Week of Jan. 15, 2007/US$10.00

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International Petroleum News and Technology / www.ogjonline.com

Forecast and Review

W. Africa second only to Russia in non-OPEC supply contribution
N-removal technology improved to process W. Texas Yates gas
US gasoline markets to rebalance by 2010
Boulders, artificial reef modules provide seafloor mitigation

OIL&GAS JOURNAL®

Jan. 15, 2007
Volume 105.3

FORECAST AND REVIEW

REGULAR FEATURES

COVER

Oil production began in December 2006 from the Okume complex off Equatorial Guinea, operator Hess Corp. and its partners, Tullow Oil and GEPetrol, announced. Production will grow during 2007, as infield drilling progresses to peak production of 60,000 b/d during 2008. The Okume complex, 150 miles south of Bioko Island in the Gulf of Guinea, employs two tension-leg platforms, three satellite platforms, and a central processing platform. Central processing facilities are tied back to the Sendje Ceiba floating production, storage, and offloading vessel. Photo courtesy of Hess.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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General Interest — Quick Takes

Tepco seeking more stable LNG sources

Tokyo Electric Power Co. (Tepco) will not renew long-term agreements to purchase LNG from projects in Alaska and Indonesia when they expire in 2009.

Reports said Tepco is seeking to obtain stable long-term supplies while diversifying its geographical risk. In 2005, Tepco purchased 30% of Japan's imports of LNG, with more than 6% of those supplies coming from Alaska and Indonesia.

Under existing contracts Tepco receives 920,000 tonnes of Alaska LNG from Phillips Alaska Natural Gas and Marathon Oil, along with an additional 130,000 tonnes of LNG from the Arun facility of Indonesia's state-run PT Pertamina.

Indonesia had trouble meeting its commitments to Japanese LNG buyers due to demand growth for domestic gas supplies. In Alaska, moreover, there are questions about long-term LNG prospects, given proposals for gas pipelines to feed growing US needs.

Tepco has had other uncertainties over the security of its supplies. In November 2004 the company signed a contract with Sakhalin Energy Investment, operator of the Sakhalin-2 project, to buy 1.5 million tonnes/year of LNG for 22 years from April 2007. Those supplies are now in question due to the sale of a 50% stake in the project to Russia's OAO Gazprom.

In an apparent effort to begin redressing the situation, Tepco last December concluded a heads of agreement on the purchase of 300,000 tonnes/year of LNG from six sellers of Australia's North West Shelf LNG from April 2009 to March 2017.

The contract volume is about one fourth of the 1.18 million tonnes/year that Tepco buys from NWS LNG based on a 20-year agreement that will expire at the end of March 2009.

FERC issues final EIS for Mississippi LNG project

US Federal Energy Regulatory Commission staff released a final environmental impact statement favoring Bayou Casotte Energy LLP's proposed LNG terminal and pipeline on Bayou Casotte adjacent to parent Chevron Corp.'s refinery near Pascagoula, Miss.

FERC said commissioners will take the EIS into consideration when they make a final decision on the project. FERC found the project environmentally acceptable for several reasons:

- The site adjoining Chevron's refinery would provide "numerous synergies and environmental benefits, including use of existing services for security and safety, minimization of landowner impacts, and use of waste heat from the refinery to accomplish LNG vaporization."
- Only short lengths of pipeline are needed to tie into an existing natural gas pipeline grid.
- The project would not likely affect threatened or endangered species.
- No residences are near construction areas.
- Bayou Casotte Energy plans to implement a modified version of FERC's plans and procedures to minimize impacts on soils, wetlands, and bodies of water.
- No noise-sensitive areas are located near the proposed project.
- Before construction could begin, appropriate consultations would be required with the US Army Corps of Engineers, US Environmental Protection Agency, National Oceanic and Atmospheric Administration, State Historic Preservation Office, and Mississippi Department of Environmental Quality.
- Safety features would be incorporated into the design of the terminal and LNG vessels that use it.
- Local pilots and the US Coast Guard would impose operational controls to direct the movement of LNG ships, and security provisions would be put in place to deter possible terrorist attacks.
- The project's environmental and engineering inspection and mitigation monitoring program would ensure compliance with all mitigation measures, which would be conditions of FERC's authorization.

McMoRan's Main Pass Energy Hub project approved

McMoRan Exploration Co. reported it has received approval from the US Maritime Administration for its Main Pass Energy Hub project on Main Pass Block 299 in 210 ft of water off Louisiana in the Gulf of Mexico.

Marad concluded that construction and operation of the MPEH deepwater port would be consistent with national objectives such as energy sufficiency and environmental quality. It also said the project will fill a vital role in meeting national energy requirements for many years and that the port's offshore deepwater location will help reduce congestion and enhance safety in receiving LNG cargoes to the US.

As approved, the MPEH facility will be able to regasify LNG at a peak rate of 1.6 bcfd, store 28 bcf of gas in salt caverns, and deliver 3.1 bcfd of gas, including gas from storage, to the US.

Unique advantages of the project include use of existing offshore structures, onsite gas cavern storage capabilities, logistical savings associated with the offshore location, and premium markets available from its eastern gulf location. ✦

Exploration & Development — Quick Takes

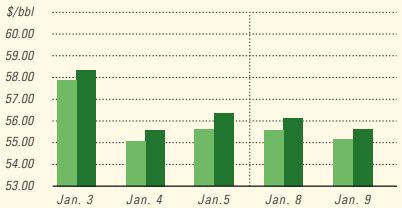
Apache finds oil, gas in Egypt's Western Desert

Apache Corp. reported encouraging results from several recent wells drilled in Egypt's Western Desert.

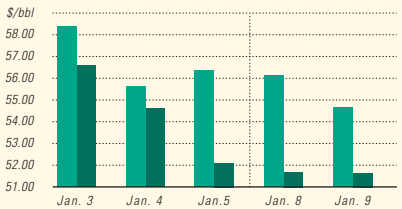
Its Qasr 34 appraisal well has tested 18.4 MMcfd of gas and 725 b/d of condensate after reaching a TD of 14,000 ft in Jurassic Lower Safa rock. The well extends the Qasr field, 2.5 km to the

Industry Scoreboard

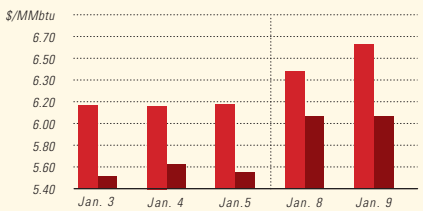
IPE BRENT / NYMEX LIGHT SWEET CRUDE



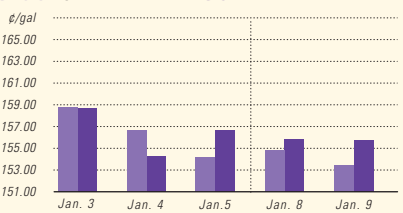
WTI CUSHING / BRENT SPOT



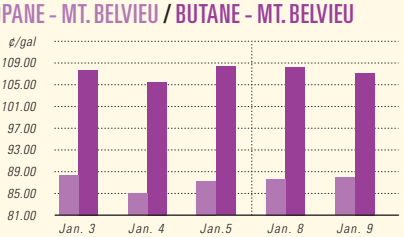
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



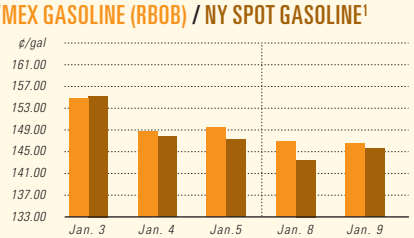
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB) / NY SPOT GASOLINE[1]



[1]. Nonoxygenated regular unleaded.

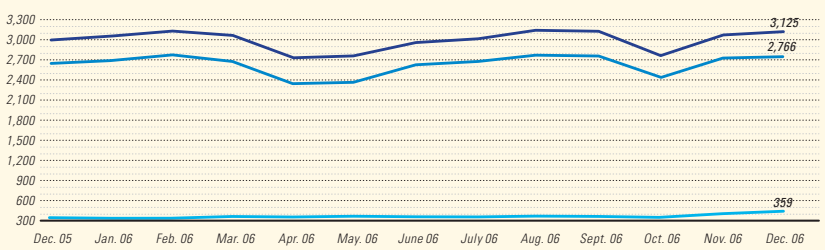
US INDUSTRY SCOREBOARD — 1/15

Latest week 1/5	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	9,674	9,194	5.2	8,978	8,727	2.9
Distillate	3,871	4,307	–10.1	3,936	4,161	–5.4
Jet fuel	1,684	1,715	–1.8	1,531	1,529	0.1
Residual	610	996	–38.7	729	861	–15.3
Other products	5,165	5,036	2.6	5,041	4,833	4.3
TOTAL DEMAND	21,004	21,248	–1.1	20,216	20,110	0.5
Supply, 1,000 b/d						
Crude production	5,357	4,996	7.2	5,352	5,047	6.0
NGL production	2,429	1,499	62.0	2,181	1,684	47.3
Crude imports	9,749	9,939	–1.9	9,146	9,713	–5.8
Product imports	3,400	3,607	–5.8	3,577	3,863	–7.4
Other supply[2]	1,054	1,141	–7.7	1,071	1,240	–13.6
TOTAL SUPPLY	21,988	21,183	3.8	21,627	21,548	0.4
Refining, 1,000 b/d						
Crude runs to stills	15,373	15,003	2.5	15,486	14,806	4.6
Input to crude stills	15,736	15,221	3.4	16,003	15,080	6.1
% utilization	90.8	88.6	—	92.3	87.0	—

Latest week 1/5	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	313,279	321,003	–7,724	316,936	–3,657	–1.2
Motor gasoline	216,489	207,918	8,571	210,673	5,816	2.8
Distillate	147,147	143,103	4,044	139,516	7,632	5.5
Jet fuel	39,589	38,072	1,517	42,401	–2,812	–6.6
Residual	44,963	44,525	438	38,291	6,672	17.4
Stock cover (days)[3] **12/29**			**Change, %**		**Change, %**	
Crude	20.6	20.7	–0.5	21.3	–3.3	
Motor gasoline	22.4	21.7	3.2	22.0	1.8	
Distillate	31.7	31.0	2.3	29.7	6.7	
Propane	40.6	43.4	–6.5	33.6	20.8	
Futures prices[4] **1/5**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	56.74	60.76	–4.02	63.39	–6.65	–10.5
Natural gas, $/MMbtu	6.17	6.13	0.04	9.99	–3.82	–38.2

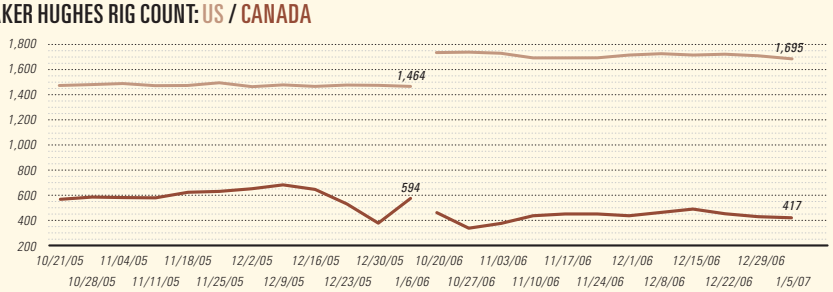
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [3]Stocks divided by average daily product supplied for the prior 4 weeks. [4]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, American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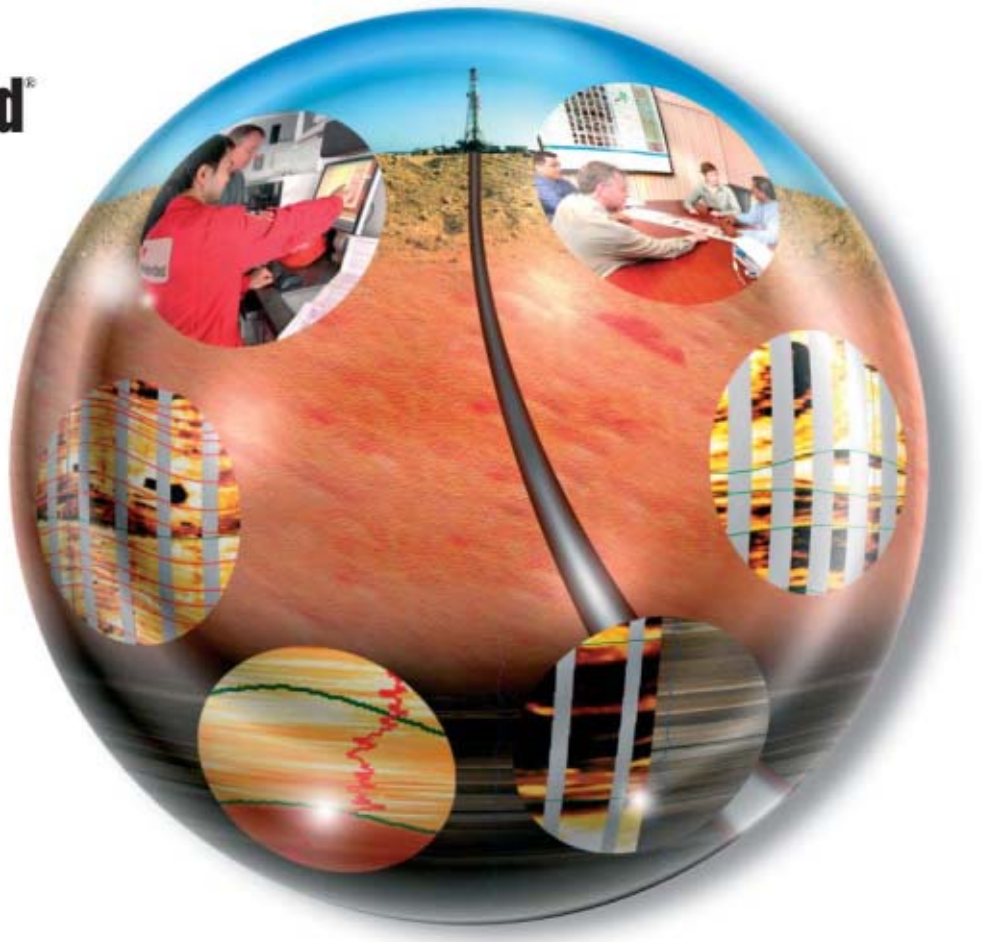

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northwest, adding 2,200 acres to the field, Apache said.

Wireline logs indicate 96 ft of net pay in the upper sand of the Lower Safa at 13,328-13,442 ft. A total of 72 ft of Lower Safa pay at 13,328-13,400 ft was tested through a ¾-in. choke with 2,000 psi of wellhead pressure.

Separately, the Zasr 36 well flowed 2,945 b/d of oil and 2.1 MMcfd of gas. The well was a new Alam El Bueib (AEB) discovery in the field. Apache drilled the well to 12,424 ft in AEB 3G sands and targeted AEB 3D and 3E sands. Log analysis showed 58 ft of net pay in the AEB 3D and 3E sands.

The Hathor Deep 1X well on the Khalda Offset concession tested 12 MMcfd of gas in the AEB 6 formation and 1,237 b/d of oil from the AEB 3D formation. Apache will proceed with developing the Hathor Deep 1X having received approval from state-owned Egyptian General Petroleum Corp. It has installed surface equipment and needs the petroleum minister's approval before it can begin production.

The Qasr 40 well logged 60 ft of net oil pay in the AEB 3E sands and in secondary pay intervals in the AEB 3A and 3C. The new well is a step-out northwest from the Qasr 31, which currently produces 2,005 b/d.

The Kenz 35 well will be completed in the AEB 3E formation as a gas and condensate producer. Apache said it was drilled 1 km northwest of the nearest producing well in the Kenz field on the Khalda Ridge. Kenz 35 logged 140 ft of AEB net pay as well as 18 ft of net pay in the Upper Bahariya.

Vermilion to drill wildcat off southwest France

Vermilion REP, a subsidiary of Calgary-based Vermilion Resources Ltd. and Vermilion Exploration SAS, is planning to drill an exploration well on the Aquitaine maritime permit which covers a 1,211 sq km area in the northern part of offshore Aquitaine basin in southwest France.

Following 2D and 3D seismic surveys carried out in September and October 2005 at a cost of $6 million, with final processing completed in February 2006, Vermilion is planning an exploratory well in this year's third quarter at a cost of $25-30 million.

Six large structural leads have been mapped at the primary Lower Cretaceous reservoir target. In addition, a large structural lead has been identified at the Upper Cretaceous-Lower Tertiary level, and a location for the hole is being selected, said Paul Beique, director of investor relations for parent firm Vermilion Energy Trust.

"A well depth of 3,000 m would be sufficient to penetrate the entire Lower Cretaceous sequence," Beique said, adding that it would take 30-40 days to drill. "The big question," he said, "is the quality of the reservoir, whether the rock is porous and permeable."

Although it is an extension of the onshore oil-prone Parentis subbasin, and its distance to shore varies at 20-80 km in 50-200 m of water, the 22 exploration wells drilled over time by Esso, Shell, or Elf have never so far yielded commercial results. Esso, which never found a partner to share the development costs, drilled the most recent well, Pegasus, in 1998.

Petroceltic makes gas find in eastern Algeria

Petroceltic International PLC, Dublin, said two wells have confirmed the potential to commercially exploit shallow, laterally extensive hydrocarbon reservoirs on part of the 10,872 sq km Isarene permit in the Illizi basin in eastern Algeria.

The company is reviewing options with respect to appraisal and development.

ISAS-1, the permit's obligation well, tested 360 Mcfd of wet gas on a 40/64-in. choke at 41 psi stabilized wellhead pressure from Devonian F2 at 851-856 m and 861-865 m. Formation damage was indicated. The well also tested 850 Mcfd of wet gas on a 56/64-in. choke with 36 psi stabilized wellhead pressure from Carboniferous Visean B at 558-564 m.

The well produced small amounts of gas from Ordovician open hole.

About 40 km west, Hassi Tab Tab-2 flowed 12.56 MMcfd of wet gas on a 56/65-in. choke with 590 psi stabilized wellhead pressure from Devonian F2 at 907-921 m and 939.5-943 m. It flowed 2.44 MMcfd of wet gas on a 44/64-in. choke with 231 psi stabilized wellhead pressure from Carboniferous Tournaisian at 677-681 m. And it flowed 440 Mcfd of wet gas on a 32/64-in. choke with 84 psi stabilized wellhead pressure from Carboniferous Visean B at 436.5-441.5 m.

The Devonian F2 flow rate at HTT-2 is one of the highest for this horizon in the basin, said Petroceltic, which holds 75% of the block. Sonatrach holds the other 25%.

Isarene is 120 km south of In Amenas, Algeria's largest wet gas project. It is just southwest of another permit on which Rosneft has drilled two oil discoveries and one gas-condensate discovery in Ordovician and Devonian F6 reservoirs. And it is less than 15 km from Repsol YPF-operated Tifernine field, where processing facilities have spare capacity (OGJ, May 17, 1993, p. 26).

Well off Vietnam gauges high oil flow rate

A new appraisal well in Te Giac Trang on Block 16-1 off Vietnam has flowed oil at high rates on a drillstem test.

The TGT-5X well, drilled to a TD of 3,405 m, gauged 7,000 b/d, said Thailand's PTT Exploration & Production PLC, which holds a 28.5% interest in Block 16-1 through subsidiary PTTEP Hoang Long Co.

PTTEP said a second drillstem test, in progress at the time of the report, recorded an initial flow rate of 7,300 b/d.

Drillstem test flows of other appraisal wells on the same structure are 600 b/d from TGT-4X, 9,432 b/d from TGT-1X, and 9,908 b/d from TGT-3X (OGJ Online, Apr. 28, 2006).

Trinidad and Tobago round gets one bidder

The latest bid round for the Trinidad Deep Atlantic Area received only one bid, the fewest since production-sharing contracts were introduced in the 1990s.

Statoil ASA submitted a bid for the TDAA Block 5. The Trinidad and Tobago government promised that it would make a decision within 3 months on Statoil's bid.

Eleven other oil companies paid for 2D seismic data on deepwater blocks but did not offer any bids.

The eight blocks involved in the bid round were in 1,700-

2,500 m of water and adjacent to areas from which most of Trinidad and Tobago's oil and gas are produced. The area has not been explored.

ONGC strikes gas in Krishna-Godavari basin

India's government-owned Oil & Natural Gas Corp. (ONGC) said it made a major gas discovery in the Krishna-Godavari basin off India's eastern coast.

ONGC is the operator with 90% interest in the KG-DWN-98/2 block. Scottish energy firm Cairn India holds 10% interest.

A senior ONGC executive told OGJ that test results for the first well in the KG basin confirmed 30 m of gas pay at 5,300 m below the seabed. The executive said seismic studies indicate 80 m of potential pay at 6,450 m.

ONGC has identified five more drilling locations on the block. ✦

Drilling & Production — *Quick Takes*

BP suspends production at Shah Deniz project

BP PLC has halted gas and condensate production from its first production well at the Shah Deniz project because of a technical fault.

The $4.5 billion project, in the Azerbaijan sector of the Caspian Sea, has encountered some unexpected problems with gas pressures in the well, the company said. Shah Deniz came on stream in mid-December and was shut down just before the end of that month.

"We hope to bring the project back on as soon as possible," a BP spokesman said, but declined to give a specific time frame.

Shah Deniz holds 25-35 tcf of gas and in Stage 1 is expected to produce 8.6 billion cu m/year of gas and 37,000 b/d of condensate, which will be shipped to Ceyhan, Turkey, for processing (OGJ, Aug. 21, 2000, p. 68).

Gas will be exported to Azerbaijan, Georgia, and Turkey via the $1.3 billion, 700 MMcfd South Caucasian Pipeline. The line, also operated by BP, extends 430 miles from Baku to Tbilisi, Georgia, and Erzurum in eastern Turkey, paralleling the Baku-Tbilisi-Ceyhan oil pipeline.

UK Buzzard oil-gas field starts production

Buzzard oil and gas field in the UK Central North Sea has come on stream and will bring an additional 200,000 b/d of oil to international markets later this year and 60 MMcfd of gas.

Buzzard, which is operated by Nexen Petroleum UK Ltd., has reserves of more than 500 million boe and the potential to deliver about 10% of the UK's annual forecast oil demand at peak rates. It is the largest North Sea discovery to be developed in more than a decade.

Buzzard production will be processed through a 12,000-tonne production deck (OGJ Online, June 29, 2006). So far nine production and five injection wells have been drilled. Buzzard will be developed with 27 production wells and 11 water injection wells.

Buzzard lies in 317 ft of water about 100 km northeast of Aberdeen in the Outer Moray Firth. Oil is exported through an 18-in. pipeline to the Forties Pipeline System for processing at the BP Kinneil plant. Gas from Buzzard will be exported through a 10-in. pipeline on the UK Frigg pipeline to the St. Fergus gas terminal.

Dave Thomas, an oil analyst at Citigroup, told OGJ that the $2.9 billion invested to develop the field was "very competitive" bearing in mind rising industry costs. "However, there is still the question on how BG Group will deal with handling high sulfur levels in Buzzard oil," he added. Installing an amine unit offshore to strip sulfur from the oil could cost an additional estimated $200-300 million.

A BG Group spokesman told OGJ that the sulfur was contained in some parts of the reservoir and production would go ahead as planned.

Shell lets contracts for deepwater ESP systems

Units of Royal Dutch Shell PLC have awarded contracts to Centrilift, Claremore, Okla., to provide electrical submersible pumping (ESP) systems in deepwater seabed production-boosting systems for projects in the Gulf of Mexico and off Brazil.

It will be gulf's first ESP system using seabed vertical booster stations, said Centrilift, a division of Baker Hughes Inc.

Shell Offshore Inc.'s Perdido development will include five enhanced run life ESP vertical booster stations. Centrilift will supply the ESP equipment, provide engineering design, qualification, and testing services. Each installation will include a liquid-gas separator to maximize ESP performance.

The vertical booster stations will handle production from Great White, Silvertip, and Tobago satellite fields tied back to the Perdido spar, moored in 8,000 ft of water (OGJ, Nov. 27, 2006, Newsletter).

The booster stations will be under the spar and tied to the platform via top tensioned risers. First production is expected in 2010. ✦

Processing — *Quick Takes*

Indonesia to expand refineries' capabilities

Indonesia's state-run PT Pertamina and Japan's Mitsui & Co. plan to establish a joint venture to build a $1 billion gasoline cracker at the Cilacap refinery on Java.

Pertamina processing director Suroso Atmomartoyo said the new unit would have a capacity of 40,000-50,000 b/d. He said Pertamina plans to start construction by 2008 at the latest and expects operations to begin in 2010.

The Cilacap refinery has two crude distillation units with respective capacities of 118,000 b/d and 230,000 b/d. The facility also has a 29,000 b/d gasoline-making reforming unit and a 50,000 b/d visbreaker.

Last December Pertamina Pres. Ari Soemarno said Indonesia

wanted to make the Cilicap refinery more economic and competitive as part of a general strategy to develop the country's refining capacity, especially after suffering gasoline shortages in mid-2005.

He said Pertamina aims to double the country's crude output to 300,000 b/d within 4 years and to modernize several of its biggest refineries, inviting overseas partners to join $18 billion of projects aimed at boosting crude oil production and fuel refining.

In addition to the Cilicap refinery development, Pertamina plans to build a cracker at its Balikpapan refinery, and it is conducting talks with SK Corp. of South Korea to expand capacity of the 125,000 b/d Dumai refinery on Sumatra Island to 160,000 b/d.

Hydrogen plant due Polish refinery

PKN Orlen SA let an engineering, procurement, and construction management contract to Technip for a hydrogen plant at its 376,500 b/cd refinery in Plock, Poland.

The €50 million lump-sum contract covers licensing, design, and supply of equipment and materials; construction management and supervision; and start-up services and training.

The hydrogen plant, scheduled to be operational in first quarter 2009, will have a capacity of 5 tonnes/hr. The hydrogen produced will be used in the refinery to produce diesel oil in compliance with the European norms.

Kufpec joins GTL project in Papua New Guinea

Kuwait Foreign Petroleum Exploration Co. has signed a joint development agreement with Syntroleum Corp. for participation in the development of a 50,000 b/d gas-to-liquids plant in Papua New Guinea.

PNG Prime Minister Michael Somare gave the proposal formal support following submission of a feasibility study.

The facility will produce sulfur-free diesel fuel and other petroleum products. Syntroleum said the project has been granted priority in PNG's effort to establish a commercial gas industry.

The company plans to progress financing and to begin placing major construction and fabrication contracts. ✦

Transportation — *Quick Takes*

Chubu-Toho JV to expand LNG terminals

Japan's Chubu Electric Power Co. and Toho Gas Co. plan to expand their LNG facilities by constructing two natural gas pipelines and further developing the jointly owned Chita LNG import terminal in Aichi prefecture.

To maintain a steady LNG supply for Japan, especially from Qatar, Chubu and Toho will build the pipelines to connect Chita terminal to Chubu's Kawagoe thermal power plant and to Toho's regasification plant. The pipelines are scheduled for completion in 2013.

The Chita terminal, one of the largest in Japan, receives about 6.5 million tonnes/year of LNG in about 110 tankers. By 2009, the JV plans to refit and expand the terminal to receive tankers that can carry 200,000 cu m of LNG. Chita currently receives vessels with capacities of as much as 170,000 cu m of LNG.

Hirotaka Iwase, spokesman for Chubu Electric, said more suppliers are using larger-scaled vessels, and the ability to accept the new ships will contribute to securing a stable LNG supply.

In addition to the changes at Chita, Chubu Electric has separate plans to refit by 2010 another LNG terminal near the Kawagoe thermal power plant to accept tankers that can carry as much as 200,000 cu m of LNG.

LNG supplies could come primarily from Qatar Liquefied Gas Co. (Qatargas), which has been a main supplier to Chubu since December 1996 when its first LNG cargo departed Ras Laffan and was delivered to the Kawagoe terminal.

In June, Qatargas said that by 2010 it would add more than 50 tankers, each capable of carrying more than 200,000 cu m of LNG to markets in Asia, the US, and Europe.

GDF seeks partners for LNG terminal expansion

To cope with LNG growth in France and Europe, Gaz de France has issued an invitation to new players to participate in development of new regasification capacity at its Montoir-de-Bretagne terminal on the Atlantic coast.

Capacity enhancement would occur in two stages:

- An initial addition of 2.5 billion cu m, scheduled for commissioning in 2011, will bring current delivery capacity to 12.5 billion cu m/year.
- In the second stage, construction of a fourth large-capacity LNG tank and the additional boosting of regasification and emission facilities would add an additional 4 billion cu m/year, increasing capacity to 16.5 billion cu m/year from 2014 onwards.

The extension will be built on the basis of long-term ship-or-pay contracts.

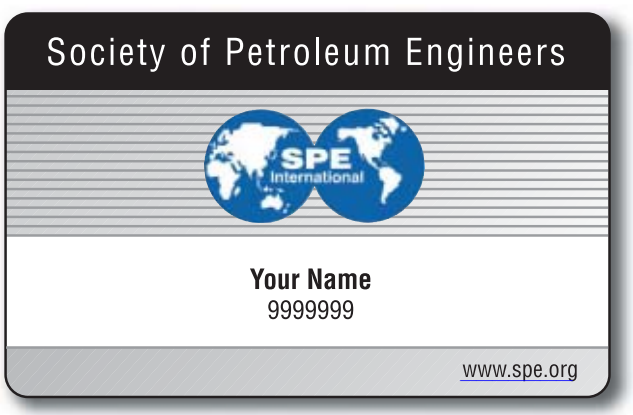
On stream since 1980, the Montoir-de-Bretagne terminal can handle LNG carriers with a capacity of up to 200,000 cu m. It currently receives LNG from Algeria, Nigeria, and Egypt and has a storage capacity of 360,000 cu m.

GDF sees the development of LNG imports worldwide reaching 300 billion cu m of gas (in gaseous state) by 2010, up from 176 billion cu m in 2005. ✦

US terminal sees two LNG tankers at once

In mid-December 2006 two LNG tankers were at Southern LNG's Elba Island regasification terminal near Savannah, Ga. This is the first time a US LNG import terminal has had two LNG tankers simultaneously. Docked at the Elba Island terminal North Dock was the 138,000 cu m British Trader while the 127,500 cu m Edouard LD was moored at the facility's South Dock. Photo from El Paso Corp.

