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Automating the Oil Field

Companies take steps to avoid bribe hazards
Exploration trends show continued promise in offshore basins
EPA proposes elimination of current MACT policy
Regulators must possess early risk-assessment understanding

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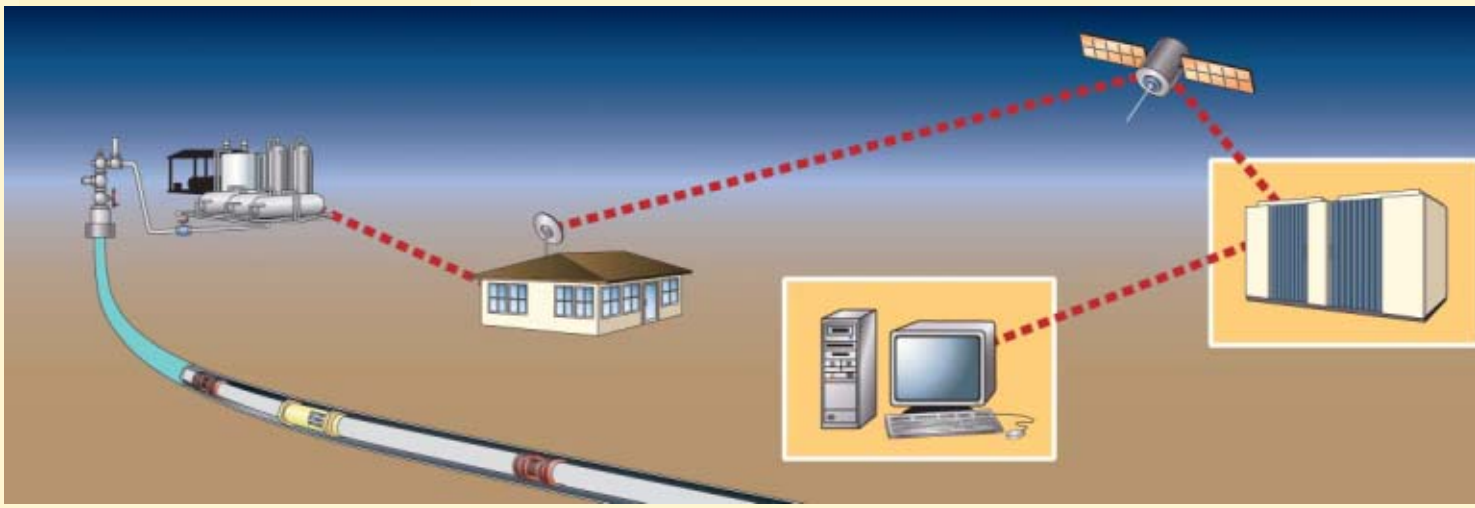
OIL&GAS JOURNAL®

Mar. 5, 2007
Volume 105.9

AUTOMATING THE OIL FIELD



REGULAR FEATURES

COVER

Brunei Shell Petroleum Co. Sdn. Bhd. employed SeaDrill Ltd.'s West Pelaut tender rig to drill wells off the Champion West platform. This highly automated platform is fully integrated for remotely controlled operations. Systems on the platform gather pressure, temperature, fluid, and flow data continuously and transmit it to end users for on line monitoring and control. Completed wells include multiple downhole hydraulically controlled interval control valves, permanent downhole gauges, and distributed temperature sensing. The articles in OGJ's special report section, starting on p. 41, describe various hardware and software operators have installed for automating oil fields. Photo from Shell.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General Interest

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Drilling & Production

Processing

Transportation

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OGJ Newsletter

Mar. 5, 2007

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General Interest — Quick Takes

Demand rising for unconventional oil, gas

Wood Mackenzie Ltd., Edinburgh, estimates unconventional hydrocarbons resources of 3.6 trillion boe worldwide. Unconventional resources include heavy oil, tight gas, coalbed methane, oil sands, and shale oil. WoodMac sees them playing a key role in the future world oil and gas supply mix.

In its study, "Unconventional Hydrocarbons—The hidden opportunity," WoodMac said anticipated tightening global oil supply and tightening regional gas supply intensify the demand for unconventional oil and gas.

Recent high commodity prices are driving future development of unconventional assets. Development so far has focused on Canadian oil sands and US unconventional gas. "In the future, we believe that we will see more global development of these unconventional hydrocarbons," said WoodMac analyst Rhodri Thomas.

Heavy oil development is seen as being particularly competitive and likely to be successful if the technologies can be proved and can remain viable for the long term.

WoodMac said unconventional oil is expected to supply at least 20% of oil production by 2020 compared with less than 10% of total worldwide oil production today.

Unconventional gas, meanwhile is expected to make up 42% of US gas supply in 2010, up from 27% in 2005.

Canadian oil sands production is expected to quadruple from today's level to 4 million b/d by 2020.

Meanwhile in the US, oil shale deposits in Utah, Wyoming, and Colorado are attracting renewed interest. Companies will need both technology and a thorough understanding of the subsurface, the study said.

WoodMac identified technical, fiscal, and environmental challenges before unconventional development can proceed. "As unconventional resources are distributed widely around the globe, the key risk is not discovering the resource, but in identifying areas where the critical factors are in place to enable economic development," said Phaedra Powilanska-Burnell, WoodMac analyst.

Regional and country-specific factors must be taken into account, the study said. Independents traditionally dominated unconventional oil and gas plays in the US and Canada. But integrated companies are beginning to take larger stakes in such projects.

"With conventional non-OPEC supply expected to peak within the next decade and the difficulties in discovering accessible gas reserves, international oil companies with growth ambition cannot afford to ignore these unconventional resources," Powilanska-Burnell said.

FERC: Offshore gathering authority limited

The US Federal Energy Regulatory Commission is dropping efforts to expand its jurisdiction over offshore natural gas gathering facilities. But it still intends to intervene if an interstate pipeline's gathering affiliate uses market power to benefit the pipeline as it supplies transportation and sales services to producers.

A Feb. 15 policy statement responds to comments received after FERC launched a notice of inquiry in September 2005 at Shell Offshore Inc.'s request to consider reexamining offshore gathering system regulation criteria established in a 1994 proceeding involving Arkla Gathering Service Co. FERC had previously ruled in Shell Offshore's favor in a complaint relating to Transcontinental Gas Pipe Line Corp.'s North Padre Island offshore gathering system in Texas, but a federal appeals court vacated the order in 2004.

"The commission has tried a number of times to assert jurisdiction over offshore gathering facilities to protect against undue preference and the exercise of monopoly power but has been repeatedly rebuffed by the courts," FERC Chairman Joseph T. Kelliher observed. "We must accept the judgment of the courts. Under current law, offshore gathering is an unregulated monopoly. That will remain the case unless and until the law changes."

Gathering systems beyond state waters are not regulated, but FERC has tried to establish its authority by arguing that a pipeline and gathering system should be treated as a single entity if the gathering system circumvents the commission's regulation of the pipeline. The Natural Gas Act allows FERC to invoke its authority in such instances, the commission said. It said it also does not need to determine that concerted action between the pipeline and gathering affiliate necessarily occurred in those cases.

FERC also denied Shell Offshore's request for a rehearing of its complaint and suggested that the producer take the matter up with the US Department of the Interior since it has regulatory jurisdiction over offshore gathering systems under the Outer Continental Shelf Lands Act.

Ecuador to rejoin OPEC in second quarter

Ecuador will rejoin the Organization of Petroleum Exporting Countries in the second quarter of this year, Energy Minister Alberto Acosta said.

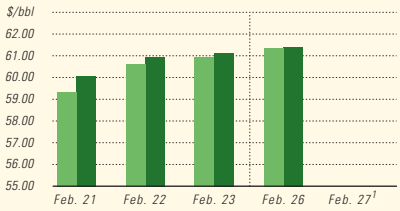
Ecuador, South America's fifth largest oil producer, quit OPEC in 1992. It exports about 70% of its oil production, which late last year was 516,000 b/d.

Acosta called Ecuador's withdrawal from the group a "mistake" and said belonging to the organization would bring "numerous benefits such as controlling the price of crude."

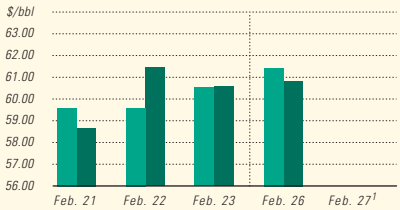
Angola joined OPEC Jan. 1. Sudan also is considering membership. ✦

Industry Scoreboard

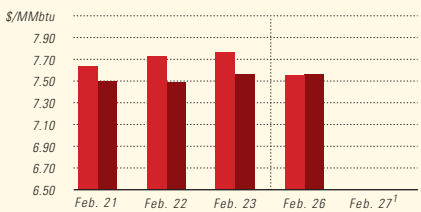
IPE BRENT / NYMEX LIGHT SWEET CRUDE



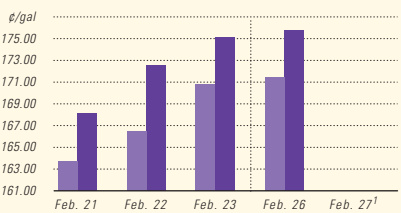
WTI CUSHING / BRENT SPOT



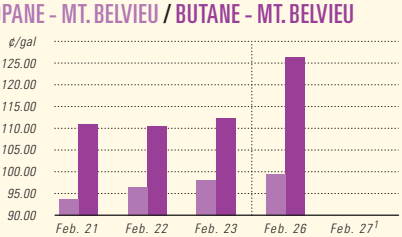
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



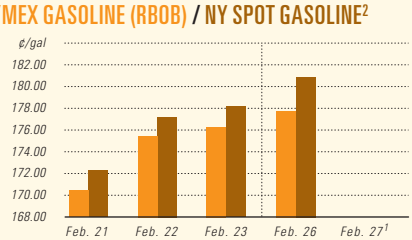
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Not available.
[2]Reformulated gasoline blendstock for oxygen blending

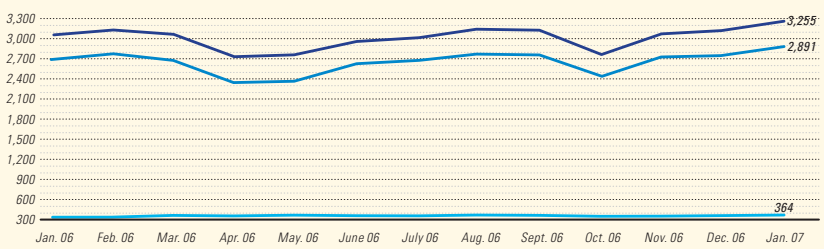
US INDUSTRY SCOREBOARD — 3/5

Latest week 2/16	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,152	8,789	4.1	9,077	8,781	3.4
Distillate	4,468	4,251	5.1	4,391	4,240	3.6
Jet fuel	1,691	1,535	10.2	1,647	1,534	7.4
Residual	629	811	–22.5	614	817	–24.8
Other products	4,899	4,842	1.2	4,881	4,841	0.8
TOTAL DEMAND	20,839	20,228	3.0	20,611	20,213	2.0
Supply, 1,000 b/d						
Crude production	5,274	5,048	4.5	5,311	5,048	5.2
NGL production	2,360	1,680	40.4	2,397	1,681	42.6
Crude imports	9,622	9,810	–1.9	9,646	9,794	–1.5
Product imports	2,931	3,612	–18.8	3,095	3,654	–15.3
Other supply[2]	955	1,431	–33.3	1,000	1,399	–28.5
TOTAL SUPPLY	21,142	21,581	–2.0	21,450	21,575	–0.6
Refining, 1,000 b/d						
Crude runs to stills	14,491	14,676	–1.3	14,736	14,698	0.3
Input to crude stills	14,865	15,033	–1.1	15,151	15,039	0.7
% utilization	85.8	86.7	—	87.4	86.8	—

Latest week 2/16	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	322,953	325,251	–2,298	327,532	–4,579	–1.4
Motor gasoline	212,683	215,430	–2,747	217,794	–5,111	–2.3
Distillate	131,153	135,118	–3,965	135,493	–4,340	–3.2
Jet fuel	40,309	41,430	–1,121	43,842	–3,533	–8.1
Residual	42,488	43,943	–1,455	41,046	1,442	3.5
Stock cover (days)[3] **2/9**			**Change, %**		**Change, %**	
Crude	21.8	21.8	—	22.3	–2.2	
Motor gasoline	24.8	25.0	–0.8	25.2	–1.6	
Distillate	29.6	31.6	–6.3	32.5	–8.9	
Propane	22.1	25.6	–13.7	29.3	–24.6	
Futures prices[4] **2/16**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	58.61	59.05	–0.44	59.36	–0.75	–1.3
Natural gas, $/MMbtu	7.33	7.73	–0.40	7.15	0.18	2.5

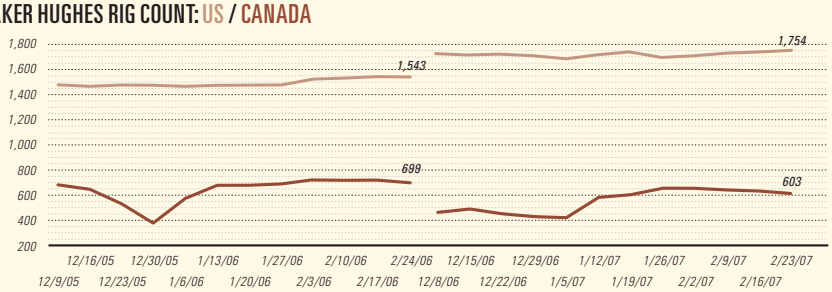
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Stocks divided by average daily product supplied for the prior 4 weeks. [4]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, American Petroleum Institute, 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

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Exploration & Development — *Quick Takes*

Aramco makes oil discovery with Dirwazah well

Saudi Aramco reported an oil discovery in Saudi Arabia about 70 km southeast of Gawar field and 280 km south of Dharan field. The Dirwazah-1 well tested in the Unayzah reservoir at 15,310 ft.

The well flowed 3,915 b/d of oil with 11.9 MMscfd of gas at 4,466 psi wellhead pressure through a $^{32}/_{64}$-in. choke.

Under normal production completion, the well is expected to flow at a higher rate. Aramco did not provide further details on the rate that might be expected.

Sherritt to shoot Cuba gulf blocks, export oil

Sherritt International Corp., Toronto, plans a $6 million 3D seismic survey on four Gulf of Mexico blocks off Cuba in the second quarter.

The company also plans to export part of its Cuban North Coast heavy crude this year for the first time.

Sherritt holds Blocks 15, 23, 24, and 33 north of the western part of the island.

The eastern part of Block 15 abuts the boundary with US waters along the US Minerals Management Service Rankin and Dry Tortugas planning areas (see map, OGJ, Dec. 11, 2000, p. 42).

Block 15 is 145 miles west-southwest of Key West, Fla., and 130 miles west of Cuban Block 27, where Repsol-YPF SA drilled Yamagua-1 in 2004 to TD 3,410 m in 1,660 m of water. The well found evidence of oil generation and an excellent carbonate complex (OGJ Online, Oct. 12, 2005).

Sherritt recently said it averages 30,000 b/d of oil production from mostly heavy oil fields along Cuba's northern coast.

The company forecast 2007 capital expenditures in Cuba at $130 million, including eight wells on blocks in which Sherritt has 100% interest and 10 wells on Block 7, in which it has 45% interest. Four wells are to be exploratory or appraisal wells, and more appraisal wells may be required.

Gross working interest oil production could climb 5-10% from 2006 levels, and limited demand for the domestic heavy oil could allow exports, the company said.

Sherritt is appraising Majaguillar field, obtaining greater efficiencies at the Canasi water treatment plant, and improving recovery from other production activities. Majaguillar is expected to be declared commercial this year.

Deep South Louisiana, shelf prospects score

McMoRan Exploration Co., New Orleans, reported apparent discoveries at two deep Tertiary prospects in South Louisiana and the Gulf of Mexico shelf.

Logs at the Laphroaig exploratory well onshore in St. Mary Parish indicated a potential 56 net ft of hydrocarbon-bearing sands in a 75-ft gross interval. The well is drilled to 20,250 ft measured depth, 19,060 ft true vertical depth, and is near production infrastructure. Working interests are McMoRan 50%, Energy XXI (Bermuda) Ltd. 31.5%, and a private partner the rest.

The Hurricane Deep well, in 12 ft of water on South Marsh Island Block 217, is drilling below 20,600 ft TVD and projected to 21,500 ft.

"Logging while drilling tools have indicated that an exceptionally thick upper Gyro sand was encountered totaling 900 gross ft. The top of this Gyro sand is credited with a potential of 50 ft of net hydrocarbons in a 53-ft gross interval," McMoRan said. "These exceptional sand thicknesses suggest that prospects in the Mound Point/JB Mountain/Hurricane/Blueberry Hill area may have thick sands as potential Gyro reservoirs," it said.

Logs indicated that the well previously cut 27 net ft of hydrocarbon-bearing sands in a 200-ft gross interval in a laminated Rob L section and a potential 20 ft of hydrocarbon-bearing sands in a 70-ft Operc section. The well is near production facilities. McMoRan's interest is 25%.

HI-31 find to produce from Pan Andean platform

Hunt Oil Co., Dallas, has made an oil and gas discovery on High Island Block 31, just 800 m from the borders of High Island Block 30, another shallow-water block in the Gulf of Mexico off Galveston, Tex.

Pan Andean Resources PLC is the operator and 63% interest owner of High Island Block 30.

Encouraged by the close proximity of Hunt Oil's discovery, Pan-Andean said it will reassess the exploration potential of its block.

Pan Andean and Hunt Oil have agreed to tie in production from the discovery to Pan Andean's platform on High Island 30. The agreement also allows Hunt Oil to become operator of the platform.

The agreement will improve the cash flow from Block 30 through a monthly production handling fee of $40,000 and will lower expected operating costs, extend the life of the platform by an expected 7 years, and improve prospectivity of the block, where little prospecting has been conducted in the past 3 decades.

Pan Andean said tying in the new discoveries and refitting the platform will take upwards of 6 weeks. In addition, ownership changes at High Island 24 have delayed refurbishment of the High Island 24 platform, which will pump the oil from High Island Blocks 30 and 31 to shore.

It is anticipated that all facilities will be on stream during the second quarter. Oil production from High Island 30 is expected to start at over 300 b/d. ✦

Drilling & Production — *Quick Takes*

Sakhalin-1 hits first-phase production peak

Exxon Neftegas Ltd., operator of the Sakhalin-1 project off eastern Russia, has reached its targeted first-phase peak production rate of 250,000 b/d of oil.

The first phase of the Sakhalin-1 project includes the Chayvo field onshore processing facility and a 140-mile pipeline, which transports crude west across Sakhalin Island and the Tatar Strait to the DeKastri terminal in the Russian Far East.

The project's natural gas production for the 2007 peak winter season has been 140 MMcfd and is being marketed to two domestic customers in the Khabarovsk Krai.

Consisting of three offshore fields—Chayvo, Odoptu, and Arkutun Dagi—the Sakhalin-1 project, over its life, will provide Russia with direct revenues of more than $50 billion. The Russian content of contracts awarded to date for the Sakhalin-1 project exceeds $3.6 billion.

The project's future phases of development are expected to sustain export gas production from all three fields to 2050.

Petrobras eyes oil in Jordanian shales

Brazil's state-owned Petroleo Brasilerio SA (Petrobras) signed a memorandum of understanding with Jordan's Ministry of Energy and Mineral Resources to study the technical and economic viability of Petrobras's patented Petrosix mining technology at the Attarat Umm Ghudran (AUG) oil shale deposit 50 miles south of Amman.

Petrobras international and downstream representatives will conduct the 24-month study, which covers 11 sq km Block AUG 21. Jordan's Natural Resources Authority estimated that the block has a potential of 1.7 billion bbl of oil.

Cretaceous shales in the entire 348 sq km AUG deposit average 70 m thick with 45-62 m of overburden, a Jordanian report said.

Petrobras mines oil from Permian Irati shale using the Petrosix process at Sao Mateus do Sul in Parana State. Production averaged 4,200 b/d in 2006 (OGJ, June 12, 2006, p. 37). The Irati formation bituminous shales cover parts of Sao Paolo, Parana, Santa Catarina, Rio Grande do Sul, Mato Grosso, and Goias states.

As oil prices have remained relatively high in recent years, Jordan, Morocco, the US, and China have contacted Petrobras to discuss shale oil production partnerships, Petrobras said. Jordan has numerous shale deposits but no commercial shale oil production. ✦

Processing — *Quick Takes*

Fire delays Porvoo refinery diesel line start-up

A small-scale fire Feb. 25 caused by a flange leak at Neste Oil Corp.'s Porvoo refinery in Finland will delay to mid-April the commissioning of the new diesel production line at the refinery. Start up of the more than €700 million diesel expansion was originally expected by year-end 2006, then was rescheduled to late March.

No other part of the refinery was affected in the incident. Neste said, "Personnel were not injured in the fire that caused damage primarily to some electric cables." Neste said in 2003 it would expand diesel production by 1 million tonnes/year at the sophisticated 200,000 b/d refinery, and construction began in 2004.

Porvoo produces high quality, low-emission motor fuels from residue oil. Although the overall capacity of the refinery will remain the same, Neste said, the diesel production line will enable an increase in the refining of heavy oil or other crude into products such as sulfur-free diesel to meet strict European and North American environmental standards.

Marubeni plans biodiesel project in Brazil

Japan's Marubeni Corp. and Dutch grain trader Agrenco Group jointly plan to start producing biodiesel fuel from soybean oil produced in Brazil beginning in 2008.

In a bid to tap growing demand amid heightened concerns over global warming, the joint venture partners—Agrenco 66.7% and Marubeni 33.3—plan to produce 400,000 tonnes/year of the alternative fuel. The JV, Agrenco Energia, will construct two mills for extracting oil from soybeans and three additional facilities to process the soybean oil into biofuel.

The bioenergy complexes are designed to produce pure B100 biodiesel, which the firms said can be used "in any vehicle without adaptation." The biofuel, to be produced in compliance with European Community EN 14424 regulation, will first be sold in Brazil, which will require diesel fuel to contain 2% biodiesel starting in fiscal 2008.

Under a 10-year supply agreement signed by the two companies in 2005, Marubeni has priority sales rights for Agrenco's products, including biodiesel, from South America to Japan and other Asian markets except China.

Pembroke refinery FCC unit to be revamped

Chevron Corp. has let an engineering, procurement, and construction management contract to AMEC PLC for a revamp of the 90,000 b/d FCC unit at its 210,000-b/cd refinery in Pembroke, Wales.

AMEC said the project will improve reliability of the unit's main fractionator and improve product yields. The complex refinery produces about 3.5 million gal/day of gasoline.

Sabic mulls site change for China petchem plant

Saudi Basic Industries Corp. (Sabic) is growing impatient with Chinese delays concerning a planned $5.2 billion petrochemical plant for Dalian, Liaoning Province, and may seek another location, according to the company's chairman.

Prince Saud bin Thunayan al-Saud said his state-owned firm had been in talks about the project with Sinopec and Dalian Shide for 3 years, and that the companies have been waiting 18 months for Chinese authorities—the National Development and Reform Commission—to approve the project.

"We hope this approval gets completed so that we can go ahead with our investment in the project," Al-Saud said, adding that Sabic has alternatives in more than one country and that there are many other opportunities worldwide. However, he conceded that "there isn't a specific alternative to China."

He said, "We still believe the China market is promising and that the opportunity to invest in China is a good one," adding that "there is no doubt any project or economic feasibility study depends on a certain timeframe."

In October 2004 Sabic announced the 50-50 joint venture project that is to include a 1.3 million tonne/year ethylene plant and a 10 million tonne/year refinery. At the time Sabic hoped to see the facility online by 2010.

China, foreign partners to expand Fujian refinery

Subsidiaries of China Chemical & Petroleum Corp. (Sinopec), ExxonMobil Corp., and Saudi Aramco jointly signed two separate contracts for a related project to triple refining capacity at a Fujian Province refinery. The projects seek to meet China's rapidly growing demand for petroleum and petrochemicals.

