from any computer with an internet connection to view current and historical well production information. This solution encompasses sales, installation, and support of well site sensors, communications, and software.

WELLKEEPER: Albuquerque NM

For FREE Literature, select #268 at ogpe.hotims.com

Safe, clean well, pipeline abandonment



Patented **NuWave well and pipeline abandonment system** is highlighted in this free brochure as a new method with "dramatic improvements over traditional cut-and-cap methods."

Its Canadian-designed technology is regulatory board approved and offers minimal environmental disturbance plus increased safety in oil wells, natural gas wells, pilings, or pipeline risers, declares the literature.

The mobile and portable system features an abrasive water jet cutting tool lowered into a well casing. It rapidly cuts from the inside, slicing through steel and concrete layers.

NuWave's vented cap is compression-fit to the casing strings, the hole is backfilled, and the job complete with minimal ground disturbance.

NuWave Industries USA Incorporated: Houston

For FREE Literature, select #269 at ogpe.hotims.com

*Free Information or literature — **Click the link***

PSC COUPLINGS.

PSC Couplings, an innovation leader in disc couplings for power transmission applications, announced the introduction of the Series 57 drop-out spacer disc coupling. This innovative design features enhanced AGMA Class 9 rating as standard with no balance required up to 3600 rpm; Class 10 and Class 11 ratings are optional. All couplings have fully interchangeable parts without the need for match marked components. The couplings are fully manufactured in the United States and use 4140 alloy steel components, 301 XH stainless steel discs, and PSC's patent pending self-piloting disc cartridges. With continuous torque ratings ranging from 2,500 to 3.5 million inch-pounds, the Series 57 fits a wide variety of applications. More information is available at www.psccouplings.com.

WEATHERFORD INTERNATIONAL

Weatherford International plc announced that it has won two large contracts with a super-major operator for sand screens and for upper completions products including gas-lift equipment, chemical-injection equipment, subsurface safety valves (SSVs) and downhole measurement tools. These two multi-year contracts will supply this equipment to multiple rig lines drilling extended-reach wells at Sakhalin Island.

The Sakhalin multi-year sand-screen contract covers both extended-reach onshore and offshore wells. As part of the second multi-year Sakhalin contract, Weatherford will provide gas-lift mandrels, gas-lift valves, chemical-injection equipment, surface-controlled SSVs, and downhole temperature and pressure gauges for wells on multiple rig lines.

PETROTECHNICS

Petrotechnics, the developer of the hazardous industries' first software platform for Operational Excellence, has released the results of its Operational Excellence Index into attitudes towards operational excellence among the oil, gas and petrochemical industries. The Index shows operational excellence is regarded as a key priority for the majority of organizations.

A third of respondents said that it has become more or very important to everyone in their organization, while 47% say that it has become more or very important to some people in their organization. Only 10% say nothing has changed over the past two years, while 5% believe it has become less important.

The importance of operational excellence was also reported by those sponsoring it within a business. 46% of respondents said that achieving operational excellence is sponsored at a corporate level by members of the board. 31% said that everyone within the organization is responsible, while 18% said that it lies with a specific operational excellence function.

When it comes to the drivers for achieving operational excellence, 63% cited the need to achieve greater cost efficiencies and reduce operational and major accident risk. The next most popular drivers are optimizing maintenance programs and influencing cultural and behavioral change 56%.

When ranked by importance, the need to reduce operational and major accident risk came top of the list, followed by developing a more systematic approach to operational excellence (a better operating model). Achieving greater cost efficiencies is the third most important driver, while influencing cultural and behavioral change is fourth.

ROCK PILE ENERGY SERVICES

After conducting an extensive marketing process, RockPile selected White Deer from a number of other potential financial sponsors due to their shared vision for the future of the Company.

As part of the transaction, RockPile will move forward with a debt-free balance sheet and adequate capital required to pursue a robust growth pipeline. Important to note, the transaction was concluded on an out of court basis and involved no form of bankruptcy for the Company or subsidiaries.

PJT Partners and AlixPartners served as financial advisors to RockPile. Skadden, Arps, Slate, Meagher & Flom served as legal advisor to RockPile and Locke Lord served as legal advisor to White Deer Energy.