Survival necessity.



Career necessity.

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

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2007

JANUARY

Petrotech India Conference and Exhibition, New Delhi, +44 (0) 20 8439 8890, +44 (0) 20 8439 8897 (fax), e-mail: adam.evan-cook@reedexpo.co.uk, website: www.petrotech2007.com. 15-19.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: oaconference@pennwell.com, website: www.offshoreas-iaevent.com. 16-18.

GTLtec Conference, Doha, (65) 6345 7322, (65) 6345 5928 (fax), e-mail: cynthia@cmtsp.com.sg, website: www.gtltec.com. 22-23.

Power-Gen Middle East Conference, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 22-24.

API Exploration and Production Winter Standards Meeting, Scottsdale, Ariz., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 22-26.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwater-operations.com. 23-25.

SPE Hydraulic Fracturing Technology Conference, College Station, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 29-31.

Underwater Intervention Conference, New Orleans, (281) 893-8539, (281) 893-5118 (fax), website: www.underwaterintervention.com. Jan. 30-Feb. 1.

FEBRUARY

NAPE Expo, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: nape@landman.org, website: www.napeonline.com. 1-2.

IPAA Small Cap Conference, Boca Raton, Fla., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 5-8.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 6-7.

Russia Offshore Oil & Gas Conference, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyex-change.co.uk. 7-8.

Multiphase Pumping & Technologies Conference & Exhibition, Abu Dhabi, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.multi-phasepumping.com. 11-13.

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

International Petrochemicals & Gas Technology Conference & Exhibition, London, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 12-13.

IP Week, London, +44(0)20 7467 7100, +44(0)20 7580 2230 (fax); e-mail: events@energyinst.org.uk, website: www.ipweek.co.uk. 12-15.

Pipeline Pigging & Integrity Management Conference, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: info@clarion.org, website: www.clarion.org. 12-15.

CERA Week, Houston, (800) 597-4793, (617) 866-5901, (fax), e-mail: register@cera.com, website: www.cera.com/ceraweek. 12-16.

International Downstream Technology & Catalyst Conference & Exhibition, London, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 14-15.

Pakistan Oil & Gas Conference, Islamabad, (92-21) 6634795, (92-21) 6634795 (fax), website: www.pakoil-gas.com. 18-20.

SPE/IADC Drilling Conference and Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-22.

AustralAsian Oil Gas Conference and Exhibition, Perth, (704) 365-0041, (704) 365-8426 (fax), e-mail: sarahv@imexmgt.com, website: www.imexmgt.com. 21-23.

Pipe Line Contractors Association Annual Meeting, Aventura, Fla., (214) 969-2700, e-mail: plca@plca.org, website: www.plca.org. 21-25.

International Conference and Exhibition on Geo-Resources in the Middle East and North Africa, Cairo, 00202 3446411, 00202 3448573 (fax), e-mail: alisadek@mailer.eun.eg, website: www.grmena.com.eg. 24-28.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-3136, (405) 325-7329 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 25-28.

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.

SPE Reservoir Simulation Symposium, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-28.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. Feb. 27-Mar. 1.

International Symposium on Oilfield Chemistry, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Feb. 28-Mar. 2.

MARCH

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

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

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

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

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

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

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New year, new look

Laura Bell
Statistics Editor

Most of us after the holidays are ready for a change. That is why we try to make New Year's resolutions, such as to lose weight, stop smoking, save more money, and spend more time with family. Some people, mainly women, simply like to change their look or improve their appearance.

At the Oil & Gas Journal, we have in the past changed the look of the magazine so that it appears sharp and serves readers better. Over several years we have adapted and utilized new computer software to enhance the quality of color, layout, and art.

Statistical changes

Another area of steady progress at OGJ is statistical reporting, which has changed in both format and content to help readers analyze oil and gas operations and markets.

Several years ago, for example, we added to the Newsletter at the front of the magazine bar graphs of price data for crude oil, natural gas, and oil products and linear graphs of rig counts.

A new look that includes a content enhancement occurs this week. The Scoreboard in the Newsletter has a new data series.

For many years, the Scoreboard has summarized data on US oil supply, demand, refinery operations, inventories (stocks), and crude and gas futures prices. Now it also includes US Energy Information Administration numbers depicting stocks of crude, total motor gasoline, distillate fuel, and propane in terms of days of supply.

Inventory figures are under much analysis these days, as huge swings in inventories affect prices. Information on days of supply provides a new dimension of analysis.

EIA calculates days of supply for a commodity by dividing inventory levels by the average daily amount supplied or, for crude, refinery inputs during the prior 4 weeks. The calculation thus relates absolute stock levels to recent consumption rates.

The resulting number, days of supply, is sometimes called "stock cover." Some analysts divide stock volumes by projected daily consumption rates to yield "forward cover."

Assessing adequacy

Stock cover is a valuable test of the adequacy of oil or gas in storage.

Stocks represent immediately accessible supply and serve important operational functions. A refinery that receives intermittent deliveries of crude by tanker, for example, must use storage to stabilize flows into distillation columns.

But stocks also provide buffers against supply disruptions—for individual refiners, for other positions along the distribution chain such as pipelines and terminals, and for the whole market. It's in US oil markets that the new EIA data on days of supply will be valuable.

A stock level of x might represent an adequate—or at least historically normal—cushion at consumption level y. But at consumption level $1.5y$, the same stock level would be low, probably perilously so. It covers proportionally more days of consumption at level y than at $1.5y$.

So an observer might see inventory levels of crude oil holding steady over several years and think conditions are normal. But if demand, measured as input to refineries, rises steadily over the same period, the actual supply buffer actually is shrinking. The effect, not evident in stock volumes, would show up as a shrinking days-of-supply number.

Those are simple illustrations of the much more-sophisticated analyses that are possible with the new data series, which will appear weekly. ✦

Editorial

Democrats in control

Misunderstanding typical of past energy mistakes is pushing triumphant congressional Democrats to the brink of new error. Americans do not need to worry about this unless they use modern forms of energy or pay taxes.

Giddy as they are with their recovery of power, Democrats can be forgiven a few days of rhetorical excess. But they really should try to be correct.

"For too long, our country's energy policy has had only one concern: oil company profits," declared new Senate Majority Leader Harry Reid of Nevada (OGJ Online, Jan. 8, 2006). This is quite a condemnation of energy policy. Until extraordinary events—strikes in major producing countries, wars, hurricanes—combined with relentlessly rising demand to push up prices for crude oil and natural gas in the past 4 years, oil industry profitability languished well below levels of most other industries for at least a decade and a half. If energy policy really were as concerned about oil company profits as Reid alleged, it failed spectacularly.

Whose profits?

In fact, the only major energy initiative enacted during the recent spurt in oil profitability was the Energy Policy Act of 2005 (EPACT). With it, Congress clearly was more concerned about profits of farmers, grain distillers, biodiesel producers, and makers of alternative-fuel vehicles than it was about those of oil companies. Why aren't Reid and his colleagues holding profit margins in those industries up for public scorn?

The answer, of course, is that oil companies are unpopular in the US, largely because of the unavoidable association of their profitability spikes with fuel prices that consumers find distressing. This is a simple business reality. Exploiting it for political gain is tawdry practice. But it always works. And it too frequently leads to policies costly to energy consumers and taxpayers.

The Democrats can't wait to pick American pockets on energy. The Senate already has a bill that the new leadership claims will reduce US dependence on foreign oil and the risks of global warming. Here, as described by Reid and reported by OGJ Washington Correspondent Nick Snow, are the key provisions:

1. Require reductions in emissions of greenhouse gases.
2. Diversify and expand the use of "secure, efficient, and environmentally friendly"—which means congressionally specified—energy forms.
3. Reduce the burdens of rising energy costs on consumers.
4. Eliminate "tax give-aways" to large energy companies.
5. Prevent energy "price-gouging, profiteering, and market manipulation."

This list contains striking contradictions. While addressing the build-up of greenhouse gases is a righteous aim, requiring emissions reductions as called for in item 1 would raise energy costs in conflict with item 3. Whatever hope item 1 leaves for the achievement of item 3 will be dashed by item 2. To win market acceptance of its favorite energy types, the government must resort to subsidies and mandates, which are very expensive. An example is EPACT's fuel ethanol program, a breathtaking tax give-away unlikely to receive much attention in item 4. And item 5 just shows how effective propaganda can immortalize repeatedly discredited fiction. As a market cop, Congress can only duplicate enforcement mechanisms already in place and, if it gets carried away, discourage sales during fuel shortages. Item 3 takes another blow.

The US needs a better energy policy than it has now. It doesn't need high-cost futility. Lurches like this happen when politicians think they can disengage from markets. Sen. Ken Salazar (D-Colo.) last week encapsulated American wrong-headedness on energy with this observation: "The only thing lacking, really, has been the will of the leadership of America to move forward to get us to that energy independence."

Innovation and markets

In fact, energy progress comes not from political will but from technical innovation applied within the discipline of robust markets. And energy independence is just an illusory goal with which politicians seduce Americans into subsidizing uncompetitive energy and wasteful government programs.

There's hope, though. Congress didn't plan to take up energy until Jan. 18. Energy consumers and taxpayers can hope that, sometime during the few days until then, Democrats quit partying and get serious. ✦

US energy market to expand in 2007 as prices ease

Marilyn Radler
Senior Editor-Economics

US energy demand will increase this year as the economy grows at a tempered pace. Winter weather will be milder than normal, requiring less heating, but temperatures in the summer are also expected to be higher than usual, requiring more cooling.

Demand for electric power generation will drive much of the energy needed in the US in 2007. OGJ forecasts increases in consumption across all forms of energy. Oil, natural gas, coal, nuclear, and renewable energy each will gain small demand increments from a year ago.

Transportation fuel consumption will push US oil demand in 2007. This will be the result of slightly lower prices, economic growth, and growing volumes of ethanol entering the gasoline market.

US production of crude and condensate will move up nearly 2% this year after declining in 2006. Oil production will increase worldwide.

US natural gas supply will be up just 1% from 2006. Gas demand will be up by less than that, though, despite the need for more electricity generated from gas. Inventories will decline a bit on stronger demand in the summer.

Economy, energy

OGJ forecasts that the US economy will grow in 2007 but that the pace will be down from last year.

Many factors are weighing on the economy, including the cooled housing market. But energy prices will be lower this year. Additionally, personal income has been rising steadily for the past few years, according to the US Bureau of Economic Analysis.

With the Federal Reserve watching inflation and interest rates, real gross domestic product (GDP) will climb 2.2% this year after last year's 3.2% gain.

US ENERGY DEMAND

	2005	2006	Change, % 2006/05	2007	Change, % 2007/06	% share of total energy		
	Trillion btu			Trillion btu		2005	2006	2007
Oil	40,735	40,600	-0.3	41,030	1.1	40.6	40.3	40.2
Gas	22,636	22,610	-0.1	22,670	0.3	22.6	22.4	22.2
Coal	22,788	22,780	0.0	23,100	1.4	22.7	22.6	22.7
Nuclear	8,160	8,290	1.6	8,300	0.1	8.1	8.2	8.1
Hydro, other	6,039	6,525	8.0	6,850	5.0	6.0	6.5	6.7
Total	**100,358**	**100,805**	**0.4**	**101,950**	**1.1**	**100.0**	**100.0**	**100.0**

Sources: 2005 US Energy Information Administration; 2006 and 2007 OGJ estimate and forecast

US energy demand this year will grow 1.1%. Consumption of all forms of energy, including oil, gas, coal, nuclear, and renewable energy, will total 101.95 quadrillion btu (quads).

Energy efficiency will barely improve this year. Energy use will decline to 8,750 btu/$ of GDP from 8,840 btu/$ a year ago.

In 2006, total US energy demand increased an estimated 0.4%. Consumption of oil and gas declined a bit, while coal demand was unchanged, and consumption of nuclear and renewable energy grew.

Energy sources

While this year's growth rates for all types of energy will be modest, the largest percentage of growth will be for renewable energies. Included in this group are wind and solar energy and hydroelectric power generation.

OGJ expects energy from renewable sources to climb 5% this year. This group will still account for the smallest share of total US energy used: 6.7%.

Total US energy consumption for renewable energy will be 6.85 quads this year. In 2006, demand for renewable energy sources increased 8%, mostly as a result of an increase in hydroelectric power generation. Hydro is the largest component of the group of renewable energy sources.

But oil will remain the largest of all energy sources in the US this year. Representing 40.2% of US energy demand, oil consumption in 2007 will total 41 quads. This is up 1.1% from last year, when oil demand contracted 0.3% on strong crude and product prices.

Natural gas consumption will be 22.67 quads, inching up from last year. In 2006, demand for gas in the US recorded a negligible decline.

Total US coal demand will be 23.1 quads this year, up 1.4%. Coal demand was stagnant last year, as total electric power plant demand for all forms of energy was little changed from 2005.

Nuclear energy demand in the US

OGJ FORECAST OF US SUPPLY AND DEMAND

	Year 2007 Volume 1,000 b/d	Year 2007 % change from 2006	Year [1]2006 Volume 1,000 b/d	Year [1]2006 % change from 2005
DOMESTIC DEMAND				
Motor gasoline	9,340	1.0	9,250	1.0
Dist. 1-4	7,687	1.0	7,613	1.0
Dist. 5	1,653	1.0	1,637	1.0
Jet fuel	1,640	0.6	1,630	–2.9
Dist. 1-4	1,157	0.6	1,150	–2.9
Dist. 5	483	0.6	480	–2.9
Distillate	4,250	1.0	4,210	2.2
Dist. 1-4	3,680	1.0	3,646	2.2
Dist. 5	570	1.0	564	2.2
Residual	740	7.2	690	–25.0
Dist. 1-4	619	7.2	577	–25.0
Dist. 5	121	7.2	113	–25.0
LPG and ethane	2,090	—	2,090	3.0
Dist. 1-4	2,034	—	2,034	3.0
Dist. 5	56	—	56	4.9
Other products	2,900	1.4	2,860	–1.2
Dist. 1-4	2,609	1.4	2,573	–1.2
Dist. 5	291	1.4	287	–1.6
TOTAL DOMESTIC DEMAND	**20,960**	**1.1**	**20,730**	**–0.3**
Dist. 1-4	17,786	1.1	17,593	–0.3
Dist. 5	3,174	1.2	3,137	–0.8
EXPORTS	**1,250**	**–5.2**	**1,318**	**13.1**
Dist. 1-4	989	–5.2	1,043	13.1
Dist. 5	261	–5.2	275	13.1
TOTAL DEMAND	**22,210**	**0.7**	**22,048**	**0.4**
Dist. 1-4	18,776	0.7	18,636	0.4
Dist. 5	3,434	0.7	3,412	0.2
SUPPLY				
DOMESTIC PRODUCTION				
Crude & condensate	5,250	1.8	5,155	–0.4
Dist. 1-4	3,659	1.8	3,593	–0.4
Dist. 5	1,591	1.8	1,562	–0.4
NGL and LRG[2]	1,775	1.7	1,745	1.6
Dist. 1-4	1,695	1.7	1,667	1.6
Dist. 5	80	1.7	78	1.6
Total domestic production	7,025	1.8	6,900	0.1
Dist. 1-4	5,355	1.8	5,260	0.2
Dist. 5	1,670	1.8	1,640	–0.3
IMPORTS				
Crude oil	10,150	0.3	10,120	–0.1
Dist. 1-4	9,090	0.3	9,064	–0.1
Dist. 5	1,060	0.3	1,056	–0.1
Products & unfinished oils	3,500	–0.7	3,525	–1.8
Dist. 1-4	3,241	–0.7	3,265	–1.8
Dist. 5	259	–0.7	260	–1.8
TOTAL IMPORTS	**13,650**	**0.0**	**13,645**	**–0.5**
Dist. 1-4	12,332	0.0	12,328	–0.5
Dist. 5	1,318	0.1	1,317	–0.4
Processing gain, loss, etc.	1,435	–6.6	1,536	44.1
Dist. 1-4	1,177	–6.6	1,259	44.1
Dist. 5	258	–6.6	277	44.1
TOTAL NEW SUPPLY	**22,110**	**0.1**	**22,081**	**1.9**
Dist. 1-4	18,863	0.1	18,847	1.8
Dist. 5	3,247	0.4	3,234	2.3
STOCK CHANGE	**(100)**	**—**	**33**	**—**
Dist. 1-4	88	—	212	—
Dist. 5	(188)	—	(179)	—
CRUDE RUNS TO STILLS	**15,400**	**1.0**	**15,245**	**0.2**
TOTAL INPUT TO STILLS	**15,700**	**0.8**	**15,570**	**–0.1**
TOTAL REFINING CAPACITY	**17,500**	**0.6**	**17,390**	**1.1**
REFINING UTILIZATION, %	**89.7**	**0.2**	**89.5**	**–1.2**
TOTAL INDUSTRY STOCKS[3]	**996**	**–2.8**	**1,025**	**1.2**
Refined products	676	–2.7	695	0.9
Crude oil	320	–3.0	330	1.9
SPR crude oil stocks	700	1.6	689	0.6
IMPORT DEPENDENCY				
Total imports % domestic demand	65.1		65.8	
Net imports % domestic demand	59.2		59.5	

[1]Preliminary estimate. [2]Liquefied refinery gases. [3]Million bbl at end of period.

will almost be unchanged from 2006 and will account for 8.1% of the energy mix. OGJ forecasts that nuclear demand this year will total 8.3 quads.

Oil supply

US oil production will increase to average 5.25 million b/d this year. Meanwhile, production of natural gas liquids and liquid refinery gases will move up 1.7% to average 1.775 million b/d.

US crude and condensate production last year averaged 5.155 million b/d, down from the 2005 average of 5.178 million b/d. NGL production last year grew 1.6%.

In 2006, declines in oil production in Alaska, Texas, and California overcame increases in crude and condensate production in Louisiana, New Mexico, and North Dakota.

Alaska's oil production decline last year was one of the largest in recent years, an estimated 11%. Average production in 2006 was 768,000 b/d. Production from the North Slope peaked in 1988, when Alaska's crude and condensate production averaged 2 million b/d.

Louisiana's oil production recovered somewhat last year following the hit it took from Hurricane Katrina. In 2005, Louisiana's output fell to an average 1.06 million b/d from 1.47 million b/d a year earlier. Last year, OGJ estimates that Louisiana's crude and condensate production averaged 1.22 million b/d.

Inventories

Volumes of crude and oil products in storage will finish 2007 lower than a year earlier. OGJ forecasts that at year-end the amount of crude in the Strategic Petroleum Reserve also will climb, reaching 700 million bbl.

Total industry stocks of crude and products will decline almost 3% this year. Crude in industry stocks will be 320 million bbl, and products will total 676 million bbl.

Inventories of crude and products ended 2006 near their end-2005 levels, with total stocks staying above normal throughout the year. Crude stocks increased to 330 million bbl last year from 324 million bbl, and product stocks were up about 1% to 695 million bbl.

Refining

Processing at refineries will remain strong in 2007, with throughputs, operable capacity, and utilization up a bit from last year.

US NATURAL GAS SUPPLY AND DEMAND

	2004	2005	2006	Change, % 06/05	2007	Change, % 07/06
	bcf				bcf	
Production						
Texas	5,067	5,255	5,550	5.6	5,650	1.8
Louisiana	1,353	1,296	1,380	6.5	1,400	1.4
Federal Gulf of Mexico	3,969	3,151	3,060	–2.9	3,150	2.9
Other states	9,128	9,249	9,410	1.7	9,520	1.2
Total production	**19,517**	**18,951**	**19,400**	**2.4**	**19,720**	**1.6**
Imports						
Canada	3,607	3,700	3,550	–4.1	3,200	–9.9
Mexico	0	9	3	–66.7	3	—
LNG	652	631	568	–10.0	570	0.4
Total imports	**4,259**	**4,341**	**4,121**	**–5.1**	**3,773**	**–8.4**
Supplemental gas	60	64	62	–3.1	65	4.8
Losses, etc.*	–479	–437	–390	–10.8	–470	20.5
Total new supply	**23,357**	**22,919**	**23,193**	**1.2**	**23,088**	**–0.5**
Supply from storage	–114	51	–300	—	100	—
Total supply	**23,243**	**22,970**	**22,893**	**–0.3**	**23,188**	**1.3**
Exports	854	729	680	–6.7	900	32.4
Total consumption	**22,389**	**22,241**	**22,213**	**–0.1**	**22,288**	**0.3**

*Extraction losses and unaccounted-for gas.
Sources: 2004 and 2005 EIA; 2006 and 2007 OGJ estimates and forecast

OIL, GAS, PRODUCTS PRICES

	Crude oil		Products		Natural gas	
Year	Average US wellhead price	Average landed cost of imports	Unleaded gasoline pump price	No. 2 fuel oil wholesale price	Average US wellhead price	Average delivered commercial price
	$/bbl		¢/gal		$/Mcf	
1976	8.19	13.32	61.4	NA	0.58	1.64
1977	8.57	14.36	65.6	NA	0.79	2.04
1978	9.00	14.35	67.0	36.9	0.91	2.23
1979	12.64	21.45	90.3	56.9	1.18	2.73
1980	21.59	33.67	124.5	80.3	1.59	3.39
1981	31.77	36.47	137.8	97.6	1.98	4.00
1982	28.52	33.18	129.6	91.4	2.46	4.82
1983	26.19	28.93	124.1	81.5	2.59	5.59
1984	25.88	28.54	121.2	82.1	2.66	5.55
1985	24.09	26.67	120.2	77.6	2.51	5.50
1986	12.51	13.49	92.7	48.6	1.94	5.08
1987	15.40	17.65	94.8	52.7	1.67	4.77
1988	12.58	14.08	94.6	47.3	1.69	4.63
1989	15.86	17.68	102.1	56.5	1.69	4.74
1990	20.03	21.13	116.4	69.7	1.71	4.83
1991	16.54	18.02	114.0	62.2	1.64	4.81
1992	15.99	17.75	112.7	57.9	1.74	4.88
1993	14.25	15.72	110.8	54.4	2.04	5.22
1994	13.19	15.18	111.2	50.6	1.85	5.44
1995	14.62	16.78	114.7	51.1	1.55	5.05
1996	18.46	20.31	123.1	63.9	2.17	5.40
1997	17.23	18.11	123.4	59.0	2.32	5.80
1998	10.88	11.84	105.9	42.2	1.96	5.48
1999	15.56	17.23	116.5	49.3	2.19	5.33
2000	26.72	27.53	151.0	88.6	3.68	6.59
2001	21.84	21.82	146.1	75.6	4.00	8.43
2002	22.51	23.91	135.8	69.4	2.95	6.63
2003	27.56	27.69	159.1	88.1	4.88	8.40
2004	36.77	36.07	188.0	112.5	5.46	9.41
2005	50.28	49.29	229.5	162.3	7.51	11.42
*2006	60.00	59.00	258.0	185.0	6.60	11.65

*Estimated.
Sources: 1976-2005 US Energy Information Administration; 2005 OGJ estimates

US PRODUCTION OF CRUDE OIL AND LEASE CONDENSATE

	[1]2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	Cumulative 1859-2006 1,000 bbl
	1,000 b/d										
District 1:											
Fla., NY, Pa., W.Va.	22	23	19	20	20	20	21	22	26	26	2,786,235
Total Dist. 1	**22**	**23**	**19**	**20**	**20**	**20**	**21**	**22**	**26**	**26**	**2,786,235**
District 2:											
Illinois	28	28	30	32	34	28	33	33	38	44	3,611,721
Indiana	5	5	5	5	5	6	6	5	6	7	553,506
Kansas	96	93	93	93	86	93	94	80	97	109	6,298,002
Kentucky	7	7	7	7	8	8	9	8	8	8	777,547
Michigan	15	15	18	18	24	20	22	21	25	28	1,258,489
Nebraska	6	7	7	8	8	8	8	7	9	9	501,094
North Dakota	107	98	85	81	85	87	89	90	97	98	1,529,783
Ohio	16	15	16	15	20	17	18	16	18	24	1,108,834
Oklahoma	173	170	171	179	183	188	192	193	213	228	14,532,550
Others[2]	5	5	4	4	3	4	4	4	4	5	65,435
Total Dist. 2	**460**	**443**	**436**	**442**	**456**	**459**	**475**	**457**	**515**	**560**	**30,237,691**
District 3:											
Alabama	21	22	20	22	24	26	29	30	34	41	638,396
Arkansas	16	17	18	20	21	21	20	20	22	23	1,775,595
Louisiana	1,220	1,061	1,470	1,562	1538	1,620	1,534	1,513	1,432	1,339	28,877,051
Mississippi	48	48	47	45	51	54	54	49	60	58	2,313,885
New Mexico	260	166	176	181	183	186	184	176	198	191	5,313,157
Texas	1,308	1,489	1285	1,356	1418	1,364	1,394	1,400	1,547	1,628	61,869,840
Total Dist. 3	**2,873**	**2,803**	**3,016**	**3,186**	**3,235**	**3,271**	**3,215**	**3,188**	**3,293**	**3,280**	**100,787,924**
District 4:											
Colorado	61	63	60	58	40	45	50	51	61	70	1,953,183
Montana	98	90	68	53	43	44	42	41	45	43	1,590,781
Utah	47	46	40	36	41	42	43	45	53	53	1,300,658
Wyoming	139	141	141	144	153	157	166	167	178	192	6,905,765
Total Dist. 4	**345**	**340**	**309**	**291**	**277**	**288**	**301**	**304**	**337**	**358**	**11,750,387**
District 5:											
Alaska	768	864	908	974	988	963	971	1,050	1,175	1,296	15,845,034
California	686	704	730	767	797	799	837	857	904	929	27,438,434
Nevada	1	1	1	1	2	2	2	2	2	3	51,456
Total Dist. 5	**1,455**	**1,569**	**1,639**	**1,742**	**1,787**	**1,764**	**1,810**	**1,909**	**2,081**	**2,228**	**43,334,924**
US total	**5,155**	**5,178**	**5,419**	**5,681**	**5,775**	**5,802**	**5,822**	**5,880**	**6,252**	**6,452**	**188,897,161**

[1]Preliminary. [2]Includes Missouri, South Dakota, and Tennessee.

OGJ expects US refining capacity to increase marginally to 17.5 million b/d this year. Total inputs will average 15.7 million b/d, resulting in 89.7% utilization.

For 2006, the utilization rate declined to 89.5% from 90.6% a year earlier. That drop was caused by refinery and pipeline outages in the first half of 2006 following Hurricanes Katrina and Rita in 2005.

Average refining margins generally were strong last year compared with 2005, although the average East Coast margin declined 11% from year to year, according to Muse, Stancil & Co. The West Coast refining margin remained the strongest, averaging $24.57/bbl and gaining 17% for the year.

Average refiner acquisition prices for crude were up 22% last year. The average domestic and imported cost of crude for US refiners was $61.36/bbl, according to EIA. But pump prices last year climbed, too, up 12% on average for regular unleaded gasoline.

Oil imports

Total US imports of crude and products will be unchanged this year. Product imports will decline by a small margin, and crude imports will rise by an even smaller amount.

In 2006, total imports declined 0.5% from their all-time high of an average 13.714 million b/d a year earlier. When US refining activity was curtailed following the hurricanes, the US imported products to meet demand.

Product imports soared above 4.7 million b/d in October 2005, compared with imports of 3.1 million b/d a year earlier. By October 2006, product imports had returned to a more typical average of 3.05 million b/d, according to estimates by the US Energy Information Administration.

With this year's total imports of crude and products averaging 13.65 million b/d, US import dependency will be 65.1%, a small decline from the past 2 years' dependency levels.

At press time EIA's import data by country was available through September 2006. These figures show that for the first 9 months of last year, the leading source of US crude imports was

SUPPLY AND DEMAND FOR CRUDE IN THE US

	[1]2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
					1,000 b/d					
SUPPLY										
Crude imports[2]	10,120	10,126	10,088	9,665	9,140	9,328	9,071	8,731	8,706	8,225
Crude production	5,155	5,178	5,419	5,681	5,746	5,801	5,822	5,881	6,252	6,452
Unaccounted for crude	20	76	143	54	110	117	155	191	115	145
Total supply	**15,295**	**15,380**	**15,650**	**15,400**	**14,996**	**15,246**	**15,048**	**14,803**	**15,073**	**14,822**
DEMAND										
Crude refinery runs	15,245	15,220	15,475	15,304	14,947	15,128	15,067	14,804	14,889	14,662
Crude used directly and loss	—	—	—	—	—	—	—	—	—	2
Crude exports	23	32	27	12	9	20	50	118	110	108
Crude into SPR	11	25	102	108	134	26	-73	–11	22	–7
Total demand	**15,279**	**15,277**	**15,604**	**15,424**	**15,090**	**15,174**	**15,044**	**14,911**	**15,021**	**14,765**
Crude stock change (industry)	16	103	46	–24	–94	72	4	–108	52	57
Primary (industry)	330	324	286	269	278	312	286	284	324	305
SPR[3]	695	685	676	638	599	550	541	567	571	563
Total crude stocks (million bbl)	**1,025**	**1,009**	**962**	**907**	**877**	**862**	**827**	**851**	**895**	**868**

[1]Preliminary. [2]Includes imports for the Strategic Petroleum Reserve. [3]Includes Alaskan crude in transit.