One contract is for the Fujian Refining & Ethylene Joint-Venture Project, which will increase the existing 80,000 b/d refinery in Quanzhou City to 240,000 b/d. The expanded refinery primarily will refine and process sour Saudi Arabian crude.

The project also will include construction of an 800,000 tonne/year ethylene steam cracker, an 800,000 tonne/year polyethylene unit, a 400,000 tonne/year polypropylene unit, and an aromatics complex to produce 700,000 tonnes/year of paraxylene. In addition, a 300,000-tonne crude berth and utilities, including cogeneration facilities of 280 Mw, also will be built.

Electricity generated by the cogeneration facilities will provide about 80% of the power requirement for the project, which is expected to start up in early 2009.

Interest in this project will be held by Fujian Petrochemical Co. Ltd. (a 50:50 Sinopec-Fujian government partnership) 50%, ExxonMobil China Petroleum & Petrochemical Co. Ltd. 25%, and Saudi Aramco Sino Co. Ltd. 25%.

The other contract is the Fujian Fuels Marketing Joint-Venture Project, which will market diesel and motor gasoline products produced by Fujian Refining & Ethylene Joint-Venture Project, as well as manage and operate about 750 service stations and a network of terminals in Fujian Province. It will be owned 55% by Sinopec, ExxonMobil 22.5%, and Saudi Aramco 22.5%.

Both JVs will be formed upon government approval. ✦

Transportation — *Quick Takes*

Two Mississippi LNG projects get FERC nod

The US Federal Energy Regulatory Commission approved two LNG terminal projects in Mississippi that could add supplies totaling 3.1 bcfd of gas.

The terminals, which would adjoin each other, are the Bayou Casotte project, next to Chevron USA's Pascagoula refinery, and the LNG Clean Energy project proposed by Gulf LNG Energy LLC. The first will deliver as much as 1.6 bcfd of regasified LNG to an interstate grid through five pipeline interconnections, while the second will send vaporized LNG through a new pipeline and a gas processing plant owned by BP America Inc.

"These are significant import projects, with a combined capacity nearly equal to the projected capacity of an Alaskan gas pipeline. More importantly, we find that these projects meet our high safety standards," FERC Chairman Joseph T. Kelliher said in the commission's Feb. 15 announcement.

FERC also authorized expansion of a 42-in. pipeline proposed by sponsors of the recently authorized Creole Trail LNG project 18.1 miles west in Cameron Parish, La., to intersect with the terminus of a pipeline system originating at another recently authorized LNG terminal at Sabine Pass. Both terminals and pipelines will be operated by Cheniere Energy of Houston.

The commission also approved Maritimes & Northeast Pipelines LLC's application to expand capacity of its existing facilities by 418,000 dekatherms/day to 833,317 dekatherms/day to accommodate imports of regasified LNG from the Canaport LNG terminal in Canada.

It also approved Maritimes' request to amend its Presidential Permit to allow the increased imported gas from Canada and to construct and operate an additional interconnection at the US-Canada border near Goldboro, NS. The proposed project will cost an estimated $321.3 million, FERC said.

Second Rockies Express pipeline segment online

Kinder Morgan Energy Partners Natural Gas Pipelines (KMP), operator of the proposed 1,663-mile Rockies Express Pipeline (REP) gas system, has initiated service on a 192-mile, 42-in. pipeline section from the Wamsutter Hub in Wyoming to Colorado's Cheyenne Hub.

The pipeline is the second section completed on the Western leg of the $4.4 billion system. REP will transport as much as 1.8 bcfd of gas from prolific Wyoming and Colorado basins to upper Midwest and eastern US markets. The owners have received binding firm commitments from shippers for almost all of the pipeline's capacity.

The first segment—136 miles of 36-in. pipeline from the Meeker Hub in Colorado to the Wamsutter Hub—began interim service in February 2006. Capacity on the combined 328-mile first two segments is 500 MMcfd. That capacity will increase to as much as 750 MMcfd when the Enterprise Gas Processing LLC plant at Meeker goes into service later this year.

KMP Pres. Scott Parker said he expects to receive Federal Energy Regulatory Commission approval this spring for the final 713-mile, 42-in. western leg of REP from Weld County, Colo., to Audrain County, Mo. Construction is expected to begin shortly thereafter and, subject to regulatory approvals, REP-West will be in service in December.

REP-East, a 622-mile segment from eastern Missouri to the Clarington Hub in Ohio is expected to be in interim service as early as Jan. 1, 2009, and fully completed by June 2009.

Nigeria misses gas supply deadlines to Ghana

Nigeria has delayed supplying gas to Ghana through its $560 million West African Gas Pipeline because of militants' vandalism on infrastructure in the Niger Delta.

According to local reports, Ghana—one of the customers of the 678-km WAGP system—has constructed its section of the line and other facilities and expected to receive gas in March. Ghana is expected to take 122 MMcfd of gas.

Nigeria is evaluating the status of the pipeline with the shareholders in West African Gas Pipeline Co. (WAGPCo), which is managing the project.

Project leader Chevron Corp. said WAGPCo is aiming for first gas deliveries in the second quarter.

Nigeria's Energy Minister Edmund Daukoru said the 470 MMcfd pipeline should have been completed in December, 18 months after the final investment decision was taken by the shareholders.

Gas through the WAGPCo system will be used for electric power generation and industrial development in Ghana, Togo, and Benin. ✦

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Natural Gas Conference, Calgary, Alta., (403) 220-2380, (403) 284-4181 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 5-6.

Gas Arabia International Conference, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 5-7.

SPE E&P Environmental and Safety Conference, Galveston, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 5-7.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), website: http://turbolab.tamu.edu. 5-8.

Purvin & Gertz International LPG Seminar, Houston, (713) 236-0318 x229, (713) 331 4000 (fax), website: www.purvingertz.com. 5-8.

African Refiners Week, Cape Town, +44 (0)20 7343 0014, +44 (0)20 7343 0015 (fax), website: www.afrra.org. 5-9.

Power-Gen Renewable Energy & Fuel Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 6-8.

Annual Fuels & Lubes Asia Conference, Bangkok, +632 772 4731, +632 772 4735 (fax), e-mail: conference@flasia.info, website: www.flasia.info. 7-9.

LNG Conference & Workshop, San Antonio, +44 (0)20 7978 0000, +44 (0)20 7978 0099 (fax), website: www.thecwcgroup.com. 7-9.

Plant Maintenance, Tooling & Safety Equipment, Technology & Service Conference, Bankok, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: rowen@oesallworld.com, website: www.allworldexhibitions.com. 8-10.

GPA Annual Convention, San Antonio, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 11-14.

SPE Middle East Oil & Gas Show & Conference (MEOS), Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: meos@oesallworld.com, website: www.allworldexhibitions.com. 11-14.

NACE Annual Conference & Exposition, Nashville, (281) 228-6200, (281) 228-6300, e-mail: Jennifer.OReilly@nace.org, website: www.nace.org/nace/content/conferences/c2007/welcome.asp. 11-15.

NPRA Security Conference, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 12-14.

China Offshore Expo, Tianjin, 84 8 9634388, 84 8 9635112 (fax), e-mail:

cp-info@hcm.vnn.vn, website: www.cpexhibition.com. 15-17.

NPRA Annual Meeting, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 18-20.

SPE/ICoTA Coiled Tubing and Well Intervention Conference and Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-21.

ARTC Refining & Petrochemical Annual Meeting, Bangkok, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 20-22.

Offshore West Africa Conference & Exhibition, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail: owaconference@pennwell.com, website: www.offshorewestafrica.com. 20-22.

Georgian International Oil, Gas, Energy and Infrastructure Conference & Showcase, Tbilisi, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 22-23.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 25-27.

American Chemical Society National Meeting & Exposition, Chicago, (202) 872-4600, (202) 872-4615 (fax), e-mail: natlmtgs@acs.org, website: www.acs.org. 25-29.

Turkish Oil & Gas Exhibition and Conference, Ankara, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 27-29.

Offshore Mediterranean Conference, Ravenna, +39 0544 219418, +39 0544 39347 (fax), e-mail: conference@omc.it, website: www.omc.it. 28-30.

SPE Production and Operations Symposium, Oklahoma City, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 31-Apr. 3.

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SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 1-3.

AAPG Annual Convention and Exhibition, Long Beach (918) 584-2555, (918) 560-2694 (fax), e-mail: postmaster@aapg.org, website: www.aapg.org. 1-4.

PIRA Natural Gas and LNG Markets Conference, Houston, 212-686-6808, 212-686-6628 (Fax), e-mail: sales@pira.com, website: www.pira.com. 2-3.

China International Oil & Gas Conference, Beijing, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 3-4.

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 3-4.

IADC Environmental Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 3-4.

Instrumentation Systems Automation Show & Conference, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 11-12.

SPE Digital Energy Conference and Exhibition, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 11-12.

ENTELEC Annual Conference & Expo, Houston, (888) 503-8700, e-mail: blaine@entelec.org, website: www.entelec.org. 11-13.

Kazakhstan Petroleum Technology Conference, Atyrau, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 11-13.

Molecular Structure of Heavy Oils and Coal Liquefaction Products International Conference, Lyon, +33 1 47 52 67 13, +33 1 47 52 70 96 (fax), e-mail: frederique.leandri@ifp.fr, website: www.events.ifp.fr. 12-13.

Middle East Petroleum & Gas Conference, Dubai, 65 62220230, 65 62220121 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 15-17.

SPE Latin American & Caribbean Petroleum Engineering Conference, Buenos Aires, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-18.

Society of Petrophysicists and Well Log Analysts (SPWLA) Middle East Regional Symposium, Abu Dhabi, (713) 947-8727, (713) 947-7181 (fax), e-mail: info@spwla.org, website: www.spwla.org. 15-19.

International Pipeline Conference & Exhibition, Moscow, +43 1 402 89 54 12, +43 1 402 89 54 54 (fax), e-mail: pipeline@msi-fairs.com, website: www.msi-fairs.com. 16-17.

Russia & CIS Refining & Petrochemicals Equipment Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 16-17.

Psychology of terminology

Uchenna Izundu
International Editor

Working for an American magazine has really driven home for me the differences in American and British English. It's the small things like "s" in British English being replaced by "z"—realized, not realised, for example.

Before joining OGJ I would write "The LNG terminal will be operational from 2010," but in American English it's rephrased as "The LNG terminal will be operational by 2010" to eliminate any confusion about whether the terminal would start in the given year or after. But to us Brits, it's clear that operations would begin in the year stated.

Language differences

Differences in American and British approaches were highlighted again last week when I attended Excelerate Energy's inauguration ceremony in the UK to celebrate the commissioning of its new GasPort, which is innovative technology that regasifies LNG onboard Excelerate's specially adapted LNG ship and transfers the gas directly into the national grid. The audience was amused to veer between different pronunciations of the term "offshore buoy" by managers of the project. In Britain, we say "boy"; Americans say "booyee." Tomaytoes, tomahtoes.

In discussing grammar, "full stops" (British English) have become "periods" (American English), and "dots" (British English)—when describing email addresses—are known as "points" when speaking to representatives from energy companies in continental Europe. And of course I've fallen into that mistake of understanding "gas" in articles to mean "natural gas," but some Americans mean "gasoline," which would otherwise be referred to as "petrol" in the UK. No statement, it appears, can be taken for granted.

Unit confusion

The above examples relate to everyday language where it should be possible to get along without confusion. Not so for the energy industry: There are no consistent units for communicating, which seems even more ironic considering the international importance of the industry. The usage of multiple units has surely baffled the majority of us upon starting our careers (if not even now many years in).

In the US, gas units of cubic feet and British thermal units are consistently used; hop over the Atlantic, and in continental Europe it changes to billion cubic meters and kilowatt-hours. Britain, however, adopts therms and kilowatt-hours. In Australia and Canada, they opt for the Joule (J). Russia prefers to price gas contracts according to cubic metres despite using kilowatt-hours in other instances. Translation is continuously needed!

Système International D'unités

Within the scientific world there is strong endorsement of the Système International D'unités (SI), which was adopted in 1960. SI presents a group of units to measure things like mass, volume, and energy and proposes a rational method to articulate them.

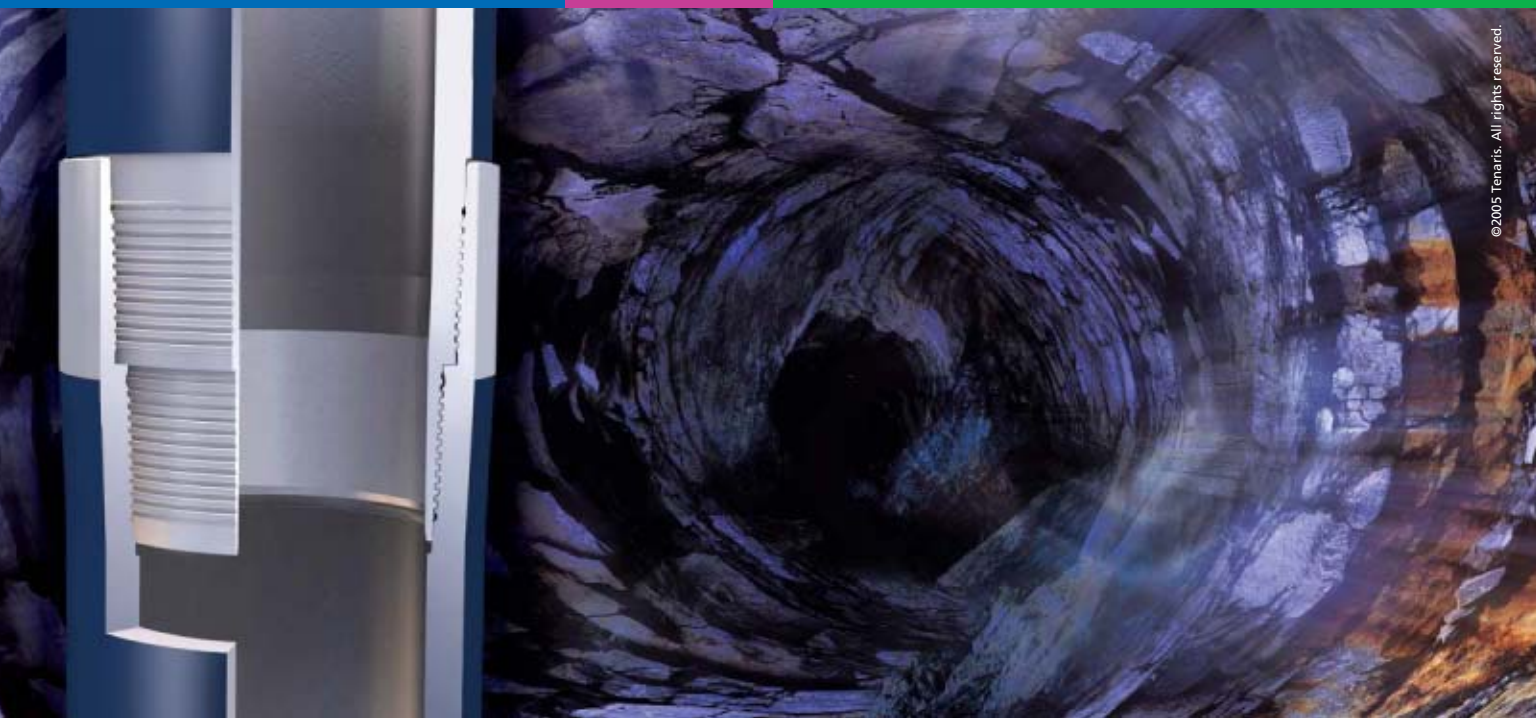
Expressing gas units, however, can be quite mystifying, say billion cubic meters per year as "Bcm/year." It is hard to rationalise—that is, rationalize—this unit under the SI, where "cm" refers to centimetres—woops, centimeters—and "cubic metres (or meters)" are written as "m^3." In commercial gas circles, "cm" means cubic meters, so perhaps "m^3," using the SI system, would be more appropriate? The letter "B," which represents "billion" in much of the gas world, would be expressed as "10^9" under SI and be written as Giga (G). Consequently "Bcm/year" would be "Gm^3/year."

Some opponents may argue that this expression is neither clear nor helpful as "Gm^3" could be interpreted to mean a Gigameter cubed, or a billion cubic meters. For those who are more pedantic, what about the "year?" Can time be consistently measured?

The moral of the example is to stress the strong need to have a consistent set of units to converse in. International natural gas usage is set to boom over the next 20 years because countries will endeavour—that is, endeavor—to have sustainable energy supplies and escape high and volatile oil prices. Security of supply is the great buzzword of the industry, and LNG is forecast to boost interconnectivity of markets. According to a PricewaterhouseCoopers report published Feb. 27, LNG trade is expected to double between 2005 and 2010, delivering around 40% of global gas supply growth.

With over 90% of current proven gas reserves lying outside the main industrial-country markets, LNG technology and infrastructure will be pivotal in monetising—monetizing, for American readers—stranded gas reserves and bringing them to market.

Natural gas will become more important in the energy mix, and so in doing international deals it would be great to operate without the translator—the calculator. ✦



Editorial

Politics of independence

Politicians who make "energy independence" a target of US governance say much about themselves. They either know little about US energy realities or stand to gain some advantage from policies motivated by unachievable goals. Neither condition provides a solid basis for policy-making.

"Whereas, energy independence can be achieved by innovation, diversifying energy sources, creating energy efficient products, and promoting conservation measures," the Democratic National Committee Resolutions Committee asserted on Feb. 1 while declaring support for "Democratic elected officials in Congress and in states and local communities across the country who are working toward energy independence, security, and diversity as well as a safe, clean environment." Voters can decide which condition—ignorance or special interest—is at work here.

No monopoly

Democrats can claim no monopoly of the politics of energy independence. At a solar-energy company in Merrimack, NH, Feb. 23, former Massachusetts Gov. Mitt Romney, a Republican presidential contender, promised a plan to induce the US to produce as much energy as it uses in 20-30 years. Energy independence in his vision will come from wind, solar energy, coal, and nuclear energy.

In the same month that these appeals for energy independence came forth from political quarters, the US Energy Information Administration produced an enlightening forecast. During 2005-30, EIA said in its Annual Energy Outlook 2007, the average reference-case growth rate for gross US imports of energy will be 1.2%/year. This is not, by historic standards, gangbuster growth. But any import growth indicates, by definition, movement away from the achievement of energy independence.

Indeed, energy independence means no imports. Zero. None. It means what Romney said: domestic production equivalent to consumption.

To use figures from the EIA's long-term projection again: The US will consume 131.16 quadrillion btu (quads) of energy in all primary forms in 2030. It will produce 88.63 quads, requiring imports totaling 46.37 quads before negligible exports and small balancing quantities. To become energy-independent, the US must lower consumption and raise production enough to turn that import number to 0.

The challenge is considerable. EIA's import projection for 2030 represents a lot of energy. It's more than the amount of energy that EIA expects the US to produce in that year in the forms of crude oil and lease condensate plus natural gas plant liquids plus dry natural gas plus nuclear power. It's slightly less than the amount of energy that EIA expects the US to consume in that year as coal plus nuclear power plus hydropower.

It's this wide gap between consumption and domestic production that the Democratic National Committee thinks can be closed by "innovation," "diversifying energy sources," "conservation," and all the rest. The favorite place to begin "innovation" these days is US agriculture and nearly anywhere else that doesn't involve oil, gas, or coal. In these areas, EIA projects healthy average growth rates over the next 25 years of 2.7%/year for biomass, 2.6%/year for other renewable energy, and 6.8%/year for other energy forms such as liquid hydrogen, methanol, and otherwise unaccounted-for refinery inputs. Total energy production from those sources: 7.82 quads. That's 9% of total domestic production and 6% of projected consumption—up impressively from 2005 shares for these energy forms of 5% of total production and 4% of consumption.

What it takes

So what would it take to raise production of the nonfossil energy forms politicians like and lower total energy consumption enough to eliminate imports and achieve independence? In a word: money. To be more precise about it: astronomical amounts of money. To put that into perspective: more money than taxpayers and energy consumers would tolerate. Because exotic energy sources cost more than conventional sources do, production depends on subsidies. And conservation beyond levels encouraged by the market can come only from officially imposed costs. Eliminating energy imports this way means raiding the national treasury and punishing consumers. Americans will figure out what's happening to them long before then.

Energy independence is an unrealizable dream. It's a pretense on which the government wastes money. Politicians who promote it are fooling themselves or trying to fool others. ✦

Companies take steps to avoid bribe hazards

Nick Snow
Washington Correspondent

Risks inherent in multibillion-dollar overseas oil and gas deals include the chances of violating the US Foreign Corrupt Practices Act (FCPA). Violations can occur in what seems to be normal and lawful business conduct. They also can be expensive. Officials at the US Department of Justice (DOJ) and FCPA specialists at leading law firms urge companies to take compliance seriously.

> *"American companies have to be very diligent because they're vulnerable."*
>
> **—Mark H. Tuohey, Vinson & Elkins LLP**

Prosecuting all kinds of corruption is a high priority at DOJ, including public corruption, corruption during the procurement process, and the FCPA, according to Alice S. Fisher, assistant US attorney general in charge of the federal department's criminal division.

"By enforcing the FCPA, and by encouraging our counterparts around the world to enforce their own anticorruption laws, we are making sure that your competitors do not gain an unfair advantage when competing for business overseas," she said at an American Bar Association conference on the FCPA in October. "And we are ensuring the integrity of our markets at home so that investors will continue to invest in your companies."

> *"Becoming the target of an FCPA enforcement action can significantly harm your company's stock price and reputation."*
>
> **—Michael L. Burton, Arent Fox LLP**

Settlements of foreign bribery allegations can be costly, whether with DOJ or with the US Securities and Exchange Commission. On Feb. 6, DOJ said three Vetco International Ltd. subsidiaries pleaded guilty to charges of violating FCPA antibribery provisions and agreed to pay $26 million in fines. The next day, the SEC said El Paso Corp. agreed to pay $7.7 million to settle charges that it and a company it acquired, Coastal Corp., paid kickbacks to Iraqi officials under the United Nations' Oil for Food program in 2000 and 2001.

Violations of the law are not confined to oil and gas producers, drilling contractors, and service and supply companies operating overseas. But the industry's global reach can create the potential for corruption. Multinational oil companies have dealt with the problem for years, but domestic firms venturing overseas for the first time may be surprised by it.

"Resources often are in parts of the world where there's not the same urgency about the FCPA as there is here," Mark H. Tuohey, a partner at Vinson & Elkins LLP's Washington office, told OGJ recently. "American companies have to be very diligent because they're vulnerable."

Avoiding problems

Michael L. Burton, a partner at Arent Fox LLP in Washington, said, "No one wants to fall into this situation because becoming the target of an FCPA enforcement action can significantly harm your company's stock price and reputation, in addition to the onerous terms of settlement with DOJ and the SEC."

More FCPA cases are settled than go to trial, according to Gregory Baldwin, a partner with Holland & Knight LLP in Miami. "If you're dealing with the FCPA, the chances of being also accused of violating the Money Laundering Control Act are substantial," he said. "That's a 20-year offense. If that's added to the mixture, the incentive to pleading guilty to a lesser charge under the FCPA is substantially heightened."

Companies charged often cooperate

because "the government has so many hammers to beat them into submission," noted Drew A. Harker, a partner at Arnold & Porter LLP in Washington. "It's one thing to pay a fine, which can be significant. But it's another to be barred from doing business with government customers who use formal bidding procedures or losing your export privileges."

He and other attorneys interviewed for this article agreed that the best way to avoid FCPA problems is to establish and operate a strong anticorruption compliance program.

"Management must fully support it," Harker said. "If it's just a few in-house lawyers talking among themselves, it won't work well. Management needs to show it rewards ethical conduct. It has to provide incentives for employees to behave properly."

