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North Sea Platform Retirement

Tullow, Heritage press exploration in Uganda
Illinois basin ASP flooding planned
Study theorizes use of geothermal energy for refineries
Upheaval buckling in shallow subsea PIP lines examined

OIL&GAS JOURNAL®

Feb. 11, 2008
Volume 106.6

North Sea Platform Retirement

Mature UK sector sets pace for N. Sea decommissioning 22
Uchenna Izundu

Three major North Sea decommissioning projects under way 24
Uchenna Izundu

Regular Features

Newsletter 5
Calendar 12
Journally Speaking 19
Editorial 21
Area Drilling 37
Equipment/Software/Literature 58
Services/Suppliers 58
Statistics 60
Classifieds 63
Advertisers' Index 67
Editor's Perspective/Market Journal 68

Cover

While the decommissioning of oil and gas platforms in the mature UK North Sea remains an issue for producers, improved technology and high oil and gas prices are extending the lives of some equipment. Numerous operators have in effect delayed decommissioning in many cases because continuing production makes economic sense. The special report beginning on p. 22 profiles platform retirement in the North Sea. Cover photo from Oil & Gas UK.

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General Interest

Editorial: Alberta's economic realism 21
Special Report: Mature UK sector sets pace for N. Sea decommissioning 22
Uchenna Izundu
Special Report: Three major North Sea decommissioning projects under way 24
Uchenna Izundu
OWA: Nigeria needs to support local businesses 25
OWA: Pressure increases for Niger Delta peace 26
DOI's $10.7 billion budget has environmental emphasis 26
WATCHING GOVERNMENT: High-stakes appeal 27
US MMS director defends leasing in Chukchi Sea 28
UK lawmakers call for moratorium on biofuel targets 30
Shell Oil's Hofmeister calls for US cap on CO_2 emissions 30
WATCHING THE WORLD: Inquiring after Aleksanyan 31
Iraq to benefit from higher oil revenues, report says 32
Operators, contractors agree safety is priority 33
Offshore cathodic protection survey completed off Ecuador 34

Exploration & Development

Tullow, Heritage press exploration in Uganda 36

Drilling & Production

Illinois basin ASP flooding planned 39
Guntis Moritis
CLASSIC BIT KINEMATICS—2: True kinematics opens way to bit improvement 42
Yuri A. Palashchenko

Processing

Study theorizes use of geothermal sources for energy in refineries 48
Mike Golombok, Kike Beintema

Transportation

Study examines causes of upheaval buckling in shallow subsea PIP lines 53
Jack X. Liu, H.M. Zhang, Q. Meng, H. Zhang

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General Interest — Quick Takes

Enbridge to lead industry CCS project

Enbridge Inc. plans to lead a group of 19 oil companies and electric utilities in the Alberta Saline Aquifer Project (ASAP), a carbon capture and storage (CCS) research and pilot sequestration project.

Other companies involved include BP Canada Energy Co., Chevron Canada Resources, ConocoPhillips, EnCana Corp., Penn West Energy Trust, and TransCanada.

Initially, ASAP will identify deep saline aquifers suitable for long-term storage of carbon dioxide in Canada. The first phase is expected to be completed by yearend.

A second phase calls for designing sequestration sites to receive injected carbon dioxide. Later phases could involve large-scale, long-term commercial sequestration.

On Feb. 1, a joint federal-provincial government panel recommended that Canadian governments invest $2 billion (Can.), to be matched by energy industry funding, toward CCS research with the goal of sequestering 5 million tonnes of carbon dioxide by 2015.

Finance minister lauds French industry fuel prices

In an unprecedented move, French Finance and Economy Minister Christine Lagarde commended oil companies and distributors for keeping a promise made at the Nov. 10, 2007, roundtable she chaired, that they would address oil price peaks and pass along price drops as quickly as possible at service stations.

She noted in a press release that the price of motor fuels had returned in late January to the preround table level following heights reached in early January. She said three factors explained variations in the price of motor fuels over the last few weeks in France, pushing up prices:

- The impact of the French biofuels plan, which since Jan. 1 has jumped to a 5.75% incorporation into motor fuels. That goal was set by the European Union for 2010, but France anticipated it earlier, leading to logistic adaptations and costlier supply.
- The turnaround of a number of refineries, the reduction in product sulfur content, and the railway strikes that resulted in higher costs in late November.
- The increase in the internal oil products tax, which the government had transferred to the regions.

Jean-Louis Schilansky, delegate general of the oil companies' trade group UFIP, told OGJ that the price of gasoline and diesel fuel increased by some €0.02/l. compared with what it should have been.

Schilansky said, "What we really appreciate is the rational analysis of the situation by the government. The price of motor fuels is now being discussed at an economic level and no longer in a political and polemical way."

Japan, S. Korea retain global LNG import lead

Japan remained the world's largest LNG importer in 2007, at 65.7 million tonnes of LNG, up 5.7% over 2006, according to Pan EurAsian Enterprises. South Korea remained the world's second largest LNG importer at 25.6 million tonnes, up 1.2% over 2006.

Pan EurAsian cited the next six largest global LNG importers in 2007, in millions of tonnes of LNG, as: Spain 19.1; US 17; France 10.2; Taiwan 8.3; India 6.2; and Turkey (with only one terminal) 3.5.

Taiwan's LNG imports were up 6.8% over 2006, Pan EurAsian reported, and China appeared in the reckoning—with imports of 2.9 million tonnes, up from less than 10% of that amount in 2006. ✦

Exploration & Development — Quick Takes

Chukchi Sea sale draws $2.66 billion in high bids

Oil and gas producers submitted $2.66 billion in apparent high bids in a record-breaking offshore federal lease sale in Alaska, the US Minerals Management Service said Feb. 6.

The 677 bids on 488 blocks in the first Chukchi Sea lease sale since 1991 made it the most successful Outer Continental Shelf lease sale in Alaska's history, MMS said. Shell Gulf of Mexico Inc. submitted the single largest bid—more than $105.3 million. Shell also led in total bids, with 302 totaling nearly $2.2 billion, 275 of them high bids for nearly $2.12 billion.

ConocoPhillips was the second most active bidder, submitting 145 bids for $1.1 billion, including 98 high bids for more than $506.4 million. Other participants included Repsol E&P USA Inc. with 104 total bids for $15.6 million, 93 of which were high bids for more than $14.4 million and Eni Petroleum US Inc. with 74 total bids for nearly $35 million, 17 of which were high bids for nearly $8.9 million.

StatoilHydro USA E&P Inc., Iona Energy Co. (US) Ltd., and North American Civil Recoveries Arbitrage Corp. also submitted high bids, according to MMS.

The US Department of Interior agency received nearly $3.39 billion in bids from the seven companies for 2,304-acre tracts spread over more than 29 million acres. It said that each high bid now will be evaluated to assure that it represents a fair market value before a lease is issued. The closest awarded tract to land is 54 miles offshore, MMS said.

The sale took place despite protests that oil and gas activity could pose a threat to polar bears, which another DOI agency, the US Fish

Industry Scoreboard

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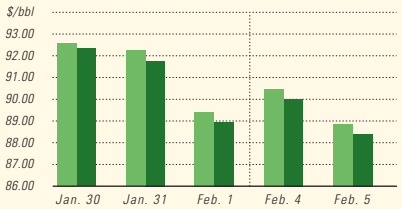
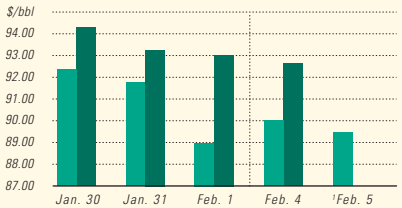
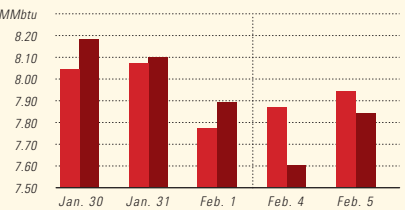


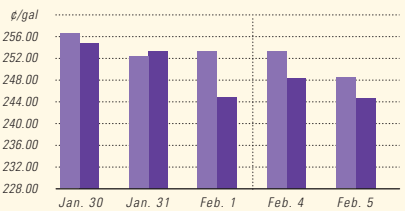
WTI CUSHING / BRENT SPOT



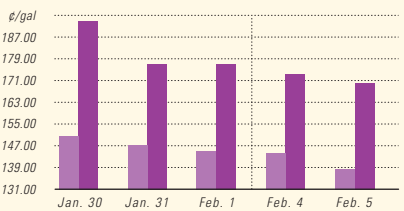
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



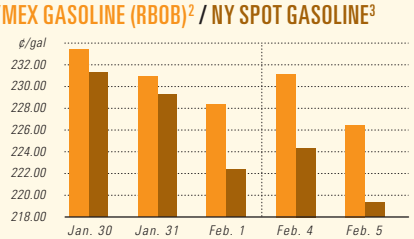
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Not available. [2]Reformulated gasoline blendstock for oxygen blending. [3]Non-oxygenated regular unleaded.

US INDUSTRY SCOREBOARD — 2/11

Latest week 1/25	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	9,081	8,955	1.4	9,081	8,891	2.1
Distillate	4,248	4,267	–0.4	4,248	4,267	–0.4
Jet fuel	1,540	1,618	–4.8	1,540	1,616	–4.8
Residual	839	750	11.9	839	753	11.4
Other products	5,115	5,003	2.2	5,116	5,032	1.7
TOTAL DEMAND	20,823	20,593	1.1	20,823	20,559	1.3
Supply, 1,000 b/d						
Crude production	50,26	5,192	–3.2	5,026	5,196	–3.3
NGL production[2]	2,446	2,273	7.6	2,409	2,250	7.1
Crude imports	10,102	10,101	—	10,102	10,192	–0.9
Product imports	3,295	3,393	–2.9	3,295	3,431	–4.0
Other supply[3]	1,143	949	20.4	1,032	1,048	–1.5
TOTAL SUPPLY	22,012	21,908	0.5	21,863	22,117	–1.1
Refining, 1,000 b/d						
Crude runs to stills	15,080	15,782	–4.4	15,080	14,964	0.8
Input to crude stills	15,251	15,692	–2.8	15,251	15,385	–0.9
% utilization	87.5	90.2	—	87.5	88.1	—

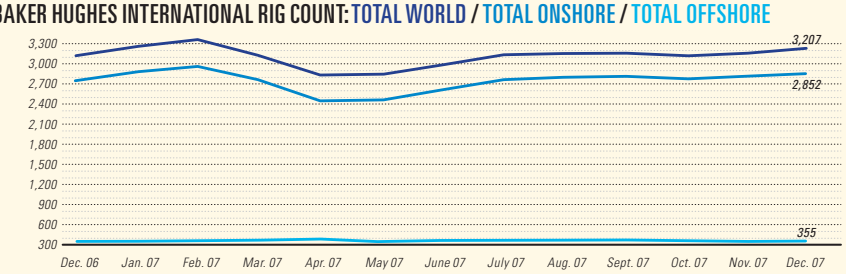
Latest week 1/25	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	292,952	289,237	3,555	324,927	–31,975	–9.8
Motor gasoline	223,899	220,341	3,558	224,614	–715	–0.3
Distillate	127,004	128,543	–1,539	39,977	–12,973	–9.3
Jet fuel-kerosine	40,609	39,752	857	40,220	389	1.0
Residual	35,351	38,540	–3,009	44,136	–8,605	–19.5
Stock cover (days)[4]			Change, %		Change, %	
Crude	19.4	19.0	2.1	21.5	–9.8	
Motor gasoline	24.7	24.0	2.9	24.7	—	
Distillate	29.9	30.0	–0.3	33.7	–11.3	
Propane	24.7	26.8	–7.8	31.8	–22.3	

Futures prices[5] 2/1			Change		Change	%
Light sweet crude, $/bbl	91.13	89.24	1.89	55.02	36.11	65.6
Natural gas, $/MMbtu	7.99	7.77	0.22	7.28	0.71	9.8

[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average of daily closing futures prices.

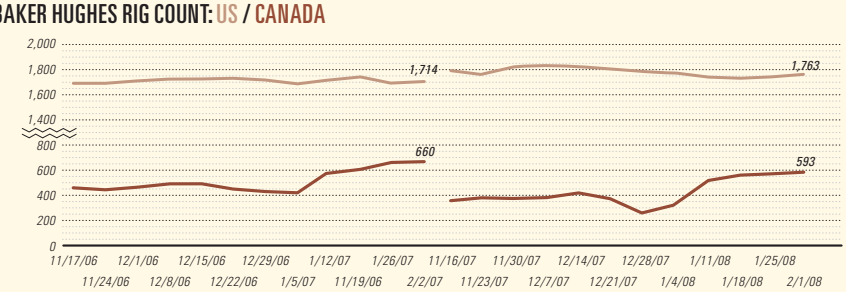
Sources: Energy Information Administration, Wall Street Journal

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

and Wildlife Service, is considering listing as an endangered species. Interior Secretary Dirk A. Kempthorne and other DOI officials have said that the threat comes from melting sea ice and that the bears already have strong safeguards under the Marine Mammal Protection Act. Lease terms will include stringent environmental provisions, MMS Director Randall L. Luthi noted.

Oil industry and other groups expressed their support for the sale on Feb. 6. The American Petroleum Institute called it "a welcome first step toward increasing much-needed energy supplies for US consumers and the US economy."

Meanwhile, National Association of Manufacturers Pres. John Engler said production from the Chukchi Sea would reduce US dependence on foreign sources.

The US Oil & Gas Association said the area's oil and gas resources represent an important domestic energy opportunity that should not be ignored.

Shell makes oil find at Vicksburg in eastern gulf

Shell Oil Co. has made an oil discovery at the Vicksburg prospect in 7,500 ft of water on DeSoto Canyon Blocks 353 and 397 and Mississippi Canyon Block 393, in the eastern Gulf of Mexico.

The well was drilled to a depth of 25,400 ft and found a 300-ft hydrocarbon column. Transocean's semisubmersible Deepwater Nautilus, on contract to Shell, drilled the well.

Shell is operator of Vicksburg with a 57.5% interest. Vicksburg partners are Nexen Inc. 25% and Plains Exploration & Production Co. 17.5%.

BP has 15th oil discovery on Block 31 off Angola

Sonangol EP and BP Exploration (Angola) Ltd., operator, have reported the Portia oil discovery on ultradeepwater Block 31, off Angola. Well test results confirmed the capacity of the reservoir to flow more than 5,000 b/d under production conditions, BP said.

The well lies 7 km north of the Titania discovery and 10.5 km southwest of Plutao field. Portia is the 15th discovery BP has drilled on Block 31. Portia was drilled in 2,012 m of water 386 km northwest of Luanda. It reached 5,678 m TVD subsea. This is the fourth discovery on Block 31 in which the exploration well was drilled through salt to access an oil-bearing sandstone reservoir beneath.

Although oil deposits are commonly associated with salt, salt distorts seismic images, so salt-affected areas require additional seismic processing and interpretation prior to drilling.

Sonangol is the concessionaire of Block 31, which covers 5,349 sq km and lies in 1,500-2,500 m of water. BP holds 26.67%. Other interest owners are Esso Exploration & Production Angola (Block 31) Ltd. 25%, Sonangol 20%, Statoil Angola AS 13.33%, Marathon International Petroleum Angola Block 31 Ltd. 10%, and Total Group subsidiary Tepa Block 31 Ltd. 5%.

Chevron completes Big Foot in deepwater gulf

Chevron Corp. reported the successful completion of an appraisal well at its Big Foot prospect in the deepwater Gulf of Mexico. Big Foot lies in more than 5,000 ft of water on Walker Ridge Block 29, about 225 miles south of New Orleans and 180 miles offshore.

The appraisal well, Big Foot No. 3, Sidetrack No. 2, confirmed the same pay intervals of the previously announced discovery and sidetrack wells, and found the main pay sand full of oil to the base, Chevron said.

Operated by a Chevron subsidiary, the appraisal well reached a measured depth of 25,113 ft (including water) to the northwest of, and deeper than, the previous wells. Chevron is evaluating a range of production development options for the Big Foot prospect.

Chevron owns a 60% working interest in Big Foot. Partners are StatoilHydro AS 27.5% and Shell Gulf of Mexico Inc. 12.5%. ✦

Drilling & Production — *Quick Takes*

PDVSA pays Total, StatoilHydro for Orinoco items

Venezuela will pay $1.1 billion in compensation to StatoilHydro AS and France's Total SA for its nationalization of an oil project they previously controlled.

State-owned Petroleos de Venezuela SA (PDVSA) agreed to pay its partners for their reduced stakes in the Sincor heavy oil venture with a combination of crude oil and cash.

However, Total and StatoilHydro must pay some $130 million of their compensation as a "bonus" to fund the new Sincor joint venture company.

After that deduction, Total will receive $735 million in the form of quarterly crude oil shipments, while Statoil will receive $235 million in cash.

President Hugo Chavez's government last May took over majority stakes in heavy oil upgrading projects located along the Orinoco River basin operated by four international oil companies.

While StatoilHydro and Total agreed to remain as minority partners under new arrangements with the government, ConocoPhillips and ExxonMobil Corp. declined to accept the government offer.

PDVSA has not announced any results of its compensation talks with the two US firms, but reports suggest that the Venezuelan firm is exploring all forms of compensation including payment in crude.

Meanwhile, StatoilHydro signed an agreement with Venezuela to quantify the reserves of the Junin 10 block in the Orinoco belt with a view to developing them.

A local StatoilHydro official said the firm sees enormous reserves potential in the country.

Chavez wants the Orinoco belt reserves certification process completed by 2010. He hopes that certification will boost his country's reserves to more than 300 billion bbl from the current 100 billion bbl.

Regardless of the amount of reserves, however, Orinoco oil will be a boost to the country's output potential and earnings.

Falling outside of the quota system of the Organization of Petroleum Exporting Countries, to which Venezuela belongs, Orinoco's heavy oil reserves would enable Chavez to ramp up production and sales without the need for any authorization from OPEC.

BPZ Energy-chartered tanker sinks off Peru

A Peruvian Navy tanker chartered by BPZ Energy Inc. of Houston caught fire and sank on Jan. 30. The tanker, Supe, which was moored near the Corvina CX-11 platform in Corvina field off Peru, was being used for oil storage.

At the time of the accident, it held 1,300 bbl of oil, most of which is believed to have burned in the fire. The tanker had a capacity of 7,500 bbl.

"Initial assessments show that environmental issues have been adequately controlled," BPZ said. A full investigation is under way, the company said.

The Supe tanker sank about 1½ miles from the platform, which started production Nov. 1, 2007 (OGJ, Dec. 10, 2007, p. 22).

The tanker stored oil produced from the 21XD and 14D wells. Current production, 4,200 b/d of oil, and the testing operations on the 18XD well were temporarily suspended.

Initial reported indicated no damage to the platform, barges, drilling, and well-testing equipment.

BPZ said damage appears to have been limited mostly to the tanker, which was moved farther away from the platform after catching fire.

Twelve Peruvian Navy sailors working aboard the tanker were injured and evacuated to area hospitals. Two sailors were treated and released while 10 sailors were evacuated to Lima via a Peruvian Navy hospital plane. ✦

Processing — *Quick Takes*

Sinopec, Sabic plan petrochemical plant in China

China Petroleum & Chemical Corp. (Sinopec) and Saudi Basic Industries Corp. (Sabic) have signed a nonbinding document outlining the main issues for a tentative 50-50 joint venture to build a $1.7 billion ethylene derivatives complex in Tianjin, China.

The proposed complex would produce 1 million tonnes/year of ethylene derivatives—600,000 tonnes/year of polyethylene and 400,000 tonnes/year of ethylene glycol—and is proposed to be completed by September 2009. All of its ethylene feedstock would be supplied by Tianjin Petrochemical Co., a branch of Sinopec.

This would be Sabic's first JV in China. Company officials said China is an important market for Sabic, which hopes to become one of the world's top petrochemical companies by 2020.

Petroecuador, PDVSA plan refinery in Ecuador

Ecuador and Venezuela plan to jointly finance and build a 300,000 b/d refinery in Ecuador's coastal province of Manabi, according to Ecuador's Mines and Oil Ministry.

The ministry said representatives of state oil companies Petroecuador of Ecuador and PDVSA of Venezuela met in Quito, Ecuador, to discuss project details.

"The group analyzed the legal aspects to constitute the mixed economies enterprise and drafted the schedule for preparing the documents," to ensure that the representatives of both companies could sign the contract in March, the ministry said.

Plans call for the completion of a feasibility study for the project in June, with construction to be completed within 4 years. No date for the start of construction was provided.

Ecuador's oil minister Galo Chiriboga Zambrano said the refinery will be financed equally by the two countries and supplied largely with crude from Ecuador. "But later on, it would (use) Venezuelan oil when ours is depleted," the minister said.

Sinopec to upgrade Changling, Baling refineries

China Petroleum & Chemical Corp. (Sinopec) will invest about $2.2 billion to raise the production capacity of two domestic refineries.

The announcement came as Chinese officials, who have pledged a better system of supply, scrambled to meet growing domestic demand in the face of a particularly cold winter.

Sinopec will spend about $1.4 billion in expanding its Changling refinery in central China's Hunan province, by doubling its production capacity to 10 million tonnes/year.

It will spend an additional $834.3 million to upgrade its Baling plant, which processes oil from Changling into chemicals.

The move follows the central government's pledge to meet rising domestic fuel demand. The Chinese state-owned refiners are required to ensure the supply after transportation systems in many provinces were disrupted by the snowstorms.

The upgrade announcement came as Chinese officials struggled to cope with their country's worst winter storms in decades.

The China Meteorological Administration said the bad weather, including more snow, was expected to continue for at least the next 3 days in parts of eastern and southern China.

"Guizhou, Jiangsu, and Shandong have suffered their worst snowfalls in 50 years," the administration said. For Hunan and Shaanxi provinces, it was the worst in 20 years.

Sinopec's upgrade also coincided with reports that China reached new highs for oil production, imports, and consumption in 2007.

In 2007 China produced 186.7 million tonnes of crude, up 1.6% from 2006, while its net oil imports were 159.28 **million** tonnes, up 14.7%.

The country's oil consumption, representing the sum of net imports plus output, rose 7.3% to 346 million tonnes in 2007, meaning that that imports account for about 46% of China's oil consumption.

China refined 326.79 million tonnes of crude in 2007, representing a growth of 6.4%—about the same as the 6.3% recorded in 2006.

The output of refined oil products, comprised of gasoline, diesel, and kerosine, stood at 195 million tonnes, up 7.2% year-on-year or about 2.5% higher than in 2006.

Officials said that the diesel shortage that occurred in the country in second half 2007 led to an especially sharp rise in diesel imports, rising by 130.1% to 1.62 million tonnes, while diesel exports fell by 14.9% to 660,000 tonnes. ✦

Transportation — *Quick Takes*

Bechtel to build Angola's first LNG plant

Angola LNG Ltd. is planning Angola's first gas liquefaction facility near Soyo in Zaire Province. The LNG plant will have a nominal capacity of 5.2 million tonnes/year of LNG and will include storage for LNG, LPG, and condensate; and a loading jetty sized to accommodate ships as large as 210,000 cu m. A subsidiary of the Bechtel group will construct the plant.

The project is an integrated gas utilization project encompassing offshore and onshore operations monetizing gas from blocks off Angola. First LNG from the project is expected by early 2012 (OGJ, Jan. 7, 2008, p. 21).

Angola LNG Ltd. has licensed ConocoPhillips's proprietary natural gas liquefaction technology. "The Bechtel-ConocoPhillips proposal was selected as the successful bid following a comprehensive evaluation of two competitive proposals submitted following the front-end engineering design (FEED) competition for the LNG facility," said Ken Marrs, Angola LNG Ltd. project manager.

Angola LNG Ltd. shareholders are affiliates of Sonangol 22.8%, Chevron Corp. 36.4%, BP PLC 13.6%, Total SA 13.6%, and Eni SPA 13.6%.

Singapore to build LNG terminal by early 2009

Construction of a planned $1 billion LNG regasification terminal in Singapore is expected to begin by late this year or early 2009 to enable the city-state to begin importing LNG by late 2011-early 2012, according to a senior official (OGJ, Oct. 1, 2007, Newsletter).

S. Iswaran, Minister of State for Trade and Industry, said Singapore needs to move forward with LNG as an important part of its policy to diversify energy sources. Currently, Singapore depends on natural gas piped in from neighboring Malaysia and Indonesia.

Iswaran said PowerGas, the wholly owned subsidiary of Singapore Power, has made good progress toward the construction start and should be able to make some critical decisions shortly.

PowerGas has been identifying core capabilities needed for the expansion, Iswaran added, and they are assessing partnerships to enhance expertise within the consortia in order to develop the terminal. "After selecting partners and completing the complex design process...they will need to start actual work by the end of this year or early next year," to meet the import target, he said.

Iswaran's remarks came after an announcement by the country's Energy Market Authority that it had short-listed five groups competing to be the sole LNG importer-consortium from a total of 18 proposals involving 22 companies. EMA did not disclose their identities due to requests for confidentiality. Selection is slated for the second quarter.

The market response was promising, Iswaran said, and Singapore had "very strong" proposals from the diverse organizations.

W. Australia assesses common-use LNG hub

Western Australia and Australia's new Kevin Rudd-led federal government have agreed to assess the Kimberley region of Western Australia as a site for a common-user LNG hub and associated regional activities to serve proposed gas fields to be developed in the offshore Browse basin.

Their aim is to prevent piecemeal development following an environmentalist outcry in 2007 at proposals by Woodside Petroleum, Inpex, and others to establish LNG plants at several locations on the Kimberley coast or on offshore islands. The region is regarded as a pristine wilderness, and public opinion is that it should be kept that way.

Industry sources appear relatively comfortable with the government initiative as long as the companies concerned are involved in the consultation process.

The Australian Petroleum Production & Exploration Association said the industry would like a list of potential sites by mid-2008 and a final decision by yearend. APPEA does not want to see the process stalled by "green politics."

The companies involved are aware of the pristine nature of the environment but know that differing distances of the offshore gas fields from the coast will mean that each company will prefer different sites. None wants to see a competitive advantage given to another. The single hub plan also raises the question of potentially massive public infrastructure investment to ensure that facilities such as ports, roads, and other access resources remain available to all users.

The single hub proposal will build on work already performed by Western Australia's Northern Development Taskforce, which has been attempting to achieve a balance between Browse basin development and environmental and heritage interests.

NNPC sets up shipping firm for Nigerian LNG

Nigerian National Petroleum Corp. has established a new shipping company, Nikorma Shipping Services Ltd., to handle the additional volume of Nigerian LNG exports expected in the coming years.

NNPC, which has taken a 51% holding in the venture, plans to reduce this to 30%, offering the remaining shares to private Nigerian investors.

NNPC established Nikorma Shipping with shareholder participation from MISC Bhd., Hyundai Heavy Industries Co. Ltd., and local shipping and logistics firm Deepwater Shipping & Maritime Co. Ltd. MISC will have a 30% holding, HHI 11.5%, and DSMC 7.5%.

Nigeria's LNG exports are projected to rise to 60 million tonnes/year from a current level of 17.9 million tonnes/year over the next 5 years.

Enbridge's N. Dakota line expansion in service

Enbridge Energy Partners LP has begun service on its recently completed Phase 5 oil transmission system expansion in North Dakota that increased the system's capacity to 110,000 b/d.

The $78 million project added 30,000 b/d of capacity, with 52 miles of loop on the existing gathering system, 10 new or upgraded pump stations, and additional tankage.

An additional 51,000 b/d of capacity is planned in Phase 6, which would bring total system capacity to 161,000 b/d by early 2010. ✦

Calendar

✦ Denotes new listing or a change in previously published information.

OIL&GAS JOURNAL online

Additional information on upcoming seminars and conferences is available through OGJ Online, Oil & Gas Journal's Internet-based electronic information source at http://www.ogjonline.com.

2008

FEBRUARY

SPE Unconventional Reservoirs Conference, Keystone, Colo., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

International Pipeline Pigging & Integrity Management Conference & Exhibition, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: clarion@clarion.org, website: www.clarion.org. 12-14.