US ENERGY CONSUMPTION AND EFFICIENCY

Year	GDP, billion 2000 $	Energy consumption, trillion btu	Energy consumption per GDP, 2000 $ (Mbtu)	Oil energy consumption, trillion btu	Oil energy consumption per GDP, 2000 $ (Mbtu)	Natural gas energy consumption, trillion btu	Natural gas energy consumption per GDP, 2000 $ (Mbtu)	Total oil and natural gas energy consumption, trillion btu	Total oil and gas energy consumption per GDP, 2000 $ (Mbtu)	Oil and natural gas energy % of total energy
1973	4,341.5	75,808	17.5	34,840	8.0	22,512	5.2	57,352	13.2	75.7
1974	4,319.6	73,991	17.1	33,455	7.7	21,732	5.0	55,187	12.8	74.6
1975	4,311.2	71,999	16.7	32,731	7.6	19,948	4.6	52,679	12.2	73.2
1976	4,540.9	76,012	16.7	35,175	7.7	20,345	4.5	55,520	12.2	73.0
1977	4,750.5	78,000	16.4	37,122	7.8	19,931	4.2	57,053	12.0	73.1
1978	5,015.0	79,986	15.9	37,965	7.6	20,000	4.0	57,965	11.6	72.5
1979	5,173.4	80,903	15.6	37,123	7.2	20,666	4.0	57,789	11.2	71.4
1980	5,161.7	78,289	15.2	34,202	6.6	20,394	4.0	54,596	10.6	69.7
1981	5,291.7	76,335	14.4	31,931	6.0	19,928	3.8	51,859	9.8	67.9
1982	5,189.3	73,234	14.1	30,231	5.8	18,505	3.6	48,736	9.4	66.5
1983	5,423.8	73,066	13.5	30,054	5.5	17,357	3.2	47,411	8.7	64.9
1984	5,813.6	76,693	13.2	31,051	5.3	18,507	3.2	49,558	8.5	64.6
1985	6,053.7	76,417	12.6	30,922	5.1	17,834	2.9	48,756	8.1	63.8
1986	6,263.6	76,722	12.2	32,196	5.1	16,708	2.7	48,904	7.8	63.7
1987	6,475.1	79,156	12.2	32,865	5.1	17,744	2.7	50,609	7.8	63.9
1988	6,742.7	82,774	12.3	34,222	5.1	18,552	2.8	52,774	7.8	63.8
1989	6,981.4	84,886	12.2	34,211	4.9	19,712	2.8	53,923	7.7	63.5
1990	7,112.5	84,605	11.9	33,553	4.7	19,730	2.8	53,283	7.5	63.0
1991	7,100.5	84,522	11.9	32,845	4.6	20,149	2.8	52,994	7.5	62.7
1992	7,336.6	85,866	11.7	33,527	4.6	20,835	2.8	54,362	7.4	63.3
1993	7,532.7	87,579	11.6	33,841	4.5	21,351	2.8	55,192	7.3	63.0
1994	7,835.5	89,248	11.4	34,670	4.4	21,842	2.8	56,512	7.2	63.3
1995	8,031.7	91,200	11.4	34,553	4.3	22,784	2.8	57,337	7.1	62.9
1996	8,328.9	92,446	11.1	35,757	4.3	23,197	2.8	58,954	7.1	63.8
1997	8,703.5	94,800	10.9	36,266	4.2	23,328	2.7	59,594	6.8	62.9
1998	9,066.9	95,200	10.5	36,934	4.1	22,936	2.5	59,870	6.6	62.9
1999	9,470.3	96,837	10.2	37,960	4.0	23,010	2.4	60,970	6.4	63.0
2000	9,817.0	98,976	10.1	38,404	3.9	23,916	2.4	62,320	6.3	63.0
2001	9,890.7	96,453	9.8	38,333	3.9	22,861	2.3	61,194	6.2	63.4
2002	10,048.8	97,967	9.7	38,401	3.8	23,628	2.4	62,029	6.2	63.3
2003	10,301.0	98,273	9.5	39,047	3.8	22,967	2.2	62,014	6.0	63.1
2004	10,703.5	100,415	9.4	40,594	3.8	23,036	2.2	63,630	5.9	63.4
2005	11,048.6	100,358	9.1	40,735	3.7	22,636	2.0	63,371	5.7	63.1
[1]2006	11,400.0	100,805	8.8	40,600	3.6	22,610	2.0	63,210	5.5	62.7
[2]2007	11,650.0	101,950	8.8	41,030	3.5	22,670	1.9	63,700	5.5	62.5

[1]Estimated. [2]Forecast.
Source: US Energy Information Administration

Canada. Mexico, Saudi Arabia, Venezuela, and Nigeria were the next largest sources of US crude imports.

Canada also was the leading source of US product imports for the first 9 months of 2006. Other top suppliers of products to the US last year were the US Virgin Islands, Algeria, Venezuela, and Russia.

Oil demand

A weather-driven reduction in demand this month led to a drop in futures prices for crude. In the first two trading days of 2007, the front-month

Crude imports by country of origin[1]

	[2]2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
	1,000 b/d									
Algeria[3]	369	228	215	112	30	11	1	25	10	6
Angola	529	456	306	363	321	321	295	357	465	425
Australia	2	10	21	27	51	34	49	31	31	31
Canada	1,723	1,633	1,616	1,549	1,445	1,356	1,348	1,178	1,266	1,198
China	29	24	14	13	20	13	33	13	42	48
Colombia	161	156	142	166	235	260	318	452	349	270
Congo, Republic of	0	0	14	2	23	1	8	2	17	21
Congo	31	25	8	27	3	40	42	46	53	47
Ecuador	279	276	232	139	100	113	125	114	98	114
Gabon	63	127	142	131	143	140	143	168	207	230
Indonesia[3]	12	19	34	26	50	40	36	70	50	51
Iran[3]	0	0	0	0	0	0	0	0	0	0
Iraq[3]	582	527	655	481	459	795	620	725	336	89
Kuwait[3]	178	227	241	208	216	237	263	246	300	253
Malaysia	5	10	18	21	9	15	29	21	26	8
Mexico	1,562	1,556	1,598	1,569	1,500	1,394	1,313	1,254	1,321	1,360
Nigeria[3]	1,019	1,077	1,078	832	589	842	875	623	689	689
Norway	90	119	143	181	348	281	302	263	221	288
Oman	37	22	10	35	17	20	2	0	0	4
Qatar[3]	1	0	4	0	9	0	0	1	1	0
Saudi Arabia[3]	1,428	1,445	1,495	1,726	1,519	1,611	1,523	1,387	1,404	1,293
Trinidad & Tobago	70	64	49	67	68	51	56	40	53	56
United Arab Emirates[3]	12	9	5	10	10	21	3	0	3	0
United Kingdom	132	224	238	359	405	244	291	284	161	169
Venezuela[3]	1,130	1,241	1,297	1,183	1,201	1,291	1,223	1,150	1,377	1,394
Others	676	651	513	438	369	197	173	281	226	181
Total imports	**10,120**	**10,126**	**10,088**	**9,665**	**9,140**	**9,328**	**9,071**	**8,731**	**8,706**	**8,225**
Total from OPEC	**4,732**	**4,757**	**5,042**	**4,578**	**4,083**	**4,848**	**4,544**	**4,228**	**4,169**	**3,775**

[1]Includes imports for the Strategic Petroleum Reserve. [2]Preliminary. [3]OPEC member.

Exports of refined products and crude

	*2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
	1,000 b/d									
Gasoline	131	136	124	125	124	133	144	111	125	137
Distillate	251	138	110	107	112	119	173	162	124	152
Residual	277	251	205	197	177	191	139	129	138	120
Lubricants	72	40	41	37	33	26	26	28	25	31
Coke	337	347	350	361	337	336	319	242	267	306
Asphalt and road oil	14	11	6	10	6	5	6	5	7	8
LPG	51	53	43	56	67	44	74	50	42	50
Other refined products	163	158	142	122	119	97	109	95	107	91
Total refined products	1,295	1,134	1,021	1,015	975	951	990	822	835	895
Crude	23	32	27	12	9	20	50	118	110	108
Total exports	**1,318**	**1,165**	**1,048**	**1,027**	**984**	**971**	**1,040**	**940**	**945**	**1,003**

*Preliminary.

delivery price for oil on the New York Mercantile Exchange plunged more than $5/bbl.

In 2006, average oil prices were strong on the expectation of continued worldwide demand growth and limited spare production capacity. The average US landed cost of imported crude was an estimated $59/bbl last year, an annual increase of 20%.

In the US this year, demand for oil products will increase 1.1%, with consumption of each product type growing or being unchanged from 2006.

Total US demand for oil products will average 20.96 million b/d this year. US exports of products and crude oil will decline 5% to 1.25 million b/d, bringing total demand for oil in the US to 22.21 million b/d.

Last year demand for motor gasoline, distillate, liquefied petroleum gas, and ethane increased, but demand for jet fuel, residual fuel oil, and other products declined, resulting in a small overall decline for oil product demand.

Consumption of these products depends on economic growth, travel, weather, fuel-switching capabilities, petrochemical production, and transport. A factor gaining importance is the growth of ethanol in the US energy mix.

Distillate

Demand for distillate will increase 1% this year. With heating-oil demand unchanged from last year due to mild weather, all distillate demand growth will be the result of increased demand for diesel fuel.

This growth in diesel demand is spurred by the need to transport more ethanol to US gasoline outlets. The ethanol, used as an oxygenate and volume extender in gasoline, needs to move to markets from many plants, mostly located in the Midwest.

Because ethanol is not transportable with gasoline via pipeline,

IMPORTS OF REFINED PRODUCTS

	[1]2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
	1,000 b/d									
Gasoline	462	603	496	518	498	454	427	382	311	309
Kerosene	6	7	2	6	5	5	2	1	1	2
Jet fuel-kerosene	187	190	127	109	107	148	162	128	124	91
Distillate	374	329	325	333	267	344	295	250	210	228
Residual	429	530	426	327	249	295	352	237	275	194
Unfinished oils	672	582	490	335	410	378	274	317	302	353
Other[2]	1,395	1,346	1,191	971	854	920	877	806	779	759
Total US	**3,525**	**3,587**	**3,057**	**2,599**	**2,390**	**2,543**	**2,389**	**2,121**	**2,002**	**1,936**

[1]Preliminary. [2]Includes plant condensate.

ROTARY RIG ACTIVITY BY STATES

	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
Alabama	4.6	3.6	2.5	2.4	3.0	5.3	4.1	5.5	6.0	3.7
Alaska	8.0	9.3	9.9	9.7	11.2	13.4	8.2	5.0	12.0	10.9
Arizona	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0
Arkansas	24.0	9.3	6.4	2.1	0.8	1.5	3.9	2.5	6.2	9.8
California	33.3	27.2	23.9	21.1	22.3	36.4	24.1	19.0	27.9	31.7
Land	29.3	23.0	20.4	17.9	19.7	32.5	20.7	17.4	26.1	28.6
Offshore	4.0	4.2	3.5	3.2	2.6	3.9	3.4	1.6	1.8	3.1
Colorado	88.5	73.9	54.2	38.8	27.8	32.3	18.4	12.5	12.8	16.3
Florida	0.3	1.6	1.1	0.7	0.2	0.4	0.2	0.2	0.1	0.4
Idaho	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Illinois	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Indiana	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.1
Kansas	9.6	6.7	6.7	8.7	7.5	22.4	22.0	7.4	13.2	19.0
Kentucky	7.2	4.7	4.4	4.3	4.8	6.4	4.9	5.5	2.4	4.8
Louisiana	188.4	182.1	166.8	157.2	162.8	213.8	194.4	141.1	187.4	193.1
North	57.5	48.4	39.3	28.5	23.2	30.3	24.1	16.2	18.9	20.7
Inland waters	19.2	22.8	18.2	14.3	16.3	20.4	15.8	15.5	21.4	23.2
South	38.5	32.5	30.3	29.6	31.6	44.1	36.7	21.1	40.8	47.8
Offshore	73.2	78.4	79.1	84.8	91.7	119.0	117.9	88.3	106.4	101.4
Michigan	2.2	2.6	3.0	3.1	1.3	1.2	2.4	2.1	5.4	6.2
Mississippi	10.3	10.3	9.8	8.0	7.6	14.2	11.2	7.4	14.0	13.3
Montana	21.3	24.0	19.9	14.0	7.9	10.0	6.5	4.3	8.6	10.8
Nebraska	0.0	0.0	0.8	0.0	0.1	0.2	0.6	0.3	0.5	0.9
Nevada	1.3	1.9	1.5	1.2	0.0	0.0	0.0	0.0	0.0	0.2
New Mexico	93.8	82.8	67.2	64.4	41.5	68.2	67.9	36.0	44.7	52.5
New York	6.4	4.3	4.9	2.8	4.3	5.4	3.3	2.5	2.2	0.4
North Dakota	31.5	20.4	15.0	13.7	10.1	14.3	13.4	5.9	11.2	18.1
Ohio	7.5	9.2	6.7	7.4	8.7	9.6	8.5	10.5	10.1	8.8
Oklahoma	178.7	152.1	158.8	128.2	90.8	130.2	99.4	61.9	84.9	103.4
Pennsylvania	15.7	13.2	8.9	10.1	10.3	10.6	8.7	7.8	10.9	9.7
South Dakota	1.1	2.0	0.5	0.2	0.2	0.6	0.2	0.5	0.1	0.8
Texas	746.4	614.7	505.9	448.5	337.5	462.5	343.4	227.1	302.3	357.4
Gulf Coast	170.3	184.6	156.1	153.0	134.3	168.1	127.1	50.0	63.4	64.7
Offshore & inland waters	14.8	10.5	14.1	20.2	16.2	26.4	16.6	13.8	11.5	15.6
North	33.5	31.8	37.4	39.4	30.1	27.4	14.5	10.5	10.5	12.1
Panhandle	68.2	62.5	47.5	26.0	14.6	21.0	16.7	13.7	20.8	24.8
East	243.3	172.5	131.2	107.2	68.1	106.1	78.0	38.9	54.7	62.7
West Central	79.0	53.0	45.3	28.4	21.9	31.7	17.4	50.1	72.9	68.3
West	137.5	100.0	74.2	74.2	52.5	81.6	73.1	50.1	68.5	109.3
Utah	40.2	27.7	21.5	13.4	13.1	20.8	15.5	8.8	12.5	13.6
West Virginia	26.5	17.4	15.1	15.5	13.2	18.1	14.1	13.7	14.3	14.5
Wyoming	99.0	78.5	73.6	53.6	40.2	55.0	41.0	31.8	38.6	39.3
Others	2.6	3.6	1.5	1.2	2.2	3.6	2.0	5.7	2.6	3.1
Total US	**1,648.7**	**1,383.1**	**1,190.5**	**1,030.3**	**830.2**	**1,156.4**	**918.3**	**624.9**	**830.6**	**943.5**
Land	1,536.6	1,265.9	1,074.0	905.6	699.9	981.4	761.2	502.0	684.7	797.7
Inland waters	22.2	23.7	19.4	16.8	17.7	21.9	17.3	16.6	22.1	24.0
Offshore	89.9	93.4	97.0	107.9	112.6	153.1	139.8	106.3	123.9	121.8
Canada—land	466.5	454.3	361.1	369.8	259.5	336.3	339.7	240.1	255.9	372.7
Canada—offshore	3.6	3.8	3.9	3.8	6.1	5.2	4.7	5.2	3.6	1.3
Grand total	**2,118.8**	**1,841.2**	**1,555.5**	**1,403.9**	**1,095.8**	**1,497.9**	**1,262.7**	**870.1**	**1,090.2**	**1,317.5**

Source: Baker Hughes Inc. Note: May not add due to independent rounding.

suppliers must use railroads cars or trucks, which now are required to use ultralow-sulfur diesel.

For the first 9 months of 2006, the average wholesale price for diesel was $2.058/gal. Diesel prices have climbed every year since 2002, when the No. 2 diesel fuel wholesale price averaged 72.4¢/gal.

Motor gasoline

Motor gasoline demand will grow 1% this year, too, the same pace at which it grew in 2006, as pump prices of gasoline have moderated from their

MARKETED NATURAL GAS PRODUCTION[1]

	[2]2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
	MMcfd									
Alabama	806	812	863	970	976	978	993	1,046	1,545	1,598
Alaska	1,311	1,335	1,289	1,305	1,269	1,292	1,254	1,268	1,278	1,283
California	889	870	874	931	987	1,035	1,032	1,049	864	783
Colorado	3,226	3,104	2,949	2,618	2,306	2,239	2,057	1,980	1,908	1,746
Kansas	998	1,034	1,085	1,150	1,246	1,315	1,440	1,516	1,654	1,883
Louisiana	3,845	3,551	3,697	3,760	3,731	4,115	3,975	4,293	14,487	14,328
Michigan	894	715	710	653	752	754	810	760	762	838
Mississippi	465	145	173	373	310	295	242	304	296	294
New Mexico	4,344	4,507	4,460	4,234	4,471	4,628	4,645	4,142	4,113	4,270
Oklahoma	4,822	4,576	4,524	4,572	4,250	4,426	4,419	4,367	4,506	4,668
Texas	15,148	14,397	13,845	14,460	14,085	14,473	14,432	13,848	17,312	17,682
Wyoming	4,666	4,491	4,350	4,125	3,983	3,737	2,974	2,661	2,086	2,023
Federal offshore	8,233	8,632	10,845	12,263	12,804	13,774	13,482	13,780	—	—
Others	4,600	3,750	3,660	3,463	3,408	3,297	3,429	3,246	3,014	3,031
Total	**54,247**	**51,920**	**53,326**	**54,877**	**54,578**	**56,357**	**55,184**	**54,260**	**53,823**	**54,428**
Volume change	2,327	–1,407	–1,550	299	–1,779	1,173	925	436	–604	296
Percent change	4.5	–2.6	–3	1	–3	2	2	1	–1	1
Imports	11,290	11,893	11,635	10,164	10,979	10,896	10,332	9,823	8,636	8,203
Exports	1,863	1,996	2,334	1,644	1,414	1,023	666	448	436	430

[1]Includes nonhydrocarbon gases. [2]Preliminary.

REFINERY RUNS BY DISTRICTS

	2006 Crude runs[1]	2006 Input to crude stills[1]	2006 % of operable capacity	Crude runs 2005	2004	2003	2002	2001	2000	1999	1998	1997
	1,000 b/d			1,000 b/d								
East Coast	1,395	1,380	85.2	1533.8	1,508	1,516	1,455	1,413	1,485	1,456	1,480	1,394
Appalachian Dist. 1	92	91	96.1	93.1	89	88	85	86	86	92	89	89
Total Dist. 1	**1,487**	**1,471**	**85.8**	**1,627**	**1,597**	**1,605**	**1,541**	**1,499**	**1,571**	**1,548**	**1,569**	**1,483**
Ill., Ind., Ky.[2]	2,180	2,181	92.6	2,143	2,157	2,107	2,108	2,165	2,239	2,232	2,263	2,256
Minn., Wisc., Daks.	415	409	92.5	420	403	395	701	414	422	392	424	424
Okla., Kan., Mo.	733	740	94.1	735	729	710	701	724	712	706	684	670
Total Dist. 2	**3,328**	**3,330**	**92.9**	**3,298**	**3,288**	**3,212**	**3,511**	**3,303**	**3,373**	**3,330**	**3,371**	**3,350**
Texas:												
Inland	611	622	95.6	579	604	572	554	574	573	557	582	589
Gulf Coast	3,468	3,493	86.6	3,489	3,682	3,652	3,475	3,549	3,455	3,383	3,490	3,311
Louisiana Gulf	2,852	2,921	88.4	2,751	2,906	2,872	2,848	2,922	2,843	2,793	2,608	2,679
N. La., Ark.	197	187	85.9	186	151	156	148	154	178	188	184	179
New Mexico	92	93	82.0	95	94	81	84	79	90	90	92	87
Total Dist. 3	**7,220**	**7,315**	**87.9**	**7,098**	**7,438**	**7,332**	**7,109**	**7,278**	**7,139**	**7,012**	**6,957**	**6,845**
Total Dist. 4	**555**	**555**	**92.9**	**558**	**556**	**528**	**520**	**500**	**505**	**498**	**480**	**479**
Total Dist. 5	**2,655**	**2,899**	**91.3**	**2,638**	**2,596**	**2,627**	**2,567**	**2,547**	**2,479**	**2,416**	**2,512**	**2,505**
Total US	**15,245**	**15,570**	**89.5**	**15,220**	**15,475**	**15,304**	**15,247**	**15,128**	**15,067**	**14,804**	**14,889**	**14,662**

[1]Preliminary. [2]Includes Appalachian Dist. 2.

summer 2006 highs.

OGJ estimates that the pump price for regular unleaded gasoline in the US averaged $2.58/gal last year. The average monthly price peaked at $2.999/gal for July, according to EIA. For November the average price had dipped to $2.241/gal.

Preliminary EIA data for 2005 indicate an improvement in passenger-car fuel-consumption mileage to 22.9 mpg. The rate for vans, pickup trucks, and sport utility vehicles remained at 16.2 mpg, its level of the prior 2 years, which was down from 17.5 mpg in 2002.

Jet fuel

OGJ forecasts that US demand for jet fuel in 2007 will average 1.64 million b/d, up from 1.63 million b/d last year. The small change is due to consolidation in the airline industry and greater efficiencies in passenger travel, as well as moderate economic growth. In 2005, jet fuel demand averaged 1.68 million b/d.

US airlines carried 561.9 million scheduled domestic and international passengers on their systems during the first 9 months of 2006, up just 0.3% from the same period in 2005, the US Department of Transportation's Bureau of Transportation Statistics (BTS) reported.

BTS said US airlines carried 0.4% fewer domestic passengers and 5.6% more international passengers during the first 9 months of 2006 than during the same 2005 period.

US carriers operated 4.2% fewer do-

US REFINED PRODUCTS, NATURAL GAS LIQUIDS, AND CRUDE STOCKS

	[1]2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
	1,000 bbl									
Gasoline[2]	174,072	209,735	219,081	208,167	210,609	211,465	197,429	195,142	217,696	211,623
Motor[3]	172,935	208,328	217,601	206,827	209,096	209,851	195,852	193,327	215,639	209,775
Aviation[3]	1,137	1,407	1,480	1,340	1,513	1,614	1,577	1,815	2,057	1,848
Special naphthas	1,473	1,524	1,800	2,006	2,038	2,006	2,112	2,351	2,207	2,171
Kerosene	3,125	5,092	4,885	5,584	5,463	5,388	4,107	4,871	6,943	7,294
Distillate	131,690	136,022	126,272	136,542	134,085	144,513	118,027	125,463	156,075	138,427
Residual	41,081	37,387	42,363	37,800	31,333	41,047	36,200	35,830	44,909	40,462
Kerosine jet fuel	40,072	41,741	40,086	38,767	39,123	41,871	44,409	40,447	44,660	44,009
Naphtha jet fuel	—	—	—	17	56	82	109	54	34	34
Natural gas liquids & LRG	120,121	118,206	111,085	100,889	113,285	128,272	87,722	94,721	123,760	95,196
Unfinished oils	88,041	85,723	81,380	75,904	75,766	87,700	84,217	86,254	90,836	88,755
Other refined products	95,325	53,926	56,512	55,364	59,447	61,784	67,030	56,075	64,907	63,669
Total products stocks	**695,000**	**689,356**	**683,464**	**661,040**	**671,205**	**724,128**	**641,362**	**641,208**	**752,027**	**691,640**
Crude stocks (ex. SPR)	**330,000**	**323,704**	**285,741**	**268,875**	**277,614**	**311,980**	**285,507**	**284,482**	**323,543**	**304,690**
Total stocks (ex. SPR)	**1,025,000**	**1,013,060**	**969,205**	**929,915**	**948,819**	**1,036,108**	**926,869**	**925,690**	**1,075,570**	**996,330**
SPR stocks	**689,000**	**684,544**	**675,600**	**638,388**	**599,091**	**550,241**	**540,678**	**567,241**	**571,405**	**563,429**
Total stocks (incl. SPR)	**1,714,000**	**1,697,604**	**1,644,805**	**1,568,303**	**1,547,910**	**1,586,349**	**1,467,547**	**1,492,931**	**1,646,975**	**1,559,759**

[1]Preliminary. [2]Beginning in 1993, includes reformulated, oxygenated, and other finished gasoline. [3]Includes blending components.

mestic flights during the first 9 months of last year than during the same period in 2005, while international flights were up 2.8%, BTS reported.

Residual fuel oil

Demand for residual fuel oil will rebound this year following a large, price-driven decline in 2006. Natural gas had a price advantage to resid last year, so power producers took advantage of available fuel-switching capabilities.

OGJ forecasts that resid consumption will average 740,000 b/d this year, up from 690,000 b/d last year.

The average retail price of resid excluding tax was just 53.1¢/gal in 2001 but has climbed each year since then with the price of crude oil. In 2005, the retail price of resid averaged $1.048/gal, while demand was 920,000 b/d. Through the first 9 months of 2006, the price averaged $1.263/gal.

LPG, ethane, other

OGJ expects consumption of liquefied petroleum gases to be unchanged this year from 2005, when demand averaged 2.09 million b/d.

Growth in demand for these products has been dampened by reduced petrochemical production in the US, as well as higher prices. Demand peaked in 2000, averaging 2.23 million b/d.

Demand for all other petroleum products, including ethanol and other gasoline blending components, will increase this year to average 2.9 million b/d.

Consumption of these products declined 1.2% last year, averaging 2.86 million b/d. The category also includes products used in construction and as feedstocks in plants that were damaged by Hurricanes Katrina and Rita in 2005.

Natural gas

OGJ forecasts that US production and consumption of natural gas will grow modestly in 2007.

Warmer-than-normal weather in the first quarter of 2007 will put a ceiling on demand, leaving plenty of gas in storage as production climbs.

Offshore gas production from federal waters of the Gulf of Mexico will lead growth in US production this year. OGJ expects total US marketed production to be up 1.6% from 2006. New producing fields will slightly outpace decline rates.

Gulf of Mexico production will climb almost 3% this year. Gulf marketed production declined 2.9% last year as a result of lingering damage to production facilities and pipelines sustained during the 2005 hurricane season.

Production in Texas and Louisiana will increase, though less than during 2006. And gas output from all other states this year will record a collective increase of 1.2%.

Through the first half of 2006, production was down in Alabama, Alaska, Florida, Kansas, New Mexico, and the federal offshore area. But big increases in production were posted in Texas, Wyoming, Oklahoma, Montana, Mississippi, and others to offset those declines.

The volume of working gas in underground storage held above the previous 5-year range throughout 2006, limiting the amount of gas that the US needed to import.

US imports of gas this year will be off 8.4%, OGJ forecasts. The decline will be the result of a 10% drop in gas imported from Canada. Imports from Canada will total 3.2 tcf this year as an increasing amount of that country's gas is needed for the production and processing of heavy oil and oil sands.

LNG imports will total 570 tcf this year, little changed from a year ago. US LNG imports plunged 10% in 2006.

US gas exports this year will increase to 900 bcf following last year's decline to 680 bcf from 729 bcf in 2005.

OGJ forecasts that US consumption of gas this year will total 22.288 tcf, up 0.3% from last year.

While the amount of gas consumed in the US over the past few years has been fairly steady, there has been a shift in demand by type of consumer. Since 2003, the volume of gas consumed by electric power plants has increased. At the same time, gas demand by residential, commercial, and industrial consumers has declined. ✦

Growth expected for global oil demand, production

Marilyn Radler
Senior Editor-Economics

Worldwide demand for oil will climb 1.4 million b/d in 2007, following growth of just 900,000 b/d last year.

Production will grow enough this year in countries outside the Organization of Petroleum Exporting Countries to enable OPEC producers to hold exports near 2006 levels.

At its Dec. 14, 2006, meeting in Abuja, Nigeria, OPEC admitted Angola as the 12th member of the organization, effective Jan. 1, 2007. For figures in this article, Angola is considered non-OPEC.

Global oil demand

Demand by member countries of the Organization for Economic Cooperation and Development will post a small increase this year.

OECD demand will average 49.6 million b/d vs. 49.4 million b/d last year, according to the latest figures from the International Energy Agency. All of this growth will be in North America. Demand will contract slightly in the European and Asian countries of the OECD.

Non-OECD countries will account for most of the world's oil demand growth in 2007, according to IEA. The Paris-based agency forecasts that non-OECD demand will average 36.3 million b/d, up from 35.1 million b/d last year.

Among these countries China will lead demand growth. Oil demand in China this year will be 7.4 million b/d, according to IEA.

Last year China's oil demand averaged 7 million b/d, compared to 6.6 million b/d a year earlier. In 2004, Chinese demand jumped to 6.4 million b/d from 5.5 million b/d the prior year.

Demand this year in other Asian countries will climb to average 9.1 million b/d from the 2006 average of 8.9 million b/d. And IEA expects oil demand in the Middle East to average 6.8 million b/d this year, up from 6.5 million b/d.

Oil supply

Including Angola, non-OPEC oil supply will climb to 52.6 million b/d this year from 50.9 million b/d.

Supply will grow modestly this year in the OECD, averaging 20.4 million b/d. But non-OECD supply will increase to 29.9 million b/d from 28.8 million b/d last year.