William E. Lawler III, also a partner in Vinson & Elkins's Washington office, said the best FCPA compliance programs are formalized in writing, have someone with significant authority in charge, are disseminated through the company, and include an audit function. The program then has to be tailored to the company, he said.

He and Tuohey argued one of the first cases that led to establishing a core meaning of the law–namely, whether payments to foreign government officials were extortion instead of efforts to get or retain business. "Two federal courts in Texas ruled that obtaining or retaining business had to be proven," Lawler said. "In one case, involving an Indonesian tax official who demanded a payment or threatened to raise a tax by five times, that relationship could not be proven."

"It's one thing to pay a fine. It's another to be barred from doing business with government customers who use formal bidding procedures or losing your export privileges."

—Drew A. Harker, Arnold & Porter LLP

Due diligence

The FCPA excludes payments to a foreign government to support infrastructure associated with a project or agreements that a specific portion of the workforce will be from that country. "Often, contracts require indigenous participation–not necessarily a local partner, but a requirement for certain percentages of the staff to be local," said Eugene A. Massey, another partner at Arent Fox in Washington who specializes in international energy transactions.

"If you're dealing with the FCPA, the chances of being also accused of violating the Money Laundering Control Act are substantial."

—Gregory Baldwin, Holland & Knight LLP

Much of his recent work has involved LNG export projects, which can require up to four times the capital for similar efforts involving oil to bring a comparable amount of energy to market. "There's a tremendous amount of scrutiny that takes place as deals are being negotiated. When everyone is sharpening their pencils to get the best deal, someone will speak up if inappropriate influence on behalf of a competitor is suspected," he said.

Dianne R. Phillips, a partner with Holland & Knight LLP in Boston, noted that several LNG developments are in countries where governments treat gas reserves as national assets and take active roles in related business projects. She said: "There is a high, high current demand for these projects and a huge value chain associated with them. There's a lot of money at stake and a lot of necessary involvement with foreign governments. Many of these countries may not have natural trade relationships with the United States so there is some potential for problems."

Thorough due diligence is crucial. "The agreements are for a long term, and a lot of money is involved," Phillips said. "There are several multiple incremental steps before the projects start up. There are literally years of negotiations, starting with a memorandum of understanding. It takes quite a period of time before there's a formal commitment to proceed. That provides an opportunity for due diligence."

Due diligence has to extend to agents or other third parties acting on a company's behalf. Burton said: "It's relatively uncommon these days to see a US company's employee make an illicit payment directly to a foreign official, although it certainly happens. Instead, the company might become involved with a third party under circumstances where the government would assert that the company should have known a payment was likely to be made for some improper quid pro quo."

When performing overseas due diligence for a company, said Harker of Arnold & Porter, "We determine what its overseas profile is, whether it uses agents, and if those agents' activities are continuously monitored." While the focus can be on sales agents and marketing representatives, he said, "Law firms, accountants, and joint ventures also can get a company in trouble. That's why negotiations are crucial, particularly in knowing what your joint-venture partner brings to the table and assuring that the joint venture is run properly."

Lawler said due-diligence issues for a joint venture can differ from those of a sale because the participants' relationship continues. During the past few years the process has become more

extensive. It now can involve books and records, which once were secondary but have gained in importance since passage in 2002 of the Sarbanes-Oxley Act on corporate governance. "Any time there's an opportunity to affect a $10 billion project, there's an opportunity to violate the FCPA," he said.

> *"There's a tremendous amount of scrutiny that takes place as deals are being negotiated."*
> **—Eugene A. Massey, Arent Fox LLP**

Spreading standards

When Congress passed the FCPA in 1977, many US companies complained it would place them at a disadvantage with foreign competitors. "Many still believe they're subject to a stricter standard," said Harker. But he added that DOJ worked hard to persuade other countries to pass similar laws, including a few that had provisions in their tax codes allowing bribes to be deducted.

Baldwin of Holland & Knight pointed out that in 1998 amendments to the law, Congress directed the government to encourage other countries to pass similar legislation. "Among the [Organization for Economic Cooperation and Development] countries, the main industrialized nations of the western world have statutes similar to the FCPA, although most aren't quite as extensive," he said. "Since around 2002, a lot of different countries signed the agreement and implemented the legislation."

In her October address to the ABA's FCPA conference, Fisher also cited the United Nations Convention Against Corruption, under which 140 countries have agreed to criminalize bribery of domestic and foreign public officials. "My hope and belief is that if our foreign law enforcement partners see our commitment to combating corruption around the world and to enforcing our own anticorruption laws, it is more likely they will prosecute corruption in their own countries," she said.

That has begun to happen, according to Burton. "With the OECD convention, other multilateral anticorruption initiatives, and pressure from the international financial institutions, cases are being brought under local laws, particularly when there has been a change of government and the new one wants to hang its predecessor out to dry. The World Bank also has anticorruption standards and can bar countries from its financing," he said.

> *"There's a lot of money at stake [in LNG projects] and a lot of necessary involvement with foreign governments."*
> **—Dianne R. Phillips, Holland & Knight LLP**

Tuohey confirmed that the World Bank and other financial sources' demands for more transparency in deals have helped the US persuade other countries to adopt antibribery laws. "This country has been able to be aggressive because its businesses have been responsible for so much commercial good," he said.

> *"Any time there's an opportunity to affect a $10 billion project, there's an opportunity to violate the FCPA."*
> **—William E. Lawler III, Vinson & Elkins LLP**

Investigations and cases

FCPA investigations can start in many ways, the attorneys said. "They have come from references from foreign governments, competitors, former employees, self disclosure, contractors, joint venture partners," Baldwin said. "There's no unique type of source you can point to for allegations. There's no central mechanism. You engage in this activity at your own risk because there are a lot of people out there with axes to grind. There also are bribery hotlines and complaint centers."

Harker said most FCPA cases he has encountered began with internal whistle-blowers. The Sarbanes-Oxley law contains a provision that encourages employees to come forward when they see questionable behavior, although it's not certain whether it applies to FCPA violations, he told OGJ. "If you measure effectiveness in prosecuting FCPA violations by the number of charges brought and settlements reached, the FCPA would appear to be an important and expanding prosecutorial tool for the government," he said.

Fisher noted that DOJ has a procedure under which companies and individuals can seek its opinion regarding proposed business conduct or a proposed transaction. "What we're talking about here is asking for advice before undertaking a transaction, not after you have discovered an FCPA violation," she said.

The law firms' FCPA specialists agreed that this could be helpful but limited in its effectiveness. "There often isn't the luxury of time in a live transaction to be able to present DOJ with the facts and get its opinion," Burton said. "In addition, DOJ can be very conservative, and the procedure often is used only when a company doesn't expect the deal to go forward."

The procedure can be "time-consuming and a deal-killer," said Harker. "If a company's inside and outside counsels are doing their jobs, it

shouldn't be necessary." Companies seeking DOJ guidance also may err in submitting best-case scenarios that don't materialize, he said.

Compliance issues

Experience is important in matters of compliance, Tuohey observed. "Large entities have experience and know how to set up joint ventures and make them work," he said. "A small, start-up oil field service company planning to bid for part of a contract may be more vulnerable."

But small companies "don't operate in a vacuum," Lawler said. "Some small companies are surprised at what they have to do because their larger partners don't want to be liable. A 20-person company isn't going to need a hotline. Its compliance framework may look different, but it still has to be active."

Baldwin noted that there are important ambiguities in the FCPA: "A foreign public official includes an officer or employee of a foreign government or instrumentality. The act doesn't say what a 'foreign instrumentality' is. Another ambiguity is in facilitating, or grease, payments. While facilitating payments are an exception to the act, there's no particular amount mentioned, so it's hard to determine what's reasonable. The higher the amount paid to the official, the less the payment looks like it's 'facilitating' and the more likely it is to appear a bribe."

Legitimate training and promotion expenditures also are allowed, including bringing foreign officials to the US as long as the trips are not lavish, he said, adding: "Anything can be deemed a corrupt payment. It depends on the purpose. It's ambiguous in the sense that the definition of a corrupt purpose depends on the circumstances."

Burton said, "You try to build features into any agreement so you have some indemnification rights. If a potential partner refuses to let you audit its finances or find out who its shareholders are beforehand, that's when to exert pressure or start looking for another deal."

Harker stressed the need for good compliance programs. "They're necessary if you're doing business overseas," he said. "Government contracts are not for the faint at heart. You need good advice. There are a lot of minefields."

Tuohey said, "The FCPA is alive and well around the world because corruption is alive and well. And the oil and gas industry is fertile ground for potential problems and will continue to be so." ✦

PHMSA chief wants review of pipeline inspection intervals

Nick Snow
Washington Correspondent

The top oil and gas pipeline regulator in the US wants operators to use inspection programs that do the best job of determining their systems' condition. That's why he would like Congress to reconsider pipeline inspection intervals, he told OGJ.

"The 7-year interval doesn't make sense from a risk management perspective. We want operators to focus their attention on areas of greatest risk. Some lines may not need to be inspected that frequently. Others might need to be inspected more often," said Thomas J. Barrett, administrator of the Pipelines and Hazardous Materials Safety Administration.

More than 50% of the baseline inspections required by the original pipeline safety law, which was passed in 2002, were completed by last summer as Congress considered a reauthorization bill, he said. "So far, very few are turning up the need for necessary repairs, and even fewer are suggesting that immediate repairs are required," Barrett said in an interview at PHMSA headquarters.

The 2002 law's 7-year inspection interval means that operators have to reexamine already inspected segments while completing remaining inspections, he explained. The provision remained in the reauthorization bill, which Congress passed and US President George W. Bush signed into law late in 2006.

A Government Accountability Office report favors risk-based intervals, so PHMSA plans to outline criteria such as inspection history and stress corrosion incidents, Barrett said. "In fairness to Congress, we may not have explained this as well as we should last summer," he said.

"I think, overall, we'd have safer systems. I am an advocate of data-driven risk management. In pipelines, that translates into integrity management," Barrett said. Better-trained employees also will be needed, he added.

He pointed out that there have been 55,000 repairs of federally regulated pipelines in the last 5 years where problems were identified and fixed without incident. "That's exactly where we want to be," he maintained.

Third-party damage

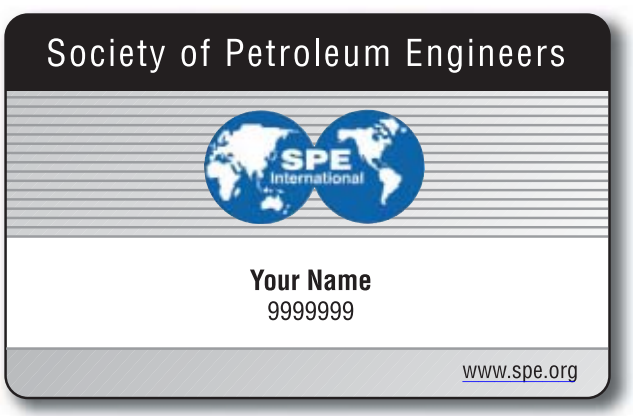
The recently enacted pipeline safety reauthorization law addresses third-party damage, which Barrett said is the most serious safety issue. "The law goes right at it. The industry was very supportive of it. So were the contractors," he said.

Also in the law are low-pressure oil pipeline provisions that go beyond proposals issued by PHMSA early last fall. The agency had been preparing its proposals, required under the 2002 pipeline safety law, when leaks began to be discovered in BP PLC's oil gathering system at Prudhoe Bay nearly a year ago.

PHMSA plans to issue a supplemental proposal this spring that will incorporate the new law's requirements. Barrett said Congress has indicated the agency can phase in the more difficult provisions.

"Prior to the BP spills, we had not

Survival necessity.



Career necessity.

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had significant problems with this type of line. These also are the largest low-pressure lines in the country so their problems were not typical," he said.

A major consequence was the potential impact on supplies when the lines were shut down during the summer for repairs, Barrett continued. "Even though we're a safety agency, Congress wants us to factor in reliability," he said, noting that PHMSA and the US Department of Energy plan to jointly examine the problem.

But Barrett emphasized that the agency will continue to focus on safe and efficient pipeline operations. "We want operators to understand the condition of their lines through their own inspection programs and take action. I'm not certain how we'll do this, but one possibility is a two-tiered inspection program where we'd make an initial evaluation and follow up with a more detailed inspection if we find a problem," he said.

He considers making sure pipelines operate safely a key element of US energy security. "We'd like to reduce congestion. We're looking at new construction and metallurgy to allow 80% SMYS [specified minimal yield strength] instead of 70% so more gas can be transported," he said.

Barrett said PHMSA and pipelines likely would play a major role in transporting alternative fuels. "We would approach it from a safety perspective. We have been talking to the National Association of Fire Marshals and industry stakeholders," he said.

"Pipelines move more oil and gas than truck, rail, and vessel barge combined. So if you plan to move large volumes of an alternative fuel, you'll need pipelines to do it," Barrett said. ✦

IOGCC: US petroleum workforce size increasing

Nick Snow
Washington Correspondent

Government and industry are making progress in increasing the number of qualified petroleum professionals in the US, says the Interstate Oil & Gas Compact Commission in a new report.

Particularly encouraging is "evidence of public-private partnerships at every level," IOGCC said. "The task force recommendations for establishing internships, scholarships, and other programs designed to attract young people to petroleum science careers have taken root in all areas."

The report, "Blue Ribbon Task Force: A Follow Up Report," updates the results of a task force created by North Dakota Gov. John Hoeven in 2001 to investigate the shrinking numbers of petroleum geologists, geophysicists, and engineers in the US workforce. Following its analysis, the task force issued recommendations to federal and state governments, colleges and universities, the oil and gas industry, and other groups for collaboration in counteracting the situation.

"The progress is encouraging," said Hoeven, who currently chairs IOGCC.

In 2001, the original task force noted that enrollments in petroleum-related majors at US colleges and universities had decreased over many years. The updated report, which IOGCC issued Feb. 26, says that the number of bachelor's degrees awarded in petroleum engineering rose to 322 in 2005 from 260 in 2000, while the number of geology degrees fell slightly to 3,300 in 2004 from nearly 3,500 in 2000.

"The imperatives for action in the next 3-5 years include new directions in public policy, education, and resource development and management," the report says.

Federal performance

Grading the various sectors' performances, the IOGCC report finds that the federal government has been strongest in creating internships within federal departments for geosciences graduates and undergraduates, and in working with other federal departments and the IOGCC in a coordinated effort. However it was weakest in funding pilot and research programs, advising the IOGCC and its member states of available grants, and alerting them of similar projects to avoid duplication.

Oil and gas research funding, a federal budget reduction target since 1989, remained relatively flat from 2001 to the present. "Of the $8 billion budgeted in 2006 for energy R&D, only $65 million was slated for oil and gas R&D," noted the latest report, adding that the 109th Congress failed to approve the fiscal 2007 budget altogether.

"To date, nothing is budgeted for oil and gas R&D within the US Department of Energy. All that remains is the $50 million allocated from royalty receipts under the Energy Policy Act of 2005 for ultradeepwater and unconventional hydrocarbon development," IOGCC report said.

Despite reduced funding, it continued, some interesting federal research has occurred, including progress in developing clean and renewable energy sources by DOE's fossil energy office, reduction of methane emissions through DOE's Natural Gas STAR initiative, and funding from DOE's natural gas and petroleum technology office for a global partnership to reduce gas flaring and venting associated with crude oil production.

The new IOGG report also notes progress as other federal departments and agencies have developed partnerships with the oil and gas industry. These include the Department of the Interior's Bureau of Land Management and Minerals Management Service, which both have addressed royalty regulations in ways designed to offer incentives; the Internal Revenue Service, which revised rules applicable

to depreciation and amortization, and the Department of Commerce, which established an emergency oil and gas guaranteed loan fund.

State, industry progress

States have been strongest in involving their employment services, regulatory agencies and education entities into oil and gas training and education, says the report. States also have done well in creating partnerships with the industry, providing internships, continuing education for teachers, working with career counselors, and funding of research. They also reached out to the federal government through the Western Governors Association and other groups.

"Progress in this sector has been stronger overall. Of the IOGCC's 37 state members, 30 reported positive activity toward improving the investment climate for the petroleum industry in their state," the IOGCC's new report indicates.

The industry's biggest contributions, it says, have been to provide summer jobs, reach out to high school and college students, and develop scholarships and grant programs for employees to extend their education. Oil and gas executives also have alerted human resources professionals of the need for a sustained effort, and they financially supported public relations, public education, and scholarship/internship programs.

The popularity of summer job and internship programs has soared as sophomores make $4,000/month and juniors and seniors make $5,600/month, according to the report. "From the students' perspective, internships not only help fund their college expenses, but they receive valuable training in the various aspects of their chosen field. From the companies' perspective, they are recruiting qualified people familiar with their culture and operations," it says.

Copies of the report can be ordered from IOGCC or viewed online at www.iogcc.state.ok.us/PDFS/2007-Blue-Ribbon-Task-Force-Update.pdf. ✦

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

Republicans challenge IG

US Department of the Interior Insp. Gen. Earl E. Devaney intended to mention reforms that have been implemented as well as problems he has identified at DOI when he came before the House Natural Resources Committee on Feb. 16. But Republicans on the committee had other ideas.

They charged that his report on his office's investigation of missing price thresholds in federal deepwater oil and gas leases issued in 1998 and 1999 was not balanced and omitted several questions and documents.

Rep. Steve Pearce (R-NM), who led the criticism, also questioned the report's conclusion that thresholds were omitted by mistake, suggesting instead that managers and employees at the Minerals Management Service and DOI decided in 1998 and 1999 that the thresholds were not necessary because oil prices were low.

"I don't think there was double-dealing on the part of the Clinton administration. I don't believe there was inherent criminal activity. I simply think they felt the price would never reach a level where thresholds would be needed," Pearce said.

'Never written down'

Devaney replied, "There never was a policy. The practice of the department was to put addendums on these leases, which included price thresholds. If there's reference to a policy, it probably refers to a statement by witnesses that there was a policy, but it was never written down. My solicitor has been searching frantically for a written policy and hasn't found one."

Pearce characterized this as "policy by innuendo" and asked Devaney if he thought it would withstand a legal challenge. Devaney declined to offer an opinion, noting that he is not a lawyer, but added that investigators from his office have found similar situations throughout DOI.

Their difference in opinion regarding the price thresholds' omission from the 1998 and 1999 deepwater leases was that Devaney thought it apparently was a mistake while Pearce suggested it could have been casually deliberate–essentially, omitting the thresholds because they had not seemed to matter in the past.

Strategy signal

Their exchanges signaled that House Republicans intend to vigorously oppose Democrats' efforts to legislatively pressure holders of those 1998 and 1999 deepwater leases to renegotiate terms.

"Based on your testimony in the Senate and here today, there was no statute to require inclusion of price thresholds. There was no policy requiring their inclusion. There simply was a deliberate omission," Pearce said toward the hearing's conclusion.

"I don't see where the Clinton administration was so inept that it would go 30 months after discovering the absence of price thresholds before including them. I do see a bad decision by the Clinton administration that assumed the price of oil would not go above $28/bbl," he told Devaney.

Chairman Nick J. Rahall III (D-W.Va.) said there would be more hearings. "Something is amiss in this program," he said. "We will work to find ways to find and remedy it." ✦

TODAY'S DECISIONS CAN'T WAIT FOR NEXT WEEK'S LOGS.
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IFP: Oil, natural gas prices to remain high for 2007-08

Doris Leblond
OGJ Correspondent

Oil prices should remain at the $50-55/bbl level over this year and possibly part of 2008, interspersed with periods of tension, and thereafter continue to rise on the back of strong demand, constrained supply, and continuing refining tensions, reported Institut Français du Pétrole (IFP) in its 2007 Panorama presented in Paris last month. The tentative economic outlook also indicated that gas markets would likely suffer from interenergy competition, driven by high prices.

IFP Pres. Olivier Appert said 2006 might be viewed as a year of transition, correcting 2005 oil price excesses as oil demand slowed, the call on OPEC stabilized, and non-OPEC supply increased by nearly 1.4 million b/d—to 51 million b/d.

The oil market presented signs of short-term stabilization, with prices remaining under $60/bbl. However, beyond 2008, futures markets seem to indicate sustained price hikes, taking into account the forward price for West Texas Intermediate crude, noted Appert. While it plunged to a recent low, the 2012 forward price has "fallen by less than half the short-term prices" as the market players still perceive a future production squeeze, he said.

The current slowdown in world oil consumption conceals great regional disparities, supporting higher longer-term prices. Demand is down in all Organization for Economic Cooperation and Development (OECD) countries, but it is still strong in rapidly emerging countries, including China (up 6.2% to 410,000 b/d). Demand also is rising in the Middle East (up 5.4% by 330,000 b/d).

Although 2006 confirmed the decline of mature areas like the North Sea and a decrease of OECD output for the fourth straight year, non-OPEC oil production increased significantly elsewhere, namely in the Commonwealth of Independent States, Latin America, and Africa.

Future OPEC output

Before Angola joined OPEC on Dec. 14, 2006, IFP had anticipated the call on OPEC decreasing in 2007-08 and had forecast non-OPEC supply growing by an average rate of 1.4 million

b/d/year to the end of the decade. This forecast has been revised downwards to 700,000 b/d from 2009.

Production in many non-OPEC countries is nearing peak, Appert said, but OPEC's influence and its output, which would gain about 1 million b/d over the 2006 figure, will be singularly boosted by Angola's joining OPEC, possibly followed by Sudan and Ecuador, which are mulling such a move.

IFP estimates that OPEC's share of world oil production likely would jump to 44% in 2009 from 41% last year, while global oil demand increases by 4.8 million b/d. "Non-OPEC countries will not be able, alone, to provide the surplus needed in the medium-term," insisted Appert.

He also pointed to other factors likely to push up oil prices beyond 2009, including resource nationalism in a number of countries, growing domestic needs of oil exporting counties, and determination of countries such as Qatar to conserve resources for future generations.

Natural gas

Uncertainties also are besetting the gas industry, as higher prices and supply security in particular have impacted the development of competing energies—oil, coal, and nuclear power—to the detriment of natural gas, said Marie-Françoise Chabrelie, secretary general of Cedigaz.

She sees a "probably slower and more-jerky development" for natural gas in the future. Gas use should continue to rise steadily by an average 2.5%/year to 2010, pulled along by Latin America, Asia-Oceania, Africa, and the Middle East. The construction of additional gas production and transportation infrastructure to aid deliveries also will contribute to increased gas usage.

Escalation of gas use should then slow to 2.2%/year at best. Higher prices are boosting competition from other energies, especially coal, in the power industry in Europe, where several plants are being planned with at least partial carbon dioxide capture. These are due on stream after 2010.

Also emerging are production constraints: lack of exploration and production investment in Russia; difficulties with available gas volumes to supply liquefaction facilities in some countries such as Oman and Trinidad and Tobago; technical problems in Indonesia; and the political decisions of producing countries as in Bolivia or Russia that could jeopardize the future regional and world supply balance.

Chabrelie also perceives growing imbalances in international gas trade between producing areas with surplus supplies and OECD countries where production can no longer satisfy demand. In addition to the huge volumes transported from one area to another, transportation management will become increasingly complex, exacerbated by the proliferation of LNG routes. The share of LNG in total gas trade is due to rise sharply to 30% in 2015 from 22.3% in 2005 driven by flexibility, source diversification, and improved supply security. ✦

DOJ fines Vetco units record $26 million in FCPA case

Nick Snow
Washington Correspondent

Eric Watkins
Senior Correspondent

Three Vetco International Ltd. subsidiaries pled guilty to violating antibribery provisions of the Foreign Corrupt Practices Act and agreed to pay $26 million—the largest criminal fine in an FCPA prosecution by the US Department of Justice so far, Deputy Atty. Gen. Paul J. McNulty reported Feb. 6.

The pleas by Vetco Gray Controls Inc., Vetco Gray Controls Ltd., and Vetco UK Ltd. came before US District Judge Lynn N. Hughes in the Southern District of Texas. The three subsidiaries also pleaded guilty to conspiracy to violate the FCPA.