Deep Offshore Technology International Conference & Exhibition, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 12-14.

SPE International Formation Damage Control Symposium & Exhibition, Lafayette, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 13-15.

Alternative Fuels Technology Conference, Prague, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: Conferences@EuroPetro.com. website: www.europetro.com. 18.

IP Week, London, +44 (0)20 7467 7100, +44 (0)20 8561 0131 (fax), e-mail: events@energyinst.org.uk, website: www.ipweek.co.uk. 18-21.

International Catalyst Technology Conference, Prague, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: Conferences@EuroPetro.com. website: www.europetro.com. 19-20.

Pipe Line Contractors Association Annual Conference (PLCA), Maui, (214) 969-2700, (214) 969-2705 (fax), e-mail: plca@plca.org, website: www.plca.org. 20-24.

International Petrochemicals & Gas Technology Conference & Exhibition, Prague, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: Conferences@EuroPetro.com. website: www.europetro.com. 21-22.

AAPG Southwest Section Meeting, Abilene, Tex., (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 24-27.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-3136, (405) 325-7329 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 24-27.

Middle East Refining Conference & Annual Meeting, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 25-26.

CERI Natural Gas Conference, Calgary, Alta., (403) 220-2380, (403) 284-4181 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 25-26.

SPE Intelligent Energy Conference & Exhibition, Amsterdam, (972) 952-9393, (972)

952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 25-27.

IADC Drilling HSE Asia Pacific Conference & Exhibition, Kuala Lumpur, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 26-27.

Middle East Fuels Symposium, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 27-28.

MARCH

GPA Annual Convention, Grapevine, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 2-5.

GEO Middle East Geosciences Conference & Exhibition, Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), (fax), e-mail: geo@oesallworld.com, website: www.allworldexhibitions.com. 3-5.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 3-5.

NPRA Security Conference, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 4-5.

ARTC Annual Meeting, Bangkok, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 4-6.

Global Petrochemicals Annual Meeting, Dusseldorf, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 4-6.

IADC/SPE Drilling Conference & Exhibition, Orlando, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 4-6.

SPE Indian Oil & Gas Technical Conference & Exhibition, Mumbai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

Annual Middle East Gas Summit, Doha, +971 4 336 2992, +971 4 336 0116 (fax), e-mail: sarita.singh@ibc-gulf.com, website: www.ibcgulfconferences.com. 5-6.

NPRA Annual Meeting, San Diego, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 9-11.

World Heavy Oil Congress, Edmonton, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 10-12.

New Zealand Petroleum Conference, Auckland, +64 3 962 6179, +64 4 471 0187 (fax), e-mail: crown.minerals@med.govt.nz, website: www.crownminerals.govt.nz. 10-12.

Gastech International Conference & Exhibition, Bangkok, +44 (0) 1737 855005, +44 (0) 1737 855482 (fax), e-mail: tonystephenson@dmgworldmedia.com, website: www.gastech.co.uk. 10-13.

API Spring Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 10-14.

European Fuels Conference & Annual Meeting, Paris, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 11-12.

IADC International Deepwater Drilling Conference & Exhibition, Rio de Janeiro, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 11-12.

SPE North Africa Technical Conference & Exhibition, Marrakech, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 12-14.

NACE International Conference & Expo, New Orleans, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org. 16-20.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoreasiaevent.com. 17-19.

Sub-Saharan Oil, Gas & Petrochemical Exhibition & Conference, Cape Town, +27 21 713 3360, +27 21 713 3366 (fax), e-mail: expo@fairconsultants.com, website: www.fairconsultants.com. 17-19.

Turoge and Black Sea Oil & Gas Exhibition & Conference, Ankara, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 18-20.

AAPG Prospect & Property Expo (APPEX), London, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 24-26.

AAPG Pacific Section Meeting, Bakersfield, Calif., (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. Mar. 29-Apr. 2.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. Mar. 30-Apr. 1.

SPE Middle East Petroleum Engineering Colloquium, Dubai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 30-Apr. 2.

PIRA Understanding Global Oil Markets Conference, Tokyo, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. Mar. 31-Apr. 1.

ERTC Sustainable Refining Conference, Brussels, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Mar. 31–Apr. 2.

APRIL

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 1-2.

ERTC Biofuels+ Conference, Brussels, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

GIOGIE Georgian International Oil & Gas Conference & Showcase, Tbilisi, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-4.

Middle East Petroleum & Gas Conference, Doha, +65 6222 0230, +65 6222 0121 (fax), e-mail: mpgc@cconnection.org, website: www.cconnection.org. 6-8.

Calendar

ACS National Meeting & Exposition, New Orleans, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 6-10.

American Institute of Chemical Engineers (AIChE) Spring National Meeting, New Orleans, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 6-10.

CIOGE China International Oil & Gas Conference, Beijing, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-8.

API Pipeline Conference & Cybernetics Symposium, Orlando, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 7-10.

EAGE Saint Petersburg International Conference & Exhibition, Saint Petersburg, +7 495 9308452, +7 495 9308452 (fax), e-mail: eage@eage.ru, website: www.eage.nl. 7-10.

IADC Well Control Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

ENTELEC Annual Conference & Expo, Houston, (888) 503-8700, website: www.entelec.org. 9-11.

North Caspian Regional Atyrau Oil & Gas Exhibition & Petroleum Technology Conference, Atyrau, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 9-11.

API Spring Refining & Equipment Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 14-16.

API/NPRA Spring Operating Practices Symposium, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 15.

SPE Gas Technology Symposium, Calgary, Alta., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

SPE International Health, Safety & Environment Conference, Nice, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

GPA Midcontinent Annual Meeting, Okla. City, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 17.

AAPG Annual Convention & Exhibition, San Antonio, 1 (888) 945 2274, ext. 617, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org/sanantonio. 20-23.

SPE Improved Oil Recovery Symposium, Tulsa, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

ERTC Coking & Gasification Conference, Rome, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 21-23.

WestAsia Oil, Gas, Refining, & Petrochemicals Exhibition & Conference, Oman, +968 24790333, +968 24706276 (fax), e-mail: clemento@omanexpo.com, website: www.ogwaexpo.com. 21-23.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), website: http://turbolab.tamu.edu. 21-24.

SPE Progressing Cavity Pumps Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27-29.

MAY

IOGCC Midyear Meeting, Calgary, Alta., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

PIRA Canadian Energy Conference, Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 5.

API International Oil Spill Conference, Savannah, Ga., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 5-8.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 5-8.

GPA Permian Basin Annual Meeting, Odessa, Tex., , (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 6.

PIRA Understanding Global Oil Markets Conference Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 6-7.

ERTC Asset Maximization Conference, Lisbon, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 12-14.

International School of Hydrocarbon Measurement, Oklahoma City, (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu, website: www.ishm.info. 13-15.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 13-15.

NPRA National Safety Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 14-15.

IADC Drilling Onshore America Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15.

SPE Digital Energy Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: service@spe.org, website: www.spe.org. 20-21.

Mediterranean Offshore Conference & Exhibition (MOC), Alexandria, Egypt, + 39 0761 527976, + 39 0761 527945 (fax), e-mail: st@ies.co.it, website: www.moc2008.com. 20-22.

NPRA Reliability & Maintenance Conference & Exhibition, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 20-23.

Society of Professional Well Log Analysts (SPWLA) Annual Symposium, Edinburgh, (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 25-28.

Middle East Refining and Petrochemicals Conference & Exhibition, Bahrain, +973 1755 0033. +973 1755 3288 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com. 26-28.

SPE International Oilfield Corrosion Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27.

SPE International Oilfield Scale Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-29.

JUNE

ERTC Management Forum, Copenhagen, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

Caspian Oil & Gas Exhibition & Conference, Baku, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-6.

Oklahoma Independent Petroleum Association (OIPA) Annual Meeting, Dallas, (405) 942-2334, (405) 942-4636 (fax), website: www.oipa.com. 6-10.

SPEE Society of Petroleum Evaluation Engineers Annual Meeting, Hot Springs,Va., (713) 651-1639, (713) 951-9659 (fax), e-mail: bkspee@aol.com, website: www.spee.org. 7-10

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 9.

Asian Geosciences Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7862 2136. +44 (0) 20 7862 2119, e-mail: geoasia@oesallworld.com, website: www.geo-asia.com. 9-11.

Independent Liquid Terminals Association (ILTA) Annual Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 9-11.

SPE Tight Gas Completions Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 9-11.

EAGE/SPE EUROPEC Conference & Exhibition, Rome, +31 30 6354055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.nl. 9-12.

ASME Turbo Expo, Berlin, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 9-13.

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 10.

Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com. 10-12.

Global Petroleum Show, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 10-12.

IADC World Drilling Conference & Exhibition, Berlin, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 11-12.

PIRA Understanding Global Oil Markets Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 11-12.

Asia's Subsea Conference & Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: subsea@oesallworld.com, website: www.subseaasia.org. 11-13.

CIPC/SPE GTS Joint Conference, Calgary, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 16-19.

American Association of Professional Landmen (AAPL) Annual Meeting, Chicago, (817) 847-7700, (817) 847-7704(fax), e-mail: aapl@landman.org, website: www.landman.org. 18-21.

LNG North America Summit, Houston, (416) 214-3400, (416) 214-3403 (fax), website: www.lngevent.com. 19-20.

IPAA Midyear Meeting, Colorado Springs, Colo., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 19-21.

PIRA Scenario Planning Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 23.

API Tanker Conference, San Diego, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-24.

API Exploration & Production Standards on Oilfield Equipment & Materials Conference, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-27.

PIRA Understanding Global Oil Markets Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 24-25.

Russian Petroleum & Gas Congress, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

Calendar

NEFTEGAZ Exhibition, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

PIRA's Globalization of Gas Study Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 25.

PIRA Understanding Natural Gas Markets Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 26-27.

World Petroleum Congress, Madrid, +34 91 745 3008, +34 91 563 8496 (fax), e-mail: info@19wpc.com, website: www.19wpc.com. June 29- July 3.

JULY

International Offshore & Polar Engineering Conference, Vancouver, (650) 254 2038, (650) 254 1871 (fax), e-mail: meetings@isope.org, website: www.isope.org. 6-11.

Colorado Oil & Gas Association Conference, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: conference@coga.org, website: www.coga.org. 9-11.

IADC Lifting & Mechanical Handling Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15-16.

Oil Sands and Heavy Oil Technology Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 15-17.

AUGUST

ACS National Meeting & Exposition, Philadelphia, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 17-21.

IADC/SPE Asia Pacific Drilling Technology Conference, Jakarta, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 25-28.

Offshore Northern Seas Exhibition & Conference, Stavanger, +47 51 59 81 00, +47 51 55 10 15 (fax), e-mail: info@ons.no, website: www.ons.no. 26-29.

Summer NAPE Expo, Houston, (817) 306-7171, (817) 847-7703 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

China Power, Oil & Gas Conference & Exhibition, Guangzhou, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.chinasenergyfuture.com. 2-4.

ECMOR XI-European Mathematics of Oil Recovery Conference, Bergen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-11.

IADC Drilling HSE Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

API Fall Refining & Equipment Standards Meeting, Los Angeles, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 15-17.

Rio Oil & Gas Conference & Expo, Rio de Janeiro, 55 21 2112 9078, 55 21 2220 1596 (fax), e-mail: riooil2008@ibp.org.br, website: www.riooilegas.com.br. 15-18.

API/NPRA Fall Operating Practices Symposium, Los Angeles, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 16.

GEO India South Asia's Geosciences Conference & Exhibition, New Delhi, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: geo@oesallworld.com, website: www.geo-india.com. 17-19.

SPE Annual Technical Conference & Exhibition, Denver, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 21-24.

ERTC Petrochemical Conference, Cannes, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Sept. 29- Oct. 1.

International Pipeline Exposition, Calgary, Alta., 403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. Sept. 30-Oct. 2.

Unconventional Gas International Conference & Exhibition, Ft.Worth, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.unconventionalgas.net. Sept. 30-Oct. 2.

OCTOBER

NPRA Q&A Forum, Orlando, Fla., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 5-8.

KIOGE Kazakhstan International Oil & Gas Exhibition & Conference, Almaty, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-10.

IADC Drilling West Africa Conference & Exhibition, Lisbon, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 8-9.

International Gas Union Research Conference, Paris, +31 50 521 30 78, +31 50 521 19 46 (fax), e-mail: igrc2008@gasunie.nl, website: www.igrc2008.com. 8-10.

ERTC Lubes and Additives Conference, Berlin, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 13-15.

API Fall Petroleum Measurement Standards Meeting, Long Beach, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 13-17.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax) website: www.isa.org. 14-16.

PIRA New York Annual Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 16-17.

SPE Asia Pacific Oil & Gas Conference & Exhibition, Perth, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-22.

SPE International Thermal Operations & Heavy Oil Symposium, Calgary, Alta., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

Permian Basin International Oil Show, Odessa, Tex., (432) 367-1112, (432) 367-1113 (fax), e-mail: pbioilshow@pbioilshow.org, website: www.pbioilshow.org. 21-23.

AAPG International Conference & Exhibition, Cape Town, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 26-29.

SPE Russian Oil & Gas Technical Conference & Exhibition, Moscow, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-30.

IADC Contracts & Risk Management Conference, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 29-30.

NOVEMBER

ASME International Mechanical Congress & Exposition, Boston, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 2-6.

Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC), Abu Dhabi, website: www.adipec.com. 3-6.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 4-6.

Mangystau International Oil & Gas Exhibition, Aktau, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 5-7.

IADC Annual Meeting, Paradise Valley, Ariz., (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 6-7.

SEG International Exposition and Annual Meeting, Las Vegas, (918) 497-5542, (918) 497-5558 (fax), e-mail: register@seg.org, website: www.seg.org. 9-14.

IPAA Annual Meeting, Houston, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 10-12.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 11-13.

American Institute of Chemical Engineers (AIChE) Annual Meeting, Philadelphia, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 16-21.

ERTC Annual Meeting, Vienna, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 17-19.

IADC Well Control Middle East Conference & Exhibition, Muscat, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 24-25.

Annual European Autumn Gas Conference (EAGC), Cernobbio, Italy, +44 (0) 1737 855281, +44 (0) 1737 855482 (fax), e-mail: vanessahurrell@dmgworldmedia.

com, website: www.theeagc.com. 25-26.

DECEMBER

IADC Drilling Gulf of Mexico Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

Deep Offshore Technology International Conference & Exhibition, Perth, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepoffshoretechnology.com. 3-5.

International Petroleum Technology Conference (IPTC), Kuala Lumpur, +971 (0)4 390 3540, +971 (0)4 366 4648 (fax), e-mail: iptc@iptcnet.org, website: www.iptcnet.org. 3-5.

PIRA Natural Gas Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 8-9.

PIRA Understanding Global Oil Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 10-11.

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 14-16.

AAPG Annual Convention & Exhibition, San Antonio, 1 (888) 945 2274, ext. 617, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org/sanantonio. 20-23.

XSPE Improved Oil Recovery Symposium, Tulsa, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

XSPE Progressing Cavity Pumps Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27-29.

2009

JANUARY

Oil & Gas Maintenance Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 19-21.

Pipeline Rehabilitation & Maintenance Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.piipeline-rehab.com. 19-21.

SPE Hydraulic Fracturing Technology Conference, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 19-21.

FEBRUARY

ASEG International Conference & Exhibition, Adelaide, +61 8 8352 7099, +61 8 8352 7088 (fax), e-mail: ASEG2009@sapro.com.au. 22-26.

MARCH

GPA Annual Convention, San Antonio, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8-11.

Middle East Oil & Gas Show & Conference (MEOS), Manama, +973 17 550033, +973 17 553288 (fax), e-mail: aeminfo@batelco.com.bh, website: www.allworldexhibitions.com/oil. 15-18.

MAY

ACHEMA International Exhibition Congress, Frankfurt, +1 5 168690220, +1 5 168690325 (fax), e-mail: amorris77@optonline.net, website: http://achemaworldwide.dechema.de. 11-15.

JUNE

Oil and Gas Asia Exhibition (OGA), Kuala Lumpur, +60 (0) 3 4041 0311, +60 (0) 3 4043 7241 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com/oil. 10-12.

OCTOBER

International Oil & Gas Exploration, Production & Refining Exhibition, Jakarta, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: ogti@oesallworld.com, website: www.allworldexhibitions.com. 14-17.

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Texas resources: oil, wind

Sam Fletcher
Senior Writer

In Giant, the 1956 film epic about Texas, there's a scene where James Dean as Jett Rink examines a showing of crude oil swabbed up by the windmill pumping water for his dry West Texas farm. A few scenes later, the windmill is converted into a cable-tool rig and brings in an oil well. Maybe that never happened in real life, but it's an interesting image of two great Texas resources—oil and wind.

Windmills were as vital as the plow and the branding iron in settling Texas and other arid regions of the West during the 19th century. Without mechanically drilled wells and windmills to pump water, settlements would have been limited to areas near surface water sources, leaving large dry sections of the US Midcontinent and Southwest unsettled. Windmills also aided development of railroads that connected the Eastern US to the West by supplying water-stops for steam locomotives.

In 1854-1920 more than 700 companies manufactured tens of thousands of windmills in the US. Many were erected in Texas primarily to water livestock. As cattle sales changed from per head to per pound, ranchers put up even more windmills and stock tanks to prevent cattle from "walking off" weight in search of water. Back in the 1960s when I was a peach-cheeked youth hustling jugs on a geophone crew, those stock tanks were an unofficial job perk for cool swims while the seismic weight-truck was being repaired.

Renewed interest

The spread of electricity to rural areas since the 1930s essentially ended the need for windmills. But high energy prices have renewed public interest in wind power. And once again Texas is at the forefront in redeveloping that energy resource as the state with the most cumulative wind-power capacity installed—4,356 Mw, according to the American Wind Energy Association (AWEA).

Other states with large installed wind-power capacity include California, 2,439 Mw; Minnesota, 1,299 Mw; Iowa, 1,273 Mw; and Washington, 1,163 Mw. "Shattering all its previous records, the US wind energy industry installed 5,244 Mw in 2007, expanding the nation's total wind power generating capacity by 45% in a single calendar year and injecting an investment of over $9 billion into the economy," said AWEA, a national trade association of turbine manufacturers, wind project developers, utilities, and other interested parties.

Wind projects accounted for 30% of the new power-producing capacity in the US last year, enough to provide the equivalent of 1.5 million homes with electric power. Wind farms now span 34 states with 16,818 Mw of capacity. These modern windmills are expected to generate 48 billion kw-hr of power, in 2008, just over 1% of total US electricity, powering 4.5 million homes.

Tax credit for wind

Last year was "the third consecutive year of record-setting growth, establishing wind power as one of the largest sources of new electricity supply for the country," said AWEA Executive Director Randall Swisher. That growth was "driven by strong demand, favorable economics, and a period of welcome relief from the on-again, off-again, boom-and-bust cycle of the federal production tax credit (PTC) for wind power," he said.

The PTC provides a per-megawatt tax credit on the sale of electricity generated by wind power. Congress has let the PTC expire several times, only to renew it retroactively. The PTC is due to expire again in 2008, but wind power advocates want it extended for 15 years to provide "more certainty" to sustain investments in wind energy. By reducing the use of natural gas and other fossil fuels to generate electricity, modern windmills will serve customers "even in regions with low or no wind resources," AWEA said.

The oil and gas industry generally has accepted a policy of sustainable energy that makes use of all available energy resources. However, John Westwood, managing director of UK consultancy Douglas-Westwood Ltd., said the oil and gas industry already is competing with the wind industry for materials and personnel for offshore operations, primarily overseas. Some $16 billion is expected to be spent on installation of 4.5 Gw of new wind-power capacity in Europe over the next 5 years, up from 1.1 Gw today. The UK will be the biggest market, with 2.4 Gw of new capacity forecast in 2012. "Serious amounts of steel are heading offshore," said Westwood. "Offshore wind and oil and gas are competing for the same resources and with onshore wind power." ✦

Editorial

Alberta's economic realism

Environmental imperative has arrived once more at its inevitable intersection with economic realism. For the rest of the world, navigation through the impasse in Canada will be instructive.

Canada's federal government has set ambitious targets for lowering emissions of greenhouse gases (GHGs). In a policy statement called "Turning the Corner," it pursues cuts during 2006-20 of 20% and through 2050 of 60-70%. The program requires emission reductions at the company level. Companies can lower emissions at their facilities, invest in emission-reducing technology, trade emission allowances, and use the Kyoto Treaty's "clean development mechanism," which credits a company in one country for lowering emissions in another.

'Low-emissions society'

The National Round Table on the Environment and the Economy recently elaborated on this federally specified "transition to a low-emissions society." It recommends that the government "implement a strong, clear, consistent, and certain GHG emission price signal across the entire Canadian economy as soon as possible." It calls for an emission tax or cap-and-trade system or both. For parts of the economy that don't respond to the price signal or "where market failures exist," it suggests "complementary regulatory policies."

Governments proceed this way when they let the environmental imperative of GHG reduction supersede other interests. The approach follows that of the Kyoto Treaty, embraced most enthusiastically in Europe. Its emission targets are aggressive, as they must be for any program trying to stabilize atmospheric concentrations of GHGs. In fact, as the Kyoto experiment shows, they're futile. When the high costs of aggressive emission cuts become clear, economic realism awakens to breed political resistance. A lurking political complication is the lack of assurance that lowering human emissions of GHGs can alter global average temperature.

The conflict is fully developed in Alberta, where GHG regulation falls heavily on an eminent generator of wealth. The oil sands industry already faces a full menu of problems, including leaping costs, Alberta's newly increased royalty rate, labor and material shortages, questions about fuels and electric power, limits on water supply, and a range of environmental issues other than GHG emissions. Even with crude oil prices high, profit margins of the oil sands industry remain under pressure. New costs from toughened GHG regulation can't help.

Refusing to let environmental imperative supersede provincial interests, Alberta's government recently steered away from the federal path on GHG policy. It calls for a 14% cut in emissions of carbon dioxide against 2005 levels by 2050, with all reductions coming after 2020. Allowing emissions to rise until then accommodates expected increases in production of bitumen and heavy oil. It also angers all-or-nothing environmentalists. But Alberta's modified approach makes room for economic realism. In January, Alberta Premier Ed Stelmach told reporters, "It would be very difficult to bring in real reductions, immediate reductions, without devastating the economy and the quality of life of Albertans."

Alberta's GHG program further differs from its federal counterpart by eschewing new emission targets for companies and concentrating instead on CO_2 capture and storage. Critics of the approach naturally argue that the method hasn't been widely employed. That's true. But the technology is at hand. A task force with representatives from the Albertan and federal governments has just published a program for using it.

Capture and storage

The EcoEnergy Carbon Capture and Storage Task Force calls for total cuts in GHG emissions of 5 megatonnes/year from three to five capture-and-storage projects by 2015. Oil sands projects are obvious candidates. The task force further recommends that federal and provincial governments supplement industry investments in the initial projects with funding of as much as $2 billion. And it calls for follow-up work and funding for subsequent capture-and-storage initiatives. Ultimately, it says, projects of that type might reduce Canadian CO_2 emissions by 600 megatonnes/year—40% of the projected cuts for 2050.

CO_2 capture and storage can't eliminate the costs of GHG reduction. They do, however, represent a high-volume option that might keep costs under control and align environmental imperatives with economic realism. Alberta and Canada have a chance to show the world how to make such an option work. ✦

Mature UK sector sets pace for N. Sea decommissioning

Uchenna Izundu
International Editor

While decommissioning of platforms in the mature UK North Sea represents a looming problem for oil and gas producers, high commodity prices and new technology are extending the lives of some equipment.

Many operators have delayed decommissioning over the past 4 years because continuing production makes economic sense. Extending platform lives has encouraged development of small, otherwise uneconomic fields via tie-backs.

Even so, North Sea production platforms and other offshore structures eventually will have to be removed at the end of their economic lives. Of the two main producing sectors, the need is more imminent on the mature UK side, where equipment already is retiring and where companies and trade groups actively grapple with associated financial, regulatory, and operational issues.

Off Norway, less mature as a producing province, the main difficulties are expected to be removal of concrete gravity-based structures, high costs for heavy lifters, and a lack of new technologies. Norway doesn't have an official timetable for abandonment, and the variables of timing, new technologies, and the feasibility of plans make it hard to estimate costs.

North Sea requirements for total removal of offshore structures represent a decommissioning approach very different from that of the US, where hurricanes have complicated questions about handling equipment that no longer can be used.

UK needs

In the North Sea, the UK sector presents the most imminent decommissioning needs.

According to Oil & Gas UK, the trade association, of 470 offshore installations on the UK Continental Shelf (UKCS), an estimated 10% are floating structures, 30% are subsea, 50% are small steel, and 10% are large steel or concrete. Each type of structure requires its own decommissioning method.

The group estimates decommissioning costs of the UKCS, with 25 billion boe of oil and gas yet to be recovered, at £15-20 billion. The total might rise further depending on technology, product costs, and timing.

In addition to platforms and similar structures, the UKCS has 10,000 km of pipelines, 15 onshore terminals, and 5,000 wells that eventually must be decommissioned.

Of 400-500 fields on the UKCS, fewer than 100 have financial provisions

in place to cover decommissioning, according to Oil & Gas UK.

Financial questions

UKCS decommissioning requirements have raised a number of financial questions.

Concern has arisen that some of the independent producers that in recent years have replaced major operators might not be able to meet financial requirements of decommissioning under British law. A requirement for bank letters of credit has proven to be costly for some companies.

The government wants to ensure that it doesn't pay for decommissioning if companies default as it nearly had to do with Ardmore (formerly Argyll) oil field in 2005 (OGJ, Aug. 22, 2005, p. 45).

Operators have suggested different means to tackle the financial security issue.

One would be to set up a "sinking" fund for decommissioning costs, but tax relief would be required to make it successful.

Under another recommendation, companies would set up an insurance club through which members could effectively insure each other against their liability.

Subsidiary companies want the government to be satisfied with guarantees from parent firms to cover decommissioning costs, but so far this proposal has been rejected.

Oil companies have other decommissioning-liability concerns.

Under the Petroleum Act 1998, any company that has had an interest in an offshore installation must propose a decommissioning plan, even if it sells its interest or the entire asset to another company. Under Section 34, the government can call back a company for decommissioning even if it was exempted under special circumstances.

This, of course, raises additional financial obligations and other responsibilities.

Operators also are concerned because they are liable in perpetuity to monitor the environment when structures are left on the seabed after decommissioning. One industry source told OGJ the liability "contains more work than is strictly desirable."

Difficult execution

Executing decommissioning plans is difficult because of shortages of skilled personnel and of heavy-lift vessels able to handle structures weighing more than 10,000 tonnes.

Further, because decommissioning is a relatively new activity in the North Sea, operators are still learning from experience.

Three major projects are under way in the North Sea: BP PLC's North West Hutton platform in the UK sector, Total SA's Frigg platforms straddling the UK and Norwegian boundary, and ConocoPhillips's Ekofisk-1 platform in Norwegian waters (see sidebar).

All of these problems are hindering asset trading among companies, which jeopardizes investment in the UK North Sea.

"The costs of decommissioning have risen sharply over the last few years," said Malcolm Ricketts, senior analyst for Europe energy research at Wood Mackenzie Ltd., Edinburgh.

Ricketts also cites increases in the costs of drilling, operating facilities, and abandonment as well as uncertainty about the future direction of the OSPAR Commission, which administers the 1992 Convention for the Protection of the Marine Environment of the Northeast Atlantic.

"Right now, although OSPAR's Decision 98/3 requires the complete removal of all offshore installations, companies can apply for a derogation to allow part of a structure to be left in place on the grounds of safety and/or technical limitations," Ricketts said. "This exemption may be applied for if a structure weighs more than 10,000 tonnes above sea level. If this threshold is increased, then this could become more challenging for companies."

Energy bill provisions

The new UK energy bill empowers the UK secretary of state to seek financial information and security for decommissioning at an earlier stage than previously required (OGJ, Jan. 21, 2008, p. 40).

This is significant because of the influx of small producers. According to legal firm Herbert Smith, "These do not amount to an overhaul of the current decommissioning regime; rather, they are an enhancement of the current regime to give the government greater comfort that decommissioning obligations will be met in the future and will not fall on the government or the taxpayer."