IEA forecasts that oil supplied by the former Soviet Union will get a boost from Russia and Azerbaijan. This will

WORLDWIDE SUPPLY AND DEMAND

	2006					2007				
	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	Year	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	Year
	Million b/d									
Demand										
OECD										
North America	25.1	25.1	25.5	26.0	25.4	25.6	25.4	25.9	26.1	25.8
Europe	15.8	15.0	15.4	15.7	15.5	15.6	15.1	15.5	15.6	15.4
Asia-Pacific	9.3	7.9	7.9	8.8	8.5	9.2	7.8	8.0	8.8	8.4
Total OECD	50.2	48.0	48.8	50.5	49.4	50.4	48.3	49.4	50.5	49.6
Non-OECD										
FSU	3.9	3.7	3.9	4.3	4.0	4.0	3.8	4.0	4.2	4.0
Europe	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.7	0.7
China	6.8	7.1	6.9	7.2	7.0	7.1	7.4	7.3	7.6	7.4
Other Asia	8.9	8.9	8.7	8.9	8.9	9.1	9.1	9.0	9.2	9.1
Latin America	5.1	5.1	5.2	5.3	5.2	5.2	5.3	5.4	5.3	5.3
Middle East	6.3	6.4	6.7	6.4	6.5	6.7	6.8	6.8	6.9	6.8
Africa	3.0	3.0	2.9	3.0	2.9	3.0	3.0	2.9	3.0	3.0
Total non-OECD	34.6	35.0	35.1	35.7	35.1	35.9	36.2	36.1	37.0	36.3
Total demand	**84.8**	**83.0**	**83.9**	**86.2**	**84.5**	**86.3**	**84.5**	**85.5**	**87.5**	**85.9**
Supply										
OECD										
North America	14.2	14.2	14.3	14.6	14.3	14.8	14.4	14.3	14.5	14.5
Europe	5.5	5.1	4.9	5.2	5.2	5.4	5.2	5.1	5.4	5.3
Asia	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7
Total OECD	**20.2**	**19.8**	**19.9**	**20.4**	**20.1**	**20.8**	**20.2**	**20.1**	**20.6**	**20.4**
Non-OECD										
FSU	11.7	12.0	12.1	12.3	12.1	12.3	12.5	12.6	12.8	12.5
Europe	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.7
Other Asia	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Latin America	4.4	4.4	4.4	4.5	4.4	4.6	4.6	4.6	4.7	4.6
Middle East	1.8	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Africa	3.9	3.9	4.0	4.1	4.0	4.2	4.4	4.6	4.7	4.5
Total non-OECD	**28.4**	**28.6**	**28.9**	**29.2**	**28.8**	**29.4**	**29.7**	**30.1**	**30.5**	**29.9**
Processing gain	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Other biofuels	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Total non-OPEC	**50.7**	**50.5**	**50.9**	**51.7**	**50.9**	**52.5**	**52.2**	**52.2**	**53.4**	**52.6**
OPEC*										
Crude	29.9	29.8	30.0	29.0	29.7	29.0	29.0	29.0	29.0	29.0
NGL	4.6	4.7	4.7	4.7	4.7	4.8	4.8	4.9	5.0	4.9
Total OPEC	34.5	34.5	34.7	33.7	34.4	33.8	33.8	33.9	34.0	33.9
Total supply	**85.2**	**84.9**	**85.5**	**85.4**	**85.3**	**86.3**	**86.0**	**86.1**	**87.4**	**86.5**
Stock change	0.4	1.9	1.6	(0.8)	0.8	—	1.5	0.6	(0.1)	0.6

*Excludes Angola.
Totals may not add due to rounding.
Source: International Energy Agency, OGJ estimates for OPEC and total supply 4th quarter and year 2006, and all of 2007 OPEC

bring average supply from the FSU to 12.5 million b/d, up from 12.1 million b/d last year. IEA warns, though, that the Russian government's attempts to reinstate control and influence over regional energy assets and infrastructure may impede supply growth.

"Future access to Russian reserves and the legal operating framework remain uncertain. Geopolitical and infrastructure issues, not below-ground risks, may limit the FSU contribution to medium-term non-OPEC growth," IEA said.

Among the remaining non-OPEC, non-OECD regions, the only supply growth areas are Latin America and Africa. Brazil will drive the increase in Latin America, with nearly 200,000 b/d of incremental crude and ethanol supply this year. The expected average supply boost to 4.5 million b/d from 4 million b/d last year in Africa includes growing output from Angola, where average production is projected to rise to 1.72 million b/d this year from 1.41 million b/d in 2006.

OPEC supply

With the inclusion of Angola into its membership, OPEC will try to hold production in check this year to keep oil prices from falling much below $60/bbl.

The average OPEC basket crude price in 2006 was $61.08/bbl. And the average export price of Saudi Arabian Light crude was $57.22/bbl. A weak US dollar increases OPEC's incentive to defend crude prices by limiting production.

OGJ forecasts that OPEC crude supply, excluding Angola, will average no more than 29 million b/d this year. This compares to an estimated average of 29.7 million b/d last year, plus NGL supply of 4.7 million b/d. OPEC will supply the market with an average of 4.9 million b/d of NGL this year, according to IEA.

At a December meeting OPEC agreed to reduce the production by 500,000 b/d effective Feb. 1 after announcing a production cut of 1.2 million b/d last October. The effect of the cuts is a new ceiling for members other than Iraq of 25.8 million b/d. Whether Angola will be subject to OPEC's new output cuts is uncertain.

Saudi Aramco says it is proceeding with plans to increase its production capacity to 12.5 million b/d by 2009 to meet increasing worldwide oil demand. Saudi Arabia's current production capacity is about 11 million b/d. Last year the kingdom produced on average 9 million b/d of crude. ✦

Lower drilling growth seen in US, drop in Canada

Alan Petzet
Chief Editor-Exploration

Price uncertainty, especially for gas, overshadows the forecast for US and Canadian drilling in 2007.

Most signs seem to point to an increase in the US, although not as large as the 2006 gain. A drilling decline is forecast in Canada.

OGJ forecasts an 8% increase in the US active rig count to 1,780 rigs/week in 2007. This compares with increases of 19% in 2006 and 16% in 2005.

The unconventional gas plays that have been engaging increasing numbers of drilling rigs the past few years will soak up a few more rigs to be added to the fleet this year.

Here are highlights of OGJ's early year drilling forecast for 2007:

- Operators will drill 47,003 wells in the US, up from an estimated 45,398 wells drilled in 2006.
- All operators will drill 3,744 exploratory wells of all types, up from an estimated 3,550 last year.
- The Baker Hughes Inc. count of active US rotary rigs will average 1,780

A LOOK AT 30 YEARS OF US WELL COMPLETIONS

Table 1

Year	Total wells[1]	Total footage	Total exploratory wells	Year	Total wells[1]	Total footage	Total exploratory wells
[2]2007	47,003	279,001,000	3,744	1992	23,921	123,456,000	3,494
[2]2006	45,398	264,279,000	3,550	1991	28,417	141,391,000	4,399
2005	42,058	241,894,000	3,321	1990	30,615	149,518,000	5,074
2004	37,257	210,730,000	3,035	1989	28,363	134,901,000	5,251
2003	30,487	158,221,000	2,529	1988	32,238	155,164,000	6,350
2002	27,794	145,055,000	2,226	1987	36,253	163,848,000	6,903
2001	36,061	184,462,000	3,059	1986	39,015	177,641,000	7,156
2000	31,261	149,848,000	2,471	1985	70,806	316,778,000	12,208
1999	22,107	109,854,000	2,075	1984	84,983	368,796,000	15,138
1998	25,822	143,625,000	2,681	1983	75,738	316,617,464	13,845
1997	30,208	165,480,000	3,284	1982	83,889	375,382,919	15,882
1996	25,724	138,588,000	3,344	1981	89,234	406,520,453	17,430
1995	23,061	124,426,000	3,406	1980	69,486	311,444,837	12,870
1994	23,324	130,654,000	3,788	1979	51,890	243,685,430	10,735
1993	26,032	138,509,000	3,604	1978	50,061	238,386,248	11,030

[1]Well counts in most recent years subject to reporting lag. [2]Estimated.
Source: 1975-2005 American Petroleum Institute

OIL & GAS JOURNAL WELL FORECAST FOR 2007

State	2006 estimate Total comp.	2006 estimate Explor-atory wells	2006 estimate Field wells	2006 estimate Total ft (1,000)	2007 forecast Total comp.	2007 forecast Explor-atory wells	2007 forecast Field wells
Alabama	450	21	429	1,678	435	19	416
Alaska	144	5	139	947	157	5	152
Arizona	3	3	0	10	3	3	0
Arkansas	540	23	517	3,206	700	34	666
California land	2,450	69	2,381	6,475	2,550	66	2,484
California offshore	9	0	9	64	9	0	9
Colorado	3,450	148	3,302	19,762	3,350	154	3,196
Florida	1	1	0	13	1	1	0
Illinois	295	30	265	688	350	39	311
Indiana	145	8	137	225	130	7	123
Kansas	2,250	191	2,059	7,380	2,350	190	2,160
Kentucky	935	32	903	3,011	875	32	843
Louisiana	2,170	202	2,372	20,986	2,230	203	2,027
North	1,085	102	983	9,494	1,110	101	1,009
South	505	22	483	5,263	530	25	505
Offshore	580	78	502	6,229	590	77	513
Michigan	485	102	383	934	455	98	357
Mississippi	277	30	247	2,009	250	27	223
Montana	925	148	777	4,319	960	151	809
Nebraska	55	16	39	233	50	15	35
Nevada	5	4	1	25	3	2	1
New Mexico - East	1,150	64	1,086	8,055	1,230	73	1,157
New Mexico - West	895	8	887	3,959	950	10	940
New York	125	4	121	432	110	3	107
North Dakota	395	68	327	4,030	460	88	372
Ohio	505	61	444	2,054	535	63	472
Oklahoma	3,485	115	3,370	24,200	3,590	133	3,457
Oregon	8	8	0	23	10	10	0
Pennsylvania	2,885	300	2,585	9,875	2,975	292	2,683
South Dakota	12	2	10	63	14	2	12
Tennessee	155	15	140	288	175	17	158
Texas	13,485	1,166	12,319	106,843	14,160	1,257	12,903
Dist. 1	495	41	454	2,944	550	47	503
Dist. 2	605	99	506	4,766	685	103	582
Dist. 3	788	101	687	6,313	850	106	744
Dist. 4	1,295	111	1,184	11,955	1,340	118	1,222
Dist. 5	1,362	45	1,317	14,900	1,450	52	1,398
Dist. 6	1,605	151	1,454	15,963	1,675	168	1,507
Dist. 7-B	1,145	40	1,105	4,848	1,250	48	1,202
Dist. 7-C	1,450	71	1,379	11,226	1,410	75	1,335
Dist. 8	1,725	114	1,611	12,063	1,790	120	1,670
Dist. 8-A	905	96	809	5,340	965	99	866
Dist. 9	1,035	22	1,013	6,278	1,080	27	1,053
Dist. 10	965	222	743	9,150	995	241	754
Offshore	110	53	57	1,096	120	53	67
Utah	1,035	208	827	7,985	1,105	243	862
Virginia	455	70	385	1,405	475	76	399
Washington	4	3	1	56	6	5	1
West Virginia	1,845	284	1,561	7,400	1,925	293	1,632
Wyoming	4,370	135	4,235	15,649	4,425	133	4,292
US total	**45,398**	**3,544**	**41,854**	**264,279**	**47,003**	**3,744**	**43,259**
Western Canada	24,105	6,322	17,783	90,442	22,150	5,669	16,481
Alberta	18,555	4,676	13,879	68,802	16,700	4,092	12,608
Saskatchewan	3,775	1,072	2,703	12,431	3,725	1,036	2,689
British Columbia	1,225	429	796	7,275	1,100	370	730
Manitoba	550	145	405	1,934	625	171	454
NWT-Yukon	9	7	2	39	12	10	2
Atlantic offshore	6	2	4	102	6	2	4
Other E. Canada	65	5	60	151	65	5	60

rigs/week this year, up from 1,649 in 2006 and 1,383 in 2005.

- Operators will drill 22,150 wells in western Canada, down from an estimated 24,105 wells in 2006.

State estimates

OGJ forecasts a 5% increase in Texas drilling in 2007 to 14,160 wells.

Wyoming, the next largest state in terms of numbers of wells, should see 4,425 wells drilled, including about 3,000 in the Powder River basin coalbeds alone.

The outlook is for 3,590 wells to be drilled in Oklahoma, up 3%, and 3,350 in Colorado, down almost 3%.

California land drilling is likely to be 2,550 wells in 2007, up from 2,450 in

2006. Another slight gain, 100 wells, is predicted in Kansas at 2,350 wells in 2007.

OGJ looks for the drilling of 2,230 wells in and off Louisiana. That includes 590, a slight increase, offshore in state and federal waters of the Gulf of Mexico. Another 120 wells are forecast to be drilled in the gulf off Texas.

Play activity

Drilling advanced in most areas of the US in 2006, with gains in a few states far exceeding the countrywide rig count average.

North Dakota's 31 rig/week average in 2006 was up from 20 rigs/week in 2005 as drillers followed the Bakken horizontal oil play into North Dakota from Montana.

The Barnett shale play in the Fort Worth basin has seen some weakening as operators such as EnCana Corp. declined to pay strengthening rig rates, but the play is still expected to command 200 rigs/week in 2007 (OGJ,

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Dec. 18, 2006, p. 45).

Arkansas averaged 24 rigs/week in 2006 compared with 9 in 2005. Southwestern Energy Co.'s plan to drill 400-450 horizontal wells in the Fayetteville shale gas play in 2007 could foretell even busier rig activity in the eastern Arkoma basin.

Chesapeake Energy Corp., Oklahoma City, most active driller in the US, plans to operate as many as 150 rigs in 2007, up from 130 operated rigs in late 2006 when the company was participating in another 89 nonoperated rigs.

Chesapeake Energy said half its rigs are drilling to targets at 10,000-15,000 ft, a quarter to below 15,000 ft, and a quarter to shallower than 10,000 ft.

A relative latecomer to the Fayetteville shale play, the company operates 7 rigs there and is developing Little Creek field in White County, Ark.

Anadarko Petroleum Corp.'s 2007 development plan calls for drilling 280 wells with 8 operated rigs in Greater Natural Buttes gas field in the Uinta basin, Utah, and 280 wells with 5 rigs in Greater Wattenberg field in the Denver basin, Colorado.

Williams Cos., Tulsa, Okla., was operating 24 rigs drilling for Cretaceous Williams Fork gas in the valley and highlands parts of Colorado's Piceance basin in November 2006 compared with 15 a year earlier. The company expected delivery of 6 more rigs by early 2007.

Meanwhile, Southwestern Energy said it plans to drill as many as 30 wells in 2007 in a new coalbed methane play in North Louisiana.

Outlook for Canada

Declines in drilling for shallow gas and coalbed methane should moderate drilling in Canada in 2007, especially in Alberta.

Many operators are poised to boost CBM drilling if gas prices strengthen.

A federal proposal to place a new tax on income trusts could put further economic pressure on the seismic, drilling, and service-supply sectors. There is some thought that taxing trusts the same as corporations could result in more field operations by trusts, which generally seek to grow by acquiring rather than drilling for reserves.

Incentives and a geologic leaning more toward oil than gas may insulate the province of Manitoba from drilling declines seen in the rest of the country. OGJ forecasts the drilling of 625 wells in Manitoba, up from 550 in 2006. ✦

Sakhalin-2 deal will alter business climate, markets

Alex Turkeltaub
Stephen Bailey
Frontier Strategy Group
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The agreement between Royal Dutch Shell PLC and OAO Gazprom, the Russian state-owned natural gas company, under which Gazprom will become the majority shareholder in the Sakhalin-2 LNG project demonstrates that western oil companies will no longer be able to obtain majority stakes in major Russian hydrocarbon assets.

Under terms of the deal, Gazprom will purchase 50% plus one share of the project for $7.45 billion, thereby forcing Shell and its partners, Mitsui & Co. Ltd. and Mitsubishi Corp., to dilute themselves by 50% in order to accommodate their new partner (OGJ, Jan. 1, 2007, p. 29). As a result, Shell is being forced to give up majority control in one of its most lucrative assets after having invested over $6 billion to develop the project.

Immediately following the agreement, Russian President Vladimir Putin held a press conference at which he announced that the supposed environmental infractions, under the guise of which the project was halted by Russian authorities while Shell and Gazprom were negotiating, have been resolved to the satisfaction of Russian regulatory authorities. What are the implications of this deal for international oil companies (IOCs) in Russia and beyond?

COMMENT

Regulatory influence

First, the negotiations between Gazprom and Shell and the involvement of Russian regulatory authorities indicate that the regulatory organs of the Russian government are extensions of Gazprom and Rosneft, the two state-owned natural resources companies, and will be used on their behalf to muscle the companies' way into lucrative projects. It is no longer possible to believe that the Russian regulatory authorities operate independently of the interests of the Kremlin, which has sought to bolster the state-owned natural resources giants in order to gain government control over hydrocarbon assets. Resolution of environmental issues after Shell agreed to allow Gazprom into the project cannot be mere coincidence.

Particularly worrying is the clever use by Russian authorities of a campaign waged by nongovernmental organizations (NGOs) against the project, thereby providing a semblance of legitimacy to the government's actions. IOCs doing business in Russia must understand how to align their interests with Gazprom or Rosneft to avoid regulatory challenges as existing agreements and even the letter of the law will provide little protection for property rights. Given the prevalence of such NGO campaigns around the world, many governments may utilize the same tactic in the future.

Second, the Gazprom-Shell transaction indicates that Russia will no longer be a major source of reserves for IOCs. The basic point of the Sakhalin-2 deal is that major international oil companies will

not be allowed to have majority control of any substantial or strategic assets in the Russian Federation. Moreover, the deal does not even imply that minority control is possible for substantial assets.

Rather, the new status quo is likely to be as follows: Companies that already control substantial assets, particularly in technically challenging projects, will be allowed to maintain minority shares in these projects after allowing Russian state-owned entities to acquire majority stakes. New investments are likely to be restricted altogether, and even current owners of assets that are not technically difficult or can be managed profitably by Gazprom could expect complete expropriation at below-market prices. This bodes particularly poorly for the BP-TNK joint venture as well as for a number of small projects under discussion between western firms and Russian authorities.

Early disruption of this new equilibrium is possible, of course. Because Russian policies tend to change drastically with changes in presidential administrations, a new policy regime could emerge after the 2008 presidential elections.

'Exporting' tactics

Perhaps most dangerously, Russia is likely to "export" to other countries interested in renegotiating deals with IOCs its use of regulatory organs and tactics such as environmental permit reviews and retroactive tax assessments to change contractual agreements and pressure IOCs into accepting new partners or different revenue splits. Frontier Strategy Group has observed that regulatory authorities in Latin America and Africa have paid careful attention to the Russian approach and see it as a successful new tool for increasing their governments' portion of the profits from energy projects. IOCs can expect a more difficult operating environment not only in Russia but also in other developing countries that offer the best prospects for substantial discoveries of hydrocarbons.

"IOCs doing business in Russia must understand how to align their interests with Gazprom or Rosneft."

Finally, the Sakhalin-2 deal, in combination with the decision by the Russian authorities to not seek western partners for the development of Shtokman natural gas field, has significant implications for the global LNG market. As LNG assets in Russia are placed under the control of poorly managed state companies, the production of LNG in Russia over the medium term is likely to fall far short of market expectations. The impact of this trend will be felt not only by gas-consuming countries, which may end up paying higher prices for LNG in the medium to long term, but also by companies currently developing LNG terminals whose profitability will depend on a steady supply of gas from key suppliers.

"The production of LNG in Russia over the medium term is likely to fall far short of market expectations."

While the detailed implications of recent events in Russia on LNG supply and demand are beyond the scope of this article, corporate planning departments would be wise to revisit their assumptions about the likely development of this key energy market.

The saga of Sakhalin-2 is unlikely to be an isolated phenomenon and could have a substantial impact on the operating environment faced by IOCs and on global energy markets. Senior executives should study the implications and develop strategies to align the interests of their firms with state-owned companies and governments in order to maintain access to resources in emerging markets. ✦

The authors

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Democrats put global warming at center of energy plans

Nick Snow
Washington Correspondent

In their first day back in charge, US Senate Democrats said they intend to aggressively address global climate change by developing energy alternatives to oil, gas, and coal; by improving energy efficiency; and by shifting tax incentives from traditional energy sources to emerging technologies.

"For too long, our country's energy policy has had only one concern: oil company profits," Senate Majority Leader Harry Reid (Nev.) said on Jan. 4 as he described S. 6, one of 10 bills Democrats introduced on a range of issues.

Officially designated the National Energy and Environmental Security Act of 2007, S. 6 calls for reducing US dependence on foreign oil and the risks of global warming by "requiring reductions in emissions of greenhouse gases; diversifying and expanding the use of secure, efficient, and environmentally friendly energy supplies and technologies; reducing the burdens on consumers of rising energy prices; eliminating tax giveaways to large energy companies; and preventing energy price-gouging, profiteering, and market manipulation."

Reid noted that the bill aims to promote US energy independence and enhance domestic security so the country "can begin to deal with the threat—the threat—of global warming." He said he and five other senators were reminded of this during recent visits to several South American countries when they were told that Ecuador's glaciers are melting.

"So in an effort to begin to solve this energy crisis, our sixth bill takes an aggressive approach to reducing America's dependence on oil, especially foreign oil, and putting more advanced technologies in the hands of consumers," he said. "It will boost production of electricity from solar, geothermal, and other renewable resources that are abundant in states such as Nevada, and it will grow our nation's renewable energy jobs and manufacturing base."

Bingaman elaborates

Energy and Natural Resources Committee Chairman Jeff Bingaman (NM) offered more specific ideas as he elaborated on S. 6's goals.

To reduce US dependence on foreign energy sources, he said, the measure would maintain domestic production; tighten vehicle fuel-economy standards; encourage development of renewable fuels, "particularly biofuels"; and consider new motor vehicle technologies that can reduce gasoline consumption.

Bingaman said reductions of greenhouse gas emissions will be addressed by Senate committees other than his. But he added that the Energy and Natural Resources Committee expects to play a major part because "over 95% of the US carbon dioxide emissions and nearly 85% of all US greenhouse gas emissions come from energy production, distribution, and use."

The legislation also will include measures to encourage the use of energy-efficient light bulbs and to assure full funding of energy-relief programs for low-income families.

On oil and gas taxation, Bingaman asserted that the US offers one of the world's most favorable fiscal regime for oil and gas production and pointed to "big problems" in federal royalty management. He was referring to offshore leases issued in 1998-99 without price thresholds, which cap deepwater royalty relief in leases issued in other years.

"We will be examining how to rebalance the system, both from the perspective of having fair and effective royalty and tax policies for oil and gas and from the perspective of having effective tax and other incentives to promote other forms of energy, such as production of electricity from wind solar, geothermal, and renewable sources," Bingaman said.

He said energy and environmental issues probably will be addressed in multiple bills.

Environment and Public Works Committee Chairwoman Barbara Boxer (Calif.) said Reid's remarks on S. 6 sent a signal "to all of us here, both sides of the aisle, that we are going to put the environmental issue back front and center, and we are going to put the energy issue front and center, and we are going to do everything we can do to become energy-independent and to preserve this planet for future generations."

Will of leadership

Sen. Ken Salazar (D-Colo.) said tackling energy and environmental issues will not be as difficult as solving problems such as health care.

"The only thing lacking, really, has been the will of the leadership of America to move forward to get us to that energy independence," he said.

"We ought not to be in a position where the national sovereignty and security of this nation is held hostage to the whims of the Middle East and those who happen to have oil wealth under their sands," Salazar declared. On another topic he said, "We will find economic opportunity, including economic opportunity for rural America, to help us grow our way to energy independence."

House approach

In the House, Democrats also signaled some of their energy and environmental approaches for the months ahead.

Jay Inslee (Wash.) said Speaker Nancy Pelosi (Calif.), in earlier remarks, "made a commitment to the country that our nation would start a titanic and historic shift from old technologies associated with fossil fuels that are now putting massive amounts of carbon dioxide into the atmosphere and towards the use of new technologies that can produce our mode of power for our cars and our planes and our buses and our homes and our computers and even our hair dryers in a way that does not contribute to global warming."

Achieving these results, he said, will require repealing "some of the less prudent activities of the former Congress that gave $7 billion of taxpayer money to the oil and gas industry, a very imprudent move, an industry that is in tip-top form financially."

Inslee said incentives that the industry received could be moved to "a pool of funds that will be used to develop new high-tech, clean energy sources that we can go forward to build energy independence and reduce our contributions of carbon dioxide and other gases that are contributing to global warming." ✦

Bush lifts leasing bans on two OCS areas

Nick Snow
Washington Correspondent

US President George W. Bush has opened two Outer Continental Shelf areas for new oil and gas leasing after removing tracts in Alaska's North Aleutian basin (more commonly known as Bristol Bay) and the Central Gulf of Mexico from the presidential withdrawal list.

Bush announced the action in a memorandum to Department of the Interior Sec. Dirk A. Kempthorne, who immediately said the areas would receive thorough environmental reviews.

"There will be significant opportunities for study and public comment before any oil and gas development could take place in these areas," Kempthorne said.

Sen. Ted Stevens (R-Ak.) said Bush's action was welcome news to people who live and work in the Bristol Bay region. He said he originally requested a moratorium on leasing there during fiscal 1990 after the tanker Exxon Valdez ran aground in 1989 in Prince William Sound farther south. President George H.W. Bush subsequently issued an executive order prohibiting leasing in Bristol Bay, which President Bill Clinton extended through 2012, Stevens said.

Congress also continued to impose moratoria on oil and gas activities in Bristol Bay from fiscal 1990 through 1993 before discontinuing them in fiscal 1994 at Stevens' request, he said. But the moratorium's removal did not clear the way for leasing, Stevens noted. That required a presidential order, which George W. Bush issued on Jan. 9.

Stevens said imported farmed salmon, high energy costs, and the area's remoteness have limited economic growth and contributed to poverty in the Bristol Bay region.

'New opportunities'

"The possibility of oil and gas devel-

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

EIA hikes oil flow outlook

The US Energy Information Administration won't present its 2007 Annual Energy Outlook (AEO) for a few more weeks. But the reference case that it released in early December provided at least one intriguing preview.

We'll use EIA's own words to explain: "The projections for US crude oil production in the AEO 2007 reference case are significantly different from those in the AEO 2006 reference case." Different, as in higher.

In the 2007 reference case, EIA projected a US crude production increase from 5.2 million b/d in 2005 to 5.9 million b/d in 2017 as a result of more offshore production, primarily from the deepwater Gulf of Mexico, followed by a decline to 5.4 million b/d in 2030.

A year earlier, its reference case predicted "a much steeper decline in production from 2017 to 2030" (from 5.8 million to 4.6 million b/d).

The reasons for the 800,000 b/d difference? Primarily, says EIA, a slower decline for Lower 48 onshore production in the 2007 reference case, "mostly as a result of increased production from enhanced oil recovery technology and, to a lesser extent, significantly higher resource assumptions for the Bakken shale formation in the Williston basin."

Behind more EOR

Ted McAllister, an economist in the oil and gas division of EIA's Office of Integrated Analysis and Forecasting, said inferred reserves appreciation due to EOR from the Office of Oil and Gas led EIA to revise its forecast.

Wider EOR use, he told me, results primarily from higher oil prices. "We also looked more closely at our past assumptions. Given what we found in recent studies, we decided to increase our projections," he said.

EIA raised its resource assumption for the Bakken formation on the basis of a study by Advance Resources International, McAllister said.

While the estimated future offshore volumes may have changed somewhat from 2006 to 2007, the trend essentially is the same in both years' reference cases, according to Dana Van Wagner, another EIA analyst who handled that modeling. "Higher prices are contributing to more drilling offshore and in deeper waters. More cash flow is available," she said.

Price sensitivity

Large discoveries expected to come on line in the next 2 years depend less on high world oil prices than those where development economics have not been determined, Van Wagner explained.

"Some fields have been delayed due to technical issues. A couple were supposed to start producing at the end of 2006 or the beginning of 2007. But they're still expected to come on line. That's why both years' projections show a bump upward, followed by a flattening out," she said.

In its 2007 AEO reference case, EIA incorporated new resource estimates which the US Minerals Management Service gathered as part of the offshore inventory required under the 2005 Energy Policy Act. "There are more smaller fields than what we assumed last year," Van Wagner said. ✦

opment in Bristol Bay presents a series of new opportunities to the people of this region. Equally important, offshore development in Bristol Bay will occur under stringent environmental safeguards, using the most advanced technology available to help ensure our fisheries are protected," he said.

"This is not the end of the public process, but rather the start of a dialogue that could lead to important energy development in our state. It is vital for Alaskans to express their views on the upcoming Environmental Impact Statement regarding the 5-year schedule, as well as take advantage of future public comment periods," added US Sen. Lisa Murkowski (R-Ak.).

She said she had spoken with Kempthorne about Bristol Bay's environmental sensitivities and its world-leading sockeye salmon runs. "During those conversations, I received an assurance from the secretary that if leasing is ultimately proposed for the waters, that it will only be conducted with stringent environmental safeguards to protect not just salmon, but also any crab, cod, Pollock and whales, marine mammals, and birdlife that live and pass through the Bristol Bay region waters," Murkowski said.

Last year then-Alaska Gov. Frank H. Murkowski and other local government and Alaska Native leaders said they would support modifying the presidential withdrawal, according to DOI.

Consequently, the 2007-12 OCS oil and gas leasing program, which the US Minerals Management Service is preparing, contains options for one or two lease sales in about 5.6 million acres of the North Aleutian basin, DOI said.

It said MMS previously offered leases in that part of Bristol Bay in OCS Lease Sale No. 92 in 1988. There presently are no oil and gas leases there.

Sale 181 South

The Central Gulf of Mexico tracts, more commonly known as the Sale 181 South area, comprises about 5.8 million acres and is included in both the MMS's proposed 5-year OCS plan and legislation passed by Congress and signed into

law by Bush toward the end of 2006.

MMS is expected to release the final OCS program and environmental impact statement this spring, DOI said.

Kempthorne also announced on Jan. 9 that he has increased the royalty rate for most new offshore deepwater federal oil and gas leases to 16.7% (⅙ from the present ⅛). The new rate, which excludes Alaska, will take effect with the first 2007 Gulf of Mexico lease sale scheduled for late August.

Most federal oil and gas is leased at a 12.5% royalty rate both onshore and offshore, according to DOI. The Outer Continental Shelf Lands Act grants the secretary discretion to establish a higher royalty rate, it said.

It said MMS estimates the increased royalty rate for new deepwater offshore leases in the gulf will increase revenue from royalty payments by $4.5 billion over 20 years. MMS estimates that, by 2017, this increased revenue would offset any decline in bonus and rental revenues and any revenue losses from a decline in production.

MMS estimates a decline of bonus and rental revenues at $820 million over 20 years and decline in production at 5%, or 110 million boe, over 20 years, according to DOI. ✦

US foreign policy must consider changing energy world

Nick Snow
Washington Correspondent

US foreign policy needs to better recognize the impacts of a changing energy world, experts told the US Senate Energy and Natural Resources Committee on Jan. 10.

"We're fighting in a post-9/11 environment with a pre-9/11 energy policy that's not sufficient to deal with disruptions," said Robert Hormats, vice-chairman of Goldman Sachs (International). "Look at what's happening in Nigeria, where there are kidnappings; in Russia, which is trying to exercise more direct influence on oil and gas, and in Iran and Iraq, where political prospects are uncertain."