SCHLUMBERGER

Schlumberger announced today that PETRONAS, through its wholly-owned subsidiary, PETRONAS (E&P) OVERSEAS VENTURES SDN. BHD., has signed an agreement to license a significant part of the WesternGeco Campeche wide-azimuth (WAZ) deepwater multiclient seismic survey in the southern Gulf of Mexico.

The WesternGeco Campeche WAZ deepwater multiclient seismic survey is located in the southern Gulf of Mexico. More than 80,000 km^2 of newly imaged subsurface data, which have been acquired in the last 12 months, are available for oil and gas companies participating in exploration in Mexico. The project follows the Mexican government's opening of licensing rounds to non-government companies for the first time.

ERA GROUP

Era Group Inc. one of the largest helicopter operators in the world and the longest serving helicopter transport operator in the U.S., announced today that it has entered into a new contract with the Bureau of Safety and Environmental Enforcement (BSEE), a division of the U.S. Department of the Interior, for an initial term of five years that is subject to annual renewals.

Era will continue to provide helicopters and related services, including the provision of flight crews, helicopter maintenance and management of flight operations to BSEE and the U.S. Coast Guard. BSEE utilizes Era's services to transport personnel and cargo in support of its inspection and oversight of offshore oil and gas platforms and vessels located on the Outer Continental Shelf in the U.S. Gulf of Mexico. Under the terms of the new contract, Era will provide twenty-four exclusive use helicopters, five on-call helicopters and seven optional helicopters that BSEE may exercise during the contract term.

IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4 9-16 2016	Districts 1-4 9-9 2016	District 5 9-16 2016	District 5 9-9 2016	Total US 9-16 2016	Total US 9-9 2016	Total US 9-18* 2015
	1,000 b/d						
Total motor gasoline	544	635	25	14	569	649	503
Mo. gas. blending comp.	535	613	13	14	548	627	423
Distillate	72	118	5	21	77	139	164
Residual	88	149	61	110	149	259	232
Jet fuel-kerosine	117	79	30	100	147	179	51
Propane-propylene	64	59	19	24	83	83	77
Other	949	781	60	110	1,009	891	920
Total products	**1,834**	**1,821**	**200**	**379**	**2,034**	**2,200**	**1,947**
Total crude	**6,789**	**6,933**	**1,520**	**1,128**	**8,309**	**8,061**	**7,175**
Total imports	**8,623**	**8,754**	**1,720**	**1,507**	**10,343**	**10,261**	**9,122**

*Revised.
Source: US Energy Information Administration
Data available at PennEnergy Research Center.

EXPORTS OF CRUDE AND PRODUCTS

	Total US 9-16-16	Total US 9-9-16	Total US *9-18-15
	1,000 b/d		
Finished motor gasoline	606	553	419
Jet fuel-kerosine	187	129	133
Distillate	1,303	1,137	1,223
Residual	193	294	414
Propane/propylene	1,075	424	505
Other oils	1,784	1,248	1,001
Total products	**5,148**	**3,785**	**3,695**
Total crude	**588**	**418**	**477**
Total exports	**5,736**	**4,203**	**4,172**
NET IMPORTS			
Total	4,607	6,059	4,951
Products	(3,114)	(1,585)	(1,748)
Crude	7,721	7,644	6,699

*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

	9-23-16*	9-25-15*	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	58.94	60.23	(1.29)	(2.15)
Brent crude	46.24	47.33	(1.10)	(2.32)
Crack spread	12.70	12.90	(0.20)	(1.53)
FUTURES MARKET PRICES				
One month				
Product value	59.20	60.62	(1.42)	(2.34)
Light sweet crude	44.94	45.52	(0.58)	(1.27)
Crack spread	14.26	15.10	(0.84)	(5.58)
Six month				
Product value	59.13	62.00	(2.87)	(4.63)
Light sweet crude	47.50	48.52	(1.02)	(2.11)
Crack spread	11.64	13.48	(1.85)	(13.69)

*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	17,508	55,535	50,776	10,255	66,317	11,242	7,489
PADD 2	147,005	50,346	44,228	7,060	33,850	1,310	29,279
PADD 3	265,358	83,681	74,214	15,112	45,427	22,901	61,031
PADD 4	25,257	6,874	5,084	820	3,587	148	[1] 3,950
PADD 5	49,470	28,720	26,674	9,400	15,812	5,055	—
Sept. 16, 2016	**504,598**	**225,156**	**200,976**	**42,647**	**164,993**	**40,656**	**101,749**
Sept. 9, 2016	**510,798**	**228,360**	**203,117**	**42,750**	**162,753**	**40,583**	**101,091**
Sept. 18, 2015[2]	**453,969**	**218,756**	**192,040**	**41,411**	**151,877**	**39,472**	**97,076**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available at PennEnergy Research Center.