A fourth Vetco subsidiary, Aibel Group Ltd., entered into a deferred prosecution agreement with DOJ regarding the same underlying conduct.

The settlement fulfills a closing condition for the previously announced sale of Vetco Gray to GE, the Houston-based oil field service and supply company said in a separate statement.

As part of the plea and deferred prosecution agreements, Vetco Gray Controls Ltd. agreed to pay a $6 million fine, Vetco Gray Controls Ltd., $8 million, and Vetco Gray UK Ltd., $12 million.

In the charging and plea documents, DOJ said that the three Vetco subsidiaries admitted that they violated and conspired to violate the FCPA in connection with the payment of about $2.1 million in corrupt payments over 2 years to Nigerian government officials.

These corrupt payments were paid through a major international freight forwarding and customs clearance company to employees of the Nigerian Customs Service, and coordinated largely through Vetco Gray Controls Inc.'s offices in Houston. Additionally, Aibel Group agreed in its deferred prosecution agreement to accept responsibility for similar conduct by its employees.

As the charging and plea documents reflect, beginning in February 2001, Vetco Gray UK began providing engineering and procurement services and subsea construction equipment for Nigeria's first deepwater oil drilling project, the Bonga Project. Several Vetco Gray UK affiliates, including Aibel Group, Vetco Gray Controls Inc., and Vetco Gray Controls Ltd., supplied Vetco Gray UK with employees and manufacturing equipment for the project.

Period of payments

From at least September 2002 to at

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Japan voices gas concerns

In a meeting with Russian Industry and Energy Minister Viktor Khristenko, Japanese Foreign Minister Taro Aso last week asked Russia to ensure Japan's supply of LNG from the Sakhalin-2 oil and natural gas project.

As you can imagine, given Russia's interests in the Asia-Pacific oil and gas market, Khristenko gave an upbeat reply, assuring Aso that terms of existing agreements would be observed.

Aso's concerns are not unfounded, given Russia's treatment of the original Sakhalin-2 partners, including two Japanese trading houses—Mitsui & Co. and Mitsubishi Corp.—along with Royal Dutch Shell PLC.

After sustained pressure—some call it blackmail—from Russia's environmental authorities, the three original Sakhalin-2 partners reluctantly agreed last December to relinquish more than half of their combined stake in the project to OAO Gazprom (OGJ, Jan. 1, 2007, p. 29).

Sleepless nights

The sale gave the state-owned Russian gas company a stake of 50% plus one share in the project. The interests in the joint venture partnership, called Sakhalin Energy Investment Co. Ltd. (SEIC), now read as Gazprom 50% plus one share, Shell 27.5%, Mitsui 12.5%, and Mitsubishi 10%.

The sale also caused sleepless nights for some people in Japan because it raised concerns about whether the country's electric and gas companies would be able to procure LNG from the project as initially agreed.

Since then, other Japanese firms have tentatively signed up for supplies from Sakhalin-2. On Feb. 9, for example, SEIC said it had signed a heads of agreement with Japan's Osaka Gas Co. Ltd. for the supply of some 200,000 tonnes/year of LNG for more than 20 years.

The gas will be supplied from SEIC's new LNG plant at Prigorodnoye on the southern tip of Sakhalin Island. The plant is about 95% complete, with the first deliveries expected next year, SEIC said in a statement. We believe them, too, especially Shell, Mitsubishi, and Mitsui.

Oz to the rescue

Not everyone is counting on Russian promises, though, and suppliers elsewhere are reaping the benefits. Indeed, Woodside Petroleum Ltd., operator of Australia's North West Shelf venture, announced Feb. 22 the signing of a heads of agreement with Japan's Kyushu Electric Power Co. Inc.

In announcing the deal, Woodside said all eight of the NWS venture's original Japanese LNG customers have now renewed their long-term LNG purchase commitments.

That's not surprising since there's no sign of a Russian firm anywhere on the Australian horizon, a point underlined by Mitsunori Torihara, president of Tokyo Gas Co., which accounts for nearly 20% of Japan's total LNG imports.

"Besides Sakhalin-2," Torihara said in a recent interview, "we have procurement contracts with five production bases in Australia. There is little political risk in Australia, and we don't have to worry about the risk of over-concentration because each of the bases has a different operating company." ✦

least April 2005, each of the defendants engaged the services of a major international freight forwarding and customs clearing company and, collectively, authorized that agent to make at least 378 corrupt payments totaling $2.1 million to Nigerian Customs Service officials to induce those officials to provide the defendants with preferential treatment during the customs process, DOJ said.

It said that this was the second time that Vetco Gray UK has pled guilty to violating the FCPA. On July 6, 2004, the company, then named ABB Vetco Gray UK Ltd., and an affiliated company pleaded guilty to violating the antibribery provision of the FCPA in connection with the payment of more than $1 million in bribes to officials of NAPIMS, a Nigerian government agency which evaluates and approves potential bidders for contract work on oil exploration projects.

ABB Vetco Gray UK Ltd. was renamed Vetco Gray UK Ltd. following an acquisition by two private equity firms, Candover and JP Morgan Partners, of the upstream oil and gas businesses and assets of its parent corporation, ABB Handels-und Verwaltungs AG. The July 12, 2004, acquisition included the sale of Vetco Gray UK and the predecessors to the two other Vetco International subsidiaries, which pleaded guilty in the most recent case.

In anticipation of the acquisition, the private equity firms requested and obtained an opinion release from DOJ that required the new owners to institute and implement a compliance system, internal controls, training, and other procedures sufficient to have deterred and detected violations of the FCPA, among other obligations, the federal agency said.

It said that the corrupt payments underlying the latest guilty pleas continued unabated from the period prior to the acquisition until at least mid-2005, despite the acquiring equity firms' commitments to DOJ under the Opinion Release. The sale to new owners, the prior directives issued by DOJ, and Vetco Gray UK's prior FCPA conviction were all taken into account under the U.S. Sentencing Guidelines

in calculating the $12 million criminal fine against Vetco Gray UK, DOJ said.

Resolution of the criminal case against Vetco International and its subsidiaries resulted, in large part, from the Houston-based oilfield service and supply company voluntarily disclosing the matter to DOJ and the subsidiaries' agreement to take significant remedial steps.

In addition to the criminal fines, DOJ said that the plea agreements also require the defendants to: 1. Hire an independent monitor to oversee the creation and maintenance of a robust compliance program. 2. Undertake and complete an investigation of the companies' conduct in various other countries as originally required under FCPA Opinion Release No. 2004-02. 3. Ensure that in the event that any of the companies are sold, the sale shall bind any future purchaser to the monitoring and investigating obligations. ✦

S&P's: Refiners face capacity upgrade challenges

The global refining industry faces the challenges of upgrading its capacity to produce less-polluting fuels while processing increased volumes of poorer-quality crudes, Standard & Poor's said in a recent special report on fluctuating oil prices.

More heavy and sour crude is coming onto the market, and the complex process of refining this crude into fuels that meet stricter low-sulfur regulations is costly, S&P analysts said.

A growing price differential between light and heavy crudes will make it harder for refiners as they process greater volumes of lower-quality crude. Consequently, refiners must find the capital to fund enormous construction demands, S&P analysts said.

Oil and gas prices continue to be characterized by remarkable volatility, yet the impact has been minimal to the US economy so far, said David Wyss, S&P's chief economist, during a Feb. 27 conference call.

Oil prices would have to go higher than they did in the past to damage the economy, Wyss said. Greater energy efficiency means oil is not as big a percentage of household spending as it has been in the past, he added.

He expects oil prices to fluctuate widely, noting that rising prices were not a drag on the economy last year as some economists had suggested. Likewise, he does not expect recent falling oil prices to boost the economy this year.

Wyss said his forecast is absent major geopolitical events that cause dramatically swinging oil prices. ✦

GLOBAL OFFSHORE OIL—1

Exploration trends show continued promise in world's offshore basins

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The production performance of the global offshore has been remarkable, and it has not reached its full potential.

Globally, 500 billion bbl of oil have been discovered, of which 200 billion bbl have been produced. Giant offshore fields represent 41% of the total oil discovered, and these are located in several regions albeit in few geological settings.

A heuristic approach developed in this article suggests that there could easily be 30% more oil than what is currently estimated. Further, there is large undiscovered potential as several regions remain underexplored and others have not been explored at all.

The ultimately recoverable reserves (URR) for the global offshore are close to 1 trillion bbl. Over the decades, E&P trends in the offshore have remained highly encouraging, particularly given that both yearly discoveries and average field sizes have remained the same over the last three decades.

Offshore is the next frontier in global oil supply. It's amazing what $50 oil will do!

Offshore evolution

The oil industry has expanded consistently over the last decades from land operations to inland waterways and then to offshore.

Offshore barges for exploration began to be used in 1950, deepwater drillships in 1956, and semisubmersible rigs in 1964.

In the 1980s, deepwater exploration meant 800 ft of water. Today, 1,500 ft of water is considered shallow, 1,500 to 7,000 ft is considered deepwater, and over 7,000 ft is termed ultradeep water.

Offshore oil production started in the early 1940s and has grown from a modest 1 million b/d in the 1960s to nearly 25 million b/d in 2005 to represent one third of world crude oil production. Conversely, onshore crude production needed six decades to reach 25 million b/d in 1963.

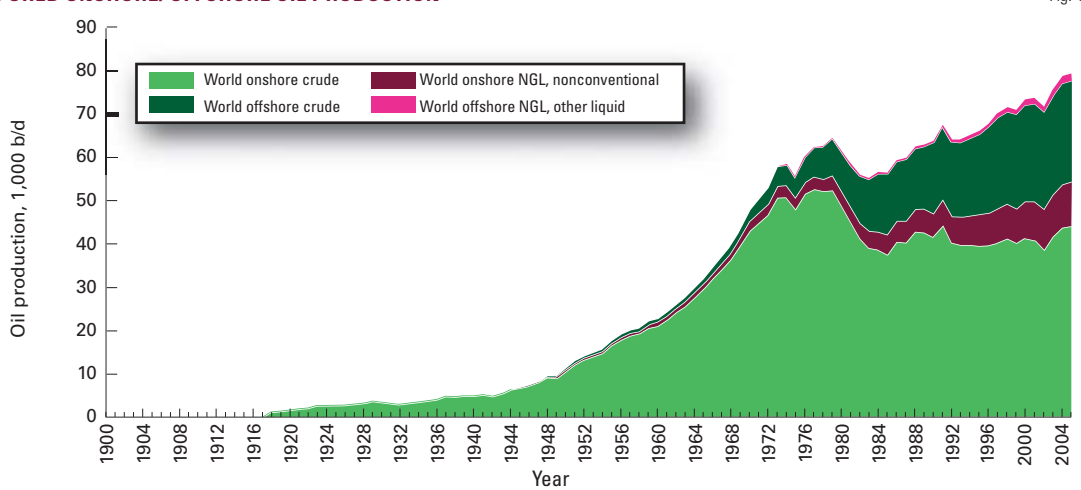
Unlike onshore oil production, offshore production has never experienced sharp downward fluctuations and has grown consistently over the years (Fig. 1). In fact, it has been the main source of growth for world crude oil production as the onshore has essentially remained at plateau for more than two decades.

In 2005, the Persian Gulf/Middle East topped the list of offshore producers, followed by the North Sea, West Africa, the Gulf of Mexico (US and Mexico), Asia/Australasia, Brazil, China, Caspian, and Russia/Arctic (Table 1). Of the total offshore crude, shallow water accounted for 20.3 million b/d and deepwater 3.5 million b/d. Other liquids such as natural gas liquids (NGL) totaled 1.6 million b/d, mainly from the shallow water offshore.

Up through 2005,[1] a total

WORLD ONSHORE/OFFSHORE OIL PRODUCTION

Fig. 1



of 503 billion bbl (455 billion bbl of crude oil and 48 billion bbl of NGL) has been discovered offshore, of which 204 billion bbl have been produced, leaving estimated remaining reserves at nearly 300 billion bbl.

The most important offshore oil discoveries have been made in the largest producing regions mentioned above. Offshore China, Caspian, and Russia/Arctic exploration has been relatively limited, while in other producing areas exploration has only yielded relatively limited success.

In terms of yet-to-find (YTF) reserves, the only institution to have published undiscovered global estimates for oil that segregates offshore and onshore is the US Geological Survey.[2,3] The USGS 2000 world petroleum assessment put the estimate for undiscovered offshore hydrocarbons at 306 billion bbl of crude oil and 95 billion bbl of NGL, representing 47% of total undiscovered oil in the world.

Therefore, there should be no doubt that from a resource and production perspective the importance of the offshore is paramount. However, most research fails to discern or disaggregate between offshore and onshore.

Furthermore, the growing significance of global offshore activities merits a reassessment of the classical Hubbert model predictions.[4] This decline model is solid and handles adequately severe events[5] such as sharp production fluctuations, new large discoveries, EOR, etc.

However the result of pooling production from different types of provinces—mature onshore with a strong emerging offshore—with different histories introduces interpretative distortions that inevitably lead to off-beam estimations of world oil resources, depletion, and maximum oil supply estimates.

In fact, the world crude oil (onshore and offshore) decline linear trend line has shifted its course[6] after 1995 following the impact of offshore production. Eventually a new trend line will develop once the offshore effect reaches steady state, sometime in the distant future. A similar situation occurs with US natural gas.[7]

The objective of this two-part article is to estimate the potential of the world's offshore oil provinces using an analogy of the size distributions of the giant onshore and offshore fields discovered to date and provide a medium-term production outlook for global offshore.

Largest regions

It is no coincidence that the world's largest offshore oil producing regions are also endowed with rich onshore petroleum systems.

The Persian Gulf/Middle East is the world's largest oil producer and has the largest concentration of reserves.

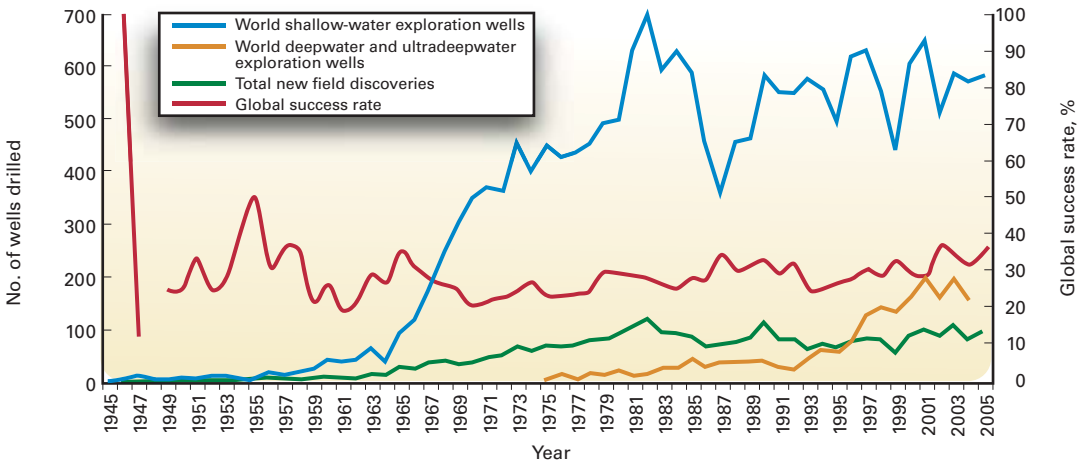
West Africa primarily produces hydrocarbons from two large offshore provinces, and it also has significant onshore reserves and production.

The Gulf of Mexico is a world class province surrounded by two countries that have significant onshore petroleum systems.

Asia/Australasia is a large region comprised of several countries, but the petroleum resources are found in tectonically linked basins that originated in the same process (i.e., Sunda). Oil production is primarily from

OFFSHORE EXPLORATION WELLS DRILLED AND OIL DISCOVERIES

Fig. 2



LARGEST OFFSHORE OIL PRODUCING REGIONS, 2005

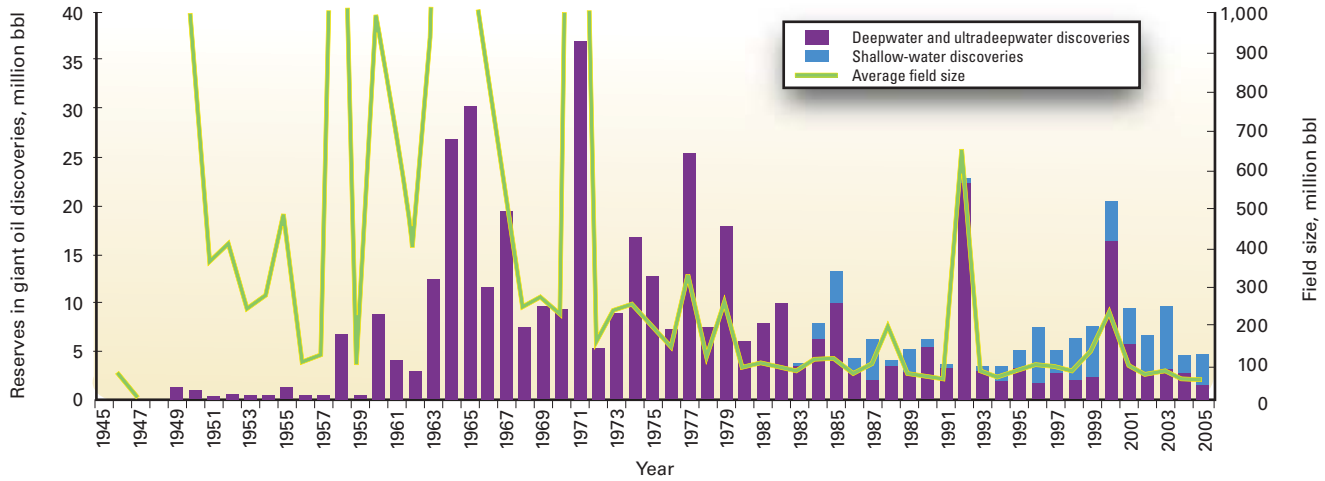
Table 1

	Crude oil production		
	Start-up	Million b/d	Cumulative, billion bbl
Persian Gulf/Middle East[1]	1957	5.3	51
North Sea[2]	1975	4.7	45
West Africa[3]	1969	3.5	25
Mexico Gulf of Mexico	1960	2.6	20
Asia-Australasia[4]	1960	2.1	21
US Gulf of Mexico	1947	1.6	24
Brazil	1973	1.5	6
China	1980	0.6	2
Caspian[5]	1950	0.4	1
Russia-Arctic	1999	0.05	0
Others[6]		0.8	2
Total NGL[7]		1.6	7
Total		**25**	**204**

[1]Egypt, Iran, Iraq, Neutral Zone, Kuwait, Qatar, Saudi Arabia, United Arab Emirates. [2]Denmark, Norway, UK. [3]Angola, Cameroon, Congo (Brazzaville), Equatorial Guinea, Gabon, Ivory Coast, Nigeria. [4]Australia, Brunei, Indonesia, Malaysia, Myanmar, New Zealand, Thailand, Vietnam. [5]Azerbaijan, Kazakhstan, bordering countries. [6]Mainly Argentina, Canada, Germany, India, Netherlands, Trinidad, Tunisia, Libya. [7]Mainly Australia, Egypt, Equatorial Guinea, Iran, Nigeria, Norway, Trinidad, United Arab Emirates, UK, US.
Sources: IHS Inc., OPEC

YEARLY OFFSHORE OIL DISCOVERIES AND AVERAGE FIELD SIZE

Fig. 3



offshore basins in this complex region, but it also has onshore oil provinces.

The North Sea and Brazil are in a class of their own as most oil reserves and production are in offshore settings.

The regions of China, Caspian, and Russia/Arctic share the following characteristics: a) onshore contains significant amounts of reserves and production, b) offshore oil production is presently either low or growing rapidly, c) limited number of offshore oil discoveries and exploration activity to date, and d) large geological petroleum systems.

Since the 1970s, the setting of the giant fields (500 million bbl or more recoverable) has been studied[8,9] with the objective of understanding the geographical and geological settings of the world's petroleum systems.

In one of the most comprehensive studies of this type, Mann et al.[10] reviewed the setting of 877 giant oil and gas fields representing two-thirds of the petroleum resources and found that these were not only located in few geographical regions but that they are concentrated in few tectonic settings. The three types of settings are: passive margins (304 giants), continental rifts (271 giants), and collisional margins (173 giants).

That study and the USGS 2000 assessment also concluded the following regarding the known petroleum systems of the world:

a) The typical depositional environment of reservoir rocks is nonmarine to marine (43% of known reserves) and shallow marine (36% of known reserves).

b) Less than 11% of the known reserves have been deposited in deep marine environments (turbidites).

c) The age of the reservoir rocks is commonly Mesozoic (65% of the known reserves) and Cenozoic (20% of the known reserves); less than 13% of the known reservoirs are Paleozoic or older; and

d) regarding trapping mechanisms, the most common traps are structural (over 71% of the known reserves); and only 5% of the resources have been found in stratigraphic traps.

GEOLOGIC SETTING OF OFFSHORE OIL PRODUCING REGIONS

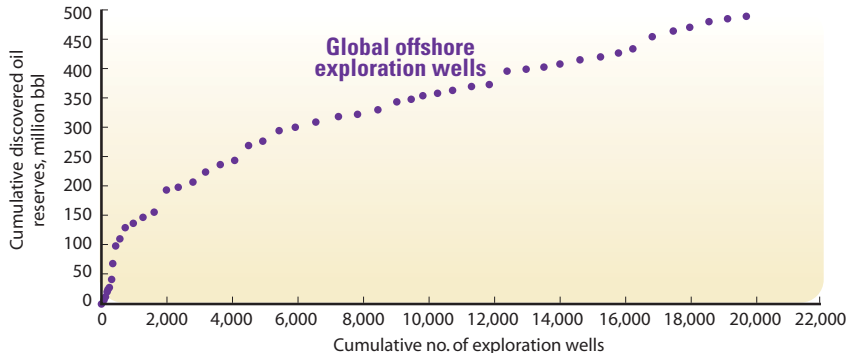
Table 2

	Number of offshore giants	Ultimate recoverable reserves (giants), billion bbl	Percent of total offshore oil discovered	Typical tectonic setting	Reservoir rock depositional environment	Typical reservoir rock age	Typical trap
Persian Gulf	14	109	69	Passive margin	Marine	Mesozoic	Structural
North Sea[1]	12	26	42	Continental rifts	Nonmarine	Mesozoic	Structural
West Africa	15	11	16	Passive margin	Turbidites	Cenozoic	Combination[2]
Mexico Gulf of Mexico[3]	2	24	75	Passive margin	Marine	Mesozoic	Combination
US Gulf of Mexico	5	3	11	Passive margin	Nonmarine/ turbidites	Cenozoic	Combination
Asia-Australasia[4]	3	3	8	Strike slip/ margin	Nonmarine to marine	Late Mesozoic/Cenozoic	Structrual
Brazil	7	9	33	Passive margin	Turbidites	Cenozoic	Combination
China	2	3	45	Passive margin	Nonmarine to marine	Cenozoic	Combination
Caspian	2	17	68	Collisional margin	Nonmarine	Cenozoic	Structural
Russia-Arctic[5]	1	1	20	Continental rifts	Marine	Mesozoic and older	Structural
Sakhalin	2	3	94	Strike slip	Marine	Cenozoic	Structural

[1]Mainly central graben. [2]Structural, growth faults, stratigraphic, salt domes, etc. [3]Main area around Cantarell complex. [4]Mainly Australia Bass Strait, Sunda. [5]Mainly Barents Sea.
Sources: IHS Inc., OPEC, US Geological Survey, Mann. P., et al., 2003

CUMULATIVE OFFSHORE EXPLORATION WELLS AND OIL RESERVES

Fig. 4



For the world giant offshore oil fields only, no similar assessment has been made. This study provides an assessment based on the classification proposed by Mann et al. and the USGS 2000 assessment using an updated database of 67 giant offshore oil fields that represent 211 billion bbl (41%) of the total oil discovered offshore. A synthesis for each region is provided in Table 2.