Hormats was one of five witnesses discussing the geopolitics of oil in the committee's first hearing of the 110th Congress. The others were Fatih Birol, chief economist at the International Energy Agency; Linda Stuntz, a former deputy US energy secretary and current partner in the law firm Stuntz, Davis & Staffier; retired US Air Force Gen. Charles Wald, who is active with the Energy Leadership Council, and Flynt Leverett, director of the geopolitics initiative at the New America Foundation.

While technically not yet the committee chairman because the Senate had not held its elections, Jeff Bingaman (D-NM) ran the hearing, which he intended to help establish a context for subsequent deliberations. "The idea is to begin the year with an overview of the geopolitics of oil. I hope that it's useful," he said.

Other committee members sought information about potential benefits of developing alternative fuels more aggressively or sharing technology with other countries. Witnesses essentially responded that there's no single solution and every option needs to be pursued to reduce US dependence on crude imports from politically unstable foreign suppliers.

Supply, demand trends

Birol suggested that world oil markets are going through a profound change as demand becomes more widespread and supplies become more concentrated. "In the next 10 years, much of the world's production will come to a peak and then decline. New production will need to come primarily from three countries—;Saudi Arabia, Iran and Iraq—;which have substantial reserves and can bring oil to market fairly easily," he said.

US policymakers also should acknowledge the growing influence of national oil companies, others said. "The reality today is that [NOCs] control some three quarters of the world's proven reserves. ExxonMobil ranks 14th among the world's reserves holders," said Stuntz.

She said while publicly traded oil companies are returning to areas still open to them, such as the Gulf of Mexico and the North Sea, because operating terms in many producing nations are turning unfavorable, an increasing amount of new exploration and development will involve NOCs.

"It concerns me that more people in this country don't know about this. [NOCs] like Aramco have been around for years. They don't need western capital as they did before. There's also a myth that they won't have access to technology if they don't get it from the United States. But they are capable of making alliances with other countries," Stuntz said.

Few people in the US also recognize the extent to which their country's military forces protect critical oil trading routes, according to Wald. "There should be partners in this mission. The free flow of oil is crucial to many parts of the world. That is one reason why the US military is working with Caspian region governments in developing partnerships," he said.

Leverett said resource nationalism is growing in countries such as Venezuela and Russia as resource mercantilism increases in consuming countries such as China and India. "In my view, during the next quarter century, the most profound challenges to America's global leadership will flow from structural shifts in the global oil market," he said.

Leverett suggested an alliance between China and Russia has been

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

After prison, the book tour

Filmmaker John Ford would have loved this tale of Ireland's little men making their misguided stand against the oil industry. Yes, we're back to the Corrib gas field project and the so-called Rossport Five, who are again in the limelight (OGJ, July 11, 2005, p. 25).

This time, the Five are out of jail and promoting their new book, Our Story, telling of their time in prison for protesting against the gas project undertaken by Royal Dutch Shell PLC.

The five men were advised by prison wardens not to mix with other inmates for their own safety.

But senior Five member Michael O'Seighin said otherwise: "One of the lads, he was waiting for trial, and he came to me early on and said: 'I guarantee you that there's no one going to hassle you.'"

Cell doors

In fact, O'Seighin says, prisoners supported the cause by banging their cell doors in solidarity whenever the Corrib gas protests were on the news.

"We stuck out a mile. We were the oldest that were there; they were nearly all young. You met all types of people in there for all different types of crime," said farmer Willie Corduff.

The book, which has sold out its first print run of 3,000 copies, describes how the Five received postcards from schoolchildren and nuns while in prison, and it tells of the strain jail time put on their wives and families.

For some members, the book redeems the entire experience. Five member Vincent McGrath said: "I think when people see what we've gone through, especially our wives, they will understand what it's all about."

That point was echoed by Corduff, who said the 208-page book would give people an insight into the dispute.

"We want to tell what we were going through and our suffering—for no gains," said Corduff. "But if we hadn't done it, we'd probably be a lot worse off like in Nigeria, where 300 people were killed on New Year's Day when an oil pipeline exploded."

More misinformation

Oh dear! Here we have a justification based on more misinformation, which is really aimed at stirring up negative feelings against the oil industry. That's where right-thinking folks—whether in the oil business or not—lose sympathy for the Rossport Five and their supporters.

The Nigerian pipeline—a gasoline pipeline, by the way, and not crude oil or gas—did not spontaneously explode. Instead, the pipeline was ruptured by thieves and burst into flames as scavengers collected the fuel in a poor neighborhood.

More to the point, the gang of thieves had been illegally tapping the Nigerian pipe for months, carting away gasoline in tankers for resale.

That's a far cry from the scenario the Rossport Five would have people believe—one in which a natural gas pipeline will simply explode—and it is that sort of false scenario-building that continues to hurt the oil industry. ✦

successfully rolling back US efforts to influence oil in new areas of the Middle East following the Sept. 11, 2001, terrorist attacks. "Russia and Iran control almost half of the world's natural gas reserves. If they cooperate, they could be almost as influential with natural gas as Saudi Arabia is with oil," he said.

Contradictory signals

Leverett said some NOCs have begun to act independently of their governments, which US policymakers should encourage. Noting the response by some US politicians to Chinese National Offshore Oil Corp.'s interest in buying Unocal Corp. a few years ago, he noted, "We encourage the Chinese to pursue market solutions on one hand and discourage their initiative on the other."

Many witnesses and committee members agreed that US development of transportation fuel alternatives is vital. "I believe in the free market. But if it becomes a national security issue, I'm prepared to consider spending money to develop alternatives which would reduce our dependence on oil from countries whose interests are different from ours," said Sen. Jeff Sessions (R-Ala.).

Hormats said incentives to develop alternatives need to last long enough to complete projects, particularly the tax credit for investing in renewable resources. "Certain kinds of institutional and other investors can't put money into the business because the time spans aren't long enough. We have the technological ability on the supply side, with this country's entrepreneurial traditions and vitality, to use new sources as well as conventional sources," he said.

Witnesses generally agreed that every option should be pursued. "None of these things are silver bullets. We have to do all of them. But if we were to do everything that was mentioned today before this panel, it would still take us 10-15 years during which we would still be vulnerable," said Wald. ✦

Venezuela to nationalize Orinoco oil operations

Peter Howard Wertheim
OGJ Correspondent

Venezuela's President Hugo Chavez announced a series of measures Jan. 8 to change the face of the country's economy and lead it further onto a socialist path.

A series of "special powers" were requested from congress to reform Venezuela's commercial legislation, and Chavez promised to end the Central Bank's autonomy and to nationalize the Orinoco belt's extra-heavy oil operations.

Because the government's party controls virtually 100% of the congress, there is little doubt that the legislature will grant the "special powers."

Chavez said that multibillion-dollar oil projects run by major oil companies should become state property.

Since last year the government had been negotiating with international consortia currently operating in the Orinoco area, so that state-owned Petroleos de Venezuela SA (PDVSA) attains a majority stake in each project.

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

The international oil companies declined to comment until they have further details.

Venezuela's oil 'opening'

Chavez, reelected by a landslide last December, promised to roll back a private investment campaign of the 1990s known as the oil "opening."

Before his reelection, the nation's congress approved a bill that hikes the income tax rate to 50% for the six foreign oil companies working in oil ventures in the Orinoco belt.

"The Orinoco belt is still a living symbol of what was an important part of the oil opening. We must eliminate this symbol," Chavez said during the inauguration of new cabinet members.

"I'm talking about the international companies that have control and dominion over these processes of what they call upgrading of heavy crude in the Orinoco belt. That must become property of the nation," Chavez said.

These latest developments come after Chavez earlier declared that he would work hard to stop oil exports to the US and divert them to China and other energy-hungry countries. Chavez's anti-US rhetoric has raised concern because the US is Venezuela's biggest oil-trading partner.

Venezuela supplies about 1.5 million b/d of crude oil and oil products to the US, according to the International Energy Agency. Venezuelan oil comprises about 11% of US oil imports, which amounts to 60% of Venezuela's total exports. PDVSA also wholly owns five refineries in the US and partly owns four refineries, either through partnerships with US companies or through PDVSA's US subsidiary, Citgo Petroleum Corp.

However, although Venezuela seeks to develop new markets for its crude, a significant short-term shift in oil relations between Venezuela and the US is unlikely because Venezuela remains heavily dependent on oil exports to the US, say Latin American analysts.

Venezuelan oil exports to China increased to 150,000 b/d in 2006 from 12,300 b/d delivered in 2004 and are expected to increase to 500,000 b/d within 5 years. As part of agreements signed in 2005, China is investing $2 billion in oil-related exploration and development projects in Venezuela's Zumano region and Orinoco oil belt.

Venezuela agreed in April 2006 to begin sending 2 million bbl/month to India, according to India Daily. Both countries are jointly exploring for heavy crude oil in India.

Venezuela and Iran agreed last August to jointly build oil refineries in Indonesia, Syria, and Venezuela. In addition, Iran's state-owned oil company Petropars began to invest in oil exploration and development in the Orinoco belt.

"Previously, PDVSA was managed as a multinational company, with criteria that did not consider our social reality. Now, it is a national company composed by a highly popular component that has allowed us to deploy, for the first time, our own oil plan, the 2006-12 "Oil Sowing Plan," which foresees a $60 billion investment in projects aligned with the interests of the country," said former Minister of Energy and Petroleum and current president of PDVSA, Rafael Ramirez.

Brazil's state-run oil company Petroleos Brasileiro SA (Petrobras) signed a joint venture agreement that brings oil E&P operations under Venezuela's government control.

The decision by Petrobras follows similar moves by Royal Dutch Shell PLC and Chevron Corp. to submit to government demands for a greater government share of control and revenues from Venezuela oil operations.

Petrobras has signed the first of four new contracts that replace agreements to independently pump oil at fields across the country, PDVSA said in a statement.

Under the new terms, PDVSA holds a 60% stake in the La Concepcion oil field in Western Venezuela, while Petrobras has a 36% stake. Williams International holds the remaining 4%.✦

IEA: EU copes with Russian oil export delays

The International Energy Agency Jan. 9 said European oil markets would cope with the halt of Russian oil exports via the Druzhba (Friendship) pipeline across Belarus, but it nonetheless called for a quick and clear resolution to the problem (OGJ Online, Jan. 8, 2007).

"There is apparently no immediate impact to any of the refineries in the countries involved, as they all have working stocks of several days. So there is no threat that product supplies to the end users will be disrupted," IEA said.

It said if the disruption should prove more prolonged, the refineries could source crude from alternative routes. Some already are organizing alternative supplies through Baltic Sea ports or through other pipelines.

The affected countries on the Northern branch of the Druzhba pipeline are Poland and Germany. Ukraine, the Slovak Republic, Hungary, and the Czech Republic are affected on the southern part of the pipeline.

In an effort to end the problem, a delegation led by Belarusan Vice-Premier Andrei Kobyakov flew to Moscow Jan. 9, but there was no immediate indication that supplies would resume, as Russian President Vladimir Putin ordered his Cabinet to consider a possible reduction in oil output.

Putin ordered ministers to discuss with Russian companies the possibility of reducing oil output in connection to problems linked to oil transit through Belarus. Analysts said Russia has a limited capacity for refining oil and would have to cut crude output if its exports suddenly decreased.

Concerned about the implications of the disruption on energy security, EU Commission Pres. Jose Manuel Barroso and German Chancellor Angela Merkel criticized Russia and Belarus, saying it is unacceptable for energy transit or supplier countries to halt deliveries without consultation.

"That always destroys trust, and no trusting, undisturbed cooperation can be built on that," Merkel said after talks with Barroso in Berlin.

Merkel said consultations are the minimum when there are such problems, and [consultations] must become normal.

As the EU called for a rapid resumption of oil deliveries, EU Energy Chief Andris Piebalgs said he may convene a meeting of the bloc's Oil Supply Group to evaluate the situation. ✦

WEST AFRICA—2

West Africa second only to Russia in non-OPEC supply contribution

Mohamed Barkindo
Ivan Sandrea
OPEC
Vienna

This is the second of two parts on the exploration and production outlook for the West African countries that border the Gulf of Guinea and Congo Delta.

In the period 2001-05, West Africa's oil production (excluding Nigeria) increased 130,000 b/d/year, while total non-OPEC oil supply increased 800,000 b/d/year. The rate of growth in non-OPEC production is the strongest in the last 20 years and is underpinned by the expansion of E&P activity worldwide due to two key reasons.

First, rising oil prices have resulted in a twofold increase in global E&P investments since 2000.

Second, the benefits of political stability and reforms in the Former Soviet Union, the start of large and challenging projects in deep water, unconventional oil projects, and the exploitation of marginal opportunities made a significant contribution to non-OPEC supply. The West African region has been a key beneficiary of rising E&P activity, and not surprisingly it was the second most important contributor to non-OPEC after the FSU (Fig. 4).

The main source of growth has been deepwater fields. In 2005, all of the deepwater production (1.13 million b/d) in West Africa excluding Nigeria came from 8 large projects. Angola was the largest producer with the most projects on stream in deep water (5 projects: Xikomba, Kizomba A and B, Girassol, and Jasmin), followed by Equatorial Guinea (2 projects: Zafiro and Ceiba) and Ivory Coast (1 project: Baobab); all but one project came on stream after 2000 (Fig. 5).

Looking at Nigeria, oil production capacity also rose 400,000 b/d between 2001 and 2005. It could have risen more if not for the destruction of some oil facilities in parts of the Niger Delta in 2003. During this time two deepwater fields made small contributions—Abo, which started in 2003, and Bonga, which started in 2005.

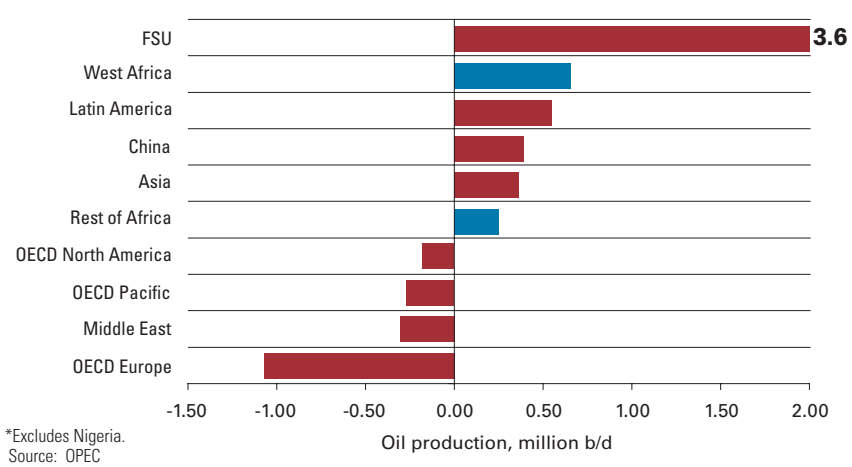
At the end of 2005 these two fields had combined capacity of 130,000 b/d; however, in late 2005 Bonga was ramping up to its design capacity of 200,000 b/d. The rest of the increase came from offshore fields in shallow water.

Projects and supply outlook

Over the 2006-12 period at least 26 new material oil projects are expected to come on stream in West African

NON-OPEC SUPPLY GROWTH, 2001-05*

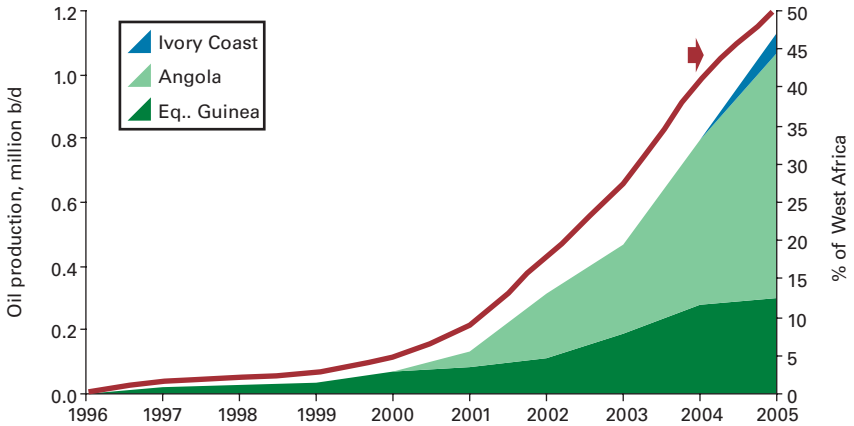
Fig. 4



*Excludes Nigeria.
Source: OPEC

WEST AFRICA* DEEPWATER OIL PRODUCTION TREND

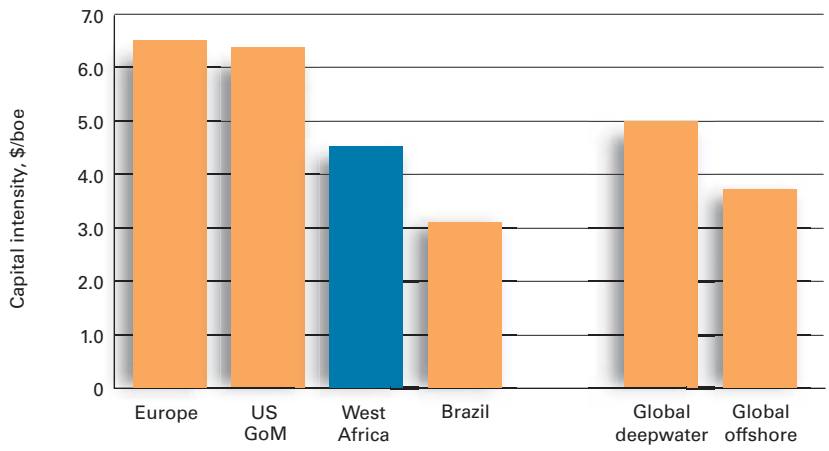
Fig. 5



*Excludes Nigeria.
Source: OPEC

UPSTREAM CAPITAL INTENSITY OF FUTURE OIL E&P PROJECTS

Fig. 6



Source: OPEC

FUTURE MATERIAL PROJECTS IN ANGOLA

Table 5

Block/field	Capacity, 1,000 b/d	Operator	Environment	Expected start date
Block 4	50	Sonangol	Deep water	2007
Block 14		Chevron	Offshore	
BBLT Phase I	200			2006, peak by 2010
BBLT Phase II	130			2009
Block 15		Exxon	Deep water	
Marimba/Mavacola	70			By 2009
Kizomba C	100-200			2008
Kizomba D	150			By 2010
Block 17		Total	Deep water	
Dalia	240			2006
Rosa	150			2007
Pazflor	230			By 2012
Cravo/Lirio	120			By 2012
Block 18	200	BP	Deep water	2007
Block 31 (north)	150	BP	Ultradeep water	By 2010
Block 31 (south and west)	100-200	BP	Ultradeep water	2010-11
Block 32	150	Total	Ultradeep water	By 2012

Sources: Company presentations, OPEC estimates, secondary sources; start date may shift and may not correspond to current official dates

countries (excluding Nigeria), most of which are in deep water.

The cumulative capital investment is $39 billion, which is 50% higher than the cumulative E&P investment in oil and gas in 2001-05. In Nigeria are over 15 large developing oil projects with an estimated combined capital investment of $35 billion, the majority of which are also deepwater projects. The cumulative investment of these projects is also 60% higher than the cumulative E&P investment seen in the 2001-05 period.

Roughly 15 billion bbl of total oil reserves are under development. Based on the estimated capex for projects and comparing it with those in other regions on a dollars per barrel of oil equivalent of reserves basis, it is clear that the future projects in West Africa are capital intensive. This is because many of the projects require the drilling of expensive wells and installation of complex infrastructure.

We estimate that future development costs for new projects average $5.70/boe in Congo (Brazzaville), $5.20/boe in Angola, $4.80/boe in Nigeria, and $3.80/boe in Equatorial Guinea (Fig. 6).

In terms of timing, most of the projects that have a start year before 2009 appear to be broadly on track. However, beyond 2010 the start year of most projects is less certain, and there is no method to predict potential delays, but they will come on stream. In fact, over 95% of the projects with a start year before 2008 are under construction, but this falls to around 30% and less for the following years.

In the current environment this appears to be normal given that services are limited, and the industry generally starts actual construction of projects 4 years ahead of the expected production start year. Having said that, some operators have signed contracts for deepwater drilling units to 2015 and even to build new rigs, which shows the industry's long-term commitment to bringing West Africa's field's on stream.

Cumulative new gross oil from all

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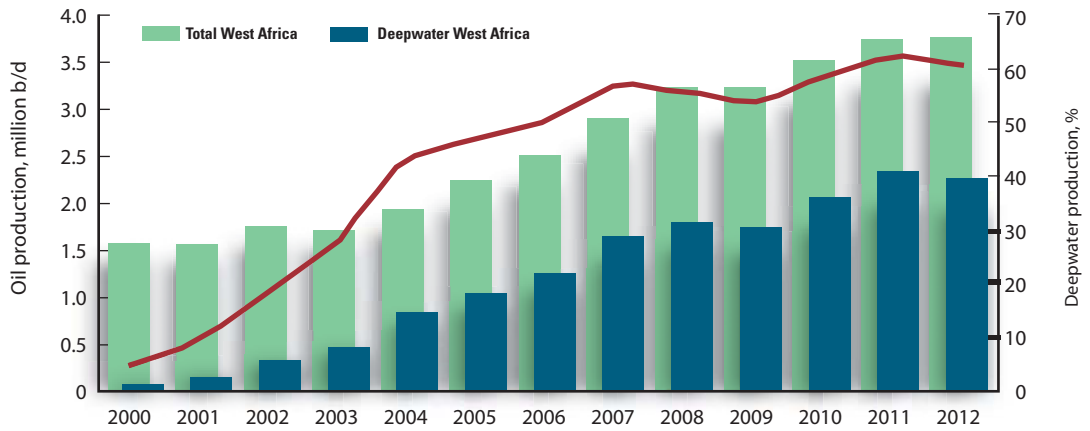
OTHER WEST AFRICA'S* OIL PRODUCTION OUTLOOK

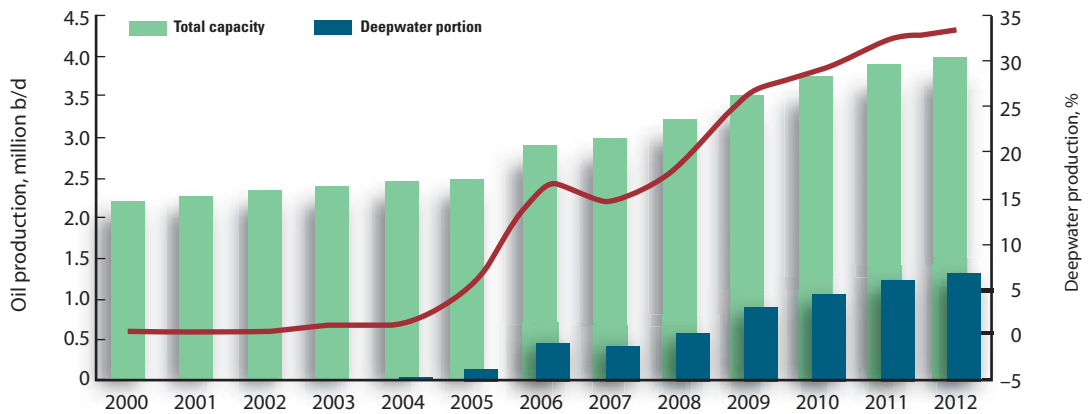
Fig. 7



*Excludes Nigeria

NIGERIA OIL PRODUCTION CAPACITY OUTLOOK

Fig. 8



Capacity 2000-05 based on average of secondary sources; projections based on projects and other assumptions. 2006 excludes Niger Delta shutdowns.

projects in West Africa (excluding Nigeria) is estimated at 2.5 million b/d, of which Angola accounts for 2 million b/d (Table 5). Of the total for the region, 2.1 million b/d or over 70% will come from deepwater fields.

In Nigeria the cumulative gross oil of all developing projects is 1.7 million b/d, and the bulk of this is also coming from deepwater fields (Table 6). Additionally, 5 projects are expected post-2010, but their timing remains uncertain.

With regard to the supply forecast for each of the main producers in West Africa (excluding Nigeria), the first point to make is that the rate of growth will be stronger than in 2001-05 even if projects are delayed (Table 7). Production from offshore fields is expected to account for the bulk of the growth, of which deepwater fields play the leading role. Simply put, plenty of projects are in the pipeline.

Oil production will rise in Angola, Equatorial Guinea, and Congo (Brazzaville) underpinned by deepwater developments (Fig. 7).

In Angola, deepwater oil production started in 2001, was 800,000 b/d in late 2006, and is to reach 1.7 million b/d by the end of 2012. Operators have chosen to combine several fields into few large developments, bringing on large volumes almost each year. Several discoveries in ultradeep water are expected to support new developments by 2012.

Deepwater oil production in Equatorial Guinea is expected to remain broadly flat through 2012 at around 300,000 b/d. Several satellite projects are expected to start, and more are under evaluation, particularly small tiebacks to large Zafiro and Ceiba fields.

Congo (Brazzaville)'s oil production is expected to increase, driven by deepwater projects (Moho-Bilondo, Mer Profonde), new start-ups offshore, and the expansion of Mboundi field (onshore). E&P activity in Congo (Brazzaville) has risen considerably, and prospects for more projects are improving rapidly.

The combined production of Gabon, Ivory Coast, and Cameroon is expected to remain broadly flat. Gabon has no deepwater production, but exploration is under way. Ivory Coast's oil production rose with the start of Baobab deepwater field in 2005, but maintaining future production will depend on improving the performance of this field and small tiebacks to existing shallow offshore infrastructure as no other deepwater fields are expected to come

Material projects in Nigeria

Table 6

Block/field	Capacity, 1,000 b/d	Operator	Environment	Expected start year
Yoho	150	Exxon	Shallow water	2006
AOR-E. Delta	120	Exxon	Shallow water	2006
Erha	150	Exxon	Deep water	2006
Erha North	40	Exxon	Deep water	2006
Abo Satellite	15	Eni	Deep water	2006
Akpo	180	Total	Deep water	2008
Ofon Phase 2	70	Total	Offshore	2008
Bosi Oil	120	Exxon	Deep water	2008
Agbami	250	CHX	Deep water	2008
Gbaran/Ubie Phase 1	120	Shell	Offshore	2009
Usan/Ukot/Togo	230	Total	Deep water	2010
H Block	140	Shell	Offshore	2010
Egina	160	Total	Deep water	By 2012
Bonga SW/Aparo	150	Shell	Deep water	By 2012

West Africa oil production outlook*

Table 7

	2005	2006	2007	2008	2009	2010	2011	2012
	Million b/d							
Angola	1.23	1.42	1.76	2.00	2.00	2.30	2.50	2.50
Eq. Guinea	0.36	0.36	0.39	0.39	0.39	0.41	0.39	0.38
Congo (Brazz.)	0.24	0.25	0.26	0.33	0.33	0.33	0.37	0.41
Gabon	0.25	0.25	0.24	0.24	0.23	0.23	0.23	0.23
Ivory Coast	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Cameroon	0.08	0.08	0.08	0.07	0.07	0.06	0.06	0.06
Mauritania	—	0.03	0.03	0.05	0.10	0.09	0.09	0.08
Total	**2.23**	**2.50**	**2.89**	**3.22**	**3.22**	**3.52**	**3.73**	**3.75**
Of which deep water	1.03	1.25	1.63	1.78	1.72	2.05	2.31	2.26
% of total	46	50	57	55	53	58	62	60

*Excluding Nigeria.

on stream.

In Cameroon, renewed offshore activity and tiebacks will slow the decline trend of the last few years. E&P activity is taking place in deep water, and a recent discovery might be commercial.

In Mauritania, oil discoveries have been made in deep water, and one field (Chinguetti) began producing in the second quarter of 2006. However, the performance of the reservoir has been poor, and this has resulted in lower production than expected from the field; we understand that until more studies are completed and wells drilled, the field's production will remain below capacity.

A second deepwater field (Tiof, 50,000 b/d) is expected to come on stream in 2009 using an early production scheme or as a tieback to Chinguetti. Beyond Tiof, no more potential oil fields are in the foreseeable future.

Based on available information, none of the nonoil producing countries in the region is expected to bring a new field on stream in this time horizon. However, E&P activity has been increasing in some countries such as Sao Tome and Principe and Senegal, and this could lead to the discovery and development of fields in the future. Most of the activity will remain concentrated in deep water.

Nigeria's output

Nigeria's oil production capacity is expected to increase to 4-4.2 million b/d by 2012 (Fig. 8).

New production from offshore fields is expected to account for the bulk of the growth, of which deepwater fields play the leading role. Deepwater production averaged 130,000 b/d in 2005, will rise to 500,000 b/d in 2006, and is expected to reach 1.3 million b/d by 2012. New production from deep water is also likely to translate into improved supply reliability.

The 14 large oil projects under development or with plans in advanced stages of engineering include Yoho, Erha, Additional Oil Recovery (AOR), Erha North, Abo Satellite, Akpo, Ofon Phase II, Agbami, Bosi Oil, Gbaran/Ubie, Usan, H Block, Egina, and Bonga SW/Aparo.

Another five projects (Nsiko, Ikija, Bolia, Doro, and Chota) are in early engineering, and given the long lead time and tightness in the service sector, we have not included any of these in the forecast, but this could clearly change.

Acknowledgments

The authors thank OPEC Secretariat. The views expressed in this report are those from the authors and do not represent those of OPEC or the Nigeria government. ✦

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Salt origin without evaporation proposed

A group of authors led by a Statoil ASA specialist in marine geology has proposed an unconventional theory for the origin of salt that could have far reaching implications for oil and gas exploration.

Masses of solid salt may form and accumulate under ground, independently of solar evaporation of sea water, Martin Hovland of Statoil and four other authors have suggested.

The article, "Salt formation associated with sub-surface boiling and supercritical water," is published in the September 2006 issue of "Marine and Petroleum Geology." The authors use as examples drilling results from the Deepsea Drilling Project Site 226 (Atlantis II Deep) in a marine setting in the central Red Sea and from Lake Asala near Danakil, Ethiopia, in a continental setting.