REFINERY REPORT—SEPT. 16, 2016

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,101	1,111	3,161	65	326	59	145
PADD 2	3,661	3,659	2,676	246	1,115	52	420
PADD 3	8,855	8,635	2,126	936	2,736	243	991
PADD 4	642	638	328	34	212	11	[1] 205
PADD 5	2,704	2,545	1,597	433	589	99	—
Sept. 16, 2016	**16,963**	**16,588**	**9,888**	**1,714**	**4,978**	**464**	**1,761**
Sept. 9, 2016	**17,126**	**16,729**	**10,049**	**1,759**	**4,933**	**501**	**1,760**
Sept. 18, 2015[2]	**16,382**	**16,202**	**9,963**	**1,504**	**5,084**	**378**	**1,584**
	18,436 Operable capacity		**92.0 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 9-21-16	Pump price* 9-21-16	Pump price 9-23-15
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	156.5	205.9	214.7
Baltimore	162.9	213.9	218.6
Boston	159.9	204.9	217.5
Buffalo	154.2	215.3	224.4
Miami	148.3	203.3	226.1
Newark	168.4	201.3	211.7
New York	176.9	238.0	230.4
Norfolk	191.1	231.8	207.7
Philadelphia	144.3	213.1	229.3
Pittsburgh	161.5	230.3	228.3
Wash., DC	184.9	226.8	226.9
PAD I avg	164.4	216.8	221.4
Chicago	221.3	269.9	285.6
Cleveland	172.4	218.8	207.2
Des Moines	165.5	215.9	257.4
Detroit	166.9	215.9	228.6
Indianapolis	168.6	216.9	207.2
Kansas City	163.1	198.8	215.2
Louisville	171.4	215.8	247.9
Memphis	179.0	218.8	214.1
Milwaukee	157.5	208.8	257.8
Minn.-St. Paul	164.8	211.8	227.6
Oklahoma City	156.0	191.4	200.9
Omaha	160.8	206.9	223.7
St. Louis	166.1	201.8	202.5
Tulsa	159.3	194.7	202.8
Wichita	164.4	206.8	208.2
PAD II avg	169.2	212.9	225.8
Albuquerque	153.2	190.4	208.7
Birmingham	164.7	203.9	203.3
Dallas-Fort Worth	160.9	199.3	200.5
Houston	160.5	198.9	200.6
Little Rock	159.0	199.2	208.0
New Orleans	162.3	200.7	205.1
San Antonio	159.4	197.8	206.3
PAD III avg	160.0	198.6	204.6
Cheyenne	176.3	218.7	254.3
Denver	189.7	230.1	261.8
Salt Lake City	184.2	232.1	259.8
PAD IV avg	183.4	227.0	258.6
Los Angeles	245.5	304.6	324.4
Phoenix	182.8	220.2	228.7
Portland	179.4	228.9	268.1
San Diego	219.9	278.9	320.1
San Francisco	225.5	284.6	311.0
Seattle	199.0	261.9	287.1
PAD V avg	208.7	263.2	289.9
Week's avg.	**173.1**	**219.7**	**232.6**
Aug. avg.	**170.1**	**216.7**	**264.7**
July avg.	**178.7**	**225.4**	**278.7**
2016 to date	**162.8**	**209.5**	—
2015 to date	**203.5**	**250.8**	—