Moreover, Herbert Smith said: "Costs of obtaining and maintaining security for decommissioning will need to be factored into companies' plans earlier than they might otherwise have been. Those persons potentially subject to a Section 29 notice [of Petroleum Act 1998] will need to review and assess their preparedness to meet the requirements of the decommissioning regime proposed by the bill." Petroleum Act 1998's Section 29 covers decommissioning responsibilities (OGJ, Oct. 22, 2007, p. 30).

Tax relief problems

Operators were also uncertain about tax relief they would receive to offset decommissioning costs, particularly as the UK tax regime has changed several times in the past 5 years. Industry tax payments reached £9 billion in 2006.

According to Derek Leith, head of oil and gas tax at Ernst & Young, the current tax law permits a 3-year carryback of losses in relation to decommissioning expenditure. This encouraged companies to decommission their fields early while they still had profits to help absorb the costs.

Following an industry consultation last fall that evaluated the fiscal elements of decommissioning, the law will change to allow producers to extend their loss carry-back period to 2002 to offset decommissioning costs, instead of 3 years as before, Leith said (OGJ Online, Dec. 4, 2007).

Three major North Sea decommissioning projects under way

There are a number of decommissioning projects currently under way in the North Sea. Three major projects are BP PLC's North West Hutton platform in the UK sector, Total SA's Frigg platforms, which straddle the UK-Norwegian boundary, and ConocoPhillips's Ekofisk-1 platform in Norwegian waters.

BP PLC and its partners have awarded a contract for the removal and disposal of the North West Hutton installation in the UK sector of the North Sea. Photo from BP.

North West Hutton

BP's North West Hutton platform produced 125 million bbl of oil between 1983 and January 2003. A heavy-lift vessel will remove the 20,000-tonne topsides and the 17,000-tonne steel jacket down to the tops of the footings (OGJ, June 20, 2005, p. 51). The units will be moved to the Able yard on Teesside for recycling and disposal and the decommissioning work will be completed next year.

This decommissioning project will use new cutting tool technology to remove a steel jacket structure of this weight, which sits in 140 m of water. After this work is finished, Heerema and subcontractors will decommission the pipeline, clear debris, and inspect the platform site.

A BP spokesman told OGJ that it will start decommissioning in the second quarter. "We did the well abandonment phase some years back when the field was still operational. We cleaned up the topsides to make them hydrocarbon free. This project has never been done before and we have estimated £169 million; we haven't revised it and we'll have a better idea of costs once we finish it."

Frigg

The Frigg platforms, whose name refers to the Norse goddess of marriage, fertility, and love, produced 80 million cu m/day of gas at its peak. It stopped production on Oct. 26, 2004.

"There should be sufficient profit for companies to get increased tax relief, and this change will become effective in relation to losses incurred in accounting periods on or after Budget Day 2008," Leith said.

Last October, Oil & Gas UK launched the Decommissioning Cost Provision Deed (DCPD) following 2 years of intense negotiations with PILOT, the industry and government forum for the oil industry (OGJ, Oct. 22, 2007, p. 30).

The DCPD aims to clarify decommissioning liabilities by offering different options for joint-venture partners in their plans for offshore assets. The government will review DCPDs approved by asset buyers on a case-by-case basis. When satisfied, it will release sellers from decommissioning liability. It will measure the program's success by how many companies take up the DCPD.

The US approach

US decommissioning of offshore structures differs in important ways from the UK approach.

In the northern Gulf of Mexico, 4,000 platforms produce oil and gas, mostly off Louisiana and Texas. From 1994 to 2003, platform decommissioning averaged 156/year—58 nonexplosive and 98 explosive.

The three main removal methods so far are complete removal, partial removal (reefing in place), and remote reefing (reefing off site). These methods use explosive or nonexplosive severing,

Total plans to remove the Norwegian steel drilling Platform 2; the steel substructure for drilling Platform 1; the topsides of the concrete installation and compression Platform 2; and the British steel platform of the quarters platform, treatment Platform 1, and the topsides of concrete drilling Platform 1. In addition the field's internal pipelines and cables and waste on the seabed will be removed and taken to land.

It will leave the behind the concrete substructure for treatment and compression Platform 2 on the Norwegian side and two concrete substructures on the UK side.

Decommissioning was meant to finish last year, but bad weather has meant missing this deadline. The company is optimistic that the Frigg platforms will be decommissioned before the summer.

Ekofisk-1

A ConocoPhillips spokesman told OGJ that its Ekofisk-1 decommissioning plan was on schedule to finish by 2013.

"We have removed the topside of the storage tank weighing 25,000 tonnes of steel. We have removed some light structures on the platforms and the rest of it will go during the contractual process," he said.

He declined to say, however, when it would award the decommissioning contract or the cost of the entire project.

lifting, transporting, and disposal.

Damage from hurricanes in 2004 and 2005 brought new attention to decommissioning in the gulf.

Steve Trammel, senior product manager for new product development at IHS Inc., told OGJ: "Key difficulties seem to be the number of platforms damaged and the fact that a damaged platform could be twisted, bent, toppled and sunk by the storms, making the removal more problematic, dangerous, and costly."

Costs of decommissioning damaged platforms and pipelines can be 15 times those of conventional abandonment, according to some estimates.

The US Minerals Management Service expects decommissioning of hurricane-ravaged platforms to continue until 2013 because of equipment scarcity and delays.

BJ Kruise, petroleum engineer for the field operations office at MMS, said, "The timetable for decommissioning depends on whether the lease is on production, and operators have a year to do the work if the lease has expired."

Kruise said issues raised by platform destruction include hazards to marine traffic and the obligations of lessees to return the seafloor to its condition prior to oil and gas activities. Environmental safeguards in place at the time of the hurricanes reduced pollution risks.

"Wells that were sheared off at the mudline had their subsurface safety valves shut in as the platforms were destroyed because of the force of the waves," Kruise said.

Beyond decommissioning associated with hurricanes, the MMS official said, "The major challenge will be handling the decommissioning of deepwater platforms as more operators move to develop deeper prospects."

Techniques for decommissioning could be improved if contractors were better at sharing information about their practices, according to Kruise. "We also need industry [professionals] to share their experience with each other through the American Petroleum Institute and the Society of Petroleum Engineers and open dialogue with their experiences all over the world," he said.

The gulf has pursued a "rigs-to-reef" program since the mid-1980s—an approach blocked in the UK North Sea by environmental protests. The program creates a habitat for fish.

"Studies as to the effectiveness and safety of rigs to reefs are still under way in both the gulf and the North Sea," said Trammel of IHS. "Both areas have a similar mud-bottom environment that can apparently benefit from manmade structures being put in place to generate coral growth and more marine life as a result." ✦

OWA: Nigeria needs to support local businesses

Uchenna Izundu
International Editor

Nigeria should financially support indigenous companies in the oil industry to ensure that Nigerians can participate in its development, a senior academic has suggested at the Offshore West Africa Conference.

Offiong Akpanika, lecturer in the department of chemical and petroleum engineering at Uyo University, said too many Nigerian companies were failing because they refused to unite and draw attention from multinationals and government as viable enterprises. "We want to have sustainable industrial growth and generate national wealth."

By setting local content targets, the government has encouraged the growth of Nigerian service suppliers to the industry and the start-up of Nigerian oil operators through the development of marginal fields. But increasing the delivery of local content is challenging, with companies facing stringent requirements to secure funding from banks and high interest rates to pay back loans.

Another challenge is developing a sophisticated legal framework for local content and ensuring that there are sufficient jobs for trained personnel. Delayed projects are leaving too many companies without work or guarantees that they will be paid for that standby period. "We need to develop a strong industrial and manufacturing industry," Akpanika stressed.

Competitive costs with other international centers are fundamental if companies are to build a sustainable

engineering work force in Nigeria, said Femi Aisida, chief office manager for Shell Nigeria Exploration & Production Co. Following a Nigerian directive for front-end engineering design (FEED) work to be performed in Nigeria from 2006, Shell developed a Nigerian team to carry out the FEED for the deepwater Bonga NorthWest field, a subsea tieback to an existing manifold.

"An economic challenge is the cost of establishing the expertise in addition to executing the FEED," he added. Mistakes on technical work are extremely expensive to rectify, so Shell trained the staff by bringing in experienced engineers from overseas to monitor the work. "Coordinating expertise from diverse locations was difficult," Aisida said. The company is keen to retain the Nigerian team and develop its expertise beyond FEED work to support its other business units, provided that the quality of work is sound and performed within a competitive timeframe.

Next month Bonga will be shut in for routine maintenance for 10 days with a loss of 225,000 b/d to the market. Attacks on oil and gas pipelines in the Delta have reduced supplies by an average of 850,000 b/d, leading to a fall in investor confidence and a loss of income for the country. ✦

OWA: Pressure increases for Niger Delta peace

Uchenna Izundu
International Editor

The $4 billion Nigeria allocated to the Niger Delta for its development over the last 4-5 years has been swallowed up by increased governmental staff wages, security, and corruption, a senior official has said.

Speaking at the Offshore West Africa conference, Delta State Deputy Governor E. Utuama said staff numbers in government posts have risen because there weren't any jobs in the private sector. "Everyone is looking for a job."

But Nigeria should form an Inspector General's office to monitor sustainable development projects in the Niger Delta and help quell the unrest that is blocking oil and gas production, suggested a Niger Delta community relations advisor at the conference session looking at sustainable development in the Niger Delta.

Stephen Benstowe, who has provided advice to the Bonny Island community that hosts the Nigeria LNG plant, said timely release of funds for development in the Niger Delta was critical. The problems in the region can be blamed upon government inaction and the insincerity of oil companies with their sustainable development policies. Operators are failing to integrate with and engage the communities.

"Who is responsible for sustainable development in Nigeria? It has earned $20 billion/year over the last 4 years from oil, and there are 20 million inhabitants in the Niger Delta who live in abject poverty and are grossly neglected," Benstowe charged.

The government has formulated a Niger Delta master plan to reduce poverty, diversify the economy, improve health, and develop new transport, communications, and waste management facilities. So far, militants and residents from the region have complained bitterly about its poor implementation.

Community Development Foundations, where communities and oil companies work together to address community needs, have had some success, said Anthony Bolarin, general manager of sustainable development at Elf Petroleum Nigeria Ltd. But he cautioned against creating projects doomed to failure: "There have been lots of national development plans proposed before, and if we're not careful there will be another one. Things have started to be built, but haven't [been] finished, or those that have finished have been grassed up."

He said global memorandums of understanding have been a failure in spearheading development in the Niger Delta. "We need to let the community come back to the center and ask them what they want; we must stop dictating to them." ✦

DOI's $10.7 billion budget has environmental emphasis

Nick Snow
Washington Editor

The US Department of the Interior's proposed budget for fiscal year 2009 makes environmental protection a priority while increasing access to domestic oil and gas resources, officials said on Feb. 4.

DOI's $10.7 billion budget request, slightly more than what it sought for FY 2008, includes $528.1 million for energy-related programs on lands and in waters under its management, $15.1 million more than what it received for the current fiscal year. It would increase US Minerals Management Service funding by $10.3 million from the enacted amount to $307.1 million, while the Bureau of Land Management's budget would fall by $5.8 million to $1.002 billion.

But Interior Secretary Dirk A. Kempthorne said DOI agencies involved in energy will continue to take a more deliberate planning approach. "In some of these areas, world-class wildlife habi-

tat sits atop world-class energy resources," he observed, adding that planning "ridge top-to-ridge top instead of acre-to-acre" is required in such cases.

Following the formal budget presentation, BLM Director James L. Caswell confirmed that his agency has adopted more deliberate planning for oil and gas projects in response to greater public interest. "We can make better decisions if we look across broader areas," he told OGJ.

Species do not respect boundaries, he explained. They may return once oil and gas operations are complete, but BLM also needs to determine where wildlife would relocate during the interim, he said.

"Will it reduce lawsuits later on? For the people interested in achieving a solution, yes. For those who aren't, no. But the fact is that we need to take this more thorough approach because it's the right thing to do," Caswell said.

Drilling permit charge

The proposed budget also notes that BLM will continue charging $4,000 for each onshore drilling permit application that it processes. It began collecting these fees on Jan. 2 after the charge became a part of DOI's FY 2008 budget during congressional negotiations in December.

The agency estimates that the fee will raise $22.5 million before its authorization expires on Sept. 30. BLM not only seeks repeal of the 2005 Energy Policy Act (EPACT) provision that bans this charge, but also requests authorization to increase it to $4,150 while the rulemaking is developed.

The agency has identified other areas where it can use such charges to reduce costs, but none of them involve oil and gas, Caswell said. It intends to continue the permit processing program under the energy pilot office project that EPACT authorized because it is working very well, he indicated.

The budget request also includes an $11.2 million increase to $17.1 million for BLM's well remediation program on Alaska's North Slope and a $2 million

WATCHING GOVERNMENT

Nick Snow, Washington Editor

High-stakes appeal

The US Supreme Court moved one step closer to addressing a $2.5 billion question this term when it placed Exxon Shipping Co. vs. Baker on its docket on Feb. 1 and scheduled arguments for Feb. 27.

The case stems from the Mar. 24, 1989, grounding of the tanker Exxon Valdez in Prince William Sound, which discharged more than 11 million gal of oil into Alaskan coastal waters.

More than 250 lawsuits by area fishermen, processors, Alaska Natives, landowners, businesses, and others were consolidated into a single action. A jury awarded plaintiffs $297 million of compensatory damages and $5 billion of punitive damages following a 4-month trial in 1994.

ExxonMobil Corp. appealed the punitive damages award, which the Ninth US Circuit Court of Appeals cut to $2.5 billion on Dec. 22, 2006. The company's attorneys appealed to the Supreme Court, which agreed on Oct. 29, 2007, to hear the petition.

'Further punishment'

In a statement at the time, ExxonMobil expressed deep regret for the spill and said all compensatory claims were resolved. "The punitive damages case has never been about compensating people for actual damages. Rather it is about whether further punishment of ExxonMobil is warranted. The company does not believe any punitive damages are warranted in this case," the company said.

Alaskan government officials disagree. In a brief filed with the Supreme Court on Jan. 29, the state asserted that maritime law permits a court to hold what then was Exxon Corp. responsible for ship captain Joseph J. Hazelwood's conduct. It also argued that the federal Clean Water Act (CWA) does not keep injured parties from obtaining punitive damages. Alaska's congressional delegation also filed a brief. So did the state's legislature, which was joined by four former governors. The high court also received briefs from 26 other groups and individuals including the International Association of Tanker Owners, American Petroleum Institute, American Institute of Marine Underwriters, and Maryland and 33 other states.

Three main questions

In its docket placement notice, the Supreme Court said ExxonMobil indicated that the company's lawyers asked three primary questions: First, may punitive damages be imposed under maritime law against a ship's owner for conduct of a ship's master at sea without a finding that the owner directed, countenanced, or participated such conduct?

Second, when Congress specified criminal and civil penalties for maritime conduct in a controlling statute (the CWA, in this case) but did not provide for punitive damages, may a judge add such penalties?

Third, is the $2.5 billion punitive damages award within limits of federal maritime law or, if maritime law could permit such an award, constitutional due process? The Supreme Court granted a writ of certiorari to all but the second part of the third question. The arguments before the court on Feb. 27 should be interesting. The court's decision later this year promises to be very significant. ✦

reduction in the oil shale management program because most of its environmental impact statement activities will be completed this year. It proposes redirecting $400,000 from the oil shale program to oil and gas inspections to build on a $2 million increase for FY 2008. Funding for natural gas hydrates research would be reduced by $425,000.

BLM's budget request also assumes congressional authorization of oil and gas leasing within the Arctic National Wildlife Refuge during FY 2009, which would generate an estimated $7 billion of bonus receipts from an initial lease sale in 2010. Kempthorne said this merely moves ANWR leasing back by a year and continues administration support for opening the area.

Asked about other opportunities to increase access to domestic energy resources, the secretary mentioned reduced environmental impacts from operations. "We've learned a lot about oil and gas development onshore, particularly reducing the footprint per well from 8-10 acres to about a half acre. Also, we've learned techniques in Alaska to apply onshore in the Lower 48 states, such as using wooden pallets for roads. Interestingly, these pallets do not require extensive land restoration but retain moisture which encourage sagebrush growth," he said.

MMS budget highlights

The $307 million that DOI is requesting for MMS in FY 2009 includes $160.4 million in current appropriations ($660,000 less than in FY 2008) and $146.7 million in offsetting collections from rental receipts and cost recovery fees. For the first time, the budget would separate offsetting collections (comprised of $133.7 million in rental receipts) from the estimated $13 million of cost recoveries, which would no longer be capped so MMS can retain all of the collected fees.

The proposed budget seeks $8.5 million more to implement the agency's 5-year OCS oil and gas leasing program, which went into effect on July 1, 2007; $1.1 million more to acquire and maintain geoscientific interpretive tools; and $8.6 million less for the OCS Connect System, which provides an electronic interface between MMS and its customers because the system will be largely improved by FY 2009.

MMS also would receive $2 million to improve its compliance and audit program by implementing recommendations from DOI's Office of Inspector General. Of that amount, $1.5 million would be used to develop a risk-based compliance tool that would select properties to be reviewed based on additional risk factors such as chronic erroneous reporting or possible fraudulent reporting. Oil spill research funding would be reduced by $180,000 to $6.1 million because of operating efficiency improvements.

Kempthorne said he saw no conflict between MMS's Chukchi Sea lease sale, which was scheduled for Feb. 6, and the US Fish and Wildlife Service's decision whether to list the polar bear as an endangered species, which has been delayed until later this month. When FWS began to examine the situation, it identified melting sea ice as the primary threat and not oil and gas operations, he said.

Leases would be at least 25 miles offshore, he noted. "The initial production, in all likelihood, would be 10-15 years from now during which there would be extensive public comment," the secretary said.

DOI's Ocean and Coastal Frontiers Initiative also includes a $4 million component to assist in mapping and defining US jurisdiction of the extended OCS.

The US Geological Survey would work with the National Oceanic and Atmospheric Administration to map the sea bed. Kempthorne said this will occur even if the Senate does not ratify US participation in the international Law of the Sea treaty, but added that talks are continuing to make this happen. ✦

US MMS director defends leasing in Chukchi Sea

Nick Snow
Washington Editor

Oil and gas activity in Alaska's Chukchi Sea can occur without threatening polar bears, US Minerals Management Service Director Randall B. Luthi said just a day after environmental and Alaska Native groups sued to block a Feb. 6 lease sale.

"The two activities are compatible. Energy production can occur while maintaining strong polar bear populations," Luthi said in an op-ed article posted Feb. 1 on the US Department of Interior agency's web site. The groups sued in federal district court in Alaska on Jan. 31.

Exploration and initial development will occur only with the approval of the US Fish and Wildlife Service, another DOI agency, and must be in open water at least 25 miles from shore, he continued. Although a spill is unlikely, MMS recognizes that the potential for such an event exists and would require lessees to have containment and recovery equipment available, Luthi said.

"Leasing is just a first step in the energy development process. Actual production in the Chukchi Sea realistically is 10-15 years in the future, and will not occur without many environmental reviews, public commentary and application of environmental protections," he indicated.

The record of MMS in protecting the environment while providing access to the nation's offshore energy resources is good, Luthi continued. A 2002 National Academy of Sciences study found that over the previous 20 years, less than

0.001% of oil produced in US waters was spilled, he said. "The same study reported that 150 times more oil enters the ocean every day from natural cracks in the ocean floor than through oil and gas activities," Luthi said.

Sale timing questioned

Luthi reiterated several points he made when he testified Jan. 17 before the US House Select Committee on Energy Independence and Global Warming (OGJ, Jan. 28, 2008, p. 26). The chairman of that committee, Rep. Edward J. Markey (D-Mass.), questioned whether MMS should proceed with the Chukchi Sea sale before FWS decided whether to list the polar bear as an endangered species. US Senate Environment and Public Works Committee Chairwoman Barbara Boxer (D-Calif.) raised the same point in a Jan. 30 hearing of that committee (OGJ Online, Feb. 1, 2008).

Luthi noted in his Feb. 1 article that the polar bear already is subject to stricter regulation under the Marine Mammal Protection Act than it would receive under the Endangered Species Act. Bear dens must be protected, and no action is allowed that would have more than a negligible impact. If FWS decides to list the animal as threatened, energy exploration and other potential activities would occur only after requirements of an ESA listing were met, the MMS director said.

"Over the past 30 years, MMS has funded nearly $300 million for environmental studies in Alaska waters and scientific research of marine mammals, including the polar bear. Annually since 2000, we have benefited from 30-40 environmental studies, some focused specifically on polar bears. We now know more about the bear and its habitat requirements, which will help in the long-term survival of the species," Luthi said.

A Chukchi Sea lease sale was included in both the 2002-07 and 2007-12 US Outer Continental Shelf oil and gas leasing program, which were subject to rigorous congressional and public scrutiny, he continued. "Congress did not take action to disapprove either program," he said.

"Our decision comes down to the bare necessities: Where do we want to get our energy? Having a domestic supply is far more reliable and secure than relying upon foreign sources. Can we develop domestic supplies and provide protection for the environment and wildlife, including polar bears? Yes, we can and should," Luthi maintained.

Native village impacts

But the 10 environmental organizations and three Alaska Native villages said in their lawsuit that MMS failed to adequately consider leasing impacts not only on polar bears but also on North

Slope Native villages. The groups are being represented by Earthjustice, a nonprofit environmental law firm.

They said the Chukchi Sea is the lifeblood for communities such as the Village of Point Hope. "We've hunted and fished in the ocean for thousands of years. One oil spill could destroy our way of life," said Jack Schaefer, president of the village's tribal council.

The groups, which include the Sierra Club, Wilderness Society, and National Audubon Society, also contend that MMS has not fully addressed impacts from other oil and gas activities such as seismic testing, which they say can have significant biological impacts on bowhead whales and other marine mammals. The lawsuit contends that the DOI agency also failed to consider the combined impacts of global warming and oil and gas activities on the region when deciding to proceed with the Chukchi Sea lease sale. ✦

UK lawmakers call for moratorium on biofuel targets

Uchenna Izundu
International Editor

The UK should impose a moratorium on its biofuels targets because they are jeopardizing reliable food supply in developing countries and harming the environment, a group of UK parliament members has recommended.

In a report analyzing government policy, the Environmental Audit Committee (EAC) said not all biofuels are sustainable, and targets should not be implemented at a national and European level if this contributes to rainforest destruction and competition for land use.

"Biofuels are generally an expensive and ineffective way to cut greenhouse gas emissions when compared to other policies," EAC said. "Emissions from road transport can be cut cost-effectively and with lower environmental risk by implementing a range of other policies."

The committee recommended that the government focus on sustainable biofuels such as waste vegetable oil and improving sustainable biofuels technologies.

The report also found that increasing biofuels use in the energy mix as "an environmentally sound" solution posed a conflict because biofuels require fossil fuels for their production.

"Advanced second generation biofuels may have an important role in the future, but these technologies are some years away." said Tim Yeo, chairman of EAC. "The government should support their development by creating a stable investment climate out to 2020."

By April, the UK wants 2.5% of gasoline and diesel to be drawn from biofuels—rising to 5% by 2010. The EU wants to raise this to 10% by 2020. Presently, biofuels account for 1% of transport fuel in the UK.

BP PLC, DuPont, and Associated British Foods have proposed the construction of a 420 million l./year bioethanol plant using wheat as feedstock at Saltend, Hull, UK. Operations are to begin late 2009.

The analysis is a dampener in the government's approach to find alternate sources of energy as demand soars and greenhouse gases rise due to the burning of fossil fuels. The report follows recent similar criticisms from the European Commission's scientific community, which has questioned the impact on the environment of producing crops for energy use.

As competition from overseas producers rises, however, any delay in supporting the fledgling industry could be damaging, critics said. The National Farmers Union stressed that biofuels represent the only renewable alternative for replacing fossil fuel in transport and tackling one quarter of the UK's carbon emissions.

BP also has teamed with UK-based D1 Oils to launch a global joint venture to plant, over 4 years, 1 million hectares of jatropha curcas, an oilseed tree that grows in tropical and subtropical regions and produces inedible vegetable oil for biodiesel. ✦

Shell Oil's Hofmeister calls for US cap on CO_2 emissions

Paula Dittrick
Senior Staff Writer

Shell has implemented voluntary reductions on emissions from its refineries, said Shell Oil Co. Pres. John Hofmeister, who is calling for governments to set mandatory limits on greenhouse gas emissions.

Speaking at a Rice University forum on carbon dioxide in Houston Jan. 31, Hofmeister said governments must take the lead in establishing regulatory frameworks within which companies can compete equally.

"And we don't have that yet today in the United States of America and in many countries around the world," he said. "Government leadership is necessary to establish what those standards should be. This is one reason why Shell is publicly, nationally calling for a United States cap on all sorts of emissions, but primarily CO_2, so that companies have to work in harmony to achieve that."

Meanwhile, companies can volun-

tarily reduce GHG emissions, Hofmeister noted. In 1997, Royal Dutch Shell PLC made a commitment to reduce its worldwide CO_2 footprint to 5% below 1990 levels by 2010 as part of its efforts to provide cleaner energy.

"Today, our footprint of CO_2 emissions as a worldwide company, including locally here in the Houston area, is below 1990 levels," he said. That achievement has cost Shell billions of dollars worldwide.

"But that makes us less competitive, because these are costs that our shareholders must bear that some of our competitors are not bearing," Hofmeister said.

"Today, [Shell's] footprint of CO_2 emissions as a worldwide company, including locally here in the Houston area, is below 1990 levels."

—Shell Oil Co. Pres. John Hofmeister

Need for standards

Houston Mayor Bill White said refiners have made progress on CO_2 emissions, but he noted government still needs to set standards on other

Eric Watkins, Senior Correspondent

Inquiring after Aleksanyan

Efforts to bring some humanity into Russia's treatment of former OAO Yukos officials may be bearing some fruit.

While the fate of former Yukos Chief Executive Mikhail Khordorkovsky remains ambiguous, some gains apparently have been made for former Yukos Executive Vice-Pres. Vasily Aleksanyan.

Moscow's Simonovsky Court Feb. 6 ruled to hospitalize Aleksanyan and suspend his trial. The court handed down the ruling based on a document provided Feb. 5 by the Matrosskaya Tishina detention facility's administration, which said that Aleksanyan had cancer and needed treatment.

The decision came quickly after Nikolai Vlasov, the counsel for the prosecution in Aleksanyan's trial, told journalists Feb. 6 that he could be transferred to a special clinic if doctors at the Matrosskaya Tishina detention facility decided he needs to be hospitalized. "This issue is to be decided by the chief doctor at the detention facility's infectious ward. If the medical workers decide that [Aleksanyan] needs to be transferred to another medical institution, then this will be done," said Vlasov.

Enter the inquirer

Don't imagine for an instant that this decision came from the goodness of the prosecutor's heart. The prosecutor is just following orders, and the orders are coming from high up in the Kremlin due to pressures being brought to bear on the government there. Consider an editorial in the Philadelphia Inquirer on Feb. 6, which begins: "Another presidential campaign is under way this week—this one in Russia."

The editorial notes that on Mar. 2 Russians will vote in a "proforma election" for a successor to KGB man Vladimir V. Putin. It says that the Kremlin has handpicked a former law professor, Dmitry Medvedev, although Putin may try to remain the power behind the scenes.

It says Medvedev, however, is trying to present a softer face than his mentor; he pledged in his first campaign speech last week to make everyone accountable before the law.

Putin's 'club'

The editorial notes that Putin, by contrast, has used the law as "a club" to bludgeon opponents. "If Medvedev means what he says, he ought to condemn a travesty of justice going on now in Moscow that makes Russia look as if it has reverted to the Stalin era." The editorial continues, "Moscow courts are refusing medical treatment to a former Russian oil executive, Vasily Aleksanian, who is on trial for money laundering, and has late-stage AIDS."

It shrewdly notes that the Russian aim is to force Aleksanian "to testify against imprisoned oil tycoon Mikhail Khodorkovsky." Not least, the paper noted the especially cruel point that "without the treatment, Aleksanian will die."

