Week of Mar. 12, 2007/US$10.00

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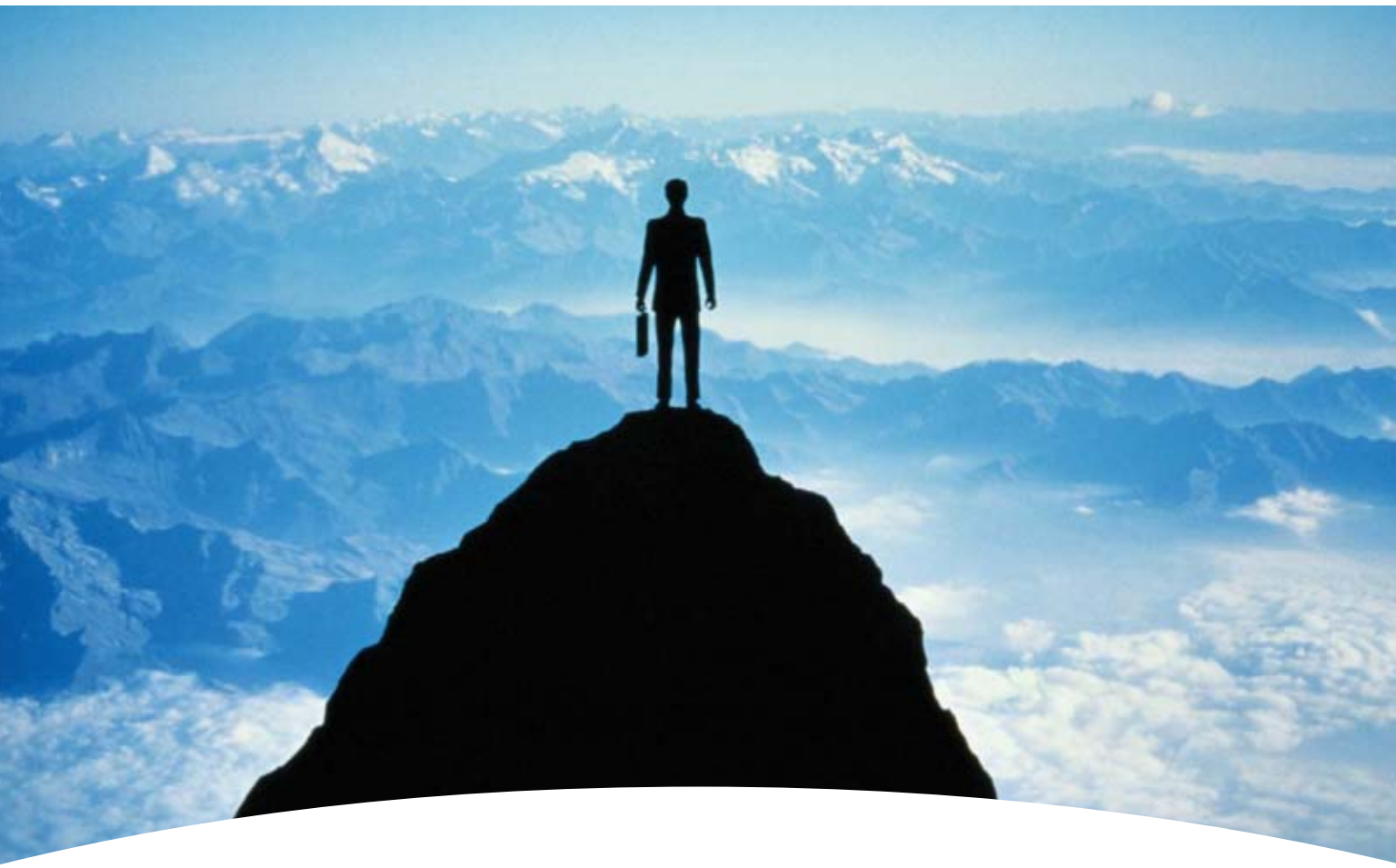
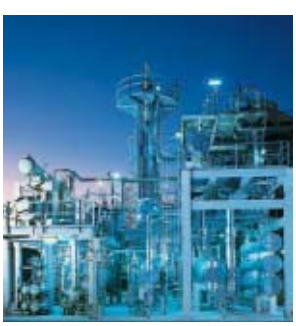
International Petroleum News and Technology / www.ogjonline.com

Meeting Diesel Demand

Growth expected in global offshore crude oil supply
Great Wall drilling swiftly in Thailand
Method estimates K values quickly
Methods help remove black powder from gas pipelines

vision





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OIL&GAS JOURNAL®

Mar. 12, 2007
Volume 105.10

MEETING DIESEL DEMAND

REGULAR FEATURES

COVER

Workers install an ultralow-sulfur diesel reactor on its foundation within the existing diesel hydrotreater unit at Alon USA Energy Inc.'s 70,000 b/d refinery in Big Spring, Tex. Addition of this new reactor, installed in series with an existing reactor unit, more than doubled the catalyst used in the process. The company, a subsidiary of Alon Israel Oil Co. Ltd., also is considering building a biodiesel plant at that facility. Industry analysts say more supplies of low-sulfur diesel is needed in virtually every area of the world. See related story on diesel supply and demand on p. 20.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

 Oil & Gas Journal (ISSN 0030-1388) is published 48 times per year by PennWell Corporation, 1421 S. Sheridan Rd., Tulsa, Okla., Box 1260, 74101. Periodicals postage paid at Tulsa, Okla., and at additional mailing offices. Oil & Gas Journal and OGJ are registered trademarks of PennWell Corporation. **POSTMASTER:** send address changes, letters about subscription service, or subscription orders to P.O. Box 3497, Northbrook, IL 60065, or telephone (800) 633-1656. Change of address notices should be sent promptly with old as well as new address and with ZIP code or postal zone. Allow 30 days for change of address. Oil & Gas Journal is available for electronic retrieval on Oil & Gas Journal Online (www.ogjonline.com) or the NEXIS® Service, Box 933, Dayton, Ohio 45401, (937) 865-6800. **SUBSCRIPTION RATES** in the US: 1 yr. $60, 2 yr. $85, 3 yr. $109; Latin America and Canada: 1 yr. $64, 2 yr. $100, 3 yr. $135; Russia and republics of the former USSR, 1 yr. 1,200 rubles; all other countries: 1 yr. $109, 2 yr. $175, 3 yr. $250, 1 yr. premium digital $59 worldwide. These rates apply only to individuals holding responsible positions in the petroleum industry. Single copies are $10 each except for 100th Anniversary issue which is $20. Publisher reserves the right to refuse non-qualified subscriptions. Oil & Gas Journal is available on the Internet at http://www.ogjonline.com. (Vol. 105, No. 10) Printed in the US. GST No. 126813153. Publications Mail Agreement Number 602914. Return Undeliverable Canadian Addresses to: P.O. Box 1632, Windsor, ON N9A 7C9. Ride-A-Long enclosed.

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OGJ Newsletter

Mar. 12, 2007

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General Interest — Quick Takes

ConocoPhillips concerned about Orinoco work

ConocoPhillips Chief Executive Officer James Mulva said he is concerned about his company's heavy-oil production operations in Venezuela's Orinoco region.

His comment came in answer to questions from reporters on Mar. 1 during a Rice University Baker Institute conference on national oil companies.

Mulva was asked about Venezuelan President Hugo Chavez's recent comments that he has decreed that state-owned Petroleos de Venezuela SA take majority control of Orinoco projects by May 1.

Such a move could have "commercial and operating implications for heavy oil," Mulva said, noting that international oil companies have made massive investments there.

"It's important for us to start our discussions with the ministry and PDVSA," Mulva said, adding that it was "premature" to speculate on the possible outcome. "Obviously, there have been significant changes in Venezuela over the last several years." Since last year, the Venezuelan government has been negotiating with international consortia operating in the Orinoco area, seeking a PDVSA majority stake in each project (OGJ, Jan. 15, 2007, p. 41).

Joint ventures of PDVSA with ExxonMobil Corp., Chevron Corp., ConocoPhillips, Total SA, BP PLC, and Statoil ASA produce about 600,000 b/d of tar-like Orinoco crude. PDVSA currently holds an average 40% stake in these ventures.

Except for Mulva's comments, the international oil companies have declined to comment until they have further details.

Saudis plan $95 billion capacity upgrades to 2015

Saudi Arabia plans to invest $95 billion to develop its oil and natural gas industry over the coming 4-8 years, according to the Kingdom's advisor to the oil minister.

"Saudi Arabia plans to invest $70 billion to increase its oil and gas production capacity until 2015 and invest $25 billion to increase its refining capacity before 2011," said Majid Al Moneef, advisor to Saudi Oil Minister Ali al-Naimi, in a speech at the Jeddah Economic Forum. Al Moneef also confirmed previously announced plans to increase the country's upstream output capacity to 12.5 million b/d by 2009 from the current 11.3 million b/d output level, as well as to step up downstream refining capacity by some 50% to 6 million b/d.

Al Moneef said he expected developing nations, especially those in Asia, to spur 85% of new demand for oil over the next 25 years. He said, "We will see increasing oil roles coming from OPEC and Middle Eastern countries."

Indonesia to boost gas output to offset deficit

Indonesia expects a natural gas production shortage of some 300 MMscf for 2007 and must increase production to meet its projected demand of 8.7 bcf, said Energy and Mineral Resources Minister Purnomo Yusgiantoro during a meeting with members of the country's House of Parliament.

However, he said the country has no plans to terminate existing natural gas export contracts

Luluk Sumiarso, director general for oil and gas at the Ministry of Energy and Mineral Resources said Indonesia has sufficient reserves of gas to meet domestic needs as well as export contracts but he did not explain how the country would service the projected shortfall.

Luluk spoke in reference to forecasts of Indonesia's long-term gas supply and needs, a "gas balance" drawn up by the government to help determine its future export policy. According to Purnomo, the national gas balance for 2007 shows a supply of 8.4 bcf, and demand of 8.7 bcf, creating the deficit.

Last year Indonesia produced a total of 8.217 bcf, of which about 54% was exported, with the remaining 46% sold on the domestic market.

But a shortage of gas due to declining output in 2006 prevented the government from fully meeting its export commitments to overseas buyers, while this year the government has already cut LNG exports by 19% to Japan, South Korea, and Taiwan.

It will not export gas to neighboring Malaysia and Singapore beyond current contracts, because of its need to meet rising domestic demand (OGJ Online, Mar. 1, 2007).

During the meeting in parliament, the government announced a number of moves to deal with the problem, including incentives to boost production from existing fields and accelerate the development of new onshore and offshore fields.

Purnomo, who provided no details of the proposed incentives, said there is no other way forward for the country except to increase production of natural gas in the near future.

The government has set a goal increasing gas output by 30% by 2009. ✦

Exploration & Development — Quick Takes

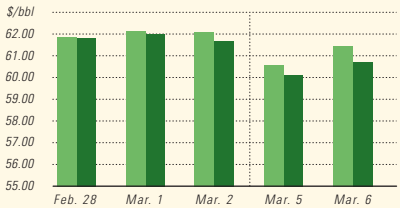
Japan discovers large methane hydrate deposit

Japan's Ministry of Economy, Trade, and Industry reported a methane hydrate discovery of some 1.1 trillion cu m of estimated gas in place in a section of the Nankai Trough about 50 km off eastern Japan.

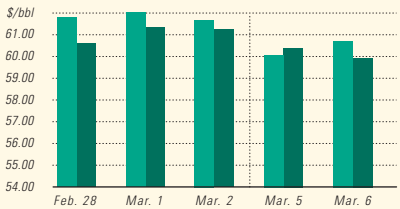
The figure includes recoverable and unrecoverable gas in natural methane hydrate in the area, the METI statement said. State-run Japan Oil, Gas & Metals Corp. (JOGM) assessed the 5,000-sq-km

Industry Scoreboard

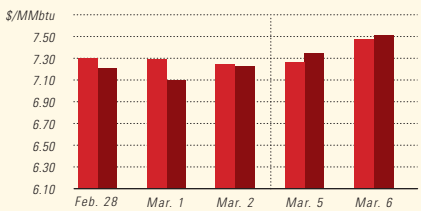
IPE BRENT / NYMEX LIGHT SWEET CRUDE



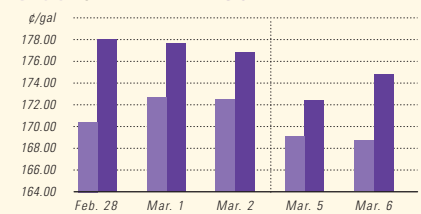
WTI CUSHING / BRENT SPOT



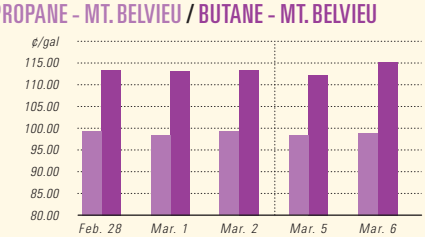
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



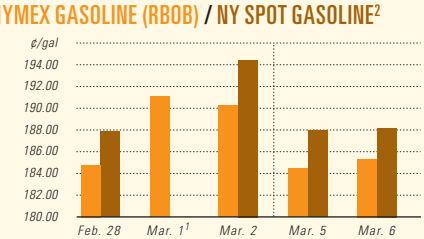
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

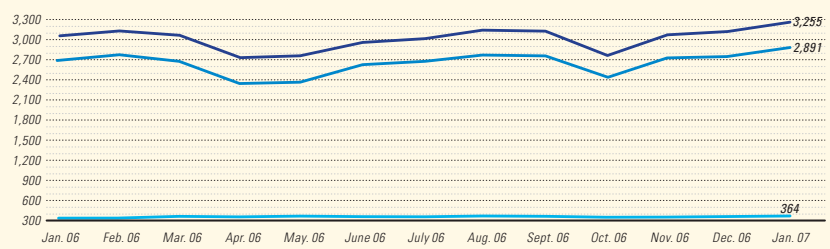
US INDUSTRY SCOREBOARD — 3/12

Latest week 3/2	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	9,288	8,857	4.9	9,135	8,897	2.7
Distillate	4,388	4,330	1.3	4,394	4,320	1.7
Jet fuel	1,606	1,541	4.2	1,614	1,545	4.5
Residual	832	777	7.1	690	821	–15.9
Other products	5,163	4,838	6.7	4,971	4,790	3.8
TOTAL DEMAND	21,277	20,343	4.6	20,804	20,374	2.1
Supply, 1,000 b/d						
Crude production	5,307	5,046	5.2	5,312	5,037	5.5
NGL production	2,389	1,678	42.4	2,402	1,683	42.7
Crude imports	9,590	9,879	–2.9	9,582	9,806	–2.3
Product imports	2,942	3,397	–13.4	3,058	3,449	–11.3
Other supply[2]	931	1,517	–38.6	981	1,182	–17.0
TOTAL SUPPLY	21,159	21,517	–1.7	21,335	21,157	0.8
Refining, 1,000 b/d						
Crude runs to stills	14,399	14,579	–1.2	14,652	14,658	—
Input to crude stills	14,791	14,991	–1.3	15,062	14,995	0.4
% utilization	85.3	86.4	—	86.9	86.4	—

Latest week 3/2	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	317,434	323,994	–6,560	335,971	–18,537	–5.5
Motor gasoline	204,442	211,890	–7,448	216,978	–12,536	–5.8
Distillate	127,783	128,682	–899	129,729	–1,946	–1.5
Jet fuel	40,994	40,937	57	42,586	–1,592	–3.7
Residual	39,708	40,697	–989	39,838	–130	–0.3
Stock cover (days)[3] **2/23**			**Change, %**		**Change, %**	
Crude	22.4	22.3	0.4	22.6	–0.9	
Motor gasoline	24.1	24.4	–1.2	25.1	–4.0	
Distillate	26.5	27.5	–3.6	31.4	–15.6	
Propane	17.1	18.6	–8.1	24.3	–29.6	
Futures prices[4] **3/2**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	61.72	60.06	1.66	62.28	–0.56	–0.9
Natural gas, $/MMbtu	7.38	7.68	–0.30	6.76	0.62	9.2

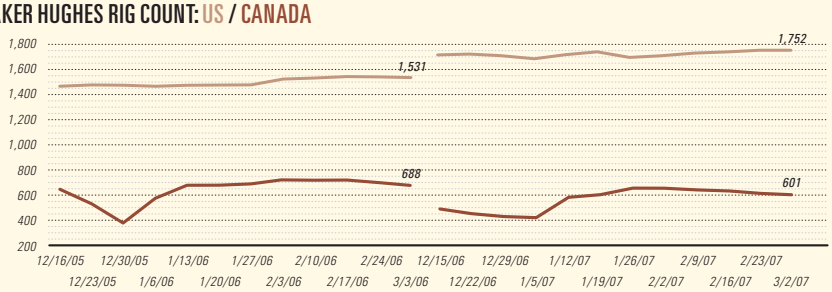
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Stocks divided by average daily product supplied for the prior 4 weeks. [4]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, American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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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area as part of a project to draw gas from the hydrate.

As a result of the find, METI said it will broaden the scope of its exploratory efforts in Japan's coastal seabeds, which are thought to hold substantial deposits of methane hydrate that as yet cannot be produced economically.

Last October METI announced new efforts in Canada to develop technologies associated with the development of methane hydrate. Starting in December, METI and JOGM planned to conduct methane production tests in northwestern Canada with the Canadian government.

Following the drilling of an exploratory well in Canada's Arctic Circle on Feb. 23, JOGM said Feb. 27 it will start test-production of gas from methane hydrate in the permafrost area this month.

Depending on the outcome, Japan expects to start trial exploitation of methane hydrate deposits from the Pacific Ocean floor in 2009 with the hope of beginning commercial output from 2017.

The US, Canada, and Germany are all studying ways to use methane hydrate. In February, BP Exploration (Alaska) Inc. successfully drilled a research well on the Alaska North Slope in partnership with the US Department of Energy and the US Geological Survey to collect samples and gather knowledge about the potential gas source.

Drilling crews and research team members collected about 430 ft of core samples, which will be distributed to US-based gas hydrate researchers.

Caracas, Trinidad reach border fields accord

Trinidad and Tobago has approved a framework agreement for the unitization of hydrocarbon reserves in offshore fields bordering the Caribbean twin-island nation and Venezuela. It is the first such cross-border initiative in the Americas and one of only eight worldwide.

After 4 years of negotiations, there has been agreement at the technical level for the exploitation of reserves in the offshore Plataforma Deltana area, said Trinidad and Tobago Minister of Energy Lenny Saith.

Saith said the first field to be jointly produced would be Loran-Manatee, which contains 10 tcf of gas. It has been agreed that in Loran-Manatee, Venezuela owns 7.3 tcf, while 2.7 tcf is on the Trinidad side of the border.

Chevron Corp. is the operator of Loran, while it partners with BG Group in Manatee field.

The treaty focuses on general provisions, exploitation of cross-border hydrocarbon resources, and establishment of a committee for implementing the treaty, the applicable law, and final provisions.

The treaty provides for determination and allocation of the reserves volumes, the way in which costs and benefits from the unitization will be distributed, and the construction, operation, and use of installations related to the project.

The agreement also provides for construction of a cross-border pipeline.

Each state will continue to exercise civil, administrative, and criminal jurisdiction over the various areas that fall within the treaty.

Parties will settle disputes by negotiation through the respective steering teams and a ministerial committee from each country, e.g., the ministerial teams will decide what the states will do with the gas reserves.

Although the agreement will have indefinite life, either party may terminate it.

Saith said no decision has been made as to where Manatee gas will go, but Trinidad and Tobago and Venezuela will exploit the reserves "as partners" and make whatever decisions were in the best interest of each country.

It is expected that the treaty will be signed in Caracas later this month when Venezuela's President Hugo Chavez is scheduled to hold energy talks with Trinidad and Tobago Prime Minister Patrick Manning. ✦

Drilling & Production — *Quick Takes*

Coal project may tip oil sands energy balance

Sherritt International Corp., Toronto, has floated a development plan for a $1.2 billion clean coal gasification project in south-central Alberta that would produce syngas, hydrogen, carbon dioxide, and elemental sulfur.

One of as many as four coal gasification units could start up in late 2011 on flat agricultural land about 50 miles southeast of Edmonton, just south of Beaverhill Lake. Feasibility of a second unit would be investigated once the first unit is operating at design capacity. Sherritt noted, "The development of Alberta's vast oil sands resource has resulted in increased demands for natural gas to produce steam for bitumen recovery and as a source of hydrogen for bitumen upgrading." Use of natural gas is costly and unsustainable, the company said.

Coal carefully reacted with oxygen and steam produces a syngas mix of hydrogen, carbon monoxide, and CO_2. This mix, with more steam, converts CO to hydrogen and CO_2. Then acid gas is applied to remove the CO_2 and other impurities such as hydrogen sulfide. Output is 320 MMcfd of syngas, further refined into 270 MMscfd of pipeline-grade hydrogen, and as much as 12,500 tonnes/day of high-quality CO_2.

The Dodds-Roundhill coal gasification project would be Canada's first commercial coal gasification application. Sherritt and the Ontario Teachers' Pension Plan are 50-50 partners in the developer, Carbon Development Partnership. CDP owns or has the rights to 12 billion tonnes of economically minable coal in Alberta, British Columbia, and Saskatchewan.

The initial project would involve a single coal gasification unit on 640 acres and a 312 sq km surface mine with 320 million tonnes of subbituminous coal, enough to support two gasifiers for 40 years. Average overburden depth is 15 m.

Shell starts Changbei field gas production

Commercial gas production has begun at Changbei gas field in China, said Royal Dutch Shell PLC, the field's operator, on Mar. 1. The field is expected to plateau at 3 billion cu m/year in 2008 and

deliver gas to Beijing, Tianjin, Shandong, and Hebei.

Shell will use long multilateral horizontal wells to achieve this production level because Changbei is a difficult reservoir.

PetroChina and Shell are jointly developing the field under a production-sharing contract, with Shell currently being the field development operator. The field is on the edge of the Maowusu desert in the Ordos basin of Shaanxi Province and Inner Mongolia Autonomous Region and is the largest onshore upstream cooperative development Shell has had in China.

Changbei development includes the construction of the central processing facilities, interfield pipelines, and a drilling program that is expected to involve about 50 horizontal and multilateral wells over 10 years.

Gas delivery starts from Indonesia's Suban field

ConocoPhillips, operator of Suban gas field on the Corridor Block production-sharing contract (PSC) area in South Sumatera, has achieved first gas delivery via a gas processing plant recently completed as part of the Indonesian field's second-phase development.

The development also includes a series of planned development wells, the first of which, the Suban-10 well, was drilled, completed, and is producing at a constrained rate of 150 MMscfd.

ConocoPhillips, under a 17-year gas sales agreement, will supply 2.2 tcf of gross gas to Perusahaan Gas Negara via the South Sumatera-West Java pipeline. Gas sales deliveries from the field are expected to start later this year.

Interest holders in Suban field are ConocoPhillips 54%, Talisman Energy Inc. 36%, and PT Pertamina 10%.

Kearl oil sands project gets conditional nod

Imperial Oil Ltd. has received conditional approval from the Alberta Energy and Utilities Board and the Canadian government for the development of the Kearl oil sands project in the Kearl Lake area of the Athabasca region.

The approval comes after a joint federal and provincial review of the proposed oil sands mining project, which is similar in design to existing Fort McMurray-region oil sands mines that use large-scale shovels, trucks, crushers, and oil sands hydrotransport technology.

The Kearl mining project will be developed in stages. Plans call for an initial mine train with production capacity of about 100,000 b/d, and possible subsequent expansions to about 300,000 b/d. The mine plan does not include any on-site bitumen upgrading. Any future upgrading capacity to support the project would be submitted in separate applications.

Imperial will review the approved conditions before advancing engineering work to define the project design, execution strategies, and project cost estimate, said Randy Broiles, senior vice-president of resources.

The company previously had reported that the total project investment is estimated at $4.5-6.5 billion (Can.). The project was scheduled to start up by yearend 2010, with possible second and third mine trains starting up in 2012 and 2018, respectively (OGJ Online, July 18, 2005, Newsletter).

Kearl oil sands project is a joint venture of Imperial Oil Resources Ventures Ltd. 70% and ExxonMobil Canada Properties 30%. Imperial is the designated operator of the project. ✦

Processing — *Quick Takes*

CEPSA lets contract for refinery expansion

Cia. Espanola de Petroleos SA (CEPSA) has let a detailed engineering contract to Foster Wheeler Iberia SAU for a major expansion of its 100,000-b/cd La Rabida refinery in Huelva, Spain.

The project will add a 90,000-b/sd crude unit, 30,500-b/sd vacuum distillation unit, and 148-ton/hr gas concentration unit.

The contract value was not disclosed. CEPSA is spending more than $1 billion at the refinery to meet growing demand in Europe for middle distillates.

Foster Wheeler Iberia has completed the front-end engineering design for the planned units (OGJ, Nov. 13, 2006, Newsletter).

Mechanical completion of the new facility is scheduled for fourth-quarter 2009.

Pearl GTL plant foundation stone laid

Qatar's Crown Prince Shaikh Tamim bin Hamad Al Thani laid the foundation stone Feb. 26 for the Pearl gas-to-liquids (GTL) facility, reportedly the country's largest energy project.

The complex will have two 70,000 b/d GTL trains and associated facilities. Production from the first train is expected to begin in 2009-10, with start-up of the second train due a year later (OGJ, Aug. 7, 2006, Newsletter).

Pearl GTL, 100% funded by Royal Dutch Shell PLC, is being developed under a development and production-sharing agreement with Qatar; it covers offshore as well as onshore project development and operations.

In a statement, Shell said upstream some 1.6 bcfd of wellhead gas will be produced, transported, and processed to produce 120,000 boe/d of condensate, LPG, and ethane.

Downstream, dry gas will be used as feedstock to produce 140,000 b/d of clean, high-quality GTL fuels and products.

Shell said Pearl GTL is expected to produce 3 billion boe of wellhead gas over the agreement period.

A total of $10 billion in contracts for the project has been awarded, Shell said, including major engineering, procurement, and construction contracts. Construction began in third quarter 2006.

Sinopec, Syntroleum sign technologies deal

China Petroleum & Chemical Corp. (Sinopec) and Syntroleum Corp., Tulsa, have signed a nonbinding memorandum of understanding aimed largely at advancing natural gas-to-liquids and coal-to-liquids technologies.