Underground precipitation

The Norwegian research team demonstrated how solid salt forms in high temperature/high pressure (HTHP) conditions when seawater circulates in hydrothermal systems in the crust or under piles of sediment.

It is the physical properties of supercritical water that stimulate the precipitation.

When water no longer boils because the pressure is too high, it enters the supercritical phase and attains a relatively low density (3 gm/cc).

For fresh water this occurs at temperatures above 374° C. combined with pressures above 221 bar. For seawater, the values are 405° C. and 300 bar (equivalent to a depth belowground of 2,000 m or below sea level of 2,800 m).

Both molecular theory and laboratory experiments prove that the solubility of salt in supercritical water is practically zero, Hovland noted. Therefore, when sea water enters into an HTHP (hydrothermal) convection cell, its salts precipitate out and accumulate within the surrounding rock fissures or sediment pores.

Geologists, whose current model for salt deposition and accumulation relies only on solar evaporation of seawater, have overlooked this novel hydrothermal outsalting mechanism.

The main beauty of the new model is its lack of demand for large ocean basins (such as the Mediterranean Sea) to evaporate up to 10 times for salt several kilometers thick to accumulate.

The hydrothermal process occurs totally independent of surface evaporation, as it relies only on high heat flow in the earth. Another strength of the model is its ability to predict how brines and sulfate (salt) masses are likely to have accumulated on other planets, such as Mars, where it is hard to account for there having existed a deep ocean that evaporated.

Hydrocarbon implications

The novel hypothesis on subsurface accumulation of salt has fundamental implications for hydrocarbon accumulation because it is a result of the processes that create sedimentary basins.

Basins are formed by tectonic movements, and the deep basinal faults are frequently associated with processes in the mantle, causing high heat flow in the fault systems. The faults allow the circulation of sea water and brines, driven by heat and gravity.

When brines come into the "supercritical zone" of water, water will gradually lose its ability to dissolve salt, and salt will accumulate in the fracture systems.

In traditional thinking, a prerequisite for the accumulation of salt is a dry climate, and this is contradictory to the frequently observed high rate of water-transported sediments into the basin.

The subsurface accumulation of salt opens up the possibility to have a wet climate that promotes a high rate of erosion and transportation of sediments into the basin, at the same time as salt accumulates in the subsurface. Rapid and extreme shifts in climate and sea level (e.g., the "Messinian Salinity Crisis") are therefore not necessary prerequisites in the authors' model.

This knowledge will have a fundamental impact on the interpretation of basin development that is a cornerstone in the exploration for hydrocarbons, Hovland said. ✦

Italy

The ministry approved the Vega Oil SPA unit of Cygam Energy Inc., Calgary, to explore the 83,264-acre Aretusa permit, its designation changed to C.R148. VG, in the Mediterranean off Sicily's southeastern tip.

Primary target is porous dolomites of the Upper Triassic Taormina formation, and a secondary target is carbonates of the Lower Jurassic Villagonia formation deposited above Streppenosa black shales, the area's main source rocks.

The area's only well, Aretusa-1 in 1985, flowed 1,500 b/d of 36° gravity oil and 11.5 MMcfd of gas on a short test from Villagonia fractured pelagic limestones. The well stopped short of the Taormina formation.

Vega plans to acquire, reprocess, and interpret all existing seismic data previously shot on and around the permit. Then it will shoot 80-100 sq km of 3D seismic to define two indicated seismic structures and select a drilling location.

Several companies have expressed interest in participating. The block is in 20-130 m of water.

N-removal technology improved to process West Texas Yates gas

Nina M. Rach
Drilling Editor

Removing nitrogen from natural gas increases production potential and may spur drilling in the Yates formation, Permian basin.

Midland's BCCK Engineering Inc. is building new nitrogen removal units in Texas and Oklahoma that will help capture the value of nitrogen-rich natural gas.

The company initially developed a low-volume nitrogen-removal process that was installed at the Mist gas field, northwestern Oregon in 1994 (OGJ, Mar. 13, 1995, p. 92).

BCCK's Nitech process cryogenically separates nitrogen from methane in a single column, but does not employ a cryogenic pump or any rotating cryogenic equipment. The basic Nitech equipment includes a molecular-sieve gas dehydrator, regeneration gas heater, aluminum plate-fin heat exchanger, and a single distillation column with integral patented reflux condenser.

The company installed a Nitech system in Gaines County, Tex., in 2004. In April 2005, BCCK Engineering received the Hearst Energy Award for Technology in Midland for its improved Nitech process.

Beginnings

The introduction of the 10 MMcfd capacity nitrogen rejection unit (NRU) at the Mist gas field created salable gas from low btu natural gas containing 30-50% nitrogen. The Mist NRU was moved to Denver City, Tex., in 1996 and adapted to handle a different inlet stream, traditional gas containing 10-40% nitrogen.

In 2002, BCCK built a 24 MMcfd NRU in Grand Junction, Colo., to handle produced gas containing 15-50% nitrogen.

To date, NRUs have been installed at production facilities in nine states: Oregon, Texas, Colorado, Alabama, Kansas, Wyoming, California, North Dakota, and Oklahoma. BCCK's original Nitech nitrogen removal process handles flow rates as low as 1 MMcfd and has been suitable for small fields.

The Nitech process is also used to remove natural gas liquids and helium, both of which can generate separate revenue streams. It's suitable for capturing coal mine methane (CMM) and BCCK has installed CMM units in Pennsylvania, Alabama, and Illinois.

More recently, BCCK has implemented a new technology that enables the process to handle flow of 250 Mcfd or higher. The company recently modified the reflux (knock-back) condenser so that it would be more efficient at higher inlet gas flow rates. The older design could recover 98-99% of the hydrocarbons; the new design recovers up to 99.9%, nearly 2% improvement. The new condensor was implemented in five NRU facilities in 2006.

The enhanced Nitech units are now being implemented in West Texas, enabling operators to produce natural gas from the shallow Yates reservoir, long ignored because its high nitrogen content prevented it from being accepted in regional pipelines.

West Texas

The Permian basin has historically been an oil province but strong prices for natural gas have inspired gas-focused drilling. The Yates formation is a natural gas reservoir with some condensate, found in northern Ector and Midland counties and running north through Gaines and Yoakum counties, Tex. The natural gas found in the Yates is often low-pressure, containing 15-20% nitrogen, causing it to be sold at a discount.[1]

Yates sediments are the product of cyclic marine flooding—dolomites, anhydrites, and halites—with a "regional trend of increasingly more open marine facies...to the south and west in the Permian basin."[1]

Researchers at the University of Texas at Austin Bureau of Economic Geology assessed the Yates formation, particularly the Schaeffer Lake field in Andrews County. "Although the reservoir has a rather higher nitrogen content, there continues to be great interest in the production and sales of Yates gas."[2]

Netherland, Sewell, & Associates Inc. studied the effect of the double displacement nitrogen injection process on enhanced oil recovery in Yates field. The project was subsequently converted to CO_2 injection.[3]

In 2004, BCCK installed a nitrogen rejection plant in Gaines County, Tex., near Seminole, to process 5 MMcfd from the Yates formation for Dallas-based Lynx Operating Co. Inc. This turnkey project included system design, site work, procurement, and installation of the inlet gas dehydration system and the Nitech NRU, as well as installation of leased compression. The Nitech NRU and two 730-hp compressors successfully reduced nitrogen content in the produced gas to 4% from 20-30%, according to BCCK.

R. Clark Butts, BCCK president, said the Lynx facility took 24 weeks to develop from concept to production. "This will be a big benefit to the Permian basin. This [Yates] is a very prolific horizon that has been largely untapped in the Permian basin. It's a shallow formation that exists in lots of areas."[4]

The Yates formation has been identified in Lee County, NM, and in nine Texas counties. Butts told OGJ the "sweet spots" are in Yoakum, Ward, Gaines, Ector, Midland, and Andrews counties. Gas in the zone was ignored, he said, because of its high nitrogen content despite being tagged in about 2,000 well penetrations in Andrews County.[5]

This nitrogen removal unit, installed in Gaines County, Tex., in 2004, was the first successful NRU to process Yates gas (photo from BCCK Engineering Inc.).

More recently, BCCK designed two other nitrogen removal facilities in Texas, capable of processing 12 MMcfd and 50 MMcfd. The company is also building a 48 MMcfd CO_2 removal facility in Oklahoma.

Construction of the 12 MMcfd facility, near Seminole, Tex., began in August 2006. It should be complete by end of first-quarter 2007.

BCCK designed the 50 MMcfd nitrogen rejection facilities in Madisonville, Madison County, Tex., for the Madisonville Gas Processing LP (which took over the assets of Hanover Compressor Co. in 2005). The new NRU facility is under construction parallel to an existing, less-efficient, 18 MMcfd facility built by AET in 2005.

The Madisonville NRU facility includes a mole sieve dehydration system, Modicon PLC control system, and facility engineering for ancillary equipment, including an amine unit used for removing CO_2 prior to removing nitrogen. This conventional technology employs a blended MDEA (methyl diethyl amine) solvent that has an affinity for CO_2 and H_2S. It will begin operating this month.

Butts reviewed the new technology last year[6] and will present a paper on nitrogen rejection in the technology development forum at the Gas Processors Association 86th annual convention, Mar. 11-14, 2007, in San Antonio. ✦

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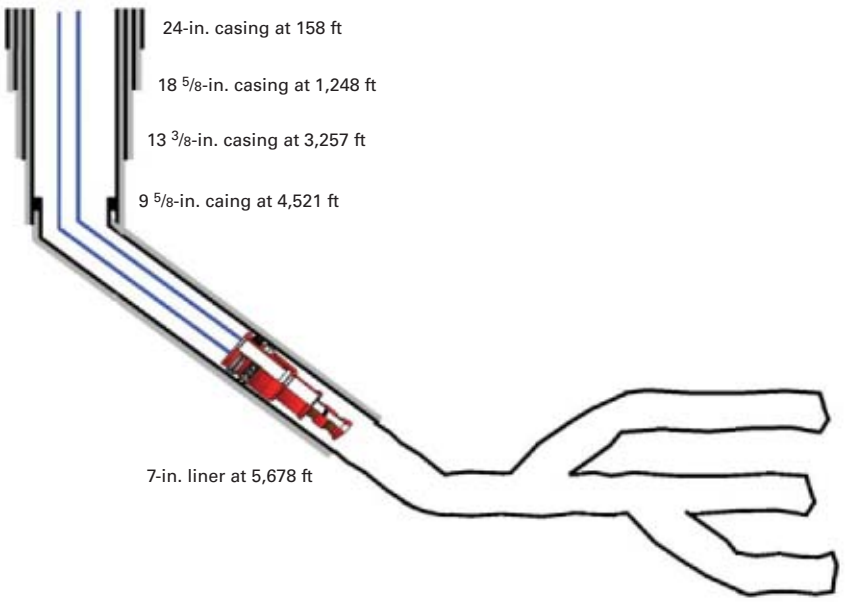
FORK-TYPE MULTILATERAL

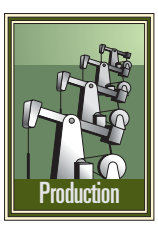
Fig. 1



Expandable tubulars facilitate intelligent technology placement

Mark Rivenbark
Enventure Global Technology
Dubai

Khaled Abouelnaaj
Saudi Aramco
Dhahran



Installation of solid expandable tubulars in combination with intelligent-well technology facilitates remedial operations in multilateral wells in a Saudi Arabia oil field producing from a limestone reservoir.

The field's development included long reach, openhole multilateral wells that produce at high rates. The inability to reenter the openhole sidetracks for remedial work, however, hampered recovery. In wells producing water, the operator either could not identify the source of the water or if found, could not remediate the problem.

The introduction of solid expandable tubulars in combination with intelligent-well technology overcame this problem. Wells with this technology generally have higher production rates and greater recoveries. Lower unit development and operating costs also are key drivers for installing this technology.

Solid expandable tubulars combined with intelligent-well technology allows for reentry into laterals for remedial work and to obtain real-time pressures, temperatures, and flows without the need for well intervention. Intelligent-well components allow for quick identification of water-producing zones and provide a means for shutting off water production without the need for well intervention.

Integrating technology

Completion reliability and the potential for higher sustainable production rates are two major drivers that have led to the acceptance of intelligent-well technology. Combined with solid expandable tubulars, operators can install the technology during workovers in wells previously unable to benefit from intelligent completions.

During the early to mid-1990s, development of intelligent-well technology was in its infancy. Conventional completion methods requiring intervention were the primary means for completing oil and gas wells.

The move to deepwater and extended-reach drilling (ERD) motivated increasing the reliability of this technology because these environments require high flow rates for economical production. With respect to wells drilled with solid expandable tubulars, operators are able to expose more reservoir rock while maintaining optimum control of the production profile.

The ongoing improvements in drilling equipment, drilling fluids, downhole tools, and ancillary items continue

Based on a presentation to the SPE Annual Technical Conference and Exhibition, San Antonio, Sept. 24-27, 2006.

to expand the envelope for intelligent wells in combination with solid expandable tubulars. As with any other evolving technology, however, limitations exist that must be addressed. Wellbore preparation and well-path architecture must meet certain minimum requirements to facilitate successful placement of a solid expandable liner.

The industry now has bits and underreaming devices that enable isolating longer intervals while maintaining the required casing geometry to accommodate the intelligent-well equipment. Wellbore cleanup tools help in placing solid expandable tubulars. Other improvements in the hardware associated with the intelligent completion systems ensure that the completion will be fit-for-purpose.

Drilling equipment also has advanced. The industry now has available bottomhole assemblies that drill straighter holes and eliminate the spiraled tortuosity normally associated with conventional drilling assemblies. These advancements enhance hole cleaning and reduce torque and drag to allow placement of solid expandable liners on depth.

An obvious advantage of combining intelligent-well technology with solid expandable tubulars is that it can control the flow from the added reservoir rock exposed in multilateral wellbores as if the flow was in a single wellbore.

This type of completion also facilitates remedial drilling operations should they become necessary. In a multiple-well development project, this technology potentially can reduce overall well count and thereby reduce overall project capital expenditures.

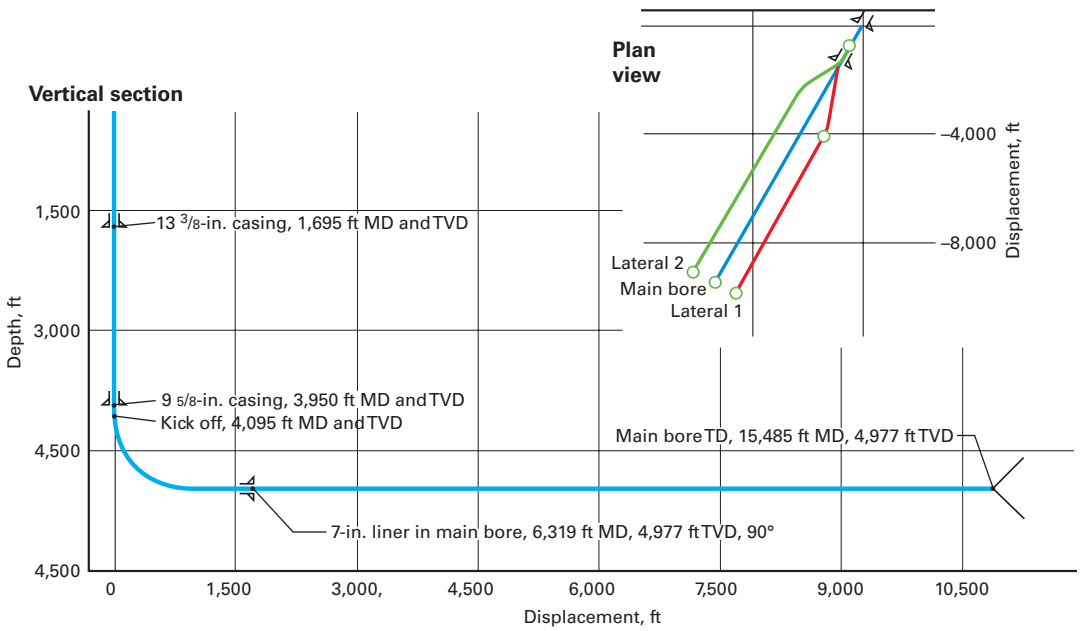
These factors are critical in deepwater and ERD-type wells where development requires greater capital than in conventional locations.

Larger reservoirs that can produce at high rates and have higher recoverable volumes are targets for this combined technology. Also, for the costly environments of deepwater and ERD drilling, another key issue in well design is completion reliability.

Integrating drilling and completions is critical in developing openhole,

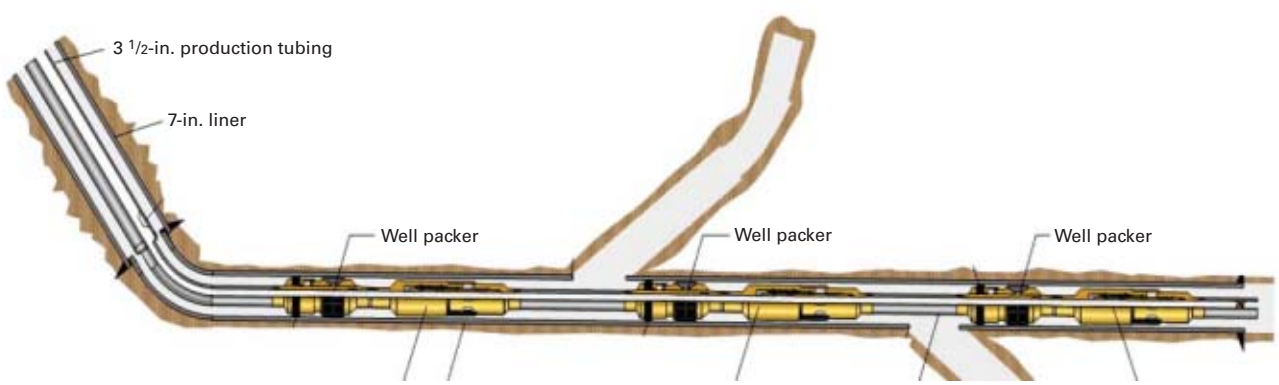
Wellbore construction

Fig. 2



Combination completion

Fig. 3



The retrievable production packer has a multiple control-line bypass (Fig. 4).

horizontal wells because the drilling process can influence the productivity and cycle time for the completions. The industry has a growing recognition that hole quality directly affects successful deployment of expandable casing and thus completion reliability.

Previous wells show that poor hole quality was a major factor for failure of expandable casing liners to reach the planned setting depth. Irregular hole geometry can lead to problems with hole cleaning and with increased torque and drag.

Debris in the hole can induce stress risers on the expandable liner OD and lead to failure during the expansion process. These failures might be due to the expandable casing rubbing against debris when going through tight spots in the wellbore.

Conventional downhole-steerable motors require periods of oriented drilling, during which the drillstring is not rotating. This lack of rotation can lead to washouts and increased wellbore tortuosity. Furthermore, drilling with conventional steerable assemblies may result in an irregular hole geometry such as a corkscrewed wellbore.

Rotary-steerable tools can have a positive effect on drilling costs as well as the ability to deploy effectively the solid expandable casing. Rotary-steerable assemblies guide the system in the wellbore in any given direction while rotating the drillstring. This feature results in a straighter hole with less variance in gauge drift. Some advantages of rotary-steerable systems include:

- Lower wellbore friction, which aids in running the casing to depth.
- Improved hole cleaning and minimized drill pipe trips, which result in less time required for circulating and tripping.
- Minimized time that the open hole is exposed, which reduces the risk of hole collapse and washouts.
- Reduced spiraling, which provides better logs.

These advantages enhance the odds of successfully deploying the expandable liner to bottom. Reducing washouts minimizes chances of low spots where debris could accumulate and damage the expandable liner during deployment.

An added benefit in ERD wells is the ability to drill longer hole sections.[1] The combination of rotary-steerable tools and near-bit reaming devices to open the wellbore is another positive factor in helping ensure that the expandable liner reaches the planned depth.

Field development

Installation of the solid expandable tubulars combined with intelligent-well technology occurred in a field located in a desert terrain consisting of salt flat areas and mountainous sand dunes up to 600 ft high. Because of rugged terrain, initial field development was from a limited number of flat areas so that the wells required highly accurate directional drilling to reach their targets.

The field, developed in the mid-1990s, produces 42° gravity oil and includes 1-km long, single-lateral horizontal wellbores. The field went on production in 1998.

Because of a large gas cap and a relatively weak aquifer, the horizontal completions minimized the chances of early water breakthrough and provided the desired economic production rates. The operator recognized that additional laterals in the same zone could yield substantially improved production results, thereby increasing reservoir contact. Subsequently, it drilled two laterals off the main bore in an angle that resembles a fork (Figs. 1 and 2).

Historic field data have shown that a fork-type multilateral to be the best fit for this field application compared to fishbone or some other type.

A workover converted the existing 1-km horizontal well into a trilateral fork-type multilateral. Total reservoir exposure from the three legs was more than 18,000 ft.

Workover

The workover included underreaming the original main bore to 7½-in. from 6⅛ in. in a 1,209-ft interval measured from the 7 in. shoe. Then a 2⅞ in., PH-6 inner-string ran the 5½ × 7-in. expandable liner in the hole. Once on depth, circulation of water ensured adequate hole cleaning while batch mixing spacer and slurry.

The next step pumped 10 bbl of spacer and 28 bbl of cement, displaced

with 55 bbl of water, as the well program called for. After landing of a dart, the program included pressure testing the liner before its hydraulic expansion. Expansion initiation pressure was 5,100 psi and subsequent expansion of the 1,010-ft liner required pressures between 4,500 and 4,800 psi. A pressure to 1,500 psi for 30 min tested the liner.

The next step involved running a cement retainer and setting it at 6,697 ft, followed by the running of a 5¼-in. OD whipstock inside the expandable liner and setting it on top of the cement retainer after it was oriented 54° left. The drilling of the lateral was through a window milled in the casing from 6,678 to 6,690 ft with a 5½-in. directional drilling assembly. The lateral achieved a 4,625-ft length before retrieval of the whipstock in preparation for drilling of the second lateral.

Drilling the second lateral involved running a retrievable plug and setting it at 6,430 ft. A whipstock run on top of the plug had a 55° right orientation.

A 5½-in. assembly also drilled the second lateral. This lateral achieved a 7,340-ft length, better than expected. A concave mill drilled out the float shoe in the expandable liner after retrieval of whipstock and plug.

The final step in the workover operation involved installing the intelligent completion system, which included:

- Three fit-for-purpose retrievable, hydraulic-set packers (Figs. 3 and 4).
- Three control valves (Fig. 5).
- Required encapsulated hydraulic control lines.

The procedure called for function testing of all critical components before their arrival at the well site. The workover operation paid particular care to ensure the hydraulic lines were undamaged while running the completion system in the hole. After the completion system was on depth, the next step closed control valves and tested tubing to 3,000 psi to set the packers.

Because these packers have no mandrel movement, they set simultaneously. The next steps tested the packers to 1,500 psi for 30 min and each control valve through 10 choke settings to ensure functionality.

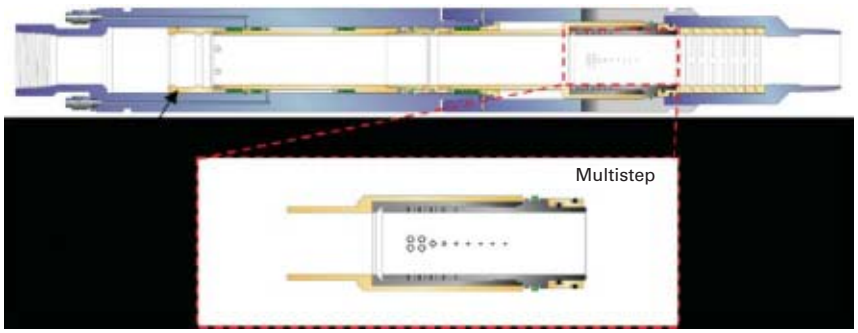
After completion of workover operations, the well had more than 18,000 ft drilled in the reservoir; more than 11,000 ft from the two laterals drilled through the window exits in the expandable liner.

The well subsequently produced 6,000 bo/d with 6% water cut compared with 1,500 bo/d at 15% water cut before the workover.

Based on the increased production, the operator recovered all workover costs in about 10 days.

Control valves

Fig. 5



Three hydraulic, remotely operated downhole chokes control flow from isolated well sections.

Observations

This application in a limestone reservoir describes one of the first successful installations of intelligent-completion equipment inside an expandable liner. The work encountered no serious difficulties because of lessons learned on other projects. The combination of these technologies provides several benefits:

- Ability to drill long lateral lengths after exiting the window cut in the expandable liner.
- Controlled liner ID, which aids in friction reduction and minimizes helical buckling.
- A large 5.570-in. ID through the liner, which allowed the use of 4-in. drill pipe with high torque connections, thereby enhancing drilling operations.
- Improved cement bond due to the expansion process squeezing out unwanted stringers.
- Ability to monitor and manage the flow from each lateral in real time with no wellbore intervention required. ✦

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Khaled Abouelnaaj's biography and photo were unavailable at press time.

US gasoline markets to rebalance by 2010

Mike Wilcox
Wood Mackenzie
London

A detailed analysis of the US gasoline market shows that a market rebalancing will be under way by 2010, when additional refining capacity will reduce the imbalance between demand and supply. The US need for gasoline imports, one of the key market factors that has supported the refining boom, will have less of an influence by then.

Internationally, this outlook suggests that while Europe and Latin America will continue to have an outlet for surplus gasoline production into the next decade, market volatility seen since 2004 is likely to decline and margin peaks will also fall.

The window of opportunity for export refiners (e.g., in Latin America and the Middle East or Asia) building capacity to target the US gasoline market could also diminish by 2010.

As more projects come on stream, there will be increasing competition between these refiners to export gasoline to the US market.

The early investors will see the best returns. Some projects being planned today may not find a market and it will become increasingly diffcult for developers beyond 2010.

In the longer term, the successful importers will be those investors with the best partners, economic crude supplies, optimal configuration in the right location, and those that can exploit multiple opportunities in the global marketplace.

Other market forces must emerge to ensure that the balance does not tip completely and the refining boom lasts into the next decade. Although we have restricted our analysis to the US gasoline market, it only accounts for 42% of total oil product consumption in the US.

Supply-demand dynamics for other products such as LPG, naphtha, jet-kerosine, diesel, gas oil, low-sulfur fuel oil, and high-sulfur fuel oil combined will have an effect on future industry prospects and the longevity of the refining boom.

It is likely that the middle of the barrel will become increasingly important for refinery profitability into the next decade.

Moreover, supply-demand dynamics in other regions will also have a crucial influence on the US. It is possible, for example, that demand growth in Asia-Pacific could exceed increases in regional product supply. If so, Asia could pick up a large proportion of any future slack in the global market, and it could be the key region that prolongs the boom. Indeed, Asia could supplant the US as the key region for the global refining market.

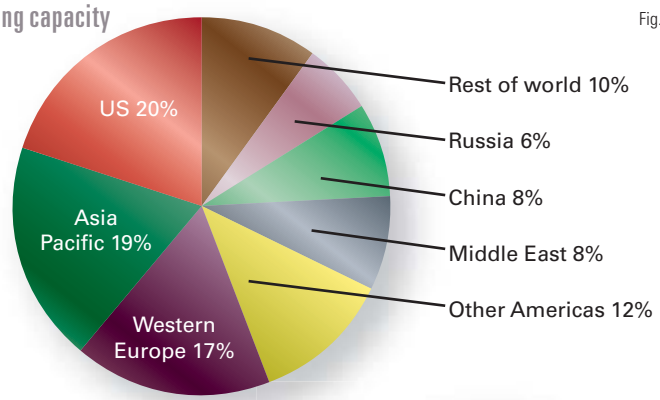
An alternative scenario would be a global gasoline surplus due to new build capacity in Asia; this is a particularly gloomy long-term prospect for the industry. Although gasoline in the US remains the most influential single refined-product market and can provide

US REFINING IN A GLOBAL CONTEXT

Fig. 1

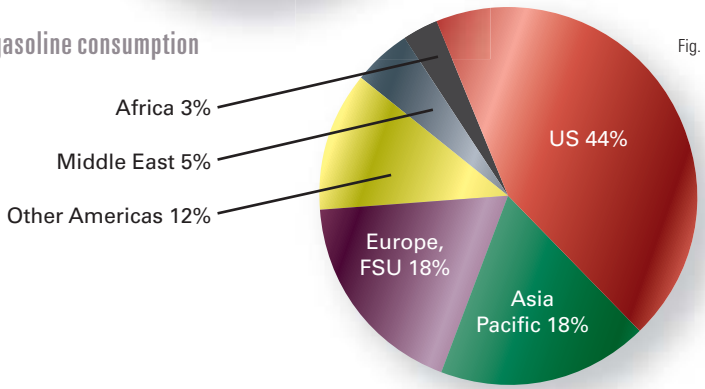
World refining capacity

Fig. 1a



World gasoline consumption

Fig. 1b



some insight to the global picture, it cannot be considered in isolation from other products or regions.

US refining

Refining has been transformed into an industry that is once again attracting significant investment. Many factors have converged to improve dramatically the industry's profitability, especially in the US:

- *Growth.* Oil demand has increased significantly.
- *Historic underinvestment.* Refinery capacity and supply growth have lagged demand.
- *Oil prices.* High crude prices and widening light-heavy crude price differentials have provided a significant margin boost for highly upgraded facilities.

Hurricanes, growing deficits, and recent specification changes have further stoked the US boom. New capacity, however, will hit the market in the next few years.

Based on our Global Products' Outlook service, we conclude that demand will outstrip capacity additions for the next 2 years, thus maintaining the current sustained period of strong refining margins. In the medium term, however, the market may begin to rebalance by around 2010 as more capacity is added.

A critical market to watch as a bellwether for any correction is the US gasoline market. Consumption there represents more than 40% of total global gasoline demand, and the US is home to about 20% of total world refining capacity (Fig. 1).

By year 2020, the US gasoline deficit—a key factor underpinning margins in the Atlantic Basin—could be significantly lower than it is today because domestic gasoline supply will increase. There could be fierce international competition, therefore, to supply the US market, and potential major implications for global trade flows.