Some discernable observations about offshore giants are:

a) The tectonic setting is commonly passive margin (45 giants).

b) The depositional environment of the reservoir rock is dominated by nonmarine to marine sands (43 giants).

c) The age of the reservoir rock is Cenozoic (33 giants) and Mesozoic (29 giants).

Accumulations in deepwater giants are exclusively associated with turbidite reservoirs (26 giants) of Cenozoic age. The typical trap is structural (34 giants) and a combination of structural and stratigraphic (31 giants).

Offshore trends

Since offshore exploration began in the 1940s, some 17,700 exploration wells have been drilled in shallow water resulting in 2,500 new oil discoveries.

In deep water, exploration began in the late 1970s and since then nearly 2,000 exploration wells have been drilled resulting in 400 new oil field discoveries (Figs. 2 and 3).

In shallow water, the number of exploration wells drilled has remained at around 500/year in the last 25 years. In contrast, the number of deepwater wells has been increasing steadily since 1997 and is now over 100 wells/year.

Over the last 25 years, the average number of new offshore oil field discoveries has remained close to 80/year and the success rate more than 30%. The highest number of discoveries was recorded in 1982 at 118; two other record years were 1990 with 109 new oil discoveries and 2003 with 104 new oil discoveries.

The above efforts have resulted in the discovery of 500 billion bbl of oil in three broadly defined exploration phases (Table 3).

The first identifiable phase is from the 1940s to 1972.

This phase is characterized by the first offshore discovery made in the US Gulf of Mexico in 1947, the discovery of the supergiants in the Persian Gulf, the first discoveries in West Africa, and in the later part of the period, the first giant discoveries of the North Sea.

Elsewhere, two giant discoveries were made in Australia and one in China. During this initial phase, the cumulative oil discovered was 198 billion bbl, the yearly average discoveries totaled 8.3 billion bbl, and the discovery size averaged 770 million bbl.

The second phase is from 1973 to 1990.

This phase is characterized by giant discoveries in the North Sea, Mexico, Caspian, Russia/Arctic, and the first deepwater discoveries in the US Gulf of Mexico (1983) and Brazil (1984).

There are also two notable giant discoveries outside the previous regions: Bombay High off India and Hibernia field off Canada. Elsewhere, discoveries continued to be made in West Africa, Asia/Australasia, and shallow US gulf. During this phase, the cumulative oil discovered was 171 billion bbl, the yearly average discoveries totaled 9.5 billion bbl, and the discovery size averaged 135 million bbl.

The last phase began in 1991 and extends to today.[11]

This phase is characterized by giant deepwater discoveries in the Big 4 (Brazil, Angola, Nigeria, and the US gulf). However, several giant discoveries have been made in other regions including the North Sea, Caspian, and China; smaller discoveries were made in Asia/Australasia, shallow-water West Africa, and the Persian Gulf.

During this recent period, the cumulative oil discovered was 121 billion bbl, the yearly average discoveries totaled 8 billion bbl, and the discovery size averaged 116 million bbl. Of the total oil discovered, deepwater and ultradeepwater fields accounted for 44 billion bbl, 3 billion bbl/year.

Looking specifically at the deepwater, the geological evidence to date suggests that it is a play with limited prospectivity within the context of the global offshore, primarily due to the fact that the best quality reservoirs are

OFFSHORE OIL EXPLORATION PHASES

Table 3

	Phase 1 (until 1972)	Phase 2 (1973-90)	Phase 3 (since 1991)
Number of exploratory wells	2,333	8,986	8,419
Number of new oil discoveries	330	1,454	1,183
Volume of oil discovered, billion bbl	198	171	121
Average volume of oil discovered, billion bbl/year	8.3	9.5	8
Average discovery size, million bbl	777	135	116

exclusively associated with turbidities.

It should be noted that deepwater Mexico is considered the single largest prospective province of this kind remaining in the world. It has seen no exploration whatsoever with only three wells drilled in established areas.

Other deepwater provinces outside the Big 4 have seen some successes (i.e., Australia, Malaysia, Mauritania, Ivory Coast, China), but the global impact has yet to be seen. The ultradeepwater play has been much discussed following the recent Jack well in the US gulf.

No attempt is made in this article to evaluate the E&P record or address the potential of the ultradeep worldwide, as not enough information and history are available. However two points are worth making.

First, global prospectivity is very unique to geological settings only so far known in limited areas. Second, having the technology to go to ultradeep water does not mean one can go to any water depth to explore. In most parts of the world, 12,000 ft of water is touching the edge of the continental shelf, beyond which no sedimentary rocks can be expected.

Overall, measured in terms of cumulative exploration wells drilled and wells per square kilometer of sedimentary basin, the regions more explored have been the shallow US gulf, North Sea, Persian Gulf, and Australasia; West Africa, Mexico, China, Caspian, and Russia/Arctic are the least explored.

Offshore regions such as North Africa and eastern Canada have seen very limited exploration with some successes; others like deepwater Mexico, Red Sea, Pacific, and North Atlantic have seen no exploration.

Fig. 4 shows the cumulative number of exploration wells drilled and oil discovered worldwide offshore. As can be seen, the global offshore does not show the signs of a mature exploration play.

Next: Estimating the global offshore oil reserve base. ✦

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Cameroon

Log evaluation has indicated that the IE-2 appraisal well drilled to TD 8,675 ft subsea by BowLeven PLC's EurOil Ltd. subsidiary encountered two hydrocarbon-bearing zones.

The well, on Etinde Block MLHP 7 in the Rio del Rey basin, found 50 ft of net gas pay in good quality Miocene Biafra sandstone at 3,310 ft and 130 ft of net gas-condensate pay in good quality Miocene Isongo sandstone at 7,850 ft. EurOil plans to drillstem test the Isongo.

It is the first of four wells to be drilled consecutively (OGJ Online, Feb. 15, 2007).

Peru

The government awarded Gold Oil PLC and Plectrum Petroleum PLC, London, an exploration license on Block Z-34 off Peru's northern coast in the Talara basin.

The block covers 3,713 sq km close to a producing concession and is in 100-3,000 m of water. The companies plan to run electromagnetic surveys and shoot at least 2,000 line-km of 2D seismic surveys in the first 18 months. Gold Oil is operator with 50% interest.

Ontario

A flow rate of more than 100 Mcfd of gas from a thin gas zone over water at the top of the Cambrian sandstone at 3,616 ft at the Echo 57 deeper pool test in southwestern Ontario provides encouragement for further exploration, said Echo Energy Canada Inc., London, Ont.

The company plugged back and completed the well as a gas well in the Silurian Thorold sandstone, one of 71 wells that have tested gas from Thorold since 2001 in Elgin and Norfolk counties south of Tillsonburg, Ont.

Output is a combined 1 MMcfd from 54 wells, restricted due to soft natural gas prices. Gas produced but not sold is parked in a gas storage account with Union Gas for sale at any time.

Magnetic and gravity surveys acquired in 2006 in Bayham, Houghton, and Malahide townships clearly outline trend areas for deeper targets and Thorold development (OGJ Online, May 16, 2006). The company holds 60,000 acres of leases, one of the province's largest undeveloped land positions, in the area.

Texas

South

Comstock Resources Inc., Frisco, Tex., reported 25.5 bcfe of proved reserves and 27.6 bcfe of probable and possible reserves in Las Hermanitas gas field in Duval County.

The company acquired the field at the end of September 2006 at $67 million for three producing wells and 18 drilling locations and drilled two wells in the last quarter of 2006. The proved and possible reserves relate to 10 drillable locations.

The company plans to drill 21 wells in 2007 in South Texas, where it had 10 successful completions in 2006 that averaged 5.6 MMcfd in Ball Ranch, Javelina, and Las Hermanitas fields.

Remote monitoring, control enable smart-field in Gabon

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Jose Rincon
vMonitor Inc.
Houston

Robert Clinton
Shell Gabon
Libreville, Gabon

Wireless technology is a critical component in "smart-field" operations, such as in producing fields operated by Shell in Gabon, West Africa.

Shell's smart-field vision has many intertwined technology and business methodology components that extend from downhole systems, to well surface equipment, and to a variety of tools in the office for analyzing and optimizing production operations. A key prerequisite for implementing any integrated smart-field system is the ability remotely to capture well and other critical asset data and remotely to control processes at the wellsite.

Shell worldwide has several on-going smart-field implementations. In two major initiatives in West Africa—in Nigeria and Gabon, each implementation has a different scope and objective.

Remote operations are critical in any smart-field implementation. Because most, if not all, wells are remote especially in countries such as Gabon, implementing smart-field technology requires wireless technology.

In most upstream applications, connecting remote wells and other remote assets via a physical connection, such as fiber-optic cable along a pipeline, has proven impractical, very expensive, and extremely difficult to maintain because of potential cracks in the fibers that render the entire fiber link useless. For such reasons, the petroleum industry generally agrees that the only viable option to link many remote sites is with wireless technology.

Wireless technology, however, has major obstacles in environments such as West Africa, where dense and high vegetation impede radio signals.

As a result, the industry requires a new generation of wireless technology to link effectively these remote wells to the office.

Smart digital oil field

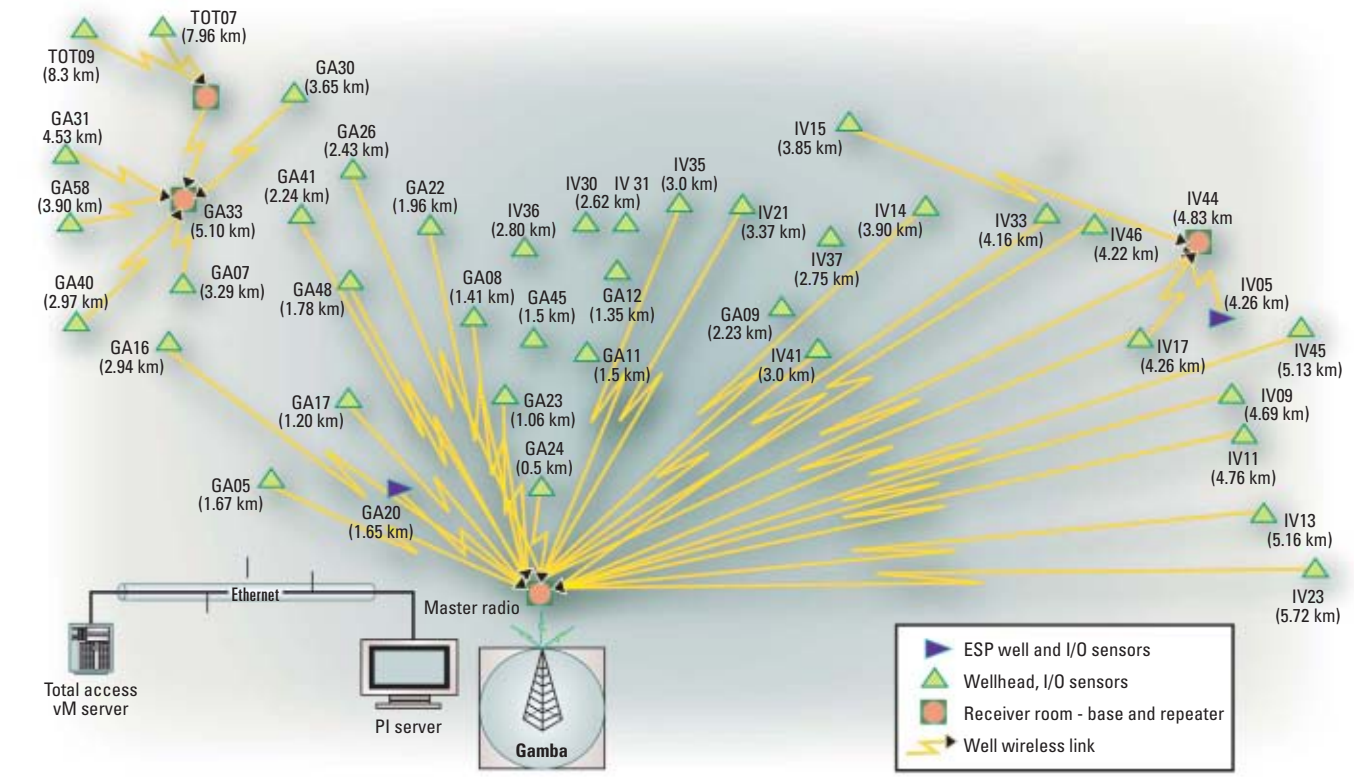
Many major oil and gas companies have adopted the "digital oil field" strategy. These strategies have various names in the industry. Shell calls it the "smart-field," while other companies call it "I-field," "field of the future," or other names.

The aim of all these strategies is to extract more oil and gas from existing reservoirs through implementation of smart technologies and processes. These technologies can be placed in the wellbore, at the wellhead, and in the office.

The technologies include intelligent well technology and production optimization software. The industry has various estimates on the worth of smart digital oil field. Some predictions are

COMMUNICATIONS LINK LAYOUT

Fig. 1



that the technology can:

- Improve ultimate recovery by 1-5%.
- Accelerate production by 2-8%.
- Reduce downtime by 3-10%.
- Improve operating efficiency by 5-20%.

These are significant numbers, given these technologies can be implemented at a fraction of the investment needed for exploring, drilling, and producing new fields.

On each gas-lift well, the monitoring system measures tubinghead pressure, casinghead pressure, tubing temperature, differential pressure (gas-lift flow line), and annulus pressure (Fig. 2).

In addition to these benefits, many companies such as Shell Gabon face major operational challenges and want fully to automate their assets because of the harsh nature of their environments. Wells are too remote to reach, which affects their ability to detect problems such as well shut-in. Weather conditions in such locations prevent operators from visiting wells because of heavy rains that go on for several days and weeks at a time. In other Shell West Africa operations such as Nigeria, security is major issue.

System overview

Shell Gabon operates several fields in Gabon, one of which is Gamba field. Most wells in Gamba field are on artificial lift.

With production in Gamba declining, Shell put forward a smart-field

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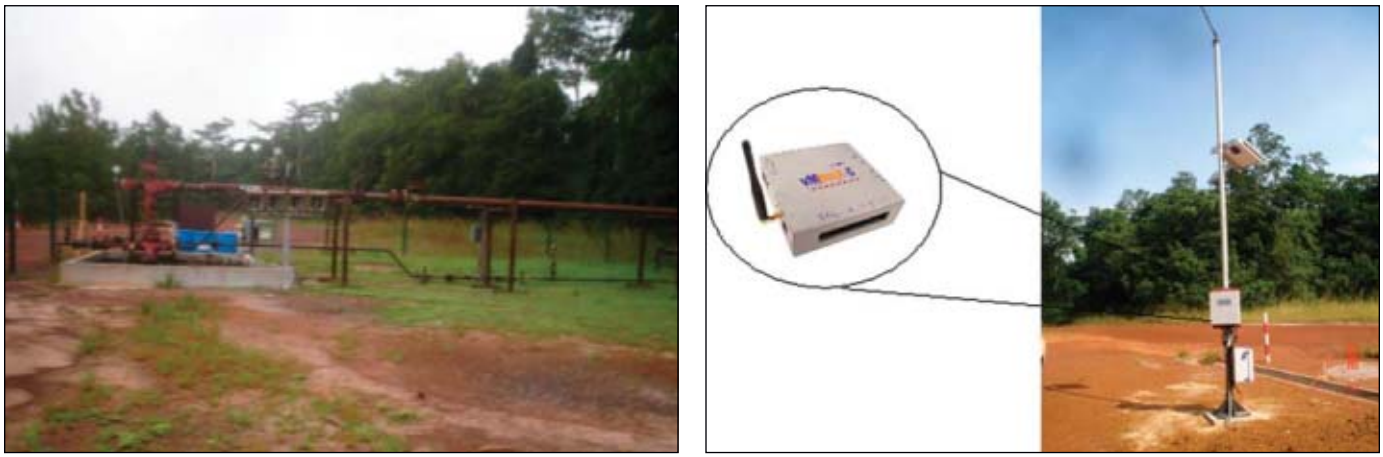


On the ESP wells (photo on left), the monitoring system required an interface to the ESP surface controller, the ability to extract critical ESP parameters such as motor frequency, motor current, motor voltage, and other motor parameters (Fig. 3). A new generation of wireless remote terminal units called vMBusX-C (photo on right) provides a high-power output (Fig. 4).

strategy for implementing several new technologies for stabilizing and ultimately increasing production for the field. Installing a remote operation system was the first step in overall system implementation (Fig. 1).

The main part of the system includes remote monitoring and control of gas-lift wells, electric submersible pump (ESP) wells, and pipeline gas flow

On each gas-lift well (Fig. 2), the system had to measure tubinghead pressure, casinghead pressure, tubing temperature, differential pressure (gas-lift flow line), and annulus pressure.

The monitoring system on the ESP wells (Fig. 3) required an interface to the ESP surface controllers, the ability to extract critical ESP parameters such as motor frequency, motor current, motor voltage, and other motor parameters.

The system also transmits various downhole measurements such as pump intake and discharge pressure and temperature, vibration, current, and several other parameters.

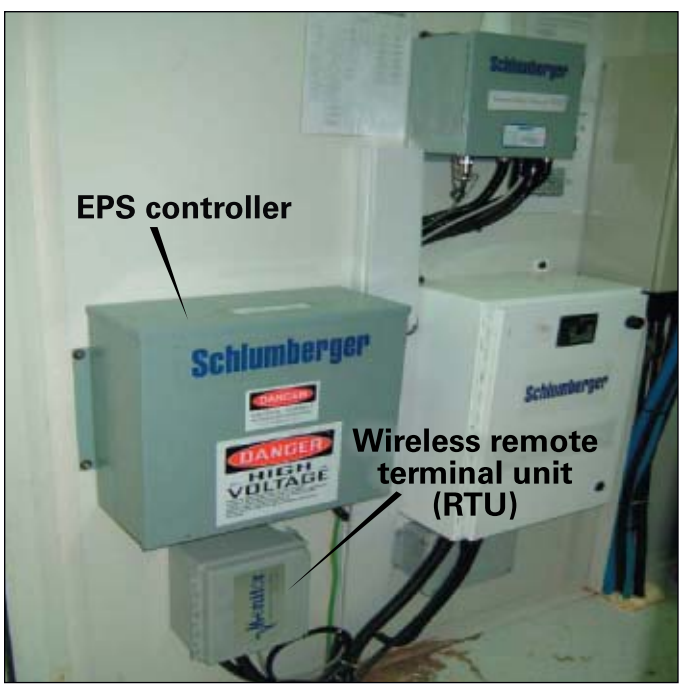
To verify and regulate injected gas, the operator needed to measure pipeline flow to complement the other measurements from the gas compressors and the wells.

The pipeline measurement system is a nonintrusive clamp-on type with an ultrasonic meter.

Remote operations

The implemented system has the following major components:

- Data-acquisition system to interface to well sensors (pressure, temperature, and differential pressure), ESP controllers, and pipeline measurement system.
- Wireless communication subsystems to interface to the data-acquisition system.
- Nonintrusive flow measurement meter for the gas pipeline.
- A gateway to receive data from the wells and the pipeline and to send control commands back to the wells.
- Software to manage the data, provide reports and alarms, enable operator control, and provide interface to other systems and databases.
- Data historian, to be implemented in the future.
- Smart-field production optimization software, Shell FieldWare, also to be implemented in the future once the data stream becomes available.



The new remote operations system monitors and controls various existing subsystems (Fig. 5).

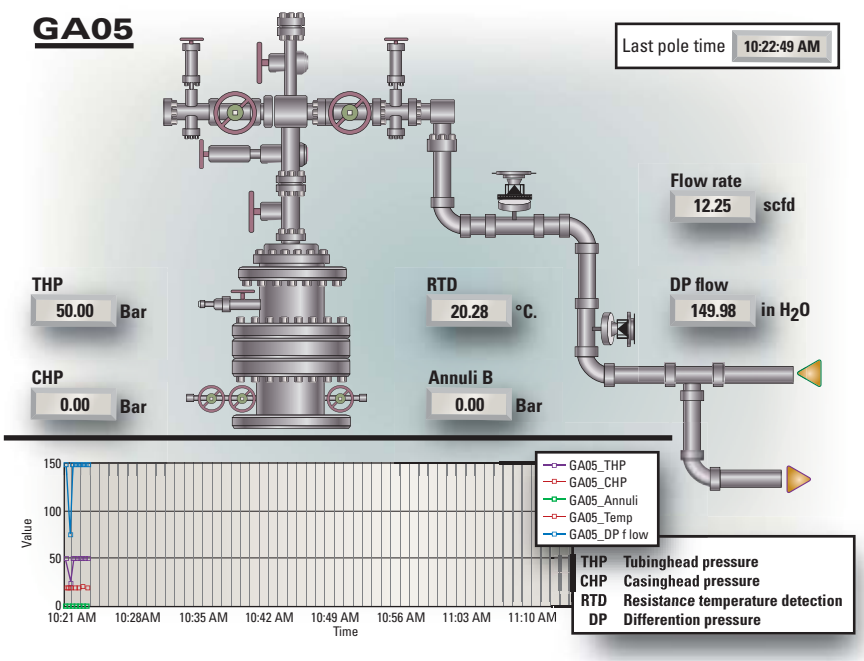
Wireless communication

The wells are spread out in a geographic area with a radius of about 10 km. Under normal circumstances with clear line of sight between the wells and main communication towers, a wireless communication system should easily operate

One of the new subsystems installed was a pipeline ultrasonic flowmeter (Fig. 6).

WEB-BASED MONITORING SOFTWARE

Fig. 7



over a 10-15 km range. The thick jungle vegetation in Gabon, however, renders the system inoperable at 3-4 km.

To deal with these limits, Shell Gabon, decided to install a new generation of wireless remote terminal units called vMBusX-C (Fig. 4) from vMonitor Inc. The units deliver a high-power output signal, but delivering extra transmission power is insufficient by itself in this case.

The vMBus wireless system also has intelligent processing and multihoping capabilities to carry the signal from well to well to the base station.

Higher output radios deliver better performance, but these systems have a limited 5-km range. Because most units could not communicate directly from many of the wells back to the main control station, the system required that each vMBus unit installed at each well act as a self-repeater whenever it detected a signal from a nearby well.

This approach allows the signal to carryover over several short hops, each 3-4 km, until it reaches the main station.

System integration

The new remote operations system must monitor and control various subsystems. Some subsystems, such as for the ESPs, already existed (Fig. 5). Other subsystems were installed as part of the new remote operations system. The pipeline ultrasonic flowmeters were one of these (Fig. 6).

The ESPs were from Schlumberger Reda, while Controlotron (Siemens) provided the pipeline ultrasonic flowmeters and Fisher Rosemount provided the wellhead instrumentation,

With different vendors involved, the system needed a great deal of integration work at the hardware and software levels to ensure data compatibility and system operability.

Data capture, visualization

A gateway installed at the Gamba base station tower captures the data transmitted from all the wells. The gateway connects to a server hosting TotalAccess software. TotalAccess is a web-based host software with a polling engine, a data visualization system, and an OLE (object linking and embedding) for process control (OPC) server that will data interface to other software systems. TotalAccess provides real-time, well data, well diagnostics, reports, and alarms (Fig. 7).

The system connects to the Shell network so that anyone in the world with proper Shell security permission can have web-based access to the system.

System installation

Shell Gabon completed installation of the system in mid-2006. Since then, it has delivered reliable real-time data from all wells in Gamba field.

Data captured by this system will

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be interfaced to various smart-field production optimization software. Shell Gabon's goal is for this system to help achieve a 3% production gain annually during the next few years.

The system already has delivered several operational cost savings. ✦

The authors

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Robert Clinton is a senior engineer in Shell E&P. He was the project lead for the remote operations project in Gamba field and worked in Shell Gabon on several projects in Rabi, Toucan, and Gamba fields. Before Shell Gabon, he worked with Shell Expro. Clinton is currently working in PDO Oman.