The MOU aims at cooperation in verifying Syntroleum GTL technologies on an industrial scale, construction of a 17,000 b/d GTL plant and a 100 b/d CTL pilot plant in China as well as joint marketing of Sinopec Syntroleum technology there.

Syntroleum will provide Sinopec with access to its complete set

of proprietary GTL technologies, including catalyst technology and Fischer-Tropsch (F-T) technologies related to CTL, for use in China on an exclusive basis during the period of cooperation.

After signing a formal cooperation agreement, Sinopec will provide Syntroleum with $20 million/year over the next 5 years to support the technology's development.

Sinopec will start feasibility studies for construction of the plants as well as the CTL pilot plant in China, upon completion of the cooperation agreement.

Both plants will be fully capitalized by Sinopec, with technological support from Syntroleum. The two projects will provide the basis for the two parties to jointly market the combined F-T technology capabilities to third parties within China.

A Sinopec spokesman said the company was investing in the technology to complement existing efforts to develop its gas reserves in the long term.

Last December, Syntroleum signed a joint development agreement with Kuwait Foreign Petroleum Exploration Co. for development of a 50,000 b/d GTL plant in Papua New Guinea (OGJ Online, Dec. 22, 2006).

PNOC moves forward on biofuels projects

Philippine National Oil Co. subsidiary PNOC Alternative Fuels Corp. is moving forward with projects related to the production of biofuels from japtropha following approval of its 2007 budget for 1.257 billion pesos ($26 million).

PNOC-AFC Pres. Peter Anthony Abaya said the company plans to invest in a planned biodiesel refinery, but he did not disclose details.

For feedstock, PNOC-AFC expects to sign a memorandum of understanding this month with Malaysian firm Biogreen Energy Sdn. Bhd. to establish jatropha "meganurseries" on 1,500 hectares to grow about 30 million seedlings within 2 years for commercial plantations and research, Abaya said.

Abaya said other international firms interested in undertaking biodiesel-related projects with PNOC-AFC include South Korea's Samsung Corp, Sumitomo Corp. and JGC of Japan, National Biofuels of the US, Malaysia's HDZ, and Brunei National Petroleum Co.

PNOC-AFC has already signed an MOU with Samsung for an 8.2-billion-peso jatropha plantation and refinery project, while Sumitomo has agreed to conduct a feasibility study on the establishment of a biofuels central terminal in Bataan. ✦

Transportation — *Quick Takes*

Alaska governor outlines gas pipeline bill

Alaska Gov. Sarah Palin has introduced legislation intended to induce construction of a multibillion-dollar pipeline that would deliver North Slope natural gas to the Lower 48 states.

On Mar. 2 Palin outlined elements of the proposed Alaska Gasline Inducement Act, or AGIC. The legislation sets aside a previous effort by former Gov. Frank Murkowski. It's unknown when the legislature will begin public hearings on AGIC. Murkowski had negotiated a draft contract with Alaska North Slope producers ExxonMobil Corp., ConocoPhillips, and BP PLC. The first draft was released in May (OGJ, June 5, 2006, Newsletter).

Despite changes to the draft and special legislative sessions, state lawmakers never approved the proposed plan from Murkowski, who lost a reelection campaign in November.

Palin's bill initiates an application process open to any project sponsor, meaning that ExxonMobil, ConocoPhillips, and BP must start their negotiations over again. At least 12 companies or groups of companies have expressed an interest in building the pipeline.

Tangguh LNG nears completion, seeks financing

Construction on Indonesia's Tangguh LNG facility is 70% complete, and startup is expected by fourth quarter 2008, if operator BP Indonesia receives further financing for the project, said Kardaya Warnika, chairman of Indonesia's upstream oil and gas executive agency BP Migas.

To build the plant BP needs financing of $6.5 billion altogether, he said, of which $3.5 billion consists of loans, with the remainder coming from the company's own resources.

Warnika said BP Indonesia has secured more than $2 billion in loans and is negotiating with a group of Chinese banks for another $884 million. If BP's current negotiations are successful, these loans should be disbursed in April.

BP secured loans of $2.616 billion in 2006, including $1.2 billion from the Japan Bank for International Corp., $350 million from the Asian Development Bank, and $1.066 billion from commercial banks, Warnika said.

Meanwhile, according to BP Migas, Indonesia has signed contracts with Fujian-China for 2.6 million tonnes/year of gas over 25 years, SK Power Korea for 550,000 tonnes/year over 20 years, Posco Korea for 550,000 tonnes/year over 20 years, and Sempra Energy for 3.7 million tonnes/year over 20 years.

Nigeria LNG lets FEED for Bonny Island trains

Nigeria LNG (NLNG) has hired Foster Wheeler and Chiyoda Corp. to carry out front-end engineering and design work for the SevenPlus project on Bonny Island, which would add two liquefaction trains, each with a capacity of 8.5 million tonnes/year.

Foster Wheeler and Chiyoda will produce a project specification package that will form the basis for an invitation to bid for an engineering, procurement, and construction contract.

Foster Wheeler said the two trains once finished would be the largest in the world. A spokeswoman for Foster Wheeler declined to say when the trains would go on line, but press reports have said this would be 2012.

NLNG recently signed 20-year sales and purchase agreements with units of BG Group, Eni SPA, Total SA, Royal Dutch Shell PLC, and Occidental Petroleum Corp. for offtakes from SevenPlus.

Eni will take 1.375 million tpy of LNG to sell into the US via a terminal at Cameron, La., where it holds regasification capacity of 4.4 million tpy. Total's 1.375 million tpy will be sent to its Sabine Pass and Altamira regasification terminals in the US and Mexico.

Shell Western LNG and Oxy, meanwhile, will receive 2 million tpy and 1 million tpy, respectively, but have not revealed the destination for their supplies. BG has bought 2.25 million tpy. ✦

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Calendar

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

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2007

MARCH

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

China Offshore Expo, Tianjin, 84 8 9634388, 84 8 9635112 (fax), e-mail: cp-info@hcm.vnn.vn, website: www.cpexhibition.com. 15-17.

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

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

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

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

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

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

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

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

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

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

APRIL

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

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

PIRA Natural Gas and LNG Markets Conference, Houston,

212-686-6808, 212-686-6628 (Fax), e-mail: sales@pira.com, website: www.pira.com. 2-3.

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

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

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

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

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

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

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

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

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

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

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

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

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

API Spring Refining and Equipment Standards Meeting, Seattle, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 16-18.

ERTC Coking and Gasification Conference, Paris, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 16-18.

SPE Rocky Mountain Oil & Gas Technology Symposium, Denver, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 16-18.

Pipeline Technology Conference & Exhibition, Hannover, +49 511 89 31240, +49 511 89 32626 (fax), e-mail: info@messe.de, website: www.hannovermesse.de. 16-20.

API/NPRA Spring Operating Practices Symposium, Seattle, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 17.

TAML MultiLateral Knowledge-Sharing Conference, Singapore, +44 (0) 1483 598000, e-mail: info@taml.net, website: www.taml.net. 17.

IADC Drilling HSE Middle East Conference & Exhibition, Bahrain, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 17-18.

API Annual Pipeline Conference, Albuquerque, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 17-18.

✦ETF Expandable Technology Forum Technical Conference, Singapore, +44 (0) 1483 598000, +44 (0) 1483 598010 (fax), e-mail: sally.marriage@otmnet.com, website: www.expandableforum.com. 18-19.

Russia & CIS Bottom of the Barrel Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 18-19.

GPA Midcontinent Annual Meeting, Oklahoma City, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 19.

American Institute of Chemical Engineers Spring National Meeting, Houston, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 22-26.

EnviroArabia Environmental Progress in Oil & Petrochemical Conference, Bahrain, +973 17 729819, +973 17 729819 (fax), e-mail: bseng@batelco.com.bh, website: www.mohandis.org. 23-25.

IPAA OGIS East, New York, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 23-25.

Completion Engineering Association Perforating Symposium, Houston, +44 1483 598 000, +44 1483 598 010 (fax), e-mail: crispin.keanie@otmnet.com, website: www.completionengineeringassociation.com. 24-25.

International Conference & Exhibition on Liquefied Natural Gas, Barcelona, +34 93 417 28 04, +34 93 418 62 19 (fax), e-mail: lng15@lng15.com, website: www.lng15.com. 24-27.

Pipeline Pigging and Integrity Management Conference, Kuala Lumpur, +44 (0) 1494 675139, +44 (0) 1494 670155 (fax), e-mail: jtiratsoo@pipemag.com. 25-26.

SPE Research and Development Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-27.

Williston Basin Petroleum Conference & Prospect Expo, Regina, (306) 787-0169, (306) 787-4608 (fax), e-mail: enickel@ir.gov.sk.ca, website: www.wbpc.ca. Apr. 29-May 1.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. Apr. 30-May 3.

Calendar

MAY

PIRA Canadian Energy Conference, Calgary, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 2.

NPRA National Safety Conference, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 2-3.

IOGCC Midyear Meeting, Point Clear, Ala., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 6-8.

GPA Permian Basin Annual Meeting, Midland, Tex., (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 8.

Annual Oil and Gas Pipelines in the Middle East Conference, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 14-15.

AchemAsia Exhibition and Conference, Beijing, +49 (0) 69 7564 249, +49 (0) 69 7564 201 (fax), e-mail: achemasia@dechema.de, website: www.achemasia.de. 14-18.

International School of Hydrocarbon Measurement, Norman, Okla., (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu, website: www.ishm.info. 15-17.

INTERGAS IV International Oil & Gas Conference & Exhibition, Cairo, +44 20 7978 0081, +44 20 7978 0099, e-mail: erenshaw@thecwcgroup.com, website: www.intergasegypt.com. 15-17.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 15-17.

IADC Drilling Onshore America Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 17.

ERTC Asset Maximization Computing and Reliability Conference, Rome, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 21-23.

Libya Oil & Gas Conference and Exhibition, Tripoli, +44 20 7978 0083, +44 20 7978 0099 (fax), e-mail: sshelton@thecwcgroup.com, website: www.cwclog.com. 21-24.

Asia Bottom of the Barrel Technology Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: conferences@europetro.com, website: www.EuroPetro.com. 22-23.

NPRA Reliability & Maintenance Conference & Exhibition, Houston, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 22-25.

Africa Oil & Gas Trade & Finance Conference & Exhibition, Nairobi, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 23-25.

Asia Petrochemicals and Gas Technology Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: conferences@europetro.com, website: www.EuroPetro.com. 24-25.

Russia Power Conference, Moscow, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 29-31.

SPE European Formation Damage Conference, Scheveningen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. May 30-June 1.

JUNE

Society of Petrophysicists and Well Log Analysts (SPWLA) Annual Symposium, Austin, (713) 947-8727, (713) 947-7181 (fax), e-mail: info@spwla.org, website: www.spwla.org. 3-6.

International Caspian Oil & Gas Exhibition & Conference, Baku, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: julia.romanenko@ite-exhibitions.com, website: www.caspianoilgas.co.uk. 5-8.

International Liquefied Petroleum Gas Congress & Exhibition, Nice, 32 2 566 91 20 32 2 566 91 29 (fax), website: www.aegpl.com. 6-8.

Society of Petroleum Evaluation Engineers Annual Meeting, Vail, Colo., (713) 651-1639, e-mail: bkspee@aol.com, website: www.spee.org. 9-12.

PIRA Scenario Planning Conference, London, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 11.

Asian Petrochemicals & Gas Technology Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 11-12.

*Central European Gas Conference, Berlin, +44 (0)20 8275 5198, +44 (0)20 8275 5401 (fax), e-mail: CEGC@lynne-evens.com, website: www.thecegc.com. 11-13.

ERTC Refining Management and Strategy Conference, Vienna, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 11-13.

ILTA Annual International Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 11-13.

IPAA Midyear Meeting, Henderson, Nev., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 11-13.

EAGE/SPE Europec Conference and Exhibition, London, +31 30 6354055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 11-14.

PIRA London Energy Conference, London, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 12.

GO-EXPO Gas and Oil Exposition, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 12-14.

Asian Downstream Technology & Catalyst Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 13-14.

IADC World Drilling Conference, Paris, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 13-14.

PIRA Understanding Global Oil Markets Conference, London, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 13-14.

Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, +60 3 4041 0311, +60 3 4043 7241 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com. 13-15.

Newfoundland Ocean Industries Association Conference, St. John's, Newf., (709) 758-6610, (709) 758-6611 (fax), e-mail: noia@noianet.com, website: www.noianet.com. 18-22.

Offshore Newfoundland Petroleum Show, St. John's, Newf., (403) 209 3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 19-20.

Brasil Offshore International Oil & Gas Trade Show & Conference, Macae, 55 11 3816 2227, 55 11 3816 2919 (fax), e-mail: contato@brasiloffshore.com, website: www.brasiloffshore.com. 19-22.

PIRA Scenario Planning Conference, Houston, 212-686-6808, 212-686-6628, e-mail: sales@pira.com. website: www.pira.com. 25.

API Exploration and Production Standards Conference on Oilfield Equipment and Materials, San Francisco, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 25-29.

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

CERA East Meets West Executive Conference, Istanbul, (800) 597-4793, (617) 866-5992 (fax), e-mail: register@cera.com, website: www.cera.com. 26-28.

Power-Gen Europe Conference, Madrid, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 26-28.

Russian Petroleum Congress, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-28.

Moscow International Oil & Gas Conference & Exhibition, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 26-29.

CIS Oil and Gas Summit, Paris, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. May 30-Jun. 1.

JULY

IPAA OGIS, London, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 11.

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwellpetroleumgroup.com. 18-20.

West China International Oil & Gas Conference, Urumqi, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-27.

International Petroleum & Petrochemical Exhibition, , Urumqi, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-28.

AUGUST

Coal-Gen Conference, Milwaukee, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 1-3.

Rocky Mountain Natural Gas Strategy Conference & Investment Form, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: cogaconference@aol.com, website: www.coga.org. 13-15.

American Chemical Society National Meeting & Exposition, Boston, (202) 872-4600, (202) 872-4615 (fax), e-mail: natlmtgs@acs.org, website: www.acs.org. 19-23.

NAPE Summer Expo, Houston, (817) 847-7700, (817) 847-7703 (fax), e-mail: nape@landman.org, website: www.napeonline.com. 23-24.

IADC Well Control of the Americas Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 28-29.

SEPTEMBER

Brasil Subsea Conference & Exhibition, Rio de Janeiro, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwellpetroleumgroup.com. 1.

SPE/EAGE Reservoir Characterization and Simulation Conference, Muscat, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 3-5.

Power-Gen Asia Conference, Bangkok, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 4-6.

Offshore Europe Oil & Gas Conference and Exhibition, Aberdeen, +44 (0) 208 439 8890, +44 (0) 208 439 8897 (fax), e-mail: oe2007@spearhead.co.uk, website: www.offshore-europe.co.uk. 4-7.

✦Corrosion Solutions Conference, Sunriver, Ore., (541) 926-4211, ext. 6280, website: www.corrosionconference.com. 9-13.

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

SPE Asia Pacific Health Safety Security Environment Conference, Bangkok, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

Turbomachinery Symposium, Houston, (979) 845-7417 (979) 845-1835 (fax), e-mail: turbo@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 10-13.

Oil Sands Trade Show & Conference, Fort McMurray, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 11-12.

Russia & CIS Petrochemicals & Gas Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 17-18.

Russia & CIS Refining Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 19-20.

IOGCC Annual Meeting, New Orleans, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 23-25.

Society of Exploration Geophysicists (SEG) Annual Meeting, San Antonio, (918) 497-5500, (918) 497-5557 (fax), e-mail: web@seg.org, website: www.seg.org. 23-28.

Annual Engineering & Construction Contracting Association Conference, Colorado Springs, Colo., (877) 484-3322, (713) 877-8130 (fax), e-mail: registration@ecc-association.org, website: www.ecc-association.org. 27-28.

Global subsea spending up

Marilyn Radler
Senior Editor-Economics

A presentation on future subsea oil and gas field development trends, challenges, and technology requirements was featured at PennWell's Subsea Tiebacks Forum held last month in Galveston, Tex. The talk was presented live as well as over the internet as a webcast, which was archived for future access on www.OGJOnline.com.

One of the speakers, Howard Wright, senior analyst with Infield Systems Ltd., presented the London-based firm's forecast of worldwide subsea oil and gas development spending.

Infield expects subsea spending over the next 5 years to total $86 billion. This will include $10.6 billion on subsea equipment, $31.5 billion on pipelines and control lines, and $44.2 billion on drilling and completions.

The biggest growth area will be West Africa, making up 24% of the total spend. Other key areas are the US Gulf of Mexico, Brazil, and the northwest European continental shelf.

Also over the 5-year period, the forecast calls for increased subsea activity to boost spending to $4.9 billion from $1.3 billion in Australasia and to $5 billion from $1 billion in Southeast Asia.

Key trends

Wright defines deepwater developments as those in more than 500 m of water.

These developments have gone from being the technological frontier to being strategically vital to operators, such that even national oil companies are moving into deeper offshore areas outside their domestic markets.

The three primary arenas for deepwater developments through 2006 were the Gulf of Mexico, Africa, and Latin America, and Infield expects these areas to maintain the current level of offshore activity.

But activity in the Asia-Pacific will also ramp up, providing the impetus to the forecast growth. Still under-explored are the deep and ultradeep waters of the Gulf of Guinea, the deepwater South China Sea, the Indian Ocean margins, the Arctic, and the ultradeepwater Gulf of Mexico.

Activity in the short term will remain little changed geographically, though. The analysts call for 37% of all deepwater field activity to remain off North America, 32% off Brazil, and 27% off Africa.

Forecast to 2012

Infield forecasts that the number of subsea wells brought on stream will reach 500/year by 2011, with floating production in West Africa, Brazil, the Gulf of Mexico, and Asia driving the growth.

Currently there are subsea production facilities in the waters of 47 countries, and Infield see this number expanding by 12 through the forecast period.

Water depths will increase, too. The share of offshore wells completed in water depths greater than 500 m will grow to 67% in 2012 from 55% this year, Wright said, with the deepest completions expected at about 3,000 m.

In the ultradeepwater frontier, the number of subsea wells forecast to come on stream will grow to over 100 in 2012 from about 20 in 2002.

When asked whether high rig rates are driving project architecture towards more dry-tree solutions over subsea developments, Wright said the leading developments are still employing subsea systems. In developing heavy oil in Latin America, dry-tree completions possibly will become a trend, though, he said.

Looking back

Surprising the analysts was a look back at one difference between their 2002 forecast and the actual split in the types of companies that recently have drilled deepwater subsea wells.

In the 5-year forecast that it formulated in 2002, Infield predicted that through 2007 fully integrated operating companies would account for 68% of deepwater wells brought on stream in the Gulf of Mexico, leaving just 29% drilled by independent operators and 3% by other companies.

The actual share of wells drilled in the deep waters of the Gulf of Mexico by integrated companies during the 5-year span was just 44%, while independent operators were responsible for 52% of all wells brought on stream in the same area. Wright said this shows that, more than expected, the independents have been able to overcome some of the major challenges of deepwater developments.

Those challenges that remain for companies involved in offshore development include limited equipment availability and limited manpower, which raise costs and threaten the momentum of development activity levels.

But with higher demand and prices for oil and gas, Infield has seen companies shift from taking a low-cost development approach to one of doing what it takes and paying what it takes to get the job done. ✦

Editorial

Energy extremism

Energy extremism has tricked its way into the mainstream. Three shades of it now control politics in the US. In an area where mistakes cost large amounts of money, the potential for error is high.

Triangular extremism has infused American politics with repugnance for oil and gas. It might be more accurate to say that extremism has pushed onto center stage a prejudice never absent from the political fringe. Either way, it threatens to radicalize energy law and regulation.

Aversion to fluid hydrocarbons is manifest in legislation that would raise taxes uniquely on oil and gas producers and divert proceeds to energy forms preferred by politicians—and energy providers receiving the money—but not by markets. It's manifest in federal budget proposals that cancel funding for oil and gas technical research. It's manifest in a US president who bewails an "addiction" to oil and presumes to know how much gasoline Americans should use, in congressional inquisitions of oil executives in times of high gasoline prices, and in a thundering failure of confidence in the ability of energy markets to dissipate stress.

Wasting money

The problem with antioil politics isn't that oil and gas face any threat of losing their commanding positions in the energy market. Hydrocarbons dominate the market because they offer value that other energy forms—no matter how much the government spends on them—can't match. The main problem with the current political mood is the amount of taxpayer and consumer money that the government might waste combating economic forces that never yield to political caprice. Another problem is the political mire accumulating before an industry that should be focused on meeting demand for its products.

Through political expression contradicted by consumption trends, the US thus is acting out a futile ambition to disengage from hydrocarbon energy, especially oil. For the sake of its operations and the interests of its customers, the oil and gas industry needs to confront the off-oil agenda head-on. It can best do so by addressing the three presumptions of antioil extremism: that oil destroys the environment, funds terrorism, and enriches a despised industry.

By its nature, extremism begins with some core truth then spirals away from reality. Antioil extremism is no exception.

The production and consumption of oil and gas do harm the environment. But they do so less and less as technology and regulation make industry operations diminishingly intrusive and petroleum fuels remarkably less polluting than they were in years past. Lately, global panic over climate change has preempted consideration of real environmental progress. In fact, however, the contributions of fossil energy to observed warming remain less certain and almost certainly smaller than a frenzied political discussion seems to assume. With extremists controlling debate, the political choice so far is between extreme response and no response. As long as people yearn to prosper, that's a prescription for stalemate.

It is no doubt true as well that money from oil sales ends up funding terrorist groups. But such problems require diplomatic and military rather than economic solutions. Mandates for expensive substitutes for cheap energy hurt only Americans and impoverish no terrorists at all. They also reflect dreadful American xenophobia, insult oil exporters, and undermine US promotion of global trade.

And, yes, oil sustains an industry with scale and operations that many outsiders find incomprehensible and therefore suspect. The industry easily slides into the role of villain in rants by politicians too ignorant, lazy, or corrupt to provide constructive energy leadership. When uninformed hate becomes policy that blocks work essential to energy supply, national interests suffer.

Politics vs. economics

These extreme prejudgments have put politics in conflict with economics. While US political leaders profess to hate oil, their country consumes the substance at a rate that both leads the world and grows. The paradox is typical. Extremism always generates unachievable ambitions. It deserves neither the attention nor the expenditure it demands.

Energy extremism promises high cost and low supply. It belongs on the political fringe. Now, before politicians make any more mistakes, is the time to put it back there. ✦

US diesel use rising in ultralow-sulfur era

Sam Fletcher
Senior Writer

While US demand for ultralow-sulfur diesel (ULSD) is expected to escalate, no industry or government organization has solid data on how much of the fuel will be available or needed.

And no one seems concerned. Unlike in the period prior to the 2006 deadlines for refiners to reduce highway diesel sulfur to 15 ppm from 500 ppm, government and industry officials interviewed for this report said they are confident the market will function smoothly while meeting new deadlines in 2007 and beyond. Refiners approached last year's changes confident that they could meet demand for ULSD but worried about logistics they couldn't control, especially the possibility of downstream contamination (OGJ, May 22, 2006, p. 18). Any such problems have been minor.

Since Oct. 15, most of the diesel fuel sold at retail outlets in the US and Canada has been ULSD—more than the 80% of US diesel production mandated by the US Environmental Protection Agency. The first diesel engines specifically designed for the ultralow-sulfur fuel are in 2007 model vehicles now in car and truck showrooms. The 2007-model diesel trucks also will reduce particle emissions by 90% and significantly lower emissions of nitrogen oxide (NOx). But no one has a dependable estimate of how many of those new diesel vehicles will be produced, much less sold, in this or other years.

Meanwhile, EPA is mandating by June a 500 ppm sulfur cap on all off-road diesel, with a 2010 deadline for all highway and some off-road diesel to be at the 15 ppm ULSD level. In June 2010, the sulfur cap is to be lowered to 15 ppm for all nonroad diesel other than locomotive and marine, but small refiners are exempted from that rule. In June 2012, the ULSD requirement will apply to locomotive and marine diesel, and by June 2014 the ULSD cap will extend to small refiners that make nonroad diesel.

Supply outlook

The only data on ULSD production available through the US Department of Energy's Energy Information Administration show refinery and blender net production totaled 1.9 million b/d last June; 2.2 million b/d in July; 2.4 million b/d, August; 2.6 million b/d, September; 2.5 million b/d, October; and 2.6 million b/d, November. Imports tallied at 97,000 b/d in June; 202,000 b/d in July; 182,000 b/d in August; 263,000 b/d in September; 137,000 b/d in October; and 143,000 b/d in November.

But after allowing for adjustments and stock change, the total ultralow-sulfur distillate fuel supplied amounted to 1.3 million b/d in June; 1.8 million b/d in July; 2.3 million b/d in August; 2.4 million b/d, September; 2.6 million b/d, October; and 2.7 million b/d as of November. No later or more detailed data were available, EIA officials said.

US inventories of ULSD totaled 57.3 million bbl in the week ended Feb. 23, the latest period available at deadline, down from 58 million bbl the previous week but up from 1.7 million bbl during the same period a year ago, before the mandate took effect. Low-sulfur diesel (LSD) stocks amounted to 22.3 million bbl on Feb. 23, down from 23.6 million bbl the previous week and 79.5 million bbl during the same period in 2006. EIA officials told OGJ that data

on distillate fuel exports come from the Bureau of Census. "Currently, Census does not break out ULSD from LSD. Normally exports of diesel are small, and ULSD exports would be expected to be even smaller. This means that the product supplied (which is a surrogate for demand) for ULSD potentially is slightly overstated," EIA said.

EIA said refiners likely will see little shift in diesel and gasoline demand in the next decade because of the slow growth in the fleets of vehicles requiring ULSD. Diesel prices no longer provide an incentive to switch over as when they were lower than gasoline prices some years ago. But high fuel prices in general should maintain consumer interest in more fuel-efficient diesel vehicles, EIA officials said.

The US gasoline price on Feb. 26 averaged $2.383/gal at the pumps, up 8.7¢/gal from the prior week and 12.9¢/gal from the same period a year ago. US diesel averaged $2.551/gal at the pump, up 6¢/gal from a week before and 8¢/gal from a year ago. For the month of January, the US retail price of gasoline averaged $2.24/gal. EIA said factors contributing to that price included the price of crude, 54%; refining, 11%; distribution and marketing, 15%; and state and local taxes, 20%. In that same month, the retail price of diesel averaged $2.49/gal. Contributors to that pump price included crude, 49%; refining, 18%; distribution and marketing, 12%; and taxes, 21%, EIA reported.

