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Fuels Update

Deepwater projects present surface, downhole challenges
Refurbished jack up produces marginal field off Malaysia
Multiproduct software sets optimal pump use

OIL&GAS JOURNAL

Dec. 4, 2006
Volume 104.45

Fuels Update

Regular Features

Cover

The bus used for farm tours by the Agricultural Research Service (ARS), the research arm of the US Department of Agriculture, is powered by a soybean-based biodiesel fuel. Like many other groups and companies, ARS is involved in fuel research with government encouragement. With increased political pressure for cleaner transportation fuels and world demand for energy on the rise, there is a robust market for a growing variety of petroleum-based and alternative supplies. In this issue, articles beginning on pp. 18 and 44 examine the transportation markets for propane, biofuel, ultralow-sulfur diesel and gasoline, CNG, LNG, and propane.

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PennWell, Houston office
1700 West Loop South, Suite 1000, Houston, TX 77027
Telephone 713.621.9720/Fax 713.963.6285/Web site www.ogjonline.com

Editor Bob Tippee, bobt@ogjonline.com
Chief Editor-Exploration G. Alan Petzet, alanp@ogjonline.com
Chief Technology Editor-LNG/Gas Processing Warren R. True, warrent@ogjonline.com
Production Editor Guntis Moritis, guntism@ogjonline.com
Drilling Editor Nina M. Rach, ninar@ogjonline.com
Refining/Petrochemical Editor David N. Nakamura, davidn@ogjonline.com
Pipeline Editor Christopher E. Smith, chriss@ogjonline.com
Senior Editor-Economics Marilyn Radler, marilynr@ogjonline.com
Senior Editor Steven Poruban, stevenp@ogjonline.com
Senior Associate Editor Judy R. Clark, judyrc@ogjonline.com
Senior Writer Sam Fletcher, samf@ogjonline.com
Senior Staff Writer Paula Dittrick, paulad@ogjonline.com
Survey Editor Leena Koottungal, lkoottungal@ogjonline.com
Associate Editor Angel White, angelw@pennwell.com
Editorial Assistant Linda Barzar, lbarzar@pennwell.com

Petroleum Group President Michael Silber, msilber@pennwell.com
Vice-President/Group Publisher Bill Wageneck, billw@pennwell.com
Vice-President/Custom Publishing Roy Markum, roym@pennwell.com

PennWell, Tulsa office
1421 S. Sheridan Rd., Tulsa, OK 74112
PO Box 1260, Tulsa, OK 74101
Telephone 918.835.3161 / Fax 918.832.9290

Presentation/Equipment Editor Jim Stilwell, jims@ogjonline.com
Associate Presentation Editor Michelle Gourd, michelleg@pennwell.com
Statistics Editor Laura Bell, laurab@ogjonline.com
Illustrators Alana Herron, Kermit Mulkins, Mike Reeder, Kay Wayne
Editorial Assistant Donna Barnett, donnab@ogjonline.com
Production Director Charlie Cole

London
Tel +44.(0)773.498.6359
International Editor Uchenna Izundu, uchennai@pennwell.com

Washington
Tel 703.963.7707
Washington Correspondent Nick Snow, nsnow@cox.net

Los Angeles
Tel 310.595.5657
Senior Correspondent Eric Watkins, hippalus@yahoo.com

OGJ News
Please submit press releases via e-mail to: news@ogjonline.com

Subscriber Service
P.O. Box 2002, Tulsa OK 74101
Tel 1.800.633.1656 / 918.831.9423 / Fax 918.831.9482
E-mail ogjsub@pennwell.com
Circulation Manager Tommie Grigg, tommieg@pennwell.com

PennWell Corporate Headquarters
1421 S. Sheridan Rd., Tulsa, OK 74112

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General Interest — *Quick Takes*

Firms win MMS royalty in-kind oil contracts

More than 12.7 million bbl of crude oil and condensate from federal leases in the Gulf of Mexico was sold to six companies as part of a royalty in-kind (RIK) sale, the US Minerals Management Service said.

Chevron Products Co., ConocoPhillips, ExxonMobil Corp., Plains Marketing, Sempra Energy, and Shell Trading Co. submitted winning bids. Most of the contracts were for 6 months, with one contract awarded for 12 months.

"A record number of 14 companies submitted aggressive bids on the 34 packages offered," compared with nine bids in an unrestricted RIK sale concluded in August, MMS Director Johnnie Burton said. "These RIK sales continue to generate very high interest," she added.

The contracts awarded 12,710,700 bbl of crude, or 53,615 b/d, and provide for delivery to begin Jan. 1, 2007.

In mid-October, MMS sold 114.8 bcf of Gulf of Mexico gas to 10 companies in the first RIK transaction that included production from off Alabama as well as Louisiana and Texas. It said 15 companies tendered a record 115 offers for the RIK gas.

MMS proposes to expand Lease Sale 205 acreage

MMS proposed to expand the available acreage in Outer Continental Shelf Lease Sale 205, scheduled for September 2007. MMS will accept comments on this proposal through Dec. 29.

The proposal seeks to include all available acreage in the Central Gulf of Mexico planning area in Lease Sale 205, which originally only included acreage along the eastern boundary of the Central gulf planning area.

While this additional acreage would be new to Sale 205, it is the same acreage proposed for the other Central gulf lease sales scheduled for 2008-12.

Lease Sale 205 is included in the proposed 5-year program for 2007-12 and the accompanying draft environmental impact statement. The comment period for the 2007-12 program closed on Nov. 24, and the comment period for the draft EIS closed on Nov. 22.

The MMS proposal also includes the acreage that would have been offered in Lease Sale 201, which was originally scheduled for March 2007 and included all of the available acreage in the Central gulf planning area as proposed in the 5-year program for 2002-07.

As part of a lawsuit settlement agreement with Louisiana, MMS has agreed to prepare an EIS before conducting any additional lease sales in the gulf. As a result of this agreement, MMS is cancelling Lease Sale 201 (OGJ, Nov. 13, 2006, p. 27).

Japan objects to Russia's new pipe import tax

Japan has objected to a decision by Russia to impose an 8% import duty on Japanese-made steel pipe. Nippon Steel, JFE, and Sumitomo Metal Industries are the manufacturers primarily affected.

"Japan expresses deep regret for Russia's decision to take such a protective measure," said Japanese Economics, Trade, and Industry Minister Akira Amari in a statement released Nov. 25.

He said Japan might call on Russian authorities to cancel the 3-year tax measure to be imposed starting Dec. 18, reportedly to protect Russia's industry from the rapidly increasing growth of imported pipe from Japan.

Russia's import of Japan-made pipes increased to 270,000 tonnes in 2004 from 3,000 tonnes in 2002, mainly due to the implementation of large-scale oil and gas development projects on Sakhalin Island, where the last batch of pipe for the Sakhalin-2 pipeline was delivered Oct. 1.

The Russian tax coincides with efforts of pipe mills in both countries to increase output to match international demand, especially for natural gas pipelines.

In mid-November, Alexander Deineko, head of the Russian Pipe Industry Development Foundation, said investment in his country's pipe industry could total $1.5 billion during 2006-10.

He said investment in modernization and refitting capacity had reached $1.5 billion over the past 5 years, and he expects the same amount to be invested in the next 5 years.

Equatorial Guinea raises oil royalty

Equatorial Guinea President Teodoro Obiang ratified a new hydrocarbon law increasing the minimum royalties that oil and gas companies must pay to 13% from 10%.

Raymond James & Associates Inc. issued a Nov. 28 research note saying the new law also gives Equatorial Guinea the right to a 20% share in contracts with foreign operators and mandates that producers will be required to pay "any windfall tax that may be imposed by the state."

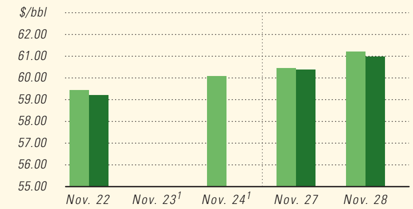
The new hydrocarbon law was posted Nov. 24 on the African government's Mines and Energy web site.

"Equatorial Guinea has historically been welcoming to foreign producers, and these new laws are modest increases as opposed to what the more aggressive governments such as Bolivia and Venezuela have imposed in the last few years," RJA said.

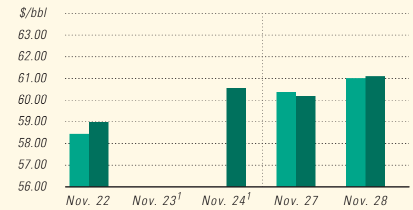
Oil companies having operations in Equatorial Guinea include ExxonMobil Corp., Devon Energy Corp., Marathon Oil Corp., and Hess Corp. In addition to ratification of the new law, the government extended the closing date of its 2006 Licensing Round to Mar. 31, 2007, from Jan. 31, 2007, saying this was "to allow prequalified companies to fully evaluate the available acreage."

Industry Scoreboard

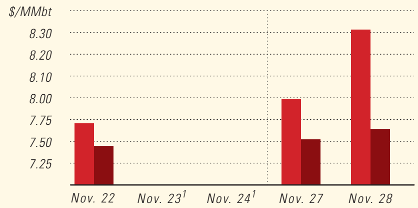
IPE BRENT / NYMEX LIGHT SWEET CRUDE



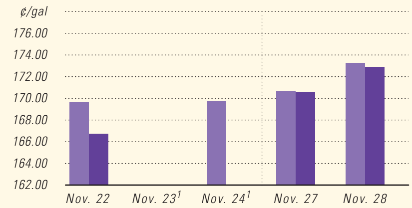
WTI CUSHING / BRENT SPOT



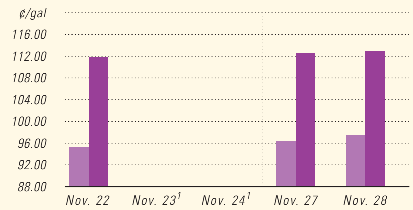
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



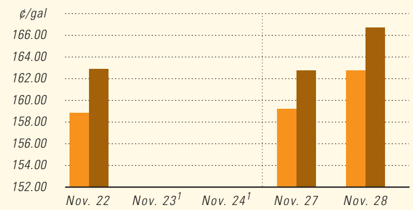
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE / NY SPOT GASOLINE[2]



[1]Not available.
[2]Nonoxygenated regular unleaded.

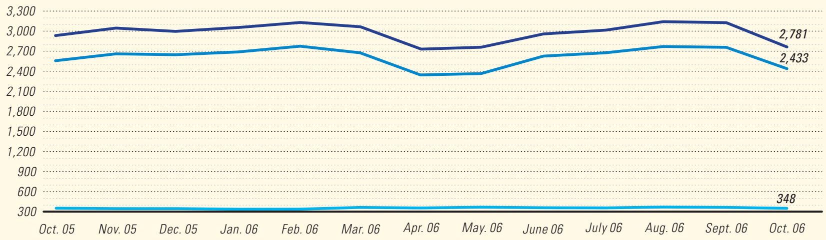
US INDUSTRY SCOREBOARD — 12/4

Latest week 11/17	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	10,080	9,053	11.3	9,832	9,112	7.9
Distillate	4,448	4,055	9.7	4,157	4,091	1.6
Jet fuel	1,606	1,605	0.0	1,604	1,617	–0.8
Residual	465	975	–52.3	724	906	–20.0
Other products	5,210	4,707	10.7	4,960	4,861	2.0
TOTAL DEMAND	21,808	20,395	6.9	21,277	20,587	3.4
Supply, 1,000 b/d						
Crude production	5,298	4,544	16.6	5,124	5,135	–0.2
NGL production	2,395	1,586	51.0	2,237	1,733	29.1
Crude imports	9,867	9,918	–0.5	10,246	10,020	2.2
Product imports	3,178	4,129	–23.0	3,436	3,467	–0.9
Other supply[2]	1,112	1,167	–4.8	1,093	1,250	–12.6
TOTAL SUPPLY	21,849	21,344	2.4	22.135	21,605	2.5
Refining, 1,000 b/d						
Crude runs to stills	15,042	14,483	3.9	15,149	15,220	–0.5
Input to crude stills	15,521	14,747	5.2	15,577	15,500	0.5
% utilization	89.6	86.1	—	90.5	90.6	—

Latest week 11/17	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	338,184	339,927	–1,743	325,969	12,215	3.7
Motor gasoline	202,937	203,703	–766	202,642	295	0.1
Distillate	137,269	138,718	–1,449	128,193	9,076	7.1
Jet fuel	39,115	40,012	–897	42,060	–2,945	–7.0
Residual	44,569	45,028	–459	38,786	5,783	14.9
Futures prices[3]						
Light sweet crude, $/bbl	57.28	59.88	–2.60	57.01	0.27	0.5
Natural gas, $/MMbtu	7.99	7.76	0.23	11.77	–3.78	–32.1

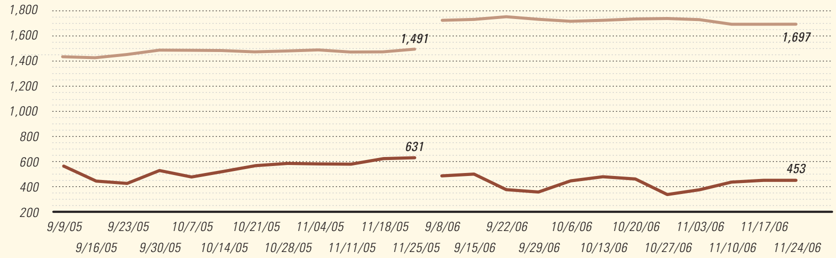
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Weekly average of daily closing futures prices.

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

Gazprom marketing directly to French consumers

Russia's gas giant Gazprom officially launched Gazprom Marketing & Trading France Nov. 24 in Paris to further develop a total upstream-to-downstream natural gas export strategy. Describing France as "a strategic market," it intends to sell gas directly to consumers rather than through wholesalers.

GM&T France, which started operations in October through UK subsidiary Gazprom Marketing & Trading Ltd., is targeting medium and large industrial and commercial customers.

Gazprom Vice-Pres. Alexander Medvedev said the aim is to supply, within the next 2-3 years, 2 billion cu m of gas directly to consumers in France and to have as many as 1,000 customers within 5 years.

GM&T France wants easier access to transport networks and infrastructure to deliver its gas "to the consumer's door," and Medvedev said Gazprom would acquire local companies and set up joint ventures for this purpose.

GM&T France has begun extending activities to electricity and is planning to become involved in CO_2 emissions trading, oil products, and chemicals, said Medvedev. ✦

Exploration & Development — *Quick Takes*

ExxonMobil advances Piceance tight gas work

ExxonMobil Gas & Power Marketing Co. has signed a 30-year agreement with Enterprise Products Partners LLC for gathering, compression, treating, and conditioning services for natural gas it is developing in tight sands of the Piceance basin of Colorado.

ExxonMobil began a development program last year of about 270,000 gross acres it holds under lease in the area. Company officials have estimated recovery potential at more than 35 tcf and predicted the area will produce gas for more than 50 years.

At a presentation for analysts early in November, ExxonMobil Senior Vice-Pres. Stuart McGill said an initial development project on the leasehold is producing about 50 MMcfd. A first production phase of 150-200 MMcfd is in the "definition stage," he said. Later stages are planned.

"There is the potential for gross production to reach some 1 bcfd at its peak," McGill said.

ExxonMobil is using proprietary "multizone stimulation technology" and drilling multiple deviated wells from individual locations.

"We now routinely fracture 40-50 sands/well and recently completed 64 of these fractures in a single wellbore," McGill told the analysts.

Under the new, fee-based agreement, ExxonMobil dedicates to Enterprise production from 29,000 acres in Rio Blanco County. Enterprise has the option to recover NGL beyond liquids recovery required to make the gas meet pipeline specifications.

Enterprise expects to invest $185 million on new plant and pipeline facilities related to the agreement and to complete construction late in 2008. It will extract liquids at a gas processing plant it is building at the Meeker hub. The plant will have initial capacities of 750 MMcfd of inlet gas and 35,000 b/d of liquids extraction. A planned later phase will boost capacities to 1.3 bcfd of gas and 70,000 b/d of liquids.

Turkmenistan claims supergiant gas find

The reported discovery of a supergiant gas field near the town of Iolotan in the Amu Daria basin of Turkmenistan would, if confirmed, help justify construction of a gas pipeline to China.

The field is said to contain 23 tcf of gas at 16,400 ft, but it was not clear whether this is the recoverable volume or the amount of gas in place. Turkmenistan, which already pipes gas to several countries and intends to serve several more, invited China National Petroleum Corp. to develop the field, press reports said.

Iolotan is east-northeast of supergiant Dauletabad-Donmez gas field, discovered in 1976 with estimated ultimate recovery of 49 tcf from a reservoir at about 9,800 ft (OGJ, June 3, 1991, p. 104).

Endeavour makes gas strike in UK North Sea

Endeavour International Corp., Houston, said its Columbus well in the UK North Sea encountered a gross gas column of at least 125 ft in the Palaeocene Forties formation.

Testing operations are under way on Block 23/16f with results expected by midmonth. It is anticipated that additional appraisal drilling will be required.

Endeavour is operator of the drilling and testing operations and holds a 25% working interest in the license, which is operated by Serica Energy PLC.

Statoil lets contract for Trestakk studies

Norway's Statoil ASA has let a contract to a unit of John Wood Group PLC to perform feasibility and conceptual studies for facilities modifications associated with the Trestakk subsea field development expected to be tied into the Aasgard platform in the Norwegian Sea.

The £2 million contract commits Wood Group Engineering (North Sea) to evaluate options for the topsides modifications on the Aasgard A and Kristin floating production facilities and to verify the alternatives required for concept selection. Wood Group aims to prepare the selected concept to the required level for full project sanction.

The project involves a number of challenges in high-pressure, high-temperature systems, Statoil said.

Eni Goliat appraisal encounters deeper oil

Eni Norge AS has found deeper oil pay during appraisal drilling of its Goliat oil discovery on Production License 229 in the Barents Sea off Norway.

Its 7122/7-4 S on the South Goliat structure encountered an oil column in Early Triassic Klappmys sandstone. The well also confirmed a deeper oil-water contact in the Late Triassic Realgrunnen subgroup and proved a gas-oil contact in Middle Triassic Kobbe.

The Transocean Polar Pioneer semisubmersible drilled the well to a TD of 2,366 m subsea in 372 m of water. The license is 50 km southeast of Snohvit field and 85 km northwest of Hammerfest (OGJ, Nov. 13, 2006, p. 31).

Eni owns 65% interest in and operates PL 229.

Firm shoots seismic survey off Seychelles

PetroQuest International has acquired 2,500 line-km of seismic data off Seychelles in the East Africa island nation's first seismic work in 14 years.

"It is being processed at the moment, and the government is keen to build on its oil and gas business," said Chris Matchette-Downes, vice-president of business development at Black Marlin Energy Ltd., which is conducting geophysical work for PetroQuest.

PetroQuest's 20,000-sq-km block is in the southern portion of the Seychelles plateau (see map, OGJ, July 6, 1998, p. 85). The reservoir is believed to be coarse-grain Karoo sandstones with porosities of up to 23% at 8,000 ft for the reservoir horizon.

"Over 15 large structures were mapped by Texaco and Amoco in the past," Matchette-Downes said. "New seismic has verified the presence of large leads." Oil shows and locally derived tars have been classified as having come from Paleozoic and Lower Mesozoic regional sources.

The seal comprises interbedded shales and a thick Cretaceous shale section.

Sinopec to develop Iran's Yadavaran oil field

Iran has invited China Petrochemical Corp. (Sinopec) to finalize an agreement initiated in 2004 for development of Iran's Yadavaran oil field (OGJ, Apr. 18, 2005, Newsletter).

The Petroenergy Information Network, operated by Iran's oil ministry, said Sinopec would also secure oil and natural gas supplies.

Under the 2004 informal agreement, Sinopec would pay Iran up to $100 billion over 25 years for oil and gas purchases and for a 51% stake in Yadavaran field.

China would be able to buy 250 million tonnes of LNG and 150,000 b/d of Iranian crude oil at market rates over that period.

"All elements of the contract have been finalized, and it is in the final process for signing by Sinopec," said National Iranian Oil Pres. Gholamhossein Nozari. ✦

Drilling & Production — *Quick Takes*

ConocoPhillips starts up Alpine satellite

ConocoPhillips has brought on line a second Alpine satellite oil field, called Nanuq, on Alaska's North Slope.

Nanuq, 3 miles south of Alpine, is expected to reach peak production of 15,000 b/d of oil in 2008.

Production from Nanuq, as well as from Fiord—the first Alpine satellite—will be processed through the existing Alpine facilities. Together, the two fields are expected to have peak production of 35,000 bo/d in 2008 (OGJ, Aug. 21, 2006, Newsletter).

Nanuq field was developed exclusively with horizontal wells. It will have gas and water injection. The Nanuq development plan involves 19 wells.

ConocoPhillips used 50 miles of temporary ice roads to move construction equipment, facilities, drilling rigs, and drilling supplies to the site, which is 35 miles west of Kuparuk field on the border of the National Petroleum Reserve-Alaska.

Alpine, Nanuq, and Fiord oil field interests are ConocoPhillips Alaska Inc. 78% and Anadarko Petroleum Corp. 22%.

ConocoPhillips is pursuing state, local, and federal permits for additional Alpine satellite developments, including the recently announced Qannik discovery, which flowed an average 1,200 b/d of 30° gravity oil from a 25-ft thick sandstone overlying the Alpine reservoir at 4,000 ft (OGJ, July 24, 2006, Newsletter).

Gorgon geosequestration gets government grant

Chevron Australia's Gorgon gas project is still alive following an Australian government grant of $60 million (Aus.) towards the company's proposed carbon capture storage project on Barrow Island.

The $850 million (Aus.) carbon dioxide geosequestration project is expected to be the largest of its kind in the world.

The plan is to inject 125 million tonnes of excess CO_2 produced during the life of the Gorgon LNG project planned for Barrow Island off Western Australia.

The offshore Gorgon gas field has about 12% CO_2 content, a figure that prompted the geosequestration project.

Environment Minister Ian Campbell says the underground storage of Gorgon CO_2 has the potential to reduce Australia's greenhouse emissions by as much as 3 million tonnes/year.

The government's funding will provide for a commercial-scale demonstration project that liquefies the CO_2 stream and injects it into reservoirs 2.5 km under the island.

The project includes long-term monitoring to ensure the integrity of the storage. The funding, however, is conditional on the Gorgon Gas project meeting environmental approvals.

Co-op programs to drill nine N. Sea wells

Six independent oil companies plan to drill nine wells next year in the central and northern UK North Sea with two semisubmersible rigs under two cooperative programs managed by AGR Peak Well Management Ltd., London.

The companies involved are Antrim Resources (NI) Ltd., three wells; Nautical Petroleum PLC, two wells; and Bow Valley, Vermilion Rep SAS, Ithaca Energy (UK) Ltd., and Xcite Energy Resources Ltd., one well each.

One of the programs will begin next April and the other, next May. The semis will come from Transocean Offshore (North Sea) Ltd. and Dolphin Drilling Ltd. AGR Peak Well Management will provide full well project management, including rig and support services. ✦

Processing — *Quick Takes*

Technip to supply HDS unit to Polish refinery

PKN Orlen SA has awarded Technip a contract worth €67 million for construction of a diesel oil hydrodesulfurization (HDS) unit at its 376,500 b/cd refinery in Plock, Poland.

This project, which will enable the refinery to increase production of high-purity diesel oil in compliance with the European Norm, also includes a wild naphtha-stripping unit and a gas amine treating-regeneration unit.

The HDS unit, which will be based on the Albemarle ultradeep HDS process, will produce 260 tons/hr of high-purity diesel oil, with a maximum of 10 ppm (wt) of sulfur. It will be one of the largest of its kind, Technip said.

Construction of the unit is scheduled for completion in June 2009.

The contract covers license, basic and detail engineering, procurement and supply of equipment and materials, supervision of construction, precommissioning and commissioning, start-up, and test runs.

Contract let for fourth Khalda gas plant train

Khalda Petroleum Co. (KPC) has hired Petrofac of London to design and construct a fourth gas-conditioning train at Salam on the Khalda Concession in the western desert of Egypt, said Apache Corp.

KPC is a joint venture of Apache and Egyptian General Petroleum Corp.

The fourth train, combined with a recently approved third train, will increase total conditioning capacity for production from Apache's Jurassic gas reserves to 710 MMcfd of gas and 66,000 b/d of condensate (OGJ Online, Nov. 15, 2006).

Each train will have capacity to process 100 MMcfd of sales gas and 14,000 b/d of sales condensate. The expansions are scheduled for completion by late 2008.

This is the second train contract that KPC let to Petrofac during November, and it increases the value of the total Khalda contracts to $375 million from $200 million.

Lurgi's technology selected for plants in China

Datang International Power Generation Co. Ltd. and Shenhua Ningxia Coal Industry Group have awarded Lurgi AG two contracts for the first two commercial-scale propylene plants based on Lurgi technology for the production of plastics from coal. The plants, expected to be the largest in the world according to Lurgi, will be built in China.

Total capital investment for both projects amounts to more than €2 billion.

Lurgi's contracts, valued at more than €100 million, cover the technology license, engineering services, and supply of special equipment. Certain proprietary equipment and major machinery are to be supplied from Europe, but most materials will be purchased in China.

The plants, due on stream in late 2008 and early 2009, will produce about 500,000 tons/year of polypropylene from coal. They will incorporate Lurgi's technologies for raw gas conditioning, methanol synthesis (5,000 tons/day of methanol with the Lurgi MegaMethanol process), and Methanol-to-Propylene (MTP).

The Lurgi MegaMethanol technology will provide feedstock for the company's MTP process. MTP complexes constitute the first step to diversification into the field of coal-to-chemicals and fuels in China, Lurgi said. ✦

Transportation — *Quick Takes*

Japanese firms to form LPG operations alliance

Mitsui & Co., Sumitomo Corp., and Marubeni Corp., all of Japan, are reported to be negotiating to form an alliance by yearend for the joint procurement of liquid petroleum gas (LPG), operation of tankers to carry it, and eventual consolidation of their respective distribution and storage facilities.

The companies apparently view their proposed alliance as a way of strengthening their operations, as competition is increasing among Japan's 20 or so LPG wholesalers due to shrinkage of the wholesale market and a doubling of the cost of supplies from Middle East producers.

Marubeni operates its LPG business indirectly through Marubeni Liquefied Gas Inc, while Mitsui imports and sells LPG through Mitsui Liquefied Gas Co. Sumitomo imports LPG directly and sells it through Sumisho LPG Holdings Co.

Shanghai LNG building LNG terminal in China

Shanghai LNG Co Ltd. is building an LNG terminal at Zhong Ximentang Island in China's Zhejiang province, with plans for the facility to become operational in the first half of 2009.