*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

	9-23-16	9-25-15
Alabama	1	3
Alaska	6	13
Arkansas	0	3
California	6	14
Land	6	13
Offshore	0	1
Colorado	19	33
Florida	0	0
Illinois	2	3
Indiana	0	0
Kansas	0	9
Kentucky	1	0
Louisiana	40	70
N. Land	14	28
S. Inland waters	3	4
S. Land	4	8
Offshore	19	30
Maryland	0	0
Michigan	0	0
Mississippi	4	5
Montana	0	1
Nebraska	0	1
New Mexico	27	50
New York	0	0
North Dakota	28	66
Ohio	14	19
Oklahoma	67	105
Pennsylvania	22	33
South Dakota	0	0
Texas	246	363
Offshore	1	1
Inland waters	0	1
Dist. 1	21	41
Dist. 2	14	39
Dist. 3	4	24
Dist. 4	8	14
Dist. 5	7	7
Dist. 6	8	17
Dist. 7B	6	4
Dist. 7C	20	32
Dist. 8	134	153
Dist. 8A	14	15
Dist. 9	1	3
Dist. 10	8	12
Utah	5	5
West Virginia	9	17
Wyoming	13	24
Others NV-1	1	1
Total US	**511**	**838**
Total Canada	**138**	**176**
Grand total	**649**	**1,014**
US oil rigs	418	641
US gas rigs	92	197
Total US offshore	20	33
Total US cum. avg. YTD	**487**	**1,059**

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]9-23-16	[2]9-25-15
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	27
Alaska	470	447
California	535	573
Colorado	307	348
Florida	6	7
Illinois	22	26
Kansas	96	136
Louisiana	1,290	1,301
Michigan	16	18
Mississippi	52	70
Montana	61	78
New Mexico	359	412
North Dakota	1,047	1,204
Ohio	63	72
Oklahoma	282	432
Pennsylvania	16	19
Texas	3,557	3,743
Utah	80	103
West Virginia	21	24
Wyoming	187	236
Other states	50	44
Total	**8,535**	**9,320**

[1]OGJ estimate. [2]Revised. Source: Oil & Gas Journal.
Data available at PennEnergy Research Center.

US CRUDE PRICES

	9-23-16 $/bbl*
Alaska-North Slope 27°	37.05
Light Louisiana Sweet	39.85
California-Midway Sunset 13°	35.25
California Buena Vista Hills 26°	45.94
Wyoming Sweet	40.73
East Texas Sweet	38.50
West Texas Sour 34°	36.00
West Texas Intermediate	41.00
Oklahoma Sweet	41.00
Texas Upper Gulf Coast	34.75
Michigan Sour	33.00
Kansas Common	40.00
North Dakota Sweet	32.50

*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

OPEC reference basket Wkly. avg. 9-23-16 — $/bbl 42.47

	July-16	Aug.-16
	Mo. avg., $/bbl	
OPEC reference basket	42.68	43.10
Arab light-Saudi Arabia	43.14	43.47
Basrah light-Iraq	41.37	42.01
Bonny light 37°-Nigeria	45.30	46.35
Es Sider-Libya	44.00	44.85
Girassol-Angola	45.09	46.06
Iran heavy-Iran	41.59	42.17
Kuwait export-Kuwait	41.37	41.88
Marine-Qatar	43.53	43.44
Merey-Venezuela	36.71	36.46
Minas 34°-Indonesia	41.84	41.26
Murban-UAE	46.54	46.25
Oriente-Ecuador	40.72	40.84
Saharan blend 44°-Algeria	45.30	46.35
Other crudes		
Fateh 32°-Dubai	42.64	43.58
Isthmus 33°-Mexico	45.07	44.22
Brent 38°-UK	45.00	45.85
Urals-Russia	43.76	44.06
Differentials		
WTI/Brent	(0.10)	(1.10)
Brent/Dubai	2.36	2.27

Source: OPEC Monthly Oil Market Report.
Data available at PennEnergy Research Center.

REFINED PRODUCT PRICES

Spot market product prices

	9-16-16 ¢/gal
Motor gasoline (Conventional-regular)	
New York Harbor	154.90
Gulf Coast	141.90
Motor gasoline (RBOB-regular)	
New York Harbor	148.70
No. 2 heating oil	
New York Harbor	132.30

	9-16-16 ¢/gal
No. 2 Distillate	
Low sulfur diesel fuel	
New York Harbor	139.30
Gulf Coast	137.30
Los Angeles	142.10
Kerosine jet fuel	
Gulf Coast	129.80
Propane	
Mont Belvieu	48.80

Source: EIA Weekly Petroleum Status Report.
Data available at PennEnergy Research Center.