US gasoline markets

Recent market tightness and associated high prices and margins are stimulating a market response for both demand and supply.

In the short term, oil product consumption has remained surprisingly inelastic to price fluctuations. Wood Mackenzie maintains, however, that in the medium to long term, consumers will begin to respond.

This response will take the form of improved automobile energy efficiency and the greater use of alternative energy products. The key questions concern the degree of the response and the ultimate impact that it will have on refined-product demand.

On the supply side, there has been a wave of refinery investment announcements caused by the prospect of attractive returns. The primary questions are: How much of this new capacity will be built? Where and when will it be built? And what will be the impact upon oil product supply?

US in global context

Due to the current state of tight market fundamentals and with the predominant US position on both sides of the supply-demand situation, any disruption in the US gasoline market sends ripples through the global market.

This was evident when global gasoline prices spiked in 2005 when the hurricanes hit the US and again in 2006 when methyl tertiary butyl ether was phased out.

Response to high oil prices

US gasoline demand has grown at 1.6%/year during the past decade because car ownership and travel have increased, while vehicle fleet efficiency has changed very little. Passenger car ownership has grown only slightly during the past 20 years; much of the incremental growth was in sales of light trucks, such as sport utility vehicles (SUVs) and multi-purpose vehicles.

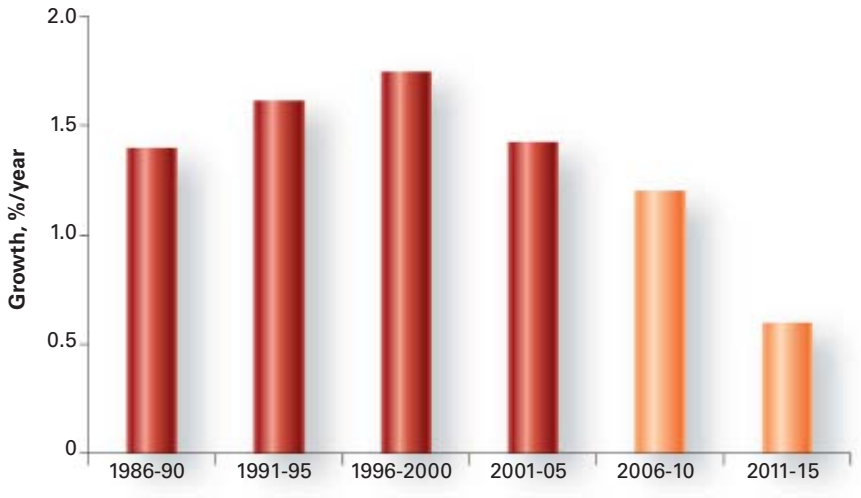
These light trucks have less stringent mandatory fuel-efficiency standards than cars. Indeed, the average fuel efficiency of the light-truck fleet has remained largely unchanged since 1990, although the passenger car fleet efficiency has improved somewhat.

There were 780 cars/1,000 people in the US in 2005, the highest in the world. Recent high pump prices have brought fuel economy into focus once more and sales of SUVs have faltered. Wood Mackenzie expects that the fleet's fuel economy will gradually improve because motorists will seek more efficient cars and SUVs.

Some of this improvement will be mandated. Unchanged for a decade at 20.7 mpg, the light-truck fuel efficiency standard is now being increased progressively between 2005 and 2007

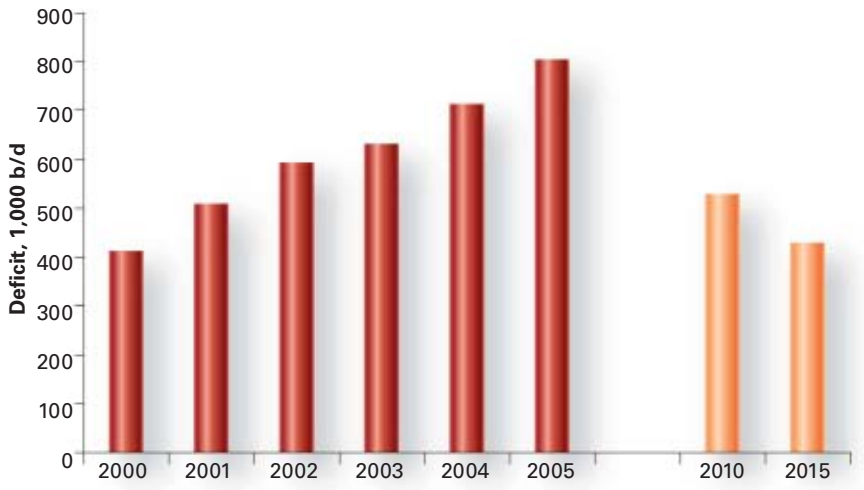
US GASOLINE DEMAND

Fig. 2



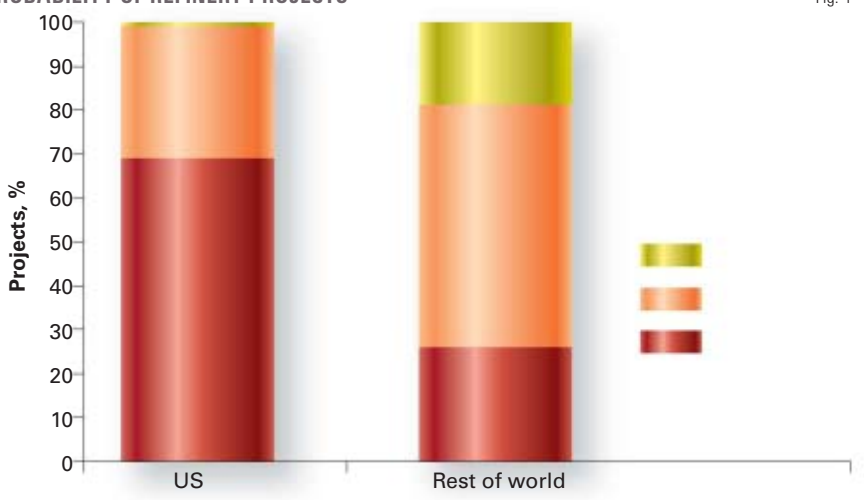
US GASOLINE DEFICIT

Fig. 3



PROBABILITY OF REFINERY PROJECTS

Fig. 4



to 22.2 mpg. Hybrid sales will account for some of the efficiency gains due to increased sales, possibly 1 million vehicles by 2010.

Diesel vehicles will make a modest contribution to fleet fuel efficiency and the erosion of gasoline demand, although not to the extent seen in Europe. Diesel-powered cars have never caught on in the US as in Europe due to inexpensive gasoline and consumer resistance; less than 5% of light truck sales are diesel and the proportion of diesel passenger cars is negligible.

Using technologies improved in Europe, and with tailpipe emissions reductions enabled by the imminent introduction of ultralow-sulfur diesel, some increases in diesel vehicle sales are likely.

Wood Mackenzie anticipates that the overall effect of these efficiency improvements and other factors, such as saturation of the vehicle fleet, will be a reduction in the future rate of growth in gasoline consumption to below historic levels.

We expect that the slow-down already seen in gasoline demand growth since the 1990s will continue during 2005-10 (Fig. 2); growth rates will fall even further until 2015, such that demand could even begin to stagnate after 2015.

Market response?

Our analysis includes all known and realistic capacity expansions and upgrading projects, and allows for the effects of capacity creep. We believe that the high number of refinery investments being implemented in the US will have an effect on the country's utilization rates. Shut-downs to tie in new infrastructure will prevent US utilization rates from rising above 90% in 2010.

Although the 2005 deficit was inflated due to hurricane disruptions, the US gasoline deficit is forecast to drop markedly by 2010, back to levels seen in 2001-02 level (Fig. 3). After 2010, this deficit is expected to reduce even more because incremental refining supply will outpace ever-slower demand growth.

US supply response

The US refining industry consists of 133 refineries with a capacity of nearly 18 million b/d. Although a new refinery has not been built in the US in more than a generation, the industry has been quick in developing its response to improved margins since 2004.

Of the more than 600 projects in Wood Mackenzie's global refining investment database, some 100 are in the US. Of these, more than 40% are for quality compliance, while the rest are for investment in upgrading or new crude capacity.

We believe that many of the investment projects have a high likelihood of proceeding. We rank almost 70% of these projects as having a "strong" probability rating, a fact that reflects the quality of the sponsors as well as the powerful project rationale. In contrast, only about 25% of projects for the rest of the world are considered as "strong" (Fig. 4).

Equipment delays and escalating

construction costs also have an effect. Although the effect of delivery delays on some long lead items, such as large pressure vessels needed for hydrocrackers, can be minimized by smart project-management strategies, rising costs have already caused some postponements and even project cancellations.

In addition to the large number of small expansions totaling slightly more than 700,000 b/d, there are three major crude expansion projects in the US:

- The 325,000-b/d expansion of Motiva's Port Arthur, Tex., refinery.
- The 180,000-b/d expansion of Marathon Oil Co's. Garyville, La., refinery.
- Chevron is evaluating expanding its Pascagoula, Miss., refinery to become the second largest in the US. This would involve adding at least 200,000 b/d of capacity to the existing 325,000 b/d.

We expect all of these major expansions to proceed, although not all of them will start up by 2010. There is one new grassroots refinery proposed, the 150,000-b/d Arizona Clean Fuels refinery in Yuma. We do not believe, however, that this refinery will be constructed within the next decade, if ever.

The total additional crude capacity currently announced in the US, and which Wood Mackenzie believes to be realistic, is about 1.1 million b/d added by 2010.

Americas—overall outlook

The analysis from our Global Products' Outlook service shows that, in overall terms, North America currently has a large deficit of oil products supply vs. demand. Wood Mackenzie's view is that this region's deficit of oil products could fall significantly by 2020 as a result of increased crude capacity (mainly in the US) outpacing growth in oil product demand.

In contrast, Latin America has a current surplus of oil products supply vs. demand and is a major exporter. Our analysis shows that the products surplus (and level of exports) will rise significantly by 2020, primarily due to new crude-distillation capacity coming on stream and the effects of increasing biofuels use, particularly in Brazil. Much of the crude capacity in Latin America is being developed primarily as a means of monetizing extra-heavy crude reserves.

These findings have some fundamental long-term implications. Refiners in Europe and Latin America that currently rely on exporting products to the US could find competition for this market becoming increasingly fierce. New capacity being built in Latin America, which will push this region further into surplus, will need to find alternatives to the US markets, possibly as distant as Asia.

Although this may be an opportunity for shipping companies, it does not bode well for long-term refining profitability in Latin America. Moreover, any additional new crude capacity in the region beyond that which Wood Mackenzie is already forecasting could further increase the risk of a capacity overbuilds and depressed refining profitability in the long term.

Acknowledgment

This article draws upon an in-depth analysis that Wood Mackenzie has completed for North America and Latin America. This analysis forms part of our newly developed Global Products' Outlook service, which analyzes the fundamental market issues facing refiners. ✦

The author

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ENVIRONMENTAL MITIGATION—3

Limestone boulders, artificial reef modules provide seafloor mitigation

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Gulfstream Natural Gas System LLC created habitat replacement sites on the Gulf of Mexico seafloor during installation of its subsea pipeline as part of efforts to mitigate its effect on both epiflora-epifauna and fish.

The habitat replacement sites consisted of either groupings of limestone boulders or prefabricated reef modules (Fig. 1), both of which served as substrate for live bottom community development.

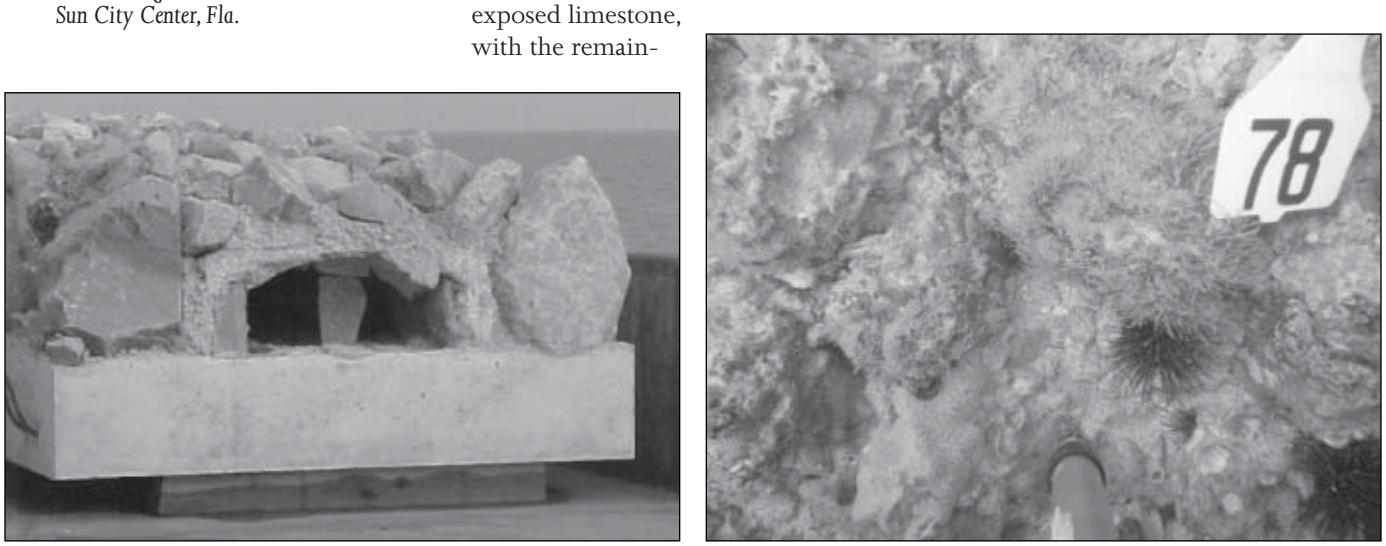
The boulder sites consisted of limestone boulders spread across the mitigation area. The limestone used to construct the limestone boulder sites had specific gravity of 2.1 to 2.6 and median diameter of 3 ft. These specifications ensured that the boulders maintained their integrity when exposed to salt water dissolution. The module sites consisted of simulated reef modules arranged in a nonlinear fashion. The modules contained a minimum of 75% exposed limestone, with the remaining exposed concrete surface brushed to expose the limestone aggregate.

The spatial arrangements used in habitat placement were chosen to increase the overall benefit of the habitat. The sites selected for habitat placement were located in the vicinity of the pipeline trench, near natural live bottom areas and on sand bottom that did not exceed 0.6 m thick. Gulfstream established three limestone boulder sites (150 m × 150 m) within each of three depth zones (12-21 m, 24-30 m, and 30-60 m).

The prefabricated reef modules consisted of limestone in a concrete matrix and were also placed in 150-m × 150-m areas. A total of 153 reef modules formed three groupings of 17 modules within each of the three reef module areas (Fig. 2).

Part 2 of this article (OGJ, Jan. 8, 2007, p. 52) discussed the findings of Gulfstream's postconstruction monitoring program, focusing on epiflora and epifauna. Part 3 of this article, presented here, evaluates the success of the habitat replacement sites in terms of both colonization by sessile epifauna, and habitat use by reef fishes. This evaluation includes:

- Comparison of epifaunal-epifloral abundance and community structure at the habitat replacement sites with unaffected live bottom reference habitat.



Gulfstream used prefabricated reefs such as this (left) to provide seafloor replacement environments (right) for epiflora, epifauna, and fish disturbed by its pipeline construction (Fig. 1).

• Comparison of fish abundance and community structure at the habitat replacement sites with unaffected live bottom reference habitat.

The article's conclusion will offer a detailed examination of the project's postconstruction fish community.

Methodology

Video documentation surveys delineated live bottom areas close to the pipeline route before construction began. Entering the live bottom polygons and pipeline corridor route into a geographic information system (GIS) randomly established the reference habitat stations for biological comparisons. Unaffected live bottom polygons near the habitat replacement sites and outside of the pipeline corridor served as potential reference habitat station locations.

Epifauna-epiflora sampling

Two different types of sampling, transects and photostations, estimated the percent cover of sessile epifauna and epiflora within the habitat replacement areas and reference habitat. Transect coordinates were provided to the field survey crews, which entered them into the vessel's navigation system before deployment. The survey vessel navigated to the coordinate locations, where divers were deployed.

In the shallowest depth zone, survey divers navigated to each transect coordinate end point and established a transect end point marker. After establishing the transect end points, survey divers measured the transect with a weighted tape measure to verify the transect length.

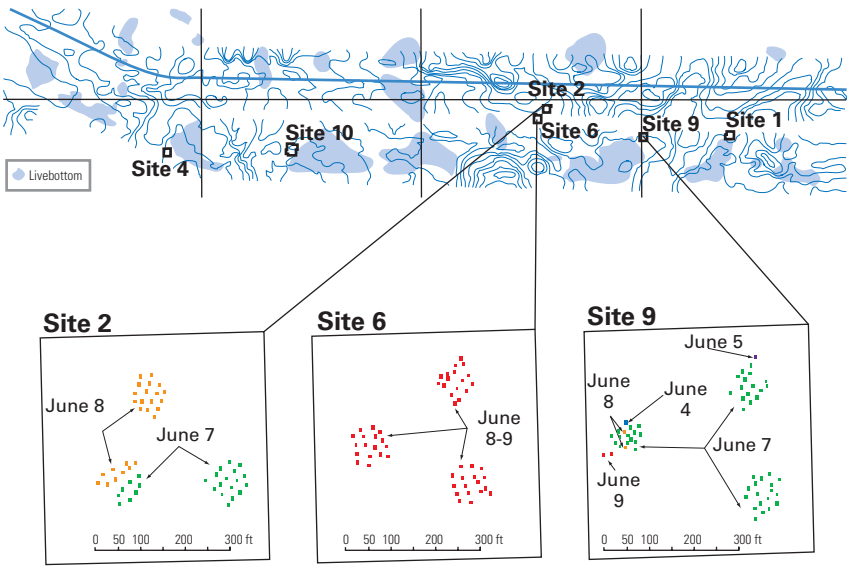
In the two deeper zones, survey crews provided divers with one end point coordinate and a defined azimuth for each transect. After navigating to the end point, survey divers extended a weighted tape measure 25 m along the defined azimuth and established the second transect end point.

Divers used an Olympus Camedia C-5060 wide-angle digital camera with 5.1 megapixel capacity to collect the transect photographs. An Olympus PT-020 underwater housing with a retractable rod affixed to the bottom held the camera. The retractable rod allowed divers to accurately maintain a fixed distance from the seafloor during photograph collection, providing a fixed scale for each photograph.

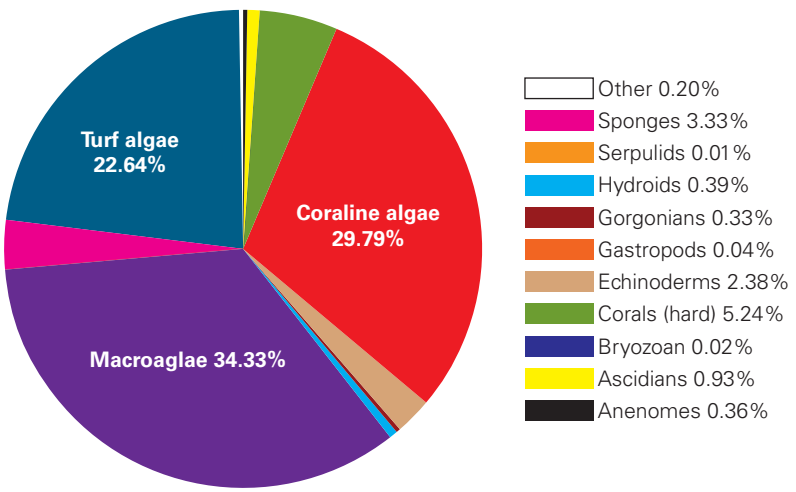
Divers photographed the entire length of each transect using sequential, overlapping photographs that contained a clear view of the tape measure within each frame. Survey crews established three random 25-m transects inside each habitat replacement site and reference habitat (Fig. 2).

Gulfstream established permanent photostations on three limestone boulders, two reef modules, and nine reference sites in the shallowest depth zone. Each photostation collected four photographs that were later combined as a mosaic capturing 0.707 sq m of habitat.

SAMPLE MODULAR REEF LOCATIONS, PLACEMENT DATES (2002) Fig. 2



REPLACEMENT-AREA TAXA COMPOSITION Fig. 3



Photostation information collection happened in May 2005, with transect information collected in August 2005. Analysis of the photographs focused on percent biotic cover, species richness, and species diversity. Gulfstream analyzed all photostation images and 45 randomly selected photographs from each transect.

Photographic analysis followed random point analysis as described by Bohnsack. This method electronically transposes 100 random dots onto each image. It then determines percent biotal cover for a given taxon by tabulating the percentage of dots touching organisms of each individual taxon. Averaging data from individual images produces a mean for the entire photostation or transect.

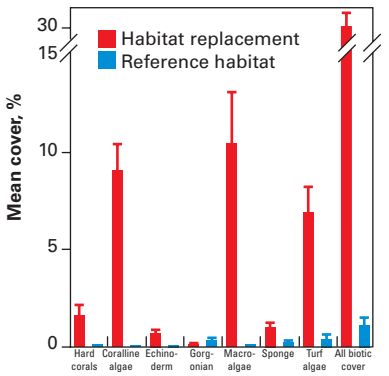
Fish sampling

Gulfstream conducted nonoverlapping census counts following point count census procedures outlined in Bohnsack and Bannerot and Bohnsack et al. This protocol requires each diver-observer to census fish within a 5-m radius. Observers position themselves on the center point of the census area and wait for 3 min before recording. The waiting period allows dampening of any disturbance. After the initial waiting period, the observer identifies and counts all fish that enter the census area. For the 5-min duration of the census time, the observer slowly rotates around the center point.

Gulfstream conducted censuses in June 2005 and November 2005-January 2006 during late morning and afternoon hours. For the summer census, survey teams performed 10 counts each in the limestone boulder sites, reef module sites, and reference habitat. For the winter census, teams conducted 11 counts in the limestone boulder sites, 10 in the reef module sites, and 9 in the reference habitat.

During the winter census, Gulfstream increased the census time to 10 min at seven of the habitat replacement stations in order to determine if a 5 min census time was most appropriate. Bohnsack and Bannerot noted that more time might be required to sample species within structurally complex habitats.

DOMINANT TAXONOMIC COVERS Fig. 4



A series of T-tests showed no significant differences in abundance based on the two different times for all fish species ($t = -1.38$, $P = 0.18$), demersal fish species ($t = -1.09$, $P = 0.29$, log transformed data), or commercially important species ($t = -0.31$, $P = 0.76$). Pelagic species were not observed during any of the 10-min samples, so that sampling time did not affect the count of this community component either.

These results agree with the conclusions that Bohnsack and Bannerot drew for their own study area, that a standardized 5-min sampling window provides a representative value. The use of a longer time window could lead to increased bias due to highly mobile species that are hard to distinguish as discrete visitors if they return to the sampling area. All samples, therefore, were combined for analysis, regardless of their duration.

Survey teams collected abiotic and habitat characteristics at each fish census location to assess differences between the study areas that may affect either fish populations or data collection. Teams measured surface water temperature at each sampling point. Secchi disk measurements assessed if divers had sufficient light and water clarity to conduct the fish census at each station.

Surface roughness contributes substantially to habitat complexity and was measured during the summer fish survey as rugosity. The ratio of linear distance traversed by a fixed length of chain yielded the rugosity at each station. The 9.6-m chain traversed less distance in areas with a high degree of topographic relief, showing greater rugosity.

Statistical analysis

A series of statistical tests compared epifaunal-epifloral and fish abundance and community assemblage at the habitat replacement stations to that found at unaffected hard-live bottom reference stations. Specifically, T-tests or one-way ANOVA tests addressed differences in abundance values. A nonparametric Mann-Whitney test or Kruskal-Wallis ANOVA on Ranks mitigated circumstances when assumptions of normality and heterogeneity of variances could not be satisfied with standard transformation.

If ANOVA results showed a significant p-value, a Student-Newman-Keuls (SNK) or Dunn's multiple comparisons test was performed ($\alpha = 0.05$). A Spearman rank correlation test determined if a relationship exists between fish abundance and habitat complexity (e.g., rugosity). Analysis of similarities (ANOSIM), a PRIMER v5 multivariate analysis technique, assessed differences in the community assemblage between habitat replacement types and reference stations. If ANOSIM results showed a significant difference between groups, a similarity percentages (SIMPER) analysis (another PRIMER v5 multivariate analysis technique) was run to determine which groups were most influential in creating the differences.

The SIMPER technique examines not just the average similarity within a group, but also the average dissimilarity between groups. Analysts square root-transformed the data prior to applying ANOSIM or SIMPER. Clarke and Warwick recommend the use of Bray-Curtis similarity matrices as well.

MANN-WHITNEY TEST RESULTS

Table 1

Metric	T value	P value[1]	Multiple comparison results[2]	
Corals (hard)	1,126.5	*0.001	Habitat replacement	Reference habitat
Coralline algae	1,101.5	*0.001	Habitat replacement	Reference habitat
Echinoderm	1,117.0	*0.001	Habitat replacement	Reference habitat
Gorgonians	702.0	0.197	Reference habitat	Habitat replacement
Macroalgae	1,027.0	*0.001	Habitat replacement	Reference habitat
Sponge	1,006.0	*0.001	Habitat replacement	Reference habitat
Turf algae	1,053.0	*0.001	Habitat replacement	Reference habitat
Total biotic cover	**1,176.0**	***0.001**	**Habitat replacement**	**Reference habitat**

[1]Significant P values are denoted with an asterisk. [2]Treatments sharing an underline are not significantly different.

T-TEST, MANN-WHITNEY TEST RESULTS; TAXONOMIC GROUPS, SPECIES DIVERSITY

Table 2

Metric	Multiple comparison results[1]		T value	P value[2]
Species richness	Habitat replacement	Reference	1,110.50	*0.001
Margalef's index, d	Habitat replacement	Reference	262.000	0.513
Pielous's index, J	Habitat replacement	Reference	753.000	0.099
Shannon's index, H'	Habitat replacement	Reference	999.0	*0.001
Simpson's index, 1-λ'	Habitat replacement	Reference	234.000	0.867

[1]Treatments sharing an underline are not significantly different. [2]Significant P values are denoted with an asterisk.

COMMUNITY COMPOSITION DIFFERENCES; REPLACEMENT VS. REFERENCE

Table 3

Species	SIMPER results: contribution to treatment differences, %*	Species	SIMPER results: contribution to treatment differences, %*
Porolithon	12.2	Macroalgae	5.6
Turf algae	9.1	Cladocora arbuscula	5.4
Asteroidean	8.0	Encrusting sponge	5.1
Dictyota sp.	6.6	—	—

*Percent contribution is only reported for species contributing >5% of differences.

The four diversity indices calculated include:

- Margalef's Species Richness (d).
- Pielou's Evenness Index (J).
- Shannon-Wiener (H').
- Simpson's (1-Lambda').

Margalef's and Pielou's indices bias toward rare species, while the Simpson index is biased toward dominant species. Shannon-Wiener is generally the most balanced index of the four, but it is still sensitive to rare species.

Some analyses classified fish species according to their predominant habitat: pelagic or demersal. Specifically, Peterson Field Guides: Atlantic Coast Fishes, Fishes of the Gulf of Mexico, Volume 1, and Fishbase provided the bases for habitat classification.

If a habitat use description was not given for an individual species, the description given at the next higher taxonomic level, usually family, classified the species. The following guidelines governed assigning each fish species to one of the two categories:

1. Demersal (Benthic)—bottom-dwelling; occurring on the seafloor, whether shallow or deep water.
2. Pelagic—living in open waters away from the bottom or a demersal species that commonly preys upon benthic organisms.

For example, filefishes (Aluterus sp.), are not considered demersal, but they feed on benthic organisms such as soft-bodied invertebrates and sponges.

Recognizing the presence of pelagic species is important as many tend to be schooling fishes, which can skew statistical analyses.

Gulfstream also performed a separate analysis of commercially important species. The Gulf of Mexico Fishery Management Council's Commercial Fishing Regulations for Gulf of Mexico Federal Waters (December 2004) species list, and the red drum fishery and reef fish fishery sections of NOAA's draft for the Generic Essential Fish Habitat Amend-

ment to the following management plans of the Gulf of Mexico (GOM), determined which species were of commercial interest.

Results

The transect information showed that a diversity of fauna was found within the habitat replacement areas (Fig. 3) and that biotic cover was 10 times greater in habitat replacement stations than at reference habitat stations (Table 1). Percent biotic cover was also significantly greater in the habitat replacement areas than in the reference habitat for all of the dominant taxonomic categories except gorgonians (Fig. 4).

Photostation information also showed that mean biotic cover in habitat replacement areas (93.9, 1.0%) was more than 25 times greater than in the reference habitat (3.3, 1.8%). The difference in cover was significant for habitat replacement areas as compared to reference habitat photostations but not between habitat replacement types (one-way ANOVA, $F = 440.3$, $P = *0.001$, SNK multiple comparison results) which were almost identical for the limestone boulder (mean = 94.6, 1.4%) and reef module (93.6, 1.4%) stations.

The transect information showed the dominance of turf algae, macroalgae, and coralline algae at the habitat replacement stations (Fig. 4). This coincided with the photostation information showing that cover was dominated by turf algae along with Cladocora arbuscula (coral) and Halisarca sp. (sponge). Taxonomic diversity in the habitat replacement sites varied significantly from that of the reference habitat (Table 2). The community structure in the habitat replacement sites also varied significantly from the natural hard-live bottom reference habitat using PRIMER. SIMPER analysis showed a greater number of algal species (including coralline algae) contributing to the difference in community composition (Table 3).