The complex, which includes docking facilities, a regasification plant, and an undersea pipeline, will have an initial capacity of about 3 million tonnes/year—enough to process newly contracted supplies.

In October, Petronas subsidiary Malaysia LNG signed deals with Shanghai LNG Co. Ltd. to supply up to 3.03 million tonnes/year of LNG for 25 years (OGJ Online, Oct. 30, 2006).

Shanghai LNG Co Ltd. is a joint venture of the Shenergy Group Ltd., 55% and CNOOC Gas & Power, 45%, a wholly owned unit of China National Offshore Oil Corp.

Indonesia to choose LNG partner by yearend

Indonesia's state-owned oil and natural gas company PT Pertamina and its partner the Medco Group are still in the process of selecting a Japanese partner for a 2 million tonnes/year liquefaction plant they plan to build in Senoro, Sulawesi, starting in 2007.

A spokesman said the two firms have yet to decide whether Mitsui Corp. or Mitsubishi Corp., both of Japan, will become the working partner for constructing the LNG facility.

"We have already been late too long, therefore, a decision has to be made by the end of this year," said Pertamina executive Tri Siwindono, who said LNG produced at the plant would be exported to Japan.

The plant will liquefy gas from Pertamina's wholly owned Matindock block and from the Senoro block owned equally by Pertamina and the Medco Group. ✦

Calendar

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

OIL&GAS JOURNAL online research center.

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

DECEMBER

Annual Energy Caribbean Conference, Port of Spain, +44 (0)20 7017 4037, +44 (0)20 7017 4981 (fax), e-mail: monique.quant@informa.com. website: www.ibcenergy.com/caribbean. 4-5.

Independent Operators Forum, London, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.operators-forum.com. 4-6.

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 4-6.

GASTECH International Conference & Exhibition, Abu Dhabi, +44 (0)1895 454 592, +44 (0)1895 454 584 (fax), e-mail: info@gastech.co.uk, website: www.gastech.co.uk. 4-7.

Renewable Energy in the New Low Carbon Britain Conference, London, +44 (0) 20 7467 7100, +44 (0) 20 7255 1472, e-mail: info@energyinst.org.uk, website: www.energyinst.org.uk. 5.

IADC Drilling Gulf of Mexico Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 5-6.

OSEA International Exhibition & Conference, Singapore, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: osea@oesallworld.com, website: www.allworldexhibitions.com. 5-8.

Annual CO2 Flooding Conference, Midland, Tex., (432) 552-2430, (432) 552-2433 (fax), website: www.spe-pb.org. 6-8.

Annual China Gas Conference, Beijing, 65 6536 8676, 65 6536 4356 (fax), e-mail: marcy.chong@abf.com.sg, website: www.abf-asia.com. 11-12.

Ethanol Summit, Houston, (207) 781-9603, (207) 781-2150 (fax), website: www.intertechusa.com/ethanol. 11-12.

2007

JANUARY

Petrotech India Conference and Exhibition, New Delhi, +44 (0) 20 8439 8890, +44 (0) 20 8439 8897 (fax), e-mail: adam.evancook@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.offshoreasiaevent.com. 16-18.

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.theenergyexchange.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.

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

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.

Natural Gas Conference, Calgary, Alta., (403) 220-2380, (403) 284-4181 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 5-8.

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

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

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

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

NACE Annual Conference & Exposition, Nashville, (281) 228-6200, (281) 228-6300, website: www.nace.org. 11-15.

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

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

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

Journally Speaking

The mass appeal of biomass

David N. Nakamura
Refining/Petrochemical Editor

There's fuel in slime. That was part of the message given by Michael Pacheco, director of the National Bioenergy Center, at a recent conference. Algae as a source of biofuels, according to Pacheco, has enormous potential because it is much more productive than other sources of biomass—up to 50 times more productive than traditional crops.

Speaking at the University of Houston's Global Energy Management Institute's Conference, "The Future of Gulf Coast Refining," on Nov. 3, Pacecho also reviewed potential biomass sources, processes, and products. Although it represents about 3% of the US energy supply, biomass has much potential for supplying transportation fuels.

It is even possible to feed biomass products to conventional refining process units, such as an FCC or diesel hydrotreater, according to another study.

The National Bioenergy Center, which is part of the National Renewable Energy Laboratory (NREL), considers biomass feedstocks to include trees, grasses, agricultural crops, residues, animal wastes, municipal solid waste, food oils, and algae. Processes to convert these to useable products include enzymatic fermentation, gas-liquid fermentation, acid hydrolysis/fermentation, gasification, combustion, cofiring, and transesterification.

The biofuels products, besides ethanol and biodiesel, include green diesel (fats, waste oils, or virgin oils converted to low-sulfur diesel in refining units), other fermentation products, pyrolysis liquids, and algae-derived fuels.

Biomass basics

Biomass can be divided into edible and nonedible constituents. The edible constituents include starch from corn, which is the basis for existing biorefineries (ethanol); oils from corn or soybeans, which are the basis for biodiesel; and proteins from corn or soybean meal.

"These are things that we don't view in the long run as being the core of the bioenergy industry...these materials are very limited in their supply," Pacheco said. "The materials that we focus our research on are the lignin, hemicellulose, and cellulose (nonedible constituents)."

The reason for the shift in research is that the nonedible constituents represent a much larger resource than the edible constituents. According to Pacheco, corn (edible) converted to ethanol has the potential to displace 10% of US gasoline supplies. Soybeans, fats, and greases (also edible), can potentially displace 5-10% of US diesel in the form of biodiesel. On the other hand, more than 1 billion tons/year of lignocellulosic biomass (nonedible) could be available in the US, potentially displacing 50-70% of gasoline use.

Refinery feedstocks?

NREL, in conjunction with UOP LLC, has studied the possibility of using oils, fats, and greases as petroleum refinery feedstocks. The results, which were presented at the First International Biorefinery Workshop July 20-21, 2005, in Washington, DC, showed that oils and greases fed to an FCC unit or a distillate hydrotreater can yield products similar to or better than those from a crude oil feed.

The "green diesel" produced entails lower capital costs than a biodiesel plant and has excellent fuel properties. The unit diesel yield is nearly 90% of the feed, the cetane number is 80-100, and the sulfur content is less than 10 ppm.

"The quality of the diesel is just phenomenal," Pacheco said. "This is a fascinating technology that represents a better fit with the asset base that [refiners] have."

Algae

NREL is working on algae technologies for creating nonedible lipids. Algae can store carbon in two ways: as a lipid or as a carbohydrate.

"What we are working on is engineering algae strains that produce a very high yield, up to 60%, of their weight as lipids," Pacheco said. "Lipids are a very highly energy-dense material, the same as diesel fuel particularly when we crack it.

"The other reason we are looking at algae is because it integrates very well with carbon capture. When you take an enriched carbon dioxide stream, whether it's a flue gas or a concentrated stream for sequestration, you can bubble that CO_2 through the solution that you are growing the algae in...you dissolve that CO_2 in the growth media and can kick up the growth rate of the algae by about a factor of 50."

For soybeans, the fuel yield is about 300 gal/acre; for corn the yield is 800-900 gal/acre. For algae, 1 acre can yield 10,000-20,000 gal of fuel, according to Pacheco.

"With the research we are doing, we've estimated that about 25 million acres would produce all the oil that the US uses," Pacheco said. "This is a game-changing technology if we can make it work." ✦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Deepwater controversies

A casualty of US political fights this year might prove to be a concept central to the most successful energy law since oil and gas price decontrol. The Deep Water Royalty Relief Act of 1995 (DWRRA) created an industry in the Gulf of Mexico. Its success far exceeds the hopes that inspired 3 years of struggle to win enactment. It has created wealth, incomes, and government revenue where otherwise there would be none. Yet the core mechanism—a delay in royalty collection to encourage risky investment—is in jeopardy.

Success of the DWRRA is beyond question. According to the Minerals Management Service, deepwater Outer Continental Shelf leases from sales held in the 5 years following enactment in November 1995 generated bonus-bid revenue exceeding $2 billion. Deepwater leasing had proceeded slowly during 1992-95 but "exploded" after DWRRA took effect, MMS says in a May report. As of last Dec. 31, there were more active gulf leases with water depths exceeding 1,000 ft than there were leases in shallower water: 4,395 vs. 3,826. Since 1995, the MMS report says, operators have drilled 980 wildcats in deep water and announced more than 126 discoveries.

Production beginning

Because of the DWRRA, deepwater production has begun where exploration might only now be starting if former Sen. J. Bennett Johnston (D-La.) hadn't consulted industry officials in July 1992 about ways to revive gulf operations. Because of the DWRRA, which grew out of a royalty holiday idea suggested to Johnston by former Marathon Oil Co. Pres. Victor Beghini, gulf ports and shipyards have business that might only now be reviving in response to elevated prices for oil and gas—or maybe not. Because of the DWRRA, the government has revenue, Americans have energy, and industry has technology that otherwise wouldn't exist.

Last January, however, an attentive New York Times reporter noticed in budget documents that the Department of the Interior projected revenue from deepwater leases awarded in 1998 and 1999 sharply lower than that from deepwater leases of different vintage. The reason: Leases from those years contain no oil and gas price thresholds above which royalty becomes due. Disclosure of the apparent omission came in an election year while oil and gas prices were high and producers were reporting record profits. "This irresponsibility will cost the taxpayers almost $10 billion," declared Rep. Darrell Issa (R-Calif.) as he opened hearings on the issue last June in the Committee on Government Reform Subcommittee on Energy and Resources, which he chairs.

Oil and gas companies should not let the supposedly lost royalties obscure benefits that the DWRRA has delivered and will keep delivering for decades. Even without price thresholds, royalty relief has limits-based production volumes, which vary with water depth. Beyond those volumes, production will be subject to royalty.

Furthermore, someone at the Department of the Interior might deliberately have withheld price thresholds for fear the agency lacked authority to impose them. The part of the law that describes price thresholds refers to sections dealing with deepwater leases other than those issued in 1996-2000, when eligibility for relief was automatic. Because a major concern during development of the DWRRA was budget neutrality, drafters limited automatic eligibility to 5 years, knowing that production would start later, outside the statutory period of budget analysis. But deepwater leases in effect at the time of enactment raised a problem. Without royalty relief, some of them would have lost work to the new leases. So the DWRRA made relief available on existing leases to operators who applied to MMS and showed economic need. It also applied price thresholds.

Threshold intent

As a Kerr-McGee Corp. representative argued in Issa's hearing, Congress might never have intended for price thresholds to apply to leases automatically eligible for deepwater relief. MMS officials have reason to worry that price thresholds in deepwater leases issued in 3 of 5 of the automatic-eligibility years are illegal.

The larger concern for the industry should be that the price-threshold controversy not discredit the DWRRA approach. The incentive worked, and the country is profiting in several ways because it did. ✦

Alternative fuels gaining transport market share

Sam Fletcher
Senior Writer

With the petroleum industry under political pressure to market cleaner fuels and refineries operating near capacity rates in the face of rising demand, markets for conventional and alternative transportation fuels appear robust.

Gasoline and diesel command the lion's share of the transportation fuel market, but alternatives are expanding.

"Ethanol and biodiesel technologies should allow for the displacement of 5-10% of current [gasoline and diesel] consumption," said analysts at Simmons & Co. International in a recent report. "Future technologies, such as cellulosic ethanol, could allow displacement of nearly 30%. Overall, we expect compelling growth from alternative fuels in the coming years."

However, Jefferey A. Dietert, a research director at Simmons & Co., warned, "Gasoline demand is only up 0.3% for January-August 2006 vs. January-August 2005. While Department of Energy weekly stats suggest [a rise of] 3-4% compared to the hurricane-impacted 2005 [market] for September-November, I would not get carried away on how 'strong' gasoline demand growth is."

Renewable resources currently provide just over 6% of total US energy, but officials of the Worldwatch Institute and the Center for American Progress in Washington, DC, expect that figure to grow rapidly. Global production of fuel ethanol more than doubled between 2000 and 2005, and biodiesel expanded nearly four-fold, they said in a joint report in late September.

A major stimulus for alternative fuels is the increasing renewable fuel standard (RFS) mandated by the Energy Policy Act of 2005. It would increase renewable motor fuel in the US to at least 7.5 billion gal in 2012 from 4.5 billion gal in 2006. "With the Democrats gaining control of the House and the Senate, an increase in the renewable fuels standard or more subsidies is a distinct possibility," Dietert said.

Ethanol

Worldwide production of ethanol, the predominant alternative fuel, exceeds 12 billion gal/year. In the US, production last year totaled 4 billion gal, about 2% of gasoline consumption on a btu-equivalent basis.

US ethanol capacity is coming on stream quickly. Production is expected to exceed 7 billion gal/year by 2007, when the mandate will be 4.7 billion gal/year. Ethanol currently is blended in 40% of all US gasoline, having replaced methyl tertiary butyl ether (MTBE) in reformulated and oxygenated gasoline.

Along with the volumetric mandate, ethanol receives support from federal and state governments. The federal government provides a 51¢/gal tax credit to ethanol blenders, and all but four US states offer other incentives, including tax credits, to promote sales. The US also has an ad valorem tariff on imported ethanol of 2.5% of product value and imposes a secondary protective tariff of 54¢/gal.

The tariff expires next October. The Energy Information Administration (EIA) estimates that lifting the tariff, discussed briefly earlier this year when

VeraSun Energy Corp., Brookings, SD, started up this ethanol plant, one of the largest in the US, outside Fort Dodge, Iowa, in October 2005. The plant can convert 39 million bushels/year of corn into 110 million gal/year of ethanol. Photo from VeraSun.

supplies were under strain, would increase imports by 10,000-20,000 b/d from 22,000 b/d currently. Industry analysts said Brazil—the world's largest producer of ethanol—could increase exports to the US by only 5,000-7,000 b/d. They thought China, the third largest producer, would be most likely to step up ethanol exports to the US if protections eased.

The National Petrochemical & Refiners Association opposes government mandates for ethanol, biodiesel, and other renewables but not alternative fuels competitively priced without government subsidies. "We believe that alternative fuels will be a growing component of the nation's future energy supplies as their economic viability improves," said Bob Slaughter, NPRA president.

However, Dietert said, "It seems to me that ethanol is going to have to compete on a cost basis with refinery-produced gasoline in order to take market share."

Meanwhile, the price of corn—the biggest US crop and one of the most heavily subsidized—shot up 63% during Aug. 16-Nov. 17, raising production costs of meat and poultry, sweeteners, breakfast cereals, and other packaged foods. Market analysts blamed increased production of ethanol, the third largest market for US corn behind livestock feed and exports. Nearly 13% of the 2005 US corn crop went into ethanol production. Ethanol producers' demand for corn is expected to grow from 1.2 billion bushels in 2003-04 to 3 billion bushels in 2009-10.

Still, the International Energy Agency (IEA) in Paris claims that, even without subsidies and despite its lower energy density, ethanol from corn is cost-competitive with US gasoline in the US when oil is above $45/bbl—well below oil's price in mid-2006.

Ethanol makers say cost reductions are possible with improvements in manufacturing and scale economies, asserting that a tripling of ethanol plant size can cut unit cost by 40%. Many ethanol plants now under construction have production capacity of 100 million gal/year, up from a typical earlier capacity of 40 million gal/year.

However, opponents of renewable-fuel mandates question whether the energy provided by biofuels exceeds the energy required to make them. They claim biofuels produced from low-yielding crops and processes fueled by fossil energy potentially could generate as much greenhouse gas emissions as petroleum fuels do or more.

When ethanol is mixed in a stronger 85:15 blend with gasoline, it becomes E85, the fuel for a new generation of "flexible-fuel" vehicles being produced with the help of tax incentives in 2007. If the RFS is increased and federal and state subsidies continue, Simmons analysts said, "Corn-derived ethanol [in the US market] could reach 16 billion gal in 10 years (7% of the total gasoline pool on a btu-equivalent basis)." However, they said, "For ethanol to grow beyond that, cellulosic technology needs to gain traction."

The Worldwatch Institute disputes claims that biofuels require more energy to make than they provide. "Thanks to technological advances throughout the production process, all of today's biofuels have a positive fossil energy balance," it said in its study report. "If bioenergy is increasingly used for feedstock processing and refining as well, the balance sheet tips further in biofuels' favor." However, it acknowledged, "Producing half of US automotive fuel from corn-based ethanol would require 80% of the country's cropland. Thus, large-scale reliance on ethanol fuel will require new conversion technologies and feedstock."

The largest US producers of ethanol are Archer Daniels Midland, VeraSun, Hawkeye, Aventine, and Cargill. Together they account for 36% of total US capacity. "Today's corn-based ethanol industry leaders are best positioned to co-opt the new technologies, having logistics management experience and customer relationships," said Jacques Rousseau, senior energy analyst at Friedman, Billings, Ramsey Group Inc., Arlington, Va.

Cellulosic ethanol

Ethanol made from the nonfood portions of plants expands the potential supply while reducing competition with food. A joint study by US Departments of Agriculture and Energy concluded the nation has enough biomass resources to satisfy a third of US petroleum needs if cellulosic technologies and resources are employed.

The potential to produce low-cost cellulosic ethanol from various alternative agricultural feedstocks and processes "is truly remarkable," Rousseau said. However, he sees "a number of technological, operational, and economic issues to overcome before this industry makes a successful transition from research and development to genuine large-scale, commercial operations."

There are only a handful of cellulosic ethanol pilot plants around the world with capacities of 5 million gal/year or less but no operating plants of a size to suggest mainstream commercial viability. Moreover, the low sugar density of cellulosic feedstock requires plants to be located near large supplies of feedstock. The high processing cost and inherent risks of such projects make it difficult to obtain financing, so many companies seek government grants and loan guarantees. Therefore, Rousseau said, "Commercial economics for cellulosic ethanol production is likely still several years away."

Although cellulosic ethanol has the best growth potential for the biofuel market, its current production cost of $2.25/gal ($3.38/gal of gasoline equivalent) is uneconomic, Simmons analysts said.

Biodiesel

The biodiesel market is far smaller than ethanol and concentrated primarily in Europe. But it is the fastest-growing fuel in the US, according to the joint study by the Worldwatch Institute and the Center for American Progress in Washington, DC. The US produced 75 million gal of biodiesel in 2005, up from 500,000 gal in 1999, according to the National Biodiesel Board, which says production might reach 150 million gal this year. It puts current US production capacity, which is growing rapidly, at 580 million gal/year from 85 plants. Plants under construction and expansion will add 1.4 billion gal/year to total capacity.

Biodiesel uses monoalkyl esters from vegetable oils and animal fats. Soybeans are the predominant feedstock in the US. But biodiesel has a greater number of potential feedstocks than other fuels do, as well as the flexibility to be shipped by pipeline, which cannot be done with ethanol-gasoline blends.

Biodiesel can be blended with conventional diesel at any concentration. Most diesel vehicles can run on blends of up to 20%, and a few engine warrantees allow for 100% biodiesel. More than 600 vehicle fleets now use biodiesel. The US Navy, the world's biggest diesel consumer, has begun processing its used cooking oil into biodiesel.

Still, said Simmons analysts in their September report, "The cost to produce biodiesel is $2.40/gal ($2.64 on a diesel gal-equivalent basis), which is substantially higher than conventional diesel at [the then-current price of] $1.80/gal."

The Worldwatch report acknowledged, "Costs must continue to fall if biodiesel is to be used widely."

Ultralow-sulfur diesel

As of Oct. 15, the sulfur content of 80% of highway diesel sold in the US could not exceed 15 ppm, down from 500 ppm previously. All but the smallest refiners had to start making ultralow-sulfur diesel (ULSD) last June, and several are processing to well below the specified level to offset contamination by residual sulfur in distribution systems.

"We were nervous about the rollout of this program. It's going smoothly. We haven't seen problems in supplies or vehicle performance," said Alfonse Mannato, fuels issues manager in the American Petroleum Institute's downstream department at that group's annual meeting in October (OGJ Online, Oct. 17, 2006). US refiners spent $8 billion, and pipelines and terminal operators spent hundreds of millions more to bring ULSD to market.

Despite earlier fears, Adam Dreiblatt, senior manager of BearingPoint Inc., McLean, Va., said, "There were little to no supply disruptions due to ULSD implementation. Refiners are putting out fuel at a lower sulfur levels than they estimated prior to implementation."

However, the Societe Generale corporate investment-banking group said Nov. 22, "Diesel stocks continue to tumble, apparently undermined by this year's new, cleaner specification."

Dreiblatt told OGJ, "There still does seem to be some confusion among industry participants with the logistics of the regulations as well as the interpretation of the regulations for nonstandard situations (e.g., importing of some undesignated materials), but these seem to be working themselves out as they gain experience," However, the "true test" will come, he said, when "designate and track" (D&T) reporting begins, with the first report due Feb. 28 to designate the classifications of distillate flowing through US pipelines and track the progress of various batches.

"It will not be until this time that the majority of the potential hiccups in the regulatory scheme will be exposed," Dreiblatt said. "Things to watch out for are variances in the handoff volumes between custody holders. While we know of some industry participants who plan to prevalidate their planned submissions with their business partners, we doubt that this step will occur through most of the industry. Thus, there could very well be a 'February surprise' when it comes to D&T reporting."

Ultralow-sulfur gasoline

At the start of 2006, specifications for gasoline content changed from the previous 500 ppm sulfur ceiling for RFG outside of California to a required 30 ppm annual average and a cap of 80 ppm/gal for most gasoline, with some delays for gasoline produced in the Rocky Mountain area or produced by small refiners.

Desulfurization will make regular gasoline more like reformulated fuel, proponents say. Early this year, US refiners were estimated to have spent $8 billion to reduce sulfur levels in gasoline.

CNG and LNG

It's estimated that 22 bcf of natural gas, just 0.1% of total US gas demand, was used to fuel transportation in 2005. Natural gas vehicle fuels have been cheaper than gasoline and diesel through much of this year. Most natural gas engines already meet 2007 emission standards and can satisfy the more stringent 2010 requirements "with relatively inexpensive modifications," Simmons analysts said. "CNG and LNG also produce significantly lower emissions than biodiesel and ethanol."

Simmons said, "CNG holds solid promise as a low-cost, clean fuel that can compete with diesel for commercial fleets. However, we do not expect widespread retail adoption due to the challenges of establishing a gaseous fuel infrastructure as well as the long-term supply challenges for natural gas."

Building a new CNG fueling station costs $750,000-1.5 million, while retrofitting an existing station with a CNG option would cost $200,000, said the Simmons study.

Propane

Late in the 20th Century, when a government program required the posting of notifications of alternative fuel suppliers along US highways, the first sign erected in Houston was for a propane outlet.

Propane or LPG has been fueling automobiles, pickup trucks, and other light vehicles in the US for more than 60 years. More than 200,000 propane-fueled vehicles are on US roads, primarily in fleet operations. The fuel also has the largest distribution network for any alternative fuel in the US, with more than 3,000 propane fueling stations.

A Battelle Institute study said propane is the most economic alternative fuel for fleet vehicles on a per-mile basis. The National Propane Gas Association claims the higher octane rating (104-112) and low carbon and oil-contamination characteristics help engines last three times longer than those fueled by gasoline. Vehicle conversion costs are relatively cheap at $1,500-3,000 and can be partially offset through tax deductions or other incentives available through local, state, and federal programs.

But while the public will use propane to fuel their outdoor grills, Simmons analysts said, "We do not expect to see widespread acceptance of propane as a transportation fuel due to engine availability and infrastructure requirements." ✦

Canada removes tax advantages for income trusts

Paula Dittrick
Senior Staff Writer

The Canadian government's decision to remove tax advantages from companies doing business as income trusts will mean the end of the oil and gas trust structure in its current form, said a report by Wood Mackenzie Ltd., Edinburgh.

Separately, Raymond James & Associates Inc. issued a research note in which it compared Canada's efforts to stem a widespread conversion of companies to trusts with what the US experienced decades ago with the emergence of master limited partnerships (MLPs).

Canada's new tax structure for all income trusts will reduce the value of the oil and gas trusts, said WoodMac Canada and Alaska energy analyst John Dunn. Trusts account for 20% of western Canadian conventional production.

"We estimate that in the conventional western Canadian oil and gas sector, the removal of the tax benefits could result in a transfer of value from the trusts to the government of $640 million (Can.) in 2011 alone, with up to

$2 billion in net present value lost over the expected life of the trusts' assets," Dunn said.

On Nov. 1, the Canadian government announced its Tax Fairness Plan, which includes a tax on distributions paid by publicly traded income trusts.

Canada Finance Minster Jim Flaherty said the plan was designed to "restore balance and fairness to the federal tax systems by creating a level playing field between income trusts and corporations."

WoodMac report

WoodMac's Dunn believes "some of the smaller, more-focused trusts may struggle to adapt to the new regime, especially if they are exposed to the more marginal plays such as heavy oil and tight gas, and could become targets for acquisition."

As for the larger trusts, which benefit from a diverse portfolio, he expects these companies might continue under a new corporate structure or strategy.

"It is possible that their traditional focus on western Canada may shift to other regions, or even other countries, where more attractive fiscal terms are available," Dunn said.

Oil and gas trusts have had to maintain production both through acquisitions and development to provide cash flows to unitholders, Dunn said.

"However, recent cost escalation and labor shortages have made the Canadian upstream operating environment increasingly difficult, with projects becoming progressively marginal," Dunn said. "The new tax structure will only add to these challenges."

US comparison

In a Nov. 21 monthly review on MLPs, RJA analyst Ted Gardner said Canada's Tax Fairness Plan includes a tax on distributions paid by publicly traded income trusts, including large telecommunications, financial, and energy companies.

Some of these companies sought to convert to the trust structure to avoid paying taxes, Gardner said.

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Wheat, chaff, and oil deals

Separating wheat from chaff is important in every business, the oil industry included. Such a separation has become especially important in Australia, where fallout from the United Nation's Oil-for-Food Program continues.

Last week, BHP Billiton Ltd. said it broke no Australian laws in its dealings with Iraq under the UN program despite allegations that a former executive conspired to defraud the scheme of millions of dollars.

Norman Davidson Kelly was one of 12 people named in a government investigation of $222 million in kickbacks paid by Australia's monopoly wheat exporter, AWB Ltd., to former Iraqi dictator Saddam Hussein under the program.

Tainted reputation

BHP became tainted by the scandal by evidence that one of its subsidiaries, BHP Petroleum—apparently in hopes of winning favor with the regime and gaining access to oil exploration rights—paid $5 million for an AWB wheat shipment to Iraq in 1996. Four years later, Tigris Petroleum, a company founded by Kelly, the former BHP executive, sought to recover the $5 million as a debt and allegedly contracted AWB to recover the money by inflating the price of wheat it was charging the program.