IHS PETRODATA RIG COUNT

SEPT. 23, 2016

	Total supply of rigs	Marketed supply of rigs	Marketed contracted	Marketed utilization rate (%)
US Gulf of Mexico	104	49	34	69.4
South America	51	44	38	86.4
Northwest Europe	107	85	62	72.9
West Africa	70	53	27	50.9
Middle East	170	159	121	76.1
Southeast Asia	94	79	40	50.6
Worldwide	833	680	480	70.6

Source: IHS Petrodata
Data available in PennEnergy Research Center

US NATURAL GAS STORAGE[1]

	9-16-16	9-9-16	9-16-15	Change, %
		bcf		
East	851	832	805	5.7
Midwest	985	954	908	8.5
Mountain	230	227	196	17.3
Pacific	318	317	351	(9.4)
South Central	1,167	1,169	1,151	1.4
Salt	278	285	308	(9.7)
Nonsalt	889	884	844	5.3
Total US	**3,551**	**3,499**	**3,411**	**4.1**
	June-16	**June-15**	**Change, %**	
Total US[2]	**3,196**	**2,656**	**20.3**	

[1]Working gas. [2]At end of period.
Source: Energy Information Administration
Data available at PennEnergy Research Center.

PACE REFINING MARGINS

	June 2016	July 2016	Aug. 2016	Aug. 2015	Change	Change, %
			$/bbl			
US Gulf Coast						
Composite US Gulf Refinery	9.83	12.25	10.73	9.07	1.67	18.4
Mars (Coking)	10.88	12.89	11.15	10.87	0.27	2.5
Mars (Cracking)	7.94	9.64	8.34	7.37	0.97	13.1
Bonny Light	6.29	7.82	4.90	5.31	(0.42)	(7.8)
US PADD II						
Chicago (WTI)	11.41	15.92	14.16	20.37	(6.21)	(30.5)
US East Coast						
Brass River	6.66	7.80	6.81	9.37	(2.56)	(27.3)
East Coast Comp	8.21	9.36	8.87	10.13	(1.27)	(12.5)
US West Coast						
Los Angeles (ANS)	8.87	8.76	14.34	14.88	(0.54)	(3.6)
NW Europe						
Rotterdam (Brent)	0.66	1.06	1.23	3.82	(2.60)	(67.9)
Mediterranean						
Italy (Urals)	2.76	3.30	4.74	5.01	(0.26)	(5.3)
Far East						
Singapore (Dubai)	3.15	1.50	4.15	5.91	(1.76)	(29.8)

Source: Jacobs Consultancy Inc.
Data available at PennEnergy Research Center.

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	June 2016	May 2016	June 2015	Sept. 2016-2015 change	Total YTD 2016	Total YTD 2015	YTD 2016-2015 change
				bcf			
DEMAND							
Consumption	2,026	1,989	1,916	110	14,315	14,507	(192)
Addition to storage	318	402	430	(112)	1,406	1,691	(285)
Exports	173	178	139	34	1,053	856	197
Canada	51	63	45	6	390	383	7
Mexico	106	105	91	15	613	462	151
LNG	16	10	3	13	50	11	39
Total demand	**2,517**	**2,569**	**2,485**	**32**	**16,774**	**17,054**	**(280)**
SUPPLY							
Production (dry gas)	2,167	2,261	2,224	(57)	13,410	13,343	67
Supplemental gas	2	5	3	(1)	28	29	(1)
Storage withdrawal	94	75	68	26	1,883	2,170	(287)
Imports	241	248	207	34	1,494	1,406	88
Canada	233	243	204	29	1,446	1,360	86
Mexico	0	0	0	0	0	0	(0)
LNG	8	5	3	5	48	46	2
Total supply	**2,504**	**2,589**	**2,502**	**2**	**16,815**	**16,948**	**(133)**

NATURAL GAS IN UNDERGROUND STORAGE

	June 2016	May 2016	Apr. 2016	June 2015	Change
			bcf		
Base gas	4,360	4,358	4,356	4,367	2,477
Working gas	3,196	2,975	2,654	2,656	540
Total gas	**7,556**	**7,333**	**7,010**	**7,023**	**3,017**

Source: DOE Monthly Energy Review.
Data available at PennEnergy Research Center.