The Inquirer said, "It is almost impossible to believe this case is going on in the 21st century, in a country whose president hobnobs with European leaders and President Bush."

We applaud the example of the Inquirer. An oilman in far-off Russia may have benefitted. ✦

emissions coming from petrochemical plants and refineries.

"We don't have good standards in Houston for a couple of the chemicals that need to be regulated," White said. "Benzene is one of them. People at other levels of government don't want the city to [establish such regulations].... Most states have some rules. It's only fair that there be clear rules that apply to all firms, otherwise why can one firm justify to its shareholders making an investment?"

Industry can reduce emissions, White said, noting that nitrogen oxides emissions fell significantly in 15 years because there are standards regulating NOx emissions. Shell's worldwide NOx emissions were 180,000 tonnes in 2006, a 20% reduction since 1997, its web site indicated.

Shell managers tour US

Hofmeister and 250 Shell managers visited 50 US cities in 18 months speaking to public audiences about energy issues and answering questions about Shell's program to find new ways to manage the environmental impact of producing and using fossil fuels.

"America runs on energy, and the amount of energy necessary to run America is not decreasing," Hofmeister said. The US relies heavily on hydrocarbons.

"In producing that gasoline or in producing that coal, there are very difficult consequences for the environment, which requires leadership to manage, corporate leadership, government leadership, academic leadership," he said. ✦

Iraq to benefit from higher oil revenues, report says

Eric Watkins
Senior Correspondent

The Iraqi government could earn an extra $19.2 billion in revenues this year because of higher oil prices and the revival of the country's oil industry, according to a US government report.

The increased revenues are supported by figures set out in the latest quarterly report from Stuart Bowen, the special inspector general for Iraq reconstruction, who is accountable to the US Congress.

Bowen's report says Iraq's budget plans are being drawn up on the assumption of an average international crude price of $64/bbl in 2008 but that the actual figure likely will be $85/bbl.

Concerning Iraq's rise in revenues, Bowen's report says the country's average oil production this past quarter reached a postwar quarterly record of 2.38 million b/d, while average exports maintained the previous quarter's 1.94 million b/d record.

"Taken together, these developments could cause a significant rise in available revenue for [Iraq] in 2008 and further underscore the need for [Iraq's government] to pass the pending hydrocarbon law," the report said.

Iraq's 2008 budget is about $48 billion, an increase of 18% over 2007, with more than 84% funded by oil revenues.

The potential increase in revenues brought by higher oil prices could generate a national income windfall for Iraq, providing new funds for Iraq's relief and reconstruction.

Postwar output record

The report said Iraq's record quarter oil production was tied to increases in output in northern Iraq. Production from this region reached its highest level since the start of the war, averaging 492,000 b/d, a rise of more than 123% from the same period in 2006.

The record exports during the most recent quarter virtually matched last quarter's postwar high, and was 31% higher than the quarterly average for the same time in 2006, the report said.

Iraqi exports through the Ceyhan pipeline, averaging 360,000 b/d, were the highest for any quarter in the postwar period. "Increased security, more effective repair efforts, and added redundancy have increased export capabilities from the northern pipeline system," the report said.

Exports from the Al Basrah oil terminal in southern Iraq remained relatively steady last year, with the 2007 average increasing by 3% from 2006.

Iraq lacks the domestic refining infrastructure to supply its population with refined fuels such as gasoline, kerosene, and diesel. Moreover, current storage levels of refined fuels are insufficient to meet the estimated winter demand.

The US and Iraq have thus taken some steps to increase supply, planning to install two 70,000 b/d refining units at the Doura refinery, which could increase daily refinery production by 156%.

Pipeline security

Pipeline security programs are boosting the country's oil exports and its income. The Infrastructure Security Protection (ISP) Program, funded by the Economic Support Fund, provided $110 million for oil pipeline exclusion zones (PEZ) to prevent the illegal tapping and attacks on pipelines.

Oil PEZ projects are under way from Baiji to Kirkuk, Baghdad to Kerbala, and Baiji to Baghdad, the report said. "When completed next spring, the 80-km PEZ from Kirkuk to the Baiji oil refinery will potentially save the GOI more than $30 million/day and ensure the delivery of 700,000 b/d to the market."

This PEZ project, which was started in mid-July 2007, appears to be facilitating the consistent export of oil through Turkey. The reduction in interdictions has helped contribute to

the rise in exported oil; similar results are expected when the Baghdad-to-Baiji PEZ is completed.

Iraq has yet to implement hydrocarbon legislation, which, among other things, would define rules for oil revenue distribution and foreign investment. The legislation was originally slated for adoption in 2006, but the legislative timetable has repeatedly slipped since then.

The framework law is currently with the Council of Representatives, but no action had occurred as of the end of 2007, and the three supporting laws have yet to be submitted for parliamentary approval.

The Kurdistan Regional Government (KRG) passed its own law in August 2007, which the GOI declared illegal, stating that companies conducting business with the KRG may face legal action once national hydrocarbon legislation passes.

In late December 2007, Bowen noted, Iraq stated that companies signing agreements with the KRG before passage of a new national oil law may face "blacklisting" and "exclusion of future cooperation" with the ministry of oil. ✦

Operators, contractors agree safety is priority

Paula Dittrick
Senior Staff Writer

Although oil companies call their safety programs by different names, operators agree that safety must come first, and that drilling contractors and operators can help one another improve safety.

ExxonMobil Corp. calls its safety program "Nobody gets hurt," while ConocoPhillips labels it "Journey to Zero," and Chevron Corp., "Incident-free Operations," speakers told a health, safety, environment, and training conference in Houston sponsored by the International Association of Drilling Contractors (IADC).

"We are so closely aligned on this one aspect that you lose track of who works for which company," David R. Anglin, ExxonMobil Development Co. global drilling manager, said during a Feb. 5 panel discussion.

The other panelists were Glenn D. Schaaf, ConocoPhillips operations services manager, Lower 48, and Jeff Smith, drilling and completions manager for the Chevron Midcontinent-Alaska business unit.

Anglin said safety performance is the first thing he reviews daily. He said employees throughout an entire company must be held as accountable to a safety culture as the workers on the rig floor.

"The near-miss could have been an

accident," Anglin said, adding that he believes in studying near-miss incidents and to take the conclusions seriously in ongoing efforts to make sure nobody gets hurt.

Safety cost cheaper

Schaaf emphasized, "Safety is not about statistics but about people caring for each other." He urged industry to implement better employee mentoring programs and "to invest in new technologies to take people out of harm's way.... At the end of the day, safety is actually cheap compared to what an accident costs contractors and oil companies."

Anglin agreed, saying ExxonMobil is willing to spend whatever it takes to achieve safer working conditions.

Chevron's Smith said safe operations translate into less missed production time, a key performance measure for oil companies. In addition, equipment tends to last longer when safety is observed, he said. "At the end of the day, our overall rig costs are down" as a result of technology and safety upgrades to rig fleets, Smith said.

Better equipment

IADC Chairman John Lindsay, Helmerich & Payne International Drilling Co. executive vice-president for US and international operations, agreed that the use of better equipment can reduce risks.

For instance, he said, the use of iron roughnecks eliminates the number of people handling tongs. Iron roughnecks save fingers and also make the industry more attractive to young people considering a job on the rig floor, Lindsay said.

The use of hydraulic catwalks helps prevent dropped objects, which is a high risk issue, Lindsay said.

IADC administers an accident statistics program (ASP) in which members voluntarily submit monthly statistics on injury accidents and illnesses within specified levels of severity. IADC compiles the results.

Lindsay said it's estimated that 60-70% of US land rigs participate in ASP. Consequently, IADC estimates that more than 2,000 drilling contractor injuries were not posted in ASP results. ASP statistics show an average of 12 fatalities/year for the last 12 years, he said. "Fatalities are something we've just got to get out of our business," Lindsay said.

ASP participants report each work-related, recordable injury or illness only in the following categories: fatality, lost-time incident, days away from work case, restricted work case, and medical treatment.

First-aid cases, defined as treatment of minor scratches, cuts, burns, splinters, etc., are not reported. ✦

Offshore cathodic protection survey completed off Ecuador

Christopher E. Smith
Pipeline Editor

Corrintec, a division of Cathelco Ltd., reported Jan. 31 the completion of a cathodic protection (CP) survey on the subsea section of the Oleoducto de Crudos Pesados off Ecuador. The subsea section consists of four pipelines from storage tanks at the Esmeraldas marine terminal to two coupling buoys 7 km offshore: one for use with tankers as large as 150,000 dwt and the other capable of supplying tankers as large as 325,000 dwt. The buoys are in 30-40 m of water. Each of the four pipelines can transport as much as 60,000 bbl/hr.

Corrintec has completed a subsea cathodic protection survey of the pipeline connecting this coupling buoy, 7 km off Ecuador, to the Esmeraldas marine terminal. The buoy is the final link in the Oleoducto de Crudos Pesados, loading Andean crude onto tankers as large as 325,000 dwt. Photo from Corrintec.

Corrintec, which also surveyed the 500-m landfall section of each pipeline, used the trailing wire method to verify the effectiveness of CP on the subsea sections. The work was undertaken to satisfy insurance requirements for OCP Ecuador SA, the pipeline's operator.

The 450,000 b/d mainline portion of OCP consists of 24-in. and 36-in. pipe, extending 500 km from the Amazon, across the Andes, to Esmeraldas. The system uses three pumping stations and heats the transporting oil to a peak elevation of 4,000 m, after which a combination of gravity and depressurization units delivers the oil to Esmeraldas.

OCP transports 18-24° gravity crude from the Amazonas terminal, Neuva Loja, Sucumbios; picks up additional crude at Sardinas station, Napo, near the town of Borja; and arrives at Esmeraldas' five 750,000 bbl storage tanks. ✦

rethinking
RECOVERY METHODS

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September 30 – October 2, 2008
Hilton Fort Worth
Fort Worth, Texas USA

THE RETHINKING CONTINUES

By rethinking recovery methods, producers have brought to a hungry market gas from reservoirs once considered economically and technically impossible. Tight sands, shales, and coalbeds now represent large and growing sources of an essential form of clean energy.

But they're still unconventional. The reservoirs are complex. The costs of drilling into and completing wells in them are high and rising. They present unique environmental problems.

Producing gas from unconventional reservoirs profitably, safely, and in amounts demanded by the market requires continuous rethinking – the kind of thinking that shoves back limits on what's possible with gas supply.

Rethinking of recovery methods will continue Sept. 30 – Oct. 2, 2008, at the Unconventional Gas International Conference & Exhibition at the Hilton Fort Worth in Fort Worth, Texas. Planned by editors of Oil & Gas Journal and an advisory board of industry experts, the event will highlight innovation from unconventional gas plays around the world. It will be your chance to meet and learn from other professionals in the fastest-growing sector of the gas-producing industry.

So mark your calendar.
Plan to attend the first annual Unconventional Gas International Conference & Exhibition.

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Tullow, Heritage press exploration in Uganda

Heritage Oil Corp., Calgary, and Tullow Oil PLC are attempting to tap Uganda's first oil discoveries in what could become Africa's next oil production megaproject.

Seismic and drilling are ramping up in the Lake Albert rift basin with expectations of reaching commercial status and identifying sufficient reserves to support construction of a pipeline some 1,300 km to the Indian Ocean.

The currently drilling exploration well is expected to reach its primary target in late March 2008, and the outlook for the first oil production is in 2009.

Tullow, operator of Block 2 with 100% interest, plans to invest more than $200 million—double its 2007 outlay—in 2008 in Uganda.

Both Tullow and Heritage hold interests in blocks on both sides of the lake in Uganda and remote eastern Congo (former Zaire). Oil discoveries so far include Kingfisher, Nzizi, Mputa, Waraga, and Turaco, and eight wells have been successful (OGJ, June 10, 2002, p. 42).

Exploratory drilling

Tullow, with 100% interest in 3,900 sq km Block 2, expects to reach the primary target in March 2008 at the Ngassa exploratory well, spud in November 2007.

The well, which was at 1,400 m in late January, has a primary objective expected at 3,000-4,900 m and several intermediate reservoir targets.

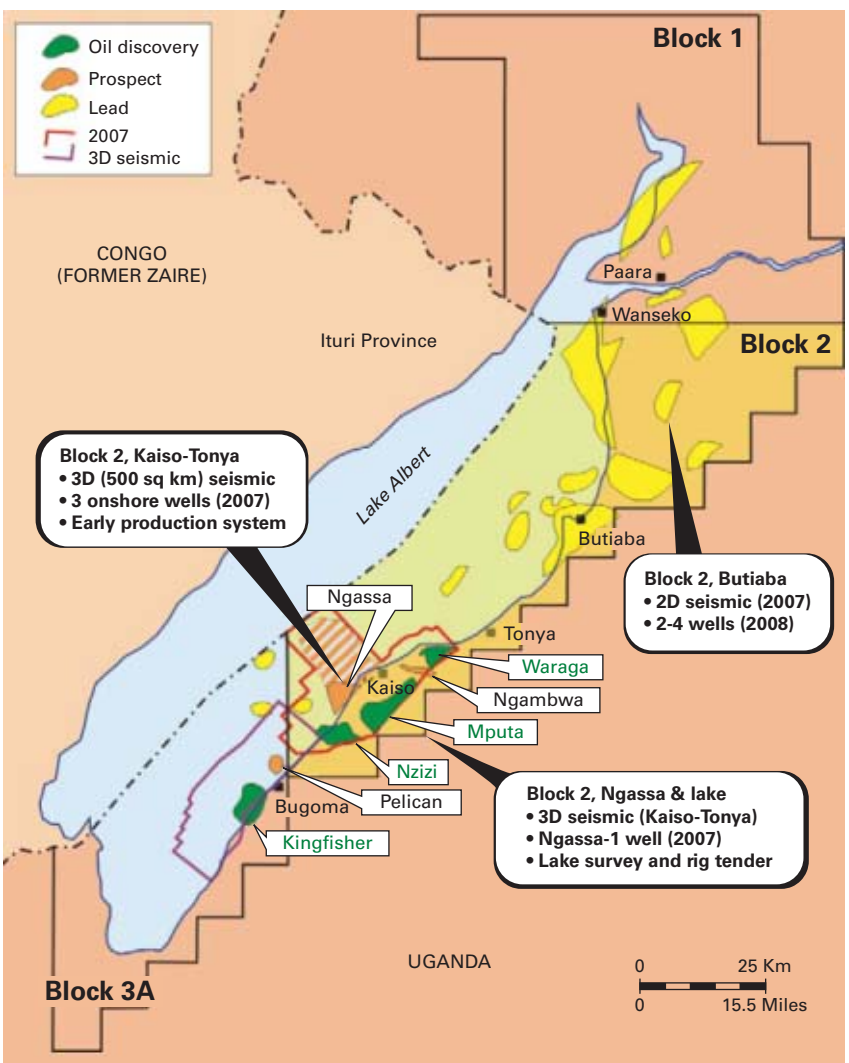
Wellsite construction problems, technical difficulties drilling through faulted claystones, and supply disruptions related to the unrest in Kenya have delayed the well, which originally was to take 110 days to reach the primary target.

Meanwhile, Tullow plans to start an eight-well exploratory program near Butiaba late in the 2008 first quarter. Land 2D seismic has been shot on Blocks 1 and 2.

The Block 2 program was 80% complete in late January. The company had already identified numerous prospects, some with amplitude effects characteristic of hydrocarbons.

"These early results indicate considerably greater prospectivity in the Butiaba region than in the adjacent Kaiso-Tonya

UGANDA'S LAKE ALBERT RIFT BASIN



Source: Tullow Oil PLC

area," Tullow said. The first well will most likely be on the Taitai prospect, formerly Waki-2, near Waki-1 drilled in 1937.

Tullow completed Mputa/Nzizi appraisal drilling in December 2007 when the Mputa-4 well proved the lateral extent of oil-bearing reservoirs across the region. Pressure data from the extended well test indicated some depletion over the test period.

Tullow is integrating appraisal well and 3D seismic data with an updated geological model to refine reserve estimates and development planning assumptions ahead of the anticipated sanction of the early production system in the 2008 second quarter.

Other areas

Heritage and Tullow are interpreting 3D seismic shot over the Kingfisher discovery on Block 3A. Heritage operates 3A, and interests are held 50-50.

The data will be used to plan the Kingfisher-2 appraisal well, to spud after the Ngassa well completion.

Heritage's Kingfisher discovery well, deviated from shore to TD 3,195 m beneath the lake, yielded an overall cumulative maximum flow rate of 13,893 b/d of oil on a 1-in. choke.

A shallower 10-m interval at 1,783 m produced 4,120 b/d in November 2006, and three other intervals of a combined 44 m thick at 2,260-2,367 m totaled 9,773 b/d in February 2007.

Kingfisher oil is 30-32° gravity sweet crude with a low gas-oil ratio and some associated wax. The sandstone reservoir permeability is as high as 2,300 md.

The rig drilling Ngassa is of a larger capacity needed to explore the deepest objectives not penetrated by the Kingfisher discovery well.

Interpretation of the Pelican prospect, in Lake Albert off Kaiso town, looks "particularly encouraging with some good seismic amplitude anomalies potentially indicative of hydrocarbons," Tullow said.

Further technical work is needed before a drilling decision on a number of other lake prospects.

Meanwhile, Tullow and Heritage were awaiting Congolese presidential sanction of Blocks 1 and 2, on which they signed a production sharing agreement in July 2006. The blocks total 6,500 sq km on and offshore in the southern part of the lake. Interests are Tullow operator with 48.5%, Heritage 39.5%, and Cohydro 12%. ✦

Bulgaria

Direct Petroleum Exploration Inc., private Denver independent, said a subsidiary has drilled Deventci-R1, the deepest well in Bulgaria in the last 30 years, to TD 19,313 ft and set production casing at 19,280 ft.

The well, on the A-Lovech block in northwestern Bulgaria, bottomed in the Lower Triassic Alexandrovo formation and encountered gas-saturated reservoirs in the Dolni Dabnik member of the Middle Triassic Doirentsi formation. Other potential reservoirs are in the Upper Triassic Rusinovdel and the Lower Jurassic Ozirovo formations.

Egypt

Groundstar Resources Ltd., Calgary, will shortly invite bids for a planned 700 line-km 2D seismic program over five large Lower Cretaceous structures on the West Kom Ombo Block in southern Egypt.

The company identified the structures on previous seismic shot by Repsol-YPF SA. Groundstar's shoot is to start around the end of the 2008 first quarter. Groundstar operates the block with 60% working interest.

A contractor will be mobilized to conduct the seismic program in a joint campaign with Centurion Energy and possibly Melrose Resources.

Ivory Coast

Exploration success off Ghana at the Jubilee discovery, formerly Mahogany and Hyedua, has opened a new play off Ivory Coast in Upper Cretaceous turbidite sands, said Tullow Oil PLC, London.

The new play and a previously discovered play in tilted Albian fault blocks such as Espoir field and the East Grand Lahou prospect in Block CI-105, both extend throughout the West Africa Transform Margin.

Tullow holds nine licenses in these fairways, three off Ghana and six off Ivory Coast, and expects to drill in both plays in 2008.

Western Sahara

The Saharawi Arab Democratic Republic plans a second licensing round in early 2008 with the offer of six offshore and three land blocks in Western Sahara, West Africa.

SADR said, "The licensing initiative has been launched in preparation for the full recovery of all of our territory, as the [United Nations'] mediation process progresses towards a lasting solution to the conflict between the SADR and Morocco. The licensing initiative has been arranged in accordance with the UN legal opinion regarding commercial activities in Western Sahara."

The blocks total 48 million acres in 0 to 3,600 m of water.

Most of the area is in the underexplored Mesozoic and Tertiary Aaiun basin, where the most recent exploration occurred in the 1950s-60s. That work proved the existence of a 6,000-m thick sedimentary section and the presence of all the ingredients of a working petroleum system.

SADR awarded nine licenses to eight companies in the first bid round in 2006.

Yemen

Dragon Oil PLC agreed to acquire 10% interests in three blocks in Yemen from Virgin Resources Ltd.

The interests are in Blocks 35, 49,

and R2. A drilling program is under way on Blocks 49 and R2 with as many as six prospects being drilled as part of the first development phase.

Dragon's main project is the redevelopment of Dzheitune (Lam) and Dzhygalybeg (Zhdanov) oil fields in the Cheleken contract area in the Caspian Sea off Turkmenistan.

Alberta

Great Plains Exploration Inc., Calgary, completed and tested its first exploration well in the Crossfire area of Pembina, Alta., as a Devonian Nisku zone discovery.

Logs indicate the 11-12-50-05w5 well encountered a 10.5-m hydrocarbon column, and the well flowed at rates as much as 1,390 b/d of oil. It stabilized for 4 hr at 730 b/d of 35° gravity clean oil and 470 Mcfd of gas at 3,253 kPa flowing pressure on a 9.53-mm choke.

The well, which suggests an important northeast extension of the Pembina Nisku trend, is the first of as many as six more wells that target similar Nisku light oil prospects that Great Plains and partners plan in 2008.

California

Foothills Resources Inc., Bakersfield, Calif., will shortly spud a projected 9,300-ft exploratory well in Grizzly Bluff gas field in northern California's Eel River basin.

The Grizzly Bluff-4 well, in Humboldt County, is to test the deep Grizzly Bear prospect and is to be drilled using the oil-base mud system employed on the Christiansen 3-15 and Vicenus 1-3 wells in 2006.

The upper part of the hole will evaluate the Pliocene Lower Rio Dell formation that previously flowed 5 MMcfd of gas on a 4-day test. The well's lower portion is to test good gas shows encountered in thick sandstones in deeper formations in the Vicenus-1 well in 1971.

Foothills is designing fracs for the Vicenus 1-3 reentry, TD 6,068 ft, and Grizzly Bluff-5, TD 4,325 ft. Vicenus had indicated gas zones in the primary objective Lower Rio Dell 15 sand and secondary objective Lower Rio Dell 16 sand. Grizzly Bluff-5 mud logs and electric logs had good gas indications in three Pliocene Anderson sands.

Neither well recovered gas on test, and the company suspects polymer drilling fluids damaged the formations.

The basin's gas production comes from Tompkins Hill field, 6 miles north of Grizzly Bluff, and one Grizzly Bluff well making 290 Mcfd.

Colorado

Bill Barrett Corp., Denver, is shooting a 3D seismic survey on its Yellow Jacket shale gas prospect in the Paradox basin in southwestern Colorado.

The company said, "The third vertical test well continues to test gas after encouraging gas contents and shale composition were recorded from the [Pennsylvanian] Gothic geological cores (OGJ, Sept. 24, 2007, p. 48)."

Barrett will develop a plan for at least one horizontal test well to be drilled in 2008.

Kentucky

Platina Energy Group Inc., Cheyenne, Wyo., completed the acquisition of a gas field near Corbin in Laurel and Whitley counties, Ky., from an undisclosed seller.

It plans to rework existing wells and drill as many as 100 potential locations at the field, which has an existing pipeline connection.

Louisiana

Browning Oil Co. Inc., private Dallas operator with 83.2% working interest, will start commercial production from the Fisher Lindsey-1 well in Calcasieu Parish in February, said Ausam Energy Corp., Calgary.

The well on the Quatre prospect tested at 7.2 MMcfd of gas and 115 b/d of condensate on a $^{14}/_{64}$-in. choke with 6,797 psi flowing tubing pressure from an undisclosed formation. Ausam's working interest is 16.8%.

Oklahoma

Unit Corp., Tulsa, plans to drill 10 more wells in Panola field in Latimer County in 2008.

The Cox-7, in which Unit has 63.47% working interest, was testing gas after frac at the rate of 12.9 MMcfd with 5,500 psi flowing tubing pressure from a Pennsylvanian Lower Atoka sand.

The well's production is limited to 2 MMcfd until pipeline capacity is added in early February 2008, Unit said.

Texas

Gulf Coast

Foothills Resources Inc., Bakersfield, Calif., will drill eight more wells in giant Goose Creek oil field in Harris County in 2008.

The last two 2007 wells, Gaillard-49 and Smith C-19, averaged 40 b/d and 100 b/d of oil from Miocene Frio with TDs of 3,388 ft and 3,992 ft, respectively. Electric logs indicated several shallower intervals with commercial potential in both wells.

Wyoming

Consulting engineers estimated that the 2,273-acre South Glenrock C Unit in Converse County, Wyo., could yield 4.9 million stb of oil in 25 years under continuous carbon dioxide injection from the 17.67 million stb estimated to remain in place in the Cretaceous Lower Muddy formation.

The unit, 15 miles east of Casper in the southern Powder River basin, has produced 5.3 million stb by primary recovery and 2.4 million stb under waterflood, said Ameriwest Energy Corp., Houston. It is one of three units in South Glenrock field.

Ameriwest has signed a letter of intent to secure a 99.5% working interest in the C Unit from an undisclosed seller.

Illinois basin ASP flooding planned

Guntis Moritis
Production Editor

One recent announcement on enhanced oil recovery activity is Rex Energy's plan for starting two alkali-surfactant-polymer (ASP) flood pilots in an old oil field in the Illinois basin.

Benjamin Hulburt, CEO of Rex Energy Corp., State College, Pa., said during a presentation to BMO Capital Markets Corp.'s Fourth Annual Appalachian E&P Forum, Jan. 10, 2008, New York City, that the company plans to start ASP injection in the pilots in early second-quarter 2008.

The pilots will be on 1-acre spacing in Lawrence field, near Bridgeport, Ill. (Fig. 1).

Discovered in 1906, Lawrence field still produces about 1,800 bo/d from 1,000 wells. Hulburt said that initial oil in place in the field, the largest in the Illinois basin, is an estimated 1 billion bbl of which about 400 million bbl has been produced.

ASP process

Hulburt explained that in the ASP process the injectant alkali reduces the needed amount of surfactant to recover the remaining oil in place by interacting with the injected surfactant and rock to form additional surfactant in the reservoir (Fig. 2). The alkali is either sodium hydroxide (NaOH) or soda ash (Na_2CO_3) and the polymer is a polyacrylamide.

Rex Energy notes that the alkali (1-2%) and surfactant (0.1-0.4%) combination washes residual oil from the reservoir mainly by reducing interfacial tension between the oil and the water. The polymer (800-1,400 ppm) improves sweep displacement efficiency.

The alkali is less costly than surfactant; and therefore, using ASP reduces the injectant costs compared with earlier field pilots that used surfactant and polymer without the alkali. Hulburt said about 90% less surfactant is needed because of the alkali injection.

He said that seven field pilots with surfactant-polymer flooding in sands such as in Lawrence field all had good technical results in the 1960s and 1980s.

In the case of Marathon Oil Corp.'s Robins lease Maraflood surfactant-polymer flood in Lawrence field, about 1 mile from the proposed pilots, the 25-acre pilot recovered 459,000 bbl of incremental oil from 1982 to 1998 (Fig. 3). The production peaked at 370 bo/d in 1988 with the oil cut increasing to 21% up from the 1% oil cut produced prior to the Maraflood.

Although the flood was a technical success, Hulburt said that that the injectant cost $35/incremental bbl

LAWRENCE FIELD

Fig. 1

Source: Rex Energy Corp.

recovered during a time when oil prices were in the $10-12/bbl range.

Lawrence field

Hulburt said that Rex Energy owns 13,500 net acres in Lawrence field, which covers most of the field and accounts for about 85% of the total gross production from the field. Marathon operated the field for much of its life before selling it to Plains Illinois Inc.

After Plains divested the field, Rex Energy acquired one quarter of it in 2004 for $3 million, Hulburt said.

Because of its potential for enhanced oil recovery, Hulburt said the company continued to purchase remaining parts of the field at substantially higher costs. The total acquisition cost is now $70 million, Hulburt said.

Rex Energy plans to inject the ASP fluid in two of the major sandstone production horizons in the field: the Mississippian Cypress and the Pennsylvanian Bridgeport sands. Hulburt noted that each sand has had a technically successful surfactant-polymer pilot in the past.