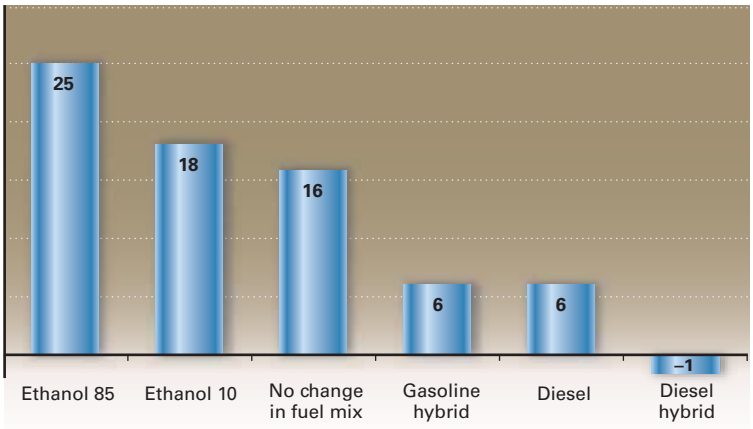
The absence of good data on true supplies of and demand for ULSD is "one of the key issues all of us are painfully aware of in trying to understand" that market," said Allen Schaeffer, executive director of the Diesel Technology Forum. He blames reduced reporting by EIA "because of budgetary restraints."

Schaeffer said, "Diesel demand in the US is directly related to the economy. When the economy is growing consistently, as it has in the last couple of years, that creates a demand for moving goods. That means locomotives, ships, trucks—the primary sources of diesel fuel consumption." Meanwhile, increased demand for crude around the world and especially in China, India, and the US influences prices, refiners' strategy, and other factors. "And there's no relief in sight for that," Schaeffer said.

"The DOE data are pretty good and shows in 2006, for example, that the road diesel demand increase was 4.2% year-on-year, even though the total heating oil and diesel demand increase was little more than 1%," said Jeff D. Morris, a former Fina executive who is president and chief executive of Alon USA Energy Inc. Alon Israel Oil Co. Ltd. bought the US downstream assets of TotalFinaElf SA in 2000. "The diesel demand growth rate over the last 3 years has been double that of gasoline. It has been 3.5-4% for 3-4 years in a row now, very strong, whereas gasoline has been around 2%," Morris said.

Markets need "more diesel and less gasoline" in virtually every area of the world, said Aaron F. Brady, associate director of global oil for Cambridge Energy Research Associates, at that group's annual Houston energy conference in February. He expects rapid growth in commercial demand for diesel and jet fuel over the next 25 years, with refiners having to squeeze light and middle products from heavier crudes. Asia will be the greatest growth area for oil demand by 2030, primarily in transportation fuels, Brady said.

Number of new refineries needed in 25 years



Source: Alon USA Energy Inc.

Refineries and infrastructure

Refineries are relatively flexible and can move the manufacture of gasoline or diesel "up and down about 10%," Morris said. So if US diesel demand increased by 10%, displacing an equal amount of gasoline demand, "The existing refineries can handle that. Beyond that, we would have to do some retooling, but the technology exists to do that. And it's a lot cheaper retooling than building ethanol plants all over the country."

He said, "Today we're importing 15% of the gasoline used in this country. If gasoline demand grows by 1%/year for the next 25 years, the US would need to build 16 new 200,000 b/d refineries over that period just to maintain the present level of gasoline production and imports. Assume that 2% of US motorists convert to E-85 vehicles; the US then would have to build 25 refineries, including ethanol plants." But if instead 2% of US motorists bought advanced diesel cars, only six new refineries would be needed, Morris said. And if a diesel hybrid vehicle were developed and marketed at the same annual rate, he said, no new refineries would be necessary. "I don't understand why this is not talked about

more and why more incentives are not being provided," he said.

At the recent CERA energy conference, Gary Heminger, executive vice-president of Marathon Oil Co., projected that the industry will need to build "a couple of world class refineries each year" to keep up with global demand for fuel. The average number of motor vehicles in Asia is expected to grow to 47 per 1,000 persons by 2020 from 18 per 1,000 in 1997. Neither development of alternate fuels nor increased refining capacity will do much to reduce US gasoline imports in the short term, he said. However, he said, the world will need all new forms of energy "that can stand on sound investment." For the present, Heminger said, ULSD inventories "look decent."

In the US, concentration of the diesel-distribution infrastructure varies. A US map supplied through the Diesel Technology Forum by Air Improvement Resource Inc. shows county by county the density of retail diesel service station and truck stop locations per 100 sq miles. According to that data, 498 US counties have 5-75—or more—retail diesel locations per 100 sq miles. But 1,115 counties were indicated to have less than one location per 100 sq miles. Many of those areas with the fewest stations were in large and sparsely populated counties encompassing long stretches of interstate highways in West Texas, New Mexico, Arizona, Utah, Nevada, Nebraska, South Dakota, North Dakota, Wyoming, Montana, and Idaho.

The largest group of counties in any of the 11 density levels indicated on the map had 792 with one or two locations per 100 sq miles; the second largest group was 738 counties with two to five locations per 100 sq miles. Virtually all of the density divisions had similarly overlapping numbers. The largest evident concentration of diesel outlets was essentially east of the Mississippi River.

However, Morris said there is "more than sufficient infrastructure" for supplying diesel to a larger US market. "Assume half of the motorists are driving diesel engines all of a sudden; the conversion per station is simple. All it takes basically is a change in the [size and color of the pump] nozzle. It's a relatively small fix, whereas if you want to put E-85 at a station, you have to put a new tank and completely segregated system in the ground at a cost of $30,000 per site," he said. "Diesel has a big advantage in infrastructure in that it can go through [existing] pipelines." Of course, ULSD can't afford to pick up much sulfur contamination during the distribution process, or it will be sent back to the refiner for reprocessing.

"In the past, the diesel pump used

to be kind of on the 'back 40' of a service station, off to the side because the trucks that fueled up there were too tall to fit under the station's canopy and needed extra space to turn," Schaeffer said. But now companies "like Shell and Chevron and BP" are integrating a diesel pump right alongside the gasoline on the pump islands. "That suggests to us that refiners and marketers believe diesel fuel is going mainstream and that they need to treat it as a mainstream fuel. There's no reason I should stand out in the rain while filling my diesel car," said Schaeffer.

US vehicle fleet

The number of diesel-fueled cars and light trucks sold in the US has "grown consistently in the last 10 years and is up 80% in the last 6 years," said Schaeffer. Predictions that as much as 15% of the light vehicles on US roads could be diesel-powered by 2015 "could create additional demand in fairly tight supply," he said.

The best way to meet the goals set by President George W. Bush to reduce greenhouse emissions and gasoline consumption by 20% over the next 10 years is with advanced diesel engines, said Morris. "What I'd really like to see introduced in the US is a diesel-hybrid vehicle—a diesel engine, but not the 'plug-in' rechargeable electric car," he said.

"I think the only thing standing in our way [to a larger US diesel market] is Detroit, which has chosen so far to offer fewer diesel engines rather than more," Morris said. "The Europeans are beginning to expand their diesel fleet slowly; they see the potential in the market." He sees "a limited amount of marketing" primarily by foreign-based automobile companies to sell diesel vehicles to US motorists.

"I've heard Detroit executives say they don't bring the diesels to the US because the public has the perception that diesel engines are slow, loud, and smoky," Morris said. "I interpret it to mean they're unwilling to put marketing effort into it."

Loren K. Beard, senior manager of environmental and energy planning at Daimler Chrysler Corp., told the CERA conference he sees "a big, big role for diesel" by 2015 when it is expected to fuel 15% of the light cars on the road, in addition to commercial trucking. The result, he said, will be a major shift in transportation fuels with more diesel replacing gasoline.

DOE calculates US demand for petroleum will increase 25% in the next 25 years because of jumps in both population growth and vehicle miles traveled. However, Beard said demand could be

reduced 30% through greater use of E-85 and a 20-80 blend of biodiesel. Even if the changeover to E-85 were perfect, it would take 10-20 years to turn over the existing fleet of motor vehicles to where most could run on that fuel, he said.

Morris suspects the driving public will not pay more for a fuel like ethanol that delivers 25% less fuel efficiency. He also doesn't believe ethanol production capacity will go to the 15 billion gal/year level some analysts predict from the 8 billion gal/year projected for next year while sustaining a 54¢/gal tariff on ethanol imports.

Biodiesel

Biodiesel blends are mixtures of petroleum-based diesel fuels and fuels produced from soybean oil, waste cooking grease, or other organic matter. These fuels may contain biodiesel in concentrations 2-100% by volume.

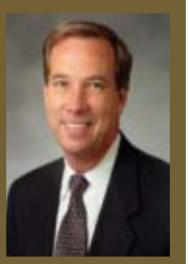
Because biodiesel is a more efficient fuel than ethanol, Morris said, there should be a bigger government push for biodiesel. "There would be more of a push for biodiesel if there were more diesel engines," he said.

The National Biodiesel Board said US biodiesel production increased from "very little 10 years ago" to 75 million gal in 2005 and 225 million gal in 2006, with production tripling in each of the last 2 years. Most of that fuel was produced from soybean oil at 35 major facilities and sold by 1,400 distributors and 450 retail stations. Blends of 20% biodiesel with 80% petroleum diesel (B20) can generally be used in unmodified diesel engines, provided the blend meets accepted American Society for Testing and Materials fuel-quality standards. Some industry representatives say biodiesel can be used as an additive to improve the lubricity of ULSD, which is negatively affected by the removal of sulfur.

"Biofuels are typically being blended or loaded at the jobber's rack and are not part of a fundamental pipeline distribution system," said Schaeffer with Diesel Technology Forum. "At this stage, we view biodiesel as a niche fuel in certain markets where it makes sense. But to grow into something more, there is a serious issue now of quality. The National Biodiesel Board, which is the body that represents most of the producers of biodiesel fuel, recently did a survey that found over 50% of the samples it measured around the country did not meet their own quality specs. That is a serious issue for consumers that will buy a $50,000 diesel car and have the expectation that if they're pumping a 5% blend of biodiesel in there that it's the right purity and mixed in well and doesn't attract water. At this point, we can't guarantee that nationwide. This is going to be a big issue for that industry to grow and be a renewable fuel."

The best way to meet the goals set by President George W. Bush to reduce greenhouse emissions and gasoline consumption by 20% over the next 10 years is with advanced diesel engines.

—Jeff Morris
CEO of Alon USA Energy Inc.



The National Biodiesel Board said it issued a "winter warning" to motorists about biodiesel quality. Meanwhile, it has certified under its BQ-9000 voluntary quality control program 6 biodiesel marketers and 17 producers who account for 40% of the biodiesel production capacity in the US. The board has asked state and federal government agencies to adopt and enforce fuel quality standards for biodiesel.

"There's nothing wrong with biodiesel blended to specifications by reputable firms," Morris said, "but you don't want to buy fuel from a guy blending vegetable oil in a barrel in his garage. There's plenty of high-quality biodiesel out there that meet the specifications." He said Alon USA is considering building a biodiesel plant at its Big Springs, Tex., refinery.

So far there is also limited experience with how biodiesel reacts with ULSD. "One concern that vehicle manufacturers have at this point is that starting in 2007 diesel vehicles will have particulate filters that are very sensitive to ash formation. All of the oils in the engines are being reformulated to a very low ash content. Biodiesel does introduce ash into the system where lots of people are working to take it out," said Schaeffer.

Allen Schaeffer, executive director of the Diesel Technology Forum, uses a white handkerchief to demonstrate the lack of exhaust soot from a vehicle fueled with ULSD. Photo from Diesel Technology Forum.

Urea needed

The ULSD rule issued by EPA in 2000 not only required that refiners drastically reduce the sulfur content of diesel but also imposed emission controls on heavy-duty diesel engines to slash the output of NOx, particulate matter (PM), and hydrocarbons (HC).

Those standards require stricter control of PM (0.01 g/bhp-hr), NOx (0.20 g/bhp-hr), and HC (0.14 g/bhp-hr) emissions and apply to diesel-powered vehicles with gross vehicle weight of 14,000 lb or more. The PM standard applies to all on-road heavy and medium-duty diesel engines. The NOx and HC standards are being phased in at 50% of new vehicle sales in 2007-09. By 2010, all new on-road vehicles will be required to meet the NOx and HC standards.

For 2007-09, however, diesel engine manufacturers have the option to design and produce engines to meet an average of 2004 and 2007 NOx and HC emission standards (1.1 g/bhp-hr) by using less-stringent emission control systems. Application of new emission control technology will provide a 3% or greater increase in efficiency, government officials said.

Urea is used as an active ingredient for some selective catalytic reduction (SCR) systems to reduce NOx emissions. It was the first organic compound to be artificially synthesized from inorganic materials.

One product is AdBlue, the European trade name of AUS32, a 32.5% solution of urea in demineralized water used as an operating fluid in diesel-powered freight trucks to clean up emissions. Not a fuel additive, AUS32 is stored in a separate tank and is sprayed in the hot exhaust gases in a specific catalytic converter. The oxides of nitrogen formed at combustion are converted into elementary nitrogen and water. AUS32 allows diesel-powered freight trucks to meet the Euro IV emission standard introduced in 2005 by the European Union, as well as the new EURO V emission standard proposed for 2008. With many EURO V and SCR trucks on European roads, retail gasoline stations are being built to supply AdBlue.

Correct materials must be used in construction of both the storage and dispensing facilities to keep SCR systems free from contamination, manufacturers said. Otherwise, ions can be passed from dispensing materials into the porous head on the SCR, making it ineffective and reducing the catalytic unit's life expectancy from more than 500,000 km to less than 200,000 km.

However, there is no infrastructure for distribution of urea in the US. Yet another issue is that the solution freezes in extremely cold weather. EPA is concerned with compliance issues because truck drivers may cut costs by not refilling urea tanks. Engine manufacturers are working with EPA to develop control systems to address these issues. ✦

IEA recommends UK energy policy improvements

Uchenna Izundu
International Editor

Data on current and future offshore oil and gas production on the UK Continental Shelf (UKCS) should be more transparent so the industry is better informed about future drops in production, urged Claude Mandil, executive director of International Energy Agency, in London Mar. 1.

Unveiling IEA's latest review of UK energy policy, Mandil said the latest information on production in 2006 showed a 6% drop on the year before, which had been "a surprise," as production had declined faster than originally anticipated. He recommended that government increase resources to improve the quality of information and that data should be given to market participants to provide signals about investing in supply infrastructure.

The UKCS is a mature province where companies are investing larger sums to produce amounts of oil and gas smaller than the large finds made in the last 20 years. The UK has produced about 70% of its total possible oil reserves and 65% of its total possible gas reserves. However, the UK Offshore Operators' Association estimates there are 16-25 billion boe yet to be recovered from the UKCS. In the report, IEA endorsed domestic production and advised the government to provide the appropriate fiscal and regulatory regime to attract investors.

"The government has managed gas and oil production in the North Sea without undue interference in private-sector activities. This production has provided a financial boon for the producers (UK and international), economic development for many regions bordering the North Sea, substantial taxes at national and local levels, and enhanced energy security," the report added.

Other recommendations

A key recommendation proposed in the report is that the government uphold a predictable fiscal regime to attract investment and achieve a balance between oil producers and the country's interest.

Also, because the UK has become a net importer of gas, Mandil said, it is important for the government to streamline its planning process for strategic energy infrastructure or it will find new projects not built on time. Local communities have successfully delayed major gas storage projects because of the bureaucratic planning process.

"Local communities can and should have a degree of permitting authority for new facilities. However, since these facilities benefit the country as a whole, the UK government has a role in ensuring that permitting is not duly delayed," the report said.

Mandil commended the UK government for having one of the most liberalized markets in Europe and using market mechanisms to attract investment. He stressed the need for

long-term certainty and targets as the government prepares to publish its White Paper on energy within the next month. In pursuing government policy, communication across government departments is important, he added, as is assessing overlaps with European initiatives to ensure there are no adverse impacts on European goals such as the Emissions Trading Scheme and the carbon levy.

UK Energy Minister Peter Truscott welcomed IEA's findings, describing them as "constructive and positive." He said, "It shows that the UK is heading in the right direction, especially with security of supply and climate change."

He acknowledged that the government needs to improve energy efficiency—a central tenet of its policy to reduce energy consumption—and curtail carbon emissions. "There is no room for complacency as we've got to achieve reductions in emissions. The UK has introduced climate change legislation, but we've got to act internationally to move towards a low-carbon economy."

Nuclear power

However, the role of nuclear power in the UK's future energy mix remains uncertain. Mandil said the UK could progress on this if it makes clear to the public how it will dispose of waste, saying France and Finland are "more advanced on dealing with this."

IEA recommended that the government establish a legal and regulatory framework for potential investors to assess the short and long-term risks and benefits of building a new nuclear plant.

Truscott said that the government will not directly intervene in the development of the nuclear sector. "Any new nuclear capacity will be developed and financed by the private sector," he added.

Greenpeace, in a recent High Court judicial review, succeeded in compelling the government to hold a wider consultation on the future role of nuclear power in the UK's energy mix. The Department for Trade and Industry, which develops energy policy, has committed to wider consultancy, and will publish its nuclear policy in the Energy White Paper within the next month. ✦

Study projects influence of national oil companies

Paula Dittrick
Senior Staff Writer

National oil companies, controlling 77% of global oil reserves, will gain geopolitical influence as their domination of worldwide production grows, says a study by Rice University's Baker Institute for Public Policy.

The study said the top 10 reserve holders internationally are NOCs that allow no equity participation in production by foreign oil companies. Partially or fully privatized Russian oil companies control a further 6% of global reserves, for which the study uses a 2005 estimate of 1.148 trillion bbl.

Baker Institute scholars analyzed historical case studies of NOCs and developed an economic model to examine the interplay between economic, political, and geopolitical factors in oil production and investment.

Empirical analysis shows NOCs that are fully government-owned and sell oil products at subsidized prices—a group that includes NOCs of the Organization of Petroleum Exporting Countries—have lower operating efficiency than privately held companies with no such obligations.

"Specifically to the extent that NOCs must meet the noncommercial objectives of politicians and other political interests, they may not produce at a technically efficient level," said a summary report released Mar. 1 during a 2-day NOC conference at Rice.

"In other words, by allocating rents to various special interests, a NOC will be less likely to be able to produce as much as it would have if it had been a private company that could operate without government interference in its decision-making," the summary said.

The Baker Institute, together with the Japan Petroleum Energy Center, released a lengthy study analyzing the strategies, objectives, and performance of NOCs.

The study includes individual examinations of Saudi Aramco, Nigerian National Petroleum Corp., India's Oil & Natural Gas Corp., Russian's OAO Rosneft, Russia's privately held OAO Lukoil, Malaysia's Petronas, Indonesia's PT Pertamina, National Iranian Oil Co., Petroleos de Venezuela SA, China National Petroleum Corp., China Petroleum & Chemical Corp. (Sinopec), China National Offshore Oil Co., Norway's Statoil ASA, and Kazakhstan's KazMunaiGaz. Iraq's Oil Ministry also was a research subject.

Privatization, efficiency

The study reports empirical evidence that at least partial privatization brings commercial benefits. The conjectures of the theoretical modeling exercise were verified through empirical analysis using a sample of 80 firms during 2002-04.

The empirical exercise also demonstrated the importance of vertical integration to a firm's ability to capture maximum value from its production.

"On average, for the sample of NOCs analyzed, those that both are fully government-owned and sell petroleum products at subsidized prices will be only 35% as technically efficient as a comparable firm which is privately held and has no obligation to sell refined products at discounted prices," the study said.

While individual NOCs vary in efficiency, on average the modeling shows that fully government-owned firms exhibit 60-65% the operating efficiency

Mulva: energy interdependence rather than independence

Paula Dittrick
Senior Staff Writer

ConocoPhillips Chief Executive Officer James J. Mulva said energy independence is a popular topic in the US, but believes that energy interdependence among worldwide energy companies is a more realistic goal.

"We believe it is unrealistic to believe the US can become energy independent," Mulva said Mar. 1 in a speech at Rice University's Baker Institute in Houston. His speech was part of a 2-day conference on national oil companies (NOCs).

Bader al-Khashti, chairman and managing director of Kuwait Foreign Petroleum Exploration Co. (Kufpec), and Victor Zhikai Gao, senior vice-president and general counsel-company secretary of CNOOC Ltd., also spoke at the conference.

In separate speeches, al-Khashti and Zhikai Gao each talked of corporate growth plans and the need for cooperation with international oil companies (IOCs).

Mulva said cooperation and collaboration between NOCs and publicly held IOCs is vital. He advocated a supportive government attitude on the part of both producing and consuming nations in order to encourage the massive investments by energy companies that will be needed to fulfill anticipated world oil and gas demand.

US policy

"The US must start sending clear signals to partners around the world that their contribution to energy is vital now and for years to come," Mulva said, adding that any efforts against allowing foreign investment in the US upstream or downstream sectors "is out of touch with the real world."

A new model is evolving for NOC-IOC partnerships, Mulva said. Components of a successful partnership include sharing costs and risk, complementary business and technical skills, good relationships, and a commitment to uphold contracts.

"Partnerships must take into account the big picture," and partners must seek to help each other meet goals, Mulva said. "We believe there are a multitude of ways NOCs and IOCs can work together" in both upstream and downstream projects.

Mulva said NOCs are "in a stronger position to bankroll big projects on their own as well as make acquisitions." Western "Big Oil" companies no longer necessarily have a lock on technology. "In comparison to NOCs today, Big Oil is not so big."

CNOOC's Zhikai Gao said his company's mission is to become "more and more international" going forward. He expressed disappointment about CNOOC's failed attempt to buy Unocal Corp.

CNOOC bid $18.5 billion for the US independent, but eventually withdrew its bid in the face of opposition from some US congressional members about a Chinese company buying a US oil company. Chevron Corp. bought Unocal for $18 billion.

"I really do believe CNOOC's offer was a better deal," Zhikai Gao said. "It did not go the way we wished, not for commercial reasons, but for other reasons."

CNOOC believes "greater openness and greater cooperation between one country and another is in the fundamental interests of all the countries, all the consumers," he said.

Kufpec

Kufpec expects to meet its previously announced goal to produce 100,000 boe/d by 2010. It produced more than 65,000 boe/d at yearend 2005, al-Khashti said. The company has operations in 15 countries including Australia, Egypt, Indonesia, and Pakistan.

"Our presence helps bring economic prosperity," al-Khashti said. "We are here not only to make oil and gas. We are here to make a profit."

The company's strategy calls for continued growth by expanding existing partnerships and also through the creation of new partnerships, he said. Kufpec is considering many possibilities, including Commonwealth of Independent States countries, he said.

"NOCs represent their nations as official and unofficial ambassadors in energy," al-Khashti said. "Kufpec has successfully carried the Kuwaiti flag into many host governments."

of a privately held international oil company (IOC), the study said.

This means NOCs might have more difficulty replacing reserves and expanding oil production than the industrialized West, which was responsible for 40% of increased worldwide oil production capacity in the past 30 years—with most of that investment coming from IOCs, the report said.

Supply, demand

NOCs' influence over global oil supply and demand will affect future oil prices and security trends. Consuming nations, like the US, might need to adjust national energy strategies to reduce vulnerability to NOC oil supply.

The study's summary calls Saudi Aramco "the powerhouse of geopolitical NOCs" because it's the only state oil company that is truly a global oil swing producer.

"The critical question for the future is whether Saudi Aramco, along with other major NOCs, will be able to continue to invest adequate amounts to meet the projected rise in oil demand in the United States, Europe, China, and emerging economies in Asia and elsewhere," the summary report said.

The International Energy Agency projects investments totaling $2.2 trillion will be needed during the next 30 years to meet rising world oil demand.

An NOC's ability to meet its business strategies will be challenged by its obligations to support national interests. NOC noncommercial objectives can include:

- Oil wealth redistribution to society at large.
- Foreign and strategic policy and alliance-building.
- Energy security, including assurance of domestic fuel supply and security of demand for producing countries.
- Wealth creation for the host nation.
- Participation in national-level politics.
- Industrialization and economic development. ✦

Purvin & Gertz: World LPG supply headed for surplus

Warren R. True
Chief Technology Editor-LNG/Gas Processing

World LPG prices, boosted by high oil and natural gas prices, have pushed up supply but depressed demand in developing markets, according to Craig Whitley of Houston-based consultancy Purvin & Gertz Inc. in opening remarks Mar. 6 to the firm's 20th Annual International LPG Seminar in Houston.

Especially in China and India have high prices halted LPG demand that had seen several years of steady growth as those countries' economies have expanded.

On the other hand, higher oil production rates have pushed up LPG production, especially in the Middle East. The region, led by Saudi Arabia, historically leads the world in LPG produced for export. Adding to the growing supply is a spate of new LPG production projects around the world, including many associated with new LNG production.

In 3 years' time, said Whitley, world LPG trade has moved from being demand-driven to supply-driven, building toward a global surplus and beginning to affect "price relationships."

Mideast charge

Global LPG production during 2006-12 will rise to 273 million tonnes from 227 million tonnes last year. This growth in fact will exceed growth by all other petroleum supplies, said Whitley.

Middle East LPG production—rising the fastest—will surpass North American production about 2010, taking over as world leader. North American production in that period will remain flat.

Middle East production, according to Whitley, will expand by more than 60% through 2016, as oil production continues strong and the region ensures ample feedstock for rapidly growing petrochemical capacity.

Following relatively flat growth in the 1990s, Middle East production expanded by 18% during 2003-06, increasing by 6.6 million tonnes/year.

With projects virtually all over the Arabian Gulf, especially Saudi Arabia, the UAE, Qatar, and Iran, regional production will grown by 6.3%/year to reach 62 million tonnes/year by 2012, said Whitley.

Asian push

Demand has been especially strong in developing nations of Asia, primarily China and India, but Middle Eastern petchem demand has also begun to attract larger volumes, he said.

Sometime shortly after 2000, Asia surpassed North America as the world's leading consuming center, and in 2006 reached 66.5 million tonnes in demand, compared with North America's 61.8 million tonnes.

With rapid expansion in the Middle East's petchem sector, LPG demand growth there is also being driven up by continued growth in the residential and commercial sector.

Demand in the developed world, primarily Europe and North America, has been relatively flat. Both regions' petchem industries remain markets for price-sensitive supplies of LPG.

Worldwide, residential and commercial markets continue to dominate LPG demand and will reach close to 150 million tonnes in 2012. ✦

Senate energy leaders voice concerns in budget requests

Nick Snow
Washington Correspondent

US Senate energy leaders have formally raised questions about oil and natural gas-related aspects of President George W. Bush administration's proposed fiscal 2008 budgets for the Departments of Energy and the Interior.

Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) and Ranking Minority Member Pete V. Domenici (R-NM) cited proposals to double the Strategic Petroleum Reserve's size and eliminate funding for oil and gas, geothermal, and hydroelectric research and development in DOE's budget request.

In a Feb. 28 letter to Budget Committee Chairman Kent Conrad (D-ND) and Ranking Minority Member Judd Gregg (R-NH), Bingaman and Domenici also questioned proposals in DOI's budget request to authorize oil and

gas leasing within the Arctic National Wildlife Refuge and to repeal portions of the 2005 Energy Policy Act related to funding for processing of drilling permit applications on federal lands.

Their letter was required under Senate rules for each committee to provide views and estimates annually of programs under its jurisdiction to the Budget Committee.

Of the proposal to double the SPR's size, Bingaman and Domenici wrote, "We will need to look closely at the need for a larger reserve, its cost, its impact on world markets, and its effect on oil and gasoline prices, before we authorize any such expansion."

They also said they believe that eliminating R&D funding for oil and gas and other traditional energy sources "will compromise efforts to fully develop our domestic energy resources." Administration officials have said they do not believe federal funding for oil and gas R&D is justified because prices for the commodities have grown dramatically the past few years.

Regarding the ANWR proposal in DOI's budget request, Bingaman and Domenici noted that the Energy Committee and the Senate overall are deeply divided over the issue, but added that they do not consider it likely that the 110th Congress will approve the plan.

They listed the drilling permit application processing proposal with three others involving cuts or changes. The others were proposed reductions of Land and Water Conservation Fund support to its lowest point in history, of Payments in Lieu of Taxes and of water programs at the US Bureau of Reclamation and US Geological Survey.

Bingaman and Domenici also expressed their concern over omissions of price thresholds from federal deepwater Gulf of Mexico oil and gas leases that were issued in 1998 and 1999. They said that the omissions may result in billions of oil and gas royalty payments being lost and indicated that the committee would look it ways to mitigate such losses.

The committee also will consider additional legislation this year to reduce US dependence on foreign oil by promoting the use of new energy technologies, they said. "It is important that the budget resolution accommodate the necessary funding to allow the committee to report such legislation. We urge the Budget Committee to include a deficit neutral reserve fund in the budget resolution to accommodate such legislation," Bingaman and Domenici said. ✦

Waxman questions EPA's handling of SoCal LNG project

Nick Snow
Washington Correspondent

US House Oversight and Government Reform Committee Chairman Henry A. Waxman (D-Calif.) has asked the Environmental Protection Agency to supply evidence that politics did not play a role in EPA's apparent decision to overrule career employees and award a permit to a proposed LNG project off Southern California.

Waxman said the committee received documents that raise questions about how EPA is handling the air permit for the BHP Billiton LNG floating storage and regasification project off Ventura County and that EPA is withholding "potentially important information" from the committee and "impeding Congress' investigation into the issue."

The question is whether the project should receive an air quality permit under the Ventura County Air Pollution Control District's requirements, which would make it necessary for BHP Billiton to obtain emissions reduction credits to offset the project's anticipated emissions. EPA asserted in a series of letters in 2004 that the project would have to meet these and other requirements, Waxman said.

But the agency reversed its position June 29, 2005, based on "further analysis" of the federal Deepwater Port Act and district rules, Waxman continued, adding that it has "provided no analysis that justified the reversal" and does not now claim that such an analysis exists.

EPA, in a Jan. 27 letter, offered some rationales for the reversal, said Waxman, including the importance of natural gas to California and the nation, the project sponsor's offering to make some environmental commitments, unidentified "unique issues posed by the first West Coast deepwater port application," and the proposed facility's location in an undesignated part of the ocean.

But Waxman said other documents EPA provided raise additional questions about how it reached its decision. They show that Assistant Administrator for Air and Radiation Jeffrey R. Holmstead met with BHP on Mar. 16, 2005, subsequently telephoned the agency's Region 9 office to discuss the project, and scheduled a conference call for Apr. 27, 2005, the lawmaker said. Meanwhile career EPA employees continued to insist that the project should be subject to the Ventura district's rules, including the offset requirement.

"Based on the information provided to the committee, it appears that (1) career officials at EPA opposed the permit decision reversal; (2) a senior EPA political official intervened in the permit decision after meeting with the company seeking the permit, and (3) the analysis that EPA cited to justify reversing the career officials does not exist," Waxman maintains.

Waxman said he has invited EPA to bring supporting documents and letters by Mar. 16 to the committee's office for examination. ✦

Rig shortages to delay Libya's E&P projects

Uchenna Izundu
International Editor

Exploration and production programs in Libya are facing significant delays because of a shortage of drilling and workover rigs, according to Phoenicia Group, a Libya-based investment and trade consultancy firm.

The scarcity of equipment also means higher prices for available rigs, which is straining already high E&P costs in the area.

A Phoenicia spokesman told OGJ that some projects are facing delays as long as a year. "Day rates for both drilling and workover rigs have gone up by as much as 15-25% in some cases, and in others it can be as much as 40-60%. It really depends on the company and the circumstances. Contracts need to be done early before rigs are brought into the country."

Ryad Sunusi, Phoenicia's interim president and chief executive, said, "Libya needs at least 40 rigs for the next 10 years to support [international oil company (IOC)] exploration programs, and this represents a great opportunity for the Libyan private sector to get involved, in forming [joint ventures] with overseas drilling and workover contractors, as outlined by GPC Decree 443/2006."

IOCs wishing to do business in Libya must do so through JVs with a Libyan partner, according to GPC Decision 443/2006, which was passed last November by the General People's Committee, Libya's executive decision-making body.

Foreign partners can take a maximum share of 65% and have the majority of representatives on its board. The Libyan partner, however, legally must have a minimum 35% stake in any joint stock company.

According to Phoenicia, major oil services companies such as "Schlumberger, Halliburton, Weatherford, and others are scrambling to conform to the new decree, and newcomers keen to pinpoint Libyan partners." ✦

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Security: the Chinese view

The other day, I was chatting with one of China's oil and gas people—let's call him Ooh Hyun—who was at pains to tell me (and the world we watch) that his country does not deserve the bad press it gets these days.

In fact, sitting on a verandah overlooking the port of Hainan, one of his country's leading gateways for the import of oil and natural gas, Ooh raised his hands in a gesture that could be interpreted as one of despair.

"I find it hard to understand why people are not talking about those countries with a high level of consumption and imports threatening the world's oil security but who say, on the contrary, that our low level of consumption and imports is a threat to world energy security," he said. "This is not fair. China is not only not a threat to energy security, but is a positive factor in safeguarding world energy security."

No threat

Ooh insisted that China poses no threat because it has traditionally been able to meet 90% of its own energy needs.

In fact, he said, China imported 100 kg/person of oil in 2005, while Japan imported 20 times as much in the same year.

Not only does China import less than other countries on a per-capita basis, it also consumes less, Ooh said. Per-capita oil consumption in Japan is about eight times higher than in China, he said.

To Ooh's obvious embarrassment, I mentioned security problems over oil and gas between his country and Japan in disputed waters of the East China Sea.

Ooh recovered and shrugged. "You see?" he said. "Your observation just proves my point. It's those energy-hungry Japanese who are the ones causing the problems in the East China Sea. Not us."

I was not sure how to reply to that since Japan a week before—in a bid to break the stalemate with China over joint development of gas fields in the area—proposed launching a project that would cover a broad area of the East China Sea and encompass the contested demarcation line between the two nations.

Talks sought

If China agrees to the proposal, Japan would offer to pay for a drilling facility already constructed by the Chinese.

Japan hopes to enter talks with China over such details as the selection of companies that will carry out drilling, natural gas allocations, as well as resource management and cost-sharing.

But China has yet to respond to Japan's proposal. It has indicated a willingness to pursue joint development on the eastern side—the Japanese side—of the existing median line but has said it seeks to go it alone on the western side.

Ooh agreed with his country's position, citing a famed literary man in support: "East is East and West is West." ✦

GLOBAL OFFSHORE OIL—2

Growth expected in global offshore crude oil supply

Ivan Sandrea
OPEC Secretariat
Vienna

Rafael Sandrea
IPC
Tulsa

This is the second of two parts on the outlook for global offshore oil discoveries, production, and reserves.

The reserve base is the sum of cumulative production and remaining reserves; these two combined with undiscovered potential (or yet-to-find) give the ultimately recoverable reserves (URR).

Estimates for the first two may be obtained from IHS Inc. IHS uses a systematic, bottom-up approach compilation of known technically recoverable estimates (proved and probable) for discoveries, but these numbers are also subject to uncertainty.

Estimates for undiscovered oil (crude and NGL) in offshore provinces are only available from the US Geological Survey's 2000 world petroleum assessment. The USGS methodology is based on assessments of a total petroleum system (TPS) of known and frontier provinces, which is a less restrictive measure than known field-by-field estimates.

Table 4 shows the global offshore reserve base at end 2005 based on a combination of these two sources adjusted for discoveries and type of liquid. But how can we get a second opinion?

Alternative 1: decline curve

The world has produced/consumed 1 trillion bbl of crude oil in the last 150 years, of which roughly 800 billion bbl came from onshore oil fields and 200 billion bbl from offshore.

Fig. 5 shows the cumulative pro-

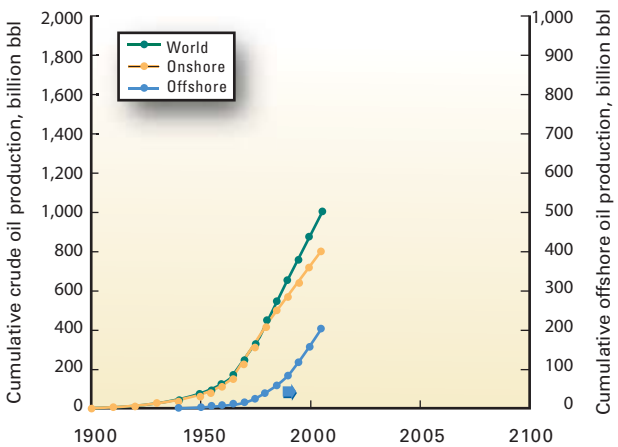
WORLD OFFSHORE OIL RESOURCE ESTIMATES, 2005

Table 4

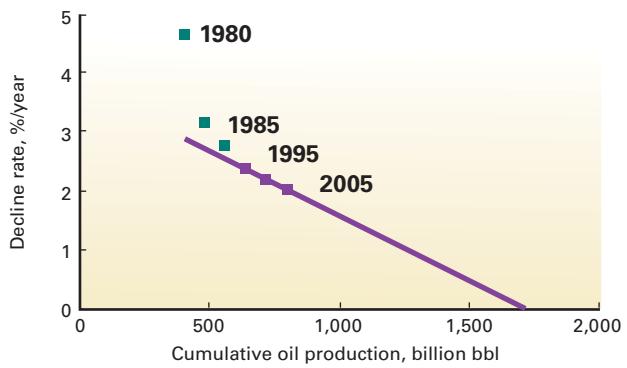
	Cumulative production	Remaining reserves	Total discovered	Adjusted undiscovered US Geological Survey[1]	Composite ultimate recoverable reserves[2]
			Billion bbl		
Crude					
Shallow offshore	190	205	395	NA[3]	NA
Deep water	7	45	52	NA	NA
Ultradeep water	NA	7.5	7.5	NA	NA
Subtotal	**197**	**258**	**455**	**251**	**706**
NGL	**7**	**41**	**48**	**95**	**143**
Total liquids	**204**	**299**	**503**	**346**	**849**

[1]Reflects discoveries during 2000-05. [2]Total discovered + adjusted undiscovered URR. [3]Not available.
Sources: IHS Inc., US Geological Survey, OPEC

WORLD CUMULATIVE CRUDE OIL PRODUCTION GROWTH Fig. 5



WORLD ONSHORE CRUDE OIL PRODUCTION DECLINE TREND Fig. 6



duction growth patterns of each genre that are remarkably similar except for the phase lag in development. Offshore production started 40 years later.

Characteristically the cumulative production curve begins growing exponentially up through the half-life point of the reserves ($Q = K/2$); thereafter it reverts to an exponential decline pattern, finally approaching asymptotically the value K, the ultimate reserves of the field.

Overall it resembles a somewhat S-shaped curve that is best represented by the logistic equation[1]:

$$Q = \frac{K}{(1 + ae^{rot})} \qquad (1)$$

Q is cumulative production, K ultimate reserves, ro the initial growth rate constant, and the constant a which has no physical significance. Unfortunately, it is not possible to curve fit equation (1) and obtain a unique set of values for the three constants. However, the derivative of Equation 1, namely:

$$(dQ/dt)/Q = r_o\,(1 - Q/K) \qquad (2)$$

defines a straight-line relationship between production decline, $(dQ/dt)/Q$, and Q. This constraint allows the establishment of definitive values for K and r_o.

Generally the straight line trend would kick off after a substantial volume of oil has been produced, at least 25% of the ultimate reserves. This has been the observed[2] decline behavior of oil production in many producing countries with large onshore production.

However, global offshore production is still in its early exponential growth stage, and this precludes the use of production decline analysis to establish its K-value. Laherrere[3] developed an elegant parabolic fractal distributions approach to estimate the K-value for a region with only few estimates about the size of the largest fields, a condition very akin to the offshore environment that is in a nepionic stage of development.

The methodology, however, assumes that the discovery of large fields has peaked and that no additional fields will be discovered. As discussed before, this is unlikely to be the case. The parabolic fractal method, moreover, requires the determination of three free constants, none of which has any physical significance; a physical tie would normally allow obtaining independent anchor values.

Alternative 2: exploration by analogy

In order to establish a second estimate for the global offshore crude oil reserve base, a heuristic approach[7] is proposed, using an assumed analogy of the size distributions of the giant oil fields discovered to date in both the onshore and offshore environments.

The basis for the analogy stems from the premise and observation that oil fields are often found together in the most important hydrocarbon provinces and petroleum systems. Moreover, giant oil fields are the core of the oil industry because they provide a significant share of the world's production and reserves.

This methodology requires knowledge of the global onshore reserve base for comparative purposes. This was obtained by using two methods: decline curve analysis and data from IHS.

The oil production decline performance for global onshore crude since 1980 is shown in Fig. 6. The linear trend line starts in the early 1990s and extrapolates to a K-value of 1,800 billion bbl, thus indicating that onshore production would reach its half life in the next 6 years at current production rates.

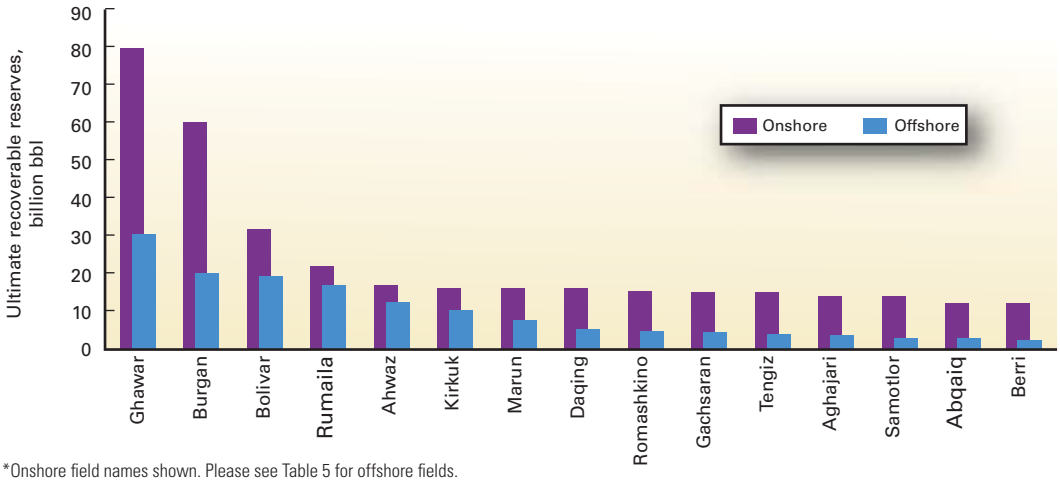
The least squares-fitted trend line has a correlation coefficient of 0.984. IHS estimates that at the end of 2005, the reserve base for the global onshore stood at 1,838 billion bbl. It is worth mentioning that both estimates exclude undiscovered oil potential and reserve growth.

Table 5 summarizes the ultimate reserves and production capacity of the 67 giant offshore oil fields discovered to date. Fig. 7 compares the size distributions of the 15 largest onshore and offshore fields.

The largest onshore oil giants range in size from 80 billion bbl to 12 billion bbl of ultimate reserves. In comparison,

SIZE DISTRIBUTION OF LARGEST 15 ONSHORE AND OFFSHORE OIL FIELDS*

Fig. 7



*Onshore field names shown. Please see Table 5 for offshore fields.

GIANT OFFSHORE OIL FIELDS*

Table 5

Region, field	Discovery year/ first oil	Est. of ultimate recoverable reserves, billion bbl	Est. of max. capacity, 1,000 b/d	Water depth	API gravity, °
Persian Gulf-Middle East					
Safaniya-Khafji	1951/1957	30	1,200	Shallow	27-32
Zakum (Lower and Upper)	1965/1967/2006	20	750	Shallow	33-39
Manifa	1957/1964/2011	17	1,000	Shallow	27-32
Zuluf	1966/1967	12	660	Shallow	27-32
Forouzan-Marjan	1966/1974/1994	10	750	Shallow	27-32
Abu Safah	1957/1967	7.5	300	Shallow	27-32
Umm Shaif	1958/1962	4	280	Shallow	37
Doroud	1961/1964	3.4	220	Shallow	34
Soroosh/Norouz	1962/1967	1.2	190	Shallow	18
Abuzar	1969/1976/1994	1.1	220	Shallow	26
Fateh	1965/1969	1.1	300	Shallow	32
Al Shaheen	1992/1994	1	525	Shallow	30
Salman	1965/1969	0.5	135	Shallow	35
Belayim (Deep)	1997/2003	0.5	100	Shallow	28
North Sea					
Statfjord	1974/1979	4.5	740	Shallow	38
Ekofisk	1969/1971	3.8	300	Shallow	32
Oseberg	1979/1988	2.8	500	Shallow	35
Forties	1970/1975	2.7	520	Shallow	37
Brent	1971/1976	2.4	440	Shallow	38
Gullfaks	1978/1986	2.5	530	Shallow	31
Draugen	1984/1993	2	210	Shallow	39
Snorre	1979/1992	1.4	360	Shallow	68
Ninian	1974/1978	1.2	300	Shallow	37
Heidrun	1985/1995	1.1	225	Shallow	27
Valhall	1975/1982	0.8	168	Shallow	42
Buzzard	2001/2006	0.5	190	Shallow	32
West Africa					
Dalia	1997/2006	1	240	Deep water	23
Bonga	1996/2005	1	220	Deep water	29
Akpo	2000/2008	0.9	180	Deep water	>40
Girassol	1996/2001	0.8	220	Deep water	32
Agbami	1998/2008	0.8	210	Deep water	45
Bonga SW	2001/2012	0.7	150	Deep water	30
Bosi	1996/2008	0.7	120	Deep water	<40
Amenam-Kpono	1990/2003	0.7	125	Shallow	32
Erha	1999/2006	0.7	190	Deep water	>35
Kuito	1997/2000	0.7	100	Shallow	>35
Benguela	1998/2006	0.7	100	Shallow	24-38
Kizomba A-Hungo	1999/2005	0.5	120	Deep water	28-30
Kizomba A-Chocalho	1999/2005	0.5	120	Deep water	28-30
Kizomba B-Kissanje	1998/2006	0.5	120	Deep water	28-30
Kizomba B-Dikanza	1998/2007	0.5	120	Deep water	28-30
Gulf of Mexico					
Cantarell (Complex)	1976/1979/2000s	19	2,000	Shallow	25
KMZ (Complex)	1970s/1979/2000s	5	800	Shallow	13-24
Thunder Horse	1999/2008	1	250	Deep water	33
Atlantis	1998/2005	0.6	200	Deep water	30
Mars	1989/1996/2006	0.7	220	Deep water	30
Shenzi	2001/2009	0.5	100	Deep water	>30
Ursa	1991/1999	0.4	150	Deep water	30
Asia-Australasia					
Kingfish (Australia)	1967/1969	1.2	160	Shallow	46
Halibut (Australia)	1967/1970	1	160	Shallow	43
Bach Ho (Vietnam)	1975/1986	0.9	340	Shallow	34
Brazil					
Marlim	1985/1998	2.7	590	Deep water	20
Roncador	1996/2002	2.3	480	Deep to ultradeep	25
Marlim Sul	1987/2004	1.2	150	Deep water	26
Barracuda	1989/2002	1	150	Deep water	24
Jubarte	2000/2002	0.8	180	Deep water	17-20
Albacora East	1986/2006	0.7	180	Deep water	20
Albacora	1984/1996	0.6	175	Deep water	28
FSU-Arctic					
Kashagan	2000/2008	12	1,200	Shallow/ice	42
ACG (complex)	1984/1997	5	1,000	Shallow/deep	34
Sakhalin-1 (complex)	1979/2005	2.3	250	Shallow/ice	>35
Sakhalin-2 (complex)	1979/1999	1	160	Shallow/ice	>35
Prirazlomnoye	1989/2008	0.7	100	Shallow	<30
Others					
Shengli complex of fields (China)	1961/1993	2.2	650	Shallow	<25
Bombay High complex of fields (India)	1974/1976	1.3	400	Shallow	39
Hibernia (Canada)	1978/1997	0.8	150	Shallow	30-34
Peng Lai (China)	1999/2006	0.5	180	Shallow	11-20

*Some fields have onshore/offshore reserves. Several field complexes are undergoing redevelopment or expansions despite that first oil may have been produced in the past.
Sources: Mann, P., et al., 2003; Company data; Sandrea, I., 2004; Secondary sources

the offshore giants range in size from 30 billion bbl to 2.5 billion bbl.

In general, the mean size of the onshore giants is three times that of the offshore giants, 24 billion bbl vs. 8 billion bbl. Consequently, the expected value of the offshore crude reserves would be around 600 billion bbl, corresponding to one-third of the K-value estimated for the onshore.

Using the tail-end values of the offshore size distribution, it is also possible to obtain a range of values. The high end corresponds to the oil fields of the Persian Gulf. They are the largest offshore oil fields in the world, varying in size from 30 billion bbl to 4 billion bbl. Their onshore counterparts are also the biggest in the world. The size ratio of onshore to offshore fields is estimated at 2.5.

At the low tail-end of the distribution are the giant oil fields discovered in the Gulf of Mexico. With the sole exception of the fields in Mexico, the largest fields discovered in the Gulf of Mexico to date tend to be relatively small, less than 1 billion bbl, and average 500 million bbl and less. The onshore fields contiguous to the gulf are also relatively small.

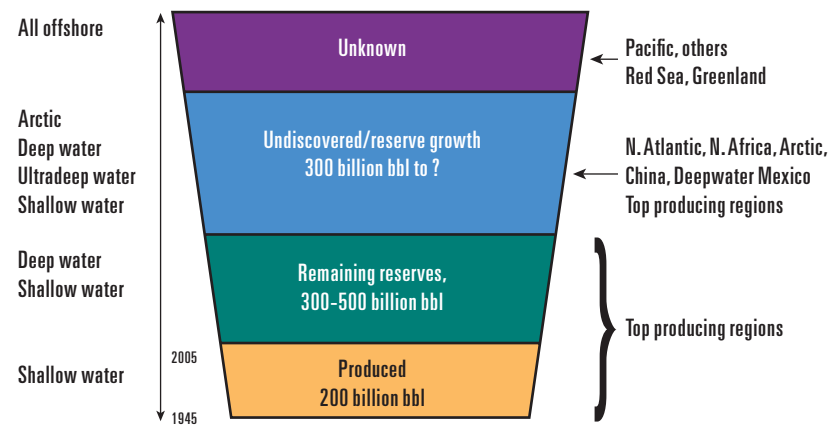
The 10 largest onshore oil fields in the US Lower 48 have sizes varying from 6 billion bbl to 1.4 billion bbl with an average of 2.5 billion bbl. The size ratio for the onshore Gulf of Mexico is 5, which is twice that for the Persian Gulf.

These size ratios would indicate that the offshore reserve base can range from 720 billion bbl to 360 billion bbl.

The heuristic methodology shows that the average estimate for the global offshore oil reserve would be closer to 600 billion bbl, which is nearly 30% more than the IHS bottom-up estimate; considering the difference in the approach, the proximity of the results is reassuring. However, given that both methodologies may not apply to unexplored regions with probably significant reserves and potential, it can be concluded that additional offshore reserves must exist over and above this

GLOBAL OFFSHORE OIL RESERVE BASE AND URR*

Fig. 8



*Defined in this article as cumulative production, reserves, and yet-to-find potential.

new estimate.

By combining the average result of the heuristic approach with the USGS 2000 assessment estimate for undiscovered oil, the URR for the global offshore could be closer to 1,000 billion bbl, of which just 200 billion bbl have been produced (Fig. 8).

Production potential

Shallow offshore oil production in several underexplored hydrocarbon rich provinces including China and Caspian is just ramping up; it may be a slow ramp up but the fact is that it is increasing and will continue to do so.

The shallow offshore is expected to continue to grow at a slower pace to the end of this decade until the pressure from declining North Sea oil is reduced. At least three giant fields will contribute significant volumes in the medium term: Azeri-Chirag-Guneshli, Manifa, and Kashagan; however, more than 200 fields will be developed. On the other hand, deepwater oil production will double over the next 5 years, underpinned by more than 60 projects globally grouping an even larger number of fields.

It is very possible that with the rapid rate of increase deepwater will reach its maximum level in the medium term due to the nature of turbidite reservoirs. However, this scenario remains uncertain due to the potential impact of technology and unexplored deepwater provinces, both of which could extend the growth and certainly the postpeak production level.

The ultradeep water will remain constrained, but in 5 years several fields will be producing in the US gulf, Angola, and Brazil. Offshore production in Russia/Arctic is also just taking off with new production from Sakhalin, Pechora, and the Barents Sea.

Fig. 9 shows historical and modeled future world offshore oil production. Deepwater is included separately given the importance of this source. The near to medium term has been modeled with known projects (over 200) and assumed decline rates. The model has also been calibrated so that projected R/P ratios remain stable.