Software continuously estimates each well's production

Ron Cramer
Shell Global Solutions
Houston

Charlie Moncur
Shell Global Solutions
Rijswijk, the Netherlands

Software installed in several Shell operated oil and gas fields transforms real-time data from commodity instrumentation via supervisory control and data acquisition (SCADA) systems and distributed control systems (DCS) into estimates of oil, water, and gas rates for all wells continuously.

Knowing what wells and reservoirs produce at all times facilitates improved asset management and integrity.

Shell has implemented its software, Fieldware Production Universe, during the last 2-3 years in 20 projects that now are seeing improved safety, increased production, reduced costs, reduced well testing, and improved hydrocarbon accounting.

The company plans to scale-up these benefits to full global brown and greenfield operations and transform the traditional manual operations culture into a new "smart fields" way of working based upon remote surveillance and control (Fig. 1).

Managing wells, reservoirs

A key upstream operations question is how does one effectively manage wells and reservoirs? The trite answer is "inadequately," due to lack of a continuous, reliable measurements of well and reservoir performance on more than 90% of wells.

Measurements not taken continuously impede operations management, monitoring of well and reservoir performance, and hydrocarbon accounting.

Operating companies traditionally use discontinuous well testing to determine well performance. They typically test wells once per month and assume that the wells produce the same during the rest of the month. Nature usually is not that predictable, and the quality of the well tests often is unsatisfactory, requiring repeated tests.

Regulatory authorities specify a minimum well test frequency, such as once/month/well. Continuous well testing is more desirable; however, it is impractical to install a test separator for every well. At the heart of this problem is multiphase flow. Very few wells deliver a clean, measurable, single-phase stream, and it is impractical to install multiphase flowmeters on all wells.

The software application developed by Shell is capable of continuously estimating oil, gas, and water flows for all wells. The software enables improved well surveillance, more accurate hydrocarbon accounting, automatic production reporting, and production optimization.

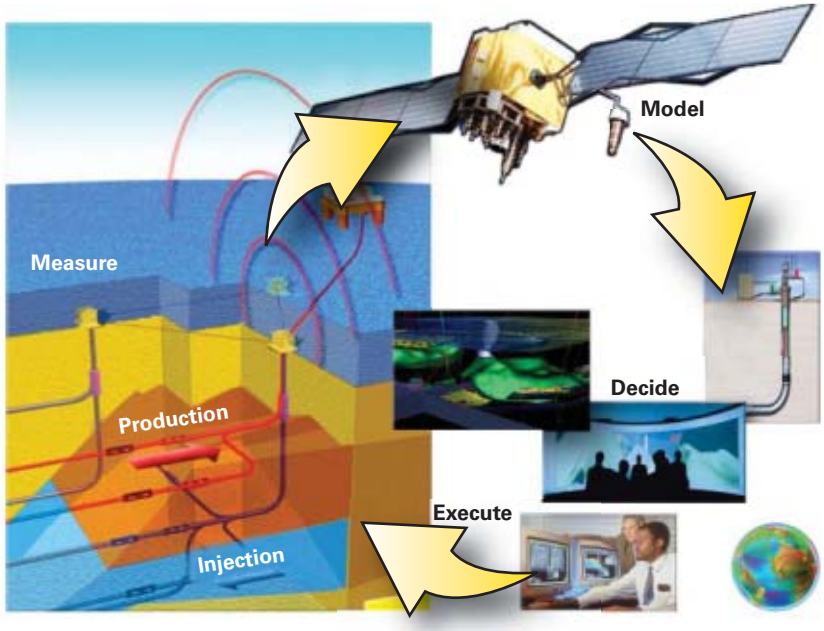
The software enables safeguarding of the technical integrity of wells and reservoirs, for example early detection and control of gas, or water breakout. It is cost effective in that it requires minimal, commodity instrumentation and information technology systems, much of which may already be present in field operations.

The software is a module in Shell's FieldWare suite of real-time applications. FieldWare applications are modular and are designed to be easily dropped into a personal computer (PC) based server network with access via either a thick or thin (web-based) client.

A thin client is a computer (cli-

SMART FIELDS VISION

Fig. 1



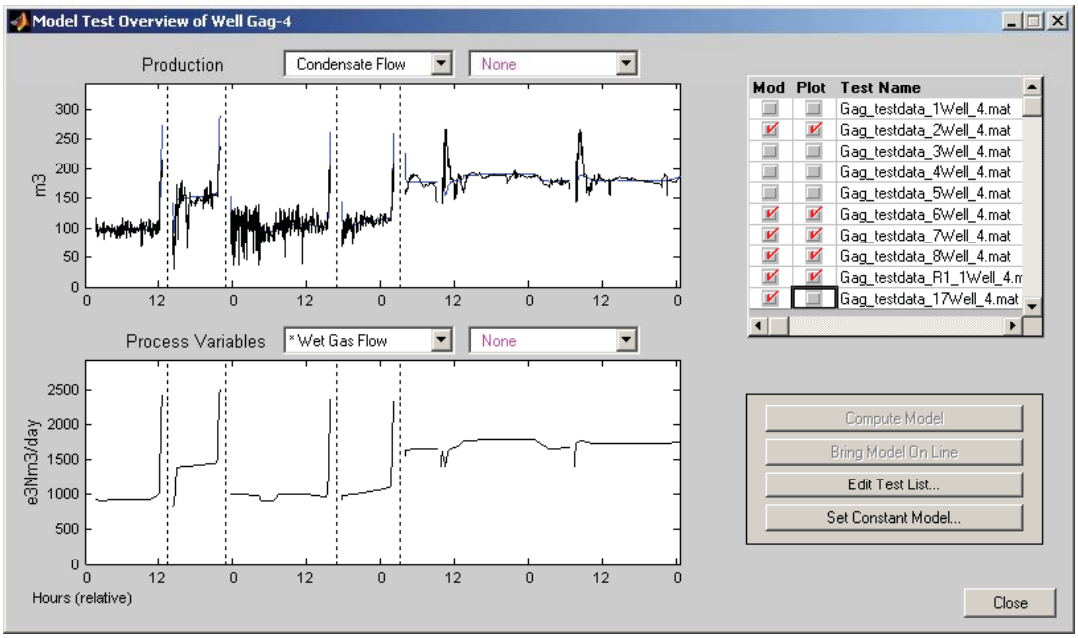
ent) in client-server architecture networks that depends primarily on the central server for processing activities. In contrast, a thick or fat client does as much processing as possible and passes only data required for communications and archival storage to the server.

The FieldWare applications are hence compatible with PC-based SCADA, DCS, or Historian systems.

Successful deployment of the production software also requires changing how people operate. This can be much harder than deploying the technology.

MULTIPLE DDWT DATA SETS

Fig. 2



Software operations

The production-monitoring software

uses dynamic data-driven models of the production system. The well models estimate water, oil, and gas production flows in real time, primarily from existing well instrumentation. These models capture such effects as back-out of weaker producers at headers.

The software does not use physical models such as well tubing diameters, roughness, fluid properties, near-wellbore skins, and presumed multiphase flow correlations. It relates, however, real-time well measurements to volumetric flows from test separators.

This data-driven approach has proven robust and usable in oil and gas production operations.

A key aspect of the software is the deliberately disturbed well test (DDWT), which is used to characterize well performance. These tests go beyond traditional production well testing. The objective is to relate well production (oil, gas, and water) to measured well parameters such as flowing tubinghead pressure, downhole pressure, gas-lift injection rate, and temperature.

The emphasis is on capturing the response of the well to step changes in controllable parameters.

The upper screen in Fig. 2 shows DDWT data in which five data sets model the well. In the lower screen, one can view the parameters used in the respective models. The upper right-hand panel provides a way to select and deselected models to achieve a best model fit.

Once created, the software uses the individual well models to compute the well production per stream. The software accumulates daily flow per well, which reflects the actual producing conditions, including trips and restarts, and plant operating mode changes.

The software constructs a simplified abstract topography that relates the wells to a calibration point (Fig. 3). Typically that point is a bulk separator, preferably providing oil, water, and gas measurement on a continuous basis.

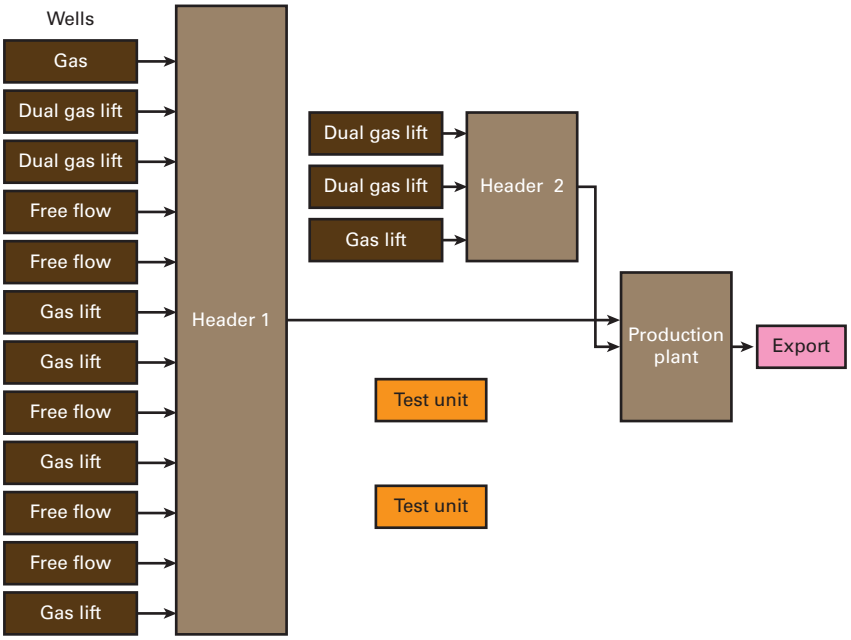
The software compares production data per well and reconciles the production automatically against the installation's overall export meter. This provides a reconciliation factor for each produced and injected stream on a continuous basis for the current day and the last 24 hr.

The screen also has a diagnostics panel alerting the user of production systems events, such as event detection, single-point measurements, or complex logic to detect specific events such as contamination of the water disposal stream with oil. Another part of screen provides an information panel that contains alerts on defective instruments and communications infrastructure.

With this single screen, an asset manager can gauge the current health of the production systems. If all the reconciliation factors are within acceptable bounds, the manager knows that the production system is under con-

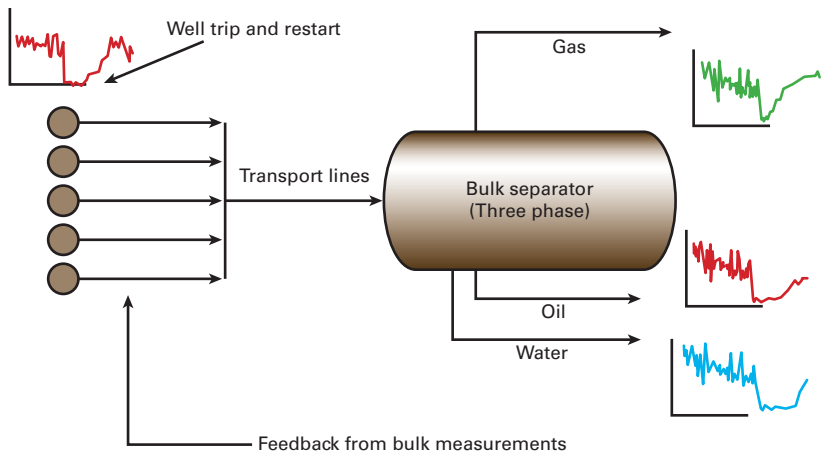
TYPICAL PRODUCTION FACILITY

Fig. 3



RECONCILIATION CONCEPTS, PROCESS DYNAMICS

Fig. 4



trol—well models are accurate, instruments work, and the communications highway functions.

If this is not the case, that manager can access other screens that are at the process, header, and well level.

The output from measurements on the bulk separator provide a continuous 24 hr/day, 7 days/week data stream. The software uses the dynamic variation seen at the calibration point further to tune its well models. Plant trips and restarts are visible and generate useful data especially when the field is brought back on line.

The software updates the dynamic well models every 24 hr to reflect the total information available in the preceding period. This allows the software to track a decline in well rate or an increase in GOR and water cut (Fig. 4).

The software thrives on dynamics, such as increases or decreases in choke size, continuously to update individual well models.

Normal operations provide a dynamic environment with well interventions, process trips, etc. If wells exhibit stable production with minimal dynamics, then software can introduce dynamics. The software can choke wells up or down for short periods to cause transients to ripple through the process. It can introduce single or multiple disturbances simultaneously. These pseudo tests are known as deliberately disturbed production tests (DDPT's). If these tests are insufficient to realign the models, then the software initiates a full DDWT.

The production software's low maintenance, data-driven, production workflow-based (well test) modeling approach contrasts with the harder to sustain, specialized physical models requiring frequent tuning by process engineers. Building and upkeep of physical models are hard to sustain.

Well tests that are a normal part of oil and gas operation are the basis of the production software model's workflow. The software also is more tolerant of errors in process measurements and instrument drift over time.

Experience to date

Shell's implementation of the production software has yielded several benefits.

In moving to real-time operation and optimization, several field operations have reduced their production declines. In one field, the sustained reduction in production decline is in part attributed to more stable field operations and constant attention to well performance and adjustment of well parameters, such as early detection of coning, water breakthrough, and manual optimization.

Operators can optimize wells much more quickly by having a good understanding of well performance and the effect of changing separation pressures and well routing. The software provides immediate visibility of the changes. Where changes have a negative effect, they can be reversed immediately.

Historically the cycle time for opti-

mization was days if not weeks. With the current version of the software, optimization of a field is possible daily or hourly from the office desktop.

With data being available in real time, operators can detect quickly underperforming wells and compensate for this by adjusting other wells or opening up closed in wells.

The net result is that fields with the software have reduced deferred production.

Implementation of the software has reduced the time spent by production technologists and operations engineers on gathering and validating well data and making decisions. This has allowed redeployment of scarce staff to other tasks. In one operation, a single operations engineer runs several fields where previously the work required five staff members.

With better well performance data, short and medium-term forecasts become more accurate. This has become evident in one particular field where actual production is consistently 5% above forecast. Previously the gap between forecast and actual was consistently a negative percentage.

The improved allocation of production to wells will influence the accuracy of long-term forecasts from reservoir simulators.

Several fields have reduced the variance in daily production. The peaks and troughs have leveled off. This again is thought to be a result from the attention paid to individual wells, daily field review and optimization, and reduced plant trips.

One field conducted no routine well test for 15 months, but the production software continued to run and track well performance and adjust the well models.

Other fields have seen a reduction in well testing duration. With software in place, more wells can be connected to one test facility. This lowers costs in the cases that the operations can have a single test train instead of two trains. Also the test separator can operate as a bulk vessel or for well service activity for longer periods.

The software also lets the operator know when a well needs to have a well test.

In another Shell operation, introduction of the software has reduced costs by allowing release of one service and transport vessel because operators no longer have to visit regularly the remote offshore location.

Fewer visits also lower health, safety, and environmental risks.

The production software has become a catalyst, focusing attention on the quality of production surveillance instrumentation and measurement data. The software is visible and used actively from field to asset-manager level so that problems with instrumentation or measurements become readily apparent because of deviations between well model predications and export flows.

Acknowledgments

The authors thank the management of Shell for permission to publish this paper and to contributors within Shell's operations who assisted with development and implementation of the Production Universe software ✦

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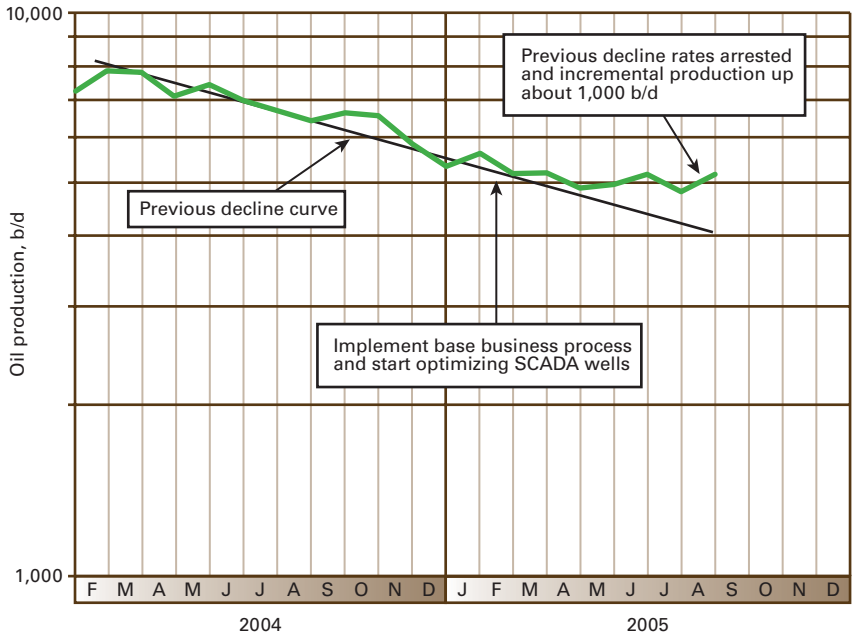
BALAM SOUTH PRODUCTION

Fig. 1



Rod-pump automation increases oil rates in Sumatran field

Faried Efendi
Kurza Mulyadi
PT Chevron Pacific Indonesia
Riau, Indonesia

Emir Syahrir
PT Catur Khita Persada-
eProduction Solutions
Jakarta

Resizing pumps, installing rod-pump controllers (RPCs), and monitoring and analyzing wells remotely with software specific for that purpose increased operational efficiency in Balam South field on Sumatra Island, Indonesia.

PT Chevron Pacific Indonesia operates the field.

The company's optimization program involved phased installation of state-of-the-art technology. The wells highest on the prioritized list were determined to be more likely to provide the most return for the investment in automation.

The results were better than expected with several wells increasing production by about 200 bo/d. The wells also had lower electrical and repair costs.

Initial phase

Balam South field has about 220 wells with 95 of the wells having a rod pump. Average well depth is 1,000 ft. The produced oil has a 28-30° gravity and the wells produce with an average 85% water cut.

Before implementation of this program, the wells had no automation or control systems installed. Many of the pumps ran 24 hr/day without pumping off the well. These wells would benefit from merely an increase in pump size; however, an increase in the pumping capacity could cause the wells to pump off and subject the pumps to excessive wear.

To minimize the number of strokes after pumping off the well, the com-

pany installed RPCs from eProduction Solutions (eP). A controller allows the well to pump down to a minimal fluid level and stops the pump when fluid pound occurs.

The controller ensures that the pump shuts off at the appropriate time and calculates the appropriate idle time from the changing run times. A desktop analysis program, eP's csBeam, optimizes run times and pump-off points.

The software provides up-to-date surface dynamometer cards, downhole cards, runtime statistics, and trends of well parameters. With this information, the well analyst fine-tunes the controller to optimize production.

Results

Implementation of this program increased production, decreased repair costs, and lowered electrical costs. Several factors provided these benefits.

Lower fluid levels in a well decreases backpressure on the reservoir and consequently increases production. Additionally, reduction in downtime lowered repairs and ensured more pumping time and ultimately, more produced fluid.

Four wells that pumped off increased oil production by about 200 bo/d/well.

Pumping the wells less than 24 hr reduces average run time with no loss in oil production. The pumps only run when the barrel is full of fluid, about 5-10 min. This increases pump run life by avoiding accelerated wear from fluid pounding the pump.

In the long-term, this will reduce downtime associated with pump repair, thus reducing repair costs.

The work has arrested the field's production decline (Fig. 1) and the field still has more wells to optimize.

The company continues to prioritize target wells, execute the optimization plan, and ensures that return on investment is weighted early in the project. This provides an early payout for the project.

The combination of well design, hardware at the wellsite, analysis software at the desktop, training of the well analysts, and corporate commitment to implement the program benefited field profitability in both the short and long-term.

The company also has other rod pumped fields in Sumatra that could benefit from this type of automation. ✦

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EPA proposes elimination of current MACT policy

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On Jan. 3, 2007, the US Environmental Protection Agency (EPA) published a proposed rule in the Federal Register that would eliminate its "once in, always in" policy on maximum achievable control technology (MACT) standards.[1] If promulgated, reversal of this decade-old policy will allow facilities currently subject to MACT standards to be exempt from MACT upon reducing emissions below major source thresholds for hazardous air pollutants (HAPs).

Under existing policy, if a facility is a "major source" of HAP emissions on the first substantive compliance date of the MACT standard, it will always be subject to the MACT standard. With several MACT standards already in place for the oil and gas industry and others being considered, the new rule would give facilities flexibility to determine how best to control HAP emissions, rather than the "one-size fits all" MACT standards.

Clean Air Act, HAPs

Section 112 of the Clean Air Act provides that any stationary source that has the potential to emit more than 10 tons/year of any of the 188 listed HAPs, or 25 tons/year of any combination of HAPs, is considered a "major source" and subject to technology-based regulations, referred to as MACT standards.

Sources that have a potential to emit less than the HAP thresholds are "area sources," which are subject to lesser controls or no controls depending on the particular industry.

EPA's policy

On May 16, 1995, EPA's Director of the Office of Air Quality Planning and Standards John S. Seitz distributed a guidance memorandum to EPA's regional offices. This memorandum clarified that "when a major source of hazardous air pollutants can become an area source—by obtaining federally enforceable limits on its potential to emit—rather than comply with major source requirements."[2]

The memorandum indicated that EPA had received a number of requests for clarification on "when facilities may limit their potential to emit to avoid applicability of major source requirements of promulgated MACT standards."[2]

One such timing question involved facilities that were subject to a MACT standard on the "first compliance date" on account of being a major source but had since fallen below HAP emission thresholds and wanted to be area sources not subject to MACT regulatory requirements.

The memorandum set forth EPA's "once in, always in" interpretation: "EPA is today clarifying that facilities that are major sources for HAPs on the 'first compliance date' are required to comply permanently with the MACT standard to ensure that maximum achievable reductions in toxic emissions are achieved and maintained."[2]

According to EPA, a "once in, always in policy ensures that MACT emissions reductions are permanent, and that health and environmental protection provided by MACT standards is not undermined."

As a consequence of this policy, facilities that have reduced emissions below the thresholds are permanently subject to MACT requirements such as equipment leak detection, work practice measures, housekeeping, testing, monitoring, recordkeeping, and reporting procedures, etc. Furthermore, by remaining subject to a MACT standard, the facility must obtain and continue to maintain a Part 70 operating permit.[2,3]

EPA's proposal to eliminate the "once in, always in" policy is a welcome change that will offer refineries and petrochemical plants greater flexibility in reducing hazardous air pollutant emissions.

EPA's proposed rule

The proposed rule to eliminate the "once in, always in" interpretation was under development within EPA for some time. The Natural Resources De-

fense Council (NRDC) publicly released the draft proposed rule in April 2006, claiming that the rule would "weaken nearly 100 toxic air pollution standards and allow industrial plants across the country to emit significantly greater amount of toxins."[4]

The preamble to the Jan. 3, 2007, proposal differs from the draft released by NRDC in April 2006 by being less dismissive of earlier criticisms and inviting public comment on those topics that have raised so much controversy. In addition, the proposed rule contains some additional caveats regarding switching from a major source to an area source and reverting from area source back to a major source.

EPA currently proposes replacing the May 16, 1995, "once in, always in" policy with amendments to 40 CFR Part 63.[5] The regulatory amendments, if made final after the public notice and comment period, will "allow a major source of HAP emissions to become an area source at any time by limiting its PTE [potential to emit] for HAPs below the major source thresholds."[1]

According to EPA, "there is nothing in the CAA that compels the conclusion that a source cannot attain area source status after the first substantive compliance date of a MACT standard," and that the US Congress "placed no temporal limitations on the determination of whether a source emits or has the potential to emit HAPs in sufficient quantity to qualify as a major source."[1]

EPA contends that its proposed amendments are wholly consistent with the Clean Air Act's definition of "major source" found in Section 112(a)(1) of the CAA and solicits comment on this position.