Along with other surfactant pilots in the area, Hulburt said that most of these pilots demonstrated technically successful surfactant-polymer flooding by producing 15-25% of the incremental original oil in place; however, the projects were not economical because the chemical cost per incremental barrel of oil ranged from $10-35. The high cost was because of the large surfactant amounts used, he said.

Rex Energy estimates that ASP flooding in the two sands could recover 84 million bbl of oil. Hulburt said the estimate was based on 16 laboratory-run radial core floods in each sand that showed ASP flooding could recover 20.9% more oil from the Cypress and 24% more oil from the Bridgeport sands.

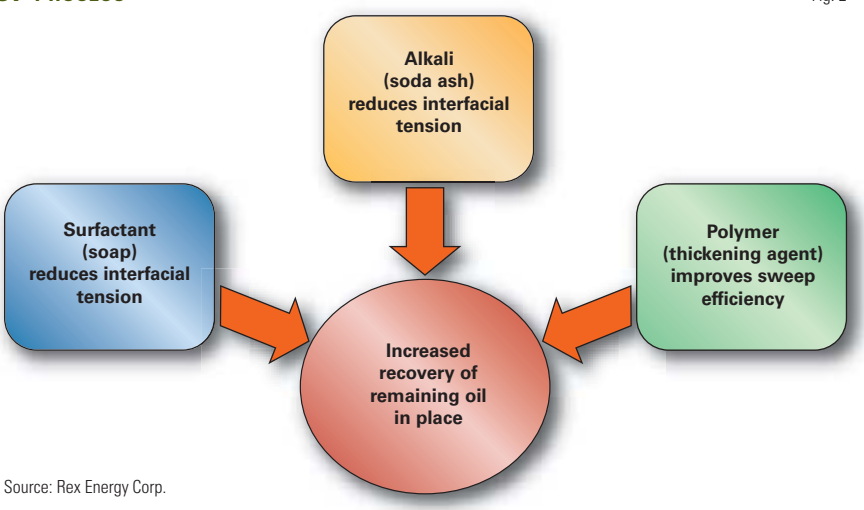
Because of the small size of the pilots, Hulburt noted that the pilots should respond to the injectant in 3-4 months with peak production occurring in 6-8 months. This compares with the 3½ years that it took the larger 25-acre Marathon pilot to show a response, he said.

Hulburt estimated that the finding and development costs for the project will be $11/bbl with the lifting costs being $3-4/bbl.

For the full field project, Hulburt said Rex Energy plans to develop the flood on 10-acre well spacing in 640 acre increments/year. He expects 12-15 months' response times for the flooded areas. ✦

ASP PROCESS

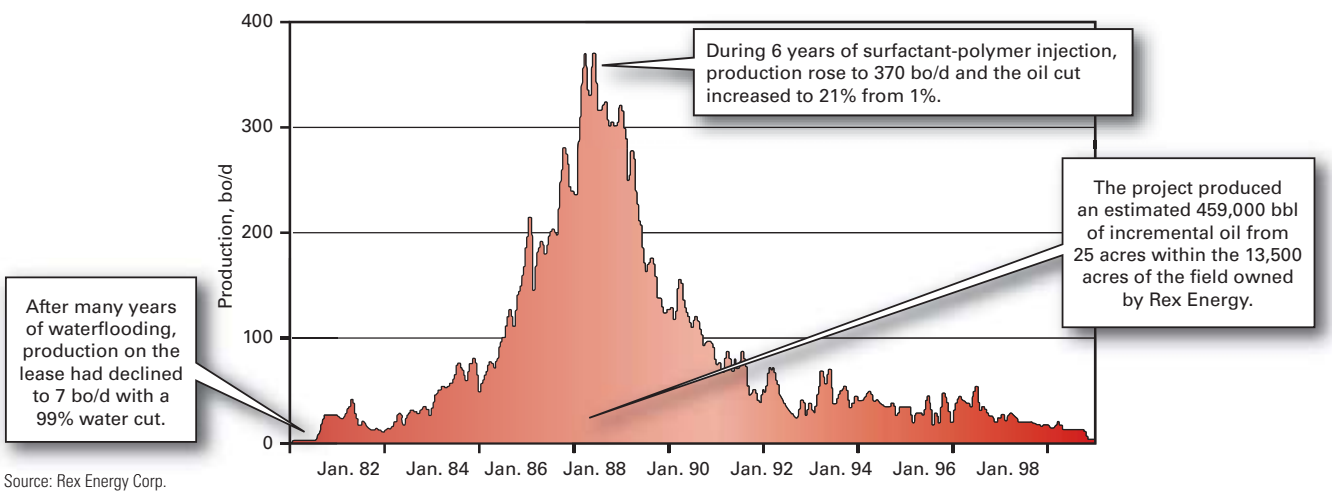
Fig. 2



Source: Rex Energy Corp.

ROBBINS LEASE MARAFLOOD

Fig. 3



Source: Rex Energy Corp.

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True kinematics opens way to bit improvement

Yuri A. Palashchenko
Consultant
Moscow

In the first part of this series, published last week (OGJ, Feb. 4, 2008, p. 46), we began to show how roller cone bit design analysis can predict cone behavior, with heel teeth having equal pitch.

This second of four articles presents how bit kinematics are modeled differently when the heel teeth on all roller cones have varied pitch.

CLASSIC BIT KINEMATICS—2

In this case, after completing a third of the bit revolution, the well-bottom rack will consist of three sectors, each sector resulting from the interaction of the corresponding cone with the well bottom and having its own, individual profile. The further rolling of the well-bottom rack during bit rotation will be determined by this initial profile, which sets the total number of rack "teeth" with variable pitch that changes every other 120°.

Parts three and four will follow in weeks to come.

120° rotation

Let's calculate the rack "teeth" number when the bit turns a third of its revolution (120°). Each of the three cones will roll its own individual estimated "teeth" number:

$Z_{r1} = (N_1 + \Delta_1)/3$, $Z_{r2} = (N_2 + \Delta_2)/3$, and $Z_{r3} = (N_3 + \Delta_3)/3$, where $N_1 + \Delta_1$, $N_2 + \Delta_2$, and $N_3 + \Delta_3$ are the estimated number of rack "teeth" that can be imprinted on the well bottom by the given cone per bit revolution. This assumes that the two other cones do not take part in forming the rack, i.e., $N_k + \Delta_k = i \cdot Z_k$, and $Z_{rk} = (N_k + \Delta_k)/3 = N'_k + \Delta'_k$.

The total estimated number of the well-bottom rack "teeth" after the bit turn for a 120° revolution is shown in Equation 1. Assuming that $Z_{r1} = (\pi D)/3t_1$, $Z_{r2} = (\pi D)/3t_2$, and $Z_{r3} = (\pi D)/3t_3$, where $t_1 \neq t_2 \neq t_3$, we may write this as Equation 2.

By analogy with the previous section, let's determine the boundaries for the actual number of the rack teeth, Z'_a.

1. If $N^1_k = N_k/3$ and $\Delta^1_k = \Delta_k/3$ or $\Delta^1_k = 0$ at constant $\Delta_k < 1$ and $0 < 0.5$, then we derive Equation 3.

2. If $N^1_k = (N_k - 1)/3$ and $\Delta^1_k = (1 + \Delta_k)/3$ at constant $0 \leq \Delta_k < 1$ and $0 \leq \Delta^1_k < 0.5$ (or $0.5 < \Delta_k < 1$), then we derive Equation 4.

3. If $N'_k = (N_k - 2)/3$ and $\Delta'_k = (2 + \Delta_k)/3$, then at $0 < \Delta_k < 0.5$ and $0.5 < \Delta'_k < 1$, we can write Equation 5.

4. If $N^1_k = (N_k - 2)/3$ and $\Delta^1_k = (2 + \Delta_k)/3$, then, at $0.5 < \Delta_k < 1$ and $0.5 << \Delta^1_k < 1$, we have Equation 6.

Note that $Z'_a = \Sigma Z_{ak}$, and in the general case, the number of Z_a values will be determined by combinations of 3 out of 12, i.e., $C^3_{12} = 220$.

Analyzing the data presented in the two tables in Part 1 (OGJ, Feb. 4, 2008, p. 46) and taking into account that the number of teeth on the cone heel rows of commercial bits usually corresponds to three successive numbers, we may find the 10 most probable profile combinations of individual sections of the well-bottom rack, as shown in Box 1.

These equations show that the actual number of the rack "teeth" when drilling with the commercial three-cone bits may finally have six values, as shown in Equation 7.

Leading cone

Having determined the value Z'_a, let's compare it with the values $N_k + \Delta_k$ for each of the cones. Equal or nearly equal Z'_a and $N_k + \Delta_k$ values point to the so-called "leading" cone. If, for the leading cone, $N_k + \Delta_k = Z'_a$, then $i_{ak} = i$, as $i = (N_k + \Delta_k)/Z_k$ and $i_{ak} = Z'_a/Z_k$.

If the leading cone has $N_k + \Delta_k < Z'_a$, then $i_{ak} > i$. At $N_k + \Delta_k > Z'_a$, the leading cone will have $i_{ak} < i$. In other words, the leading cone may have a gear ratio corresponding to pure rolling or slightly more or less than that.

The term "leading" cone and the technique used to calculate the cone skidding rate were introduced in technical literature nearly 50 years ago. A commonly held opinion is that during use of a three-cone bit, the bottom-well rack is formed by a leading cone that controls the motion and cutting of the other cones.[1]

The lead cone is usually the one that rolls over the well bottom almost without skidding[2] or the one with the least number of the teeth on the heel row.[3]

MOST PROBABLE PROFILE COMBINATIONS

Box 1

1. $Z'_a = \frac{N_1}{3} + \frac{N_2 - 1}{3} + \frac{N_3}{3} = \frac{(\Sigma N_k) - 1}{3}$
2. $Z'_a = \frac{N_1 - 1}{3} + \frac{N_2}{3} + \frac{N_3 - 1}{3} = \frac{(\Sigma N_k) - 2}{3}$
3. $Z'_a = \frac{N_1}{3} + \frac{N_2 - 2}{3} + \frac{N_3 - 2}{3} = \frac{(\Sigma N_k) - 4}{3}$
4. $Z'_a = \frac{N_1}{3} + \frac{N_2 - 2}{3} + \frac{N_3}{3} = \frac{(\Sigma N_k) - 2}{3}$
5. $Z'_a = \frac{N_1 + 1}{3} + \frac{N_2 - 1}{3} + \frac{N_3 + 1}{3} = \frac{(\Sigma N_k) + 1}{3}$
6. $Z'_a = \frac{N_1 - 1}{3} + \frac{N_2 + 1}{3} + \frac{N_3 - 1}{3} = \frac{(\Sigma N_k) - 1}{3}$
7. $Z'_a = \frac{N_1}{3} + \frac{N_2 - 2}{3} + \frac{N_3 - 1}{3} = \frac{(\Sigma N_k) - 3}{3}$
8. $Z'_a = \frac{N_1 - 2}{3} + \frac{N_2 - 1}{3} + \frac{N_3 - 2}{3} = \frac{(\Sigma N_k) - 5}{3}$
9. $Z'_a = \frac{N_1 - 1}{3} + \frac{N_2 - 2}{3} + \frac{N_3 - 1}{3} = \frac{(\Sigma N_k) - 4}{3}$
10. $Z'_a = \frac{N_1 - 2}{3} + \frac{N_2 - 1}{3} + \frac{N_3 + 1}{3} = \frac{(\Sigma N_k) - 2}{3}$

EQUATIONS

$$Z_r' = \Sigma Z_{rk} = \frac{(N_1 + \Delta_1) + (N_2 + \Delta_2) + (N_3 + \Delta_3)}{3} = N + \Delta' \quad (1)$$

$$Z_r' = \frac{\pi D}{3}\left(\frac{1}{t_1} + \frac{1}{t_2} + \frac{1}{t_3}\right) = i\,\frac{Z_1 + Z_2 + Z_3}{3} \quad (2)$$

$$Z_{ak} = Z_{rk} - \Delta_k' = \frac{N_k}{3} + \frac{\Delta_k}{3} - \frac{\Delta_k}{3} = \frac{N_k}{3};\ Z_{ak} = \frac{N_k}{3} \quad (3)$$

$$Z_{ak} = Z_{rk} - \Delta_k' = \frac{N_k - 1}{3} + \frac{1 + \Delta_k}{3} - \frac{1 + \Delta_k}{3} = \frac{N_k - 1}{3};\ Z_{ak} = \frac{N_k - 1}{3} \quad (4)$$

$$Z_{ak} = Z_{rk} - \Delta_k' = \frac{N_k - 2}{3} + \frac{2 + \Delta_k}{3} - \frac{2 + \Delta_k}{3} = \frac{N_k - 2}{3};\ Z_{ak} = \frac{N_k - 2}{3} \quad (5)$$

$$Z_{ak} = Z_{rk} - (\Delta_k' - 1) = \frac{N_k - 2}{3} + \frac{2 + \Delta_k}{3} + 1 - \frac{2 + \Delta_k}{3} = \frac{N_k + 1}{3};\ Z_{ak} = \frac{N_k + 1}{3} \quad (6)$$

$$Z_{a1} = \frac{(\Sigma N_k) - 1}{3};\ Z_{a2} = \frac{(\Sigma N_k) - 2}{3};\ Z_{a3} = \frac{(\Sigma N_k) - 3}{3};$$
$$Z_{a4} = \frac{(\Sigma N_k) - 4}{3};\ Z_{a5} = \frac{(\Sigma N_k) - 5}{3};\ Z_{a6} = \frac{(\Sigma N_k) + 1}{3} \quad (7)$$

$$i_{a1} = \frac{i_{1\text{-}1} + i_{1\text{-}3} + i_{1\text{-}2}}{3};\ i_{a2} = \frac{i_{2\text{-}2} + i_{2\text{-}1} + i_{2\text{-}3}}{3};\ i_{a3} = \frac{i_{3\text{-}3} + i_{3\text{-}2} + i_{3\text{-}1}}{3} \quad (8)$$

$$i_{1\text{-}1} = \frac{3 \cdot Z_{a1}}{Z_1};\ i_{1\text{-}3} = \frac{3 \cdot Z_{a3}}{Z_1};\ i_{1\text{-}2} = \frac{3 \cdot Z_{a2}}{Z_1};$$
$$i_{2\text{-}2} = \frac{3 \cdot Z_{a2}}{Z_2};\ i_{2\text{-}1} = \frac{3 \cdot Z_{a1}}{Z_2};\ i_{2\text{-}3} = \frac{3 \cdot Z_{a3}}{Z_2};$$
$$i_{3\text{-}3} = \frac{3 \cdot Z_{a3}}{Z_3};\ i_{3\text{-}2} = \frac{3 \cdot Z_{a2}}{Z_3};\ i_{3\text{-}1} = \frac{3 \cdot Z_{a1}}{Z_3} \quad (9)$$

$$i_{a1} = \frac{1}{3}\left(\frac{3 \cdot Z_{a1}}{Z_1} + \frac{3 \cdot Z_{a3}}{Z_1} + \frac{3 \cdot Z_{a2}}{Z_1}\right) = \frac{\Sigma Z_{ak}}{Z_1} = \frac{Z_a'}{Z_1}$$
$$i_{a2} = \frac{1}{3}\left(\frac{3 \cdot Z_{a2}}{Z_2} + \frac{3 \cdot Z_{a1}}{Z_2} + \frac{3 \cdot Z_{a3}}{Z_2}\right) = \frac{\Sigma Z_{ak}}{Z_2} = \frac{Z_a'}{Z_2}$$
$$i_{a3} = \frac{1}{3}\left(\frac{3 \cdot Z_{a3}}{Z_3} + \frac{3 \cdot Z_{a2}}{Z_3} + \frac{3 \cdot Z_{a1}}{Z_3}\right) = \frac{\Sigma Z_{ak}}{Z_3} = \frac{Z_a'}{Z_3} \quad (10)$$

$$i_{k\text{-}k} = \frac{i \cdot \frac{Z_k}{3} - \Delta_k'}{\frac{Z_k}{3}} = i - \frac{3 \cdot \Delta_k'}{Z_k} = i - \frac{\Delta_k}{Z_k} \quad (11)$$

$$i_{k\text{-}k} = i - \frac{3 \cdot \Delta_k'}{Z_k} = i - \frac{1 + \Delta_k}{Z_k} \quad (12)$$

$$i_{k\text{-}k} = i - \frac{3 \cdot \Delta_k}{Z_k} = i - \frac{2 + \Delta_k}{Z_k} \quad (13)$$

$$i_{k\text{-}k} = \frac{i\frac{Z_k}{3} - (\Delta_k - 1)}{Z_k/3} = i - \frac{3(\Delta_k' - 1)}{Z_k} = i + \frac{3 - 2 - \Delta_k}{Z_k} = i + \frac{1 - \Delta_k}{Z_k} \quad (14)$$

$$Z_{am} = Z_{rm} - \Delta_m' \text{ or } Z_{am} = Z_{rm} - (\Delta_m' - 1) \text{ and } Z_{an} = Z_m - \Delta_n' \text{ or } Z_{an} = Z_{rn} - (\Delta_n' - 1) \quad (15)$$

$$Z_{rk} - Z_{am} = \Delta_{k\text{-}m}' \text{ and } Z_{rk} - Z_{an} = \Delta_{k\text{-}n}' \quad (16)$$

$$i_{k\text{-}m} = \frac{(i \cdot \frac{Z_k}{3} - \Delta_{k\text{-}m}')}{Z_k} = i - \frac{3 \cdot \Delta_{k\text{-}m}'}{Z_k}$$
$$i_{k\text{-}n} = \frac{(i \cdot \frac{Z_k}{3} - \Delta_{k\text{-}n}')}{Z_k} = i - \frac{3 \cdot \Delta_{k\text{-}n}'}{Z_k} \quad (17)$$

$$i_{ak} = \frac{1}{3}\left(i - \frac{3\Delta_k'}{Z_k} + i - \frac{3\Delta_{k\text{-}m}'}{Z_k} + i - \frac{3\Delta_{k\text{-}n}'}{Z_k}\right) = i - \frac{\Delta_k'}{Z_k} - \frac{\Delta_{k\text{-}m}'}{Z_k} - \frac{\Delta_{k\text{-}n}'}{Z_k} \quad (18a)$$

$$i_{ak} = \frac{1}{3}\left(i + \frac{3(1 - \Delta_k')}{Z_k} + i - \frac{3\Delta_{k\text{-}m}'}{Z_k} + i - \frac{3\Delta_{k\text{-}n}'}{Z_k}\right) = i + \frac{1 - \Delta_k'}{Z_k} - \frac{\Delta_{k\text{-}m}'}{Z_k} - \frac{\Delta_{k\text{-}n}'}{Z_k} \quad (18b)$$

$$S^* = t_k \cdot \Delta_k' + \Delta_{k\text{-}m}' \cdot t_m + \Delta_{k\text{-}n}' \cdot t_n \text{ or } S^* = (\Delta_k' - 1)t_k + \Delta_{k\text{-}m}' + \Delta_{k\text{-}n}' \cdot t_n \quad (19)$$

$$S_{k\text{-}m} = /(t_m - t_k)/(Z_{rk} - 1) + /t_m - t_k + \Delta_m' \cdot t_m/$$
$$\text{and } S_{k\text{-}n} = /(t_n - t_k)/(Z_{rk} - 1) + /t_n - t_k + \Delta_n' \cdot t_n/ \quad (20)$$

$$S_{k\text{-}m} = /t_m - t_k/ \cdot Z_{rk} + \Delta_m' \cdot t_m$$
$$S_{k\text{-}n} = /t_n - t_k/ \cdot Z_{rk} + \Delta_n' \cdot t_n$$
$$\text{or } S_{k\text{-}m} = /t_m - t_k/ \cdot Z_{rk} + (\Delta_m' - 1) \cdot t_m$$
$$S_{k\text{-}n} = /t_n - t_k/ \cdot Z_{rk} + (\Delta_n' - 1) \cdot t_n \quad (21)$$

$$S_{k\text{-}m}^* = (t_m - t_k)Z_{rk} + \Delta_m' \cdot t_m = (t_m - t_k)(Z_{rk} - 1) + (t_m - t_k) + \Delta_m' \cdot t_m \quad (22)$$
$$\text{Similarly, } S_{k\text{-}n}^* = (t_n - t_k)Z_{rk} + \Delta_n' \cdot t_n = (t_n - t_k)(Z_{rk} - 1) + (t_n - t_k) + \Delta_n' \cdot t_n$$
$$\text{or } S_{k\text{-}m}^* = (t_m - t_k)Z_{rk} + (\Delta_m' - 1) \cdot t_m = (t_m - t_k)(Z_{rk} - 1) + (t_m - t_k) + (\Delta_m' - 1) \cdot t_m;$$
$$S_{k\text{-}n}^* = (t_n - t_k)Z_{rk} + (\Delta_n' - 1) \cdot t_n = (t_n - t_k)(Z_{rk} - 1) + (t_n - t_k) + (\Delta_n' - 1) \cdot t_n$$

$$S^* = \pm S_k \pm S_k^m \pm S_z^m \pm S_k^n \pm S_z^n;\ S = S_k + S_k^m + S_z^m + S_k^n + S_z^n \quad (23)$$

$$S_z^k = S_k = \Delta_k' \cdot t_k \text{ or } S_z^k = S_k = (1 - \Delta_k') \cdot t_k \quad (24)$$

$$S_z^{k\text{-}m} = \frac{S_k^m}{Z_{rk\text{-}1}} = t_m - t_k;\ S_z^m = t_m - t_k + \Delta_m' \cdot t_m, \text{ or } S_z^m = t_m - t_k + (\Delta_m' - 1)\ t_m;$$
$$S_z^{k\text{-}n} = \frac{S_k^n}{Z_{rk\text{-}1}} = t_n - t_k;\ S_z^n = t_n - t_k + \Delta_n' \cdot t_n, \text{ or } S_z^n = t_n - t_k + (\Delta_n' - 1)\ t_n \quad (25)$$

$$S_x = 2\pi(R_x - r_x \cdot i) \quad (26)$$

$$S_x' = \frac{S_x}{2\pi r_x i} = \left(\frac{R_x}{r_x i} - 1\right) \cdot 100 \quad (27)$$

$$S_{Zx} = \frac{2\pi}{Z_x}\left(\frac{R_x}{i} - r_x\right) = \frac{S_x}{Z_x \cdot i} \quad (28)$$

Nomenclature

t	= rack pitch, mm
t_c	= pitch of heel teeth, each once
t'	= increased pitch of one of the well bottom rack craters
Z_c	= number of heel teeth, each once
d	= gauge tip diameter of the cone
D	= diameter of the bit
Z_{cr}	= number of craters
Z_{rd}	= number of ridges between the craters
Z_r	= estimated number of the "teeth" on the hole bottom rack
$i = \frac{D}{d}$	= gear ratio for the cones at pure rolling
i_a	= actual gear ratio
N	= an integral number
Δ	= a fractional number, while $0 \le \Delta < 1$
S	= skidding path
$S_z = S/3$	= slide path for three "completing" teeth
$Z_r = (N + \Delta)/3$	= number of teeth on bottom hole rack
r_x	= teeth row radius
R_x	= the radius of the row rotation around the bit axis

This choice of leading cone is made without ascertaining the real nature of its destination[2,3] or based upon the assumption that the heel row teeth with maximum pitch display the highest kinetic energy and, consequently, they should form the deeper rack.[4]

Such assumption can hardly be admitted because the difference between the maximum and minimum pitch of the bit cone heel teeth is only 2-3 mm and therefore the difference cannot, to any significant extent, affect the value of the kinetic energy of the teeth.

In addition, even if there exists some difference in the kinetic energy of the teeth, the intensity of the grinding, and the depth of the bottom rack craters will be determined by the cone with the lowest kinetic energy.

Alternative choice

Due to insufficient validation of this assumption, as revealed by many experiments in which the cone rotational speed was recorded at Moscow's I.M. Gubkin Institute of Petrochemical and Gas Industry, it is sometimes necessary to choose as the leading cone the one that has the next-to-largest size pitch of the heel teeth.[4]

Explaining the transformation of the leading cone features is based on the assumption that it is valid for cases when the length of the heel row teeth with maximum pitch is less than the length of the teeth of the other two heel rows, while the rack craters, shortened in their length, impede slippage of teeth of the other cone rows into them.

However, this assumption also contradicts the hypothesis concerning maximum kinetic energy of the leading cone row. In this case, strictly speaking, there should be two cones rolling over the well bottom almost without any skidding: the one with the largest heel teeth pitch (as nothing impedes the cone teeth slippage into the formed craters) and the cone with the second-largest pitch of the heel teeth.

The second cone would be the lead for the third cone while formally it would result in two leading cones, but that does not correspond either to theory or experiment. Consequently, it is reasonable to assert that the shortened length of the crater does not impede the teeth skidding because of the additional destruction that enlarges the crater. It is unlikely that a tooth capable of forming a crater might not partially destroy a crater weakened from residual stresses and strains.

Actually, the reason for the "leading" features displayed by one or another cone is seen by comparing the estimated number of the rack teeth for a 120° rotation with the estimated number of teeth for the same rack which might be individually formed by each of the three cones per revolution of the bit, i.e., $N_k + \Delta_k$.

One of the three cones is able to roll a rack with the number of teeth closest to Z'_a and therefore the apparent skidding of this cone per revolution of the bit will be minimal. This, however, does not mean that the given cone is the leading one. The racks that can be rolled individually by the other two cones may have fewer or more teeth, as compared with the actual well-bottom rack, and depending upon that, the rotation of the cones will either accelerate or decelerate. Which of the cones is the lead depends upon the actual number of teeth on the rack, Z'_a.

But according to Equation 7, since Z'_a may have six values, the minimum will be equal to $Z'_{a\,min} = Z'_{a5} = ((\Sigma N_k)-5)/3$; the maximum to: $Z'_{a\,max} = Z'_{a6} = ((\Sigma N_k) +1)/3$.

Arithmetic mean

The feature that points to the "leading" cone implies the condition $N_k + \Delta_k = Z'_a$ or $N_k + \Delta_k \approx Z'_a$. If Z_a equals the arithmetic mean, i.e., $Z'_a = (\Sigma N_k)/3$, then the leading cone would always be that with the intermediate (mean) pitch of the heel row or, in other words, the cone with the second-largest pitch of heel teeth.

But since in five out of the six cases, the value of Z'_a is less than the arithmetic mean by 1/3, 2/3, 1, 4/3, and 5/3, then, at least in four cases (at $Z'_{a2} = ((\Sigma N_k) -2)/3$; $Z'_{a3} = ((\Sigma N_k) -3)/3$; $Z'_{a4} = ((\Sigma N_k) -4)/3$; and $Z'_{a5} = ((\Sigma N_k) -5)/3$), the leading cone becomes the one with the lowest estimated number of rack teeth, $N_k + \Delta_k$, i.e., the cone with the maximum heel teeth pitch.

At $Z'_a = ((\Sigma N_k) -1)/3$, the "leading" cone may be the one that has the maximum heel teeth pitch or that with the mean pitch size, depending upon which of them corresponds to the $N_k + \Delta_k$ value closest to Z'_a.

At $Z'_{a\,max} = Z'_{a6} = ((\Sigma N_k) +1)/3$, the "leading" role will always be taken by the cone with the mean value of the heel teeth pitch.

Consequently, the most probable candidate for the "leading" role is the cone with the maximum heel teeth pitch size. The cone with minimum heel teeth pitch size may never be the lead. It will always rotate at a slowing speed.

Here, it needs to be emphasized that for a single bit, depending upon the number of the rack teeth, Z'_a, formed in the given conditions (which may vary, as shown later), the leading role will be taken by the cone with either maximum or medium heel teeth pitch. Besides, change in Z'_a value may result in transformation of the "leading" cone, i.e., for one Z'_a value the "leading" role may be taken, e.g., by the first cone while for another Z'_a value the "leading" role may be taken by the second cone, or vice versa.

Apparent skidding

We need to explain the reason for the term "apparent cone skidding" per revolution of the bit, as used previously.

Since the well-bottom rack consists of three different sections, rotational speed of each cone per revolution of the bit will change three times.