Editor's note: A full bibliography was included in Part 1 of this article (OGJ, Jan. 1, 2007, p. 58). ✦

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	1-5 2007	[1]12-29 2006	1-5 2007	[1]12-29 2006	1-5 2007	[1]12-29 2006	1-6 2005
	1,000 b/d						
Total motor gasoline	521	435	0	8	521	443	383
Mo. gas. blending comp.	531	742	1	19	532	761	450
Distillate[2]	482	401	18	16	500	417	402
Residual	462	201	81	42	543	243	600
Jet fuel-kerosine	61	173	145	134	206	307	120
LPG	280	345	2	0	282	345	375
Unfinished oils	485	477	78	30	563	507	672
Other	421	314	9	16	430	330	424
Total products	**3,243**	**3,088**	**334**	**265**	**3,577**	**3,353**	**3,426**
Canadian crude	1,685	1,601	81	126	1,766	1,727	1,651
Other foreign	6,572	7,102	808	1,114	7,380	8,216	8,176
Total crude	**8,257**	**8,703**	**889**	**1,240**	**9,146**	**9,943**	**9,827**
Total imports	**11,500**	**11,791**	**1,223**	**1,505**	**12,723**	**13,296**	**13,253**

[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

	*1-5-07	*1-6-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	63.14	75.31	–12.16	–16.2
Brent crude	54.42	61.80	–7.38	–11.9
Crack spread	8.73	13.50	–4.78	–35.4
FUTURES MARKET PRICES				
One month				
Product value	64.35	75.22	–10.87	–14.5
Light sweet crude	56.74	63.39	–6.65	–10.5
Crack spread	7.61	11.83	–4.22	–35.7
Six month				
Product value	72.97	78.59	–5.62	–7.1
Light sweet crude	60.78	65.46	–4.68	–7.1
Crack spread	12.19	13.13	–0.94	–7.2

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel	Fuel oils		Unfinished oils
		Total	Blending comp.[2]	Kerosine	Distillate	Residual	
	1,000 bbl						
PAD I	13,198	58,399	27,148	9,404	66,412	19,421	8,891
PAD II	70,300	55,530	17,113	7,550	29,227	1,770	12,501
PAD III	166,958	64,803	27,745	13,359	36,189	17,826	41,797
PAD IV	14,170	6,634	2,038	463	3,102	342	2,956
PAD V	[1]48,653	31,123	23,373	8,813	12,217	5,604	20,066
Jan. 5, 2007	**[1]313,279**	**216,489**	**97,417**	**39,589**	**147,147**	**44,963**	**86,211**
Dec. 29, 2006[3]	**321,003**	**207,918**	**93,476**	**38,072**	**143,103**	**44,525**	**85,556**
Jan. 6, 2006	**316,936**	**210,673**	**72,081**	**42,401**	**139,515**	**38,291**	**86,605**

[1]Includes 6.800 million bbl of Alaskan crude in transit by water. [2]Included in total motor gasoline. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—JAN. 5, 2007

	REFINERY OPERATIONS					REFINERY OUTPUT			
District	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
	1,000 b/d					1,000 b/d			
East Coast	3,296	1,465	1,465	1,618	90.5	1,755	79	502	136
App. Dist. 1	108	94	95	95	100.0	11	0	27	1
Dist. 1 total	**3,404**	**1,559**	**1,560**	**1,713**	**91.1**	**1,766**	**79**	**529**	**137**
Ind., Ill., Ky.	2,226	2,203	2,226	2,355	94.5	1,185	198	598	23
Minn., Wis., Dak.	389	380	385	442	87.1	256	32	129	13
Okla., Kan., Mo.	897	672	717	786	91.2	487	26	276	4
Dist. 2 total	**3,512**	**3,255**	**3,328**	**3,583**	**92.9**	**1,928**	**256**	**1,003**	**40**
Inland Texas	966	508	635	647	98.2	496	40	180	7
Texas Gulf Coast	3,876	3,451	3,562	4,031	88.4	1,347	328	880	130
La. Gulf Coast	3,420	3,135	3,190	3,264	97.7	1,409	381	877	142
N. La. and Ark.	221	186	202	215	94.0	103	9	45	7
New Mexico	161	90	92	113	81.4	127	1	34	0
Dist. 3 total	**8,644**	**7,370**	**7,681**	**8,270**	**92.9**	**3,482**	**759**	**2,016**	**286**
Dist. 4 total	**654**	**550**	**563**	**596**	**94.5**	**310**	**34**	**165**	**13**
Dist. 5 total	**2,871**	**2,752**	**2,871**	**3,173**	**90.5**	**1,786**	**469**	**592**	**124**
Jan. 5, 2007	**19,085**	**15,486**	**16,003**	**17,335**	**92.3**	**9,272**	**1,597**	**4,305**	**600**
Dec. 29, 2006*	**18,823**	**15,209**	**15,670**	**17,335**	**90.4**	**9,438**	**1,531**	**4,282**	**621**
Jan. 6, 2006	**16,837**	**14,883**	**15,253**	**17,115**	**89.1**	**8,500**	**1,512**	**4,086**	**651**

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

Statistics

OGJ GASOLINE PRICES

	Price ex tax 1-3-06	Pump price* 1-3-06	Pump price 1-4-05
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	189.2	228.9	219.2
Baltimore	187.1	229.0	218.5
Boston	191.5	233.4	213.5
Buffalo	191.0	251.1	215.2
Miami	196.2	246.5	222.2
Newark	192.8	225.7	219.9
New York	184.7	244.8	227.9
Norfolk	184.5	222.1	223.5
Philadelphia	198.8	249.5	226.5
Pittsburgh	186.9	237.6	222.8
Wash., DC	197.9	236.3	226.5
PAD I avg.	191.0	236.8	221.4
Chicago	211.6	262.5	240.3
Cleveland	181.9	228.3	214.5
Des Moines	182.0	222.4	212.8
Detroit	176.2	225.4	214.8
Indianapolis	183.8	228.8	218.4
Kansas City	175.8	211.8	215.8
Louisville	188.5	225.4	212.8
Memphis	181.2	221.0	222.1
Milwaukee	181.3	232.6	223.5
Minn.-St. Paul	181.6	222.0	222.4
Oklahoma City	175.4	210.8	211.1
Omaha	178.4	224.8	217.8
St. Louis	182.8	218.8	222.5
Tulsa	175.3	210.7	211.4
Wichita	173.0	217.2	214.1
PAD II avg.	182.0	224.2	218.3
Albuquerque	182.3	218.7	215.5
Birmingham	183.7	222.4	214.5
Dallas-Fort Worth	186.7	225.1	214.2
Houston	181.7	220.1	211.5
Little Rock	181.0	221.2	213.8
New Orleans	183.4	221.8	258.8
San Antonio	181.2	219.6	218.5
PAD III avg.	182.9	221.3	221.0
Cheyenne	179.3	211.7	212.9
Denver	172.5	212.9	220.2
Salt Lake City	183.2	226.1	217.9
PAD IV avg.	178.3	216.9	217.0
Los Angeles	203.3	261.8	230.6
Phoenix	199.0	236.4	228.2
Portland	225.4	268.7	225.5
San Diego	211.0	269.5	233.6
San Francisco	224.5	283.0	236.6
Seattle	226.6	279.0	228.9
PAD V avg.	215.0	266.4	230.6
Week's avg.	**188.9**	**232.5**	**221.2**
Dec. avg.	**184.9**	**228.5**	**216.5**
Nov. avg.	**180.1**	**223.7**	**229.9**
2007 to date	**188.9**	**232.5**	—
2006 to date	**178.8**	**221.2**	—

*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

	12-29-06 ¢/gal		12-29-06 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	164.25	New York Harbor	160.05
Gulf Coast	156.90	Gulf Coast	159.05
Los Angeles	176.15	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	147.30	ARA	165.13
Singapore	160.71	Singapore	161.67
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	162.25	New York Harbor	89.60
Gulf Coast	157.48	Gulf Coast	97.02
Los Angeles	185.15	Los Angeles	106.48
		ARA	87.44
		Singapore	102.44

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

BAKER HUGHES RIG COUNT

	1-5-07	1-6-06
Alabama	7	6
Alaska	9	10
Arkansas	36	16
California	34	33
Land	31	28
Offshore	3	5
Colorado	95	83
Florida	0	2
Illinois	0	0
Indiana	0	0
Kansas	13	7
Kentucky	7	6
Louisiana	184	165
N. Land	54	49
S. Inland waters	20	18
S. Land	41	34
Offshore	69	64
Maryland	0	0
Michigan	2	2
Mississippi	20	6
Montana	22	25
Nebraska	0	0
New Mexico	92	91
New York	10	3
North Dakota	37	27
Ohio	11	9
Oklahoma	176	149
Pennsylvania	16	14
South Dakota	1	1
Texas	767	667
Offshore	11	9
Inland waters	2	1
Dist. 1	19	22
Dist. 2	25	30
Dist. 3	62	57
Dist. 4	93	71
Dist. 5	141	123
Dist. 6	127	96
Dist. 7B	32	25
Dist. 7C	41	38
Dist. 8	102	79
Dist. 8A	26	26
Dist. 9	31	24
Dist. 10	55	66
Utah	44	27
West Virginia	24	25
Wyoming	82	87
Others—HI-1; ID-1; TN-4	6	3
Total US	**1,695**	**1,464**
Total Canada	**417**	**594**
Grand total	**2,112**	**2,058**
Oil rigs	279	243
Gas rigs	1,411	1,219
Total offshore	85	80
Total cum. avg. YTD	**1,695**	**1,464**

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	1-5-07 Rig count	1-5-07 Percent footage*	1-6-06 Rig count	1-6-06 Percent footage*
0-2,500	43	2.3	29	3.4
2,501-5,000	108	53.7	88	48.8
5,001-7,500	221	20.8	188	17.5
7,501-10,000	425	3.2	330	4.2
10,001-12,500	407	2.4	339	1.4
12,501-15,000	257	—	289	—
15,001-17,500	118	0.8	106	—
17,501-20,000	79	—	62	—
20,001-over	39	—	24	—
Total	**1,697**	**7.6**	**1,455**	**6.5**
INLAND	32		33	
LAND	1,606		1,366	
OFFSHORE	59		56	

*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]1-5-07	[2]1-6-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	21
Alaska	802	835
California	698	692
Colorado	59	59
Florida	8	7
Illinois	31	28
Kansas	94	93
Louisiana	1,401	1,126
Michigan	14	13
Mississippi	53	49
Montana	94	97
New Mexico	164	162
North Dakota	102	103
Oklahoma	173	167
Texas	1,389	1,290
Utah	44	47
Wyoming	142	139
All others	65	73
Total	**5,352**	**5,001**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	1-5-07
Alaska-North Slope 27°	49.52
South Louisiana Sweet	56.75
California-Kern River 13°	44.65
Lost Hills 30°	52.35
Wyoming Sweet	52.81
East Texas Sweet	54.39
West Texas Sour 34°	44.25
West Texas Intermediate	53.00
Oklahoma Sweet	53.00
Texas Upper Gulf Coast	49.75
Michigan Sour	46.00
Kansas Common	52.00
North Dakota Sweet	46.50

*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]	12-29-06
United Kingdom-Brent 38°	60.50
Russia-Urals 32°	56.09
Saudi Light 34°	55.94
Dubai Fateh 32°	57.92
Algeria Saharan 44°	62.36
Nigeria-Bonny Light 37°	63.28
Indonesia-Minas 34°	63.87
Venezuela-Tia Juana Light 31°	55.57
Mexico-Isthmus 33°	55.46
OPEC basket	59.20
Total OPEC[2]	57.33
Total non-OPEC[2]	54.99
Total world[2]	55.95
US imports[3]	54.00

[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]

	12-29-06	12-22-06	Change
	Bcf		
Producing region	942	947	–5
Consuming region east	1,740	1,773	–33
Consuming region west	392	401	–9
Total US	**3,074**	**3,121**	**–47**
	Oct. 06	**Oct. 05**	**Change, %**
Total US[2]	**3,452**	**3,194**	**8.1**

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

International rig count

Region	Dec. 2006 Land	Dec. 2006 Off.	Dec. 2006 Total	Dec. 05 Total
WESTERN HEMISPHERE				
Argentina	81	0	81	81
Bolivia	3	0	3	5
Brazil	14	19	33	28
Canada	452	4	456	575
Chile	1	0	1	0
Colombia	24	0	24	21
Ecuador	12	0	12	14
Mexico	57	27	84	94
Peru	5	1	6	3
Trinidad	3	4	7	5
United States	1,634	84	1,718	1,470
Venezuela	58	18	76	75
Other	2	0	2	1
Subtotal	**2,346**	**157**	**2,503**	**2,372**
ASIA-PACIFIC				
Australia	11	11	22	14
Brunei	1	3	4	2
China-offshore	0	17	17	17
India	54	31	85	83
Indonesia	35	18	53	60
Japan	1	0	1	3
Malaysia	0	14	14	12
Myanmar	8	2	10	9
New Zealand	4	2	6	6
Papua New Guinea	1	0	1	3
Philippines	1	0	1	2
Taiwan	0	0	0	0
Thailand	3	8	11	9
Vietnam	0	6	6	10
Other	2	2	4	6
Subtotal	**121**	**114**	**235**	**236**
AFRICA				
Algeria	25	0	25	21
Angola	0	4	4	3
Congo	1	0	1	1
Gabon	2	1	3	3
Kenya	0	0	0	0
Libya	12	1	13	9
Nigeria	2	9	11	9
South Africa	0	0	0	0
Tunisia	3	2	5	0
Other	2	3	5	3
Subtotal	**47**	**20**	**67**	**49**
MIDDLE EAST				
Abu Dhabi	9	5	14	13
Dubai	1	0	1	2
Egypt	31	8	39	32
Iran	0	0	0	38
Iraq	0	0	0	0
Jordan	1	0	1	1
Kuwait	16	0	16	13
Oman	41	0	41	36
Pakistan	17	0	17	11
Qatar	2	7	9	14
Saudi Arabia	66	9	75	44
Sudan	0	0	0	19
Syria	25	0	25	23
Yemen	15	0	15	14
Other	2	0	2	2
Subtotal	**226**	**29**	**255**	**262**
EUROPE				
Croatia	1	0	1	3
Denmark	0	0	0	2
France	0	0	0	1
Germany	4	0	4	3
Hungary	3	0	3	2
Italy	4	1	5	3
Netherlands	1	2	3	5
Norway	0	15	15	15
Poland	2	0	2	2
Romania	2	0	2	2
Turkey	4	0	4	5
UK	1	21	22	27
Other	4	0	4	4
Subtotal	**26**	**39**	**65**	**74**
Total	**2,766**	**359**	**3,125**	**2,993**

Definitions, see OGJ Sept. 18, 2006, p. 42
Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

Oil import freight costs*

Source	Discharge	Cargo	Cargo size, 1,000 bbl	Freight (Spot rate) worldscale	$/bbl
Caribbean	New York	Dist.	200	315	2.28
Caribbean	Houston	Resid.	380	209	1.67
Caribbean	Houston	Resid.	500	204	1.64
N. Europe	New York	Dist.	200	332	3.79
N. Europe	Houston	Crude	400	177	3.01
W. Africa	Houston	Crude	910	135	2.48
Persian Gulf	Houston	Crude	1,900	59	2.00
W. Africa	N. Europe	Crude	910	157	1.73
Persian Gulf	N. Europe	Crude	1,900	62	1.54
Persian Gulf	Japan	Crude	1,750	64	1.24

*December 2006 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

US LNG imports

Country	Oct. 2006	Sept. 2006	Oct. 2005	Change from a year ago, %
	MMcf			
Algeria	0	0	11,837	—
Brunei	0	0	0	—
Malaysia	0	0	3,109	—
Nigeria	8,957	6,025	2,895	209.4
Oman	0	0	0	—
Qatar	0	0	0	—
Trinidad and Tobago	24,677	25,197	33,212	–25.7
Others	2,551	8,782	8,523	–70.1
Total	**36,185**	**40,004**	**59,576**	**–39.3**

Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Baker oil tools workover rig count*

Region	Dec. 2006	Dec. 2005	Change, %
Gulf Coast	259	312	–17.0
Midcontinent	251	244	2.9
Northeastern	79	80	–1.3
Rocky Mountains	220	215	2.3
Southeastern	199	201	–1.0
West Texas	332	304	9.2
Western	144	138	4.3
Total US	**1,484**	**1,494**	**–0.7**
Canada	423	791	–46.5
Total N. America	**1,907**	**2,285**	**–16.5**

*Wells over 1,500 ft deep and tubing out of the wellbore. Excludes rigs on rod jobs. Definitions, see OGJ Sept. 22, 1997, p. 46. Source: Baker Hughes Inc. Data available in Oil & Gas Journal Energy Database.

Propane prices

	Nov. 2006	Dec. 2006	Nov. 2005	Dec. 2005
	¢/gal			
Mont Belvieu	95.38	96.63	99.93	105.58
Conway	95.05	94.42	100.02	107.98
Northwest Europe	94.50	98.81	99.77	114.74

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

Muse, Stancil & Co. refining margins

	US Gulf Coast	US East Coast	US Mid-west	US West Coast	North-west Europe	South-east Asia
	$/bbl					
Dec. 2006						
Product revenues	71.52	68.99	68.94	78.86	67.94	64.57
Feedstock costs	–60.08	–63.05	–56.38	–55.37	–59.87	–62.17
Gross margin	11.44	5.94	12.56	23.49	8.07	2.40
Fixed costs	–2.03	–2.35	–2.28	–2.66	–2.28	–1.78
Variable costs	–2.22	–1.45	–1.96	–3.35	–2.00	–0.74
Cash operating margin	**7.19**	**2.14**	**8.32**	**17.48**	**3.79**	**–0.12**
Nov. 2006	9.33	4.00	13.92	18.78	3.35	0.64
YTD avg.	12.49	15.00	6.01	23.72	5.77	1.06
2005 avg.	12.53	6.98	12.31	20.55	5.51	1.52
2004 avg.	6.16	3.70	6.64	11.76	5.08	1.83
2003 avg.	2.92	2.22	4.84	5.43	2.35	–0.31

Source: Muse, Stancil & Co. See OGJ, Jan. 15, 2001, p. 46.
Data available in OGJ Online Research Center.
NOTE: The refining models that comprise the basis for the Muse refining margins have been updated to reflect changing crude slates, product specifications, and market pricing. All current and historical margin series have been revised.

Muse, Stancil & Co. gasoline marketing margins

Nov. 2006	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	230.26	206.54	244.92	228.72
Taxes	52.03	38.40	55.51	48.20
Wholesale price	170.43	163.69	190.12	171.63
Spot price	160.94	161.17	181.17	163.14
Retail margin	7.89	4.45	–0.71	8.89
Wholesale margin	9.49	2.52	8.95	8.49
Gross marketing margin	**17.38**	**6.97**	**8.24**	**17.38**
Oct. 2006	27.33	19.27	31.05	30.67
YTD avg.	19.37	20.70	18.44	28.40
2005 avg.	19.77	16.26	20.39	27.13
2004 avg.	22.49	17.49	23.61	30.38
2003 avg.	22.69	19.10	30.89	31.42

*The wholesale price shown for Chicago is the RFG price utilized for the wholesale margin. The Chicago retail margin includes a weighted average of RFG and conventional wholesale purchases.
Source: Muse, Stancil & Co. See OGJ, Oct. 15, 2001, p. 46.
Data available in OGJ Online Research Center.

Muse, Stancil & Co. ethylene margins

	Ethane	Propane	Naphtha
	¢/lb ethylene		
Dec. 2006			
Product revenues	49.74	83.42	98.24
Feedstock costs	–25.97	–54.89	–85.66
Gross margin	23.77	28.53	12.58
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–5.50	–6.49	–8.75
Cash operating margin	**12.89**	**15.68**	**–3.36**
Nov. 2006	17.60	19.35	2.48
YTD avg.	19.55	22.53	1.77
2005 avg.	14.43	20.68	1.28
2004 avg.	9.00	12.03	0.51
2003 avg.	8.33	11.36	3.72

Source: Muse, Stancil & Co. See OGJ, Sept. 16, 2002, p. 46.
Data available in OGJ Online Research Center.

Muse, Stancil & Co. US gas processing margins

Dec. 2006	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	7.02	5.85
Liquids	1.00	2.73
Gas purchase cost	7.82	7.85
Operating costs	0.07	0.15
Cash operating margin	**0.13**	**0.58**
Nov. 2006	0.11	0.64
YTD avg.	0.26	0.97
2005 avg.	–0.06	0.25
2004 avg.	0.07	0.33
2003 avg.	–0.08	–0.06
Breakeven producer payment, % of liquids	84%	77%

Source: Muse, Stancil & Co. See OGJ, May 21, 2001, p. 54.
Data available in OGJ Online Research Center.

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Corruption fight should target government excess

The Editor's Perspective

by Bob Tippee, Editor

Democrats deserve applause for making ethics reform the first legislative thrust of the 110th Congress.

That Congress needs cleansing is part of the reason that Democrats now control both houses. They inherit the role of sanitizer even though members of their party contributed to the mess.

On the first day of the new congressional session, the House passed a series of rule changes prohibiting representatives and their employees from accepting gifts or travel from lobbyists and from traveling in corporate aircraft.

In the stench lingering behind favors spread around Washington by imprisoned lobbyist Jack Abramoff, the crackdown is refreshing. But it doesn't address the core problem.

Corruption happens when people in positions of authority have too much of other people's money to spend. It results, in other words, from oversized, overactive government. The Democrats don't seem on track to solve that problem. They seem, in fact, determined to aggravate it.

On a calendar for the Democratic agenda published by the office of new Senate Majority Leader Steny Hoyer of Maryland, the date Jan. 18 has this entry: "End subsidies for Big Oil and invest in renewable energy."

Comment on the first part of that item must await clarification of what the Democrats mean by "subsidies for Big Oil." But the intention to "invest in renewable energy" is clear enough.

The Democrats plan to increase the expenditure of public money on political—;meaning uneconomic—;energy. They will commit other people's money to popular ideals such as lower reliance on foreign oil if not outright—and unattainable—energy independence.

All that money dedicated to all that high purpose won't go to projects able to fulfill energy needs most efficiently, which would be projects able to compete without government help.

It will go to uncompetitive projects with sponsors best able to influence official decisions, at least some of whom will know that airplane rides aren't the only way to practice persuasion.

A political party hoping to fight corruption should be seeking ways to lower the amount of other people's money in play. It can't do this while pretending to "invest" in energy, renewable or otherwise.

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

Market Journal

by Sam Fletcher, Senior Writer

Crude suffers severe 2-day loss

The February contract price for benchmark US crude fell 9% Jan. 3-4 to near 18-month lows in the first two trading sessions of 2007 on the New York Mercantile Exchange.

The front-month contract dropped a total of $5.46 over those 2 days to close at $55.59/bbl on Jan. 4. "We have to go back to early December 2004 to find a 2-day loss that was greater than the loss of this week," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland. The market was closed Jan. 1 for the New Year's holiday and Jan. 2 for the funeral of former US President Gerald Ford.

"El Niño is taking a toll on the energy complex as it brings a warm Northern Hemisphere winter. We believe this fact has already been reflected in natural gas markets and is now showing up in oil," said Adam Sieminski of Deutsche Bank AG, New York. "Although the oil price could have further downside, we believe the drop so far combined with dollar weakness will prompt the Organization of Petroleum Exporting Countries into further action to defend the oil price, which, in an environment of still robust world growth, we believe will eventually push the oil price back up above $60/bbl in 2007."

Adjusted for the euro's increased value against the US dollar, a $55/bbl price for benchmark US crude becomes the equivalent of just $42/bbl for that crude and $38/bbl for the OPEC basket. That fact is "not lost on the OPEC ministers" who are paid for their oil in dollars while trading with Europe in euros, Sieminski noted.

Estimates adjusted

The US Energy Information Administration lowered its estimate of US crude demand by 567,000 b/d to 20.8 million b/d in October; its preliminary estimate of 21.3 million b/d would have represented a 5.3% gain from a year earlier to the highest level ever recorded for October. But even if the US economy slows in 2007, rising economic activity in Europe and Asia may easily offset the lost US demand, said analysts in the Houston office of Raymond James & Associates Inc.

"Finally, the real and existing threat of geopolitical wildcards such as Iran, Iraq, Nigeria, and Venezuela continue to hang over the oil markets, and they most likely won't disappear anytime soon," Raymond James analysts said. "Clearly, there are more fundamental and concrete reasons to support the bulls over the bears."

Nonetheless, Raymond James lowered its 2007 oil price forecast to $67/bbl from $70/bbl previously and its natural gas price estimate for the new year to $7.50/Mcf from $10/Mcf. "We still expect oil prices to firm as we move through 2007," the analysts said. "On the North American gas front, however, our 2007 natural gas outlook has deteriorated substantially from what we were expecting just a few months ago. The change to our outlook is strictly weather-related."

Raymond James analysts said, "We still look for gas prices to ramp up in the second half of the year as gas supplies begin to fall off; however, we now do not foresee gas prices reaching a more normal 7:1 ratio with oil prices until 2008."

As for 2006 price estimates, Raymond James analysts said, "For the first time in years, our natural gas forecast of $10.50/Mcf was actually too high. In fact, our estimate was more than 30% higher than the actual full-year average of $7.24. For the fourth year in a row, however, our bullish call on oil still proved too conservative, due in part to escalating concerns about Iran in the first half of the year. Even though our original $58/bbl oil forecast for 2006 was more than $2 (or 4%) ahead of Wall Street consensus at the time, it ended up falling short of the actual average by $7 (or 11%)."

Phil McPherson at C.K. Cooper & Co. in Irvine, Calif., noted that the February natural gas contract ended 2006 at $6.30/MMbtu Dec. 29 on NYMEX. That was "lower than last year's closing price for the first time in 5 years and a 37% decline year-over-year for the sector," he reported. With a glut of gas supplies and continued mild weather across most of the US, the price for natural gas is likely to average a modest $7/Mcf for 2007 and could even touch $5/Mcf this year if warm weather persists, McPherson said. He said the front-month crude futures price on NYMEX could fall as low as $55/bbl by the end of the first quarter of 2007 if a mild winter continues.

(Online Jan. 8, 2007; author's e-mail: samf@ogjonline.com)

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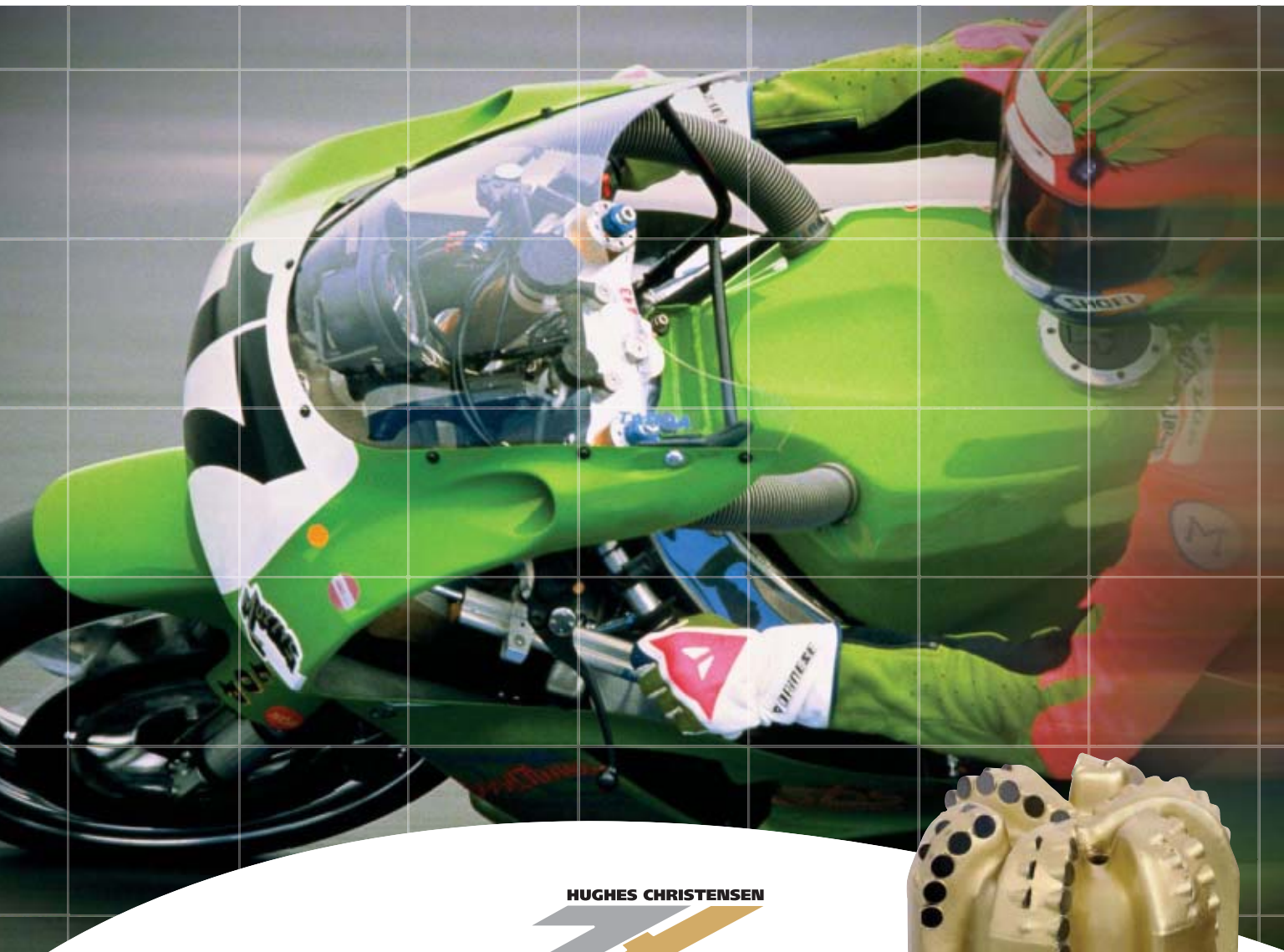

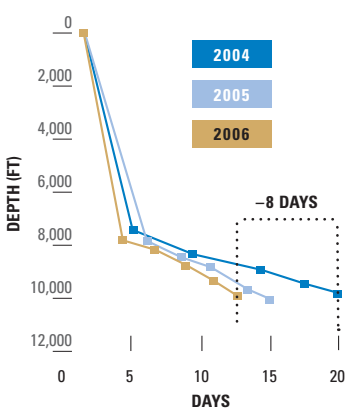

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