Judge Terence Cole cleared BHP and BHP Petroleum of wrongdoing in his report to the Australian government, but Cole found that Kelly may have breached the country's criminal laws by conspiring with AWB to inflate wheat prices across two UN oil-for-food contracts. BHP Chief Executive Chip Goodyear, who had ordered a separate investigation by the firm itself, said: "The conclusions reached by the internal review were consistent with Commissioner Cole's findings—that is that BHP and BHP Petroleum complied with Australian law and UN sanctions."

Close call

Still, BHP has had a close call with the chaff of allegation. It has learned valuable lessons from the experience, saying that its ability to operate effectively in countries that are more "difficult" and "risky" and to responsibly manage its community programs will be impaired if its reputation is damaged. To avoid damage to its reputation, as well as similar inquiries in the future, BHP said it needs to take all available steps to ensure each of its employees, agents, and contractors knows and implements the standards of conduct in its charter and Guide to Business Conduct (GBC).

The firm said it will need to:

- Clarify key criteria for community payments, donations, sponsorships, and business development expenditure.
- Review mechanisms employed to ensure that agents and contractors are aware of the standards of conduct.
- Review and assess the reach of its policies and guidelines governing recruitment, including training.
- Amend the GBC (where appropriate) to provide further guidance on dealing with conflicts of interest and on selecting contract and joint venture partners.

That sounds, to borrow an advertising line from a breakfast cereal made from wheat, like the breakfast of champions. ✦

OIL&GAS JOURNAL Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page qMags

He compared this to what happened in the US with the emergence and eventual evolution of MLPs, which have different legal structures, income distribution practices, and tax considerations than a publicly traded corporation.

During the 1980s, US tax authorities realized the trend toward companies forming as MLPs instead of corporations potentially could create a tax shortfall. Hence, the government narrowed the tax code definition of what could qualify as an MLP. Today, many pipeline and other midstream companies use the MLP model.

"As a result, the vast majority of today's MLPs are engaged in the energy and natural resources business," Gardner said. "The Canadian and US governments faced the same issue—a potentially dwindling tax base—but arrived at different solutions," he said, adding, "Given the recent push for energy independence and the growing need for energy infrastructure in the US, we do not expect the government to take it a step further and impose a corporate tax on MLPs in the near future." ✦

Ecuador presidential election troubles oil sector

Peter Howard Wertheim
OGJ Correspondent

The Nov. 26 presidential election in Ecuador of leftist economist Rafael Correa in a landslide victory against right-wing tycoon Alvaro Noboa is sounding alarms in the international oil sector.

Although all votes have not been tallied, Ecuador's Supreme Electoral Tribunal said Correa will be the President-elect even if Noboa wins all of the remaining votes. During the campaign, Correa said he wants to reduce foreign control over Ecuador's oil and distribute the benefits more broadly.

Ecuador is a former member of the Organization of Oil Petroleum Exporting Countries, and Correa also said he will consider rejoining OPEC.

Except for Venezuela, Ecuador supplies more oil to the US than any other country in the region, according to the US Energy Information Administration. It also supplies oil to Japan and other Asian nations.

The Ecuadorian government, which controls about 75% of oil production through state-owned Petroecuador, had an ambitious plan to double oil production to 700,000 b/d within the next 4-5 years. However, its production has fallen in recent months to 183,000 b/d due to inefficiency and a lack of investment, said Petroecuador.

Oil earnings fund 50% of Ecuador's national budget, and continued oil exploration and production is thought to be necessary to ensure the country's wellbeing. It plans to increase production, and it holds auctions to increase foreign investment. Dependence on oil revenue has hindered Ecuador's environmental enforcement.

Export interruptions

In May 2005, Petroecuador stopped crude oil exports following days of protests from demonstrators in the Amazon region for bigger share of oil revenues. The protesters wanted more money spent on infrastructure and new jobs and complained about the "degradation" of the environment by private oil companies.

Ecuador said it faced an "economic emergency" because of the stoppage, which sent world oil prices higher.

International oil companies agreed to give Ecuador's oil rich provinces 16% of the 25% in income tax they paid to the central government (OGJ Online, Aug. 30, 2006).

Oil sales account for about a quarter of Ecuador's GDP. According to the president of Ecuador's Petroleum Industry Association, oil revenues pay for both state sector salaries and a significant amount of the national debt.

Correa actions

Trained in the US, Correa set off alarm bells as finance minister in 2005, when he introduced a law designed to redirect 30% of Ecuador's oil revenue away from external debt payments and toward health and education, tripling the amount of revenue used for social-sector spending.

This law drew the ire of the World Bank, whose sister agency, the International Monetary Fund, had designed the Oil Stabilization Fund. Its purpose was to siphon 70% of oil revenues directly to debt repayment. The World Bank responded to the new law by delaying and ultimately canceling $100 million in loans to Ecuador. This led to Correa's resigning his post.

Recent political developments in Ecuador also have sent shockwaves around the globe. Multinational corporations were put on notice when the government decided to expel Occidental Petroleum Corp. for allegedly violating its contract with the country.

Ecuador has several claims pending at the World Bank's International Center for Settlement of Investment Disputes in Washington, including one that Oxy filed after Ecuador seized its oil fields last May (OGJ Online, Sept. 29, 2006). Ecuador accused Oxy of selling part of an oil block without government approval. Oxy is seeking the return of its assets and $1 billion in damages.

On Oct. 10, 2006, City Oriente Ltd. filed an arbitration claim against Ecuador, charging the Andean country with breaching its contract after it passed a contested oil law that affects foreign operators, said a company spokesman.

City Oriente, a Panama-based company run by US investors, has an output of around 4,000 b/d of oil in Ecuador.

The company's representative Jose Paez said the company filed the claim at World Bank arbitration center to force Ecuador to not apply the law. "This law is an unilateral modification of the contract," Paez said.

The law, approved by Congress last April, forces foreign oil companies to share with the state at least 50% of their extra oil revenues, above a benchmark price agreed in their original contracts.

Petrobras in Ecuador

Brazil's Petróleo Brasileiro SA (Petrobras) is investing $160 million in the Ecuadorian Amazonia during 2006, and it is a sure bidder should Ecuador seek bids for exploration of the Ishpingo-Tambococha-Tiputini heavy oil area in the Oriente basin field area (OGJ, Mar. 4, 1996, p. 47).

Prior to Correa's election, Petrobras had also announced planned investments of $500 million in Ecuador during 2005-11 through a strategic alliance with Petroecuador. These investments are almost equal to the total Petrobras has invested in Ecuador since it entered the country in 1988. The funds would cover hydrocarbon exploration, refining, transport, and commercialization.

However, after Correa's election, Petrobras expressed doubts about future investments and voiced concerns over profits reduction in Ecuador, given its experience in Bolivia, where President Evo Morales' government confiscated Petrobras's $2.5 billion operations.

Analysts said that Petrobras' Bolivian investment decision showed two things:

- The company does not fear an unstable political environment but thinks it is better to stay away from the possibility of arbitrary, confiscatory decisions such as those taken by Morales, who nationalized Bolivian energy resources.
- It is willing to join forces with companies such as Petroecuador in precarious financial and managerial conditions by bringing in world-class managerial skills and processes and state-of-the-art technologies.

However, with President Correa now in power—He is known for his close ties with Morales and Chavez—the planned investments might be reviewed, said Brazilian government sources. ✦

BLM inventory finds resources heavily restricted

Nick Snow
Washington Correspondent

Just 3% of federal onshore oil and 13% of onshore federal gas are currently available under standard lease terms, the US Bureau of Land Management said on Nov. 28.

Access grows to 46% for oil and 60% for gas with additional restrictions, including "no surface occupancy," the Department of the Interior agency said. But its inventory of 99 million acres of federal onshore oil and gas resources found 51% of the oil and 27% of the gas closed to leasing. The study, which was required under the Energy Policy Act of 2005, expands on one that was published in 2003 under the Energy Policy and Conservation Act of 2000.

BLM said the 11 areas inventoried in the latest study include six new oil and gas basins in Alaska, the Rocky Mountains, and the eastern US in addition to five basins studied in 2003. It said the new inventory covers an area containing an estimated 21 billion bbl of oil and 187 tcf of gas, or about 76% of total onshore federal oil and gas resources.

"This is a more complete and accurate picture than our previous inventory," said BLM Director Kathleen Clarke. The 2005 EPA directed that the new inventory consider conditions of approval attached to drilling permits that producers must follow when developing leases—i.e., restrictions such as, "no drilling during seasonal migrations of sensitive species." The 2003 inventory only considered restrictions in the actual leases.

Seeking changes

Producers said they would use the study's results to press for more streamlined and less burdensome permitting procedures.

"This report clearly demonstrates the distinction between what is available and what is accessible," said Mike Linn, chairman of the Independent Petroleum Association of America and president of Linn Energy in Pittsburgh. "There is enough onshore oil and natural gas available in the United States to significantly alleviate the burden on American consumers while strengthening our energy security," he said. "However, these public resources are not accessible because regulatory barriers and antiquated policies prevent the responsible development of these resources."

IPAA said impediments include federal agencies delaying permits while revising environmental impact statements, litigation on resource management plans designed to delay access, and unreasonable permit requirements that prevent production. In many cases, oil and gas producers are paying the costs of environmental impact statements, which the government is supposed to pay. This can cost producers hundreds of thousands of dollars, the Washington-based trade association said.

"Now that both the public and our elected lawmakers know these resources are available, we need to work to make sure they are accessible," Linn emphasized.

BLM said it prepared the new report, Scientific Inventory of Onshore Federal Lands' Oil and Gas Resources and the Extent and Nature of Restrictions or Impediments to Their Development—Phase II Cumulative Inventory, with help from the US Geological Survey, US Forest Service, US Department of Energy and its Energy Information Administration, and other coauthors, contributors, and reviewers.

Printed copies can be obtained from BLM's public affairs office at 1849 C Street, NW, MS-LS 406, Washington, DC, 20240, or online at www.blm.gov. ✦

Court order cancels Brazil's eighth licensing round

Peter Howard Wertheim
OGJ Correspondent

A federal judge in Brasila issued an injunction Nov. 27 suspending Brazil's eighth oil and gas licensing round. The round was scheduled for Nov. 28-29 (OGJ Online, Nov. 27, 2006).

The court objected to limits in the number of offers a bidder can make, a rule included by the National Petroleum Agency (ANP) for this bid round.

A federal Workers Party congresswoman requested the injunction to "protect" state-owned Petroleo Brasileiro SA (Petrobras) from being limited in the number of offers it could submit. Petrobras, responsible for some 90% of Brazil's oil and gas production, dominated previous rounds.

Bidders also were unhappy about ANP's exclusion of Campos and parts of Santos basins from the licensing round. "Campos is responsible for some 80% of Brazil's 1.9 million b/d of oil," said Alvaro Teixeira, executive secretary of the Brazilian Petroleum and Gas Institute, which has some 220 members, including 32 oil multinationals.

Two appeals to overturn the injunction, failed, but legal experts told OGJ, "this matter will probably end up in a drawn up court battle."

It is not known whether the winning bids announced during the first days of the round are legally valid or what effect the cancellation may have on future investments in Brazil's E&P. Several multinational oil executives and consultants said the cancellation bodes ill for future investments.

High bidders

Petrobras made offers for 21 blocks and won 20, becoming the operator in 8 of them. Even with the ANP limitation, Petrobras bought the largest number of blocks in the auction.

Nevertheless, Petrobras argued that the rule limiting offers was prejudicial for the company: In 2005 during the seventh round, Petrobras secured 96 of the 251 blocks available. "We have to continuously produce more oil to maintain the country's self-sufficiency," said Petrobras Corporate General Manager Francisco Nepomuceno Filho. "I estimate that we must discover at least an additional 700 million bbl/year in reserves, and this ANP rule hampered our strategy."

ONGC Videsh Ltd., the overseas arm of India's state-run Oil and Natural Gas Corp., participating for the first time in a Brazilian oil bid round, paid $68 million to win the offshore S-M-1103 block in the Santos basin.

Eni SPA placed the $140 million winning bid for rights to drill in a new deepwater frontier area in the Santos basin off Sao Paulo's coast.

Norway's Norsk Hydro ASA won a block in the same area with a $3.3 million bid. The company also had a stake in two more winning bids for blocks with Spanish-Argentine Repsol-YPF and Brazil's Petrobras as lead operators. ✦

COMPANY NEWS

Denbury Resources to acquire field for tertiary flood

Denbury Resources Inc. has signed an agreement with a Venoco Inc. subsidiary for an option to purchase Venoco's interest in Hastings field, a potential tertiary flood property near Houston.

In other recent company news:

• Dana Petroleum PLC agreed to acquire from Gaz de France a 25% additional interest in Cavendish gas field in the UK North Sea's Southern Gas basin. The $55 million transaction will double Dana's existing 25% interest in the field.

• Abu Dhabi National Energy Co. is buying from BP Netherlands its exploration and production and gas infrastructure business, including various production assets and the Piek Gas Installatie gas supply plant near Alkmaar.

• Riata Energy Inc., Oklahoma City, closed its $1.5 billion acquisition of NEG Oil & Gas LLC from American Real Estate Partners, a conglomerate owned by investor Carl Icahn.

• El Paso Corp.'s wholly owned subsidiary El Paso Exploration & Production Co. agreed to acquire producing properties and undeveloped acreage in Zapata County, Tex., for $255 million.

• Swift Energy Co. agreed to pay $20.4 million for wells and acreage in Lake Washington field in Plaquemines Parish, La. The seller's identity was not disclosed.

• GE Energy Financial Services and Sunland Resources LLC agreed to buy natural gas and oil reserves in northern Louisiana for $101 million from a consortium led by Caruthers Producing Co. Inc.

• PetroHunter Energy Corp., Denver, plans to buy Galaxy Energy Corp.'s Powder River basin assets for $45 million in a cash-equity deal. Galaxy is terminating previously announced plans to sell 25% of its Piceance basin assets to Exxel Energy (USA) Inc.

Denbury-Venoco deal

Denbury's agreement with Venoco requires an upfront payment of $37.5 million to be paid at closing of the option agreement, with additional payments totaling $12.5 million over the next 2 years.

If approved, the option period will run from Nov. 1, 2008, through Nov. 1, 2009. Denbury may extend the option beyond the primary term for as many as 7 additional years at an incremental cost of $30 million/year. None of the option payment amounts are to be credited against the purchase price, which is to be agreed upon at the time the option is exercised and may be paid in cash or through a volumetric production payment.

If the parties fail to agree to a price, a price will be determined by a predesignated independent petroleum engineering firm using specified criteria for calculation of the discounted present value of proved reserves at that time.

The purchase deal would include Venoco's interest in Hastings field, less a 2% override and a 25% reversionary interest following payout, as defined.

Hastings field currently produces about 2,400 b/d. Venoco owns about 89% interest in the West Hastings Unit and nearly 100% in East Hastings field. Based on preliminary engineering data, the West Hastings Unit (the most likely initial area to be developed as a tertiary flood) has an estimated net reserves potential from CO_2 tertiary floods of 50-90 MMboe, depending on the ultimate recovery factor, net of the pro-

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

Acknowledging the endowment

It began when Steven G. Grape and John Wood, his supervisor in the US Energy Information Administration's reserves and production division in the Office of Oil and Gas in Dallas, noticed two things. First was the perception that no significant new oil or gas deposits were being found and developed in the Lower 48. Second were production numbers suggesting the opposite.

"Many people are pessimistic about oil and gas supplies in the United States. They don't understand the scope of unconventional resources. So we thought we should get information out that coalbed methane, natural gas from shale, and other resources are making significant contributions," Grape told me recently.

Wood instructed him to prepare a special report highlighting one such area. "We were both interested in the Bakken formation because we'd started to read about it. Then we looked at some of the production curves coming out of the Williston basin, and they were striking," Grape said.

The result was a Nov. 10 report, "Shale Shock! Could There Be Billions in the Bakken?" which examines the formation's location, production, resources, geology, reserves, and technology in use. It also is the first of a series about technology-based US oil and gas plays.

Formal reviews

Wood and Grape sent the Bakken report through formal review by other divisions in EIA.

"That took more time, but it also resulted in a better product," said Grape. His next two reports will examine the Barnett shale, west of Fort Worth, and the Fayetteville shale in Arkansas.

Grape emphasized that the reports will not promote frontier areas or exotic technologies. "We want to highlight success stories. Most of them actually are being produced. People have already discovered the plays and are trumpeting the success. I'm just trying to spread the word," he said.

North Dakota Petroleum Council Pres. Ron Ness liked the report. "The work by Mr. Grape was fantastic," he said. "The Bakken's potential is enormous. Marathon Oil Corp. announced a major presence in the state and is very active. Many other companies are at work there. The completion techniques and technology to tap the resource still are in question. But these studies and reports help."

Recognizing 'endowment'

David J. Bardin, a US Department of Energy official during President Jimmy Carter's administration who has been trying to bring attention to the Bakken and other US plays, said reports like Grape's spread knowledge about what petroleum professionals call the endowment.

"How much oil is there in place? How much natural gas? When we get more of that picture to the financial community and to the policy-makers here in Washington, they're going to ask themselves what can be done to get another 5, 10, or 15% of those hydrocarbons out of the rocks and up to the surface to help our economy and displace imports," he said. "It's a big opportunity." ✦

jected reversionary interest, based on a $60/bbl oil price, Denbury said.

Initially, Denbury had expected to transport CO_2 from its natural source at Jackson Dome, but ultimately plans to use manufactured (anthropogenic) sources of CO_2 for this tertiary operation. It is initiating studies for construction of a 280-mile pipeline to transport CO_2 to Hastings from the southern end of its existing CO_2 pipeline which terminates near Donaldsonville, La. The pipeline, with a target for installation and operation within the next few years, is expected to cost $225-250 million.

Preliminary estimates indicate that it will cost $400-600 million (net) to develop the West Hastings Unit as a tertiary flood, excluding the cost of the CO_2 pipeline.

If the option is exercised, Denbury will be committed to make aggregate net capital expenditures of about $175 million over the subsequent 5-year period to develop the field for tertiary operations, and to begin CO_2 injections in the field within 3 years after exercising the option.

Meanwhile, Denbury has committed to buy all the CO_2 produced as a byproduct by a planned petroleum coke gasification project in Louisiana, scheduled to start up in 2010, and is engaged in ongoing discussions with other potential sources of manufactured CO_2. The plant, if completed, is expected to produce 190-225 MMcfd of CO_2. The purchase price of the CO_2 will vary, depending on oil price and the level of compression provided by the seller.

Denbury plans to connect this manufactured source of CO_2 to its natural source of CO_2, which will allow the company to allocate production as required between the two sources.

Dana's Cavendish share

Production from Cavendish field, scheduled to begin in first quarter 2007, is expected to flow initially at 100 MMcfd and to continue until 2016. Dana said its pending transaction remains subject to government and third-party approvals.

Dana estimates that the additional 25% interest will add 29 bcf of North Sea proven and probable gas reserves and a production gain of 17 MMscfd. After closing, Dana's overall production from its total stake in Cavendish is expected to be 34 MMscfd.

Cavendish field lies in 18.5 m of water on Block 43/19a, about 140 km northeast of Easington on the Lincolnshire coast and 180 km north of Bacton on the Norfolk coast.

Development involves three production wells and a minimum facilities platform tied back to ConocoPhillips (UK) Ltd.'s Caister Murdoch System (OGJ, Aug. 24, 2005, Newsletter).

The platform was installed in June (OGJ Online, Sept. 1, 2006).

Plans call for gas to be exported from Murdoch through the Caister Murdoch System trunk pipeline to the Theddlethorpe gas terminal in Lincolnshire, where it will be sold into the UK gas market.

ADNEC's acquisition

ADNEC, indirectly owned by the UAE government, was established in 2005 to manage water, electric, mining, and oil and gas projects worldwide. It expects to complete its acquisition from BP by Jan. 31. Value of the transaction was not disclosed.

BP operates assets, both onshore and offshore, in multiple mature gas fields in the Netherlands, associated production facilities, and the suspended Rijn oil field. The London-based parent company previously announced plans to sell these assets, which produced 62 MMcfd net to BP during 2005 (OGJ Online, May 10, 2006).

This sale does not affect BP's other business activities in the Netherlands, including energy trading, refining and marketing, and renewables energy.

Riata closes NEG deal

Riata does business as SandRidge Energy Inc. Riata signed a letter of intent on Sept. 7 and announced plans to change its name to SandRidge Energy on Sept. 29.

NEG's holdings include oil and gas properties throughout Texas and in the Gulf of Mexico. The acquisition involved essentially all of American Real Estate's oil and gas interests and all the properties previously managed by National Energy Group Inc., which was acquired by NEG Inc., another Icahn business, earlier this year.

SandRidge issued 12.8 million shares to an American Real Estate subsidiary, paid $1.03 billion in cash, and assumed $250 million in NEG Oil & Gas debt.

Tom L. Ward, SandRidge's chairman and chief executive officer, said the acquisition boosts his company's holdings in Pinon gas field in the West Texas thrust belt to 245,000 net acres with an average working interest of 83%.

"We are moving forward with plans to expand our drilling program to 20 rigs in the Pinon field by yearend 2007," Ward said.

El Paso E&P's acquisition

El Paso E&P agreed to acquire Laredo Energy III LP, operator and majority owner of the properties, and separate working interests in some other properties. The acquisitions are expected to close in January 2007 and will mark El Paso's return to the Lobo trend.

The assets being acquired have current net production of 19 MMcfd of gas equivalent. El Paso estimates proved reserves to be 84 bcf, and 73% of that is undeveloped. The 27,000 gross acres to be acquired are near El Paso's existing operations in Bob West field in Zapata County.

Swift buys wells

Swift's acquisition, expected to close before Dec. 31, involves assets northeast and southeast of Swift's existing acreage in Lake Washington field.

The purchased interests consist of 4,400 gross acres, or 2,800 net acres. Current production is 275 boe/d net to the purchased interests and consists of 86% oil.

Swift Energy says total reserves of the

PERSONNEL MOVES AND PROMOTIONS

Wood to head Murphy's worldwide exploration

David Wood, in charge of international exploration and production for Murphy Oil Corp., El Dorado, Ark., will become executive vice-president with responsibility for worldwide E&P, effective Jan. 1, 2007.

At the same time, Murphy will centralize its E&P office in Houston and close its New Orleans office. **John Higgins**, who has been in charge of Gulf of Mexico E&P operations, will retire.

Harvey Doerr, head of Canadian operations, will become executive vice-president with responsibility for worldwide refining and marketing and all strategic planning and be based in El Dorado.

Other moves

Linn Energy LLC, Pittsburgh, Pa., has appointed **Mark E. Ellis** executive vice-president and chief operating officer.

Ellis has more than 25 years of oil and gas experience. He previously worked for ConocoPhillips as president of the Lower 48. Before that, Ellis served as senior vice-president of North American production for Burlington Resources Inc. and president of Burlington Resources Canada Ltd. He began his career in 1979 with Superior Oil Co.

Crosstex Energy LP, Dallas, has appointed **Robert S. Purgason** executive vice-president and chief operating officer, a new position.

Purgason has more than 25 years of oil and gas experience. He joined the company in October 2004 as senior vice-president of the treating division.

Previously, he worked for 18 years for Williams Cos. Inc. in Tulsa, serving as vice-president of the company's Gulf Coast midstream business and in various senior-level positions in natural gas liquids, gas marketing, mergers and acquisitions, and major project development departments.

Purgason began his career in treating at Perry Gas Cos., one of the earliest gas-treating companies in the industry.

James Rundell has been appointed president of JED Oil Inc., succeeding **Al Williams**, who resigned along with Chief Financial Officer **David Ho** in what the company calls a comprehensive change to its business plan.

Rundell has been involved in JED since its inception and served as the company's drilling manager since June 2005. He has more than 30 years oil and gas industry experience, mostly related to drilling.

UK Sec. of State **Alistair Darling**, who leads the UK Department for Trade and Industry, will assume responsibility for energy in a reorganization that gives energy cabinet-level status for the first time in more than a decade.

Former Energy Minister **Malcolm Wicks** has been appointed science minister following the surprise departure of **David Sainsbury** from that post.

A spokesman told OGJ that the DTI soon will clarify how the energy portfolio will be distributed within the government.

"Darling will still be focused on the major consultations that are taking place at the moment for the energy white paper which we hope to publish next year," he added.

purchased properties are 1 million boe of proved reserves and 1.7 million boe of probable and possible reserves. About 36% of the proved reserves are proved developed.

Future development costs for the proved, probable, and possible reserves are estimated at $25.3 million for an all-in acquisition cost of $17.23/boe (or $2.87/MMcfe).

GE, Sunland acquisition

The assets being acquired by GE Energy and Sunland include 26 producing wells, 2 proved, developed nonproducing wells, and 11 proved, undeveloped drilling locations in Caspiana and Black Creek fields. Production is 44% oil, 55% gas, and 1% liquids.

GE Energy holds a majority limited partnership interest in Sunland Production Partners LP, a partnership with Sunland Resources for the reserve acquisition.

The operator will be Sunland Production, which already operates more than 60 oil and gas wells in eight fields in north Louisiana and Arkansas, producing 400 b/d of oil and 15 MMcfd of gas.

PetroHunter deal

Galaxy, also of Denver, intends to retain ownership of its unconventional Piceance basin gas properties in the Rifle Creek project in Garfield County, Colo. Galaxy and Exxel initially announced a $50 million transaction, but that amount was reduced to $40 million, Galaxy said Oct. 3 (OGJ Online, Aug. 1, 2006). Exxel is based in Vancouver, BC.

PetroHunter signed a nonbinding letter of intent with Galaxy to negotiate a final purchase agreement for Powder River basin oil and gas interests belonging to Galaxy subsidiary Dolphin Energy Corp. in Wyoming and Montana.

Dolphin owns an average 86% working interest in 197 oil and gas wells in the Powder River basin, of which 22 wells are selling gas at an average rate of 850 Mcfd. The other wells are in various stages of dewatering, shut in waiting on pipeline, or awaiting completion. ✦

DEEPWATER RISKS—2

Deepwater projects present surface, downhole challenges

David Wood
David Wood & Associates
Lincoln, UK

Saeid Mokhatab
University of Wyoming
Laramie

Selecting appropriate field development plans, risk management, and modifying project implementation methods is essential to maintaining the viability of deepwater oil and gas projects.

The second part of this two-part article lays out considerations for flow control and assurance, processing and support, transportation and storage, schedules, abandonment, and other aspects of complex projects.

Flow control and assurance

Flow assurance aspects represent both revenue and cost risks.

Any upset in flow from the wells will directly impact the volume of product available for sale, and the cost of rectifying a flow problem in deep and cold water will represent a formidable cost risk.