WORLDWIDE NGL PRODUCTION

	June 2016	May 2016	6 month average production 2016	6 month average production 2015	Change vs. previous year Volume	Change vs. previous year %
			1,000 b/d			
Brazil	123	121	103	107	(4)	(3.9)
Canada	742	737	774	684	90	13.1
Mexico	320	300	305	333	(28)	(8.3)
United States	3,618	3,593	3,476	3,180	296	9.3
Venezuela	199	199	198	211	(14)	(6.5)
Other Western Hemisphere	207	227	214	228	(13)	(5.8)
Western Hemisphere	**5,208**	**5,177**	**5,070**	**4,743**	**327**	**6.9**
Norway	342	360	372	343	29	8.5
United Kingdom	66	77	72	60	12	20.4
Other Western Europe	7	7	9	12	(3)	(21.4)
Western Europe	**415**	**444**	**453**	**414**	**39**	**9.4**
Russia	733	763	802	715	87	12.1
Other FSU	170	170	170	156	14	8.7
Other Eastern Europe	15	15	15	15	0	0.0
Eastern Europe	**918**	**948**	**987**	**886**	**100**	**11.3**
Algeria	513	497	502	527	(24)	(4.7)
Egypt	202	202	202	201	1	0.3
Libya	50	50	50	50	0	0.0
Other Africa	132	150	146	133	13	9.7
Africa	**897**	**899**	**900**	**911**	**(11)**	**(1.2)**
Saudi Arabia	1,820	1,820	1,820	1,810	10	0.6
United Arab Emirates	641	641	641	641	0	0.0
Other Middle East	738	743	738	719	19	2.7
Middle East	**3,199**	**3,204**	**3,199**	**3,170**	**29**	**0.9**
Australia	61	53	53	50	3	6.7
China	12	12	12	12	0	0.0
India	122	122	122	100	22	21.6
Other Asia–Pacific	151	148	151	165	(14)	(8.4)
Asia–Pacific	**346**	**335**	**338**	**327**	**11**	**3.4**
TOTAL WORLD	**10,983**	**11,007**	**10,947**	**10,451**	**496**	**4.7**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available at PennEnergy Research Center.

OXYGENATES

	June 2016	May 2016	Change	YTD 2016	YTD 2015	Change
			1,000 bbl			
Fuel ethanol						
Production	30,258	30,228	30	178,354	173,292	5,062
Stocks	21,199	20,792	407	21,199	20,029	1,170
MTBE						
Production	1,475	1,611	(136)	8,854	6,891	1,963
Stocks	893	929	(36)	893	983	(90)

Source: DOE Petroleum Supply Monthly.
Data available at PennEnergy Research Center.

US COOLING DEGREE–DAYS

	June 2016	May 2016	June 2015	% change	Total degree days YTD 2016	Total degree days YTD 2015	% change
New England	75	7	39	92.3	82	71	15.5
Middle Atlantic	128	17	114	12.3	145	186	(22.0)
East North Central	187	42	138	35.5	233	221	5.4
West North Central	263	48	202	30.2	328	269	21.9
South Atlantic	380	185	394	(3.6)	788	901	(12.5)
East South Central	373	125	353	5.7	578	604	(4.3)
West South Central	475	237	453	4.9	957	906	5.6
Mountain	332	91	314	5.7	501	475	5.5
Pacific	162	38	177	(8.5)	263	279	(5.7)
US average*	**270**	**97**	**255**	**5.9**	**464**	**480**	**(3.3)**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review. **NOTE: Data has been revised to conform to modified data format provided by source.**
Data available at PennEnergy Research Center.

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THE EDITOR'S PERSPECTIVE

Expectations fade for more gains in Iraqi oil output

by **Bob Tippee**, Editor

Expectations for further gains in Iraqi oil production have fallen victim to the country's deteriorating finances and struggle with Islamic State militancy.

In a January report anticipating new financial assistance, the International Monetary Fund projected Iraqi oil output in 2020 at 5.7 million b/d.

A follow-up report in July put the number at 4.4 million b/d—only 200,000 b/d above the average rate it expects this year.

"Increasing oil production as previously envisaged would require a doubling of oil investment, which the [Iraqi] authorities recognize is infeasible given the fiscal outlook," IMF explained.