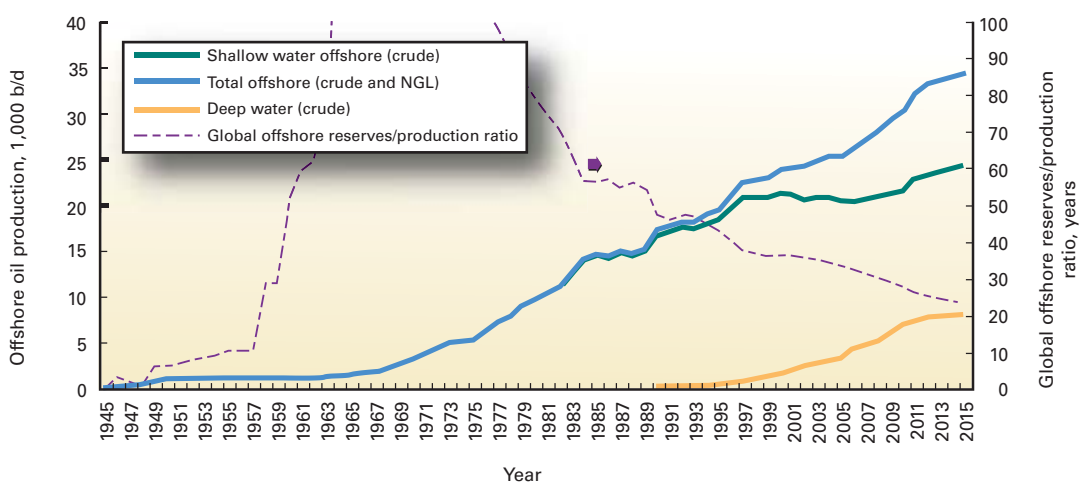
There is no doubt that global offshore oil production will continue to grow strongly in the medium term; in fact, various tests of the model show that global offshore crude oil production could grow to 34 million b/d by 2020.

Long term, once the R/P ratio reaches 10 to 15 and cumulative production exceeds 50% of URR, it is expected that production will start to level off and then decline. The current global R/P is over 32, and by 2015 it will be 23.

Based on an URR of 1,000 billion bbl, we have produced 20% and by 2015 we would have produced 35%. Given that there are uncertainties about the timing of new oil, impact of potentially large discoveries, and deliverability issues, the long term is not

GLOBAL OFFSHORE OIL PRODUCTION OUTLOOK

Fig. 9



modeled here, but there should be no doubt that offshore production will continue to perform strongly.

Top offshore producers

In contrast to conventional wisdom, the world's largest offshore producers include primarily national oil companies.

Six of the top 11 offshore producers are NOCs. Saudi Aramco is the world's largest, followed by Pemex. The merger of Statoil with Hydro will create the third largest, followed by Petrobras.

The international oil companies with the largest offshore oil production are Exxon, followed by Shell, Total, and BP. Fig. 10 shows the top offshore producers based on the estimated net entitlement offshore oil production in 2005. For Statoil Hydro, it includes the operated share of the Norwegian state (Petoro).

It is interesting to note that a simple review of the medium and long term strategy of the top companies shows that a big part is geared towards offshore operations, which is consistent with the bright picture for the global offshore discussed in this article.

Saudi Aramco has a tremendous opportunity set in its own back yard managing and developing the latest technologies on the world's largest offshore oil discoveries. Pemex has some very large mature offshore fields in its own back yard, but is also developing large complex fields in shallow water. Pemex is also moving to access the highly prospective deepwater basins, but this will take time as the company is not prepared for this type of environment.

Statoil Hydro combined will operate a significant portion of Norway's oil and gas production, and this may give the group more flexibility to explore mature parts of Norway and the far north. Interestingly, the Norwegian giant will have special characteristics that are unique among NOCs, such as a growing important international business, world class shallow EOR experience, deepwater experience, management of complex oil and gas offshore developments, and arctic experience.

Petrobras is world leader in deep water and is primarily engaged at home with many developments; the future of offshore Brazil is also bright.

Looking forward, over $200 billion will be invested in new offshore oil projects in the next 6 years alone, the bulk of which will come from NOCs.

Acknowledgments

Special thanks to Ken Chew of IHS Inc. and to Thomas Ahlbrandt, former USGS project chief. The views expressed in this report are those of the authors and do not represent those of OPEC. ✦

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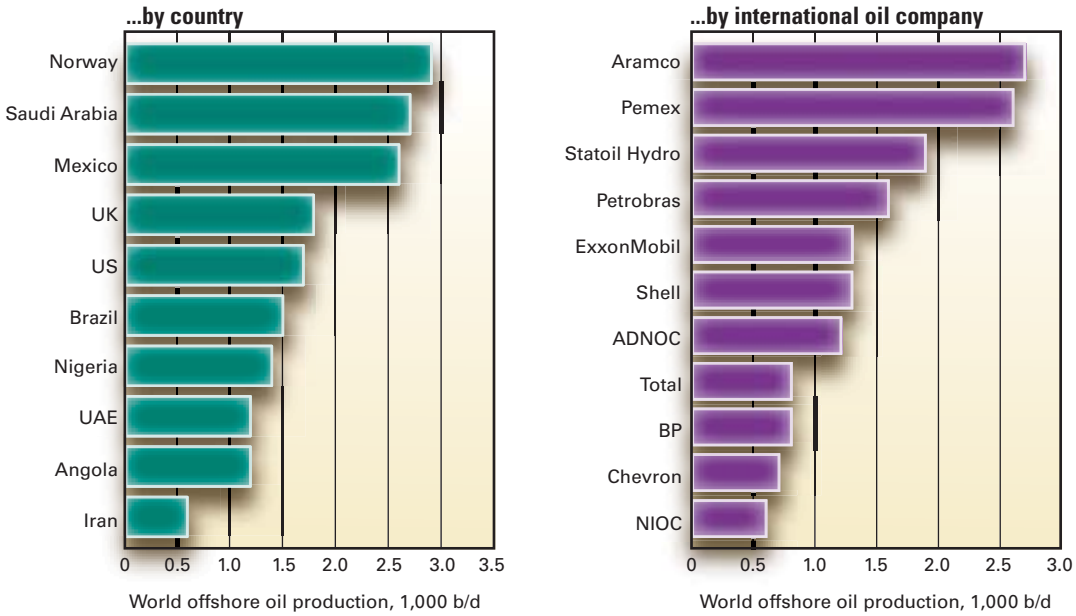
TOP 10 OFFSHORE OIL PRODUCERS IN 2005

Fig. 10



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Delta sizes up northern Paradox discoveries

Delta Petroleum Corp., Denver, is sizing up gas-condensate and oil discoveries in the northernmost Paradox basin in Grand County, Utah.

The company hopes to ultimately recover 2 to 4 tcf of gas net to its 70% interest from Pennsylvanian Hermosa Group clastics in southwestern Grand County. It has drilled the Greentown-State 36-11 and 32-42 wells south of Green River, Utah. A pipeline Delta plans to build mainly on federal land to transport the gas could take a year to complete.

The 36-11 well is completed in 2 of 12 pay intervals. From the two completed intervals it production tested at a combined 4.5 MMcfd of gas and 125 b/d of condensate. The company estimated proved reserves at 2.7 bcfe from the two perforated zones. The other 10 intervals have similar log characteristics.

The well blew out for several days in 2006 during postfrac flowback after only one interval had been perforated.

The 32-42 well, 7.5 miles southeast, is completed in 8 of 12 pay intervals. It flowed a combined 2 MMcfd of gas and 500 b/d of condensate. Proved reserve estimate is 5.8 bcfe in the eight zones.

The wells have 906 and 1,077 ft of potentially productive clastics in the 12 intervals, respectively, and the company believes all of its 40,900 gross (28,600 net) acres to be prospective.

Delta plans to drill six to eight wells in 2007 to an average 9,800 ft at $3.0-3.5 million/well. One well will be a clastic prospect on a salt anticline analogous to Greentown.

Meanwhile, about 15 miles east in Grand County, Delta completed its 70% owned Salt Valley-State 25-12 well in 13 stages. It encountered 654 ft of net sand in 15 intervals. The well, expected to recover 200,000 bbl of light, sweet crude, is to go on pump in mid-March.

Delta holds 7,100 gross (5,000 net) acres, all of which it deems prospective. It will drill five to six wells in 2007 on 40-acre spacing. Wells are to average 8,200 ft and cost $2.5 million.

An undisclosed private company holds the other 30% interest in both prospects. ✦

Colombia

Consulting engineers estimated proved and probable reserves at 694,000 bbl of oil in Centauro Sur field, Emerald Energy PLC's third oil discovery on the 503 sq km Campo Rico Association Contract area in the Llanos basin.

Two wells are producing a combined 700 b/d of 16° gravity oil from the Eocene Mirador formation, and a flow line has been installed to ship Centauro Sur field fluids northeast to the Campo Rico field facilities. Emerald discovered Centauro Sur in 2006.

Niger

China National Petroleum Corp. was moving a rig to drill the Fachi West-1 exploration well on the Tenere Concession in Niger after Saha-1, the first well in a three-well program, proved noncommercial.

Drillstem tests were run on two intervals, and one flowed oil and water, said carried 20% partner TG World Energy Corp., Calgary.

Trinidad and Tobago

Ten Degrees North Energy Ltd., San Fernando, Trinidad and Tobago, let a contract to MTEM Ltd., Edinburgh, to carry out an R-land multitransient electromagnetic survey over Tabaquite oil field.

Tabaquite is a mature producing oil field in central Trinidad 25 miles southeast of Port of Spain (see map, OGJ, Sept. 28, 1981, p. 364). The survey is aimed at locating bypassed oil by measuring subsurface resistivity changes with depth.

Quebec

Forest Oil Corp. plans to explore the St. Lawrence Lowlands south of Lac St. Pierre, Que.

Under an agreement with Gastem, Montreal, Forest could earn as much as a 60% interest in Gastem's 45,381-ha Yamaska property by contributing up to $10 million to a drilling joint venture.

Gastem plans to drill two wells in 2007, the first of which must be drilled before June. Depending on well results, Forest may conduct other tests and commit to further exploratory operations to earn its interest.

Yamaska, surrounded on three sides by land held by Talisman Energy Inc., Calgary, has geology dominated by formations of Middle and Late Ordovician age.

Great Wall drilling swiftly in Thailand

Nina M. Rach
Drilling Editor

Chinese crews in Thailand drilled about 375,500 ft with an individual land rig in 2006. This performance was achieved during a continuous contract with a single operator, PTT Exploration and Production Co. Ltd., in two areas, 400 km apart.

Great Wall Drilling Co., a subsidiary of China National Petroleum Corp. (CNPC) Services & Engineering Ltd., was set up in 1993. The company currently provides drilling services and operates rigs in Thailand, Indonesia, Canada, US, Mexico, Cuba, Venezuela, Chad, Algeria, Tunisia, Libya, Egypt, Sudan, Oman, Syria, Iran, Pakistan, Kazakhstan, Uzbekistan, and Azerbaijan.

Last month, GWDC (Thailand) Ltd. told OGJ that there were 180 GWDC rigs operating outside China.

As of July 2005, the total CNPC rig fleet numbered at least 618 rigs, predominantly 1,000-1,500-hp rigs (OGJ, July 18, 2005, p. 37).

In June 2005, Dan Pickering characterized CNPC and subsidiary Great Wall Drilling as the "global land drilling X-factor," based on its potential to affect the balance of land rig supply and demand worldwide.[1]

Unfortunately, company web sites

Great Wall Drilling Co.'s GW-80 rig has set records drilling in Thailand for state-owned PTT Exploration and Production PCL (Fig. 1; photo provided by Great Wall Drilling Co. (Thailand) Ltd.).

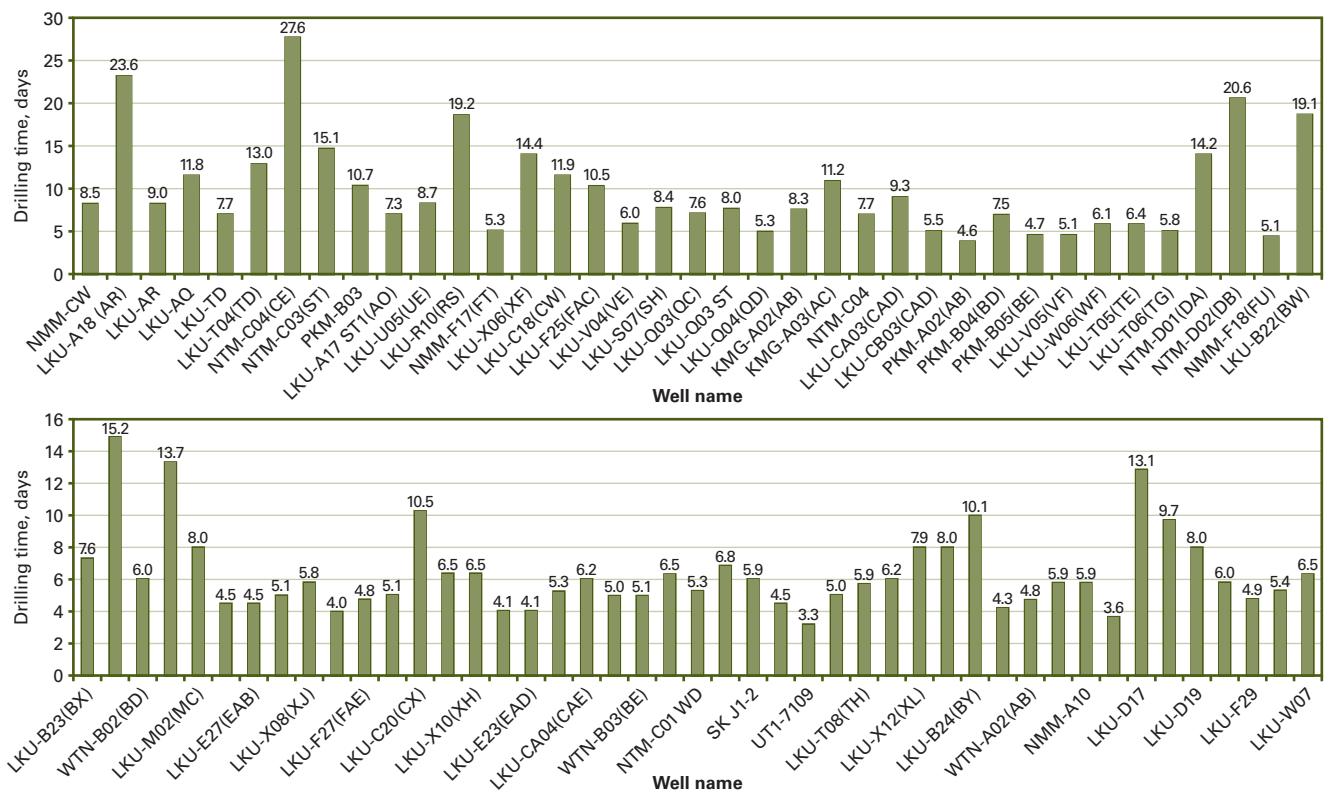
Triples (photo on left) are stacked on the drill floor of Rig GW-80 in Thailand (Fig. 2). Drill crew (photo on right) runs pipe on Rig GW-80 (Fig. 3). Photos provided by GWDC Thailand.

are infrequently updated and provide little information about the rig fleets, projects, or technical capabilities of the equipment.[2] Last month, GWDC told OGJ that it is redesigning the company web site and that additional information would be available soon.

Thai drilling record?

Great Wall Drilling Co. (Thailand) Ltd., a drilling service provider in Thailand, has a drilling rig and a workover rig in country. GWDC Thailand's Rig GW-80 has been working for state-owned PTT Exploration and Production

COMPLETION CYCLES, RIG GW-80 Fig. 4



PCL in the PTTEP S1 area, in Pitsanuloke, and Kampangpetch, and Supanburi provinces, for several years (Fig. 1).

Rig GW-80 was built in China by Honghua Machinery Manufacture, Sichuan. Model ZJ 50DBS uses variable frequency drive and is rated to 5,000m (16, 400 ft). All rig components were manufactured in China, except for the Caterpillar generators and the Varco TDS-11SA top drive.

The 1,500-hp rig features a driller's cabin and console with joystick controls, and can handle triple stands of pipe (Fig. 2). Triple stands of pipe are handled manually; there is no automated pipe handling equipment (Fig. 3).

Over a 26-month period (August 2004-October 2006), this land rig drilled 78 wells, completed 3 workovers, was skidded 27 times over a total skidding distance of 3,150 m, and moved 55 times over 380,000 km.

The drilling completion cycle ranged 3.6-27.6 days/well for 60 wells drilled in 2005-06, with an average around 7 days (Fig. 4). Rig move cycle time ranged 1.5-5.1 days/move.

During the first 10 months of 2006, Rig GW-80 drilled 40 wells, 1 workover, 1 sidetrack, and 100,500 m (about 330,000 ft). Crews skidded the rig 18 times over a total of 1,612 m and moved the rig 26 times.

During the entire year, 2006, GW-80 drilled 114,482 m (375,500 ft). It may be a land rig footage record for the country and the company, but OGJ cannot confirm record status. There is no central database for land rig performance outside the US.

The Land Rig Newsletter ranks the top 75 "most active" land rigs each year, based on footage drilled in the US. Publisher Richard Mason told OGJ that the GW-80's performance in Thailand in 2006 would rank 17th in the US. The top two US rigs finally broke the 500,000 ft. barrier in 2006.

Procedure

GWDC (Thailand) detailed the operations procedure for a typical well drilled in the PTTEP S1 area. The well program was designed by PTTEP's drilling department.

The first section is drilled from 850-1,250 m in about 12 hr, using a 12¼-in. PDC bit with a 9⅝-in. motor and MWD and fresh water. The inclination is increased from 15-60°. The choke manifold, pipe ram, and SCR are tested. After reaching TD, the driller backreams with the bottomhole assembly (BHA). The crew sets 9⅝-in. casing and cement in 7-8 hr. The well is then pressure tested for 3-4 hr.

The driller reenters the hole with an 8¾-in. BHA and drills with overbalanced mud weight, drilling 2,500-3,500 m in about 40 hr. Pulling out of hole requires about 12 hr. Two wireline logging runs take about 10 hr. The crew sets and cements 7-in. casing in about 15 hr. Completing the well (without perforating) requires about 10 hr. Another half hour is required to nipple-down the BOP.

GWDC, North America

According to RigData, Great Wall Drilling Co. of America placed 88th in a list of the top 100 drillers ranked by footage drilled in the US in January 2007 (www.rigdata.com). Company rigs drilled 33,750 ft, started 3 wells, and drilled 1 directional well in January.

Houston-based Andrews Technologies Inc. (ATI) facilitated a "3+2" contract (3-year initial term, 2-year renewable), $165 million contract with GWDC America LLC, a subsidiary of GWDC China, for 10 land rigs in the US. The Chinese-owned, fabricated, and operated rigs range 750 hp to 1,500 hp and began operating in Texas and Louisiana in late 2005.

The first two rigs, GW85 and GW86, left Tianjin port on Oct. 5, 2005, according to China National Petroleum Corp. (www.cnpc.com.cn/english) and GWDC. The two drilling crews are from Daqing No. 1 and No. 2 Well Drilling Cos.

According to ATI, the rigs arrived in the Port of Houston on Dec. 14, 2005. Both rigs were transported to drillsites in Louisiana and completed spud-in in late December 2005 for Aspect Energy LLC, a privately held, Denver-based, independent oil and gas exploration and investment company. On Jan. 17, 2006, GWDC completed the first well successfully.

The fourth GWDC America rig, 1,500-hp, spudded its first well in Sulphur, La., on Aug. 16, 2006. The fifth and sixth rigs, 750-hp and 1,000-hp, cleared the Port of Houston in September 2006 and went to work for Aspect Energy.

By January 2007, GWDC had nine Chinese-built rigs operating in the US, according to The Land Rig Newsletter (Jan. 31, 2007).

Andrews Technologies de Mexico SA de CV and Beijing's Great Wall Drilling Co. have an exclusive partnership agreement for Mexican. Four drilling rigs were operating in PEMEX's Southern Region 2002-05.

In April 2006, ATI Mexico secured two contracts, worth $43 million, for GWDC America to provide two 750-hp land rigs to Pemex Exploration and Production for drilling near Villahermosa, Tabasco state.

Since it is the nature of records to be broken, we will see what other rigs will approach or exceed the accomplishment of GW-80 in 2006. ✦

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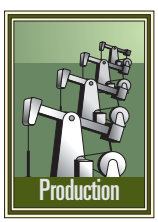
Smart pump boosts oil flow from less-productive wells

Bill Savela
Delta Computer Systems Inc.
Vancouver, Wash.

Chris Bartlett
PQ Systems Ltd.
North Burnaby, BC



A new pumping system installed on several wells in Canada allows production from wells previously classified as unproductive, as well as on new wells.

Ecoquip Artificial Lift Ltd., Calgary, designed the new pumping system.

The Ecoquip hydraulically driven rod pump, while suitable for new installations, can produce oil from wells that could not be pumped effectively with the older generation of rod pumps.

The new design allows the rods to reciprocate at varying speeds, thus improving pumping efficiency.

Oil well pumps

A typical oil well rod pump has a "bobbing donkey" design (Fig. 1). In the design, the rods typically move up and down at the same speed because of the mechanical linkage between the motor and the rod plunger. While constant-speed operations are adequate for applications where oil flows easily from the formation, it is not appropriate in many lower volume producing wells.

In these less productive wells, the key to improved pump performance is to provide various motion profiles to the pumping unit. For example, if the downhole conditions are such that the oil is viscous, the operator may want a faster upstroke to remove the oil but then have a slower downstroke to allow the oil to refill the tubing at the bottom of the well.

The old mechanical pumps do not easily allow for changing speed in mid-cycle; although, one can change the constant operating speed by changing a gear belt.

In the past, some operators have replaced mechanical pump jacks with hydraulically operated pump jacks, but these hydraulic units generally have allowed little flexibility in the pumping process.

New design

The new Ecoquip hydraulically operated rod pump allows adjustment of the pump-jack operating speed. The unit can change the speed on-the-fly to deal with short-term anomalies in the production.

Each pumping unit has two hydraulic slave cylinders, mounted vertically. The pump rods hang between them. When the cylinders extend, they pull the rods up during the suction stage. On the downstroke, the rod weight pulls the rods and hydraulic actuators down.

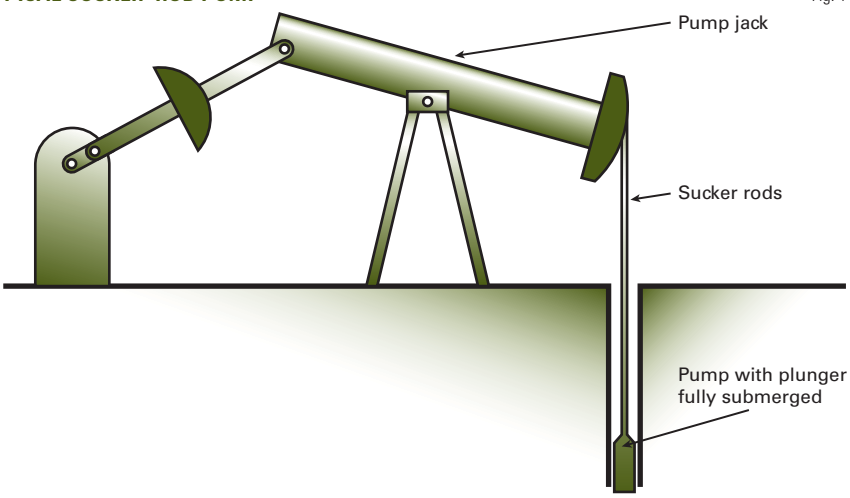
Fig. 2 shows two of the hydraulic rod pumps installed on Trident Exploration Corp. wells near Swann Hills, Alta. Next to the rod pumps are the set of pumps, valves, and hydraulic accumulators that provide the power. Fig. 3 is a closer view of the control and pumping equipment.

Each sphere is an accumulator. Under each accumulator is a large hydraulic master cylinder that forces oil into the slave cylinders that lift the rods.

Fig. 4 shows a cutaway view of the accumulator and master cylinder beneath. During the pumping cycle, as the weight of the rods in the well pulls the

TYPICAL SUCKER-ROD PUMP

Fig. 1



rods down, they force oil back into the master piston. The oil pressurizes the nitrogen in the sphere for assisting the next upstroke.

The accumulator contains nitrogen under pressure and serves as a counter balance storing energy during the down stroke to balance the weight of the pump rods.

Because the accumulator contributes to balance the weight of the pump rods, the system requires a smaller 80-100 hp hydraulic pump than would be needed if the hydraulics provided all the lifting force for the rods. The rod and its payload of produced fluid typically weighs 27,000-35,000 lb.

Hence, the accumulator accommodates a wide load range with the same power unit.

Most installations to date are on wells with a 1,000-7,000 ft depth. The average well depth is about 4,000 ft.

A typical installation has the following capacity:

- A 2.75-in. diameter sucker-rod pump at 6 strokes/min will lift a 144-in. column of fluid/stroke. At 85% pump efficiency, the pump will lift about 648 b/d of fluid.
- A 1.5-in. diameter sucker-rod pump at 6 strokes/min will lift a 144-in. column of fluid/stroke. At 85% pump efficiency, the pump will lift about 193 b/d of fluid.

Note that the stroke rates can range from 2 to 6/min, depending on well conditions.

The master cylinder below the sphere and the slave cylinders that lift the pump rods are hydraulically linked to each other. As the master cylinder moves, the slave cylinders move. Because of the difference in cylinder diameters, when the master has a 1-in. movement, the slave moves 6 in.

The main hydraulic pump providing fluid to the system is a swashplate model manufactured by Sundstrand Corp. When the pump swashes in one direction, it moves the master cylinder one way to cause the lifting cylinders to raise the rods. When it swashes in the other direction, the rods come down.

Trident Exploration Corp. installed two of the new hydraulic rod pumps on wells near Swann Hills, Alta. Two hydraulic cylinders on each pump string pull the rods up, while gravity pulls the rods under control back into the well and recharges the pressure accumulators (Fig. 2).