Increasing the robustness of a system to very high levels implies increased equipment costs, which ultimately may make the project uneconomic. Hence, it is necessary to strike a satisfactory balance between the capital investment requirement and an acceptable level of risk. Flow assurance is a critical issue for concept evaluation, commissioning, safety, security, start-up, and post start-up phases especially in long distance tieback field developments.

Innovative technology and flexible well intervention contingency plans and options should operational problems arise are the key to addressing flow assurance issues and can influence the cost risks. The implementation of transient multiphase modeling will normally provide guidelines to safe operational strategy development and in assessments of operational risks.

Most deepwater developments include a host surface facility with multiple subsea well tiebacks in order to cover the full area extent of the reservoir.

This host facility commonly only accounts for substantially less than 25% of the total project costs; however, if it fails to perform or its operations are adversely impacted (e.g., Thunder Horse platform in the Gulf of Mexico) all the expensive wells tied back to it also are unable to perform.

Even if the host facility has dry trees for the initial suite of production wells, additional subsea tiebacks in later field life are usually envisaged.

The host facility design must therefore make adequate provision for the flow assurance and operability requirements of subsea tiebacks, both initial and future, i.e., redundancy must be built in. The more redundancy that is built in the more complex the facility, and as complexity often translates into high cost some critical tradeoff decisions must be made.

Flow impedance issues such as formation, mitigation and control of hydrates, wax, and asphaltenes, sands, and scales must be assessed and modelled in detail. Particular issues which industry's experience has shown require careful consideration[7 8] include:

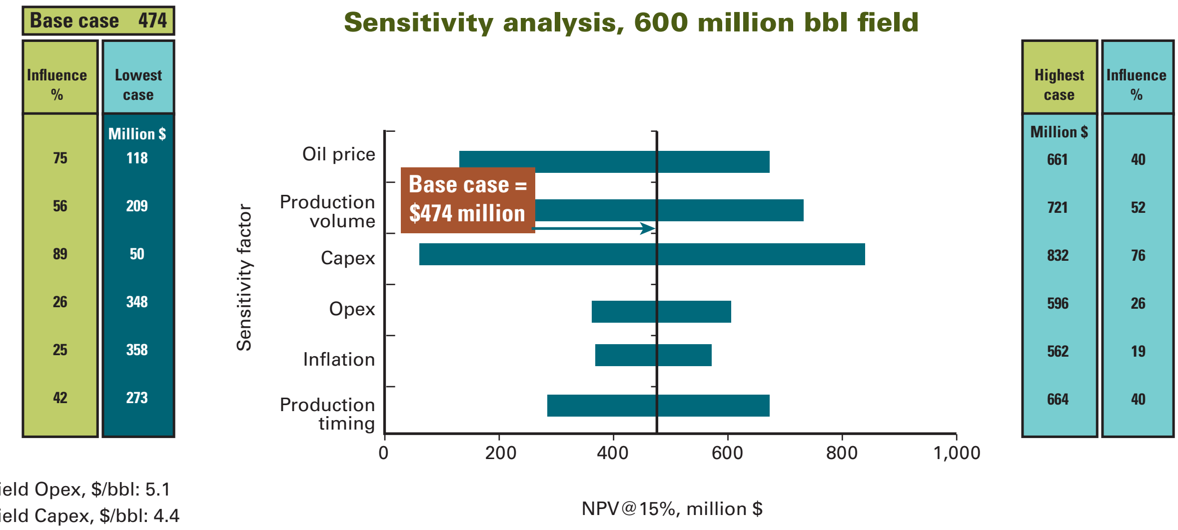
1. Arrival temperature management—provision for heating or cooling of arriving fluids may be required, over a range of operating conditions;

2. Liquids management—multiphase fluids from subsea tiebacks may generate significant slugging, either during steady state operation or during start-up and ramp-up following a turndown. Liquids carryover may also occur during flowline depressurization (blowdown). Such occurrences must be accommodated in the sizing of the host facility slug catcher/separator.

3. Hydrates management—if MEG injection subsea is proposed for hydrates management, then the storage, injection, and regeneration system and its associated utilities (particularly power for heating or cooling) may be a significant space and weight consideration for topsides design. If methanol or glycol is proposed, again the storage and injection systems need to be accommodated.

CASH FLOW SENSITIVITY OF A DEEPWATER NIGERIA FIELD*

Fig. 5



Field Opex, $/bbl: 5.1
Field Capex, $/bbl: 4.4

*See Wood, 2003a, for an in-depth discussion of this Nigeria project analysis.
Source: David Wood & Associates

4. Wax management—if hot oil circulation is selected to warm up the subsea systems prior to start-up to avoid wax deposition, then the circulation system must be provided topsides. It is important to size the system to accommodate possible additional tiebacks if these are contemplated. If wax inhibitor injection is proposed, again the storage and injection systems need to be accommodated.

5. Chemicals injection—topsides storage, injection and resupply logistics must be considered. Chemicals injected subsea may include scale inhibitor, wax inhibitor, antiagglomerant, and corrosion inhibitor. This may impact integrity issues such as design and management of corrosion and erosion problems.

6. Deliverability issues such as optimization of flowline sizes, artificial lifting, topsides equipment and arrival pressures, and viscosity management for heavy oil system and emulsions.

7. Stability issues such as control of system upsets and slugging during normal and transient operations;

8. Safety and security issues—at the flow assurance stage there is still sufficient flexibility to design inherent safety and security features into a facility.

Hence, key technology needs to provide a robust solution with acceptable risks to future production in the above-mentioned items.

Processing and support

To stabilize produced well fluids, and to separate marketable products from them, they must be processed.

Facilities to carry out some processing are usually located offshore at or close to the field but are sometimes located fully or partially onshore and linked to the wells by a long-distance multiphase pipeline. Processing facilities usually require:

• Deck and structures (fixed or floating) to support the deck.

• Manifolds to tie in producing wells to processing vessels.

• Heat tracing/insulation capabilities such as electrically heated flowlines.

• Separation, stabilization, and gas and water treatment vessels.

• Testing and metering equipment.

• Compressors and pumps.

• Export systems with metering.

• Utility, power, and safety systems.

• Personnel accommodation facilities.

Processing facilities for deepwater fields are commonly placed on floating structures. In some instances it is possible to use tension-leg platforms (TLPs), but large-scale barge-like FPSOs are becoming more widely used for the processing facilities of large remote deepwater fields. Alternatives to this include:

1. Placing substantial process functions downstream linked to shore-based facilities by multiphase pipelines.

2. Placing some process functions (e.g., water separation) upstream of the offshore surface facilities (e.g., subsea manifolds linked to downhole or subsea processing equipment).

New subsea technology options may offer less weight and reduced cost for the surface facilities but usually increase operating cost risk and revenue risk. Such higher risks should be factored into the project economic evaluations. Some technology that is currently under development to improve project economics and recovery includes:[4]

• Extra long (up to 150 km) composite umbilicals for controls, methanol injection, and signals.

• Fiber optic technology for controls of up to 300 km length.

• Advanced flow assurance techniques to design for and mitigate hydrate formation.

- Subsea multiphase pumping.
- Subsea gas/liquid separation and liquid pumping.
- Subsea gas compression.
- Two or three phase subsea separation.

Designing facilities to be flexible to facilitate the addition of extra capacity or evolving technology improvements can lead to substantial economic benefits on a life of field basis for acceptable additional costs.

Failing to design in flexibility for future unforeseen expansion of facilities may lead to prohibitive future costs and an inability to exploit opportunities as they materialize in the future.

Transportation and storage

Access to and reliability of third-party transportation and storage facilities represent a potential revenue risk.

Recent technological advances in floating LNG and floating storage and regasification units enable gas storage and transportation costs to be reduced and can ease access to gas distribution networks. Such developments offer the potential to unlock many stranded offshore gas fields for development. LNG regasification plants, now becoming more widely distributed in the main global gas markets, offer a ready market for this gas.

Building large complex floating storage and offloading (FPSO) systems, designed specifically for a field's reservoir performance characteristics and capacities, is often the critical long-lead time item in a deepwater field development. Consequently, delays in completing the construction of these vessels also pose a significant revenue risk.

Schedules

Achieving early production from a field development can significantly enhance project economics.

However, if a project's planned schedule to achieve early production is too ambitious it often leads to added costs being incurred to achieve it. Robust project planning, teamwork, cost control, and contracting strategy are essential to achieving production on schedule.

It is important to recognize that serious accidents and incidents (safety and/or climatic) can lead to persistent project delays many months after such events occur (e.g., Hurricane Katrina, 2005; Petronius accident in 1998 where a $70 million platform deck sank in the Gulf of Mexico).

Resources deployed to rectify impacts and investigate causes of incidents can seriously impede project progress. Building contingencies into project schedules and budgets for unforeseen eventualities can help to partially mitigate their impact on a project schedule.

Design-build time cycles are becoming more compact and schedule and start-up delays in deepwater fields, due to a variety of reasons, can have a substantial negative impact on project costs and ultimate project profitability, often destroying value that cannot easily be recovered.

Cash flow sensitivity analysis of deepwater projects shows that they are particularly vulnerable to cost and timing overruns because they are high-cost projects to begin with and each day of delay is so expensive.

For most onshore or shallow water field developments cash flow sensitivity analysis suggests that oil price and reservoir performance (production rate and reserves) are the key factors determining profitability. In the case of deepwater projects costs and project schedule (time to first production) can have comparable impacts on profitability.

Consider a cash flow sensitivity analysis for a deepwater field offshore Nigeria (Fig. 5). The wider the horizontal bars, the greater the project's economic sensitivity to that factor.

The capital expenditure bar is wider than the others (typical of large deepwater and LNG development projects). The production timing sensitivity case in this example were delaying (which extends bar to left) and accelerating (which extends bar to right) production by 1 year. Longer delays would extend the production timing sensitivity bar to the right.

Some may say in the current oil and gas price environments that what is lost in delayed scheduling can be recouped by high product prices. Obviously this is a risky approach as there is no guaranty that prices will remain high over project lives measured in decades. But Fig. 3 (Part 1 of this article) shows that this is actually not the case.

The bar for oil price sensitivity is asymmetrical with more downside than upside. This is due to the impact of fiscal terms that ensure that the government and national oil companies (NOCs) see most of the upside in high price environments, whereas the international oil companies (IOCs) see all of the downside risk of cost and timing overruns. IOCs therefore have added incentives to carefully manage project costs and schedule risks and mitigate carefully against overruns.

Indeed an early stage risk management strategy could be to seek tax incentives (i.e., a greater share of the upside) from governments in return for making high-risk investments offshore. This, however, is easier said than done. It was achieved in the mid-1990s in Nigeria, but once giant fields were discovered and perceived exploration risks reduced the government soon clawed back most of the incentives.

Wet gas can provide substantially more robust project economics than dry gas particularly if liquids can be tied into existing infrastructure at low cost. This additional revenue stream can help to offset the high capital cost risks of deepwater gas field developments. In a similar way integrated projects including deepwater gas field and onshore processing plant and-or LNG and GTL facilities provide more economically attractive projects than stand-alone gas field developments.

As well as revenue/cost benefits key advantages of integrated projects are that risks are spread along the gas supply chain and the projects can be made more contractually robust, mitigating some of the risks associated with government or third-party manipulation.

Managing the risks

Risk standards and tolerance levels must be set for effective project execution.

Skilled project participants are often highly specialized and are located continents and time zones apart, when different components of a complex facility are fabricated in different yards by isolated teams.

A key role can be played in this regard by an experienced interface coordinator with the objective of promoting closer teamwork and minimizing duplication of effort.

Ideally, the personnel should be familiar with the local conditions and culture, but it may be difficult to assemble such a team(s), e.g., in Southeast Asia, only one major deepwater EPC development has been installed (Unocal West Seno, Indonesia, 1,000 m of water) and only two or three others are through FEED phase.

However, a number of major engineering and construction companies in the region have executed similar projects globally and can draw on these resources if required. Also, especially in today's vibrant market, it is not always possible to have a team of superstars.

Nonetheless lack of communication is not uncommon between commercial asset managers, geologists, geophysicists, drillers, engineering and installation contractors, supply chain managers and, ultimately, those who will be tasked with operating and maintaining the deepwater facility once completed.[3]

Interface management should be able to avoid this. So can effective executive reporting—data collected from all project teams is compiled into a concise report that allows other teams, project managers, directors, partners, investors, and all stakeholders to understand the project status.

Such reports can succinctly communicate, in both commercial and technical terms, the outstanding risks and existing mitigation plans, the forecast final cost at completion, the most likely date for project completion, together with safety and quality performance issues.

Integrated execution

To effectively establish an integrated project execution framework or model it is important to formulate from the outset a contracting strategy, a holistic risk assessment methodology, an experienced and dedicated team, an applicable design criteria, and integrating this into a project execution plan and model.

Using such an integrated project execution model that identifies and manages risks throughout project execution is an essential success factor.

Project team

The organization of the team is another factor.

A dedicated team means the personnel are always available for the project, but this requires a larger personnel budget. A team shared with other projects, however, risks personnel resources being in short supply when they are required, although knowledge transfer between projects becomes possible.

Experience is invaluable, not only in the exploration and development phases, when risk assessment may frequently be called for, but also during the execution of the project, when risks have to be controlled and managed. The other aspect of team structure is contracting, i.e., the number and nature of contractors, spreading risks, expediting supplies and services, and managing the number of interfaces and communication channels.

When new technologies or complex projects are involved, it may be advisable to limit the number of contractors and EPC contracts, especially if it involves working extensively with unfamiliar parties. In all these cases, stringent gate reviews and quality milestones will help manage the technical and cost risks.

A clear understanding of the potential risks in all the phases of the project will enable the operators and contractors to set up strategies specific for a deepwater field development. It is well worth taking the time to understand the project, especially any unique traits or requirements.

In the exploration phase, the fundamental risk is reservoir uncertainty. This risk can, to a certain degree, be mitigated by appraisal drilling and advanced seismic, but economics dictate limited early investments. Reservoir uncertainties must therefore be reflected in flexible development schemes, e.g., phased developments, where large capital expenditures can be delayed until reservoir performance is verified by some production history.

During the development phase, risk analysis techniques provide a means to estimate the risks and reliability during every stage of development and during production.

By comparing the estimated risk costs and projected revenues, the operator can select the preferred alternatives. Seemingly costly feasibility and engineering studies may incur additional expense, but this is frequently justified when the information gained provides a major reduction in total costs and risks.

Substantial cost overruns in several high-profile, remote, offshore projects over the past couple of years (e.g., Bonga field Nigeria, Snohvit LNG Norway, and Sakhalin II Russia) can be attributed to a large degree to failures in the feasibility and early stage planning to adequately identify risks and to devise and employ appropriate risk mitigation strategies.

During project execution, the cost risk may be handled by limiting the use of new and unproven technology, and by employing project execution models, which are based on thorough and mutual understanding of project requirements and risks by all parties in the execution scheme.

Abandonment

The abandonment of a deepwater field challenges a company's ability to control expenses and liability.

More conventional techniques are used for abandoning dry-tree type completions, but tubing retrieval and abandonment of subsea completions require the same specialized equipment used for initial installation at a very high cost.[2]

Advances in new technology and techniques should provide the industry with cost- and risk-reduction opportunities for deepwater field abandonments. The technology, concept design and the complexity of deepwater operations have changed dramatically in the last 5 years.

To sustain the growth of deepwater operations, the industry will be continually challenged to make new advances. It is in the interests of both operator and service industry to provide solutions to the technical challenges we will face.

Acknowledgment

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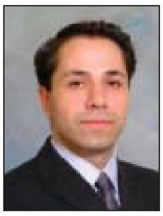
The authors

David Wood (woodda@compuserve.com) is a consultant who specializes in the integration of technical, economic, risk, and strategic information. His services include project evaluation, research, and training on a wide range of technical and commercial topics. He is based in Lincoln, UK but operates worldwide. He holds a PhD from Imperial College.



Saeid Mokhatab is a natural gas engineering research advisor to the University of Wyoming and a senior project consultant for hydraulic design and engineering of natural gas transmission pipelines and processing plants. His research is widely published, and he is a member of the SPE Distinguished Lecturer Committee and several other professional committees.

Alabama

Longford Corp., Calgary, said five recently drilled coalbed methane wells encountered more than 80 net ft of coal, some of the thickest total coal sections found in the Black Warrior basin.

The wells, near Moundville 20 miles south of Tuscaloosa, encountered individual seams as thick as 22 ft in the Pottsville formation between 700 and 3,400 ft deep. Dewatering is to begin in January 2007.

Texas

East

Wentworth Energy Inc., Palestine, Tex., will begin permitting the first of as many as eight offset locations on the same structural feature after its first well on a 27,557-acre mineral block in Anderson and Freestone counties in East Texas is a gas discovery in Cretaceous Woodbine. CAOF potential at the 1 Brakens well is 2.1 MMcfd. Woodbine, perforated in two zones at 4,918-48 ft overall, had calculated bottomhole pressure of 2,050 psi.

Meanwhile, Marathon Oil Co. signed a 3-year agreement to lease 9,000 acres of the 27,557 acres to drill deep wells. The two companies signed a joint operating agreement to partner in the development of the shallower Woodbine and Rodessa formations on those 9,000 acres.

Wyoming

Questar E&P, Salt Lake City, plugged and abandoned the deep exploratory portion of its Stewart Point 15-29 well on the Pinedale anticline in the northern Green River basin.

The company said it failed to establish commercial production from the Cretaceous Hilliard and Rock Springs formations.

Questar E&P drilled to TD 19,520 ft and briefly gauged sweet, dry gas at the rate of 10.7 MMcfd from Hilliard at 18,500-19,400 ft in what it said appears to have been industry's first attempt to frac and produce from shale at these depths and pressures (OGJ Online, July 11, 2006). Shut-in pressure was as high as 13,500 psi.

Questar E&P recorded an after-tax charge of $6.3 million related to abandonment of the deep part of the well, which was later recompleted as a commercial well in the Cretaceous Lance pool.

Production

Refurbished jack up production unit produces marginal field off Malaysia

Guntis Moritis
Production Editor

A refurbished mat-supported jack up mobile oil production unit (MOPU) recently began operating in 63 m of water on the Cendor oil field in Block PM304 off Malaysia (Fig. 1).

Petrofac Malaysia, a unit of Petrofac Ltd. UK, operates the field.

Phase 1 of the project includes seven dry-tree well completions on the MOPU that produce oil to a spread-moored floating storage and offloading vessel (FSO) through a flexible subsea pipeline.

Richard Hall, vice-president of operations and development for Petrofac's resources division and general manager of Petrofac Malaysia, told OGJ that one factor that made this low-cost development solution possible for this marginal field was the level seabed at Cendor that allowed installation of the mat-supported MOPU.

The field currently produces 12,000 bo/d and Petrofac says that the field contains about 24.6 million bbl of recoverable 41.5° gravity oil.

Petrofac has a 30% interest in the field. Other interest owners are Petronas Carigali Sdn. Bhd. 30%, Kuwait Foreign Petroleum Exploration Co. (Kufpec) 25%, and PetroVietnam Investment Development Co. (PIDC) 15%.

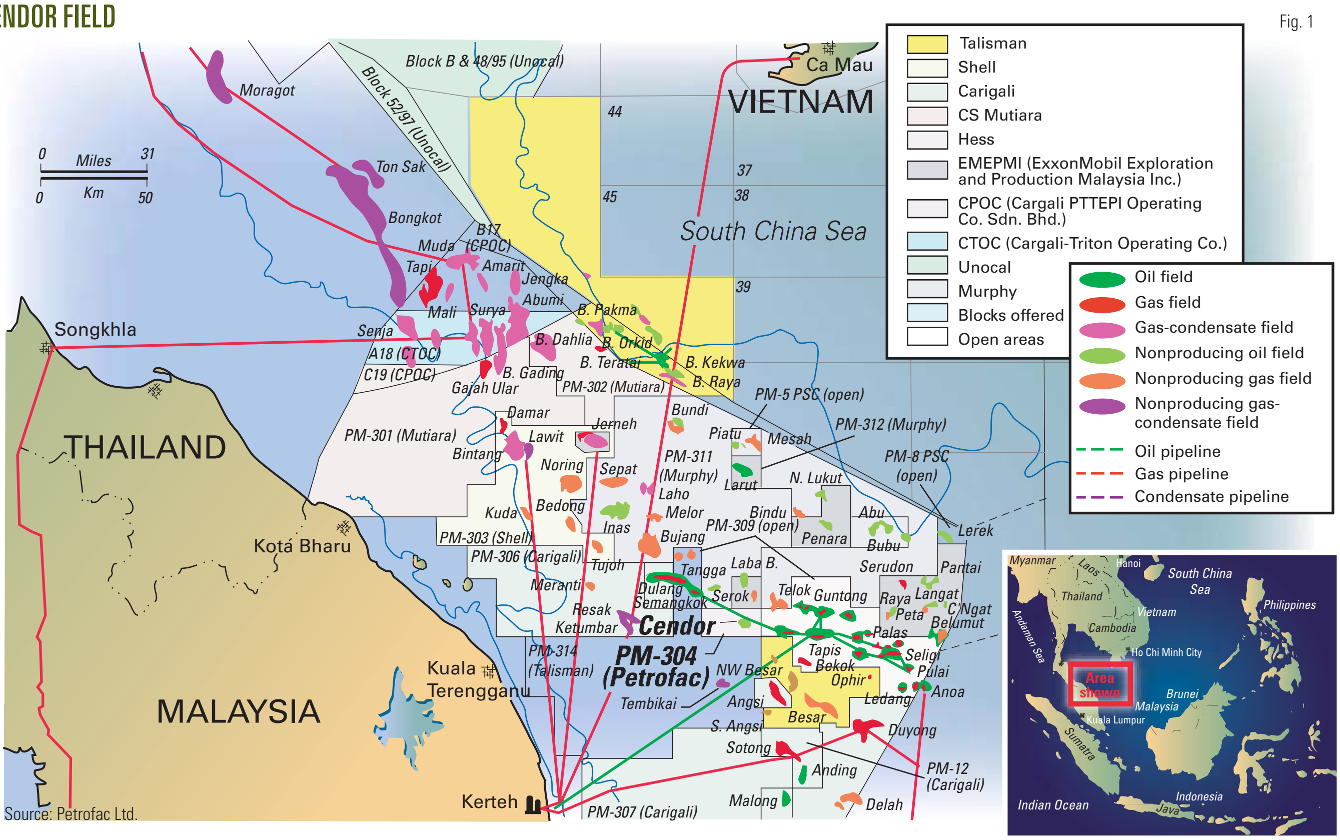
Kufpec is a wholly owned subsidiary of Kuwait National Oil Co. and PIDC is a wholly owned subsidiary of Petro Vietnam.

Petrofac

Hall described Petrofac as a company involved in three different types of oil field operations. The company has an engineering, and construction group with

CENDOR FIELD

Fig. 1



Source: Petrofac Ltd.

main locations in Woking, Sharjah, and Mumbai; a facilities management and training group that primarily works off the UK for companies that recently have purchased producing properties from larger companies; and an investment group that holds interests in oil and gas producing properties or infrastructure, aligned to its client and partner base.

Petrofac currently has interests in oil and gas field developments in Tunisia, Algeria, and off the UK. Cendor is the first field in which it is the operator under a joint operating team arrangement with Petronas Carigali.

Cendor project

Hall said that Petrofac had been able to take the Cendor project from "farm-in to full production in less than 2 years in a tight market, within budget, and ahead of the prescribed timetable."

Over the years, four different operating companies have drilled about 11 exploration wells in the block since the 1970s with only the most recent operator, Hess encountering hydrocarbon production potential.

Hess' Cendor-1 had a 1,790-m TD and tested up to 2,840 b/d of 42° gravity oil from one zone, with another zone flowing more than 5 MMscfd of gas (OGJ Online, Mar. 23, 2001).

Petrofac describes the Cendor structure as a large inversion anticline compartmentalized by a number of north-south trending faults. The principal reservoirs in the first development phase are the H15 and H20 intervals within the Middle Miocene formations that are highly stratified and vary between muddy hetereolithics, sandy hetereolithics, and clean sands.

Previous operators considered the field marginal because of the uncertainties associated with the extent of reservoir compartmentalization and the relative productivities of the different facies that caused difficulties with formulating a development plan.

Another problem in delineating the field was the presence of shallow gas that inhibits resolution of seismic horizons across the structural crest at reservoir depth.

The Atwood Vicksburg jack up drilled the seven producing wells on the mat-supported mobile oil production unit in Cendor field off Malaysia (Fig. 2). Photo from Petrofac Ltd.

Key to Petrofac's development was to obtain operational flexibility for dealing with as many potential reservoir outcomes as possible at the lowest possible cash commitment, Hall said.

He described the previous development schemes as assuming lightweight platforms with limited flexibility. Petrofac on the other hand noted that the seabed at Cendor is flat, which made installation of an old style mat-supported drilling rig as a production platform commercially feasible.

Petrofac leases the unit and also the FSO, which adds to the flexibility.

The MOPU has a deck area that accommodates two first-stage separators as well as a test unit. It can process up to 20,000 bo/d but has a turndown design to produce as little as 2,000 bo/d, which at high oil prices is economic, according to Hall.

The well completions have triple splitter wellheads, so that the MOPU effectively has 12 well slots within four 36-in. by 1¼-in. WT conductors.

The deck has sufficient deck space for a laydown area to carryout workovers with a hydraulic workover unit.

Petrofac also has had the mud pumps refurbished and installed the required piping in case the oil from the wells needs to be artificially lifted with jet pumps. The MOPU also has the capability to inject 25,000 bw/d.

The wells produce with a 250 scf/bbl GOR.

Petrofac uses carbon steel tubulars in the wells and injects chemical downhole to prevent corrosion.

A low-cost flexible composite subsea hose, installed from a motorized reel on a small dynamically positioned vessel, connects the MOPU to the FSO. Manuli Rubber Industries, Milan, Italy manufactured the hose.

Hall said the project has the following innovative firsts for Malaysia:

- First MOPU.
- Longest span of unsupported conductor, 80 m.
- First flexible subsea pipeline made of composite material.

The Atwood Vicksburg jack-up drilled and compled the seven wells (Fig. 2).

Petrofac's next plan is to evaluate reservoir performance to rapidly progress further development and to drill an appraisal well on the other side fault block where only one dry hole was drilled, Hall said. ✦

Optimized drilling fluids benefit tough Andean wells

Mario A. Ramirez
Patrick Kenny
Dennis Clapper
Baker Hughes Drilling Fluids
Houston

Drilling

Aluminum complex drilling fluids solved common drilling problems in Colombia, Ecuador, Peru, Bolivia, and Venezuela.

Drilling wells in the Andes Mountains of South America face significant difficulties. Wells located in the foothills along the Andean basin are particularly hard to drill because of tectonic stresses and unstable, microfractured shales.