Actually, when the cone rolls in its own sector, there is zero or minimal skidding.

In the other two sectors, which have been rolled by the other two cones, some slowing or acceleration of the cone rotation takes place. This means

that during drilling with a bit with different heel teeth pitch for all cones, each of the three cones is subject to skidding of periodically varying extent and direction.

Given this explanation, let's determine the values of the apparent gear ratios for each of the three cones, i_{ak}, and find the values of the actual gear ratios in different sections of the well-bottom rack.

When the actual well-bottom rack teeth number, $Z'_a = \Sigma Z_{ak}$, has been calculated and the number of teeth on the heel rows has been determined, the apparent i_{ak} values may be easily found: $i_{a1} = Z'_a/Z_1$; $i_{a2} = Z'_a/Z_2$; and $i_{a3} = Z'_a/Z_3$.

When determining the actual gear ratio values for the cones, we assume the following.

The gear ratio for each cone when changing three times/revolution of the bit is shown in Equation 8, where i_{a1}, i_{a2}, and i_{a3} are the apparent gear ratios for the given cones per revolution of the bit.

As shown in Equation 9, i_{1-1}, i_{2-2}, and i_{3-3} (in the general case, i_{k-k}) are the actual gear ratios for the given cones when drilling their "own" sectors. Equation 9 also defines i_{1-3}, i_{1-2}, i_{2-1}, i_{2-3}, i_{3-2}, and i_{3-1} (in the general case i_{k-m} and i_{k-n}), which are the actual gear ratios for the given cones during their movement along the sections rolled by the other two cones.

Equation 10 confirms that the apparent value of the gear ratio for the given cone per revolution is the arithmetic mean of the three actual gear ratio values for that cone.

Gear ratios, home sector

Let's ascertain to what extent the actual gear ratio of the cones moving along their own sector and the alien well-bottom rack sectors would differ from pure rolling.

First, we need to examine the cone's movement along its "own" well bottom sector:

1. If $N'_k = N_k/3$ and $\Delta'_k = \Delta_k/3$ or $\Delta'_k = 0$, then according to Equation 3, $Z_{ak} = N_k/3$, while $Z_{rk} = (N_k + \Delta_k)/3$, meaning that $Z_{ak} < Z_{rk}$ or $i_{k-k}(Z_k/3) < i(Z_k/3)$ and $i_{k-k} < i$.

As $Z_{ak} = Z_{rk} - \Delta'_k$, then $i_{k-k}(Z_k/3) = i(Z_k/3) - \Delta'_k$, and we reach Equation 11.

2. If $N'_k = (N_k - 1)/3$ and $\Delta'_k = (1 + \Delta_k)/3$, then according to Equation 4, $Z_{ak} = (N_k - 1)/3$, while $Z_{rk} = (N_k + \Delta_k)/3$. It means that $Z_{ak} < Z_{rk}$ and $i_{k-k} < i$.

Consequently, by analogy with Equation 11, we can write Equation 12.

3. If $N'_k = (N_k - 2)/3$ and $\Delta'_k = (2 + \Delta_k)/3$, then at $0 < \Delta_k < 0.5$ and $0.5 < \Delta'_k < 1$, according to Equation 5, $Z_{ak} = (N_k - 2)/3$. It means that $Z_{ak} < Z_{rk}$ and $i_{k-k} < I$, resulting in Equation 13.

4. If $N'_k = (N_k - 2)/3$ and $\Delta'_k = (2 + \Delta_k)/3$, then at $0.5 < \Delta_k < 1$ and $0.5 << \Delta'_k < 1$, according to Equation 6, $Z_{ak} = (N_k + 1)/3$, while $Z_{rk} = (N_k + \Delta_k)/3$. It means that $Z_{ak} > Z_{rk}$ or $i_{k-k} > i$.

APPARENT SLIDE PATH

Box 2

Based on Equations 15 and 16:

$$\Delta'_{k-m} = Z_{rk} = Z_{rm} + \Delta'_m \text{ and } \Delta'_{k-n} = Z_{rk} - Z_{rn} + \Delta'_n \text{ or } \Delta'_{k-m} = Z_{rk} - Z_{rm} + (\Delta'_m - 1) \text{ and } \Delta'_{k-n} = Z_{rk} - Z_{rn} + (\Delta'_n - 1)$$

Then, the apparent values of the slide path would be:

$$S^*_{k-m} = \Delta_{k-m} \cdot t_m = (Z_{rk} - Z_{rm} + \Delta'_m)t_m = (Z_{rk} - Z_{rm})t_m + \Delta'_m t_m = (Z_{rk} - Z_{rm})t_m + \Delta_m t_m = \left(\frac{\pi D}{3t_k} - \frac{\pi D}{3t_m}\right)t_m + \Delta'_m \cdot t_m =$$

$$\left(\frac{1}{t_k} - \frac{1}{t_m}\right)\frac{\pi D}{3}t_m + \Delta'_m \cdot t_m = \frac{t_m - t_k}{t_k \cdot t_m} \cdot \frac{\pi D}{3} \cdot t_m + \Delta'_m \cdot t_m = (t_m - t_k) \cdot Z_{rk} + \Delta'_m \cdot t_m$$

In this case, $Z_{ak} = Z_{rk} - (\Delta_k - 1)$, then $i_{k-k}(Z_k/3) = i(Z_k/3) - (\Delta'_k - 1)$, from which we derive Equation 14.

Gear ratios, alien sector

Now we examine the cone's movement along the "alien" sector of the well-bottom rack. The well-bottom rack sectors rolled by the two other cones will have the actual "teeth" number, accordingly, Z_{am} and Z_{an}, as shown in Equation 15.

Let's mark the difference in Z_{am} (or Z_{an}) and Z_{rk} values by means of Δ_{k-m} (or Δ_{k-n}), as shown in Equation 16.

Then, $Z_{am} = Z_{rk} - \Delta'_{k-m}$ and $Z_{an} = Z_{rk} - \Delta'_{k-n}$.

The actual gear ratios for the cone under consideration, moving along the "alien" sectors, will be: $i_{k-m} = (3 \cdot Z_{am})/Z_k$ and $i_{k-n} = (3 \cdot Z_{an})/Z_k$.

Then, taking into account that $Z_{rk} = i \cdot Z_k/3$, we can derive Equation 17.

Thus, the value of the apparent gear ratio for the given cone may be found using Equation 18a or 18b.

It is obvious that the path of the cone slide (meaning its gauge raw) per revolution of the bit will consist of three elements, as shown in Equation 19.

Where $\Delta'_k t_k = S_k$ and $(\Delta'_k - 1)t_k = S_k$, Equation 19 shows the path of the cone's heel row slide during its movement along its "own" sector.

Where $\Delta'_{k-m} t_m = S^*_{k-m}$ and $\Delta'_{k-n} t_n = S^*_{k-n}$, Equation 19 shows the paths of the cone's heel row slide corresponding to its movement along the "alien" sectors.

The slide path, S_k, accounts for teeth which complete the cone's movement along its own sector while the slide paths S^*_{k-m} and S^*_{k-n} correspond to the teeth number Z_{rk}. Meanwhile, considering the slide paths S^*_{k-m} and S^*_{k-n} expressed as $\Delta'_{k-m} t_m$ and $\Delta'_{k-n} t_n$, one must imply their apparent values. The actual slide path of the heel row of the cone during its movement along the "alien" sector is shown in Equation 20.

Where $|(t_m - t_k)|(Z_{rk} - 1) = S^m_k$ and $|(t_n - t_k)|(Z_{rk} - 1) = S^n_k$, Equation 20 shows the slide path of the row as conditioned by the difference in the heel teeth pitch values for the cones. Where $|t_m - t_k + \Delta'_m \cdot t_m| = S^m_z$ and $|t_n - t_k + \Delta'_n \cdot t_n = S^n_z$, Equation 20 shows the slide path of a single tooth which completes the row movement along the "alien" sector at slowed-down skidding.

In the case of the accelerated completing tooth movement, the comultipliers Δ'_m or Δ'_n should be replaced by $(\Delta'_m - 1)$ or $(\Delta'_n - 1)$. If the difference $t_m - t_k$ or $t_n - t_k$ is positive, i.e., if the cone

CHARACTERISTICS OF COMMERCIAL BITS

Table 1

Bit type	i	Cone	Z_k	t_k	iZ_k	Z_{rk}	Z_{ak}	Z'_a	i_{ak}	i_{k-k}	i_{k-m}	i_{k-n}
B-151T	1.57	I	20	15.05	31.46	10.49	10		1.6	1.5	1.65	1.65
d =96		II	21	14.3	33.03	11.0	11	32	1.52	1.57	1.43	1.57
		III	22	13.7	34.61	11.53	11		1.45	1.5	1.5	1.36
B-190T	1.53	I	20	19.46	30.64	10.21	10		1.45	1.5	1.5	1.35
d = 124		II	19	20.49	29.11	9.7	9	29	1.53	1.42	1.58	1.58
		III	21	18.54	32.17	10.73	10		1.38	1.43	1.28	1.43
K-190T	1.51	I	20	19.7	30.26	10.08	10		1.45	1.5	1.5	1.35
d = 125.59		II	19	20.7	28.75	9.58	9	29	1.53	1.42	1.58	1.58
		III	21	18.7	31.77	10.59	10		1.38	1.43	1.28	1.43
K-214T	1.57	I	18	23.7	28.3	9.43	9		1.61	1.5	1.67	1.67
d = 136		II	19	22.5	29.9	9.97	10	29	1.53	1.58	1.42	1.58
		III	20	21.3	31.5	10.5	10		1.45	1.5	1.5	1.35

Bit type	i	Cone	S_k	S^*_{k-m}	S^*_{k-n}	S^*	S_{k-m}	S_{k-n}	S mm	S^k_z	S^{k-m}_z	S^m_z	S^{k-n}_z	S^n_z	S_x	S_{zx}
B-151T	1.57	I	+7.3	–6.85	–8.25	–7.8	18.75	8.25	34	+7.3	–1.35	+5.95	–0.75	0	–8.1	–0.25
d = 96		II	0	+15.55	+0.7	+16.25	15.55	13.7	29.25	0	+0.75	+8.05	–0.6	+6.7	+16	+0.53
		III	+7.3	+6.9	+22.85	+37.05	6.9	22.85	37.05	+7.3	+0.6	0	+1.35	+8.65	+37.1	+1.17
B-190T	1.53	I	+4.17	+4.1	+24.83	+33.1	21.1	24.83	50. 1	+4.17	–0.92	+12.6	+1.03	+15.33	+32	+1.1
d = 124		II	+14.3	–5.86	–5.45	+3	12.14	28.55	55	+14.3	–1.03	+3.14	–1.95	+11.55	+2.3	+0.08
		III	+13.4	+35.25	+14.37	+63	35.25	14.37	63	+13.4	+1.95	+16.25	+0.92	+5.42	+59	+2.04
K-190T	1.51	I	+1.97	+1.1	+22.5	+25.6	19.3	22.5	43.8	+1.97	–1.0	+10.2	+1.0	+13.4	+27.6	+0.95
d = 125.59		II	+12.4	–7.63	–8	–3.23	9.57	26.4	48.4	+12.4	–1.0	+0.97	–2.0	+9.2	–2.4	–0.08
		III	+11.2	+33.6	+12.57	+57.4	33.6	12.57	57.4	+11.2	+2.0	+14.4	+1.0	+2.97	+55	+1.9
K-214T	1.57	I	+10.3	–12	–12.03	–14.7	28.6	12.03	50.9	+10.3	–2.4	+8.3	–1.2	–1.88	–15.8	–0.54
d = 136		II	–0.68	+22.3	–1.3	+20.8	22.3	20.3	43.3	–0.68	+1.3	+11.5	–1.2	+9.5	+18.3	+0.63
		III	+10.7	+11.92	+35.5	+58.12	11.92	35.5	58.12	+10.7	+1.2	+0.52	+2.4	+12.7	+52.5	+1.81

row with the pitch t_k rolls over the "alien" sector at a slowed-down rate, then Equation 20 may written slightly differently, as shown by Equation 21.

Let's verify the validity of these equalities that reflect the actual slide path of the heel row of the cone when it moves along the "alien" sector, proceeding from the apparent values of the slide path.

As we proceed from Equations 15 and 16, we follow the analysis shown in Box 2 and reach Equation 22.

A comparison of Equation 22 with Equations 21 and 20 makes their complete identity obvious, the only difference being that the actual slide path for the heel row of the cone along the "alien" sector is found as the arithmetic sum of the completing tooth's slide path while the apparent value of the same path is the algebraic sum of the same components.

It means that if the direction of slide for the row and the completing tooth in the given sector is the same (both for slow-down and acceleration), then the apparent slide path will correspond to the actual path. Otherwise, the apparent value of the slide path for the heel row of the cone along the "alien" sector will be less than that of the actual path.

Actual slide path

In the general form, the apparent slide path value for the heel row of the cone per revolution of the bit should be put down as $S^*_{k-n} = \pm S_k + S^*_{k-m} + S^*_{k-n}$, while the actual value should be $S = S_k + S_{k-m} + S_{k-n}$, where: $S^*_{k-m} = \pm S^m_k$, $S^*_{k-n} = \pm S^n_k \pm S^n_z$, $S_{k-m} = S^m_k + S^m_z$, and $S_{k-n} = S^n_k + S^n_z$, i.e., S^* is shown by Equation 23, and consequently, $S^* \leq S$.

Equation 23 shows that the slide path for the heel rows of the cones per revolution of the bit (with different pitch of the heel teeth for all cones) changes five times. Consequently, to calculate the slide path for a single tooth of the given row of the cone, a differentiating approach should be used. There is no sense in determining the value of a single tooth slide dividing the row's slide path per revolution of the cone by the number of the teeth in the given row. So, the slide path for the heel row of the cone during its movement along its "own" sector, as mentioned above, would fall at the completing tooth. It means that the slide path of this tooth would be equal to the value S_k, as shown in Equation 24.

The other teeth, $(Z_{rk} - 1)$, would move along their "own" sector without any skidding.

When the cone moves along the "alien" sectors, the slide paths of individual teeth would be expressed as shown in Equation 25.

Thus, per revolution of the bit $(Z_{rk} - 2)$, the teeth of the given cone's row would skid on the alien sectors of the rack due to the difference in the pitch values of the heel teeth of the cones.

If the apparent gear ratio for the given cone is equal or close to 1.5, then any two of its diametrically opposed heel teeth will constantly perform as the completing teeth, differing in that at each revolution of the bit, one of the teeth would slip on its own and alien sectors of the rack, while the others would slip only on the alien sector. The roles of the cones will change at each revolution of the bit. In this case, similarly to the case considering the cones with equal number of the heel teeth, wear of the teeth rows of the given cone will be uneven.

Yet, if the apparent value of the gear ratio for the given cone differs to a sufficient extent from 1.5, then its completing teeth would change after each revolution of the cone, and that would promote uniform wear of the cone's teeth.

However, the bit performance data

will be predominantly determined rather by the actual value of the teeth slide path than by the extent of wear uniformity.

Table 1 represents the estimated data for such values as actual number of the rack teeth Z'_a, the apparent and actual gear ratios for the cones i_{ak}, i_{k-k}, i_{k-m}, and i_{k-n}, the apparent and actual slide paths of the heel rows S_k, S^*_{k-m}, S^*_{k-n}, S_{k-m}, S_{k-n}, S^*, and S, the actual slide paths for individual heel teeth S^k_z, S^{k-m}_z, S^m_z, S^{k-n}_z, and S^n_z calculated for commercial bits B-151T, B-190T, K-190T, and K-214T, according to the Equations 7, 9, 10, 19, 20, and 22-25. The validity of Equations 9 and 10 may be verified by the equivalent Equations 11-14, 17, 18a, and 18b.

The same table presents, for comparison, values of the teeth row slide paths per revolution of the bit S_x, the specific slide of the row S'_x, and the slide paths of a single tooth S_{Zx} calculated by the known formulas[6] shown in Equations 26-28.

Following the above-mentioned and analyzing the data from Table 1, we come to the conclusion that Equations 26-28 are not quite acceptable for toothed cone bits because they do not give the sought true values.

Actually, as we have found, the slide path of the toothed heel rows of each of the three cones changes five times per revolution of the bit, but taking into account that in their "own" sector $(Z_{rk} - 1)$ the teeth are rolling without skidding (i.e., $i_a = i$ and $S = 0$), the gear ratio for the cone per revolution of the bit will change six times. Consequently, the position of the instantaneous axis of the cone rotation will change the same six times.

However, Equations 26-28 include the apparent value of the cone's gear ratio which does not take into consideration the multiple changes in its rotational speed, i.e., the formulas consider even rotation of the cones per revolution of the bit and a constant position of their instantaneous axes of rotation. Consequently, the presented known correlations, excluding the expression of a single tooth slide path (Equation 28), are acceptable, strictly speaking, only for bits with smooth-tapered cones.

In the next part of this series, to be published Feb. 25, 2008, we'll discuss one more aspect of the rock bit kinematics. ✦

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Correction

The coverbox text for the "Downhole Technology Review" special issue (OGJ, Jan. 28, 2008, p. 1) inadvertently failed to cite Baker Oil Tools for supplying the header image depicting a permanent inflatable straddle packer system.

The article "Operators develop, implement new downhole technologies" (OGJ, Jan. 28, 2008, p. 49) missed an attribution on p. 50 regarding swellable packers. The information came from Shell.

Study theorizes use of geothermal sources for energy in refineries

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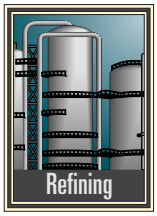


Geothermal sources for direct heating can theoretically serve as an alternative source of high-temperature (>130° C.) heat in processing plants.

Cutting CO_2 emissions from a refinery requires reducing the amount of fuel burned. Although CO_2 savings was the motivating and initial goal of this study, the real economic incentive is savings in refinery fuel burned. We estimated this at roughly 6 times the value of CO_2 emissions saved based on $15/ton CO_2 and $68/bbl of crude.

The upper sedimentary layer in the West Netherlands basin is not thermally or geomechanically interesting for creating a geothermal heat exchanger; however, the underlying deformed sediment layer and expected depth to basement of 8-10 km are favorable for the required temperatures, fracturing, and drilling prospects.

Considerable savings are possible if low-enthalpy waste water was injected for geothermal recovery. This makes most efficient use for obtaining high-quality heat, as compared to a previous EOR water-flooding proposal.

The combination of favorable geothermal gradient, large petrochemical plant or refinery, and the subsurface uncertainties means that the risks are considerable although the rewards are potentially high. The proposed scheme thus requires considerable research and development before it is an economically viable process.

Geothermal energy

Heat obtained from geothermal energy is more efficiently used for directly powering petrochemical and refining processes rather than for electricity generation. Significant reductions in CO_2 emissions from burning fuel are possible. The savings, however, from not burning refinery fuel are even greater.

If refinery waste water is injected, then the subsurface geothermal heat exchanger fracture network is more efficient.

The relatively low temperatures that are obtained and, therefore, the low efficiency thermal-to-electric energy conversion hampers use of geothermal energy for electricity generation.[1] Recently, a study proposed using EOR flooding water (OGJ, Sept. 5, 2005, p. 34) to generate electrical power. The process is still relatively inefficient. It is more efficient to use this water directly to power chemical conversion processes because this can reduce fuel burned.

Such a direct integration of an upstream and downstream process has not, to our knowledge, been proposed within the oil and gas industry. One can remove the inefficiencies associated with electricity generation by applying the heat obtained from geothermal operations directly to downstream oil and gas processing on a refinery scale.

CO_2 reduction

To reduce CO_2 emissions from a refinery means reducing hydrocarbons burned.[2] Biofuels, for example, is a step

Equations

$$P_{el} = \varepsilon_x \varepsilon_w \varepsilon_c P_{th} \quad (1)$$

$$Mw_e \approx 0.1 * Mw_{th} \quad (2)$$

$$r = \frac{m_{co_2}}{m_f} \frac{V_{co_2}}{V_f} \quad (3)$$

$$y = 43d^3 - 425d^2 + 2,112d - 7 \quad (4)$$

Nomenclature

d	=	Depth, km
m_{CO2}	=	Mass of CO_2 emitted, tons
m_f	=	Mass of fuel burned
Mwe	=	Electrical power Mw
Mw_{th}	=	Thermal power Mw
P_{el}	=	Electrical power Mw
P_{th}	=	Thermal power Mw
r	=	Relative value ratio
V_{CO2}	=	Value of CO_2, $/ton
V_f	=	Value of crude input, $/ton
y	=	Cost, $1,000
ε_c	=	Carnot efficiency
ε_{ex}	=	Exchanger efficiency
ε_w	=	Work efficiency

in this direction because its cultivation involves CO_2 as feedstock, as does subsurface sequestration of CO_2 in reservoirs. Closely related is the use of biomass, which is defined as carbon neutral. Both reduce CO_2 on a well-to-wheel basis, unless sequestration is used to offset heavier feedstocks like tar sands.

Other than these developing but nonetheless combustion-oriented, and therefore CO_2-producing, processes there are basically three reliable direct-heat options for producing the hot steam needed for refinery processes:

- Nuclear energy. Nuclear fission directly heats water to make superheated steam.
- Wind power. Turbines generate electricity, which then powers coil heaters.
- Geothermal power. Subsurface hot water directly powers processes.

Nuclear power is probably an unacceptable option for local refinery heating plants—it is better for electricity generation. Wind power is not necessarily reliable and is relatively inefficient due to limits on turbine generation of electricity that is then turned back into thermal energy. For both of these, hydrogen generation is an attractive route because it can be stored.

The advantage of geothermal heat over concentrated solar panels or photovoltaic is the continuous flow of energy; solar energy is not constant and would not be an option for a large number of refineries in, for example, Northern Europe.

The same problem applies to the use of geothermal power to generate electricity. In that case, the electrical power is related to the thermal power using Equation 1 (see equation box). Equation 1 represents the products of the heat exchange, work, and Carnot efficiencies.

This means that the geothermal water stream and the organic working fluid, which mechanically drives the turbines, must exchange heat. This further reduces efficiency—heat exchangers, secondary power fluids, and various other intervening steps mean that typically only 10% of the thermal power (250° C.) ends up as electrical power (Equation 2).

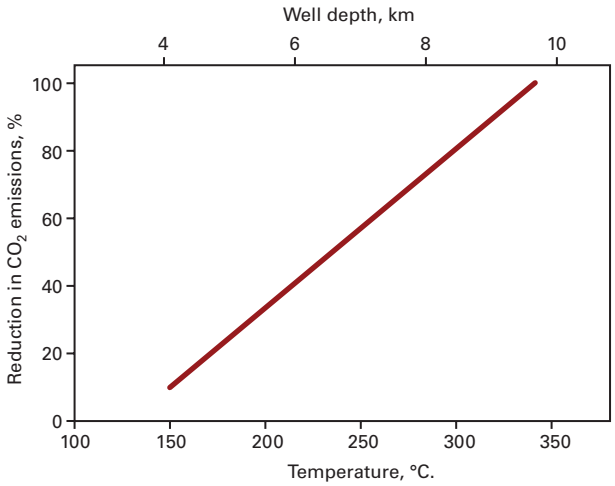
This restriction would not of course apply if only thermal power is needed. The 90% losses could still be used for running chemical conversions. It is much better to use the energy directly in its naturally generated form, i.e., thermal heat. Geothermal power is therefore an option because of its ability to generate superheated steam directly.

The problem is that many geothermal projects generate contaminated water, which is low-quality energy (low temperature). Most operations in the Netherlands, for example, are relatively shallow (<3 km) and only provide water up to about 100° C.[3] This was exactly the restriction identified in the EOR study; the authors stated that the inefficiency was reduced because the water was already available following removal of the oil after flooding production.

Refineries already have much low-energy water available, but it is all low-quality heat, typically <130° C. Because a refinery needs higher-grade (hotter) energy, our study tried to determine how much process heat, and thus fuel burning and CO_2, this would save if sufficiently hot (130° C.) water could be generated.

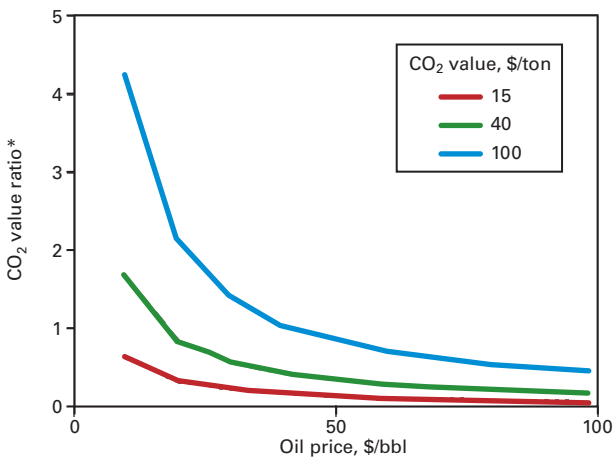
Lower CO_2 emissions

Fig. 1



Value ratio of CO_2 saved

Fig. 2



*Value of CO_2 saved/value of refinery fuel burned.

Process heat

Clearly, more than one geothermal producer well is required for a refinery, and the configuration will affect the economics. The following issues must be addressed:

- Is the necessary thermal energy flux available to directly heat units in a refinery and what will be the cost?
- What temperature will give what CO_2 savings?
- What is the cost associated with drilling to a depth to reach that temperature?

The first thing we did was estimate the heat flux required. In this case it is not just the temperature, but also the

amount of energy required.

We started by imposing the most difficult condition—we only wanted heat above 130° C. We assumed that internal refinery heat integration would provide enough process water for up to that temperature.

Waste heat, which is abundantly available at refineries, can therefore be recovered to provide the preliminary process unit heating to 130° C. This is the starting temperature at which either traditional combustion heat or geothermal heat will come into play for reaching the required process temperature. For atmospheric distillation, 340° C. is typically reached with superheated steam.

These considerations typically apply for large refineries (50,000 tons/day of crude processed) where a significant fraction (5-10%) of hydrocarbon intake is required to fuel the processes themselves. We assumed that an average of 8% of the equivalent hydrocarbon intake is actually burned to power the distillation, conversion, and treating processes (including hydrogen manufacture). The required heat fluxes, temperatures, and related mass flows form a complex system and a detailed analysis is beyond the scope of this initial study.

We started with the crude distillation unit, through which all the crude feed passes, and which usually consumes about ¼ of the heat flux. Typical heat fluxes for distilling 50,000 tons/day of crude are about 500 Mw_{th}, which is about 2% of the hydrocarbon intake (either as refinery fuel gas or fuel oil) for processing. The maximum temperature required is about 340° C.

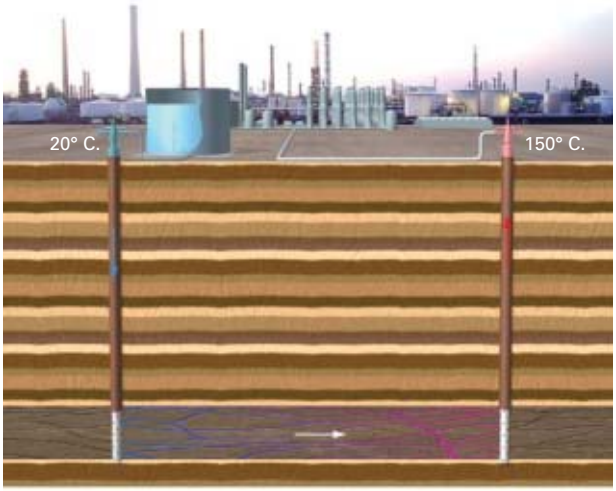
Geothermal heating to 340° C. therefore obviates the need for combustion heat (100% CO_2 emissions avoided) in the crude distillation unit and geothermal temperatures less than 130° C. are not required (corresponding to no savings in combustion CO_2). Because 2% of the fuel intake is burned, this immediately indicates the amount of CO_2 produced. Accordingly, we can calculate the reduction in CO_2 emissions as a function of the geothermal heat source temperature.

Fig. 1 shows the percentage savings in CO_2 emissions as a function of the temperature of the hot water that can be obtained. The upper axis shows the corresponding drill depth typically reached.