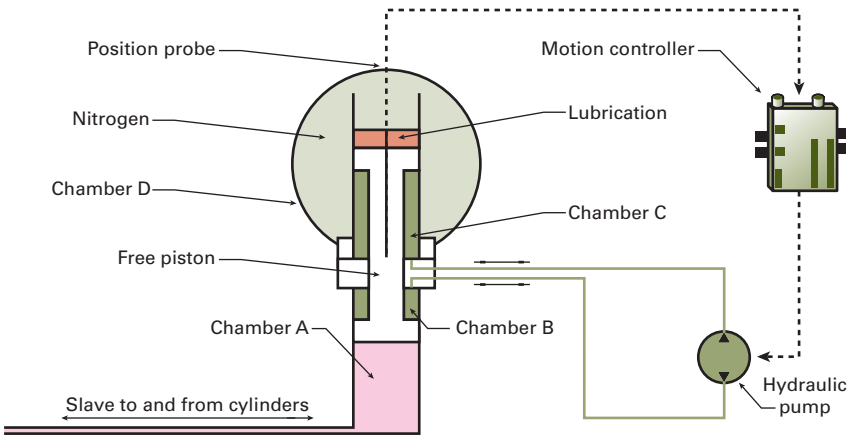
A closer view of the Trident installation shows the control-power systems for the two hydraulic rod pumps. The cylindrical vessels are the accumulators. The skids also include hydraulic pumps and control boxes (Fig. 3).

As the rods come down, the pump assists in pressurizing the nitrogen in the sphere to help the lift on the next upstroke.

A proportional hydraulic servo valve, controlled by an electrohydraulic motion controller, drives the swash plate. A small gear-driven pump maintains pilot

ACCUMULATOR AND MASTER CYLINDER

Fig. 4



Note: The master cylinder as it reciprocates in a smooth up and down motion drives oil in and releases oil out of Chamber A. The motion controller has a MTS Temposonics sensor that provides a feedback to monitor and control the position of the master cylinder.

pressure to operate the valve.

This is the first time that swash-plate hydraulic pumps have been used in rod pumping applications. Also the use of a spherical pressure-charged accumulator to balance the weight of the rod is a new innovation.

Motion controller

The motion controller, recommended by PQ Systems, is the RMC75E, manufactured by Delta Computer Systems Inc., Vancouver, Wash. Position feedback from a MTS System Corp., Cary, NC, Temposonic absolute position probe mounted on the master cylinder feeds into the RMC75 motion controller. The controller sends the correct signal to the servo valve that drives the pump, thereby providing more flow or less flow to achieve the desired cylinder speed and position.

Using feedback from the position sensor, the motion controller can control the upward and downward speeds of the slave cylinders independently, as well as stop and start the slave cylinders and adjust the stroke length.

The programmability of the motion controller allows the operator to develop sophisticated pumping recipes to produce as much oil as possible from the well.

PQ Systems also supplied a touchscreen operator interface that enables the speed up, speed down, and stroke length to be changed at the touch of a button.

The Delta RMC motion controller also can connect to hydraulic pressure sensors. The pressure information allows the controller to monitor the loads on the system, which can indicate downhole conditions. Using this information, the Delta controller can change the pumping speed to accommodate changes in well conditions.

For example, if a pocket of gas enters the oil, the load will get spongy. When the motion controller detects that, it will tell the pump jack to slow down until the gas clears. Such dynamic flexibility is impossible with the old purely mechanical pumps or even hydraulic pumps without programmable closed-loop control systems.

The RMC also provides information such as strokes/minute and hydraulic pressure, which reflects the loads in the well. Delta's software can graph these parameters to yield a visual picture of events downhole.

The RMC75E comes with an Ethernet interface, which connects the motion controller to the touchscreen operator interface. Ultimately, PQ Systems desires to use that interface to add wireless satellite communications to the pumping stations. This would enable remote monitoring and uploading of program instructions from anywhere in the world, a highly desirable feature for pumping stations in the frozen North or other remote locations.

The RMC75E model that Ecoquip uses also provides digital inputs and outputs that enable the motion controller to act as a programmable logic controller (PLC), monitoring other functions in the pumping system. For example, the motion controller can monitor the temperature of the pump, cooling fans, and hydraulic oil, as well as the system alarms.

Wireless communications added to the system will allow the pump jack to send an alarm via the wireless network.

Installation of the Ecoquip system typically takes 3-4 hr.

Current installations

Companies have installed about 50 of the new rod pumps to date. In Alberta, Trident Exploration Corp. has several pumps installed in their operations near Swann Hills. Other units are in ConocoPhillips operations near Big Valley and Duvernay Oil Corp. operations near Hinton.

One unit also is in operation near Fort St. John, BC. ✦

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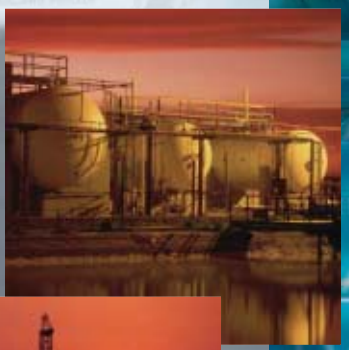

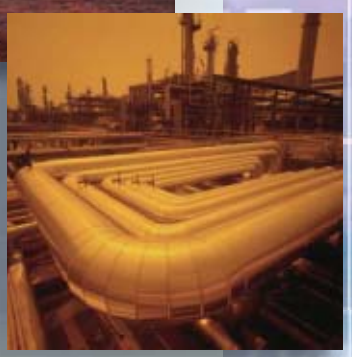

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Method estimates K values quickly

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A new method to estimate equilibrium phase distribution ratios (K values) improves on the shortcomings of older methods. The method is based on the generalized fugacity charts of Lewis, Kay, and Newton, and uses reduced temperatures and pressures as parameters.

A third-degree polynomial is prepared from Lu's chart for calculating liquid molarity, which is used for calculating liquid phase fugacity from fugacity of saturated liquid. The proposed method, therefore, requires looking up only one chart—the generalized fugacity chart (which is a well-spaced-out chart and can be read accurately) and the rest of the calculations use equations, thus enabling rapid calculation.

This article also explains the first principles for calculating K values from fugacity of real gases and liquids.

A K value is required whenever one designs a distillation column or assesses the performance of an operating column. Depriester nomographs can be used to obtain estimates of K values. The K values thus obtained depend on pressure and temperature of the multicomponent system and not on concentration.

Concentration-dependent K values can be calculated from empirical correlations involving lengthy calculations or from equations of state using commercial software because hand calculations are unwieldy. For preliminary design work and checking performance of existing columns, however, K values for multicomponent systems based on system pressure and temperature suffice.

Depriester nomographs do not explain the basis how the K values are obtained. Other methods require looking up charts or figures, where accuracy can be compromised.

K value

The equilibrium phase distribution ratio (K value) is defined in Equation 1 (see attached equation box).

For a system in equilibrium, $T^V = T^L$, $P^V = P^L$, and $\tilde{f}_i^V = \tilde{f}_i^L$

The superscripts, V and L, indicate vapor and liquid phases, respectively, and the subscript i denotes a given component. The bar above f signifies value of fugacity in a mixture. An expression for K_i formulated in terms of the fugacity equality is Equation 2.

For ideal solutions for which

LIQUID PHASE FUGACITY

Table 1

Temp,°F.	Methane	Ethylene	Ethane	Propylene	Propane	i-Butylene	i-Butane	n-Butane	i-Pentane	n-Pentane	n-Hexane	n-Heptane
	Vapor pressure, psia											
–100	866.6	65.33	31.31	3.853	2.887	0.388	0..547	0.276	—	—	—	—
–80	1,135	101.0	50.37	7.21	5.48	0.860	1.171	0.625	—	—	—	—
–60	1,451	149.5	77.29	12.55	9.68	1.739	2.295	12.85	0.296	0.179	—	—
–40	1,809	213.1	113.9	20.61	16.16	3.249	4.17	2.439	0.622	0.392	—	—
–20	2,212	294.3	161.8	31.94	25.30	5.684	7.12	4.326	1.205	0.789	0.15	—
0	2,657	395.1	223.2	47.64	38.11	9.404	11.53	7.25	2.182	1.475	0.311	—
20	3,143	217.5	299.7	68.76	55.46	14.90	17.86	11.56	3.726	2,594	0.606	—
40	3,668	663.3	393.0	96.32	78.30	22.34	26.41	17.69	6.05	4.325	1.107	0.288
80	4,829	1,031	636.2	175.5	144.6	45.85	52.93	36.87	14.10	10.54	3.143	0.960
100	5,461	1,256	789.1	229.3	190.3	63.22	72.19	51.18	20.40	15.63	4.956	1.620
120	6,120	1,510	963.8	294.3	245.6	85.23	96.34	69.45	28.54	22.20	7.531	2.616
140	6,810	1,791	1,162	371.3	311.6	112.7	126.2	92.37	39.04	30.82	11.075	4.065
160	7,523	2,102	1,385	461.5	389.3	146.3	162.4	120.6	52.34	41.90	15.89	6.106
180	8,260	2,443	1,631	565.9	479.7	186.8	205.7	154.8	67.35	55.88	21.93	8.899
200	9,029	2,813	1,902	685.7	583.5	235.2	256.8	195.7	89.21	73.21	29.69	12.62
220	9,797	3,213	2,199	821.2	702.0	291.8	316.6	244.2	113.7	94.43	39.49	17.45
240	10,590	3,642	2,521	973.4	835.4	358.0	385.6	300.7	143.0	120..0	51.69	23.47
260	11,400	4,099	2,868	1,143	984.7	434.0	464.5	366.1	177.5	150.5	66.61	31.08
280	12,230	4,583	3,241	1,330	1,150	520.7	554.0	441.0	217.9.	186.5	84.68	40.52
300	13,050	5,097	3,638	1,537	1,332	618.9	654.6	526.0	264.4	228.5	106.3	52.08
320	13,900	5,635	4,060	1,761	1,533	729.0	766.8	621.8	317.9	277.0	131.9	66.10
340	14,750	6,200	4,506	2,005	1,751	851.7	891.3	728.8	378.6	332.7	161.9	82.88
360	15,610	6,790	4,975	2,269	1,986	987.7	1,028	847.7	47.1	395.8	196.8	102.8
380	16,460	7,403	5,469	2,552	2,241	1,137	1,179	979.0	523.7	467.3	237.0	126.3
400	17,340	8,041	5,984	2,854	2,513	1,300	1,342	1,123	609.1	547.3	283.0	153.5

Amagat's Law of additive volumes holds, the fugacities $\tilde{f}_i^L$ and $\tilde{f}_i^V$ can be found with Equations 3 and 4, which are known as the Lewis and Randall Fugacity Rule.[1]

Combining Equations 2-4 gives the relationship in Equation 5 for ideal K values. f_i^L and f_i^V are the fugacities of component i in the pure liquid or vapor states at the system temperature and pressure. K_{ideal} is a function of system temperature and pressure and independent of composition.

Pure vapor

For an ideal gas, Equation 6 holds true. For a nonideal gas, Equation 7 applies, in which fugacity is substituted for pressure.[2]

Subtracting Equation 6 from Equation 7 and integrating from p = 0 to p = p, and rearranging gives Equation 8. Setting f = p at p = 0 enables canceling the two indeterminate terms in the integration.

Pure liquid

The fugacity of a component in the liquid state is identical with its fugacity in the vapor with which the liquid is in equilibrium. A pure component is in equilibrium with its vapor only at a pressure equal to the vapor pressure of the liquid. Equation 9, therefore, shows fugacity for a pure liquid at a total pressure equal to its vapor pressure.[2] The subscript p^* on a fugacity denotes the fugacity at a pressure equal to the vapor pressure.

Equation 10 shows the basic definition of fugacity. Integrating the right hand side of Equation 10 and rearranging gives Equation 11.

Assuming V^L to be independent of pressure over the range involved results in Equation 12.

Fugacities

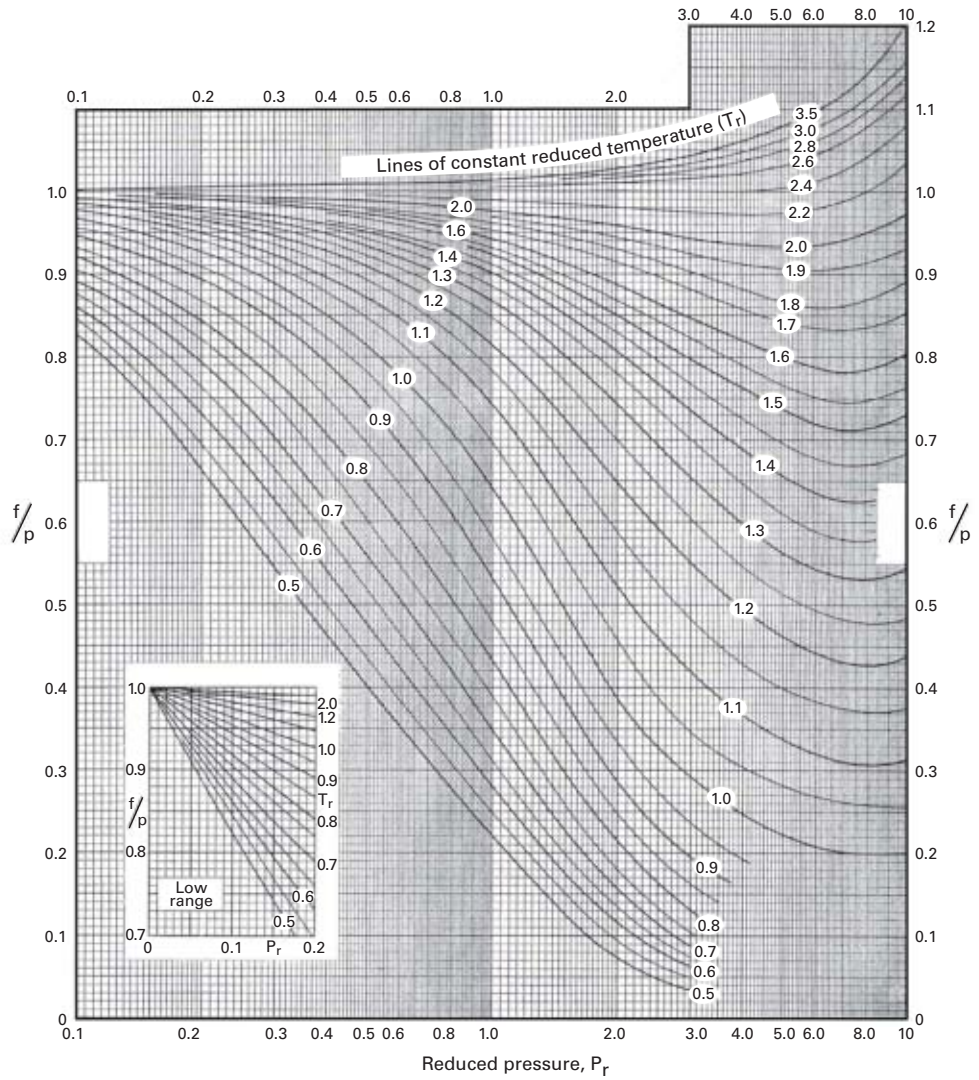
f/P values for pure components have been found from generalized correlations of pressure-volume-temperature data.

Fig. 1 shows a generalized chart for f/P as a function of T_r and P_r[1]. The plot is a composite of the work of Lewis, Kay, and Newton. Values of f/P for the less-than-unity reduced isotherms were extended to higher than saturation pressure using some experimental vapor-liquid equilibrium data. In estimating vapor-liquid equilibria K values, Fig. 1 is applied to both phases.

Fig. 1 can be used to get the values of f_i^L and f_i^V in Equation 5. Knowing the pressure and temperature conditions of the vapor and its critical temperature and pressure, reduced conditions are computed. Values of f/P are found and f_i^V is found by multiplying by the pressure.

GENERALIZED ACTIVITY COEFFICIENTS

Fig. 1



The graph may be used to calculate the fugacity of liquids at their vapor pressures because the fugacity of a pure component as a saturated vapor and saturated liquid are same at the same temperature and pressure. One can estimate the fugacity of a saturated liquid from the f/P chart by finding the corresponding vapor fugacity.

Liquid fugacities are obtained from the f/P chart using the method described at the vapor pressure at the given temperature. System pressure is higher or lower than the vapor pressures of the components in the mixture. One must consider the difference in pressure when computing the liquid fugacities of the components using Equation 11.

Vapor pressure

Vapor pressures are required for a wide range of temperatures when computing pure liquid fugacities. Some of the temperatures of interest are less than the boiling points of heavier hydrocarbons, while others are greater than the critical points of lighter components. Some vapor pressure values are available below the atmospheric boiling point, but extrapolation is required to get values of vapor pressure above the critical temperature.

The method we used to get values of vapor pressure for the new correlation is:

- Use API Research Project 44 vapor pressure values up to the atmospheric boiling point.
- Use a straight line on a log P vs. 1/T scales from the atmospheric boiling point through the critical point to get values above atmospheric boiling point. A straight line on a log P vs. 1/T graph gives a logical and a reproducible method of extrapolation to temperatures above the critical.

Table 1 shows the values of vapor pressure obtained in this way for 12 light hydrocarbons, proposed by Benedict in his empirical correlations.[3]

Equations

$$K_i = \frac{y_i}{x_i} \quad (1)$$

$$K_i = \frac{\tilde{f}_i^{L}/x_i}{\tilde{f}_i^{V}/y_i} \quad (2)$$

$$\tilde{f}_i^{L} = x_i f_i^{L} \quad (3)$$

$$\tilde{f}_i^{V} = y_i f_i^{V} \quad (4)$$

$$K_{ideal} = \frac{f_i^{L}}{f_i^{V}} \quad (5)$$

$$RT\, d\ln p = V^* dp \quad (6)$$

$$RT\, d\ln F = V^* dp \quad (7)$$

$$\ln f^{v} = \ln p - \int_0^p \frac{(V^* - V_i)}{RT} dp \quad (8)$$

$$\ln f^{L}_{p^*} = \ln f^{V}_{p^*} = \ln p_i^* + \int_0^{p^*} \frac{(V - V^*)}{RT} dp \quad (9)$$

$$\int_{p^*}^{p} d\ln f^{L}_{p} = \frac{1}{RT}\int_{p^*}^{p} V^{L}\, dp \quad (10)$$

$$\ln f^{L}_{ip} = \ln f^{L}_{ip^*} + \frac{1}{RT}\int_{p^*}^{p} V^{L}\, dp \quad (11)$$

$$\ln f^{L}_{ip} = \ln f^{L}_{ip^*} + \frac{V^{L}}{RT}(p - p^*) \quad (12)$$

$$\frac{K_i}{V^{L}_i} = \frac{K_2}{V^{L}_2} \quad (13)$$

$$K = 1.577503 - 1.92 * T_r + 2.690319 * T_r^2 - 1.801227 * T_r^3 \quad (14)$$

Nomenclature

f*	=	Fugacity of pure component, psia
K	=	Equilibrium distribution coefficient
K_{ideal}	=	K value for ideal solutions where Amagat's Law of additive volumes holds
MW	=	Molecular weight
p	=	Pressure, psia
P	=	Critical pressure, psia
P_r	=	Reduced pressure
P*	=	Vapor pressure, psia
R	=	Gas constant = 1,544/MW
T	=	Temperature, °R.
T_r	=	Reduced temperature
V	=	Volume, cu ft
V^L	=	Molar volume of pure saturated liquid, cu ft/lb-mole
x	=	Mole fraction in liquid phase
y	=	Mole fraction of component in vapor phase

Subscripts
i = component

Superscripts
L = liquid phase
V = vapor phase

Molarity of liquid hydrocarbons

Table 2

Compound	T_r	Molarity, cu ft/lb-mole
Methane	0.572093	0.617559
Ethylene	0.604706	0.786846
Ethane	0.606545	0.880107
Propylene	0.619149	1.104686
Propane	0.617117	1.204768
i-Butylene	0.653386	1.495008
i-Butane	0.669388	1.548401
n-Butane	0.642298	1.548401
i-Pentane	0.633976	1.857152
n-Pentane	0.619126	1.830622
n-Hexane	0.577049	2.090353
n-Heptane	0.542652	2.341804

Liquid fugacity

Computing pure liquid fugacity from Equation 12 requires estimation of V^L, the molar volume of pure saturated liquid. If the critical values T_c and P_c are known, Lu's generalized chart (Fig. 3.51 in reference 4) should be used for molar volume estimations.[4]

Lu's chart is a plot of T_r vs. K with P_r as a parameter. If the value of V_1^L at T_r1 is known, K_1 is read from the saturated line on the chart. If T_{r2} is the reduced temperature corresponding to the system temperature, K_2 is read from the chart, and V_2^L is calculated using Equation 13.

Table 2 shows data for V_1^L at T_{r1} for 12 light hydrocarbons, based on known temperatures. For ease of computing and to avoid looking up Lu's chart, we fit the saturated liquid line of Lu's chart into a third-order polynomial, shown in Equation 14.[5] The calculated K from this polynomial is within 1% of the saturated liquid line in Lu's chart.

K_{ideal} values calculated with the new method can be used as the first approximation for equilibrium stage calculations for light hydrocarbons.

Example 1

Estimate K value for propane at 100° F. and 300 psia given:

- T_c = 666° R.
- P_c = 617 psia.

- P* (from Table 1) = 190.3 psia.
- MW = 44.
- Molar volume of liquid (from Table 2) = 1.204768 cu ft/lb-mol at T_r = 0.6171

By definition, T_r = (100 + 460)/666 = 0.8408 and P_r = 300/617 = 0.4862.

P_r^* is therefore 190.3/617 = 0.3048. f/P from Fig. 1 is 0.692 for T_r = 0.8408 and P_r = 0.4862. f_i^V is therefore 0.692*300 = 207.6 psia.

f/P from Fig. 1 is 0.8 for T_r = 0.8408 and P_r^* = 0.3048. Multiplying by P* gives $f_{i\,P^*}^L$ = 0.8*190.3 = 152.24 psia.

Using Equation 14 and T_r = 0.6171, then K_1 = 0.9938907. Similarly, for T_r = 0.8408, K_2 = 0.7949121.

Rearranging Equation 13 gives V_2^L = $(K_2/K_1)^* V_1^L$ = (0.7949121/0.9938907)*1.204768 = 0.963571.

From Equation 12, ln $f_{i\,p}^L$ = ln 152.24 + ((0.963571*44)/(1,544*560))*(300-190.3) = 5.030837. Solving for $f_{i\,p}^L$ gives a value of 153.0611.

Using Equation 5, $K_{ideal} = f_i^L / f_i^V$ = 153.0611/207.6 = 0.737289.

Example 2

Estimate the K value for ethane at 120° F. and 400 psia given:

- T_c = 550° R.
- P_c = 708 psia.
- P* (from Table 1) = 963.8 psia.
- MW = 30.
- Molar volume of liquid (from Table 2) = 0.880107 cu ft /lb-mol at T_r = 0.606545.

By definition, T_r = (120 + 460)/550 = 1.0545 and P_r = 400/708 = 0.5650. P_r^* is therefore 963.8/708 = 1.3613.

f/P from Fig. 1 is 0.83 for T_r = 1.0545 and P_r = 0.5650. f_i^V is therefore 0.83*400 = 332 psia.

f/P from Fig. 1 is 0.59 for T_r = 1.0545 and P_r^* = 1.3613. Multiplying by P* gives $f_{i\,P^*}^L$ = 0.59*963.8 = 568.642 psia.

Using Equation 14 and T_r = 0.606545, K_1 = 1.00076. Similarly, for T_r = 1.0545, K_2 = 0.4323483.

Using Equation 13 gives V_2^L = $(K_2/K_1)^* V_1^L$ = (0.4323483/1.00076)* 0.880107 = 0.351778.

From Equation 12, ln $f_{i\,p}^L$ = ln 568.642 + ((0.3802283*30)/(1,544*580))* (400 – 963.8) = 6.33606956. $f_{i\,p}^L$ is therefore = 564.572923.

Using Equation 5 gives $K_{ideal} = f_i^L/f_i^V$ = 564.572923/332 = 1.70052085. ✦

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Methods help remove black powder from gas pipelines

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Effective removal of black powder from a gas transmission system often requires a combination of methods. Removing such particulates is a multistep process requiring a comprehensive understanding of the nature of the problem. Different tools may be effective in some instances but not in others.

This article examines Greek Public Gas Corp. SA's (DEPA's) experience in fighting black powder in its system, focused on its determining which technique provided the most efficient and cost-effective method of powder removal.

Included in this examination are the different sorts of pigs, filters, and separators DEPA used in attempting to address the problem, with the effectiveness and shortcomings of each assessed.

Based on presentation to Pipeline Rehabilitation & Maintenance Conference, Istanbul, Sept. 14-17, 2006.

Background

Black powder is a solid contaminant found in natural gas transmission and distribution systems throughout the world. Chemical or biological reactions with steel found in natural gas pipelines, gas wells, and associated facilities can create black powder.[1] Solids may be simple or complex mixtures of small particles dispersed in gas (particulates) or they may be dispersed in water or liquid hydrocarbons (slurry).

Formation cuttings, drilling mud, desiccant dust, construction dirt, sand, mill scale, iron oxide, iron carbonate, iron sulphide, welding slag and splatter, eroded steel cuttings, salt crystals, valve grease, corrosion inhibitor, and other organic materials can all contribute to the presence of black powder.[2]

DEPA's high-pressure gas network (Fig. 1) first experienced operational problems caused by black powder in imported natural gas in March 1999. DEPA performed a pigging operation on the first 12 km of the Greek pipeline from the Bulgarian-Greek border at Promachonas to the border metering station, removing 1,000 kg of powder.

Ongoing black-powder contamination of DEPA's network increased gradually as gas offtakes increased. Powder gathering in the gas piping and installations resulted in:

- Reduced flow efficiencies.
- Clogged and collapsed filters.
- Deposits on gas measurement devices.
- Clogging of instrumentation and valves.
- Accelerated deteriora-

DEPA'S HIGH-PRESSURE GAS NETWORK Fig. 1

tion of valves due to erosion.

• Other operations, maintenance, and safety concerns.

Black powder, either attached to the pipe wall, or collected in the pipe bottom, increased roughness, decreased flow area, and increased pressure drop. Black powder could also reduce the functionality and reliability of emergency shutdown systems, system isolation valves, pressure-control monitors, gauges, and other pipeline safety devices. Solids in the gas stream etched and grooved a number of DEPA's high-pressure valves.

Although the greatest accumulation of black powder was in the first segment of DEPA's pipeline immediately downstream of the Bulgarian-Greek border, the powder migrated in significant quantities down mainline pipelines to various system lateral lines and customer delivery points. Black powder could plug gas burner tips on devices ranging from large power plant burners to residential gas heaters. Black powder also threatened to cloud customers' impressions of natural gas as the "cleanest fossil fuel" in the newly introduced Greek natural gas market.