Operators have experienced difficulties drilling wells using both water-based and oil-based muds (OBM). Environmental regulations hinder the use of OBM due to the potential environmental impact and costs associated with waste disposal. In many cases, OBMs have not prevented wellbore instability.

This article explains how wellbore problems can arise from a lack of understanding of regional geology and using drilling fluids and practices designed for other areas. The water-phase salinity of OBM and use of appropriate inhibitors in the drilling fluid play a key role in minimizing wellbore problems.

Although reactive clays are present in all the shales along the basin, they represent only 30-40% of the clay fraction, while nonexpandable kaolinite clays are the major clay components. This article explains how physical and mechanical effects are more important than inhibition in controlling these shales.

Moreover, in some cases, "excessive inhibition" due to the presence of shale inhibitors such as potassium and high water-phase salinity in OBM exacerbate the problems. Pore-pressure transmission caused by fluid invasion is a major contributor. A combination of operational practices and improved fluid design minimizes mud and filtrate invasion.

Troublesome shales in the Andean basin include, from north to south, the La Rosa and Icotetea in Venezuela; the Carbonera, Leon, and Villeta in Colombia; the Napo in Ecuador, the Chonta in Peru; and the Los Monos in Bolivia and Argentina. We present case histories involving these shales.

Contrary to experiences in many other parts of the world, high water-phase salinity OBM and potassium based water-based mud (WBM) are not answers to all shale-stability problems. Rather, mud-sealing properties, correct chemical composition, and appropriate drilling practices are keys in maintaining wellbore stability.

Andean region

The difficulties of drilling in the Andes Mountains of South America are well documented. The presence of tectonic stresses combined with over pressures[1] makes this a particularly difficult area.

The stresses in this region were generated by the Andean orogeny. The geology is typified by steeply dipping sand-shale sequences; many faults have been documented. Claystones and shales dominate the lithology in the region. These can be "sticky" at times,[2] requiring the use of inhibitive drilling fluids to minimize the associated problems.

Wellbore stability therefore becomes a major problem when drilling in the Andes region, particularly when drilling directional wells.[3] Well-documented drilling problems in Colombia include stuck pipe, high torque and drag, tortuous wellbores, twist-offs, poor cementing, and unplanned backoffs.

Many of the difficulties encountered have been attributed to poor hole cleaning in enlarged holes resulting from wellbore instability. The cavings generated during hole enlargement have also presented hole-cleaning difficulties.

Success in drilling wells in this region has been attributed variously to simplifying well design, understanding the tectonic stresses and their orientations, drilling fluid design,[4] and sound drilling practices.

Considerable efforts have been devoted to studying wellbore stability issues in the Andes region.[5-7] The primary objective of these studies was to improve drilling efficiency. The major conclusion was that it is impossible to prevent borehole instability; rather, it is necessary to find methods to manage it.

Last et al. observed that hole breakout was aligned parallel to the mountains and that there was a clear time-dependency factor. They determined that the most important factors were hole deviation and azimuth, with drilling-fluid formula-

DRILLING FLUID PARAMETERS, YURALPA FIELD

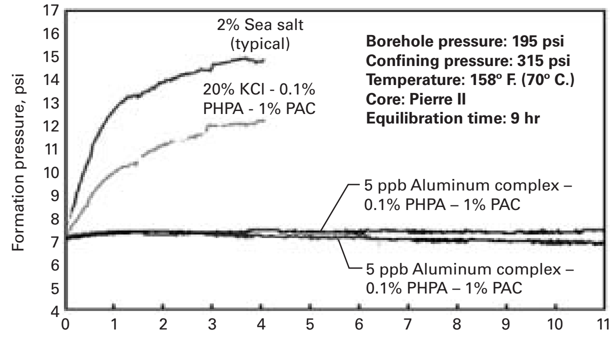
Table 1

Interval, in.	12¼	8½
Fluid type	Aluminum complex, amine	Aluminum complex, amine
Interval length, ft	3,411	770
Hole angle, °	0-64.2	64.2-77.8
Dilution rate, bbl/ft	0.67	0.49
Fluid formulation		
Aluminum complex, lb/bbl	4.9	4.4
Barite, lb/bbl	76.7	66.3
Amine inhibitor, lb/bbl	2.8	2.3
Xanthan gum, lb/bbl	0.5	0.6
PAC LV + HV, lb/bbl	1.1	1.0
Gilsonite, lb/bbl	4.6	4.1
Calcium carbonate, lb/bbl	—	4.5
Modified starch, lb/bbl	—	—
Fluid properties, typical		
Density, lb/gal	11.2	10.5
Plastic viscosity, cp	27	24
Yield point, lb/100 sq ft	27	27
Gels, 10 sec/10 min/30 min lb/100 sq ft	6/19/25	7/16/21
API filtrate, cc/30 min	5.0	4.3
MBT, lb/bbl	18.75	17.6
Solids, volume %	15	21.5
pH	12.0	11.1

Based on a poster at the SPE-ATCE, San Antonio, Sept. 26, 2006.

PORE PRESSURE TRANSMISSION*

Fig. 1



*AL-based drilling fluid.

tion, whether WBM or OBM, being of relatively minor importance.

The major cause of wellbore instability was stress-induced failure of relatively weak, naturally fractured siltstones. It was also possible to document mud infiltration with time being vital in determining the onset of wellbore failure. The authors noted the successful use of asphalt products for this purpose.

Studies have compared and integrated wellbore instability issues in the South American basins.[8] Wilson et al. concluded that the failure mechanism involves bedding plane slippage in the complex geology of the region.

Studies of other parts of the Andes address similar difficulties posed by the complex geologic conditions in this region.[9 10]

Drilling fluid design

The drilling of clay, claystones, and shales has always placed great demands on drilling fluids in terms of wellbore stability and drilling efficiency. The drilling fluids industry strives to understand the mechanisms involved in order to improve drilling fluid design.

Recent research performed by the industry shows that several mechanisms are involved and that their relative importance can be estimated:[11-16]

- Pore-pressure transmission into the formation near the wellbore appears to be very important in very-low-permeability rocks, as confirmed by experiments and analysis.
- Plasticity models better simulate wellbore behavior.
- Anisotropy of the rock can influence failure.
- Capillary effects can help greatly in oil-based drilling fluids by effectively supporting the borehole wall.
- Osmosis, although well understood, is only part of the physico-chemical interactions between borehole and drilling fluid.
- Physicochemical interaction between shale and water-based drilling fluids leads to dissolution of a mineralogical phase of the rock.
- Thermal effects (cooling of the bottom part of the well) can also be significant.

The most important factor in maintaining borehole stability is the prevention of fluid invasion into the shale matrix, thus maintaining hydraulic pressure support of the borehole wall. An ideal drilling fluid, with respect to shale stability, will allow no fluid invasion.

measuring the pressure increase across a shale core as small amounts of fluid enter into the core is an alternative method of measuring borehole stability. Royal Dutch/Shell, BP PLC, and Eni SPA have developed devices for measuring pore pressure transmission (PPT).

The PPT device is designed primarily to measure membrane efficiency and osmotic effects of fluids on shale samples. Several years ago, preliminary PPT testing of aluminum complexes revealed that aluminum compounds could be used effectively to reduce rate of pore pressure transmission in the laboratory device. Fig. 1 shows PPT plots of water-based drilling fluid systems, along with PPT plots for aluminum-hydroxide complex fluids for comparison.

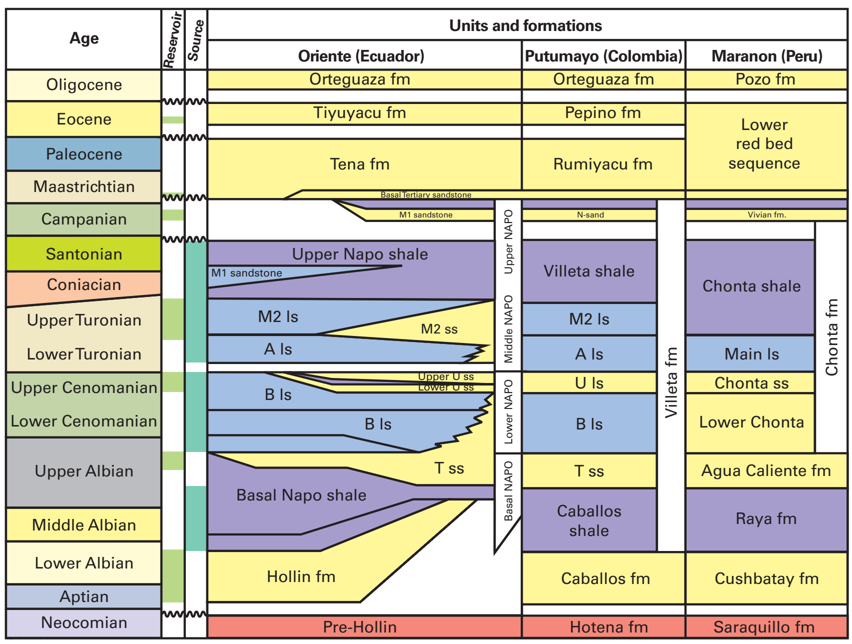
Recently, the device has been a key to the development of aluminum products and high performance water-based mud (HPWBM) systems.[17-19]

Aluminum chemistry

The Al-chemistry approach to shale stability is based on changing the

GEOLOGIC COLUMNS, EASTERN ANDEAN BASIN

Fig. 2



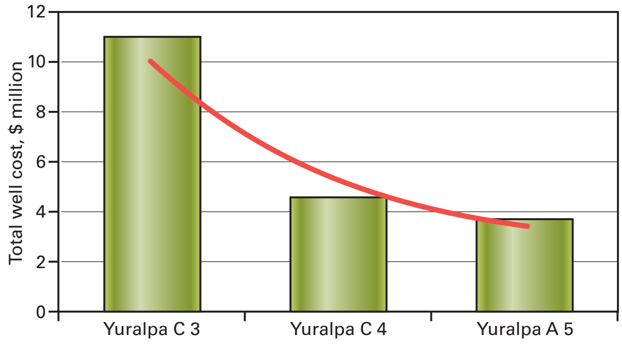
physico-chemical behavior of the shale, in contrast to the widely applied ionic-exchange approach. Aluminum chemistry has been successfully used in many wells around the world.[20-22] The work has been useful in integrating this chemistry into drilling fluid systems.

Aluminum chemistry is also a viable alternative to salt-inhibited systems where environmental regulations discourage the use of chlorides but where shale mineralogy dictates the use of an inhibitive fluid.[4]

Application of aluminum chemistry in drilling fluids was first described in 1973.[23] Early experiences with aluminum chemistry led to enhancements in the chemistry of the products being used. These enhancements, in turn, led to the products being more widely used with better success.

Various theories were postulated as to the mechanism by which aluminum chemistry benefits drilling-fluid performance. It was not until techniques for measuring pore-pressure transmission in shales were developed that the mechanism in the success of aluminum chemistry was identified—the reduction of pore-pressure transmission (as described above).

YURALPA FIELD, ECUADOR* Fig. 3



*Al-based drilling fluid systems.

CUSIANA FIELD, COLOMBIA Fig. 4

Yuralpa field, Ecuador

Many problems have been experienced during drilling of development wells in Yuralpa field in Block 21. As seen in Fig. 2, this field has a wide variety of lithologies that have presented many obstacles to the drilling operations.

The Napo shale has produced unstable wellbore conditions in the form of sloughing shale and ledges where limestone interbeds are present. As a consequence, there have been hole-cleaning difficulties, leading to pack-offs of the annulus, and eventually, to stuck pipe.

It is clear that drilling-fluid design was critical to successful drilling of these wells. Based on experience elsewhere in Latin America, including X-ray diffraction (XRD) analysis and shale-fluid compatibility studies, an aluminum complex-amine based fluid was recommended as a replacement for the potassium nitrate-based fluid being used at that time.

Napo shale dispersion tests showed 58.2% dispersion in fresh water, 38.2% dispersion in xanthan gum-PHPA (partially hydrolyzed polyacrylamide) fluid, and 14.2% dispersion in aluminum complex-amine inhibitor fluid.

One operator in 2000 introduced aluminum-based fluids to replace salt-inhibited drilling fluids that had caused severe wellbore-stability problems. Since then, more than 30 wells that include multiple directional and horizontal sections have been drilled successfully. Fig. 3 shows the learning curve for the application of the new system as compared with the conventional inhibited-potassium system.

Optimized drilling fluid design has minimized reaming and back-reaming operations due to enhanced wellbore stability. The continual improvement is clear in Wells A, B, and C.

Well A was drilled at a cost of 26% greater than the budgeted AFE (authority for expenditure). Well B was drilled at 1% less than the AFE, and Well C was drilled at 52% less than the AFE. Table 1 illustrates the recommended parameters for fluid systems used in Yuralpa field.

Cusiana-Recetor field, Colombia

Cusiana field is located on the eastern flank of the Oriental Andes cordillera (Fig. 4). This area is tectonically active, under compression from the eastward movement of the Pacific plate and the southeasterly thrust of the Caribbean plate. Cusiana field lies in an extremely environmentally sensitive area of the foothills.

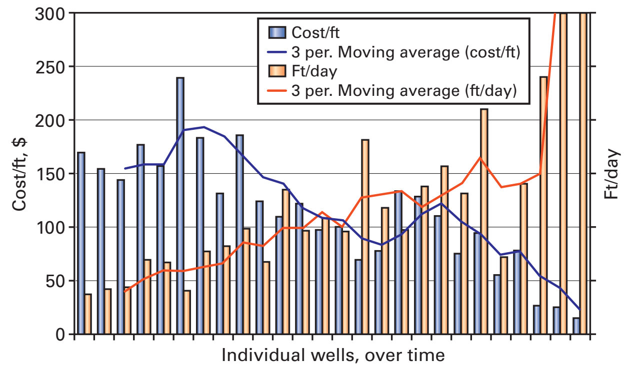
The basin is within the Llanos basin, and the field is one of the largest in the eastern hemisphere. Development of this field started in the 1990s; more than 130 deep wells have been drilled during the last 15 years, operated by BP.

The drilling problems in Colombia have been well documented.[2, 3, 5-8, 24, 25] While it is acknowledged that both chemical and mechanical factors affect borehole stability in this region, mechanical factors are believed to be the most critical. The Carbonera shale can produce unstable wellbore conditions in the form of sloughing shale and ledges. As a consequence, hole-cleaning difficulties may be experienced, leading to annular pack-offs and eventually to stuck pipe.

The Leon and Carbonera formations are believed to have been deposited in an estuarine environment. Table 2 shows XRD analyses of the troublesome Carbonera and Leon[26] shales. It is clear that these are not "swelling" clays and that any dispersion or instability will be as a result of physical rather than chemical processes.

CUSIANA & CUPIAGUA FIELDS, COLOMBIA

Fig. 5



XRD ANALYSIS, COLOMBIAN SHALES

Table 2

Formation	Carbonera	Leon	Leon
Area	Apiay	Apiay	Casanare
Mineral			
Quartz	10-15	10-15	10-15
Feldspar	Trace	1-2	1-2
Calcite	0	0	0
Siderite	0	1-2	Tr
Pyrite	1-2	2-3	1-2
Gypsum	0	0	0
Kaolinite	25-30	30-35	30-35
Illite	15-20	10-15	10-15
Chlorite	15-20	10-15	10-15
Mixed layer	25-30	20-25	25-30
Clay fraction	90	80	85
Kaolinite	30	40	40
Expandable clays	10	5	10

Various drilling fluids, including both water-based and oil-based, have been used in the field. The oil-based drilling fluids were adapted to the conditions of the basin. The most important change was the use of relatively low water-phase salinities in order to minimize the osmotic stresses. Aluminum complex chemistry was introduced in the Cusiana Buenos Aires field in the late 1990s.

Knowledge of the causes of wellbore instability led to design of a fluid to minimize pressure transmission into fractures and micro-fractures in the shales.

Two methods achieved this:

- Aluminum chemistry, in which an aluminum hydroxide precipitate will form in the fractures when drilling fluid filtrate or whole fluid encounters formation water.
- Asphaltic product, which physically plugs fractures and micro-fractures at the wellbore wall, reducing fluid invasion.

Fig. 5 demonstrates the improvement in drilling performance on the Cusiana wells. The continual improvement is clear with earlier wells being drilled at 90 to 100 ft/day (fpd), and latter wells at 250 to 300 fpd after the introduction of the aluminum complex.

PA field, Peru

PA field is in the foothills of the eastern Peruvian jungle, in the Amazon basin. It is one of several gas fields discovered in the eastern Andes. More than 20 wells have been drilled since development of this field started in the 1990s.

PA field lies in a very environmentally sensitive area of the Amazonian basin. Wellbore-stability problems make drilling the Chambira and Chonta shales difficult. The Chambira shale is very reactive and is located in the lower red beds section. The Chonta shale is micro-fractured and overlies the productive formation. The geologic column in Fig. 2 shows that this field has a wide variety of contrasting lithologies.

Aluminum complex chemistry was introduced in the PA field in the late 1990s during drilling of the PA-1103 and PA-1106 wells. The fluid design incorporated aluminum chemistry for reduction of pore-pressure-transmission effects in the troublesome Chonta shale combined with 3% potassium chloride for inhibition of the reactive Chambira shale formation.

Field results, however, showed the system performed better without the potassium chloride additions. This observation is in line with the adverse effect of potassium on kaolinite-rich shales such as those encountered in these wells. It is clear that drilling fluid design was critical to the successful drilling of these wells.

Well PA-1106 was drilled with a KCl/PHPA drilling fluid in the 12¼-in. interval containing the troublesome Chambira formation. A small concentration of aluminum complex was added at 5,700 ft to improve the hole conditions. Potassium chloride was eliminated from the formulation as a result of the problems experienced in the previous interval. The fluid performance confirmed the adverse effects of potassium chloride in the Chambira formation.

A recently completed exploratory well in this area used a HPWBM. This fluid, which possesses excellent performance characteristics, uses a second-generation aluminum complex. Lessons learned from experiences were as the basis for an optimized aluminum chemistry drilling fluid system for this area.

Palmar, Rioseco fields, Bolivia

The Palmar and Rioseco fields are in the foothills region of eastern Bolivia, in the Amazon basin. More than 20 wells have been drilled since development of the fields began in the 1990s. Many problems have been experienced while during drilling of the development wells on these fields.

Bit balling and accretion, low ROPs, and wellbore instability are common events when drilling through the Chaco, Yecua, Naranjillos, Cajones, Yantata, Ichoa, Cangapi, San Telmo, and Escarpment formations.

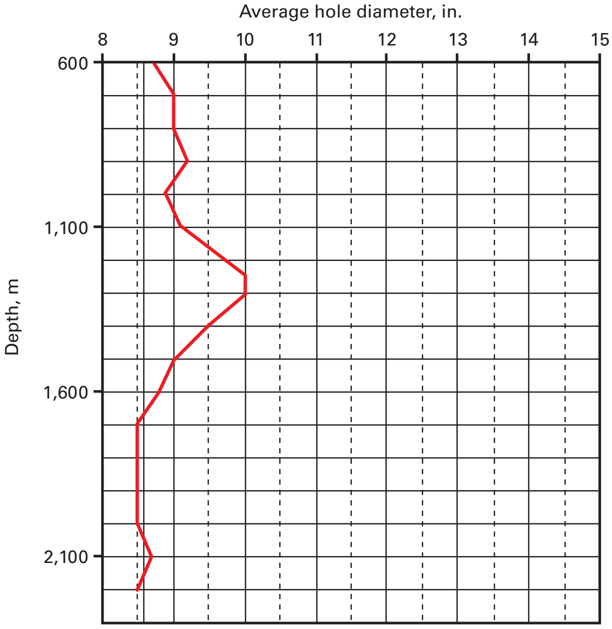
Aluminum complex chemistry was introduced to the Palmar and Rioseco fields in the early 2000s during drilling of the Palmar-17 and Rioseco X-100 wells with two different operators, Plupetrol and Don Wong. Aluminum chemistry was introduced as part of the drilling fluid design to control the reactivity of the Chaco, Yecua, Naranjillos, Cajones, and San Telmo formations. Experience elsewhere in Latin America, XRD analysis, and shale-fluid compatibility studies recommended use aluminum chemistry.

The Palmar-17 well was drilled to 11,550 ft with the PHPA-aluminum complex drilling fluid system. In the 8½-in. hole section, the aluminum complex concentration was increased to 5.5 lb/bbl from 2.7 lb/bbl to improve wellbore stability. The well remained stable when two fishing trips were made to recover bit cones. The well was logged with no problems.

The Rioseco X-1001 well was drilled to 7,000 ft with a 12¼-in. bit. This was the first time that this formation was cored with 100% recovery. Use of the aluminum complex system continued during field development. Fig. 6 shows a typical caliper log.

CALIPER OF RIO SECO WELL, BOLIVIA

Fig. 6



Acknowledgment

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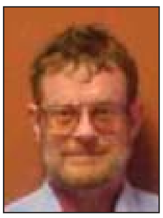
The authors

Mario A. Ramirez (Mario.ramirez@bakerhughes.com) is technical advisor of the TITAN Group at Baker Hughes Drilling Fluids, Houston. He also served as fluids coordinator in several countries and technical manager for the Latin America region. Ramirez holds a BS in chemical engineering from National University and an MS in environmental engineering from Los Andes University, both in Colombia. He is a member of SPE.



Patrick Kenny (pat.kenny@bakerhughes.com) is technical services manager at Baker Hughes Drilling Fluids, Houston. He also served as a staff engineer at Statoil, technical services representative at Baroid Drilling Fluids and as a mud logger at NEC GAS. Kenny holds a BSc (1974) from Edinburgh University, Scotland. He is a member of SPE.

Dennis Clapper (dennis.clapper@bakerhughes.com) is program manager at Baker Hughes Drilling Fluids in Houston. He holds a BA (1974) in chemistry from the University of Missouri-St. Louis and MS (1977) in chemistry from Baylor University. Clapper is a member of the American Chemical Society and SPE.

Transition to ULSD, ethanol goes smoothly for US refiners

Scott Sayles
KBC Advanced Technologies Inc.
Houston

During the last half of 2006, the initial transition to ultralow-sulfur diesel (ULSD) and ethanol blending has gone smoothly for US refiners. The Oct. 15 deadline for 15-ppm (wt) sulfur ULSD at the retail outlet was ahead of schedule, which is further evidence that the transition is proceeding as planned.[1]

The data indicate that more must be done to reach the 80% ULSD goal; the trend indicates that US refiners will attain this goal. The US Energy Information Administration tracks the volume of ULSD that is downgraded to 500-ppm (wt) sulfur diesel. Downgrades are showing a positive trend, falling to less than 1% after from a high of 20%. This indicates the industry is adapting to ULSD production requirements.

Including ethanol in the gasoline pool has used the available supply without significant interruptions.

Two initiatives have led the requirement for ethanol blending:

- Removal of the oxygen mandate from reformulated gasoline (RFG).
- The renewable fuels requirement.

Because the refining industry has had experience with ethanol blending, the use of additional ethanol was an incremental change.

Removing oxygenate from RFG allowed for replacement strategies of either using an alkylate-type blendstock or ethanol. The short-term solution appears to be the use of ethanol in the nonattainment areas.

This past summer had record high crude and product prices with constant or slightly increased demand for both gasoline and highway diesel. The increase in price and demand is contrary to historic market performance; it seems to indicate that neither ULSD nor ethanol blending affected supply.

Record price increases for gasoline and diesel are primarily crude related, masking the secondary effects due to supply or quality. The conclusion reached after studying these factors using the preliminary data is that gasoline and ULSD supplies were adequate.

Crude, product demand

To frame current and projected market situations, we studied the effect of worldwide crude and product demand on price. Historically, as crude prices increase, demand decreases and sets a crude price ceiling at about $26/bbl. Recent crude prices and demand have increased simultaneously.

Our projections are that crude demand will continue to rise and prices will reach a new equilibrium. Refinery output capacity will also rise to meet the new demand. Fig. 1 shows these effects.

Fig. 2 shows that expected increases in world demand have increased US demand.

KBC's Petroleum Economics Ltd. division's forecast for oil demand during the next decade suggests that US capacity would need to grow the equivalent of one large refinery every year to keep pace with demand.

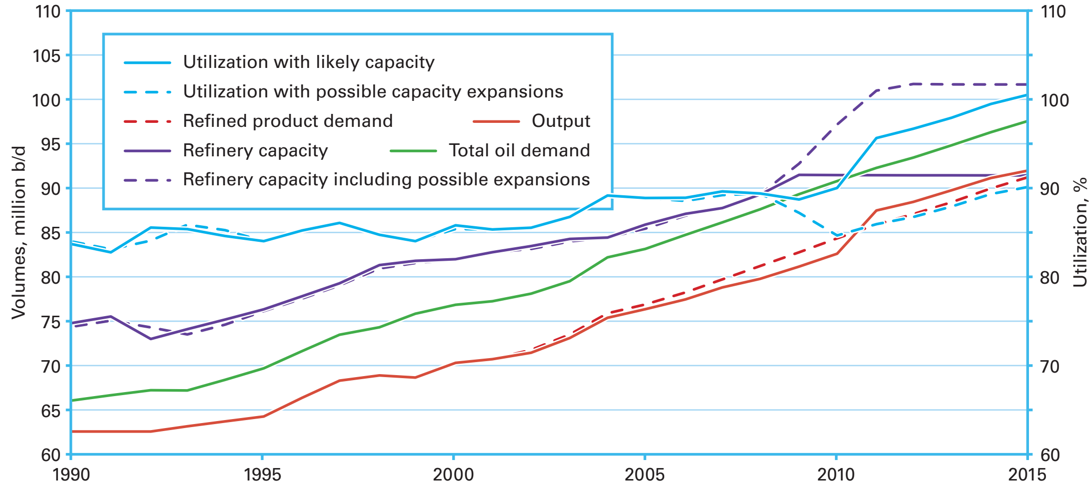
The US has a shortage of 2 million b/d of refined products; current announced refining capacity additions will provide capacity, but the deficit will remain. The current political climate in the US is unlikely to support fiscal incentives for refinery construction. US lawmakers have little desire to give downstream handouts to refiners, while these companies are paying massive dividends to their shareholders based on upstream profits.

Despite the standoff, refiners are presumably quite satisfied with the state of US refining and feel little pressure to invest in US downstream without economic incentives. ExxonMobil Corp.'s CEO-elect Rex Tillerson has echoed his predecessor's view that the company doesn't need to build refining capacity. A structural shortfall in domestically refined products should provide support for future margins, even with the capacity expansions that will no doubt emerge.

The transition to ULSD diverted expansion capital into clean-fuels projects. MTBE was removed from US gasoline due to the renewable fuels mandate and MTBE's environmental impact on groundwater. Shutting down MTBE production facilities has reduced gasoline capacity from the US markets. These two events tend to increase the US product deficit further.