EPA justifies the proposed amendments, explaining that it has received feedback from the State and Territorial Air Pollution Program Administrators and the Local Air Pollution Control Officials that the "once in, always in" policy "provides no incentive for sources, after the first substantive compliance date for a MACT standard, to implement P2 [Pollution Prevention] measures in order to reduce their emissions to below major source thresholds because there are no benefits to be gained, e.g., no reduced monitoring, recordkeeping, and reporting, and no opportunity to get out of major source requirements."[1]

EPA also acknowledges hearing from others that the policy "serves as a disincentive for sources to reduce emissions of HAP beyond the levels actually required by an applicable standard."[1]

EPA acknowledges hearing from others that the "once in, always in" policy "serves as a disincentive for sources to reduce emissions of hazardous air pollutants beyond the levels actually required by an applicable standard."

EPA disagrees with environmental groups and other opponents of the proposed amendment "that a source that currently emits at levels below the major source threshold as the result of compliance with a MACT standard would increase its emissions in response to this rule."[1]

NRDC, for example, argues that the proposed rule "would seriously erode existing standards under the Clean Air Act by permitting thousands of oil refineries, hazardous waste incinerators, chemical plants and steel mills to increase their emissions by as much as 50,000 lb/year."[4]

EPA concludes that such an outcome is unlikely because:

- Pollution control devices installed to meet MACT standards are designed to operate a certain way and cannot be operated at a level that achieves only a partial emission reduction.
- Sources will maintain the level of emission reduction associated with the MACT standard because the level is required to meet other requirements of the Clean Air Act.
- Sources have no incentive to establish their PTE limit too close to the major source threshold because repeated or frequent exceedances above the PTE could result in an enforcement action.
- Permitting authorities will likely encourage emission reduction maintenance and impose more stringent PTE terms and conditions on the source the closer the source's PTE is to the major source thresholds.
- Many sources that take a PTE limitation to become an area source will ultimately be subject to area source standards.

Despite EPA's justifications, organizations such as NRDC will likely submit comments in opposition to the proposed rule and, if the rule is made final, may challenge the rule in the US Court of Appeals for the District of Columbia Circuit.

The proposed rule includes some caveats on switching from a major source to an area source and reverting from an area source back to a major source.

First, once a source switches from major source status to area source status, it may not switch back to major source status to avoid having to meet the MACT standard for an additional 3 years, the amount of time generally allowed for existing sources to attain compliance, unless the "major source standard has changed such that the source must undergo a physical change, install additional controls and/or implement new control measures."[1]

EPA specifically solicits comment on this proposed "immediate compliance" rule and whether there are additional exceptions that would necessitate an extension of the time period. Furthermore, EPA has asked for comments on whether it should allow all sources that revert to major source status to have a specific period of time to comply with the MACT standard rather than requiring immediate compliance.

Second, when a major source switches to area source status, it must

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comply immediately with equivalent or less-stringent area source standards if the first substantive compliance date has passed. If different emission control points, however, are controlled or different controls are necessary to comply with the area source standard or other physical changes are needed to comply with the standard, additional time, not to exceed 3 years, may be granted by the permitting authority if adequate supporting data is provided by the source.

Lastly, major sources that are subject to enforcement actions or investigations cannot escape liability by becoming area sources. Similarly, becoming a major source does not absolve a source subject to an enforcement action or investigation for area source violations or infractions.

EPA's proposal to eliminate the "once in, always in" policy is a welcome change that will offer facilities greater flexibility in reducing HAP emissions. Environmental organizations will oppose the proposed amendments, arguing that industry sources currently meeting MACT standards will increase emissions so as barely to fall below the current HAPs thresholds.

EPA's proposed rule addressees these concerns and seeks comments that describe specific factual scenarios that

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NELSON-FARRAR COST INDEXES

Refinery construction (1946 Basis)

(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2003	2004	2005	Nov. 2005	Oct. 2006	Nov. 2006
Pumps, compressors, etc.	222.5	777.3	1,540.2	1,581.5	1,685.5	1,715.1	1,787.0	1,787.0
Electrical machinery	189.5	394.7	522.0	516.9	513.6	510.9	527.7	527.3
Internal-comb. engines	183.4	512.6	911.7	919.4	931.1	935.5	964.5	963.8
Instruments	214.8	587.3	1,076.8	1,087.6	1,108.0	1,118.4	1,206.5	1,220.4
Heat exchangers	183.6	618.7	732.7	863.8	1,072.3	1,079.2	1,179.4	1,179.4
Misc. equip. average	198.8	578.1	956.7	993.8	1,062.1	1,071.8	1,133.0	1,135.6
Materials component	205.9	629.2	933.8	1,112.7	1,179.8	1,206.3	1,319.4	1,295.7
Labor component	258.8	951.9	,228.1	2,314.2	2,411.6	2,467.9	2,547.9	2,550.0
Refinery (Inflation) Index	237.6	822.8	1,710.4	1,833.6	1,918.8	1,963.3	2,056.5	2,048.3

Refinery operating (1956 Basis)

(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2003	2004	2005	Nov. 2005	Oct. 2006	Nov. 2006
Fuel cost	100.9	810.5	934.8	971.9	1,360.2	1,685.2	1,434.7	1,473.1
Labor cost	93.9	200.5	200.8	191.8	201.9	210.1	219.2	213.1
Wages	123.9	439.9	971.8	984.0	1,007.4	1,043.1	1,060.3	1,072.0
Productivity	131.8	226.3	485.4	513.3	501.1	496.5	483.8	503.1
Invest., maint., etc.	121.7	324.8	643.0	686.7	716.0	732.6	761.7	758.6
Chemical costs	96.7	229.2	237.7	268.2	310.5	320.7	370.0	363.2
Operating indexes								
Refinery	103.7	312.7	464.7	486.7	542.1	582.7	580.8	580.0
*Process units**	103.6	457.5	612.5	638.1	787.2	909.3	834.5	845.0

**Add separate index(es) for chemicals, if any are used. See current Quarterly Costimating, first issue, months of January, April, July, and October.*

These indexes are published in the first issue of each month. They are compiled by Gary Farrar, Journal Contributing Editor.

Indexes of selected individual items of equipment and materials are also published on the Costimating page in the first issue of the months of January, April, July, and October.

would likely result in such emission increases. EPA will need to address these factual scenarios to establish a strong administrative record to support future challenges to any final rule.

Industry will certainly take the opportunity to submit responsive, well-written comments that support EPA's proposal. EPA is accepting public comments through Mar. 5, 2007. EPA's careful consideration of these comments and documentation of them will make the rule-making less vulnerable to being overturned by a federal court. ✦

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DECOMMISSIONING—Conclusion

Regulators must possess early risk-assessment understanding

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National Energy Board
Calgary

It is essential that pipeline regulators considering risk-based remediation plans understand early the nature and complexity of the risk assessment to be performed as part of abandonment and whether or not this approach is conducive to unconditional closure of a site.

In Canada, such understanding is particularly important when an application for abandonment pursuant to the National Energy Board (NEB) Act is being considered, as the Board's jurisdiction terminates as soon as a pipeline is legally abandoned. If the risk-based remediation plan is considered a mitigation measure pursuant to Section 20 of the CEA Act, then the NEB still has a responsibility to ensure that it is implemented.

Parts 1 and 2 of this series provided an overview of the NEB's regulatory requirements and responsibilities with respect to pipeline abandonment and a detailed examination of the Yukon Pipeline Ltd. (YPL) abandonment and remediation in terms of the pipe and pumping stations.

This concluding article looks at abandonment and remediation of the pipeline's tank farm and discusses the practical lessons that can be drawn from the YPL abandonment.

Tank farm

The upper tank farm (UTF) sits on a well-drained sand and gravel bluff above the Whitehorse Airport, which in turn lies above downtown Whitehorse. Surrounding land use consists of a highway and airport to the east, primarily commercial use to the northeast and southeast, and primarily residential land use (or probable future residential land use) to the north, south, and west.

The site is relatively level, but beyond the property lines the ground slopes steeply away to the east and southeast. The water table is about 21-34 m below grade and appears to flow principally to the northeast, toward Baxter's Gulch where groundwater seeps from the ground and forms a stream flowing east toward the Yukon River valley.

Facilities on the 56-hectare site included a pump and meter house, an office, a laboratory, storage sheds, barrel storage, an oil change pit, a spill trailer, truck loading and unloading racks and manifold, underground and aboveground yard piping, booster pumps, valves, a gravel pit, and a former pump station.

Storage tanks included twenty-four 1,600 cu m earthen bermed, bolted construction, fixed-roof aboveground storage tanks (ASTs), as well as a 22,700-l. steel underground storage tank connected to drains below the truck loading racks, a septic tank and a heating fuel AST associated with the office, and a 4,500-l. engine fuel AST associated with the former pump station.

The site is forested aside from areas cleared for facilities, tanks, and roads (Fig. 1).[1-4]

Abandonment, mitigation

YPL planned to clean and remove yard piping at the UTF in the same manner used for the main pipeline. Tank cleaning and removal were to mirror methods used at the Carcross pump station. YPL attempted to preserve the natural habitat at the UTF.[1]

Assessment approach

At the UTF, YPL combined its Phase I environmental site assessment (ESA) with its limited initial Phase II ESA. After identifying 11 areas of potential environmental concern (APEC) at the UTF, YPL drilled five boreholes to obtain preliminary soil and groundwater data. Following removal of the ASTs and other facilities at the UTF, YPL conducted a more detailed Phase II ESA, including extensive soil vapor surveys and test-hole excavations focusing on the APECs, including each AST. YPL also

drilled an additional 13 on and offsite boreholes.

YPL compared soils in the upper 3 m with Yukon Contaminated Site Regulations (CSR) and Canadian Council of Ministers of the Environment (CCME) criteria for residential land use, and screened soils more than 3 m deep against CSR and CCME industrial land use criteria. It compared groundwater samples with CSR and CCME freshwater aquatic life (FAL) criteria.

YPL identified phase-separated liquid hydrocarbons in monitoring well BH96-01 about 33 m below grade. A preliminary risk assessment determined that the site did not pose a risk to human health (of a trespasser) or the environment in its current state, but would require remediation to accommodate future development. YPL chose to involve a developer in hopes that remediation could be planned to meet both pipeline abandonment and future development needs.[2 4]

Remediation approach

YPL elected to develop site specific remediation standards (SSRSs) for soils deeper than 3 m.[5] It excavated shallow soils exceeding CSR residential criteria and a few deeper hot spots and segregated them into granular material for beneficial reuse and fine material requiring offsite bioremediation and disposal.[6-8]

YPL then planned for deeper soils exceeding the SSRSs to be subjected to in place soil vapor extraction and bioventing. The residential subdivision proposal laid out the neighborhood so that deeper soils requiring ongoing remediation would lie below cul de sacs or green spaces.[5]

The SSRS calculations showed that hydrocarbon-saturated soils could be left in place so long as phase-separated liquid hydrocarbons were not present and houses were offset 15-30 m from contaminated areas (depending on the type of basement construction).[9] Subsequent soil vapor monitoring, however, demonstrated that the dilution factors used in the SSRS calculations overestimated the actual dilution.[10 11]

Instead of lowering the SSRSs to values that would protect human health and the environment without imposing further conditions (possibly necessitating further soil remediation), YPL left the SSRSs for soil as is and introduced new SSRSs for vapors in conjunction with monitoring requirements and engineering controls for the proposed new homes.[11]

YPL has not performed remediation activity for soils deeper than 3 m other than the removal of hot spots in conjunction with excavation of shallower soils. To date, NEB has not granted formal approval to either soil or vapor SSRSs.

YPL's remediation plan called for routine liquid hydrocarbon recovery and groundwater sampling to continue until phase-separated liquid hydrocarbons were no longer detected and on site and off site groundwater met site-specific groundwater standards (SSGSs) and CSR FAL criteria, respectively, for a period of 2 years.[5] Assuming natural attenuation of dissolved hydrocarbons was occurring and that all groundwater from the site would flow into Baxter's Gulch, YPL back-calculated SSGS for use on site such that concentrations would attenuate to below CSR FAL criteria by the time the groundwater reached Baxter's Gulch.[12] Biostimulation and biosparging would accomplish groundwater remediation, if required.[5]

In February 2003, following introduction of a new version of the CSR in August 2002, YPL proposed to change the criteria it would use to determine the success of its groundwater remediation program. Instead of applying the SSGSs, YPL proposed to conduct a risk-assessment to determine whether existing hydrocarbon concentrations in groundwater would adversely affect identified human and ecological receptors.[13 14]

The Board approved YPL's request to amend its remediation plan but directed YPL to submit its formal Human Health and Ecological Risk Assessment and amended remediation plan for approval before implementing any changes.[15] The submitted risk assessment is a topic of ongoing technical debate between YPL and other interested parties and has not been approved to date.[16 17]

YPL resumed groundwater monitoring at the UTF in June 2005, following a 3-year hiatus, and liquid hydrocarbons (0.57 m thick) were detected on the groundwater table in BH96-01 for the first time since late 2000. Although subsequent monitoring events have detected no liquid hydrocarbons, the discovery raised questions with respect to understanding and delineation of the liquid hydrocarbon plume or plumes and reset the clock with respect to YPL's monitoring commitments for site closure.[18]

Issues, concerns

The UTF's visibility within Whitehorse, potential real estate value (due to its central location and thick overburden), and potential for residential redevelopment have exposed it to ongoing public interest and stakeholder scrutiny.

The UTF abandonment presents many technical logistical, and regulatory challenges. Technical challenges revolve around adequate characterization and understanding of this site to support the risk-based decisions contemplated.

Subsurface vapor migration, delineation of impacted soils at depth, characterization of the groundwater flow regime, demonstration of natural attenuation, and identification and delineation of liquid hydrocarbon plumes remain topics of discussion and debate between the NEB, YPL, and others.

Underlying these topics of discussion is the deeper question of what level of detail is sufficient for YPL and regulators to feel confident in their decisions with respect to protection of human health and the environment, particularly considering the potential for single-family residential redevelopment.

Logistical difficulties include the large size of the site, the large depth to groundwater and contamination at the

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groundwater table, the large number of discrete sources of contamination within the overall site, and the cost and limitations of drilling technology available to characterize the site.

Regulatory issues include the question of how to conclude a remediation plan approved under and regulated by a pipeline regulator, where the original contemplation of risk-based approaches and site-specific numerical standards has developed into risk-management specifications for future residential development. These are areas outside the scope of the NEB's jurisdiction that could presumably only be implemented after leave-to-abandon comes into force.

The changing understanding of the site, changing regulatory environment over the course of the project, and the company's changing approach to remediating or risk-managing the site have complicated remediation. The limited characterization of the site at the time of the abandonment hearing made it difficult to foresee some of the issues and difficulties that would arise in the remediation of this site, as well as the time required to accomplish successful remediation. Changing regulations and standards added further twists.

The Yukon CSR, in draft during the hearing, came into force later in 1996 and were revised in 2002. CCME Canada-Wide Standards for Petroleum Hydrocarbons (PHC) in Soil were endorsed in 2001. As federal standards for bulk PHC had not previously been available, the emphasis of the YPL remediation shifted from meeting federal and territorial standards to meeting just the CSR standards. As a result, participants did not apply the CCME standards for PHC even after their introduction.

In response to these changes in the regulatory environment and understanding of the site, in YPL's remediation approach shifted, resulting in some unforeseen jurisdictional issues and resource demands for increasingly complex technical analysis.

Although YPL's remediation plan follows the spirit of the Yukon CSR, it has been evaluated and approved pursuant to the NEB and CEA Acts. In order to facilitate input from regulatory and non-regulatory participants as YPL progressed from preliminary investigation at the time of the abandonment hearing to development and implementation of a remediation plan and site closure, the NEB required YPL to "provide information to and consider the comments of persons who indicate to YPL that they wish to be consulted."[19]

Yukon Pipeline Ltd.'s upper tank farm site is forested outside of areas cleared for facilities, tanks, and roads. Its proximity to land likely to be developed residentially is one factor regulators must consider during abandonment (Fig. 1).

The YPL properties, however, have not been designated "contaminated sites" or issued permits for "risk-based restoration" by the YTG pursuant to the Yukon Environment Act or CSR. A disconnect therefore exists between the federal regulatory approval of the remediation plan and the territorial regulatory tools that could be applied to the long-term risk management of the sites.

Lessons

It has been more than 10 years since the NEB wrote the YPL abandonment order and it has yet to come into force. The physical abandonment of YPL's facilities was relatively straightforward and didn't involve many of the potential environmental effects that might need to be addressed for the abandonment of a larger diameter underground pipeline. Soil and groundwater contamination issues such as those encountered on this project, however, are seldom quick or inexpensive to address and may involve many unknown variables for which it is hard to plan.

It is important that the abandonment process, including NEB decision and conditions, incorporate appropriate adaptability to address the variables and temporal changes encountered in a multi-year environmental remediation project.

In the past year, NEB has worked to revitalize lines of communication among itself, YPL, and other stakeholders in order to move toward successful, safe, and environmentally sound abandonment of this site. In review of this file, measures emerge that would make future large-scale abandonment processes more efficient and effective, particularly if considered early in the proceedings. These measures pertain primarily to matters of risk assessment, risk management, and jurisdiction.

As summarized by YPL in hearing documents, in order for an adverse health or environmental effect to occur, three components must be present: a hazardous chemical concentration, a receptor, and an exposure pathway.[1] Assessment and management of these components can effectively and efficiently address environmental risk associated with contaminated sites but can also be problematic.

Risk-assessment principles underlie many Canadian provincial, federal, and territorial regulations, standards, and guidelines for contaminated sites. Generic soil and groundwater criteria are typically based on conservative default

inputs into risk-based environmental models. The regulations, standards, or guidelines also typically contain mechanisms for tweaking generic criteria through input of site-specific parameters, or for implementing full-blown risk assessment or risk management.

The more complex the adjustment, the better the understanding of the site required, the more long-term control over the site required, and the more important full participation becomes. Characterization of the site must be sufficient to support the risk-based decisions being made.

In response to its responsibilities under the CEA Act, NEB can delay leave-to-abandon from coming into force until environmental mitigation measures have been implemented. This might be counterproductive, however, when proponents seek to implement appropriate long-term risk management measures while redeveloping former pipeline property after leave-to-abandon is in force.

Completion of as much of the site characterization and risk-assessment work before applying to abandon the facilities would enable more informed decisions with respect to potential issues, impediments, and costs. In particular, the scope of the risk assessment and timeframe of the risk-management measures being proposed should be well understood.

Options available to NEB might then include limiting the scope of risk assessment and management to measures it can ensure are implemented before formal abandonment, or working with other applicable regulatory agencies to ensure risk assessment and management measures are implemented within their regulatory frameworks and under their regulatory oversight (pursuant to paragraph 20(1.1)(b) of the CEA Act).

The latter option would depend on the jurisdictional boundaries and regulatory framework of the agencies involved and would require establishment of appropriate regulatory roles and responsibilities early in the abandonment process; requiring further analysis with respect to legal and logistical issues.

Operators and regulators alike should consider the following lessons from the YPL case when approaching future abandonments, particularly when contaminated site risk assessment and management is contemplated:

- Companies should complete as much as possible of the site characterization and risk-assessment work before applying to abandon the facilities.
- Site characterization must be sufficient to support the risk-based decisions being made.
- Roles and responsibilities of involved regulators should be determined early in the abandonment process.
- Companies and involved regulators should identify as early as possible the nature and complexity of any proposed risk assessment and management and evaluate whether the approach is conducive to unconditional site closure.
- The regulator may need to limit the scope of acceptable risk assessment and management to measures it can ensure are implemented before formal abandonment, or work with other regulators to ensure risk assessment and management measures can be implemented within their regulatory frameworks and under their regulatory oversight.
- The abandonment process, including regulatory decisions and conditions, should incorporate appropriate adaptability to address changing circumstances over the course of an abandonment project. ✦

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Know-how interfaced to offer imaging while drilling

Sperry Drilling Services, a brand of Halliburton's Drilling and Formation Evaluation division, and IntelliServ Inc., a wholly owned subsidiary of Grant Prideco Inc., all of Houston, have interfaced their know-how and successfully tested a system using IntelliServ network drillstring telemetry to transfer all the data and information generated by downhole drilling and formation evaluation tools to the surface in real time.

The firms say the data transfer is achieved at rates as much as 10,000 times those available today.

Use of the IntelliServ network, which is fully compatible with Sperry's INSITE logging-while-drilling services, offers new drilling and formation evaluation capabilities, including transmission of high-resolution images of the subsurface in real time.

Today's drilling rates can be limited by the transmission speed of high volume data collected during the drilling and evaluation process, Sperry Drilling Services notes. With the IntelliServ technology, this limitation is eliminated while also enabling a new range of logging-while-drilling services.

Halliburton and IntelliServ Inc. have entered into an agreement to market and deploy their respective technologies globally to joint customers.

Source: **Halliburton**, 5 Houston Center, 1401 McKinney, Houston, TX 77010.

New safety device for welding

The new pressure-sensitive Super 85 welding safety device meaures about 33 by 150 mm, suiting it to most applications.

If a back pressure or flashback should occur, the unit's pressure-sensitive cutoff valve interrupts the gas supply in a fraction of a second to prevent explosive mixtures from forming. A red warning ring indicates the safety device has operated, the company points out.

Once the cause of the operating fault has been rectified, the user restarts gas flow by sliding back the housing sleeve.

The Super 85's flame arrester is made of sintered chrome-nickel steel. Protection against contamination from the gas supply is provided by a filter fitted to the gas inlet, which can be changed by the user.

Source: **Witt-Gasetechnik GMBH & Co. KG**, Salinger Feld 4-8, 58454 Witten, Germany.

T.D. Williamson Inc.

Tulsa, has announced its acquisition of Williamson Industries Inc., headquartered in Georgetown, Ont., Canada. The new acquisition will be known as T.D. Williamson Canada ULC.

T.D. Williamson Inc. is a leading global provider of pipeline equipment and services, delivering safe integrity solutions for onshore and offshore applications. The company's expertise covers hot tapping and plugging, pipeline cleaning, geometry and MFL inspection, pigging, and non-tethered plugging pig technology services.

Knight Well Services

Houma, La., has announced the opening of its newest facility at Houma's Port of Terrebone. The new facility will house Knight's plug and abandonment equipment.

Knight Well Services, a div. of Knight Oil Tools, is a key provider of plug and abandonment services, equipment, and accessories to the oil and gas industry. The Well Services operations had been housed with Knight Fishing Services in Houma since Hurricane Katrina damaged infrastructure to their previous facility.

Knight Oil Tools operates from 18 locations across six oil producing states in the US.

Flint Energy Services Ltd.

Calgary, has announced the appointment of Paul M. Boechler as chief financial officer, succeeding Terry Freeman, who is retiring.

Boechler most recently served as president of Flint Energy Services Inc., the company's US division. He holds a bachelor of commerce degree from the University of Saskatchewan.

Flint Energy Services Ltd. provides a range of integrated products and services for the oil and gas industry in western North America, including production services, construction, oil field transportation, process equipment design and manufacturing, and tubular management services.

GE Oil & Gas

Florence, Italy, has announced its acquisition of Vetco Gray, a leading supplier of drilling, completion, and production equipment for on- and offshore oil and gas fields, including subsea applications. Vetco Gray has key centers in Houston, Aberdeen, Stavanger, Oslo, and Singapore.

GE Oil & Gas is a global leader in advanced technology turbomachinery products and services for oil and gas production, LNG, transportation, storage, refineries and petrochemical plants, as well as pipeline integrity solutions.