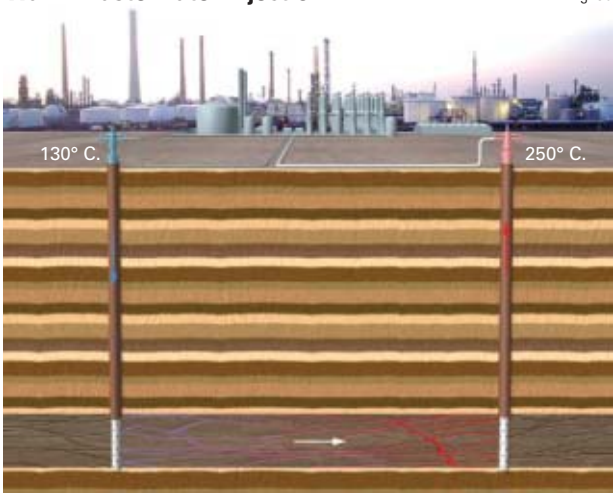
GEOTHERMAL SCHEMES

Fig. 3

Cold-water injection Fig. 3a



Warm waste water injection Fig. 3b



A geothermal source at 190° C. would therefore cut CO_2 emissions by about 30%. This was the initial target of this study; however, a cursory examination shows that much larger financial savings come from significant reductions in fuel combustion for providing process heat. We therefore considered the relative values of CO_2 saved and the mass of fuel burned and their associated values.

In Equation 3, r is the relative value ratio of CO_2 saved and fuel input burned.

The first term is the ratio of masses of CO_2 to refinery fuel burned. To a first approximation, this ratio is independent of the fuel's molecular weight; it is purely dependent on the ratio of CO_2 to carbon and hydrogen molecular weight (represented by CH_2). For any except the lightest molecular-weight fuels, the ratio converges to 3.1; i.e., it does not make any difference if it is a heavy refinery fuel or a lighter feedstock.

The more volatile portion of Equation 3 is the second multiplier—the relative value ratio. Until recently, common values were CO_2 at $15/ton and crude at $68/bbl. For a typical crude (specific gravity of 0.85), this gives a ratio value of about 0.1, which means that the value of fuel saved is 10 times that of the CO_2 saved. Although CO_2 emissions are reduced, the real economic savings come from not having to burn fuel. Total savings is the sum of the numerator and denominator.

The magnitude by which the fuel saved exceeds the value of CO_2 is geographically dependent and only gradually is a consensus emerging for this.

Fig. 2 shows how the ratio of CO_2 to refinery fuel value changes with oil price for different CO_2 values. CO_2 val-

ues range from a standard $15/ton to the high values maintained in countries like Norway. Assuming that 1 bbl of oil roughly yields 0.4 tons of CO_2, in a high CO_2-tariff ($50/ton) country like Norway, if the oil price is $50/bbl, then the associated CO_2 penalty is $20, which is 40% of the value of the crude.

There are some scenarios in which the value of CO_2 saved exceeds fuel savings. Given higher crude prices, all except the most extreme CO_2 valuations mean that the refinery fuel savings is the main motivation for using external geothermal to power refinery processes.

Geothermal heat flux

The simplest way to mine geothermal energy is to produce hot formation water from deep water-bearing layers. In most cases, water must be injected from the surface. In the local refinery case, using available waste hot water rather than cold water leads to considerable savings.

We compared the two scenarios:

- Cold-water injection (Fig. 3a). Much of the subsurface heat is used to heat ambient water to 130° C. before obtaining quality heat above this temperature. This results in unnecessary geothermal source depletion (drawdown) because high-quality heat is lost to low-quality enthalpy in the water.
- Waste water at temperatures approaching 130° C. (Fig. 3b). These energy savings and the associated value, although significant, are still small compared to the savings in burned fuel.

Under an assumption that hot water is available to meet the temperature requirement, the amount of water needed is about 500 kg/sec. A modest estimate is 50 kg/sec/well. The EOR study used projected flows of 50-250 kg/sec, which are rather high. Two options are to drill a few deep wells and obtain high-temperature water or drill more numerous shallower wells (Fig. 4).

Although configurations of one injection well and multiple production wells have been considered, a more realistic scenario is two production wells fed by one injection well (triplet option). Because we assume this case, only even numbers of producer wells should be considered in Fig. 3, which is based on each well producing 50 kg/sec of fluid with total power of 130 Mw.

Hot rock

The remaining question is the cost associated with drilling to the required depth. We have been using a generic refinery in this study. We must therefore consider the local geology underneath a refinery.

First, we must consider where the heat lies and examine the thermal gradients. Then we must assess the geological problems for accessing the heat. This depends on refinery location.

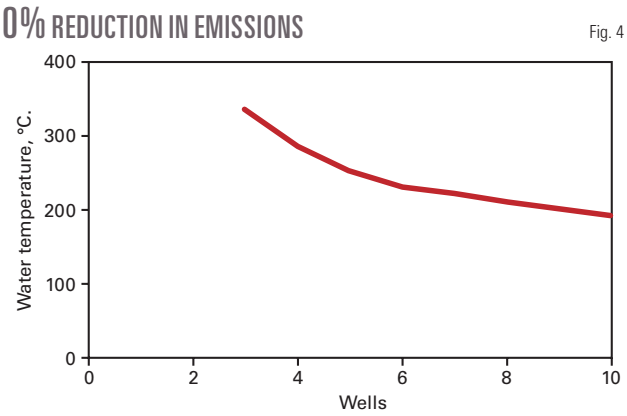
The EOR study pointed out that, although production operations are often where thermal gradients are relatively unfavorable, well drilling and pumping costs are already covered by oil production. Even if the temperature is relatively low, it is basically available for free.

Ideally the refinery is next to a production operation in which EOR is practiced with high water cuts being produced. Even without this situation, however, we can outline many requirements about the depth of wells required for direct heating of a refinery.

The EOR study used locations in Texas and Arkansas. In this study, we selected the West Netherlands basin. This region has a high manufacturing process intensity and therefore demand for process heat. It also has significant onshore and offshore gas production and therefore deeper wells.

The Earth's average thermal gradient is 30° C./km. There is evidence that this gradient is higher in the West Netherlands Basin and Roer Valley. Temperature profile maps indicate that depths of more than 4 km are required.[4] To assess the cost of drilling these wells, we examined the geology of layers deeper than 4 km.

From studies of geothermal gradients in the Roer Valley Graben, we derived the depth of drilling required to yield a particular savings in CO_2 (Fig. 1).[4,5] Ideally, we would drill as deeply as possible. We therefore considered drilling below the level normally associated with hydrocarbon deposits but still above the basement rock, which is usually associated with geothermal studies.



Access

In geothermal drilling, the aim is to reach hot granite in the basement typically 4-5 km below the surface. The West Netherlands, however, has an unusually thick layer of sedimentary rock. The actual depth to the metamorphic basement is unknown, but the upper sedimentary layer is characterized as principally Permian and younger sandstone.[6,7]

This layer is not interesting because the temperature is too low. Below 4 km there is still a considerable depth of sedimentary rock. This has a different character in that it is deformed and consists mainly of carbonate.

The top of the crystalline basement of the West Netherlands probably lies at 8 km, but its precise position beneath the sedimentary succession is

unknown.[7,8] The thickness of the upper nondeformed sandstone sedimentary layer is about 4 km. We therefore estimate the lower deformed sedimentary carbonate at about 4-km thick.

For heat-recovery purposes we focus on these deeper deformed carbonates. These folded, faulted, and fractured carbonate rocks are the target for drilling geothermal wells and represent many opportunities that have not been investigated. They might have pre-existing fracture networks that can be used for circulating between wells.

The main costs associated with geothermal programs are drilling, but we are considering pre-existing oil production facilities. It is, however, easy to drill through sedimentary rock. The sandstone and underlying carbonates in the West Netherlands basin have much higher permeabilities than the sedimentary layer above traditional geothermal operations. This leads to higher rates of penetration that will reduce drilling costs.

Although granite has a very low permeability, the candidate sedimentary region we have identified has a higher permeability than granite. The undeformed sedimentary layer on top is principally sandstone, which shows decreasing permeability with depth. The underlying deformed sediment, however, consists mostly of fractured carbonates with a higher porosity and should be easier to drill.

We compared the extra cost of drilling fewer wells to a greater depth with the costs of more shallow wells. A recent study provides an estimate of well costs using a polynomial (Equation 4).[9]

When we combine this with the number of wells required (Fig. 3) and the corresponding depths from Fig. 1, there is a slight decrease in well costs, to 6 from 4, but after that it gets rapidly more expensive.

Estimated well cost is $70 million. Assuming the normal 25 years life with a 25% operational cost add-on we obtain $3.1/$Mw_{th}$-hr.

This compares favorably with classic combustion-generated heating. The cost of refinery fuel is typically about 10% of the oil price ($68/bbl) so that current combustion-based heating costs are around $3.7/$Mw_{th}$-hr.

There are therefore too many uncertainties to make a clear-cut basis for applying geothermal heat for refinery power. Oil prices would have to be stable at higher prices to justify wholesale refinery plant modifications. ✦

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Study examines causes of upheaval buckling in shallow subsea PIP lines

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H. Zhang
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Beijing

Temperature, initial slope imperfections, and downward restraints on a pipeline all affect its propensity for upheaval buckling. A restrained pipeline is subject to compressive loads as the temperature of the transported medium rises.

A pipeline laid on the seabed is likely to experience lateral buckling. Partially or fully burying the pipeline restrains it laterally in the horizontal plane, but upheaval buckling is likely where initial imperfections of the seabed exist.

Hobbs derived analytical solutions for the buckling and post-buckling behavior of a heated pipeline assuming a buckling curve for the pipeline.[1] Hobbs established the relationship between the buckling temperature and length of buckle considering the axial pipe-soil interaction. Taylor-Gan studied the effects of initial imperfection and defined the limitation for Hobbs' relationship.[2] Palmer et al. developed a semi-empirical relationship for the downward restraints required to prevent upheaval buckling as a function of the initial imperfection and operating temperature.[3] These studies addressed single pipe.

Design temperatures of offshore pipelines approaching 150° C. or more have prompted use of pipe-in-pipe systems to prevent formation of hydrate and wax deposits in development of hot oil fields in both shallow and deep water. Thermal insulation such as polyurethane foam fills the annulus between the inner and outer pipes.

This article focuses on upheaval buckling of a pipe-in-pipe system in shallow water and develops and verifies relationships among critical temperature, initial imperfection, and downward restraints of the pipeline. The article also discusses countermeasures for preventing upheaval buckling of offshore pipelines in shallow water and develops an analytical solution for determining the spacing of intermediate spools in a PIP system.

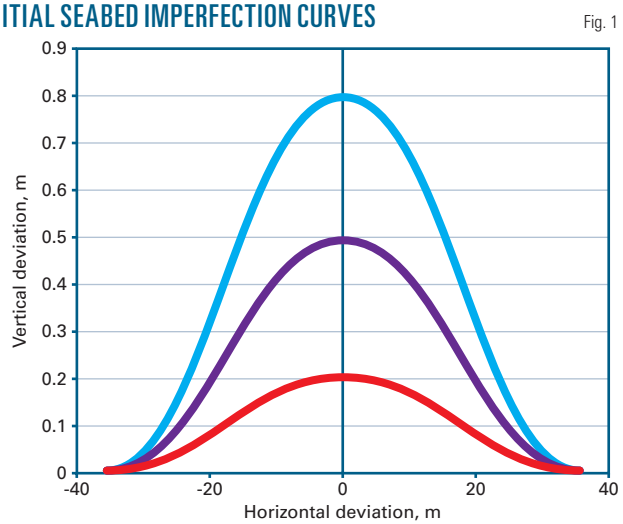
Single pipe

Height as a function of distance can describe the shape of a pipeline. Considering a pipeline as a beam, Equation 1 expresses the relationship between the axial compressive force and laterally distributed load.

Compressive load along with initial imperfections cause upheaval buckling of a pipeline. Equation 2 expresses the initial deforma-

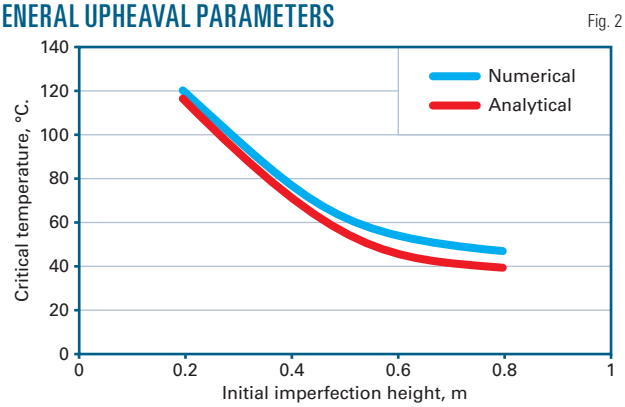
INITIAL SEABED IMPERFECTION CURVES

Fig. 1



GENERAL UPHEAVAL PARAMETERS

Fig. 2



tion assumed for a hill-type imperfection.

Palmer et al. derived the downward restraints to prevent upheaval buckling by substituting Equation 2 into Equation 1.[3]

An idealized curve for the initial deformation of the pipe provides the basis for developing Equation 3. In practice, initial deformation of an offshore pipeline differs somewhat from the known deformation of the seabed. Finite element models developed for a pipeline buried along an idealized hill on the seabed attempted to use the shape of the seabed as the initial imperfection of the pipeline, evaluating the differences in the shapes of the pipeline and seabed as well as their effects on buckling potential.

The pipeline used is 4-km long with both ends fixed in the axial direction. It has a 406.4-mm OD, 7.1-mm WT, and submerged weight of 1,778.1 Newtons/m. The Young's modulus of the pipe is 2.06×10^{11} pascals and the friction coefficient between the pipe and surrounding soil is 0.5. Equation 2 defines the initial imperfection of the seabed, shown in Fig. 1 with a length of 70 m and heights of 0.2 m, 0.5 m and 0.8 m, respectively.

Fig. 2 shows the critical temperature vs. the imperfection height of the seabed. For a small height, the numerical solution lies very close to the analytical solution. As the hill height increases, the difference between the two solutions increases. The increasing embedment of the pipe around the top as the height of imperfection increases and the difference of peak height between the pipeline and seabed cause this. Using the seabed curve as the initial imperfection of the pipeline leads to a conservative critical temperature. Such an approach, however, is still feasible in engineering as the difference is less than 10° C.

Equations

$$W(X) = -EI\frac{d^4y}{dx^4} - P\frac{d^2y}{dx^2} \quad (1)$$

Where, P is the axial compressive force, EI is the bending stiffness of the pipe, w is the distributed load perpendicular to the pipe axis.

$$y = \delta \cos^2(\pi x/L) \quad (2)$$

$$w = 2\delta P(\pi/L)^2 - 8\delta EI(\pi/L)^4 \quad (3)$$

Where, δ is the height of the imperfection, and L is the length of the imperfection.

$$w = 2\delta P(\pi/L)^2 - 8\delta E(I + I_2)(\pi/L)^4 \quad (4)$$

$$P_{max} = \alpha \cdot \Delta T \cdot EA_i \quad (5)$$

Where, I_i is the moment of inertia of the inner pipe, I_2 the moment inertia of the outer pipe, A_i is the cross - section area of the inner pipe, α is the thermal expansion coefficient, ΔT is the temperature rise of the inner pipe.

$$L_{min} = \sqrt[4]{\frac{192 \cdot \delta \cdot E(I + I_2)}{w}} \quad (6)$$

L_{min} is the minimum length of the initial imperfection for which the pipeline is conformal with the hill - type seabed.

$$P_{cr} = \begin{cases} \frac{wL^2}{2\delta\pi^2} + \frac{4\pi^2 E(I + I_2)}{L^2} & L \geq L_{min} \\ \frac{wL_{min}^2}{2\delta\pi^2} + \frac{4\pi^2 E(I + I_2)}{L_{min}^2} & L < L_{min} \end{cases} \quad (7)$$

$$P_{max} = (\alpha \cdot \Delta T - \Delta_{spool}/L_S) \cdot EA - P_2 \quad (8)$$

Where Δ_{spool} is the total displacement that one spool accommodates, L_S is the spacing for spools, P_2 is the minimum tensile force in the outer pipe occurring around the middle of the straight pipe segment between two adjacent spools.

$$(\alpha \cdot \Delta T - \Delta_{spool}/L_S) \cdot EA_i - R_{spool} = P_2 + L_E \cdot t_u \quad (9)$$

$$\Delta_{spool} = \frac{P_2 L_E}{EA_2} + \frac{t_u \cdot L_E^2}{4EA_2} \quad (10)$$

Where R_{spool} is the axial resistance from the spool, L_E is the effective length along which relative displacements occur between the outer pipe and the seabed and soil restraining forces apply.

$$\begin{cases} L_e = 0.5L_S & P_2 > 0 \\ L_e \leq 0.5L_S & P_2 = 0 \end{cases} \quad (11)$$

$$P_{max} = 0.5L_S \cdot t_u \quad (12)$$

Pipe-in-pipe

In a pipe-in-pipe system, thermal insulation materials fill the annulus between the inner pipe and outer pipe. The outer pipe normally maintains ambient temperature, while the inner pipe assumes the same temperature as the medium. Temperature changes in the medium cause axial deformations of the PIP system around the pipe ends or around the bend where a pipeline changes direction.

In addition to relative deformation between the outer pipe and the seabed, relative deformation also occurs between the inner and outer pipes, the compressive load of the inner pipe being partially transferred to the outer pipe in tension. Axial compressive forces decrease towards the pipe end or bend as axial deformations develop.

Locations away from the end or bend where there are no relative displacements among the seabed, inner, and outer pipes show the system's highest systemic axial compressive loads for a given temperature rise. These locations are more susceptible to upheaval buckling on an uneven seabed. The outer pipe does not take any axial thermal loads and only leads to increases in bending stiffness.

Equations 4 and 5 express the forces affecting a pipe-in-pipe system.

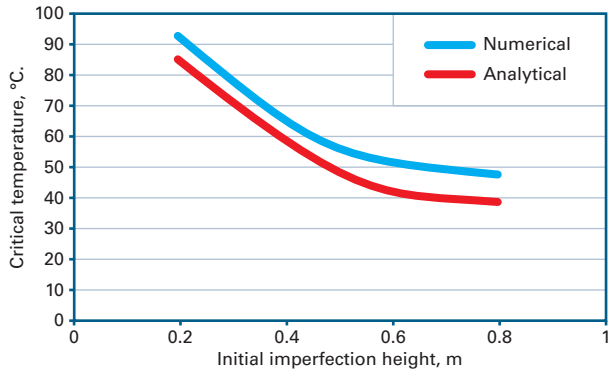
Numerically modeling the two sets of pipe-in-pipe systems listed in Table 1, including weights per unit length, tests these equations. The weight of the inner pipe includes the weight of medium (oil) and the weight of the outer pipe is the submerged weight (subtracting buoyancy).

Both models use a 4,000-m pipeline with both ends fixed in the axial direction. The friction coefficient between the inner pipe and outer pipe is 0.2, and the friction coefficient between the outer pipe and seabed is 0.5.

Fig. 3 shows the critical temperature used in the first model for the three heights in Fig. 1, preserving the temperature difference of 10° C. or less referred to in the analytical results of Equations 4 and 5.

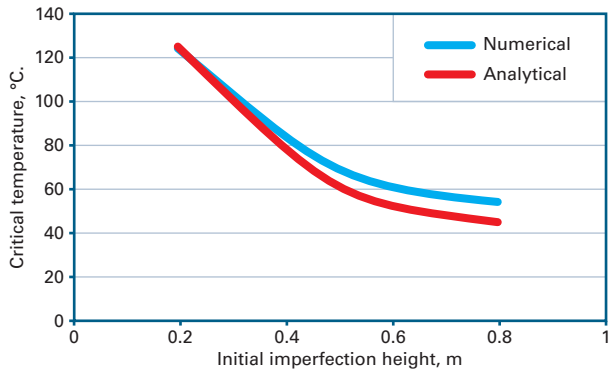
Temperature relationship, first model

Fig. 3



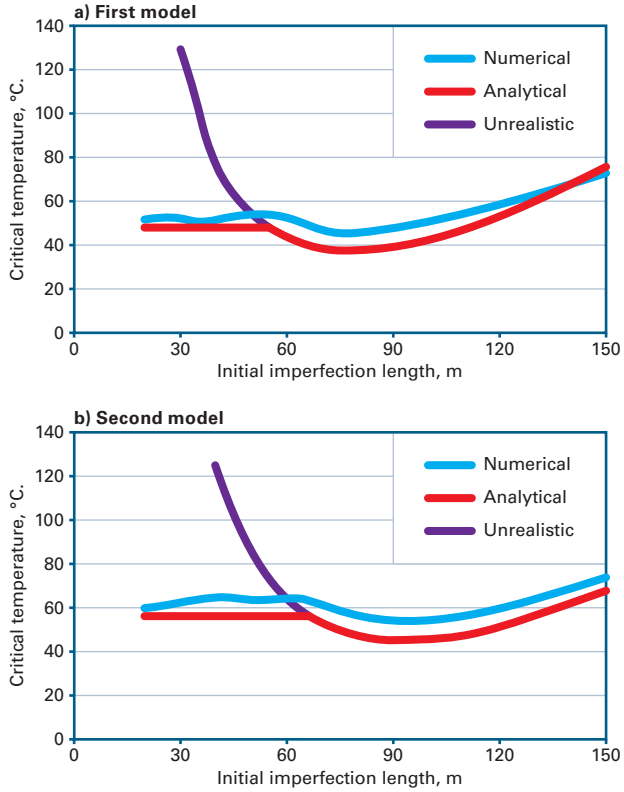
Temperature relationship, 100-m imperfection

Fig. 4



0.8-m imperfection height

Fig. 5



The second model considers a 100-m imperfection caused by the high bending stiffness of the pipes, using the same imperfection heights used in the first model. Fig. 4 shows the critical temperatures from both numerical and analytical approaches. As shown in Figs. 3 and 4, the critical temperature increased due to the high bending stiffness of the PIP system in comparison with the single pipe, and the analytical solutions match reasonably well with the numerical solutions.

Limitations

Equation 4 requires an initial deformation of the pipeline in a PIP system comparable to the initial imperfection of the seabed. A short imperfection combined with bending stiffness, however, causes suspension of the pipeline around its toes to deviate from the shape of the seabed.

A given lifting height off a flat seabed requires the pipeline be suspended under its submerged weight. Equation 6 estimates the suspended pipe length corresponding to height, δ.

Numerical models developed for an imperfection height of 0.8 m verified the minimum length of the initial imperfection applicable for Equation 4. Both the numerical model and analytical help calculate the critical temperature under the submerged weight of pipes. Figs. 5a and b show the results for the first and second models, respectively.

The minimum length from Equation 6 can act as a cut-off point for Equation 4, below which the shape of pipe is dominated by its bending stiffness and the critical temperatures are more or less the same. Equation 7 calculates the critical compressive load leading to upheaval buckling under a given initial imperfection in these circumstances.

Equations 6 and 7 apply to partially or fully buried offshore pipelines. They also apply to a single pipe in which only the bending stiffness of the pipe is considered. Pipelines laid on seabed, however, are likely to experience lateral buckling, making these equations not applicable.

Intermediate spools

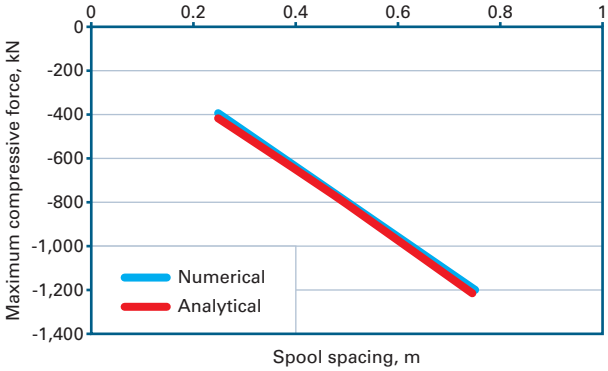
Expansion loops (i.e., intermediate spools) may reduce the axial ther-

Pipe parameters

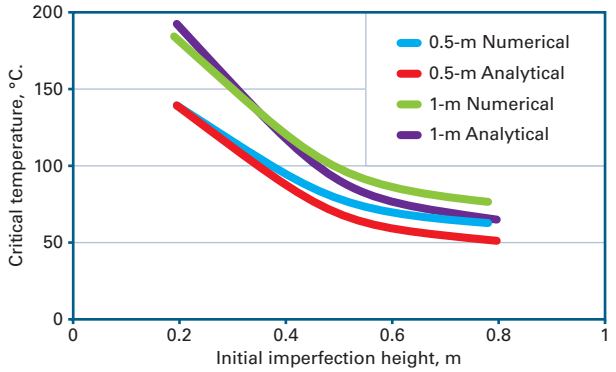
Table 1

		Poisson ratio	OD, mm	WT, mm	Unit weight, Newton/m
First model	Inner pipe	0.3	273.1	18.3	1,510.8
	Outer pipe	0.288	406.4	15.9	224.2
Second model	Inner pipe	0.3	406.4	21.4	2,889.7
	Outer pipe	0.288	558.8	15.9	-337

PIPE-IN-PIPE PARAMETERS Fig. 6



UPHEAVAL PARAMETERS, TWO BURIED DEPTHS Fig. 7



mal stresses in the inner pipe of a PIP system with high design temperatures. Expansion loops place the outer casing pipe segments between the loops under tension during operation. These tension forces tend to increase the critical temperature and reduce the buckling potential of the PIP system. Equation 8 provides the maximum compressive load of a PIP system with intermediate spools.

A bulkhead typically installed in the straight segment near the spool connects the inner and outer pipes. Equation 9 provides the bulkhead's equilibrium.

Soil restraints in the axial direction also control the outer pipe's end displacement at the spool (Equation 10).

The effective length, L_E, in Equation 10 represents no more than the half spacing of intermediate spools (Equation 11).

A PIP system designed for high temperatures functions best when the outer pipe is put in tension (i.e., $P_2 > 0$) by choosing a relatively short interval for intermediate spools ($L_e = 0.5L_s$).

Pipeline engineering casts the axial resistance from the expansion loop, Rspool, as negligible, simplifying Equation 8 as Equation 12.

Equation 12 calculates the maximum compressive force, Pmax, for a selected spacing, L_s, in the PIP system. A maximum force larger than the critical load, Pcr, from Equation 7, requires reduction of the spacing between the spools. Fig. 6 shows the maximum compressive force in the PIP system from the simplified and numerical approaches. Neglecting the resistance from the spool makes the maximum compressive force from the simplified approach slightly less than from the numerical.

Equations 8-12 also apply to a PIP system with a dogleg; spacing Ls acting as the distance between the dogleg and adjacent expansion loop or another dogleg in a short PIP system without an intermediate spool.

Design example

Engineering offshore pipelines without intermediate spools uses a given temperature of the medium and a seabed profile derived from a site survey. Equation 5 can calculate the maximum compressive force, while Equation 6 calculates the minimum length for the pipeline in conformance with the hill-type seabed. Equation 7 calculates the downward restraints required for the system to avoid upheaval buckling.

Partially exposed pipelines on the seabed use the submerged weight of the pipe and medium as the downward restraint. Buried pipelines use the submerged weight of the pipe and medium as well as the soil over the pipe.

Model 1 in Table 1 represents pipelines crossing a 70-m imperfection on the seabed with 0.5 m and 1.0 m soil covers, respectively. Equation 7 calculates the critical temperatures, shown in Fig. 7 for three heights of imperfection along with results from the finite-element approach. The results show the PIP system can transport oil at a temperature up to 120° C., a typical burial depth of 1.0 m, and a corresponding slope of imperfection is 0.011 (0.38-m high and 35-m long).

If the slope of the imperfection is more than 0.011, burying the pipeline deep into the seabed around the hill top (overbend of the pipeline) provides the most effective means of preventing bucking. Doing so not only reduces the height of the initial imperfection, but also increases the downward restraints.

Concrete mats, sand bags, or cobbles placed on top of the pipeline at the hilltop can also act as restraining means. A very hard seabed where hydraulic jetting is not possible might use pre-plough or trenching equipments to reduce the imperfection.