In addition to lowering its expectations for oil output and exports, IMF trimmed its projection for gross domestic product, citing further weakening of the nonoil economy.

The organization nevertheless approved a $5.34-billion, 3-year loan under strict conditions that include payment of overdue obligations to international oil companies.

Arrears had climbed to $4.67 billion at the end of March from $3.556 billion in December. IMF wants Iraq to clear those accounts by the end of this year and meet all obligations to the oil companies quarterly as stipulated in service contracts.

The new loan follows a "rapid financing instrument" disbursement of $1.24 billion by IMF in July 2015. It broadly requires:

- *Managing external pressures, such as by maintaining the exchange-rate peg to the US dollar, removing exchange restrictions, and fighting money-laundering and terrorism finance.*
- *Implementing fiscal consolidation while protecting the poor.*
- *Strengthening public financial management and curbing corruption.*
- *Monitoring financial risks to preserve financial-sector stability.*

This is a tough program for a politically fractious country with a 23% poverty rate, 4 million people displaced by violence, and 10 million people—27% of the population—needing humanitarian help.

Under difficult and dangerous conditions, the Iraqi oil industry has raised production to its current level from 3 million b/d in 2013.

But a fiscal trap aggravated by low oil prices, persistent violence, and political dysfunction will prevent the further gains the country needs and has the geology to achieve.

(From the subscription area of www.ogj.com, posted Sept. 23, 2016; author's e-mail: bobt@ogjonline.com)

WATCHING GOVERNMENT

Nick Snow
Washington Editor

Consulting Indian tribes

An Oct. 11 listening session will kick off formal government-to-government consultations in six parts of the US from Oct. 25 through Nov. 11 on how Indian tribes can participate more effectively and promptly in federal infrastructure decision-making.

The US Departments of the Interior, Justice, and the Army jointly announced on Sept. 23 that the listening session during the National Congress of American Indians' 73rd annual convention in Phoenix and subsequent consultations would consider two main questions:

- What the federal government should do, within the statutory framework, to better ensure meaningful tribal input into infrastructure-related reviews and decisions and the protection of tribal lands, resources, and treaty rights.
- Whether new legislation should be proposed to Congress to alter that statutory framework and promote those goals.

Consultations are scheduled for Oct. 27 in Seattle; Oct. 27 in Albuquerque; Oct. 15 in Minneapolis; Oct. 17 in Rapid City, SD; Nov. 2 in Billings, Mont.; and by teleconference on Nov. 21.

The consultations announcement came after the Army withdrew a Corps of Engineers permit for the proposed Dakota Access crude oil pipeline on Sept. 9 following days of protests by the Standing Rock Sioux and other tribes and groups. It came hours after a federal district judge in Washington rejected the tribe's request that the permit be stayed.

Business groups including the American Petroleum Institute and National Association of Manufacturers immediately called the action political. Events clearly showed that a more comprehensive look at how tribes could be involved earlier was necessary, the federal entities said.

The Obama administration has used that rationale since early 2009 within DOI as the Bureaus of Land Management and Ocean Energy Management each have emphasized involving more stakeholders sooner in the federal oil and gas leasing process.

Delays or improvement?

Some oil and gas groups have argued that this merely has created more delays. Agency officials have responded that it has reduced the number of court decisions overturning leases that have been issued. Both sides contend that they want more clarity in the process. One says it would help a lot if there was less political influence from outside organizations that simply want to see all fossil fuel projects stopped.

"It's important that a project is allowed to go forward when the government has approved it and a court upholds that approval," API Pres. Jack N. Gerard said in reference to the federal entities' Sept. 9 Dakota Access pipeline maneuver.

"Otherwise, there's a chilling effect when companies grow uncertain that government decisions might be reversed arbitrarily," he warned during a Sept. 26 teleconference hours before Hillary Clinton and Donald Trump's first presidential debate. OGJ

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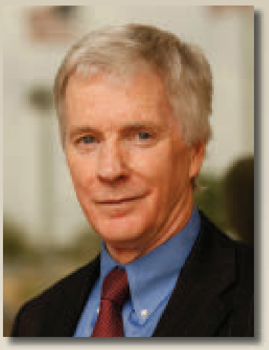

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