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	2-16 2007	[1]2-9 2007	2-16 2007	[1]2-9 2007	2-16 2007	[1]2-9 2007	2-17 2006
	1,000 b/d						
Total motor gasoline	395	218	114	21	509	239	266
Mo. gas. blending comp.	524	492	16	69	540	561	532
Distillate[2]	317	286	57	9	374	295	361
Residual	183	72	26	89	209	161	752
Jet fuel-kerosine	136	272	80	128	216	400	170
LPG	237	230	2	2	239	232	288
Unfinished oils	363	614	40	54	403	668	351
Other	382	455	13	15	395	470	457
Total products	**2,537**	**2,639**	**348**	**387**	**2,885**	**3,026**	**3,177**
Canadian crude	1,806	1,517	137	129	1,943	1,646	1,708
Other foreign	7,837	6,748	758	711	8,595	7,459	8,299
Total crude	**9,643**	**8,265**	**895**	**840**	**10,538**	**9,105**	**10,007**
Total imports	**12,180**	**10,904**	**1,243**	**1,227**	**13,423**	**12,131**	**13,184**

[1]Revised. [2]Includes No. 4 fuel oil.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

Additional analysis of market trends is available through **OGJ Online**, *Oil & Gas Journal's* electronic information source, at http://www.ogjonline.com.

OIL&GAS JOURNAL online research center

OGJ CRACK SPREAD

	*2-23-07	*2-24-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	72.25	66.12	6.13	9.3
Brent crude	59.17	59.32	–0.15	–0.2
Crack spread	13.08	6.81	6.27	92.1
FUTURES MARKET PRICES				
One month				
Product value	71.86	66.06	5.80	8.8
Light sweet crude	60.06	61.39	–1.33	–2.2
Crack spread	11.80	4.67	7.13	152.6
Six month				
Product value	75.36	73.13	2.24	3.1
Light sweet crude	63.45	65.45	–2.00	–3.1
Crack spread	11.91	7.67	4.24	55.2

*Average for week ending
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel	Fuel oils		Unfinished oils
		Total	Blending comp.[1]	Kerosine	Distillate	Residual	
	1,000 bbl						
PAD I	13,371	58,073	28,009	9,245	55,235	17,568	7,952
PAD II	67,392	52,011	15,308	7,560	28,593	1,621	13,261
PAD III	176,625	65,148	26,883	13,405	32,314	16,601	43,302
PAD IV	13,845	7,041	1,715	817	3,387	347	2,601
PAD V	[1]51,720	30,410	22,937	9,282	11,624	6,351	20,294
Feb. 16, 2007	**[1]322,953**	**212,683**	**94,852**	**40,309**	**131,153**	**42,488**	**87,410**
Feb. 9, 2007[3]	**325,251**	**215,430**	**95,999**	**41,430**	**135,118**	**43,943**	**86,399**
Feb. 17, 2006	**327,532**	**217,794**	**78,306**	**43,842**	**135,493**	**41,046**	**88,924**

[1]Included in total motor gasoline. [2]Includes 6.193 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—FEB. 16, 2007

	REFINERY OPERATIONS					REFINERY OUTPUT			
District	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
	1,000 b/d					1,000 b/d			
East Coast	3,182	1,392	1,400	1,618	86.5	1,667	63	451	136
App. Dist. 1	80	74	74	95	77.9	21	0	18	0
Dist. 1 total	**3,262**	**1,466**	**1,474**	**1,713**	**86.1**	**1,688**	**63**	**469**	**136**
Ind., Ill., Ky.	2,248	2,129	2,185	2,355	92.8	1,165	144	517	56
Minn., Wis., Dak.	352	344	349	442	79.0	268	27	114	9
Okla., Kan., Mo.	715	538	590	786	75.1	380	35	200	3
Dist. 2 total	**3,315**	**3,011**	**3,124**	**3,583**	**87.2**	**1,813**	**206**	**831**	**68**
Inland Texas	929	603	621	647	96.0	483	33	172	7
Texas Gulf Coast	3,666	3,061	3,122	4,031	77.5	1,456	269	871	140
La. Gulf Coast	3,578	3,141	3,166	3,264	97.0	1,215	400	833	147
N. La. and Ark.	217	182	182	215	84.7	91	7	46	7
New Mexico	167	97	97	113	85.8	108	2	38	0
Dist. 3 total	**8,557**	**7,084**	**7,188**	**8,270**	**86.9**	**3,353**	**711**	**1,960**	**301**
Dist. 4 total	**620**	**532**	**536**	**596**	**89.9**	**334**	**30**	**147**	**15**
Dist. 5 total	**2,733**	**2,300**	**2,397**	**3,173**	**75.5**	**1,609**	**394**	**445**	**161**
Feb. 16, 2007	**18,487**	**14,393**	**14,719**	**17,335**	**84.9**	**8,797**	**1,404**	**3,852**	**681**
Feb. 9, 2007*	**18,188**	**14,492**	**14,940**	**17,335**	**86.2**	**9,012**	**1,474**	**4,108**	**680**
Feb. 17, 2006	**16,742**	**14,441**	**14,941**	**17,115**	**87.3**	**8,573**	**1,420**	**3,779**	**637**

*Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

Statistics

OGJ GASOLINE PRICES

	Price ex tax 2-21-07	Pump price* 2-21-07	Pump price 2-22-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	178.4	218.1	221.3
Baltimore	178.2	220.1	227.2
Boston	176.4	218.3	226.9
Buffalo	180.1	240.2	245.9
Miami	187.5	237.8	247.7
Newark	183.7	216.6	220.0
New York	167.7	227.8	255.9
Norfolk	176.2	213.8	214.5
Philadelphia	191.5	242.2	242.3
Pittsburgh	173.2	223.9	233.5
Wash., DC	190.5	228.9	245.3
PAD I avg.	180.3	226.1	234.6
Chicago	202.3	253.2	257.3
Cleveland	182.8	229.2	216.4
Des Moines	179.8	220.2	218.3
Detroit	180.8	230.0	224.8
Indianapolis	190.1	235.1	213.3
Kansas City	177.6	213.6	209.9
Louisville	195.8	232.7	219.4
Memphis	173.3	213.1	220.7
Milwaukee	181.5	232.8	233.2
Minn.-St. Paul	187.3	227.7	222.0
Oklahoma City	177.6	213.0	206.0
Omaha	177.9	224.3	223.9
St. Louis	183.1	219.1	204.4
Tulsa	174.7	210.1	210.5
Wichita	177.1	220.5	208.0
PAD II avg.	182.8	225.0	219.2
Albuquerque	182.4	218.8	226.5
Birmingham	176.0	214.7	218.9
Dallas-Fort Worth	179.2	217.6	220.8
Houston	174.1	212.5	218.6
Little Rock	176.3	216.5	220.8
New Orleans	181.0	219.4	233.8
San Antonio	170.5	208.9	212.2
PAD III avg.	177.1	215.5	221.7
Cheyenne	176.5	208.9	205.9
Denver	179.5	219.9	217.2
Salt Lake City	174.5	217.4	224.4
PAD IV avg.	176.8	215.4	215.8
Los Angeles	212.8	271.3	254.0
Phoenix	192.2	229.6	233.9
Portland	206.7	250.0	213.0
San Diego	214.0	272.5	259.0
San Francisco	235.2	293.7	253.7
Seattle	207.8	260.2	234.9
PAD V avg.	211.4	262.9	241.4
Week's avg.	**184.8**	**228.4**	**226.6**
Jan. avg.	**181.7**	**225.3**	**229.6**
Dec. avg.	**184.9**	**228.5**	**227.3**
2007 to date	**181.8**	**225.4**	—
2006 to date	**186.3**	**228.7**	—

*Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

REFINED PRODUCT PRICES

	2-16-07 ¢/gal		2-16-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	164.85	New York Harbor	166.56
Gulf Coast	160.60	Gulf Coast	161.99
Los Angeles	190.10	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	146.88	ARA	164.97
Singapore	162.14	Singapore	161.67
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	164.35	New York Harbor	94.95
Gulf Coast	160.85	Gulf Coast	99.40
Los Angeles	197.60	Los Angeles	125.51
		ARA	79.53
		Singapore	106.03

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

BAKER HUGHES RIG COUNT

	2-23-07	2-24-06
Alabama	3	6
Alaska	14	10
Arkansas	41	20
California	32	30
Land	28	28
Offshore	4	2
Colorado	95	83
Florida	0	1
Illinois	0	0
Indiana	1	0
Kansas	14	6
Kentucky	10	6
Louisiana	206	182
N. Land	57	59
S. Inland waters	26	20
S. Land	49	35
Offshore	74	68
Maryland	0	0
Michigan	2	1
Mississippi	16	5
Montana	22	23
Nebraska	0	0
New Mexico	85	98
New York	9	4
North Dakota	33	27
Ohio	13	9
Oklahoma	182	174
Pennsylvania	13	16
South Dakota	0	1
Texas	812	686
Offshore	11	15
Inland waters	2	1
Dist. 1	24	15
Dist. 2	30	29
Dist. 3	51	61
Dist. 4	94	75
Dist. 5	159	124
Dist. 6	126	101
Dist. 7B	41	28
Dist. 7C	48	38
Dist. 8	109	71
Dist. 8A	28	32
Dist. 9	34	30
Dist. 10	55	66
Utah	45	30
West Virginia	29	25
Wyoming	69	97
Others—ID-1; NV-1; TN-4; VA-2	8	3
Total US	**1,754**	**1,543**
Total Canada	**603**	**699**
Grand total	**2,357**	**2,242**
Oil rigs	278	219
Gas rigs	1,472	1,322
Total offshore	89	86
Total cum. avg. YTD	**1,725**	**1,503**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	2-23-07 Rig count	2-23-07 Percent footage*	2-24-06 Rig count	2-24-06 Percent footage*
0-2,500	50	—	49	4.0
2,501-5,000	100	57.9	110	40.0
5,001-7,500	224	18.3	204	16.1
7,501-10,000	426	3.9	317	4.1
10,001-12,500	418	3.8	336	1.7
12,501-15,000	279	1.0	270	0.3
15,001-17,500	109	1.8	119	0.8
17,501-20,000	78	—	74	—
20,001-over	39	—	23	—
Total	**1,723**	**7.9**	**1,502**	**6.6**
INLAND	38		39	
LAND	1,622		1,403	
OFFSHORE	63		60	

*Rigs employed under footage contracts.
Definitions, see OGJ, Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]2-23-07	[2]2-24-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	21
Alaska	804	821
California	701	685
Colorado	59	60
Florida	7	6
Illinois	32	28
Kansas	96	96
Louisiana	1,410	1,174
Michigan	14	15
Mississippi	53	44
Montana	94	96
New Mexico	165	159
North Dakota	100	103
Oklahoma	173	172
Texas	1,370	1,288
Utah	44	46
Wyoming	144	140
All others	65	66
Total	**5,349**	**5,020**

[1]OGJ estimate. [2]Revised.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

$/bbl*	2-23-07
Alaska-North Slope 27°	49.99
South Louisiana Sweet	62.00
California-Kern River 13°	49.90
Lost Hills 30°	57.95
Wyoming Sweet	57.39
East Texas Sweet	59.27
West Texas Sour 34°	49.00
West Texas Intermediate	57.75
Oklahoma Sweet	57.75
Texas Upper Gulf Coast	54.50
Michigan Sour	50.75
Kansas Common	56.75
North Dakota Sweet	51.25

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	2-16-07
United Kingdom-Brent 38°	55.85
Russia-Urals 32°	52.27
Saudi Light 34°	51.54
Dubai Fateh 32°	55.38
Algeria Saharan 44°	58.26
Nigeria-Bonny Light 37°	59.15
Indonesia-Minas 34°	58.13
Venezuela-Tia Juana Light 31°	52.59
Mexico-Isthmus 33°	52.48
OPEC basket	55.36
Total OPEC[2]	53.74
Total non-OPEC[2]	53.55
Total world[2]	53.65
US imports[3]	51.62

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US NATURAL GAS STORAGE[1]

	2-16-07	2-9-07	Change
	Bcf		
Producing region	616	676	–60
Consuming region east	996	1,147	–151
Consuming region west	253	265	–12
Total US	**1,865**	**2,088**	**–223**
	Nov. 06	**Nov. 05**	**Change, %**
Total US[2]	**3,407**	**3,189**	**6.8**

[1]Working gas. [2]At end of period.
Note: Current data not available.
Source: Energy Information Administration
Data available in OGJ Online Research Center

PACE REFINING MARGINS

	Dec. 2006	Jan. 2007	Feb. 2007	Feb. 2006	Change 2007 vs. 2006	Change, % 2007 vs. 2006
	$/bbl					
US Gulf Coast						
West Texas Sour	9.57	9.46	10.07	11.37	–1.30	–11.4
Composite US Gulf Refinery	10.04	10.44	11.56	9.73	1.83	18.8
Arabian Light	10.12	9.71	12.21	9.25	2.96	32.0
Bonny Light	1.93	2.80	5.01	2.22	2.79	125.4
US PADD II						
Chicago (WTI)	7.64	6.29	9.90	5.93	3.97	67.0
US East Coast						
NY Harbor (Arab Med)	9.73	9.38	10.80	9.08	1.73	19.0
East Coast Comp-RFG	12.18	11.13	12.96	9.90	3.06	30.9
US West Coast						
Los Angeles (ANS)	17.25	17.83	23.37	12.21	11.17	91.5
NW Europe						
Rotterdam (Brent)	0.00	2.58	3.13	1.34	1.79	133.1
Mediterranean						
Italy (Urals)	7.36	7.83	8.31	6.35	1.96	30.9
Far East						
Singapore (Dubai)	4.18	8.28	7.89	2.03	5.86	288.1

. Source: Jacobs Consultancy Inc.
Data available in OGJ Online Research Center.

US NATURAL GAS BALANCE
DEMAND/SUPPLY SCOREBOARD

	Nov. 2006	Oct. 2006	Nov. 2005	Nov. 2006-2005 change	Total YTD 2006	Total YTD 2005	YTD 2006-2005 change
	bcf						
DEMAND							
Consumption	1,770	1,654	1,681	89	19,737	19,893	–156
Addition to storage	159	246	203	–44	2,824	2,903	–79
Exports	79	66	45	34	666	683	–17
Canada	42	31	20	22	291	335	–44
Mexico	32	32	19	13	319	288	31
LNG	5	3	6	–1	56	60	–4
Total demand	**2,008**	**1,966**	**1,929**	**79**	**23,227**	**23,479**	**–252**
SUPPLY							
Production (dry gas)	1,540	1,581	1,445	95	16,873	16,552	321
Supplemental gas	5	5	5	0	56	58	–2
Storage withdrawal	206	115	212	–6	2,051	2,406	–355
Imports	347	326	360	–13	3,785	3,932	–147
Canada	300	290	299	1	3,250	3,347	–97
Mexico	0	0	3	–3	3	5	–2
LNG	47	36	58	–11	532	580	–48
Total supply	**2,098**	**2,027**	**2,022**	**76**	**22,765**	**22,948**	**–183**

NATURAL GAS IN UNDERGROUND STORAGE

	Nov. 2006	Oct. 2006	Sept. 2006	Nov. 2005	Change
	bcf				
Base gas	4,216	4,217	4,215	4,209	7
Working gas	3,407	3,452	3,323	3,189	218
Total gas	**7,623**	**7,669**	**7,538**	**7,398**	**225**

Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

WORLDWIDE NGL PRODUCTION

	Nov. 2006	Oct. 2006	11 month average – Production – 2006	2005	Change vs. previous year Volume	%
	1,000 b/d					
Brazil	87	86	86	78	8	10.1
Canada	671	675	674	673	—	—
Mexico	389	405	431	426	5	1.1
United States	1,769	1,773	1,735	1,741	–6	–0.3
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	181	174	175	156	19	12.4
Western Hemisphere	**3,297**	**3,312**	**3,301**	**3,275**	**26**	**0.8**
Norway	309	285	284	264	20	7.5
United Kingdom	163	159	152	169	–17	–10.2
Other Western Europe	19	19	19	22	–2	–10.0
Western Europe	**491**	**463**	**455**	**455**	**—**	**0.1**
Russia	420	410	399	467	–68	–14.6
Other FSU	160	160	160	160	—	—
Other Eastern Europe	18	17	17	18	–1	–3.1
Eastern Europe	**598**	**587**	**576**	**645**	**–69**	**–10.7**
Algeria	330	320	308	295	13	4.5
Egypt	65	65	65	65	—	—
Libya	60	60	60	60	—	—
Other Africa	196	190	191	171	20	11.4
Africa	**651**	**635**	**624**	**591**	**33**	**5.5**
Saudi Arabia	1,490	1,490	1,479	1,460	19	1.3
United Arab Emirates	400	400	400	400	—	—
Other Middle East	670	670	670	571	99	17.3
Middle East	**2,560**	**2,560**	**2,549**	**2,431**	**118**	**4.8**
Australia	77	83	81	82	–1	–0.6
China	180	180	180	180	—	—
India	38	38	41	44	–3	–6.3
Other Asia-Pacific	220	220	220	218	2	0.9
Asia-Pacific	**516**	**521**	**522**	**524**	**–1**	**–0.3**
TOTAL WORLD	**8,114**	**8,078**	**8,028**	**7,921**	**107**	**1.4**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

OXYGENATES

	Nov. 2006	Oct. 2006	Change	YTD 2006	YTD 2005	Change
	1,000 bbl					
Fuel ethanol						
Production	10,279	10,308	–29	104,581	84,276	20,305
Stocks	9,212	9,814	–602	9,212	5,720	3,492
MTBE						
Production	1,482	1,575	–93	29,195	43,031	–55,081
Stocks	1,460	1,197	263	1,460	2,950	–1,490

Source: DOE Petroleum Supply Monthly.
Data available in OGJ Online Research Center.

US HEATING DEGREE DAYS

	Jan. 2007	Jan. 2006	Normal	2006 % change from normal	Total degree days July 1 through Jan. 31 2007	2006	Normal	% change from normal
New England	1,106	993	1,246	–11.2	3,227	3,290	3,708	–13.0
Middle Atlantic	980	874	1,158	–15.4	2,779	2,904	3,349	–17.0
East North Central	1,112	901	1,302	–14.6	3,378	3,291	3,774	–10.5
West North Central	1,277	945	1,390	–8.1	3,739	3,441	4,085	–8.5
South Atlantic	509	464	643	–20.8	1,477	1,541	1,726	–14.4
East South Central	705	551	820	–14.0	2,047	1,977	2,230	–8.2
West South Central	630	348	593	6.2	1,451	1,217	1,498	–3.1
Mountain	1,049	801	951	10.3	3,084	2,667	3,098	–0.5
Pacific	626	507	564	11.0	1,749	1,557	1,817	–3.7
US average*	**835**	**674**	**917**	**–8.9**	**2,390**	**2,301**	**2.656**	**–10.0**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

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Want lower oil imports? Expand federal leasing

The White House, Senate, and House of Representatives all want to reduce US dependency on foreign oil—in the most expensive ways possible.

In energy initiatives this year, they all bow at the altar of national energy security.

A sense-of-Congress bill that the Senate passed in January lists first among its purposes "to enhance the security of the United States by reducing the dependence

The Editor's Perspective

by Bob Tippee, Editor

of the United States on foreign and unsustainable energy sources."

Legislation passed by the House in January promises "to reduce our nation's dependency on foreign oil by investing in clean, renewable, and alternative energy resources."

In his state of the union address, President George W. Bush declared, "For too long our nation has been dependent on foreign oil."

Not one of them mentions increased leasing of the Outer Continental Shelf or of the tiny part of Alaska's Arctic National Wildlife Refuge that might someday become accessible to producers.

Bush, who pushed unsuccessfully for ANWR leasing when his political party controlled Congress, in January gave US petroleum a quick—and this year lonely—salute, saying, before rushing on to other subjects, "We must step up domestic oil production in environmentally sensitive ways."

With Democrats controlling Congress, of course, expanded leasing of federal land is a futile hope. All current proposals promising to cut US dependency on foreign oil therefore dedicate themselves to government expenditure on costlier energy forms.

Ethanol receives a 51¢/gal blending tax credit and comes from grain that receives government price supports. Its increasing use is raising the price of corn.

Biodiesel benefits from tax credits of 50¢-$1/gal, depending on feedstock, some types of which also enjoy price supports.

By contrast, production of oil and gas from newly leased federal land wouldn't cost the government anything. In fact, it would generate federal revenue from bonuses, rentals, and royalties. It also could come to market in much greater quantity much quicker than the agrifuels now adored by politicians.

As long as expanded oil and gas leasing of federal land remains politically improbable, utterances about foreign oil and national security should not be taken seriously. They are, in fact, hypocritical.

(Online Feb. 23, 2006; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Crude futures price tops $61/bbl

The April contract for benchmark US light, sweet crudes blew past $61/bbl to a 7-week high in intraday trade Feb. 22 in New York, following reports of a precipitous drop in US gasoline inventories and stronger defiance by Iran of the United Nations deadline to end its uranium enrichment program.

UN officials said Iran ignored earlier sanctions for noncompliance and proceeded with the installation of a centrifuge and construction of a heavy-water reactor.

Taking the front-month position in the Feb. 21 trading session, the April contract climbed past $60/bbl for the first time in 2007 to close at $60.07/bbl that day. It traded at $59.61-61.25/bbl before closing at $60.95/bbl Feb. 22.

"Oil prices have extended the rally off the lows to more than 20%. With a global tightening in progress combined with disappointing non-OPEC supply news, strong demand, and a worsening geopolitical background, we expect the push-up to continue further," said Paul Horsnell at Barclays Capital Inc., London.

Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland, said, "The [previous $57-60/bbl trading] range on crude oil has now been broken, and with higher highs and lows [and a] higher closing trading above the moving averages, the positive momentum is back into oil and should attract further momentum investment." With market resistance to crude prices of $60.80-$61/bbl now broken, Jakob said, the next major level of resistance would be $63.80/bbl.

The Energy Information Administration reported commercial US crude inventories jumped by 3.7 million bbl to 327.6 million bbl in the week ended Feb. 16 after dropping a total 1 million bbl over the 2 prior weeks. US gasoline stocks fell by 3.1 million bbl to 222.1 million bbl in the same week. Distillate fuel inventories dropped 5 million bbl to 128.3 million bbl.

"The latest US weekly data are again extremely strong, with product inventories falling by 7.6 million bbl relative to their 5-year average. Demand remains strong across the board, with distillate and total demand both running at all-time record levels," Horsnell said. "Gasoline inventories have continued to come back closer into bounds, while heating oil inventories are now below their 5-year average. With 2 months of draws still expected, heating oil inventories are likely to finish the season well below last year's level, and they stand a reasonable chance of finishing below the 5-year average."

EIA's weekly statistics "are showing that in terms of days of cover the whole US complex is now below last year," Jakob said. "While most of the focus is on gasoline and middle distillate, the days of cover for the same week in kerosine are the lowest since 1997, and stocks of residual fuel oil have been steadily drawing back to below last year."

Jakob suggested gains in the energy market "need to be put in the context of a global commodity rally where corn closed at 10-year highs" Feb. 21-22, while gold futures prices were "at the highest level since May-June." Corn is the primary feedstock for the US manufacture of ethanol, a gasoline additive and the primary ingredient in the 85-15% blend of ethanol and gasoline to create the E-85 alternative fuel.

Natural gas outlook

EIA also reported the withdrawal of 223 bcf of natural gas from US underground storage in the week ended Feb. 16. That was at the low end of the consensus among Wall Street analysts and compared with withdrawals of 259 bcf the previous week and 123 bcf during the same period a year ago. It left a little less than 1.9 tcf of gas in storage, down by 296 bcf from levels at this time a year ago but 182 bcf above the 5-year average. US temperatures during that week were just over 30% colder than last year and the 10-year average, but nearly 8% warmer than the prior week.

The consensus estimate of 2% growth in US natural gas production in 2007 is "too optimistic," said Adam Sieminski of Deutsche Bank AG, New York. "Hurricane-adjusted US gas production has risen by only 1 bcfd over the past year in the Lower 48 states. This represents just 1% output growth despite 16% growth in the rig count," he said. Meanwhile, big production jumps in Wyoming in October-November "actually seem to be masking stagnation or month-to-month declines in Louisiana, Oklahoma, New Mexico, and Texas," Sieminski said. "We see a strong likelihood that North American gas production will disappoint this year, given a stagnating US rig count, accelerating decline rates, and behind-the-scenes braking by the private operators."

(Online Feb. 26, 2007; author's e-mail: samf@ogjonline.com)

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