DEPA's primary facilities for removing black powder from gas consisted of cartridge filters at the inlet of the border metering station. DEPA cleaned and replaced these filters almost continuously. Despite these efforts, black powder continued to be deposited at all downstream gas installations. As a result, other gas filtration devices along DEPA's system clogged regularly and had to be replaced.

This extra maintenance load increased labor hours needed to keep the system functional and safe. The economic effect on the newly constructed gas transmission system was exorbitant and mounted every day that the system was operated.

Black powder also prevented DEPA from accommodating gas flow rates above a certain limit, because the amount of black powder transferred to the cartridge filters at high flow rates, was sufficient to clog a clean filter within a few hours.

To prevent further damage, DEPA installed cyclone filters at the entrance to the Greek network at the Bulgarian-Greek border. DEPA also ensured that filters were installed upstream of its network in Bulgarian territory and performed a series of pigging operations on both sides of the border using bidirectional pigs, magnetic pigs, pigs with brushes, and pigs with injection nozzles.

Pipeline purging also cleaned specific sections. All vented gas was heavily contaminated with black powder.

Laboratory analysis

DEPA analyzed samples of black powder for their chemical compositions and particle size distribution, taking samples from debris of pigging operations or from filters' deposits. The tests consisted of crystalline phase identification analysis, qualitative elemental analysis (EDS), and particle elemental analysis. Analyses of samples taken from various places and times showed great similarity (Table 1). Testing showed the bulk density of black powder samples to be 1.7 g/cu m.

Black powder consists mainly of magnetite (iron oxide), a form of rust. As the name indicates, the powder is strongly magnetic. All the other compounds determined by analysis can be found in common dirt. The magnetite most likely stems from the chemical

RESULTS OF BLACK POWDER ANALYSIS, CHARACTERIZATION

Table 1

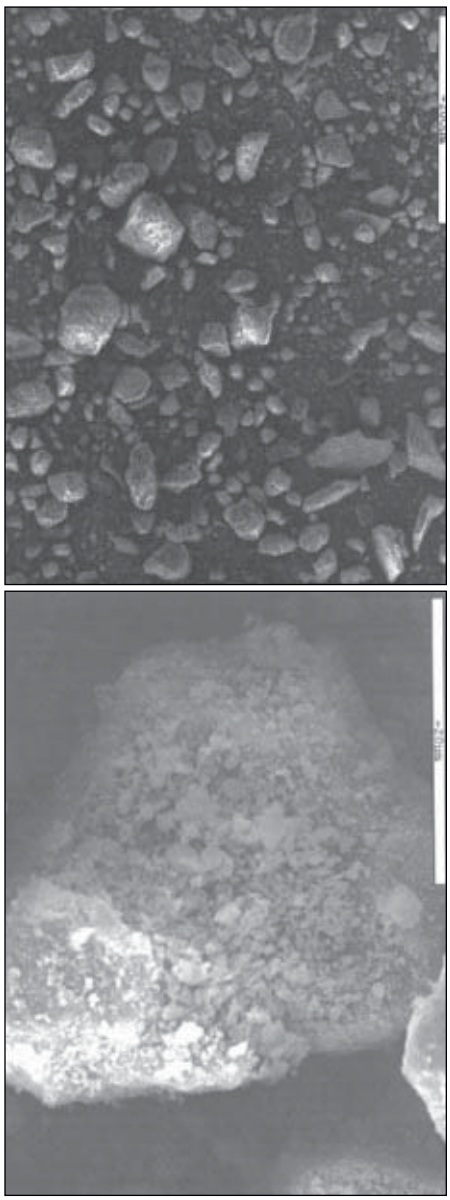
1. Crystalline phase identification analysis (X-ray diffraction, Siemens D-500):

Major components:	Magnetite ($FeFe_2O_4$)
	Quartz (SiO_2)
Minor components:	Goethite ($FeO(OH)$)
	Bementite ($Mn_5Si_4O_{10}(OH)_6$)
	Manganese Oxide (Mn_2O_4)
	Albite ((Na,Ca)Al(Si,Al)3O8)
	Cordierite ($Mg_2Al_3Si_5O_{18}$)
	Butlerite ($Fe(OH)SO_4.2H_2O$)

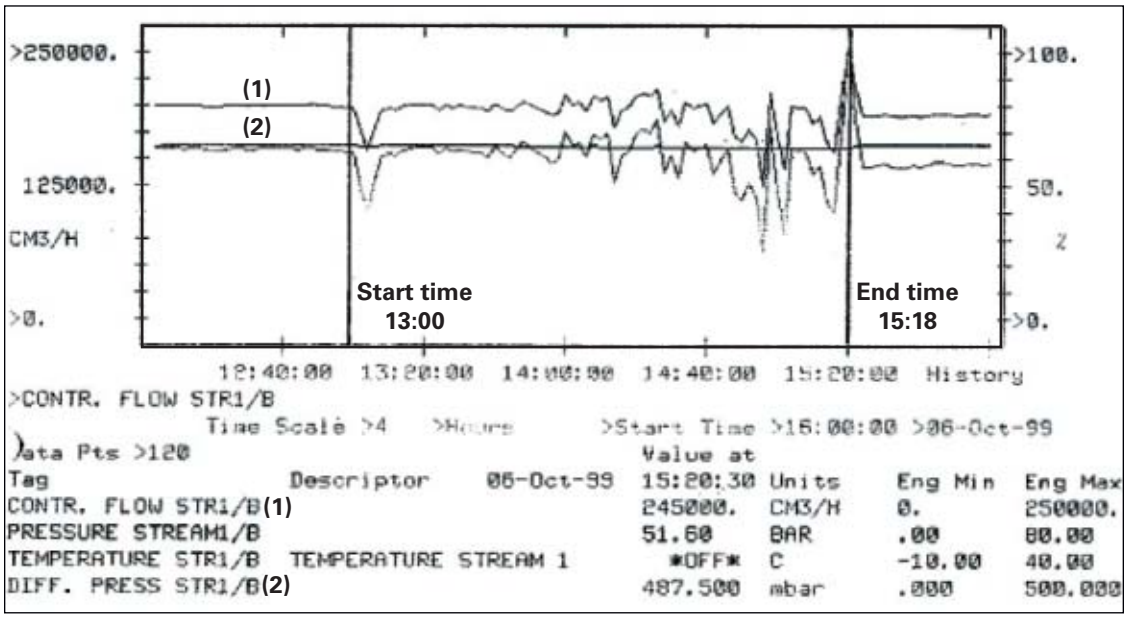
2. Qualitative elemental analysis (Jeol 6300 scanning electron microscope, Isis 2000 x-ray energy dispersive spectroscopy analysis):

Main components:	Fe, O
Minor components:	Si, Al
Trace components:	Mn, Ca, K, Na, Mg, S

3. Particle size analysis (laser diffraction, Malvern Mastersizer-S):
Bimodal particle size distribution with a dominant peak at ~30 µm and a secondary peak at ~0.3 µm.
This analysis was performed with wet dispersion and the use of ultrasonic.



Pictures of black powder through an electron microscope confirmed its amorphous nature, with a wide range of particle sizes present. Analysis detected both large particles and submicron flakes. Particles can shear easily and break into submicron sizes (Fig. 2).



Gas flow and differential pressure fluctuated during gauge pigging. Flow-fluctuation information is marked by (1) and includes the upper line in this screen shot. Differential-pressure fluctuation is marked by (2) and includes the lower line. Pigging began at 13:00 and ended at 15:18 (Fig. 3).

reaction between iron in the piping and water. Other elements in the chemical analysis may also be components of the pipe alloy (Mn, Mg).

A portion of the pipeline feeding DEPA's network included open pipes exposed for a large period of time before being welded together and set in the pipe trench. The corrosion products generated in the uncoated steel pipes migrated later to DEPA's network with the gas flow.

Even though all samples of black powder were practically dry, the presence of magnetite implies that water had to have been present somewhere in the system in the past. The water could have originated in high dewpoint gas, found reduced temperature or pressure, and naturally collected in low places of the pipes. Repair operations could also have led to water in the pipeline.

The black powder consisted of about 80% corrosion products, with the remainder typical soil minerals. No iron sulfide was found in black powder samples.

Literature regularly associates the term black powder with the presence of iron sulfide.[3] The powder DEPA found in its network, however, contained practically no sulfur compounds. Nor was the powder flammable.

Tests for bacteria (aerobic and anaerobic), coccobacillus, and mycetes yielded negative results. Also the powder was tested and found to present only natural radioactivity. Pb and Ra have led to radioactivity in black powder of similar composition,[4] but no such elements were detected in this study.

Fig. 2 presents two pictures of black powder from an electron microscope, confirming results of the particle size analysis reported on Table 1. Results of particle size analysis varied due to the amorphous nature of the powder. Analysis detected both large particles and submicron flakes. Particles can shear easily and break into submicron sizes, making filtration extremely difficult. Large particles stay in the filters, dropout vessels, etc., while smaller ones are carried downstream and tend to agglomerate due to their magnetic properties.

Physical removal

DEPA conducted a series of pigging operations in October 1999 to clean the first section of its pipeline from the border to the entrance of the border metering station. This 36 in. OD, 12-km section operated at a pressure of roughly 50 barg, with a designed pressure of 70 barg. Internal coating on all of DEPA's high-pressure pipelines (Fig. 1) facilitates gas flow.

A foam pig passed the section with an average velocity of 1.2 m/sec (4.4 km/hr). The pig became deformed at the pig receiver trap, probably due to impact with a mass of black powder. Only 20 kg of powder landed in the pig receiver trap. Pressure traces across the section during the pigging operation showed a rather smooth movement of the pig.

A gauge pig, equipped with flexible caps and an aluminum gauge plate, continued the operation. This pig moved at an average velocity of 1.4 m/sec. Fig. 3 depicts gas flow and differential pressure traces during this pigging, as logged at the distributed control system of DEPA's border metering station. A downstream metering device provided differential pressure measurements. Large fluctuations at the second half of the pig's route show that the pig swept along and carried over a large quantity of powder. Indeed, 4,500 kg of black powder landed in the pig receiver trap.

Monitoring pig movement, using flow or pressure traces (or other mechanisms), is essential for a reliable indication of how much powder the pig carried.

DEPA repeated the pigging operation using the same pig with new caps and gauge plate. The pig trap this time caught 1,600 kg of black powder and the pig showed no signs of damage. The same pigging operation repeated a third

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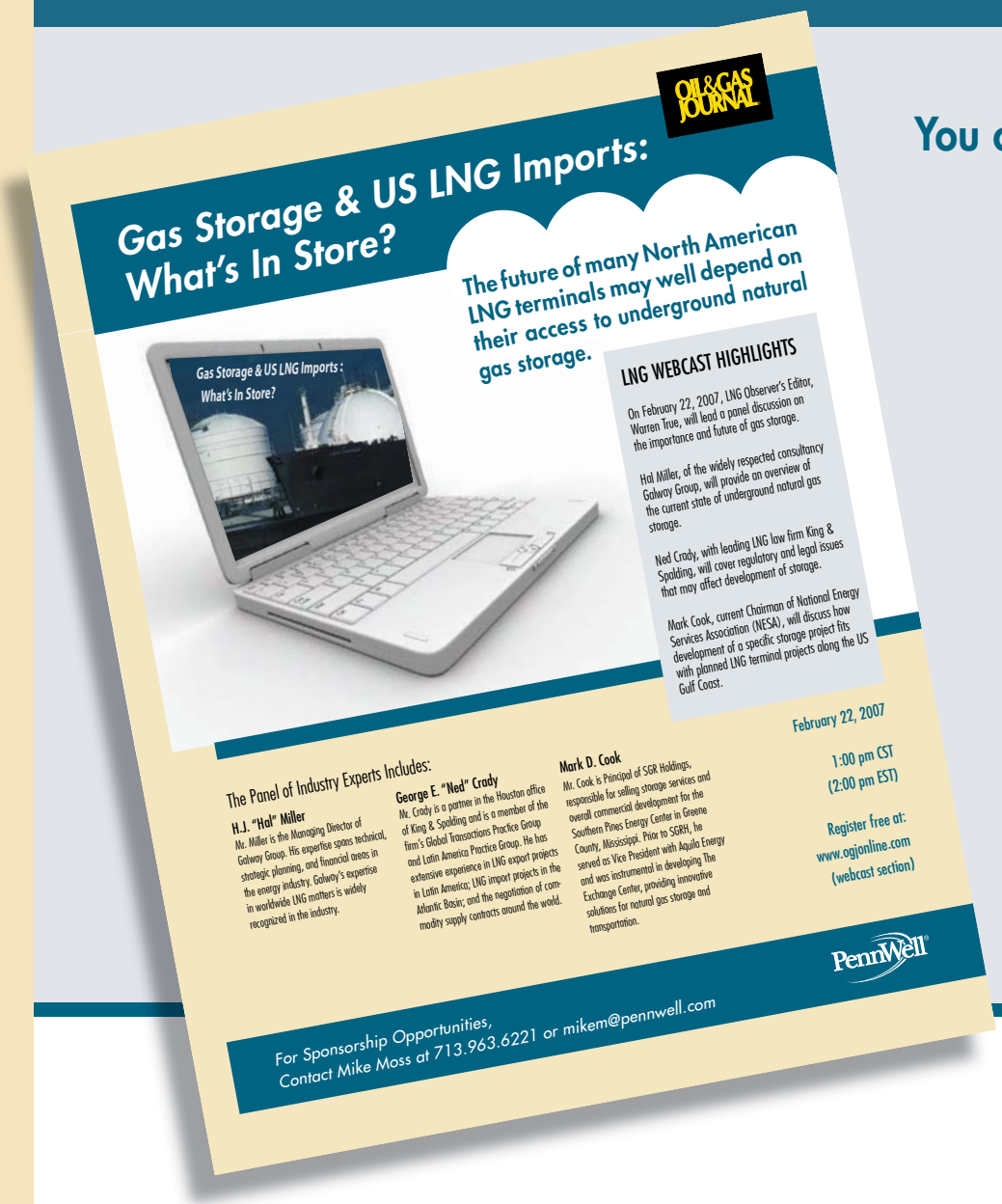

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WEBCAST HIGHLIGHTS

On February 22, 2007, LNG Observer's Editor, Warren True, led a panel discussion on the importance and future of gas storage.

Hal Miller, of the widely respected consultancy Galway Group, provided an overview of the current state of underground natural gas storage.

Ned Crady, with leading LNG law firm King & Spalding, covered regulatory and legal issues that may affect development of storage.

Mark Cook, current Chairman of National Energy Services Association (NESA) discussed how development of a specific storage project fits with planned LNG terminal projects along the US Gulf Coast.

View the complete LNG Webcast at: www.ogjonline.com (webcast section)

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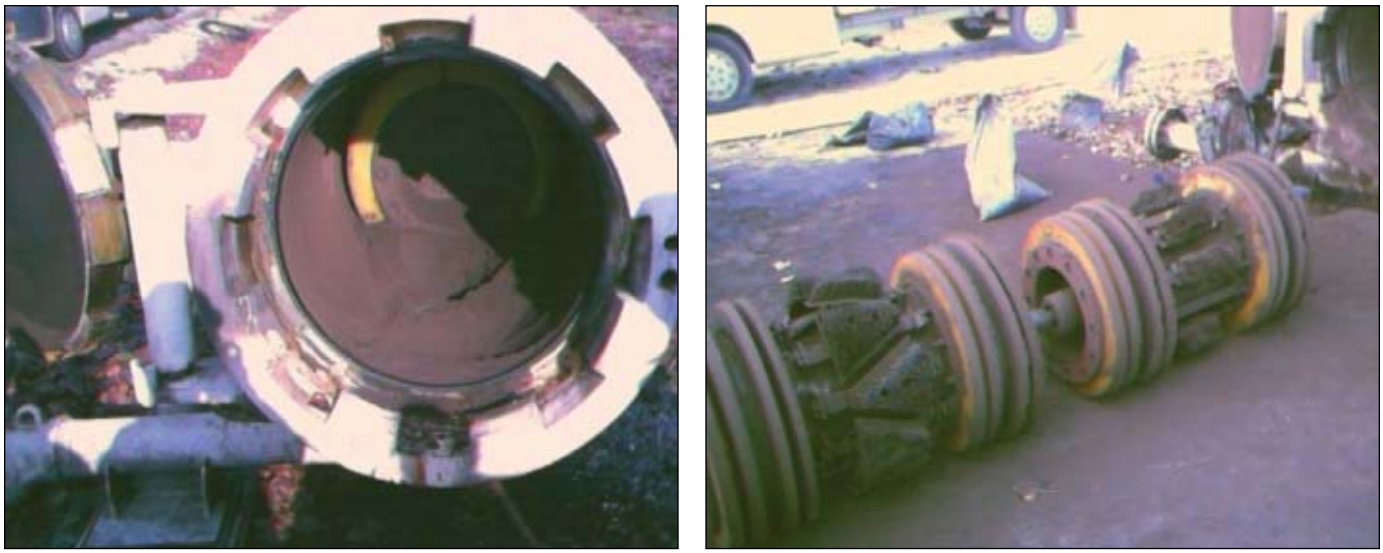

Dual module bidirectional pigs with brushes continued to remove large amounts of black powder even after other techniques had been applied. The interior of the pipeline on the Bulgarian side of the border was not protected with coating (Fig. 4).

time removed 500 kg of black powder, with the pig again undamaged.

The cleaning operation continued with a heavy bidirectional pig using polyvinyl chloride discs (two discs in front and two at the rear) at an average velocity of 1.4 m/sec. This pig experienced difficulty in moving through the line. At the final stage of its route the pig stopped and gas flow downstream was interrupted. Getting the pig back under way required venting gas with powder from the pig trap, creating a sufficient pressure drop across the pig to kick the pig into the trap. This pigging removed 5,000 kg of black powder.

All aforementioned pigging operations removed a combined total of 11,620 kg of black powder.

Pigging continued from 2000 to 2003 at DEPA's pipeline and also upstream, in Bulgarian territory, where dual module bidirectional pigs with brushes were also used, the interior of that pipeline not having been protected with coating. These operations removed a large amount of powder (Fig. 4).

All processes focused on the physical removal of the powder without any chemical treatment. Pigging with chemicals, such as dispersants, solvents, or gelling agents might be useful in other cases, but the nature of the powder and the rather large size of the pipeline prevented their use in this instance.[5]

DEPA purged the valve station at the entrance of the border metering station with gas after this round of pigging to dispose of any remaining powder and prevent rapid clogging of the cartridge filters. Gas vented during these blow downs contained large amounts of black powder (Fig. 5).

October 2003 cleaning pig operations covered the same pipeline section, initially using a gauge pig and subsequently completing three runs with a bidirectional pig. These efforts removed 770 kg of powder. Further cleaning used a magnetic pig, after which the pipeline section was declared clean and inspected by first a profile pigging and then an intelligent pigging (magnetic flux leakage).

The intelligent pigging detected no significant damage in the DEPA system, proving that the black powder was not being generated by DEPA's pipeline network but it was instead being transported from the upstream network with the gas.

Filtration

The most common means of fighting solid contaminants is to filter them at entrances of processing plants or networks. The nature of the black powder examined here, however, works against standard filtration; the particles are able to shear easily at submicron sizes and pass through gas separation devices and filters capable of trapping particles as small as submicron.

Filtration of black powder in flowing gas streams therefore requires extra effort. Operators should replace or clean filter elements at optimum points shown by pressure differentials across the filters to minimize flow resistance, powder penetration, or overfill. Filtering might also require expensive reinforced filter elements to prevent the filter from collapsing under the weight of the powder during gas flow.

DEPA installed two vertical cartridge filters with dropout vessels at the border metering station entrance to remove condensates, water, scale, or other foreign matter from the gas. The filter elements consist of fiberglass treated with phenolic resins and silicone. They collapse at a differential pressure larger than 2 bar. The separation efficiency of these elements is 100% for particles larger that 3 μm, and 99% for particles 0.5-3 μm.

During the summer of 2001, DEPA cleaned and replaced the cartridges of these filters up to three times/week, compared to an annual normal replacement frequency.

DEPA purged the valve station at the entrance of the border metering station with gas after pigging in order to dispose of any remaining powder and prevent rapid clogging of the cartridge filters, venting large amounts of black powder in the process (Fig. 5).

In order to protect its downstream system from black powder, DEPA installed two cyclone (centrifugal) filtration facilities at the start of its network next to the Bulgarian border. Use of these filters enhanced the effectiveness of trap filters further downstream (Fig. 6).

Even with these inlet filters operating continuously, however, DEPA continued to find black powder deposits downstream in metering lines, metering instruments, analyzers, densitometers, and control valves. Despite the filter efficiency, enough small particles flowed through filtration devices to agglomerate into larger masses downstream.

Operation of the cartridge filters also limited gas offtake. Every time the gas flow rate at the border metering station would rise above 200,000 cu m/hr, the pressure drop at the inlet station cartridge filters experienced a sudden and steep increase resulting in automatic flow interruption. At high gas flow rates, large black powder quantities were clogging a clean filter within a few hours, requiring that flow rates be kept low for safe system operation.

Cartridge filters should be used to protect key installations, like metering facilities, by removing limited quantities of black powder from the gas.

The amount of black powder carried into DEPA's network was inversely related to the water dewpoint (WDP) of the gas. During periods of high WDP (increased humidity of the gas) black powder quantities disposed of at the filters were relatively lower than during periods of low WDP for the same gas flow rates. The higher density of the partially wet powder inside the pipe and the subsequent difficulty in detaching the powder from the internal pipeline wall and transporting it in the gas flow led to this result.

Cyclone separators

In order to protect its downstream system from black powder, DEPA installed two cyclone (centrifugal) filtration facilities (Fig. 6) at the start of its network next to the Bulgarian border. These filters separate 99% of contaminants larger than 5 µm. Each cyclone uses a dedicated online dust collector vessel.

These cyclone separators removed black powder very efficiently. During second-half 2003, the cyclones removed roughly 7,000 kg of black powder; a quantity capable of clogging the downstream cartridge filters several times, thereby preventing normal gas offtake.

The separators continuously gathered the black powder in high-pressure dust collectors placed below the cyclones. Once full (roughly 1,000 kg), the separator would depressurize to remove the debris. In addition to the dry powder, the cyclones separated compressor oil and water from the gas stream.

Acknowledgments

The authors acknowledge the help

of DEPA's operations and maintenance department in preparing this article. ✦

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Partnership to provide computing services

CyrusOne, Houston, and Appro International Inc., Milpitas, Calif., have formed a partnership to provide secure, reliable, high performance computing, or flexible computing services to the industry.

Combining Appro's advanced blade technology with CyrusOne's flexible computing service, customers can perform reservoir modeling, seismic processing, and run simulations during times of high demand.

The partnership provides customers with scalable, cost-effective solutions. Using on-demand computing services, customers can immediately begin interpreting seismic data without investing capital into hardware or data center floor space.

Source: **CyrusOne**, 4201 Southwest Freeway, Houston, 77027.

New natural gas flow computer works fast

The new AutoEXEC multirun flow computer measures and controls the flow of natural gas products on 32 lines simultaneously and calculates flow rate at 10 times/sec.

The unit is powered by the 32-bit Freescale Coldfire processor, which calculates at 300 million instructions/sec to solve complicated mathematical equations rapidly and accurately. In addition to speed and expandability, the AutoEXEC is simple to operate and requires no programming. Optional devices, or input-output, can be turned on or off and are as simple to operate as a switch. The flow computer also features a customizable default configuration that enables measurement to begin upon the system receiving power.

Source: **Thermo Electron Corp.**, 81 Wyman St., Waltham, MA 02454.

New laser aids seismic surveys

The new AG-1 distributed feedback laser implements its company's patent-pending multivariable control system (MVCS) for dynamic signal feedback in seismic servey operations.

The laser with MVCS incorporates multiple feedback loops to deliver an effective line width of 10-400 kHz and frequency stability of ±5 MHz. Its narrow line width offers high signal coherency for accurate measurements over long distances. The AG-1 is tunable across C&L bands with a tuning range of 3 nm and a minimum step size of 0.5 pm. In systems that operate at multiple wavelengths, the tunable AG-1 reduces overall system cost because a 1:1 sparing ratio is not required—also facilitating support logistics.

The laser provides a solution for a new generation of fiber-optic seismic survey systems being deployed to map the earth's subsurface, using interferometric interrogation techniques. The laser features coherency over long distances, and can be used in harsh undersea or downhole applications. It needs no costly isolation for accurate measurements, and it is capable of reading twice the number of sensors previously possible.

Source: **Sabeus Inc.**, 26610 Agoura Road, Suite 100, Calabasas, CA 91302.