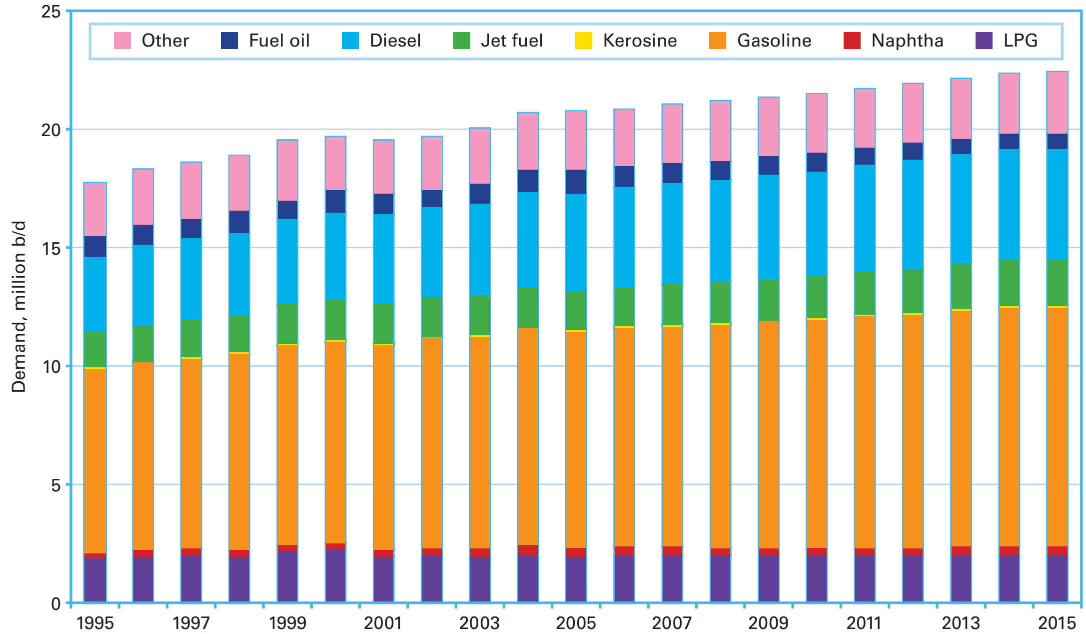
WORLDWIDE REFINING TRENDS

Fig. 1



US REFINED PRODUCT DEMAND

Fig. 2



Short term

The October 2006 EIA Energy Outlook indicates that gasoline and distillate inventories will be above critical levels (Fig. 3). Supply will be adequate for both gasoline and diesel in the short term. The winter draw is due to the annual heating-fuel requirements, mainly on the East Coast.

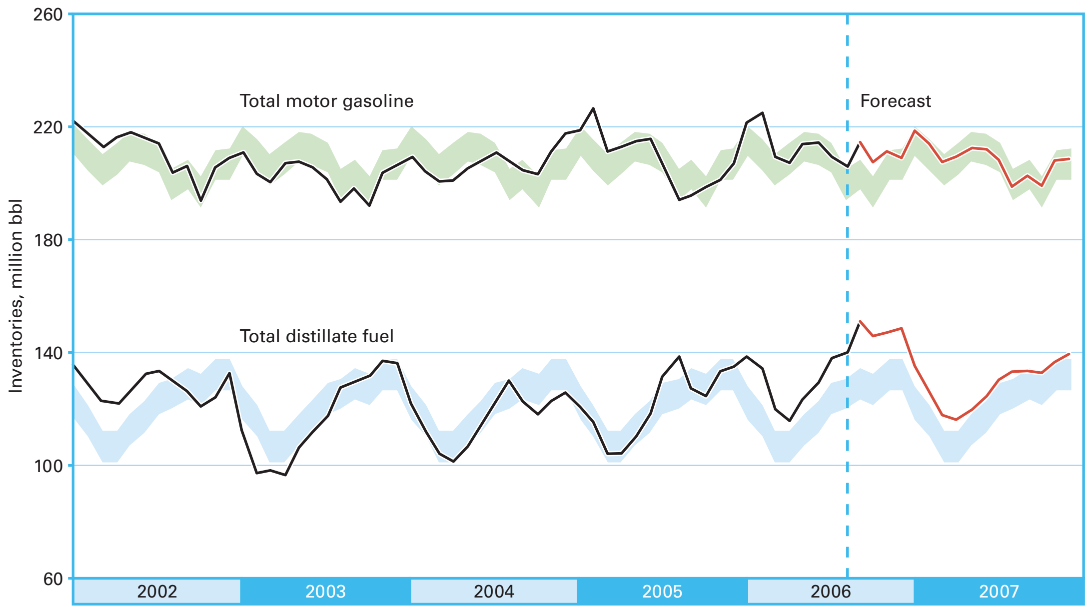
ULSD transition

The mandate for ULSD was implemented in the US in June 2006. The deadline for ULSD to reach the retail stations was Oct. 15, which was achieved.[1]

In the US, diesel-engine technology requires low sulfur levels effectively to reduce NOx and particulate matter (PM) emissions. Diesel-engine manufacturers are introducing this technolo-

US FUEL INVENTORIES*

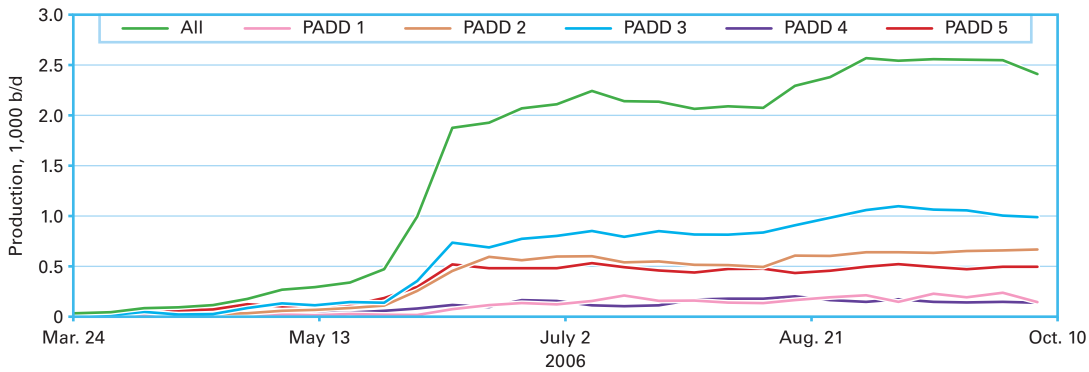
Fig. 3



*Colored bands represent a normal range.

ULSD PRODUCTION

Fig. 4



REFINERIES PRODUCING ULSD

Table 1

	EPA precompliance report, 2005	June 30, 2006 reported	Comments
	Refineries, number		
PADD 3			
100% 15 ppm	29	9	
Mix of 15 ppm and 500 ppm	3	12	7 are ULSD
100% 500 ppm	8	13	
PADD 2			
100% 15 ppm	17	7	
Mix of 15 ppm and 500 ppm	3	10	4 are ULSD
100% 500 pm			

gy in model year 2007, starting Sept. 1, 2006. The number of vehicles sold with the engine-emission-reduction technology will be a small fraction of the total fleet in calendar year 2006 but will increase steadily.

ULSD will reduce sulfur emissions, which has been the driving force worldwide. To keep engine systems clean, the US government has mandated ULSD be sold at 80% of US diesel pumps, with 100% of pumps to be ULSD by 2010.

ULSD key success factors

To provide a mechanism to evaluate the success or failure of ULSD implementation, we developed key success factors that, if positive, would indicate a smooth implementation. Negative results indicate that serious problems exist.

ULSD key success factors are:

- Prior planning with cooperative interaction between government and industry to set standards with a time frame to implement changes.
- Protection of the ULSD supply by providing regulatory compliance options such as credits and a temporary compliance option (TCO) to give refiners options for ULSD production.
- Commitment by the refining industry to invest capital for improvements to meet new demand and the regulatory community commitment to provide timely permitting to meet the construction schedules.
- Communication between the refining industry and regulatory community.

Planning—ULSD production

Total distillate demand in the US is about 4.2 million b/d. This includes highway diesel, home heating oil, off-road diesel, and other fuels.

Of the 111 refineries operating in

the US, 88 ULSD units were started up in 2006 and about 11 refineries indicated "no changes" were needed to produce ULSD for a total of 99 refineries producing ULSD. The remaining refineries produce highway diesel using sulfur credits, TCO, hardship options, or are no longer producing highway diesel.

ULSD IN HIGHWAY DIESEL

Fig. 5

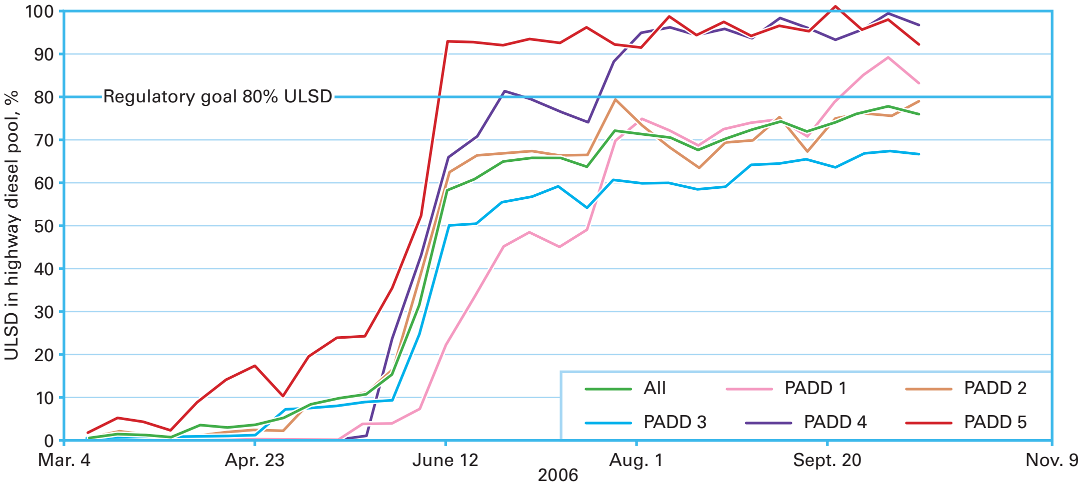


Table 1 shows the latest update for refineries in Petroleum Administration for Defense Districts (PADDs) 2 and 3 for ULSD production.[2]

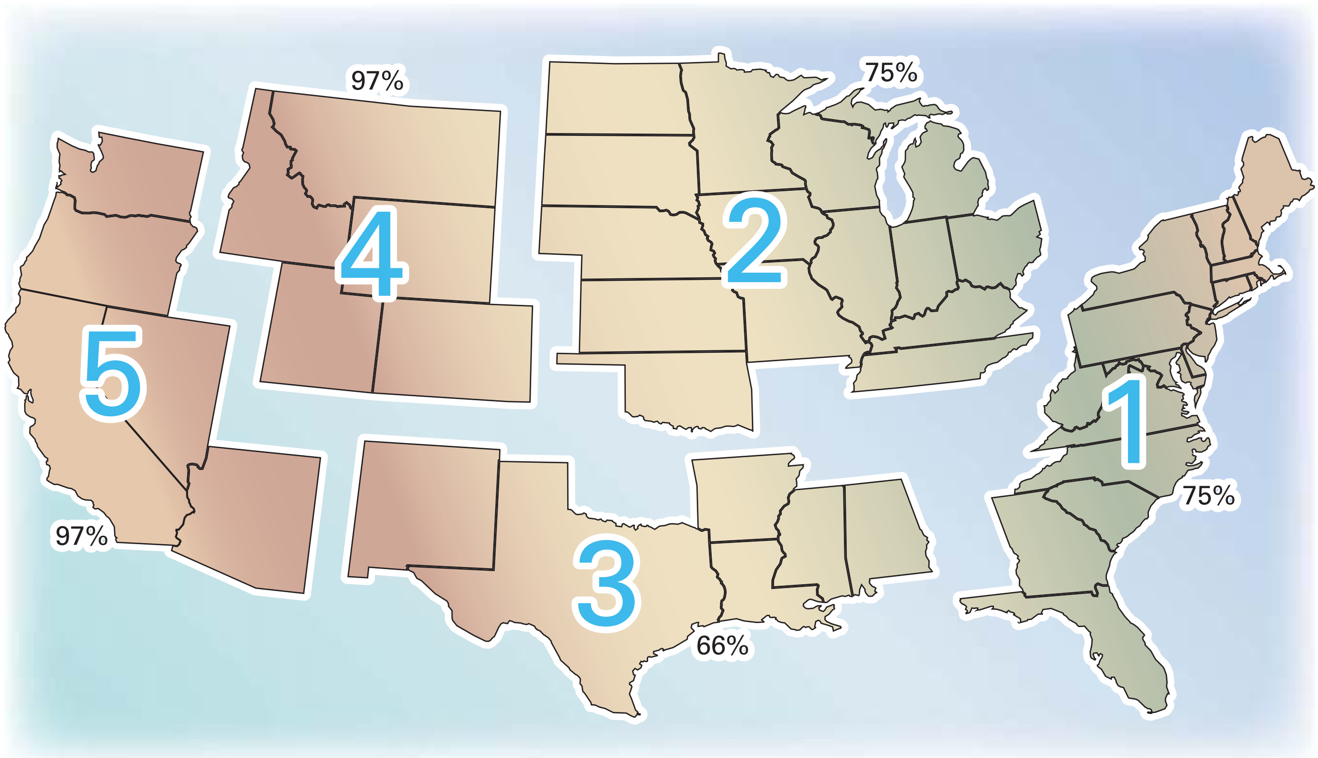
Only one third of the refineries planning to produce 100% ULSD achieved this goal by June and more were producing at the 500-ppm level than anticipated. The regulatory goal, however, is that 80% of a refineries' supply is ULSD.

Plans for these modifications were initiated and completed in the last 5 years. Implementation required transitioning refinery, pipeline, terminals, and retail systems to ULSD. This appears to have occurred smoothly without supply interruptions.

Table 2 shows the implementation plan for ULSD.

ULSD BY PADD*

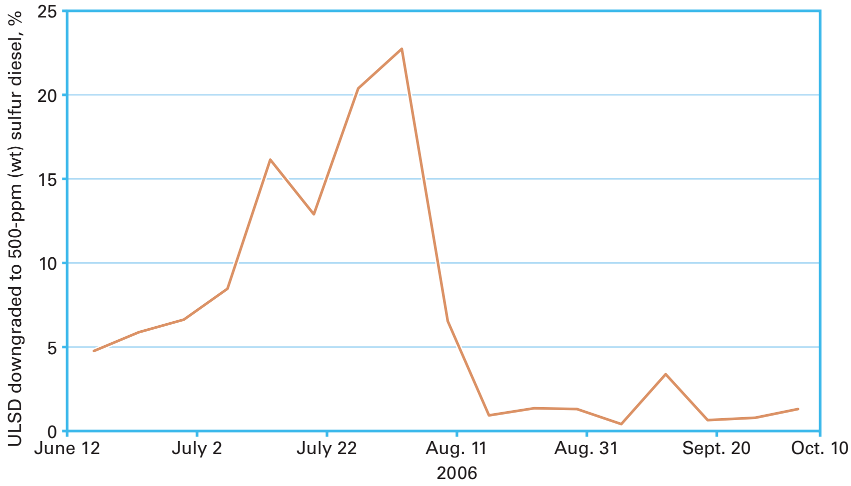
Fig. 6



*Numbers represent ULSD's share of highway diesel.

ULSD DOWNGRADED

Fig. 7



Supply flexibility

Until 2010, regulatory options are available to refiners to produce greater than 15-ppm (wt) ULSD. In general, sulfur credits can be used if they were produced and available in the same PADD as the refinery using them.

During the initial phase, June 2006-May 2010, refiners can produce 20% of the ULSD as temporary compliance option (TCO) diesel (500 ppm). This production is not offset by credit use and a refiner can produce more 500-ppm diesel by purchasing credits. Two types of diesel are then produced, ULSD and EPA diesel (500-ppm sulfur). These two fuels must be segregated from the refinery to the retail pump.

The TCO is designed for the transition period from June 2006 to May 2010. Compliance is annual, which allows refiners operational flexibility. Individual refineries can use the TCO in different ways.

In July, for example, ULSD supply was constrained in the US heartland due to refinery production problems and high irrigation pump demands during the summer drought conditions. The major problem was product delivery to rural areas—truck drivers were exceeding their allowable driving hours in a given day. The governor of Nebraska issued an emergency proclamation to extend truck driver hours to allow product deliveries.[3]

Other incidents of reported shortages were also due to extenuating circumstances and constituted a small volume of the total US highway diesel production.

Fig. 4 shows the production of ULSD by PADD from EIA data.

With ULSD production starting in June, the rapid increase in production was expected. The regulation, however, is for 80% of the total highway diesel to be ULSD.

Fig. 5 shows the PADD distribution for the ULSD percentage of the total highway diesel.

Total diesel production is currently approaching the 80% ULSD requirement but is still slightly below the goal. Surprisingly PADD 2 is only at 66% ULSD.

Fig. 6 shows average ULSD in diesel for September to mid-October.

Another positive indication that ULSD production is smoothing out is the amount of diesel being downgraded to 500-ppm (wt) sulfur from ULSD (Fig. 7). The downgrade appears to be reaching a limit of about 1% of production.

Construction, communication

To produce ULSD, 80% of US refineries installed some type of hydrotreating equipment. The construction timeline from concept to start-up was typically 3-4 years. To achieve this goal, remarkable coordination occurred between the end users (refiners, pipeline, transportation, retailers), service providers (consultants, design contractors, construction companies), and regulators. The coordinated effort shows a mutual commitment to provide ULSD to the consumer.

Communication between the regulatory community and the industry was also good. Multiple workshops and opportunities to present ideas were made available and the final regulation incorporated many of these items.

Future growth

Future growth in highway diesel demand will be as ULSD because regulations require that 100% of diesel produced in the US be ULSD by year 2010.

Fig. 8 shows this trend.

The net result of ULSD implementation is less flexibility for US refiners. In the future, for example, waivers similar to those issued in the aftermath of the 2005 hurricanes will be unavailable be-

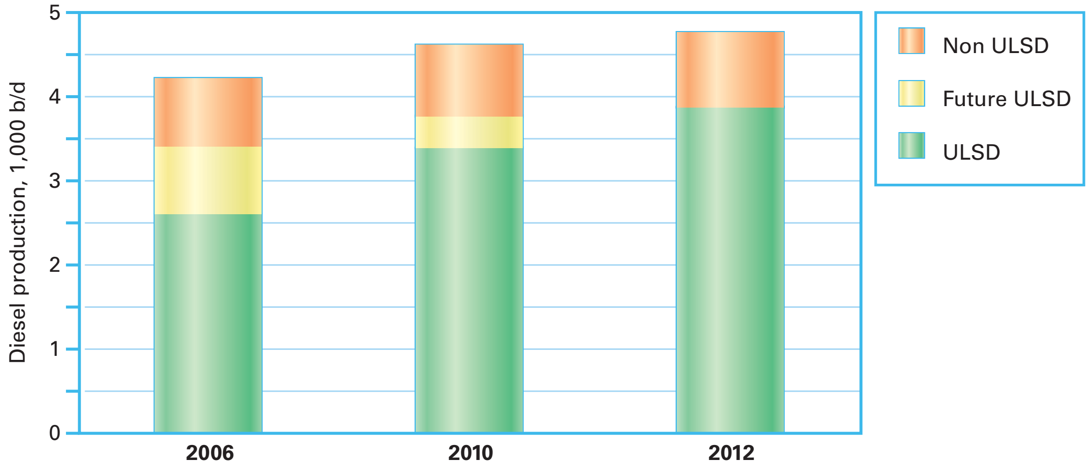
ULSD PHASE-IN

Table 2

Fuel	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Sulfur level, ppm								
Highway		80% 15 ppm 20% 500 ppm			15	15	15	15	15
Nonroad		500	500	500	15	15	15	15	15
Locomotive, marine		500	500	500	500	500	15	15	15
Nonroad locomotive, marine with credits		High sulfur	High sulfur	High sulfur	500	500	500	500	15

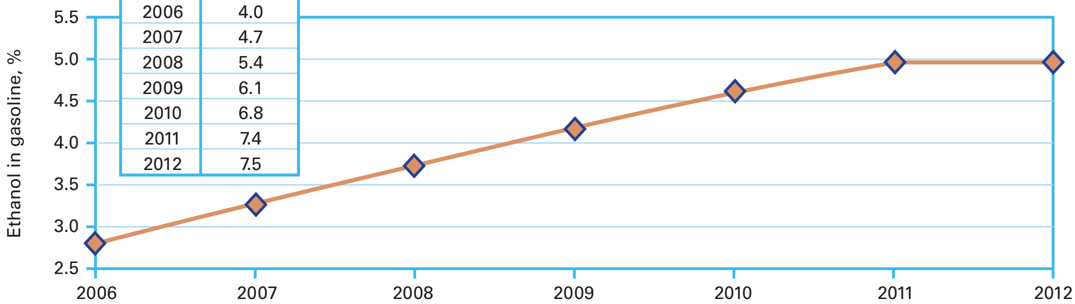
Future growth of ULSD

Fig. 8



US renewable fuels requirement

Fig. 9



Regulated volume	
Year	billion gal
2006	4.0
2007	4.7
2008	5.4
2009	6.1
2010	6.8
2011	7.4
2012	7.5

cause subsequent introductions of higher sulfur levels would cause contamination in the distribution system or motor damage.

The switch to ULSD is just the start of greater vigilance on the supply side; the US refining configuration is more susceptible to upsets than it once was because many of the ULSD projects converted existing assets. This lower flexibility means that upsets stand a greater chance of causing supply imbalances.

Until 2009, there may be some opportunities for diesel imports from Europe, but Europe's supply is tight and, therefore, the arbitrage window might not be a satisfactory relief mechanism. There may be limited alternatives for US supply.

Also, some East Coast heating oil demand could be starting to impinge on ULSD availability. Some markets are demanding lower-sulfur heating fuel, which will eventually force refiners, especially on the East Coast where heating fuel demand is greatest, to invest in additional hydrotreating capacity.

Biodiesel

Biodiesel may be a viable technical option in the near future and is being used in Europe due to the greater diesel demand. The American Soybean Association reports that US soy biodiesel production is 150 million gal (9,800 b/d) in 2006, will double in 2007, and will expand to 500-600 million gal (about 40,000 b/d) by 2015.

That represents 13% of the US soy-planted acreage. Other markets are going to find it difficult to add significant oilseed acreage dedicated to fuel usage.

ULSD second wave

In May 2010, the TCO periods will be over and all highway diesel will have to meet ULSD specifications. Until then, more units will be revamped or built to produce ULSD. As many as 50 new or revamped units will start up. These installations will benefit from the knowledge gained during current operations.

Ethanol as renewable

Ethanol in used in gasoline due to the renewable-fuels mandate and elimination of oxygenates in gasoline. The result was a net reduction in gasoline-production capacity due to the removal of MTBE capacity, which was partially offset by the mandate to use ethanol.

Ethanol use has many technical effects on refining, pipeline, and terminating facilities, all of which increase the cost of gasoline production. As with ULSD, we developed key success factors for ethanol use to determine if ethanol is being used as envisioned—data sources have large lag times.

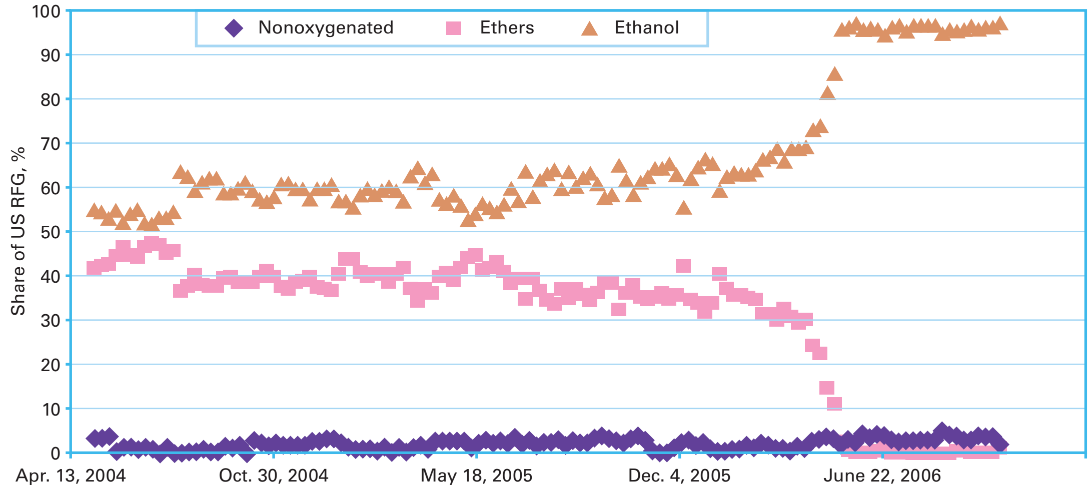
Ethanol key success factors

Success factors for renewable fuels, primarily ethanol blending and production of RFG without oxygenates, are:

- Original RFG regulations allowed for ethanol blending and most refiners

ETHANOL REPLACES ETHERS IN RFG

Fig. 10



had experience in this area. California Air Resources Board gasoline allowed for nonoxygenated gasoline that has achieved tailpipe emissions targets.

- Supply logistics.
- Refining industries' recognition of the need for renewable fuels, with ethanol blending being the first step.
- Wide consumer acceptance of ethanol as a clean, renewable fuel.

Ethanol blending—regulations

Three primary ethanol gasolines are produced in the US:

- Conventional blends with no more than 10% ethanol.
- RFG using ethanol as an oxygenate.
- E85, which is 85% ethanol and 15% conventional gasoline.

Of these three, most ethanol is used in conventional and RFG blends. E85 requires car engines designed for multiple fuel types and the majority of the US automotive fleet is not equipped to burn this fuel. The regulatory requirement for the industry is "Regulation of Fuels and Fuel Additives: Renewable Fuel Standard Program" (EPA-OAR-2005-0161; FRL 8016-9).

Fig. 9 shows US renewable-fuels requirements.

Assuming that US gasoline consumption in 2006 was 142 billion gal, then the ethanol content of the pool is 2.78%. A ratio is used to determine annual industry compliance; if the 2006 volume is not achieved, a "carryover" volume into 2007 will occur.

- Conventional gasoline containing ethanol has been produced for many years and the regulatory change does not affect production. Increases in ethanol production, however, would likely increase the use of ethanol and the ethanol-containing conventional gasoline supply.