Equation 7 verifies the effectiveness of the chosen means. ✦

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Equipment/Software/Literature

Custom shaft collars for oil field applications

These custom shaft collars can be engineered with specific aesthetic and functional design properties to match a range of oil field uses.

Collars are custom engineered to match specific requirements with regard to configuration and materials of construction. Featuring tolerances to 0.0005 in. if required, they can be machined from aluminum, steel, stainless steels, monel, inconel, Hastelloy, titanium, bronze, brass, Teflon, and other plastics.

Manufactured in prototype to production volumes, collars are available in ⅛ in. to 16 in. ID sizes with hex, square, metric, radiused, keyed, and threaded bores. They can include one or two-piece clamp types and set screws and incorporate snap and O-ring grooves, magnetic inserts, and hinges, drilled and tapped face holes, and milled ODs.

Source: **Stafford Mfg. Corp.,** Box 277, North Reading, MA 01864-0277.

New rotary seal helps avoid oil field downtime

The new Rotaflon rotary seal helps reduce or eliminate shaft damage and reduce power consumption in oil field operations.

Its design accommodates changing operating conditions, lower breakout force, and provides excellent chemical resistance, the company says.

The seal accommodates surface speeds as high as 5,900 fpm and temperatures of −58° to +500° F. and is suited for poorly lubricated conditions. It can be used in gearboxes, compressors, alternators, mixers and dryers, vacuum pumps, crank shafts, heavy duty machines, spindles, and hydraulic and electromotors.

The Rotaflon comes in two series. The RB-Series incorporates a bonded, low friction surface on the elastomeric seal lip. The MC-Series incorporates a high-performance polymer sealing lip available with a single lip, double lip, and spring energizer. The result with either lip is the same: less wear and tear on the shaft leading to a longer lasting seal, the firm points out.

Source: **American High Performance Seals Inc.,** 408 High Tech Drive, Imperial Business Park, Oakdale, PA 15071.

Services/Suppliers

KPMG LLP,

Khushalani

New York, has appointed Samir Khushalani to its Business Performance Services practice in Houston, as a principal. With over 15 years of experience, he will provide advisory services in the area of procurement and supply chain management, mainly for oil and gas industry clients. Khushalani is a certified Project Management Professional and a member of the Project Management Institute. A resident of Houston, he has an MS in electrical engineering from Rice University.

KPMG LLP is the US unit of KPMG International, one of the world's largest audit, tax, and advisory firms.

Wescorp Energy Inc.,

Houston and Calgary, has acquired certain assets and intellectual property from FEP Services Inc., a private Canadian firm specializing in water remediation. The acquisition, terms of which were not disclosed, expands Wescorp's suite of solutions to encompass water remediation and water-oil-solid/hydrocarbon-waste solid separation.

Wescorp is an energy services and engineering company committed to commercializing new technologies designed to increase existing production while also increasing economically recoverable petroleum reserves.

Mustang Engineering LP,

Houston, has named John Ellison manager of Mustang's pipeline business unit. He succeeds David Edgar, who has retired. Ellison, who joined Mustang in 1998, has 37 years of pipeline experience. He previously owned Gibbs Ellison, a pipeline services company. Most recently, Ellison served as Mustang's manager of pipeline field services.

Mustang, a subsidiary of John Wood Group PLC, specializes in design, engineering, procurement, project management, and construction management for upstream oil and gas, midstream, pipeline, automation and control, refining and petrochemicals, and process and industrial clients.

Ryder Scott Canada,

Lam

Calgary, has named Howard Lam manager of operations and managing senior vice-president. He has more than 30 years experience in the oil and gas industry, primarily in reservoir engineering and management and reserves evaluation. Lam has worked for Ryder Scott for more than 10 years. Previously, he worked for Pembina Corp., Husky Oil Operations Ltd., Esso Resources Canada Ltd., and Alberta's Energy Resources Conservation Board. Lam has undergraduate and MS degrees in chemical engineering from McGill University and the University of British Columbia, respectively.

Ryder Scott Canada is a branch of Houston-based Ryder Scott Co. LP. Founded in 1937, Ryder Scott firm independently certifies petroleum reserves quantities for financing, acquisitions and divestitures, regulatory reporting, internal quality assurance, and other purposes.

Imports of crude and products

	Districts 1-4 1-25 2008	Districts 1-4 1-18 2008	District 5 1-25 2008	District 5 1-18 2008	Total US 1-25 2008	Total US 1-18 2008	Total US *1-26 2007
	1,000 b/d						
Total motor gasoline	1,119	1,228	37	—	1,156	1,228	1,275
Mo. gas. blending comp.	651	826	22	—	673	826	949
Distillate	277	204	—	38	277	242	364
Residual	193	576	13	—	206	576	292
Jet fuel-kerosine	129	45	53	11	182	56	261
Propane-propylene	182	222	39	44	221	266	243
Other	587	400	31	4	618	404	222
Total products	**3,138**	**3,501**	**195**	**97**	**3,333**	**3,598**	**3,606**
Total crude	**8,494**	**9,088**	**1,562**	**1,068**	**10,056**	**10,156**	**9,967**
Total imports	**11,632**	**12,589**	**1,757**	**1,165**	**13,389**	**13,754**	**13,573**

*Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Purvin & Gertz LNG netbacks—Feb. 1, 2008

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.18	5.59	6.33	5.48	6.22	6.25
Everett	8.17	5.89	7.77	5.96	6.51	8.49
Isle of Grain	9.17	6.83	8.56	6.72	7.47	8.49
Lake Charles	5.43	3.40	5.19	3.58	3.87	6.09
Sodegaura	6.44	8.44	6.69	8.46	7.72	5.73
Zeebrugge	7.57	5.46	7.01	5.35	6.08	7.00

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
Data available in OGJ Online Research Center.

Crude and product stocks

District	Crude oil	Motor gasoline: Total	Motor gasoline: Blending comp.[1]	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane-propylene
	1,000 bbl						
PADD 1	14,824	62,053	31,566	8,656	49,238	15,175	4,168
PADD 2	62,257	53,784	18,260	8,208	29,367	1,296	15,246
PADD 3	150,230	66,894	31,225	12,814	29,603	13,114	21,163
PADD 4	13,408	6,955	2,169	523	2,940	429	[1]1,927
PADD 5	52,233	34,213	27,442	10,408	15,856	5,517	—
Jan. 25, 2008	**292,952**	**223,899**	**110,662**	**40,609**	**127,004**	**35,531**	**42,504**
Jan. 18, 2008	**289,397**	**220,341**	**109,278**	**39,752**	**128,543**	**38,540**	**45,425**
Jan. 26, 2007[2]	**324,927**	**224,614**	**100,550**	**40,220**	**139,977**	**44,136**	**51,477**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Refinery report—Jan. 25, 2008

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Refinery output: Jet fuel, kerosine	Refinery output: Fuel oils: Distillate	Refinery output: Fuel oils: Residual	Refinery output: Propane-propylene
	1,000 b/d						
PADD 1	1,456	1,459	1,676	94	489	108	59
PADD 2	3,282	3,252	2,330	210	973	78	235
PADD 3	6,966	6,868	3,116	719	1,822	246	651
PADD 4	523	519	298	26	160	14	[1]134
PADD 5	2,587	2,520	1,467	445	450	119	—
Jan. 25, 2008	**14,814**	**14,618**	**8,887**	**1,494**	**3,894**	**565**	**1,079**
Jan. 18, 2008	**15,082**	**14,920**	**8,965**	**1,448**	**4,104**	**707**	**1,072**
Jan. 26, 2007[2]	**15,146**	**14,784**	**9,087**	**1,379**	**3,968**	**665**	**1,056**
	17,436 operable capacity		**85.0% utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
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.

OGJ crack spread

	*2-01-08	*2-02-07	Change $/bbl	Change, %
SPOT PRICES				
Product value	99.83	64.88	34.96	53.9
Brent crude	93.24	55.93	37.31	66.7
Crack spread	6.59	8.95	–2.35	–26.3
FUTURES MARKET PRICES				
One month				
Product value	100.71	65.61	35.10	53.5
Light sweet crude	91.13	57.09	34.04	59.6
Crack spread	9.58	8.52	1.05	12.4
Six month				
Product value	104.06	72.16	31.90	44.2
Light sweet crude	90.16	60.17	29.99	49.8
Crack spread	13.90	11.99	1.91	16.0

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

OGJ GASOLINE PRICES

	Price ex tax 1-30-08	Pump price* 1-30-08	Pump price 1-31-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	269.5	309.2	220.0
Baltimore	257.2	299.1	224.0
Boston	264.9	306.8	226.0
Buffalo	266.4	326.5	245.0
Miami	271.5	321.8	232.4
Newark	262.5	295.4	219.0
New York	246.4	306.5	232.3
Norfolk	258.2	295.8	214.0
Philadelphia	258.8	309.5	247.9
Pittsburgh	257.1	307.8	230.0
Wash., DC	268.7	307.1	234.9
PAD I avg.	261.9	307.8	229.6
Chicago	289.5	340.4	223.8
Cleveland	252.8	299.2	210.0
Des Moines	256.4	296.8	205.1
Detroit	253.6	302.8	203.2
Indianapolis	256.2	301.2	202.2
Kansas City	252.5	288.5	201.0
Louisville	264.6	301.5	207.1
Memphis	252.0	291.8	212.0
Milwaukee	248.5	299.8	219.1
Minn.-St. Paul	255.7	296.1	203.1
Oklahoma City	246.5	281.9	195.1
Omaha	249.6	296.0	208.1
St. Louis	248.1	284.1	203.1
Tulsa	251.3	286.7	202.0
Wichita	240.1	283.5	198.1
PAD II avg.	254.5	296.7	206.2
Albuquerque	256.4	292.8	212.0
Birmingham	255.8	294.5	215.0
Dallas-Fort Worth	249.1	287.5	217.0
Houston	252.1	290.5	208.8
Little Rock	248.8	289.0	213.0
New Orleans	256.4	294.8	216.0
San Antonio	249.4	287.8	213.0
PAD III avg.	252.6	291.0	213.5
Cheyenne	246.4	278.8	205.0
Denver	250.1	290.5	212.8
Salt Lake City	253.1	296.0	223.9
PAD IV avg.	249.9	288.5	213.9
Los Angeles	256.4	314.9	256.1
Phoenix	250.3	287.7	235.9
Portland	259.4	302.7	265.9
San Diego	262.8	321.3	266.9
San Francisco	285.2	343.7	268.5
Seattle	259.9	312.3	266.4
PAD V avg.	262.3	313.8	260.0
Week's avg.	**256.9**	**300.5**	**221.8**
Jan. avg.	**260.9**	**304.5**	**225.3**
Dec. avg.	**257.0**	**300.6**	**228.5**
2008 to date	**260.9**	**304.5**	—
2007 to date	**181.7**	**225.3**	—

*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

	1-25-08 ¢/gal		1-25-08 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	229.23	New York Harbor	251.90
Gulf Coast	230.12	Gulf Coast	246.92
Los Angeles	217.81	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	221.81	ARA	252.26
Singapore	234.57	Singapore	243.90
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	228.73	New York Harbor	173.29
Gulf Coast	229.35	Gulf Coast	170.83
Los Angeles	223.31	Los Angeles	179.03
		ARA	183.91
		Singapore	170.43

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

BAKER HUGHES RIG COUNT

	2-1-08	2-2-07
Alabama	3	2
Alaska	9	11
Arkansas	42	38
California	34	33
Land	33	30
Offshore	1	3
Colorado	119	95
Florida	0	0
Illinois	0	0
Indiana	1	1
Kansas	13	15
Kentucky	8	10
Louisiana	142	183
N. Land	50	54
S. Inland waters	20	18
S. Land	25	45
Offshore	47	66
Maryland	1	0
Michigan	1	1
Mississippi	11	16
Montana	12	21
Nebraska	0	0
New Mexico	71	83
New York	5	9
North Dakota	50	33
Ohio	11	12
Oklahoma	193	172
Pennsylvania	20	14
South Dakota	1	0
Texas	859	803
Offshore	9	12
Inland waters	3	1
Dist. 1	21	23
Dist. 2	32	28
Dist. 3	68	58
Dist. 4	85	91
Dist. 5	183	153
Dist. 6	128	128
Dist. 7B	30	34
Dist. 7C	47	47
Dist. 8	124	103
Dist. 8A	19	29
Dist. 9	43	36
Dist. 10	67	60
Utah	39	45
West Virginia	31	32
Wyoming	74	77
Others—NV-4; TN-6; VA-3	13	8
Total US	**1,763**	**1,714**
Total Canada	**593**	**660**
Grand total	**2,356**	**2,374**
Oil rigs	324	264
Gas rigs	1,432	1,446
Total offshore	57	81
Total cum. avg. YTD	**1,752**	**1,714**

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	Rig count	2-1-08 Percent footage*	Rig count	2-2-07 Percent footage*
0-2,500	70	7.1	51	—
2,501-5,000	105	48.5	92	54.3
5,001-7,500	222	25.2	230	23.0
7,501-10,000	431	3.0	418	3.3
10,001-12,500	435	4.3	406	2.2
12,501-15,000	302	0.3	255	0.3
15,001-17,500	93	—	121	1.6
17,501-20,000	72	—	74	—
20,001-over	31	—	42	—
Total	**1,761**	**8.2**	**1,689**	**7.6**
INLAND	36		31	
LAND	1,676		1,596	
OFFSHORE	49		62	

*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]2-1-08	[2]2-2-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	14	19
Alaska	690	773
California	654	673
Colorado	48	53
Florida	6	6
Illinois	26	25
Kansas	93	94
Louisiana	1,305	1,334
Michigan	15	15
Mississippi	50	51
Montana	90	97
New Mexico	164	163
North Dakota	114	115
Oklahoma	170	171
Texas	1,330	1,325
Utah	46	52
Wyoming	144	146
All others	59	68
Total	**5,018**	**5,180**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	2-1-08
Alaska-North Slope 27°	87.07
South Louisiana Sweet	91.75
California-Kern River 13°	76.25
Lost Hills 30°	84.35
Southwest Wyoming Sweet	80.46
East Texas Sweet	85.00
West Texas Sour 34°	78.00
West Texas Intermediate	85.50
Oklahoma Sweet	85.50
Texas Upper Gulf Coast	82.00
Michigan Sour	78.50
Kansas Common	84.50
North Dakota Sweet	77.25

*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]	1-25-08
United Kingdom-Brent 38°	89.68
Russia-Urals 32°	85.69
Saudi Light 34°	85.00
Dubai Fateh 32°	83.78
Algeria Saharan 44°	89.67
Nigeria-Bonny Light 37°	90.40
Indonesia-Minas 34°	91.34
Venezuela-Tia Juana Light 31°	84.06
Mexico-Isthmus 33°	83.95
OPEC basket	86.89
Total OPEC[2]	85.40
Total non-OPEC[2]	85.69
Total world[2]	85.53
US imports[3]	82.66

[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]

	1-25-08	1-18-08	1-25-07	Change, %
	bcf			
Producing region	720	809	813	–11.4
Consuming region east	1,257	1,402	1,482	–15.2
Consuming region west	285	325	305	–5.6
Total US	**2,262**	**2,536**	**2,597**	**–12.9**
	Nov. 07	**Nov. 06**	**Change, %**	
Total US[2]	**3,456**	**3,407**	**1.4**	

[1]Working gas. [2]At end of period.
Source: Energy Information Administration.
Data available in OGJ Online Research Center.

Statistics

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Nov. 2007	Oct. 2007	11 month average production 2007	11 month average production 2006	Change vs. previous year Volume	Change vs. previous year %	Nov. 2007	Oct. 2007	Cum. 2007
	Crude, 1,000 b/d						Gas, bcf		
Argentina	620	620	627	638	–11	–1.7	130.0	134.0	1,415.34
Bolivia	42	42	44	45	–1	–2.4	41.0	43.0	456.83
Brazil	1,711	1,687	1,742	1,716	26	1.5	30.0	30.0	316.60
Canada	2,672	2,652	2,635	2,498	137	5.5	491.8	481.3	5,428.86
Colombia	540	540	527	528	–2	–0.3	21.0	22.0	211.50
Ecuador	490	500	499	536	–37	–7.0	1.0	1.0	11.00
Mexico	2,901	2,995	3,094	3,282	–187	–5.7	182.6	196.9	2,012.54
Peru	114	115	113	115	–2	–1.6	9.0	9.4	84.69
Trinidad	112	117	121	146	–25	–17.2	120.0	120.0	1,279.87
United States	5,084	5,038	5,112	5,096	16	0.3	1,690.0	1,714.0	18,179.00
Venezuela1	2,430	2,410	2,395	2,563	–168	–6.6	70.0	75.0	792.00
Other Latin America	80	80	80	79	1	0.8	5.2	5.5	59.38
Western Hemisphere	**16,796**	**16,797**	**16,989**	**17,242**	**–253**	**–1.5**	**2,791.6**	**2,832.1**	**30,247.61**
Austria	17	17	17	17	—	—	4.9	5.3	58.37
Denmark	308	310	312	334	–22	–6.7	33.1	29.2	270.76
France	20	20	19	21	–2	–9.3	2.7	3.3	33.16
Germany	64	65	68	69	–2	–2.4	51.6	51.6	551.07
Italy	113	104	109	111	–2	–1.7	28.0	28.0	314.80
Netherlands	38	34	40	25	15	61.5	200.0	150.0	2,285.00
Norway	2,287	2,273	2,275	2,489	–215	–8.6	308.5	295.0	2,846.80
Turkey	40	40	41	41	–1	–2.0	—	—	8.50
United Kingdom	1,510	1,637	1,523	1,517	6	0.4	246.2	221.4	2,416.53
Other Western Europe	4	4	4	5	—	–6.9	0.7	0.4	14.39
Western Europe	**4,402**	**4,504**	**4,407**	**4,630**	**–223**	**–4.8**	**875.7**	**784.3**	**8,799.38**
Azerbaijan	870	850	825	633	192	30.4	28.0	28.0	297.00
Croatia	16	16	16	17	–1	–4.9	6.0	6.3	66.83
Hungary	15	15	16	17	–1	–3.9	7.6	7.2	80.43
Kazakhstan	1,100	1,100	1,082	1,061	21	2.0	100.0	100.0	920.00
Romania	100	100	99	98	1	0.7	17.0	18.0	193.40
Russia	9,770	9,800	9,715	9,480	235	2.5	1,900.0	1,900.0	20,350.00
Other FSU	500	500	462	500	–38	–7.6	500.0	500.0	4,840.00
Other Eastern Europe	50	50	48	48	—	0.7	18.9	18.9	206.22
Eastern Europe and FSU	**12,421**	**12,431**	**12,262**	**11,853**	**409**	**3.5**	**2,577.6**	**2,578.5**	**26,953.87**
Algeria1	1,390	1,380	1,355	1,348	6	0.5	275.0	280.0	3,025.00
Angola1	1,808	1,803	1,688	1,398	290	20.7	4.5	5.0	36.40
Cameroon	85	85	84	87	-3	–3.5	—	—	—
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	630	630	638	671	–33	–4.9	40.0	42.0	450.60
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.66
Gabon	230	230	230	235	–5	–2.3	0.3	0.3	3.34
Libya1	1,750	1,720	1,705	1,706	–2	–0.1	22.0	23.0	242.90
Nigeria1	2,160	2,160	2,165	2,222	–57	–2.6	70.0	70.0	788.00
Sudan	480	480	472	412	60	14.6	—	—	—
Tunisia	87	91	96	66	29	44.5	5.8	6.4	71.06
Other Africa	232	232	232	239	–7	–3.0	9.7	10.2	109.37
Africa	**9,433**	**9,391**	**9,244**	**8,966**	**278**	**3.1**	**427.3**	**436.9**	**4,727.33**
Bahrain	170	169	172	172	—	–0.1	28.0	28.3	288.68
Iran1	3,930	4,000	3,925	3,892	33	0.8	240.0	250.0	2,725.00
Iraq1	2,400	2,300	2,070	1,912	158	8.3	5.0	5.0	54.00
Kuwait1,2	2,535	2,490	2,435	2,504	–69	–2.8	32.0	32.0	338.00
Oman	700	700	711	742	–31	–4.2	55.0	58.0	619.00
Qatar1	800	790	799	823	–24	–2.9	160.0	160.0	1,660.00
Saudi Arabia1,2	8,915	8,910	8,594	9,146	–552	–6.0	170.0	175.0	1,780.00
Syria	380	390	390	425	–35	–8.1	17.0	18.0	185.30
United Arab Emirates1	2,150	2,550	2,531	2,627	–96	–3.7	120.0	135.0	1,442.00
Yemen	320	330	339	348	–9	–2.6	0.0	0.0	0.00
Other Middle East	—	—	—	—	—	–35.5	8.6	8.6	95.75
Middle East	**22,300**	**22,629**	**21,965**	**22,590**	**–625**	**–2.8**	**835.6**	**869.9**	**9,187.72**
Australia	429	444	450	418	32	7.6	115.7	121.7	1,291.01
Brunei	170	183	179	204	–25	-12.2	35.4	37.8	386.36
China	3,737	3,732	3,751	3,691	60	1.6	210.2	212.8	2,222.78
India	710	708	688	679	9	1.3	87.9	88.8	907.06
Indonesia1	830	830	839	895	–56	-6.3	190.0	200.0	2,150.00
Japan	15	15	16	15	1	6.7	9.0	9.6	113.33
Malaysia	780	790	755	747	8	1.1	145.0	150.0	1,563.00
New Zealand	62	55	35	15	20	138.1	13.0	12.5	147.10
Pakistan	70	70	69	65	4	5.9	117.1	117.5	1,290.26
Papua New Guinea	50	50	50	49	1	2.0	0.5	0.5	5.45
Thailand	218	201	212	210	1	0.5	46.0	47.0	482.00
Viet Nam	300	300	311	346	–35	–10.1	12.0	13.0	140.50
Other Asia-Pacific	33	33	34	33	1	3.4	94.8	99.5	1,030.89
Asia Pacific	**7,404**	**7,411**	**7,389**	**7,368**	**20**	**0.3**	**1,076.6**	**1,110.7**	**11,729.74**
TOTAL WORLD	**72,755**	**73,162**	**72,256**	**72,649**	**–393**	**-0.5**	**8,584.5**	**8,612.4**	**91,645.65**
*OPEC	31,098	31,343	30,499	29,638	860	2.9	1,354.0	1,405.0	14,996.90
North Sea	4,125	4,237	4,128	4,357	–228	-5.2	647.5	590.3	6,216.02

[1]OPEC member. [2]Kuwait and Saudi Arabia production each include half of Neutral Zone. Totals may not add due to rounding.
Source: Oil & Gas Journal. Data available in OGJ Online Research Center.

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Like energy bill, stimulus package misses the target

The economic stimulus initiative pushing its way through the US Congress has much in common with last year's energy bill. It's superficial and insufficient, probably harmful.

The Energy Independence and Security Act of 2007 hiked the mandate for renewable vehicle fuel and raised fuel-economy standards for new cars and trucks.

The worst part of the new law isn't that

The Editor's Perspective

by Bob Tippee, Editor

it will raise vehicle prices; there's at least compensation in the hope for improved mileage. The worst part isn't even that an elevated ethanol mandate will boost prices of food and fuel, aggravate air pollution in some areas, and sap federal and state treasuries without delivering on promises about extending energy supply.

The worst part of the new energy law is how the US has heaved off its free-market moorings, resorted to government remedies with demonstrable flaws, and congratulated itself for acting on energy without meaningfully and affordably enhancing supply.

The stimulus package looks like smoke from the same fire.

At this writing, the Senate was deliberating legislation passed by the House that would inject $160 billion into the stuttering US economy with tax rebates and temporary tax cuts.

That's $160 billion in a $14 trillion economy.

If a sudden slug of dollars really can turn the US economy away from jeopardy, timing is surely important.

Yet the president and lawmakers seem to care only about paying out the cash as quickly as possible. By the time the checks arrive, the economy could look much different—maybe, for example, more vulnerable to inflation—than it does now.

With the federal budget in deficit, the dollars will represent debt, not new wealth. When all is said and done, the deficit will linger, fuel and food prices still will be high, and individuals and businesses will remain fretful about a huge tax increase in 2010 unless Congress makes permanent the rate cuts of 2001 and 2003.

Like the energy bill, the stimulus package represents dangerous tokenism.

It's the product of a government that should quit posing as the solution to all economic problems and start addressing the problems its own mistakes have caused.

(Online Feb. 1, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Mideast demand up as OPEC holds output

As expected, ministers of the Organization of Petroleum Exporting Countries made no production changes at their Feb. 1 meeting in Vienna, despite pressure from the US and other large consuming countries to increase output.

OPEC ministers repeated their frequent assertion that current production is sufficient to satisfy demand through the first quarter of 2008 and promised to monitor markets until their next meeting Mar. 5. The assumption they would take no action was already priced into the market prior to the meeting. OPEC's inaction could offset recent reports of US crude inventories steadily building above consensus expectations, and crude may continue to hover in the $90/bbl range, said analysts in the Houston office of Raymond James & Associates Inc. However, they said, "We expect incremental Middle Eastern cargoes to hit the market over the remainder of the first quarter, potentially causing further crude weakness in the short term."

Olivier Jakob of Petromatrix GMBH, Zug, Switzerland, noted Nigeria's export program for March will be constrained by maintenance, but Iraq has resumed oil exports via its Kirkuk pipeline. "Saudi Arabia has confirmed to be leaking above quota, and [very large crude carrier] activity and freight rates have started this week to rebound in the Arabian Gulf," he said Feb. 1.

In a 2008 commodities report by Barclays Capital, the investment banking division of Barclays Bank PLC, analysts said, "We expect OPEC policy to remain cautious, and we expect non-OPEC supply to again disappoint relative to consensus expectations. ...We expect prices to move up significantly in the second half of the year, with economic pessimism providing more of a brake earlier in the year."

Middle East demand

While the lion's share of OPEC's production is from its Middle East members, economic development in that area and Asia also has escalated world demand for crude. "In 2007, the three countries with the greatest absolute increase in oil demand were, in order, China, Saudi Arabia, and India. We expect the same three countries to be the main sources of demand growth in 2008. Indeed, China, India and the Middle East as a whole were responsible for virtually all net global oil demand growth in 2007, and we would expect that pattern to also continue into 2008," said Barclays Capital analysts.

They see global demand growth accelerating to 1.7% in 2008 from 1.2% in 2007. "A visible weakening of oil demand growth relative to the pattern of the past 3 years does seem to require...an economic discontinuity larger than anything that is currently envisaged," analysts said.

Middle East demand is growing because of high oil prices funneling cash into that area where government subsidies reduce domestic costs of petroleum products. Demand growth in that region could fall if there were a large drop in international oil prices. "However, in that case, one would expect increased demand from elsewhere to compensate for the decline in growth in the Middle East," Barclays Capital said. "In other words, almost half of global growth in 2007 came from a region where the direct short-term linkages to the Organization for Economic Cooperation & Development members' economic performance can be expected to be rather weak."

Barclays Capital analysts said, "OECD demand is expected to remain weak for the fourth straight year, but it has lost virtually all of its ability to occupy the margin of the market and to be a significant price driver."

A fundamental rut

The world oil market has "settled into a fairly comfortable and well-worn groove over the past 3 years in terms of its fundamental balances," said Barclays Capital analysts. "Indeed, the key dynamics on both the supply and the demand side of the market have scarcely changed at all across 2005-2007. It has been that constancy and the associated failure to generate any additional headroom within the short-term market or any additional level of comfort about longer-term balances that has helped prices to continue their drift upwards at all points along the curve."

Therefore, they said, "The rise in prices has been less about anything happening in a dynamic fashion to push prices up and has been more to do with things not happening. The failure of rising prices to loosen global balances in any significant way has been a key component of reducing resistance to the gradual and concerted move up. The key question for 2008 is, then, whether any of the key trends that have continued so stubbornly over the past 3 years are likely to show signs of losing purchases."

(Online Feb. 4, 2008; author's e-mail: samf@ogjonline.com)

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