Statistics

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	3-2 2007	[1]2-23 2007	3-2 2007	[1]2-23 2007	3-2 2007	[1]2-23 2007	3-3 2006
	1,000 b/d						
Total motor gasoline	279	291	0	71	279	362	209
Mo. gas. blending comp.	447	409	14	51	461	460	503
Distillate[2]	329	344	14	16	343	360	352
Residual	293	373	44	36	337	409	317
Jet fuel-kerosine	59	121	125	80	184	201	185
LPG	227	240	3	2	230	242	293
Unfinished oils	513	551	24	20	537	571	394
Other	480	373	18	11	498	384	488
Total products	**2,627**	**2,702**	**242**	**287**	**2,869**	**2,989**	**2,771**
Canadian crude	1,607	1,663	203	266	1,810	1,929	2,065
Other foreign	6,792	6,900	497	789	7,289	7,689	8,068
Total crude	**8,339**	**8,563**	**700**	**1,055**	**9,099**	**9,618**	**10,133**
Total imports	**11,026**	**11,265**	**942**	**1,342**	**11,968**	**12,607**	**12,904**

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

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

OIL&GAS JOURNAL online research center

OGJ CRACK SPREAD

	*3-2-07	*3-3-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	74.55	69.89	4.66	6.7
Brent crude	60.93	61.18	–0.25	–0.4
Crack spread	13.62	8.70	4.92	56.5
FUTURES MARKET PRICES				
One month				
Product value	76.41	70.45	5.96	8.5
Light sweet crude	61.66	62.28	–0.62	–1.0
Crack spread	14.75	8.17	6.59	80.6
Six month				
Product value	77.86	75.31	2.55	3.4
Light sweet crude	65.51	66.68	–1.17	–1.8
Crack spread	12.35	8.63	3.71	43.0

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel	Fuel oils		Unfinished oils
		Total	Blending comp.[1]	Kerosine	Distillate	Residual	
	1,000 bbl						
PAD I	13,672	53,253	26,563	10,138	50,696	15,565	8,071
PAD II	67,964	51,840	15,894	8,041	27,959	1,672	13,644
PAD III	170,332	64,040	27,315	12,859	33,884	16,090	44,114
PAD IV	13,412	6,857	1,808	599	3,282	449	2,653
PAD V	[1]52,054	28,452	21,487	9,357	11,962	5,932	20,656
Mar. 2, 2007	**[1]317,434**	**204,442**	**93,067**	**40,994**	**127,783**	**39,708**	**89,138**
Feb. 23, 2007[3]	**323,994**	**211,890**	**95,754**	**40,937**	**128,682**	**40,697**	**89,140**
Mar. 3, 2006	**335,971**	**216,978**	**80,987**	**42,586**	**129,729**	**39,838**	**87,628**

[1]Included in total motor gasoline. [2]Includes 5.910 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—MAR. 2, 2007

	REFINERY OPERATIONS					REFINERY OUTPUT			
	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
District	1,000 b/d								
East Coast	2,869	1,185	1,207	1,618	74.6	1,559	74	392	87
App. Dist. 1	78	78	78	95	82.1	27	0	18	0
Dist. 1 total	**2,947**	**1,263**	**1,285**	**1,713**	**75.0**	**1,586**	**74**	**410**	**87**
Ind., Ill., Ky.	2,284	2,216	2,274	2,355	96.6	1,198	186	538	45
Minn., Wis., Dak.	358	349	352	442	79.6	313	30	117	8
Okla., Kan., Mo.	629	494	528	786	67.2	349	26	176	3
Dist. 2 total	**3,271**	**3,059**	**3,154**	**3,583**	**88.0**	**1,860**	**242**	**831**	**56**
Inland Texas	923	517	586	647	90.6	491	31	192	6
Texas Gulf Coast	3,542	3,154	3,217	4,031	79.8	1,406	246	900	269
La. Gulf Coast	3,565	3,274	3,274	3,264	100.3	1,228	397	898	163
N. La. and Ark.	205	162	165	215	76.7	83	8	46	1
New Mexico	156	97	97	113	85.8	79	2	35	0
Dist. 3 total	**8,391**	**7,204**	**7,339**	**8,270**	**88.7**	**3,287**	**684**	**2,071**	**439**
Dist. 4 total	**665**	**565**	**574**	**596**	**96.3**	**326**	**30**	**188**	**14**
Dist. 5 total	**2,765**	**2,272**	**2,411**	**3,173**	**76.0**	**1,649**	**380**	**458**	**95**
Mar. 2, 2007	**18,039**	**14,363**	**14,763**	**17,335**	**85.2**	**8,707**	**1,410**	**3,958**	**691**
Feb. 23, 2007*	**18,298**	**14,348**	**14,742**	**17,335**	**85.0**	**8,625**	**1,397**	**4,066**	**672**
Mar. 3, 2006	**16,657**	**14,184**	**14,397**	**17,115**	**84.1**	**8,285**	**1,402**	**3,731**	**650**

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

OGJ GASOLINE PRICES

	Price ex tax 2-28-07	Pump price* 2-28-07	Pump price 3-1-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	183.6	223.3	220.4
Baltimore	182.1	224.0	226.3
Boston	181.6	223.4	226.2
Buffalo	185.2	245.3	245.2
Miami	192.9	243.2	247.8
Newark	189.9	222.8	217.9
New York	172.4	232.5	255.9
Norfolk	182.9	220.5	213.4
Philadelphia	195.3	246.0	242.0
Pittsburgh	176.5	227.2	232.4
Wash., DC	194.5	232.9	245.0
PAD I avg.	185.2	231.0	233.9
Chicago	207.4	258.3	257.7
Cleveland	189.9	236.3	215.4
Des Moines	184.9	225.3	218.0
Detroit	186.1	235.3	224.2
Indianapolis	196.0	241.0	212.4
Kansas City	189.8	225.8	209.2
Louisville	199.3	236.2	219.1
Memphis	181.8	221.6	220.2
Milwaukee	184.9	236.2	233.0
Minn.-St. Paul	192.1	232.5	221.9
Oklahoma City	187.5	222.9	205.3
Omaha	195.0	241.4	223.9
St. Louis	197.0	233.0	202.7
Tulsa	185.2	220.6	209.9
Wichita	184.0	227.4	207.3
PAD II avg.	190.7	232.9	218.7
Albuquerque	188.5	224.9	226.1
Birmingham	181.5	220.2	218.2
Dallas-Fort Worth	184.7	223.1	220.2
Houston	179.7	218.1	218.1
Little Rock	181.9	222.1	220.2
New Orleans	192.0	230.4	233.5
San Antonio	177.2	215.6	211.3
PAD III avg.	183.6	222.1	221.1
Cheyenne	183.8	216.2	205.2
Denver	190.2	230.6	217.0
Salt Lake City	180.2	223.1	224.7
PAD IV avg.	184.7	223.3	215.7
Los Angeles	219.2	277.7	253.9
Phoenix	199.7	237.1	233.9
Portland	210.6	253.9	212.9
San Diego	219.6	278.1	259.6
San Francisco	236.7	295.2	253.8
Seattle	211.6	264.0	234.9
PAD V avg.	216.2	267.7	241.5
Week's avg.	**191.3**	**234.9**	**226.1**
Feb. avg.	**184.4**	**228.0**	**229.6**
Jan. avg.	**181.7**	**225.3**	**227.3**
2007 to date	**182.9**	**226.5**	—
2006 to date	**185.8**	**228.2**	—

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

REFINED PRODUCT PRICES

	2-23-07 ¢/gal		2-23-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	177.53	New York Harbor	174.45
Gulf Coast	174.52	Gulf Coast	169.75
Los Angeles	214.27	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	163.59	ARA	170.33
Singapore	170.31	Singapore	168.10
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	176.96	New York Harbor	95.38
Gulf Coast	173.52	Gulf Coast	105.36
Los Angeles	220.27	Los Angeles	127.02
		ARA	87.44
		Singapore	106.53

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

BAKER HUGHES RIG COUNT

	3-2-07	3-3-06
Alabama	2	6
Alaska	14	10
Arkansas	41	20
California	31	32
Land	27	29
Offshore	4	3
Colorado	93	81
Florida	1	0
Illinois	0	0
Indiana	1	0
Kansas	14	6
Kentucky	10	6
Louisiana	209	186
N. Land	57	59
S. Inland waters	30	22
S. Land	44	37
Offshore	78	68
Maryland	0	0
Michigan	2	1
Mississippi	18	5
Montana	22	22
Nebraska	0	0
New Mexico	75	98
New York	8	4
North Dakota	32	26
Ohio	13	9
Oklahoma	182	169
Pennsylvania	15	16
South Dakota	0	1
Texas	810	680
Offshore	11	14
Inland waters	1	2
Dist. 1	24	14
Dist. 2	35	27
Dist. 3	49	63
Dist. 4	90	71
Dist. 5	158	126
Dist. 6	121	98
Dist. 7B	44	30
Dist. 7C	54	37
Dist. 8	108	74
Dist. 8A	29	31
Dist. 9	33	29
Dist. 10	53	64
Utah	44	31
West Virginia	29	25
Wyoming	78	95
Others—ID-1; NV-1; TN-4; VA-2	8	2
Total US	**1,752**	**1,531**
Total Canada	**601**	**688**
Grand total	**2,353**	**2,219**
Oil rigs	290	226
Gas rigs	1,458	1,304
Total offshore	94	85
Total cum. avg. YTD	**1,728**	**1,506**

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	3-2-07 Rig count	3-2-07 Percent footage*	3-3-06 Rig count	3-3-06 Percent footage*
0-2,500	57	—	59	3.3
2,501-5,000	100	59.0	109	40.3
5,001-7,500	210	20.0	215	14.8
7,501-10,000	427	3.5	315	3.4
10,001-12,500	409	3.9	341	1.7
12,501-15,000	276	1.0	270	—
15,001-17,500	112	1.7	121	0.8
17,501-20,000	79	—	74	—
20,001-over	34	—	20	—
Total	**1,704**	**8.0**	**1,524**	**6.2**
INLAND	41		39	
LAND	1,606		1,427	
OFFSHORE	57		58	

*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]3-2-07	[2]3-3-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	21
Alaska	780	807
California	690	685
Colorado	50	60
Florida	7	6
Illinois	30	28
Kansas	95	94
Louisiana	1,420	1,181
Michigan	14	15
Mississippi	51	45
Montana	91	97
New Mexico	162	158
North Dakota	107	104
Oklahoma	171	172
Texas	1,343	1,288
Utah	45	46
Wyoming	140	141
All others	65	68
Total	**5,280**	**5,016**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	3-2-07
Alaska-North Slope 27°	49.99
South Louisiana Sweet	63.00
California-Kern River 13°	50.40
Lost Hills 30°	58.35
Southwest Wyoming Sweet	57.89
East Texas Sweet	89.78
West Texas Sour 34°	51.25
West Texas Intermediate	58.25
Oklahoma Sweet	58.25
Texas Upper Gulf Coast	55.00
Michigan Sour	51.25
Kansas Common	57.00
North Dakota Sweet	51.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	2-23-07
United Kingdom-Brent 38°	57.20
Russia-Urals 32°	53.87
Saudi Light 34°	52.45
Dubai Fateh 32°	54.72
Algeria Saharan 44°	59.31
Nigeria-Bonny Light 37°	60.29
Indonesia-Minas 34°	57,82
Venezuela-Tia Juana Light 31°	53.21
Mexico-Isthmus 33°	53.10
OPEC basket	55.84
Total OPEC[2]	54.40
Total non-OPEC[2]	54.53
Total world[2]	54.46
US imports[3]	52.31

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

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

US NATURAL GAS STORAGE[1]

	2-23-07	2-16-07	Change
	Bcf		
Producing region	592	616	–24
Consuming region east	898	996	–98
Consuming region west	243	253	–10
Total US	**1,733**	**1,865**	**–132**
	Dec. 06	**Dec. 05**	**Change, %**
Total US[2]	**3,070**	**2,635**	**17.5**

[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

	Dec. 2006	Nov. 2006	12 month average production 2006	12 month average production 2005	Change vs. previous year Volume	Change vs. previous year %	Dec. 2006	Nov. 2006	Cum. 2006
	Crude, 1,000 b/d						Gas, bcf		
Argentina	650	605	639	645	–6	–1.0	149.5	123.2	1,601.01
Bolivia	45	45	45	42	3	7.8	40.0	38.0	470.81
Brazil	1,787	1,766	1,722	1,634	88	5.4	28.5	28.3	348.91
Canada	2,640	2,632	2,515	2,369	146	6.2	522.9	488.0	6,057.87
Colombia	518	522	527	526	1	0.3	18.0	17.0	194.53
Ecuador	515	516	535	521	14	2.7	0.3	0.3	3.71
Mexico	2,978	3,163	3,256	3,334	–78	–2.3	172.8	166.9	1,955.48
Peru	119	120	116	111	4	3.9	5.7	5.7	62.62
Trinidad	111	135	143	148	–5	–3.4	121.7	108.0	1,319.46
United States	5,360	5,149	5,143	5,179	–36	–0.7	1,682.0	1,611.0	19,341.00
Venezuela[1]	2,550	2,430	2,562	2,706	–144	–5.3	82.0	78.0	979.00
Other Latin America	80	79	79	80	–1	–1.2	7.5	7.2	88.05
Western Hemisphere	**17,354**	**17,163**	**17,281**	**17,294**	**–13**	**–0.1**	**2,830.9**	**2,671.6**	**32,422.46**
Austria	17	17	17	17	—	1.4	5.0	4.5	60.55
Denmark	328	350	334	377	–44	–11.6	31.5	31.7	347.47
France	21	22	21	22	—	–1.0	3.1	3.1	41.21
Germany	70	66	69	71	–1	–1.9	59.7	54.8	655.27
Italy	99	116	110	115	–5	–4.7	31.0	30.0	382.60
Netherlands	30	30	25	29	–4	–13.3	300.0	250.0	2,955.00
Norway	2,508	2,466	2,491	2,698	–207	–7.7	307.0	286.3	3,094.22
Turkey	40	40	41	42	–1	–1.5	3.3	2.4	31.65
United Kingdom	1,565	1,530	1,523	1,678	–156	–9.3	244.6	246.5	2,938.70
Other Western Europe	4	4	5	5	—	–9.6	1.2	1.1	20.24
Western Europe	**4,681**	**4,641**	**4,636**	**5,054**	**–418**	**–8.3**	**986.3**	**910.3**	**10,526.90**
Azerbaijan	750	750	640	443	197	44.4	21.0	22.0	267.00
Croatia	16	16	17	18	–1	–4.8	5.9	5.0	58.39
Hungary	15	16	16	20	–4	–18.8	9.1	9.3	107.57
Kazakhstan	1,100	1,100	1,064	994	70	7.0	80.0	55.0	853.00
Romania	95	96	98	100	–2	–1.8	18.0	17.0	207.00
Russia	9,700	9,550	9,498	9,189	309	3.4	2,000.0	1,950.0	22,655.00
Other FSU	500	450	500	433	67	15.4	430.0	420.0	5,215.00
Other Eastern Europe	49	49	48	50	–2	–4.4	46.2	43.9	518.40
Eastern Europe and FSU	**12,225**	**12,027**	**11,882**	**11,248**	**634**	**5.6**	**2,610.2**	**2,522.2**	**29,881.36**
Algeria[1]	1,340	1,340	1,348	1,352	–4	–0.3	285.0	275.0	3,287.00
Angola	1,354	1,453	1,395	1,238	156	12.6	2.4	2.3	27.90
Cameroon	87	82	87	82	5	6.0	—	—	—
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	660	660	670	695	–25	–3.6	42.0	38.0	484.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.72
Gabon	230	230	235	234	1	0.4	0.3	0.3	3.65
Libya[1]	1,730	1,730	1,708	1,640	68	4.2	22.0	20.0	258.50
Nigeria[1]	2,190	2,200	2,219	2,407	–188	–7.8	75.0	72.0	849.00
Sudan	300	300	293	290	3	0.9	—	—	—
Tunisia	91	75	68	71	–3	–3.6	6.9	6.6	80.80
Other Africa	262	263	269	240	28	11.8	10.2	10.0	120.75
Africa	**8,825**	**8,912**	**8,871**	**8,829**	**42**	**0.5**	**443.8**	**424.2**	**5,112.32**
Bahrain	170	170	172	174	–2	–1.4	27.0	26.0	314.25
Iran[1]	3,880	3,950	3,891	3,891	—	—	260.0	255.0	3,213.00
Iraq[1]	1,770	1,840	1,900	1,810	90	5.0	5.1	5.0	61.90
Kuwait[1,2]	2,475	2,495	2,501	2,427	74	3.1	31.0	30.0	366.50
Oman	720	720	740	758	–18	–2.3	58.0	56.0	695.50
Qatar[1]	820	810	823	798	24	3.0	116.0	112.0	1,377.00
Saudi Arabia[1,2]	8,565	8,765	9,098	9,302	–204	–2.2	160.0	160.0	2,094.00
Syria	400	400	423	460	–38	–8.2	15.3	14.8	183.80
United Arab Emirates[1]	2,600	2,530	2,625	2,458	168	6.8	134.0	128.0	1,570.00
Yemen	360	360	349	348	1	0.2	—	—	—
Other Middle East	—	—	—	—	—	1.2	7.8	7.8	90.47
Middle East	**21,760**	**22,040**	**22,521**	**22,426**	**95**	**0.4**	**814.2**	**794.6**	**9,966.41**
Australia	502	473	428	443	–15	–3.4	115.4	110.8	1,368.45
Brunei	200	204	204	187	17	9.2	37.0	36.1	427.59
China	3,601	3,682	3,683	3,620	63	1.7	190.8	181.6	2,088.33
India	693	691	680	659	21	3.2	81.0	80.0	947.85
Indonesia[1]	860	860	893	945	–53	–5.6	185.0	179.0	2,254.00
Japan	15	15	15	16	—	–2.6	10.0	9.6	112.41
Malaysia	750	760	748	770	–23	–2.9	144.0	140.0	1,683.00
New Zealand	15	15	15	15	–1	–3.3	11.0	11.0	136.20
Pakistan	65	66	65	65	—	0.6	125.0	117.4	1,405.48
Papua New Guinea	55	55	57	46	11	22.8	0.5	0.5	6.00
Thailand	200	203	210	186	24	12.7	71.0	72.2	857.00
Vietnam	330	340	345	340	5	1.3	15.0	15.0	180.00
Other Asia-Pacific	34	36	33	35	–2	–5.3	62.3	62.3	776.35
Asia-Pacific	**7,321**	**7,401**	**7,374**	**7,327**	**48**	**0.7**	**1,047.9**	**1,015.4**	**12,242.64**
TOTAL WORLD	**72,166**	**72,184**	**72,566**	**72,178**	**388**	**0.5**	**8,733.3**	**8,338.4**	**100,152.10**
OPEC	28,780	28,950	29,567	29,735	–168	–0.6	1,355.1	1,314.0	16,309.90
North Sea	4,419	4,368	4,364	4,764	–400	–8.4	672.8	639.3	7,263.93

[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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Late? Feel good; you might be saving energy

If you're late for an appointment Mar. 12, blame Congress, but feel good about yourself. You might be—cue the violins—saving energy.

The Energy Policy Act of 2005 added about 4 weeks to Daylight Savings Time (DST). This is supposed to—cue the violins again—lower energy consumption.

DST now starts on the second Sunday of March instead of the first Sunday of April and ends on the last Sunday of October instead of the first Sunday of November. Clock time advances by 1 hr on Mar. 11.

While computers, servers, and various gadgets with internal electronic clocks need adjustment, experts say the change warrants no revival of Y2K anxiety.

The idea is to shrink the period during which people need lighting. But will that really—violins, please—lower energy use?

California has studied DST and energy use much recently. Last month, a staff paper by Adrienne Kandel, in the Electricity and Demand Analysis Division of the California Energy Commission, raised doubts.

"There is no clear evidence that electricity will be saved from the earlier start to [DST] on Mar. 11, but the 7 p.m. peak load will probably drop on the order of 3% for the remainder of March, lowering capacity requirements," Kandel concluded from simulations of Californian energy-use patterns. Extending DST by a week into November would have similar but smaller effects. Capacity constraints, she added, "usually do not occur in March and early November."

With earlier DST California might, Kandel said, save "a fraction of a percent of total electricity use" unless a morning electricity spike offsets the effect.

Apparently unsure about the nationwide effectiveness of its DST tinkering in the energy bill, Congress ordered the Department of Energy to do a quick follow-up study.

Whether or not the initiative proves to have worked, date and time processing functions need changing in all electronics in or related to the US. And among those sure to be overlooked may well be the one you need for a reminder to be somewhere important on time.

If catastrophe happens, however, remember: In partnership with Congress, you—one more time on the violins, crescendo—saved energy. Or not.

(Online Mar. 2, 2007; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Profit-taking ends 7-day rally

Energy prices slipped in profit-taking Mar. 2, ending a 7-day rally of consecutive gains on the New York market that had not been matched "since last year early in the summer," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland.

The April contract for benchmark US light, sweet crudes dipped by 36¢ to $61.64/bbl Mar. 2 on the New York Mercantile Exchange yet still ended the session 1% higher than where it opened at the beginning of the week. Earlier, the front-month contract broke the $62/bbl barrier to an intraday trading high of $62.49/bbl on Mar. 1. The April contract for reformulated blendstock for oxygenate blending (RBOB) was down 0.83¢ to $1.90/gal on Mar. 2, yet up 7% from its Feb. 26 opening price on NYMEX.

The trading pattern remained similar during most of that week, with crude "pulled higher by a very firm gasoline complex and pulled lower by the spillover of the equity scare" from the Feb. 27 sell-off in global stock markets, Jakob said. The sell-off, which took 9% off the China Shanghai Composite Index, resulted in part from the Chinese government's crackdown on speculation that had pushed Chinese stock prices to record levels (OGJ Online, Feb. 28, 2007). The US stock market appeared to rebound in Feb. 28 trading, however.

There were still fears in some quarters that China's energy demand may be slowing. However, Jakob reported that in January China for the first time became a net importer of coal. That changeover wasn't expected until later this year. Moreover, it represented "a major structural change not only for the global coal trade but for the global energy balances; yet it has gone barely noticed as the numbers came out at the same time as the Shanghai stock exchange collapse," Jakob said. "Chinese power and energy demand is not decreasing, and it would be wrong to discount it on the basis of local stock market gyrations."

Analysts in the Houston office of Raymond James & Associates Inc. reported crude futures prices were down in early trading Mar. 5 following steep dives in the Asian and European equity markets. The Nikkei index was down over 3%, and increasing strength in the yen—the apparent unwinding of the currency carry trade—induced a massive global sell-off that seemed poised to carry into US trading that day.

However, as Raymond James analysts noted, oil prices remained relatively strong, supported by tensions with Iran and concerns about gasoline supply as the driving season approaches. Gas use was expected to moderate as temperatures rose across the US West and parts of the eastern seaboard.

US inventories

The market was boosted by a report by the Energy Information Association that commercial US gasoline stocks declined for the third consecutive week, down 1.9 million bbl to 220.2 million bbl in the week ended Feb. 23. Distillate fuel inventories dropped 3.8 million bbl to 124.5 million bbl. Crude inventories, however, gained 1.4 million bbl to 329 million bbl (OGJ Online, Feb. 28, 2007). Propane and propylene inventories declined by 2.8 million bbl to 31.9 million bbl.

Imports of crude into the US were down by 220,000 b/d to 9.5 million b/d that week, partly because lightering operations were disrupted by fog along the Houston Ship Channel. However, the input of crude into US refineries increased by 196,000 b/d to 14.6 million b/d with units operating at 86% of capacity. Gasoline production increased slightly to 8.7 million b/d; distillate fuel production increased to 3.9 million b/d.

"Overall US stocks (including propane) have drawn down 42 million bbl over the last month and are now 23 million bbl below last year. Excluding propane, stocks have drawn down 22 million bbl over the month and are 16 million bbl below last year," said Jakob of Petromatrix.

The 4-week average of crude imports into the US through Feb. 23 was 390 million b/d lower than in the same period last year, while gasoline imports were down by 266 million b/d. The 4-week average of gasoline production was up by 328 million b/d from a year ago when refinery runs were still recovering from damage by Hurricanes Katrina and Rita. The resulting imbalance of lower imports and higher demand resulted in a gasoline stock draw of 4.4 million bbl over the latest 4-week period, compared to builds of 3.5 million bbl in February 2006 and 7.1 million bbl in February 2005, Jakob said.

(Online Mar. 5, 2007; author's e-mail: samf@ogjonline.com)

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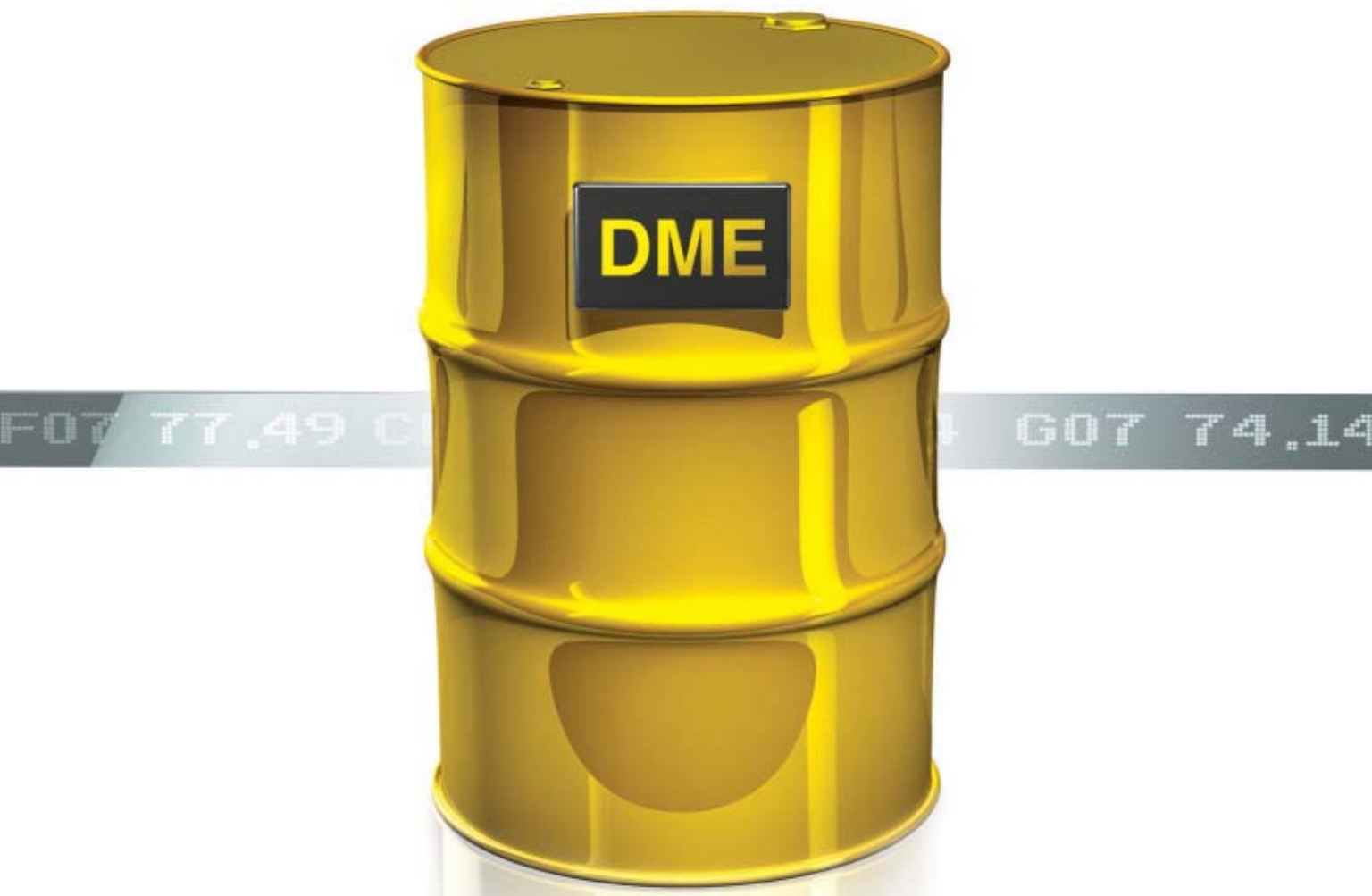

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