Nonattainment areas, RFG

The Energy Policy Act removed the requirement to use oxygenates in gasoline in nonattainment areas. Removal of the oxygenate mandate in the US enabled refiners to produce RFG without oxygenates while, at the same time, specifying that US gasoline must increase its content of domestically produced ethanol. The legislation basically makes MTBE unattractive as a US gasoline-blending additive.

Ethanol began replacing MTBE in RFG starting about April 2006. Production, availability, transportation, and delivery of ethanol were some reasons for sharp increases in the price of gasoline in early summer 2006. But these were overshadowed by a run-up in crude prices.

RFG production using ethanol was part of the original Energy Policy Act regulations. Emission calculations and other requirements for compliance were also included in the regulation. Many refiners have experience with ethanol blending and producing reformulated blendstocks for oxygenate blending, the nonethanol containing refinery product that is blended with ethanol at the terminal.

Nonoxygenate routes for producing RFG use blending components such as alkylate, iso-octane, raffinate, and others. Many options exist to produce these blendstocks with a corresponding capital investment.

Refiners can gain additional gasoline-production capacity by using ethanol as a blend stock vs. investing capital in new equipment. Ethanol, for example, supplied to the East Coast by barge may be an economic option compared to other alternatives such as capital investment to produce alkylate or iso-octane.

Fig. 10 shows that ethanol has replaced ethers in RFG, based on EIA data.

The quantity of RFG produced without oxygenates averaged 3% before and after the oxygen mandate was removed. This supports the idea that, in the short term, ethanol is the cost-effective replacement for MTBE.

Ethanol supply logistics

Ethanol requires many steps to deliver it to the consumer:

- Crop planting, fertilizing, and harvesting.
- Transportation of corn to ethanol plant.
- Ethanol production.
- Transportation to blending facility via rail or truck.

• Blending.
• Distribution.

The multiple steps required to bring ethanol to the marketplace and the requirement to deliver it to each blending site greatly increase the supply complexity. Pipelines cannot ship ethanol because of its hydroscopic nature, which causes severe corrosion. Blending is therefore done locally via splash or in-line methods.

Energy supply

Ethanol requires a large investment in fossil-fuel energy to grow the feedstock, harvest, process, and deliver it to the marketplace. All of these steps require fossil fuels. The energy delivered by ethanol as a transportation fuel should exceed the energy required for production for it to be considered a viable long-term energy source.

US ethanol production is primarily from corn, which produces an ethanol that is slightly energy positive. Improvements in cellulose fermentation and energy integration will further improve the energy balance.

Future ethanol supply, demand

Ethanol demand will exceed supplies until about 2008. This will spur imports to meet demand. After 2008, US ethanol production will satisfy the country's demands. If current projections for ethanol capacity increases are accurate, the 2012 ethanol target required in the renewable energy mandate can probably be met by 2009 without use of imports.

If Brazil continues to expand production, worldwide demand will be met.

Currently, US ethanol production is subsidized to encourage increased capacity. A phaseout of the subsidies or altering them to encourage new technologies is a possible path for regulatory consideration.

The big ethanol users will be the US and Japan, which is another significant importer from Brazil. Where gasoline demand is strong, ethanol demand will be strong. There are other producers of ethanol; possible new capacity will be built in Peru, Vietnam, and Chile.

Europe has some ethanol demand.

Fuel vs. food

The conversion of food to fuel while people are undernourished is an ethical dilemma. The benefit is the renewable nature of the fuel; however, it is produced at the expense of other options, such as food exports. If new acreage is placed into service, then the effect of fuels is minimized.

USDA predicts that 30% of US corn production will be earmarked for

Nelson-Farrar Cost Indexes

Refinery construction (1946 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2003	2004	2005	Aug. 2005	July 2006	Aug. 2006
Pumps, compressors, etc.	222.5	777.3	1,540.2	1,581.5	1685.5	1,696.2	1,751.1	1,758.6
Electrical machinery	189.5	394.7	522.0	516.9	513.6	514.1	523.2	524.6
Internal-comb. engines	183.4	512.6	911.7	919.4	931.1	931.0	961.9	965.7
Instruments	214.8	587.3	1,076.8	1,087.6	1,108.0	1,111.7	1,173.4	1,178.1
Heat exchangers	183.6	618.7	732.7	863.8	1,072.3	1,079.2	1,179.4	1,179.4
Misc. equip. average	198.8	578.1	956.7	993.8	1,062.1	1,066.5	1,117.8	1,121.3
Materials component	205.9	629.2	933.8	1,112.7	1,179.8	1,142.7	1,309.4	1,301.9
Labor component	258.8	951.9	,228.1	2,314.2	2,411.6	2,423.9	2,480.7	2,482.1
Refinery (Inflation) Index	237.6	822.8	1,710.4	1,833.6	1,918.8	1,911.4	2,012.2	2,010.0

Refinery operating (1956 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2003	2004	2005	Aug. 2005	July 2006	Aug. 2006
Fuel cost	100.9	810.5	934.8	971.9	1,360.2	1,452.1	1,579.7	1,652.4
Labor cost	93.9	200.5	200.8	191.8	201.9	185.2	199.0	192.6
Wages	123.9	439.9	971.8	984.0	1,007.4	943.2	999.0	977.7
Productivity	131.8	226.3	485.4	513.3	501.1	509.3	502.1	507.8
Invest., maint., etc.	121.7	324.8	643.0	686.7	716.0	713.2	745.2	744.5
Chemical costs	96.7	229.2	237.7	268.2	310.5	301.6	376.0	380.5
Operating indexes								
Refinery	103.7	312.7	464.7	486.7	542.1	542.0	579.5	583.7
*Process units**	103.6	457.5	612.5	638.1	787.2	813.4	873.4	896.7

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

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

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

ethanol production by 2010. Brazilian cane dedicated to ethanol production vs. sugar peaked at about 70% in 1990 and is currently 50-60% due to sugar-market dynamics.

Biodiesel crop predictions are not available. While these industries are still growing, a balance is needed between the fuel and food production to answer the ethical dilemma. ✦

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3. "Diesel Problems in the Heartland," Gasoline Column, US Federal Trade Commission, Aug. 15, 2006, http://www.ftc.gov/ftc/oilgas/archive/060815.htm.

The author

Scott Sayles (ssayles@kbcat.com) is a principle consultant with KBC Advanced Technologies Inc., Houston. He has 30 years of refinery and petrochemical experience, ranging from refinery plant manager to research engineer. Sayles holds a BS in chemical engineering from Michigan Technological University and an MS in chemical engineering from Lamar University, Beaumont, Tex.

Multiproduct software sets optimal pump use

Liang Yongtu
China University of Petroleum
Beijing

Simulation software developed by China University of Petroleum–Beijing in conjunction with China National Petroleum Corp. allows automatic determination of optimal pump use on multiproduct pipelines.

The rapid expansion of China's economy has led to the construction of several new multiproduct pipelines in the country, with still others in the construction or design stages to meet future demand for refined products.

Current multiproduct pipelines include CNPC's 587.7-km Luwan pipeline (Fig. 1).[1] The pipeline originates at Qilu refinery in Shandong province, includes three stripping stations at Zibo, Tai'an, and Xuzho, one input and boosting station at Jinan, and two junctions at Qufu and Zaozhuang, before reaching its terminus at Suzhou.

It also includes two legs, measuring 69.2 and 101.2 km, extending to Jining and Linyi terminals respectively from Qufu and Zaozhuang junctions. The pipeline transports 5,850,000 tons/year of refined products from Shandong province to Jiangsu and Anhui provinces.

Software

Although the Luwan pipeline is smaller than other multiproduct pipelines in China, its branch lines—each of which requires a particular mix of products—and multiple input stations complicate the system.

Before commissioning, CNPC asked CUPB to provide simulating software that would address pipeline scheduling, safety, and efficiency.

CNPC and CUPB decided to develop two products to address these issues: scheduling simulation software (SSS) and hydraulic simulation software (HSS).

SSS allows users to make an outline schedule for 10 days to 1 month, depending on customer demand. HSS helps operators find the most efficient pumping plan to complete the schedule set by SSS. HSS also tells users how much product contamination the selected schedule will cause and if the schedule is feasible.

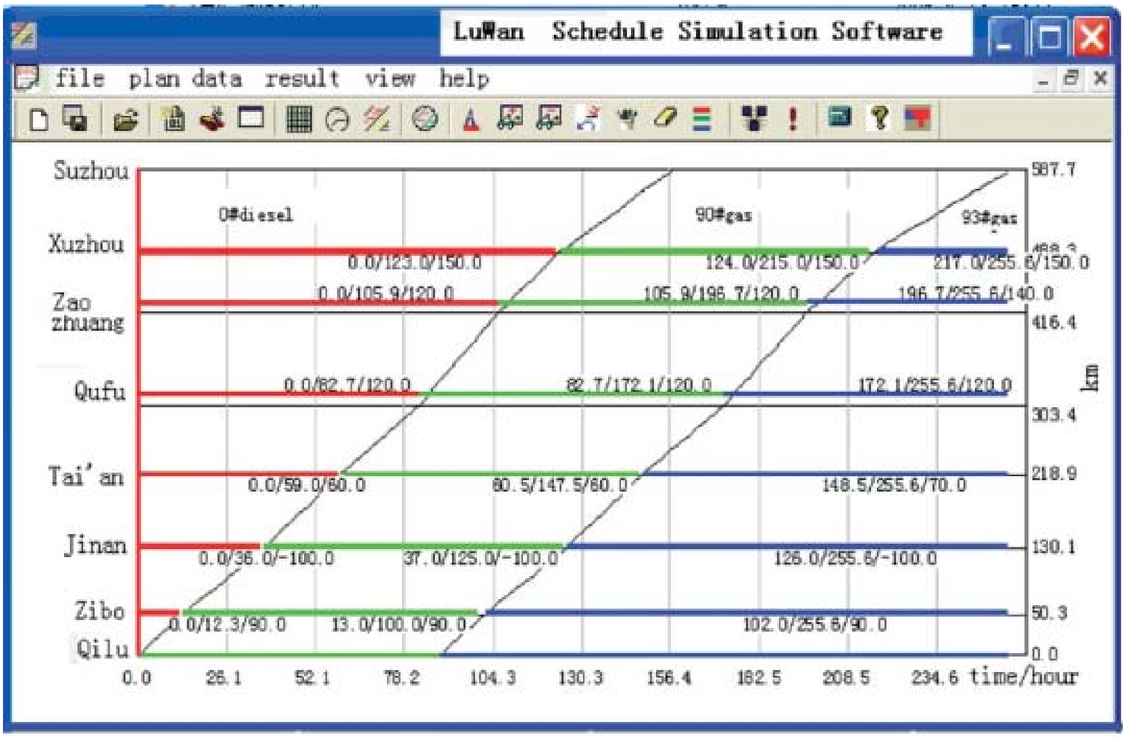
SSS

Almost all large multiproduct pipelines have their own algorithms and corresponding software to help with scheduling. Previous studies have addressed specified-order method, elemental-clock method, master-clock method, average-rate method, and displacement method as different frameworks for software development, with the master-clock method (evolved from the elemental-clock method) emerging as the most flexible.

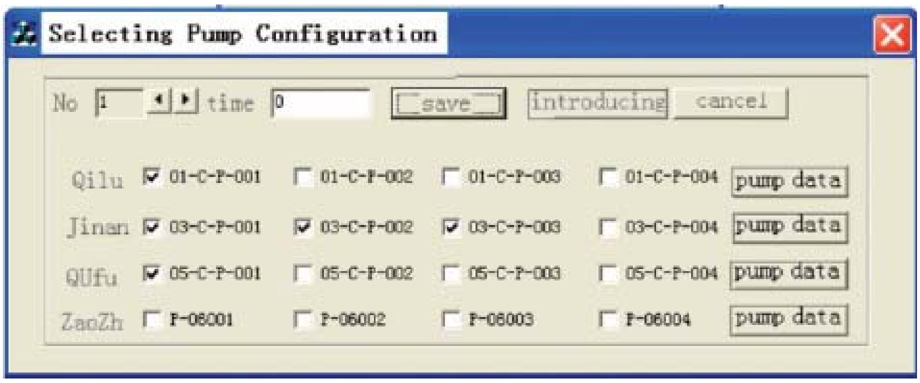
LUWAN PIPELINE MAP

Fig. 1

OIL&GAS JOURNAL Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page qMags



The main interface with the schedule simulation software allows operators to see stripping and inputting processes for various products at each station along the Luwan multiproducts pipeline, with time windows and flow rates also displayed (Fig. 2).



SSS's selecting pump configuration window lets the operator manually select which pumps to bring on or offline and also allows access to individual pump data. The "introducing" button resets the simulation to the initial pump configuration (Fig. 3).

This method defines times when particular activities, such as injecting, lifting, and stripping can take place at control points. Calculations proceed in sequence, and the state of the system as each calculation occurs defines the operating status of each control point. The sequence of calculations which produce the smallest time span to a control point is selected, and the entire system is updated by that time span.[2 3]

The method this article describes uses variable pace to accelerate the master-clock method and adds the points at which product interfaces reach stations to the variables used in simulating the operational characteristics of the Luwan pipeline and developing a new algorithm on which to base its modeling software.

Fig. 2 shows the main interface of the software. The short, horizontal, bold lines show the stripping or inputting processes, with the time window and flow rate of stripping or inputting appearing beneath.

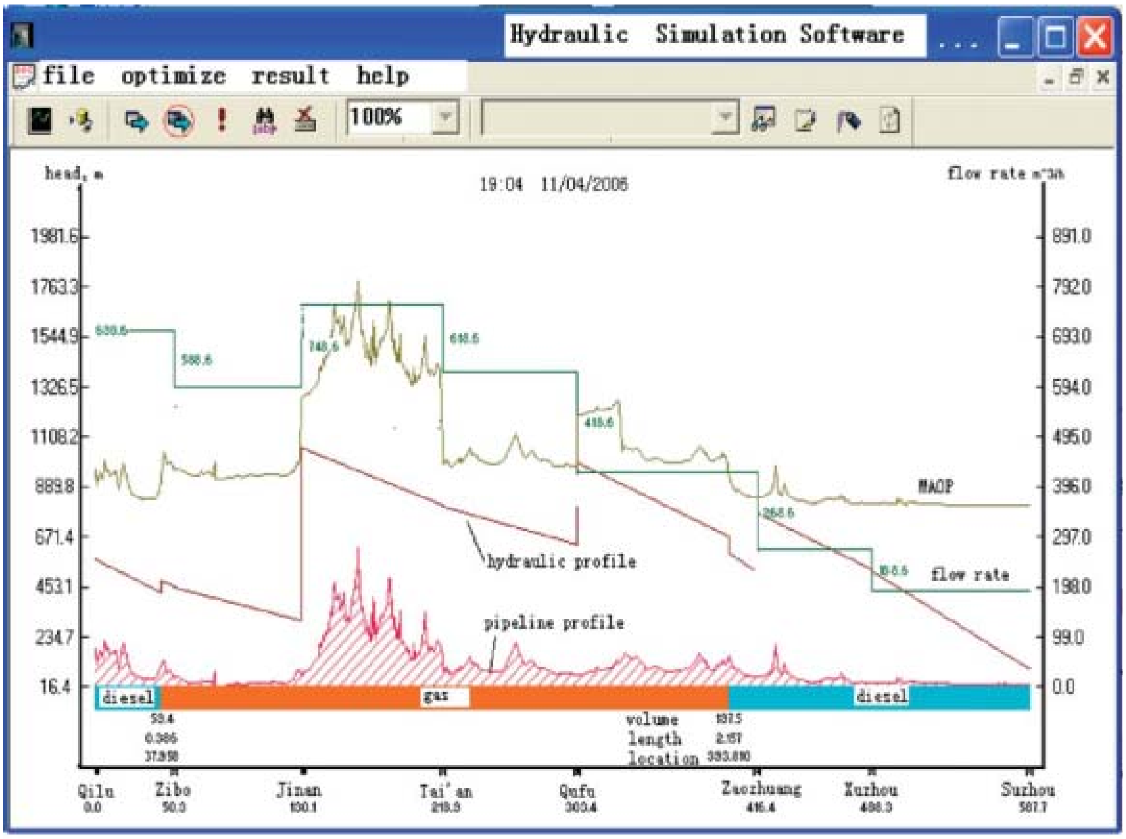
The assumptions of incompressible liquids, isothermal transport of products, and changeless density of products with pressure and temperature in the schedule model make it difficult to track the interface accurately. The difference between real time and simulated time typically measures 30 min, considered acceptable by current users. Recurring sampling data and data from SCADA allow the estimated position of batches to be adjusted over time.

Both SSS and HSS require data describing the pipeline profile, initial line fill, and the demand plans of stripping stations along the pipeline.

CNPC required that SSS provide:

- Batch interface strip picture and the timetable of interfaces arriving at stations.
- Stripping schedule of all products passing the station for local operators; including stripping flow rate, time window, and total volume.
- Stripping schedules of all products passing all stations for operators at the control center; including stripping flow rate, time window, and total volume.
- Ability to copy some previous schedule as the start point when making a new schedule.
- Unlimited number of batches.
- Several kinds of output format, modified to meet specific user (shippers, dispatchers, operators, etc.) needs.
- Intuitive processes, mirroring those a person would use absent the software.

HSS



The hydraulic simulation software simulates the process of batch transportation from beginning to end, including displays of pressure, flow rates, interface locations, pipeline topography, and the locations of both various products and contamination zones (Fig. 4).

After developing a schedule using SSS, schedulers have to determine that it is feasible given current pipeline capacity and constraints. HSS not only makes this determination but also chooses the appropriate pumping plan to maximize energy efficiency while minimizing shutdowns and contamination.

HSS provides two modes of simulating the schedule. The first automatically determines the pipeline's optimal pump configuration for the entire simulating horizon, minimizing energy costs across the system (Table 1). This simulation, however, requires a long time to perform due to the large combination of pumps involved and may also result in numerous shutdowns and start-ups of individual pumps while optimizing the system.

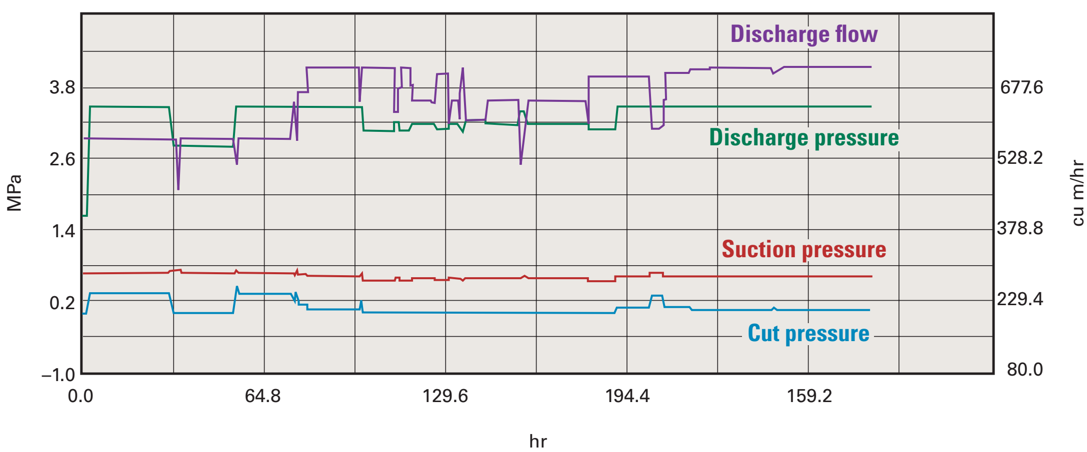
The software's second simulating engine allows users to mimic the transportation process, while manually setting pump configurations based on their practical experience. But the combination of several pump stations (with three to five pumps at each station) and changing hydraulic and material conditions make it difficult to manually combine pumps satisfactorily.

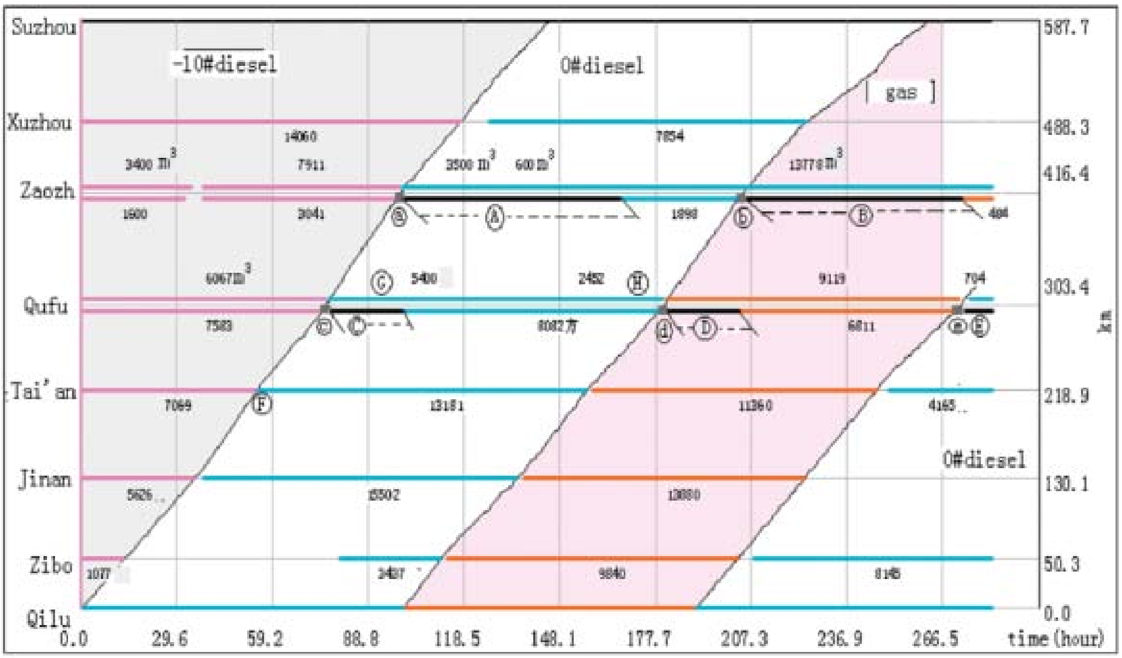
The recommended method, therefore, is to let the software produce the automatic optimal result and then manually alter the optimal pump configurations to reduce frequent startups and shutdowns.

The button "Introducing" in the software's "Selecting pumps" dialogue brings up the initial pump configuration, which users can then use to make

PRESSURE, FLOW RATE CURVES, QILU STATION

Fig. 5





HSS provides simulation results such as this window displaying its batch-tracking function. The short bars marked by lower-case letters show where contamination was stripped into stub lines. The longer bars marked by uppercased letters represent zones where pure products were diverted into stub lines to ensure they remained contaminant free (Fig. 6).

an even better pumping plan (Fig. 3).

HSS' optimal mathematical basis is a steady-state model. Dynamic programming theory can solve the multistage decision problem of optimal pump configuration.

HSS OPTIMAL PUMP CONFIGURATION

Table 1

	Pump No. 1	2	3	4
10:10, Apr. 3, 2006				
Qilu	On line	Off-line	Off-line	Off-line
Jinan	On line	On line	On line	Off-line
Qufu	On line	Off-line	Off-line	Off-line
Zaozhuang	Off-line	Off-line	Off-line	Off-line
12:52, Apr. 3, 2006				
Qilu	On line	On line	Off-line	Off-line
Jinan	Off-line	Off-line	On line	Off-line
Qufu	Off-line	Off-line	Off-line	Off-line
Zaozhuang	On line	Off-line	Off-line	Off-line
23:38, Apr. 3, 2006				
Qilu	On line	On line	Off-line	Off-line
Jinan	Off-line	On line	On line	Off-line
Qufu	Off-line	On line	Off-line	Off-line
Zaozhuang	On line	On line	Off-line	Off-line
18:10, Apr. 4, 2006				
Qilu	Off-line	On line	Off-line	Off-line
Jinan	On line	On line	On line	Off-line
Qufu	On line	On line	Off-line	Off-line
Zaozhuang	On line	On line	Off-line	Off-line

Providing optimal pump configuration information is distinct to HSS. ESI Co.'s TELNET and Advantica Co.'s SPS are both popular hydraulic simulation software products, but they cannot determine the optimal pump configuration despite simulating the hydraulic process very well.

In addition to determining optimal pump configuration, HSS:

- Shows transportation processes.

The software visually simulates the process of batch transportation. The screen displays pressures, flow rates, locations of interfaces, the topographical curve of the pipeline, and the length and volume of contamination segments in the pipeline, refreshing these variables at a time-step interval (Fig. 4). The software also replays completed simulations, making analysis of results more convenient.

- Provides simulation results.

After the simulation is complete, the software provides the suction and discharge pressure and flow rate curves of all stations (Fig. 5), the batch-track strip (Fig. 6), the power curves of all pumps (Fig. 7), and any contamination information (Fig. 8).

Fig. 6 shows the stripping process, flow rates, and the types of products transported at different positions and times. Diagonal lines indicate the trajectories of interfaces between two products. The lines' slopes show the interface velocity. The short horizontal bold lines show the corresponding stripping process, including the volume stripped at each station.

Zaozhuang and Qufu stations divide the flow into two streams, one flowing into the local tank farm and the other

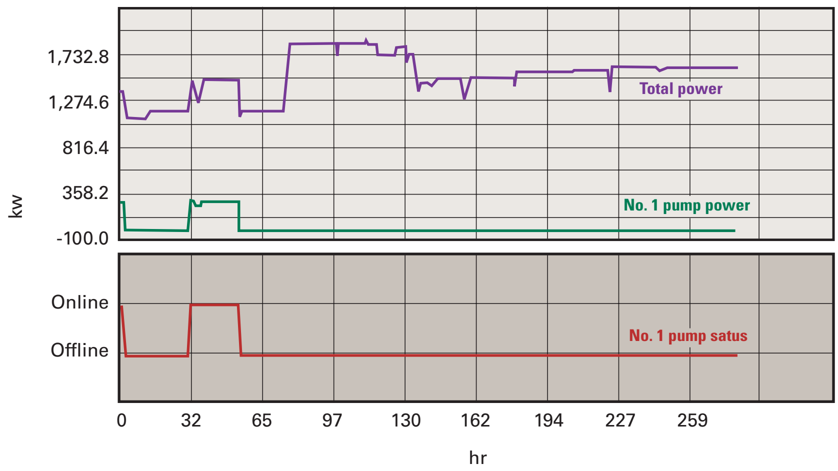
DATA COMPARISON, FEBRUARY 2006 DIESEL SHIPMENT

Table 2

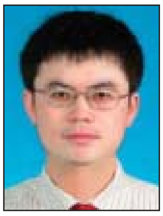
Original data: Segment	Flow rate, cu m/hr	Field data: Discharge pressure	Suction pressure	Pressure drop	Simulation data: Discharge pressure	Suction pressure	Pressure drop
		MPa					
Qilu-Zibo	394.1	1.763	1.963	–0.200	1.86	2.07	–0.21
Zibo-Jinan	394.1	1.963	1.132	0.831	2.06	1.27	0.79
Jinan-Taian	500	7.393	5.268	2.125	7.00	4.95	2.05
Taian-Qufu	500	5.268	4.699	0.569	4.94	4.40	0.54
Qufu-Zaozhuang	361.8	4.699	1.311	3.388	4.39	1.22	3.17
Zaozhuang-Xuzhou	256.5	3.769	2.149	1.620	3.58	2.06	1.52
Xuzhou-Suzhou	77.7	2.149	1.497	0.652	2.05	1.42	0.63

Pump power curves

Fig. 7



The author



Liang Yongtu (liangyt21st@sina.com) is an instructor and doctoral candidate at the China University of Petroleum—Beijing. He received his BS and MS degrees from CUPB in 1995 and 2001, respectively. In 2005, he spent 6 months at Robert Gordon University in Aberdeen as a visiting scholar. Liang's area of specialty is long-distance pipeline transportation. His multiproduct pipeline simulation software and stripping scheduling software are used by several pipelines in China.

into the stub line.

The trunk is initially filled with two different grades of diesel, and then with No. 90 gasoline and additional diesel at Jinan.

The short bars above (a,b,c,d,e...) represent the process of stripping contamination into stub lines.

The longer bars (A, B, C, D, E...) show the process of stripping pure products into stub lines to remove contamination.

Contamination segment parameters

Fig. 8

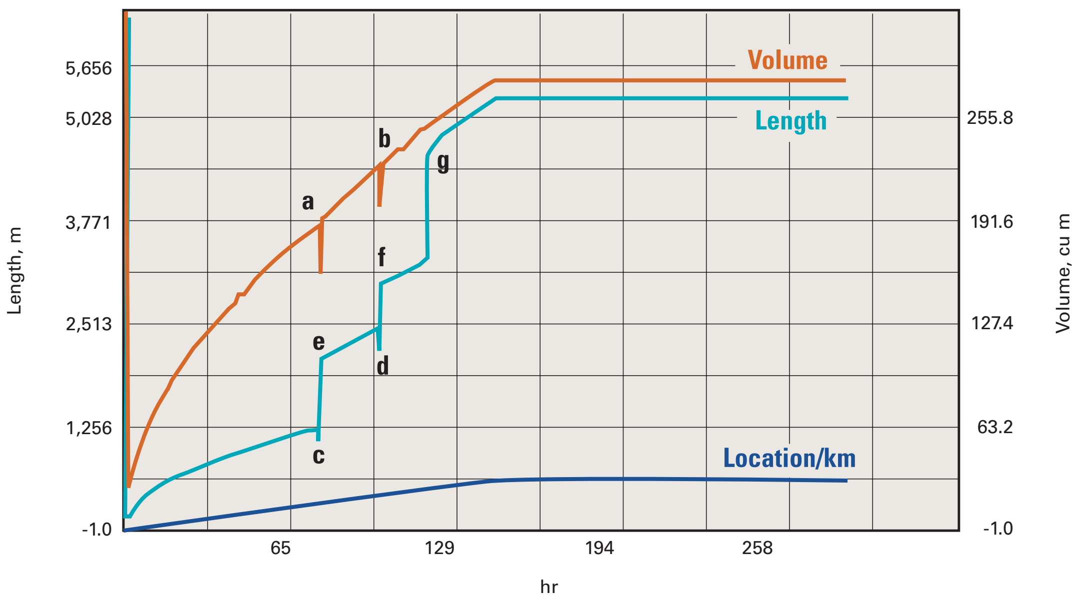


Fig. 8 shows one contamination segment, including volume and length of contamination, and the position of interface. This is shown for the whole transportation process. Removing contamination at Zaozhuang and Qufu causes the sharp decrease in volume and length seen at a, b, e, and f. A change in OD results in the increase of length seen at g.

Field data collected in February 2006 during shipment of diesel validated the accuracy of HSS. Table 2 compares the field data with simulation results for the same shipment.

Acknowledgments

The author acknowledges the contributions of CNPC in preparing this article. ✦

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API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4 11-17 2006	Districts 1-4 [1]11-10 2006	District 5 11-17 2006	District 5 [1]11-10 2006	Total US 11-17 2006	Total US [1]11-10 2006	Total US 11-18 2005
	1,000 b/d						
Total motor gasoline	334	413	10	14	344	427	555
Mo. gas. blending comp.	685	450	11	7	696	457	685
Distillate[2]	147	299	8	57	155	356	493
Residual	137	88	16	22	153	110	555
Jet fuel-kerosine	49	41	81	128	130	169	51
LPG	375	356	—	—	375	356	371
Unfinished oils	461	664	131	78	592	742	441
Other	397	204	16	15	413	219	394
Total products	**2,585**	**2,515**	**273**	**321**	**2,858**	**2,836**	**3,545**
Canadian crude	1,974	1,790	121	235	2,095	2,025	1,813
Other foreign	7,388	6,803	711	892	8,099	7,695	8,388
Total crude	**9,362**	**8,593**	**832**	**1,127**	**10,194**	**9,720**	**10,201**
Total imports	**11,947**	**11,108**	**1,105**	**1,448**	**13,052**	**12,556**	**13,746**

[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

	*11-17-06	*11-18-05	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	66.76	64.07	2.69	4.2
Brent crude	57.79	53.76	4.03	7.5
Crack spread	8.98	10.31	–1.33	–12.9
FUTURES MARKET PRICES				
One month				
Product value	67.30	65.75	1.55	2.4
Light sweet crude	57.54	57.01	0.53	0.9
Crack spread	9.76	8.75	1.02	11.6
Six month				
Product value	75.56	71.83	3.72	5.2
Light sweet crude	63.82	59.10	4.72	8.0
Crack spread	11.74	12.74	–0.99	–7.8

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel Kerosine	Fuel oils Distillate	Fuel oils Residual	Unfinished oils
	1,000 bbl						
PAD I	16,151	54,032	25,826	9,871	66,838	18,451	7,877
PAD II	71,209	50,237	15,691	6,381	25,097	2,097	13,912
PAD III	178,073	65,387	27,833	13,804	32,038	17,459	43,707
PAD IV	14,497	5,983	1,830	597	2,339	423	3,516
PAD V	[2]58,254	27,298	20,194	8,462	10,957	6,139	20,072
Nov. 17, 2006	**[2]338,184**	**202,937**	**91,374**	**39,115**	**137,269**	**44,569**	**89,084**
Nov. 10, 2006[3]	**339,927**	**203,703**	**90,955**	**40,012**	**138,718**	**45,028**	**89,056**
Nov. 18, 2005	**325,969**	**202,642**	**66,031**	**42,060**	**128,193**	**38,786**	**91,533**

[1]Included in total motor gasoline. [2]Includes 6.525 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—NOV. 17, 2006

District	Refinery operations: Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Refinery output: Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual
	1,000 b/d					1,000 b/d			
East Coast	2,846	1,413	1,441	1,618	89.1	1,781	86	517	91
App. Dist. 1	104	93	95	95	100.0	10	—	28	1
Dist. 1 total	**2,950**	**1,506**	**1,536**	**1,713**	**89.7**	**1,791**	**86**	**545**	**92**
Ind., Ill., Ky.	2,114	1,864	1,893	2,355	80.4	1,173	100	527	48
Minn., Wis., Dak.	422	406	408	442	92.3	235	36	112	13
Okla., Kan., Mo.	836	667	672	786	85.5	447	31	260	5
Dist. 2 total	**3,372**	**2,937**	**2,973**	**3,853**	**83.0**	**1,855**	**167**	**899**	**66**
Inland Texas	936	584	613	647	94.7	409	44	171	7
Texas Gulf Coast	4,031	3,604	3,627	4,031	90.0	1,375	342	924	134
La. Gulf Coast	3,144	2,892	2,963	3,264	90.8	1,190	337	806	120
N. La. and Ark.	228	191	198	215	89.8	76	9	51	6
New Mexico	150	95	95	113	84.1	84	1	28	—
Dist. 3 total	**8,489**	**7,361**	**7,491**	**8,270**	**90.6**	**3,134**	**733**	**1,980**	**267**
Dist. 4 total	**708**	**560**	**570**	**596**	**95.6**	**286**	**30**	**172**	**15**
Dist. 5 total	**2,541**	**2,418**	**2,503**	**3,173**	**78.9**	**1,719**	**403**	**484**	**133**
Nov. 17, 2006	**18,060**	**14,782**	**15,073**	**17,335**	**87.0**	**8,785**	**1,419**	**4,080**	**573**
Nov. 10, 2006*	**18,649**	**15,042**	**15,588**	**17,335**	**89.9**	**8,891**	**1,404**	**4,075**	**597**
Nov. 18, 2005	**16,172**	**14,557**	**15,012**	**17,115**	**87.7**	**8,821**	**1,474**	**3,923**	**602**

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

OGJ Gasoline Prices

	Price ex tax 11-22-06	Pump price* 11-22-06	Pump price 11-23-05
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	175.7	215.4	230.3
Baltimore	173.8	215.7	216.5
Boston	175.2	217.1	208.5
Buffalo	181.2	241.3	225.6
Miami	188.1	238.4	218.9
Newark	174.5	207.4	225.1
New York	171.0	231.1	226.8
Norfolk	172.3	209.9	230.2
Philadelphia	182.9	233.6	227.1
Pittsburgh	171.3	222.0	221.8
Wash., DC	187.6	226.0	227.4
PAD I avg	177.6	223.4	223.5
Chicago	209.9	260.8	226.8
Cleveland	174.2	220.6	210.1
Des Moines	168.2	208.6	207.6
Detroit	177.6	226.8	212.1
Indianapolis	178.5	223.5	209.0
Kansas City	173.9	209.9	208.6
Louisville	181.6	218.5	210.0
Memphis	170.4	210.2	220.7
Milwaukee	183.1	234.4	225.7
Minn.-St. Paul	180.5	220.9	213.0
Oklahoma City	172.5	207.9	202.7
Omaha	177.4	223.8	211.4
St. Louis	178.9	214.9	221.3
Tulsa	174.3	209.7	202.5
Wichita	173.4	216.8	203.0
PAD II avg	178.3	220.5	212.3
Albuquerque	180.6	217.0	217.8
Birmingham	175.1	213.8	214.3
Dallas-Fort Worth	175.2	213.6	217.0
Houston	168.6	207.0	214.5
Little Rock	171.8	212.0	212.6
New Orleans	174.6	213.0	252.6
San Antonio	170.6	209.0	218.4
PAD III avg	173.8	212.2	221.0
Cheyenne	183.0	215.4	216.8
Denver	170.4	210.8	226.5
Salt Lake City	183.4	226.3	224.9
PAD IV avg.	178.9	217.5	222.7
Los Angeles	184.6	243.1	254.3
Phoenix	183.1	220.5	239.8
Portland	200.6	243.9	229.9
San Diego	189.4	247.9	251.5
San Francisco	205.5	264.0	256.3
Seattle	202.2	254.6	243.3
PAD V avg.	194.2	245.7	245.9
Week's avg.	**179.7**	**223.3**	**222.2**
Oct. avg.	**183.8**	**228.0**	**263.9**
Sept. avg.	**208.9**	**253.3**	**282.5**
2006 to date	**215.3**	**258.9**	—
2005 to date	**182.4**	**224.4**	—

*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

	11-17-06 ¢/gal		11-17-06 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	156.38	New York Harbor	161.75
Gulf Coast	151.13	Gulf Coast	161.50
Los Angeles	168.13	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	139.37	ARA	167.53
Singapore	148.93	Singapore	166.88
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	155.88	New York Harbor	101.26
Gulf Coast	154.63	Gulf Coast	88.69
Los Angeles	176.63	Los Angeles	107.42
		ARA	98.00
		Singapore	96.00

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

Baker Hughes Rig Count

	11-24-06	11-25-05
Alabama	4	6
Alaska	6	12
Arkansas	34	14
California	36	30
Land	32	26
Offshore	4	4
Colorado	87	87
Florida	0	2
Illinois	0	0
Indiana	0	0
Kansas	13	6
Kentucky	2	5
Louisiana	195	181
N. Land	56	53
S. Inland waters	21	20
S. Land	47	39
Offshore	71	69
Maryland	0	0
Michigan	2	1
Mississippi	17	11
Montana	17	26
Nebraska	0	0
New Mexico	101	89
New York	11	5
North Dakota	35	25
Ohio	8	9
Oklahoma	181	149
Pennsylvania	15	14
South Dakota	1	1
Texas	767	671
Offshore	9	6
Inland waters	4	2
Dist. 1	14	21
Dist. 2	23	30
Dist. 3	59	66
Dist. 4	92	70
Dist. 5	143	110
Dist. 6	119	105
Dist. 7B	39	25
Dist. 7C	41	35
Dist. 8	103	78
Dist. 8A	26	27
Dist. 9	33	29
Dist. 10	62	67
Utah	46	31
West Virginia	19	24
Wyoming	94	87
Others—HI-1; ID-1; NV-1; OR-1; TN-1; WA-1	6	5
Total US	**1,697**	**1,491**
Total Canada	**453**	**631**
Grand total	**22,150**	**2,122**
Oil rigs	297	275
Gas rigs	1,395	1,212
Total offshore	85	81
Total cum. avg. YTD	**1,641**	**1,374**

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	11-24-06 Rig count	11-24-06 Percent footage*	11-25-05 Rig count	11-25-05 Percent footage*
0-2,500	51	1.9	24	—
2,501-5,000	100	45.0	80	38.7
5,001-7,500	228	19.2	178	21.9
7,501-10,000	426	2.8	329	5.4
10,001-12,500	434	1.8	330	2.7
12,501-15,000	246	0.4	289	0.3
15,001-17,500	121	—	110	—
17,501-20,000	75	—	50	—
20,001-over	33	—	21	—
Total	**1,714**	**6.4**	**1,406**	**6.9**
INLAND	37		30	
LAND	1,617		1,329	
OFFSHORE	60		47	

*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]11-24-06	[2]11-25-05
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	22
Alaska	770	873
California	695	700
Colorado	59	62
Florida	6	6
Illinois	28	27
Kansas	95	93
Louisiana	1,360	929
Michigan	14	15
Mississippi	54	49
Montana	95	97
New Mexico	164	163
North Dakota	106	105
Oklahoma	172	169
Texas	1,353	1,259
Utah	45	48
Wyoming	142	145
All others	66	75
Total	**5,244**	**4,837**

[1]OGJ estimate. [2]Revised.

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

US Crude Prices

$/bbl*	11-24-06
Alaska-North Slope 27°	56.72
South Louisiana Sweet	55.00
California-Kern River 13°	47.45
Lost Hills 30°	54.00
Southwest Wyoming Sweet	56.74
East Texas Sweet	56.98
West Texas Sour 34°	47.00
West Texas Intermediate	55.75
Oklahoma Sweet	55.75
Texas Upper Gulf Coast	52.50
Michigan Sour	48.75
Kansas Common	54.75
North Dakota Sweet	45.00

*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]	11-17-06
United Kingdom-Brent 38°	58.46
Russia-Urals 32°	55.46
Saudi Light 34°	54.62
Dubai Fateh 32°	57.37
Algeria Saharan 44°	60.30
Nigeria-Bonny Light 37°	61.31
Indonesia-Minas 34°	57.67
Venezuela-Tia Juana Light 31°	52.75
Mexico-Isthmus 33°	52.64
OPEC basket	56.67
Total OPEC[2]	56.00
Total non-OPEC[2]	53.17
Total world[2]	54.34
US imports[3]	51.50

[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]

	11-17-06	11-10-06	Change
	Bcf		
Producing region	1,015	1,015	—
Consuming region east	1,964	1,962	2
Consuming region west	470	473	–3
Total US	**3,449**	**3,450**	**–1**
	Aug. 06	**Aug. 05**	**Change, %**
Total US[2]	**2,969**	**2,662**	**11.5**

[1]Working gas. [2]At end of period.
Source: Energy Information Administration
Data available in OGJ Online Research Center.

Pace refining margins

	Sept. 2006	Oct. 2006	Nov. 2006	Nov. 2005	Change	Change, %
	$/bbl					2006 vs. 2005
US Gulf Coast						
West Texas Sour	8.16	10.67	11.65	10.07	1.58	15.7
Composite US Gulf Refinery	8.10	9.94	10.86	11.43	–0.57	–5.0
Arabian Light	7.37	10.56	11.61	10.26	0.35	13.2
Bonny Light	2.35	2.76	3.64	5.33	–1.79	–33.6
US PADD II						
Chicago (WTI)	6.39	9.07	10.86	7.31	3.55	48.6
US East Coast						
NY Harbor (Arab Med)	3.07	6.31	7.01	6.22	0.79	12.7
East Coast Comp-RFG	4.74	6.44	7.25	7.68	–0.44	–5.7
US West Coast						
Los Angeles (ANS)	9.43	12.78	18.41	9.26	9.15	98.8
NW Europe						
Rotterdam (Brent)	1.94	2.79	2.13	2.43	–0.30	–12.2
Mediterranean						
Italy (Urals)	6.71	7.27	7.17	6.49	0.68	10.5
Far East						
Singapore (Dubai)	–0.32	0.37	–0.84	2.53	–3.37	–133.2

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

US natural gas balance
Demand/supply scoreboard

	Aug. 2006	July 2006	Aug. 2005	AUug. change 2006-2005	Total YTD 2006	Total YTD 2005	YTD change 2006-2005
	bcf						
DEMAND							
Consumption	1,759	1,760	1,697	62	14,720	15,165	–445
Addition to storage	302	305	311	–9	2,025	1,998	27
Exports	55	53	52	3	464	554	–90
Canada	17	16	19	–2	197	284	–87
Mexico	32	32	27	5	222	227	–5
LNG	6	5	6	—	45	43	2
Total demand	**2,116**	**2,118**	**2,060**	**56**	**17,209**	**17,717**	**–508**
SUPPLY							
Production (dry gas)	1,542	1,549	1,565	–23	12,356	12,450	–94
Supplemental gas	6	6	6	—	46	46	—
Storage withdrawal	113	114	97	16	1,692	2,031	–339
Imports	345	363	352	–7	2,759	2,861	–102
Canada	293	305	308	–15	2,347	2,449	–102
Mexico	0	0	0	0	0	0	0
LNG	52	58	44	8	409	411	–2
Total supply	**2,006**	**2,062**	**2,020**	**–14**	**16,853**	**17,388**	**–535**

NATURAL GAS IN UNDERGROUND STORAGE

	Aug. 2006	July 2006	June 2006	Aug. 2004	Change
	bcf				
Base gas	4,213	4,214	4,416	4,203	10
Working gas	2,969	2,779	2,617	2,662	307
Total gas	**7,182**	**6,993**	**6,833**	**6,865**	**317**

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

Worldwide NGL production

	Aug. 2006	July 2006	8 month average Production 2006	8 month average Production 2005	Change vs. previous year Volume	Change vs. previous year %
	1,000 b/d					%
Brazil	91	91	86	76	9	12.4
Canada	691	646	686	667	18	2.7
Mexico	445	449	440	432	8	1.9
United States	1,726	1,755	1,721	1,812	–92	–5.1
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	175	178	172	154	18	11.5
Western Hemisphere	**3,328**	**3,320**	**3,303**	**3,341**	**–38**	**–1.1**
Norway	295	296	285	267	19	7
United Kingdom	119	126	150	173	–23	–13.4
Other Western Europe	19	19	20	23	–3	–13.9
Western Europe	**433**	**441**	**455**	**463**	**–8**	**–1.7**
Russia	420	420	396	479	–83	–17.2
Other FSU	160	160	160	160	—	—
Other Eastern Europe	17	15	17	18	–1	–4.2
Eastern Europe	**597**	**595**	**574**	**657**	**–83**	**–12.7**
Algeria	295	295	295	295	—	—
Egypt	65	65	65	65	—	—
Libya	60	60	60	60	—	—
Other Africa	194	193	190	168	22	13.3
Africa	**614**	**613**	**610**	**588**	**22**	**3.8**
Saudi Arabia	1,490	1,490	1,475	1,460	15	1
United Arab Emirates	400	400	400	400	—	—
Other Middle East	670	670	670	571	99	17.3
Middle East	**2,560**	**2,560**	**2,545**	**2,431**	**114**	**4.7**
Australia	91	90	81	82	—	–0.1
China	180	180	180	180	—	—
India	35	40	422	44	–2	–5.3
Other Asia-Pacific	219	220	220	218	1	0.7
Asia-Pacific	**525**	**530**	**523**	**524**	**–1**	**–0.2**
TOTAL WORLD	**8,057**	**8,058**	**8,010**	**8,004**	**6**	**0.1**

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

Oxygenates

	Aug. 2006	July 2006	Change	YTD 2006	YTD 2005	Change
	1,000 bbl					
Fuel ethanol						
Production	10,185	9,804	381	74,002	59,841	14,161
Stocks	9,160	7,727	1,433	9,160	5,246	3,914
MTBE						
Production	3,022	3,103	–81	23,659	33,072	–36,182
Stocks	1,759	2,100	–341	1,759	2,751	–992

Source: DOE Petroleum Supply Monthly. NOTE: No new data at press time.
Data available in OGJ Online Research Center.

US heating degree days

	Oct. 2006	Oct. 2005	Normal	2006 % change from normal	Total degree days July 1 through Oct. 31 2006	2005	Normal	% change from normal
New England	461	395	467	–1.3	666	499	657	1.4
Middle Atlantic	385	325	399	–3.5	496	363	526	–5.7
East North Central	500	384	424	17.9	679	464	580	17.1
West North Central	519	404	424	22.4	710	511	607	17.0
South Atlantic	185	143	164	12.8	217	148	189	14.8
East South Central	249	209	213	16.9	293	215	246	19.1
West South Central	97	104	83	16.9	106	105	92	15.2
Mountain	372	299	360	3.3	536	405	543	–1.3
Pacific	184	163	186	–1.1	236	229	294	–19.7
US average*	**307**	**251**	**282**	**8.9**	**403**	**300**	**383**	**5.2**

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

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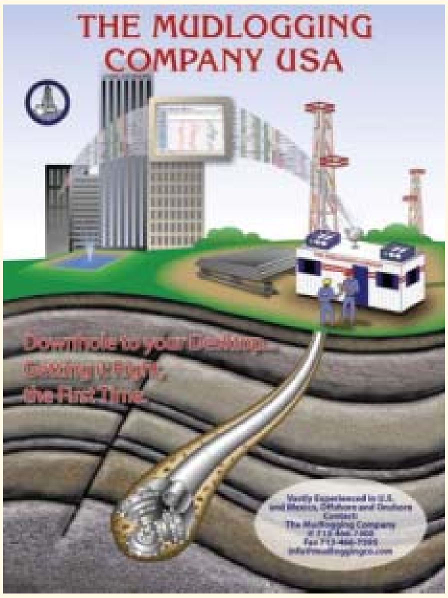

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OCS plan letter appeals to law, national interest

US oil and gas producers and contractors have resorted to basics in their efforts to expand leasing of federal land offshore. They're appealing to law and national interest.

Seven industry trade groups delivered this combination punch in a letter to Minerals Management Service officials. They were responding to the agency's proposed schedule and draft environmental impact statement for Outer Continental Shelf lease

The Editor's Perspective

by Bob Tippee, Editor

sales during July 2007-June 2012.

The 5-year plan calls for leasing in the Central and Western Gulf of Mexico, Cook Inlet, Beaufort Sea, Chukchi Sea, North Aleutian basin, and possibly a small area off Virginia.

The groups pointed out in their letter that the prospective sales still cover less than 12% of the 1.7 billion acres under MMS management.

"The agency is being much too conservative," wrote the National Ocean Industries Association, Natural Gas Supply Association, Petroleum Equipment Suppliers Association, Domestic Petroleum Council, Independent Petroleum Association of America, International Association of Drilling Contractors, and US Oil & Gas Association.

Their letter noted that the OCS Lands Act calls for lease sale schedules that "best meet national energy needs for the 5-year period" and specifies that an equitable sharing of developmental benefits and environmental risks be taken into account in leasing decisions.

"In order to complete the analysis required by conducting such 'equitable sharing' among the regions and determining the relative environmental risks, it is necessary to conduct a full analysis of all the OCS areas," the groups wrote.

Their letter also criticized the program and draft environmental impact statement for not considering the prospective "socioeconomic impacts" on citizens of all 50 states.

It called for analysis of "both producing energy from the offshore and of not producing energy from many areas of the offshore."

And it elaborated: "The resources of the OCS are owned by all Americans, and the hardship created by withholding our energy resources from people in middle America should be analyzed in the environmental impact statement and in the decision-making process."

These are polite ways of saying that leasing restricted to a small part of the OCS shirks law, cheats Americans, and therefore needs to grow.

(Online Nov. 24, 2006; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

December crude contract expires at low

The December contract for benchmark US crudes expired Nov. 17 at $55.81/bbl, the lowest closing price in 17 months on the New York Mercantile Exchange, amid calls from some members of the Organization of Petroleum Exporting Countries for another production cut.

The contract had plunged $2.50 to $56.26/bbl Nov. 16, the lowest closing for a front-month oil contract since Nov. 18, 2005.

The new front-month January crude contract slipped by 17¢ to $58.81/bbl Nov. 20 but rebounded to $60.17/bbl in the next trading session as strong winds halted tanker loadings in Valdez, Alas., and reduced the flow of crude through the Trans-Alaska Pipeline to 25% of normal capacity.

NYMEX was closed Nov. 23-24 for the US Thanksgiving holiday. But analysts in the Houston office of Raymond James & Associates Inc. reported oil prices were up in other markets Nov. 24 on news of militant attacks on crude supplies in Nigeria, which disrupted production of 60,000 b/d. Eni SPA declared force majeure at Okono-Okpoho offshore oil field. "Nigeria has suffered anywhere between 600,000 to 800,000 b/d loss in production due to the continuous militant attacks that have plagued the oil rich Niger Delta," said Raymond analysts. Although crude prices had vacillated in recent weeks, they said, "Continuous geopolitical turmoil provides a support to crude prices near the $60/bbl level."

Earlier, Raymond James analysts said OPEC's call for a second production cut reinforces suspicion that the production cut instigated on Nov. 1 was lower than the announced 1.2 million b/d. Still, Saudi Arabia's oil minister said his country might support another production cut at OPEC's Dec. 14 meeting in Nigeria. Meanwhile, Oil Movements, which tracks tanker operations, said OPEC exports are expected to increase by 150,000 b/d to 24.58 million b/d in the 4 weeks to Dec. 9 after remaining flat during the 4 weeks prior to Nov. 25.

The Nov. 23-26 Thanksgiving holiday had a dual effect on US energy demand. On one hand, it was expected to cut power demand with offices and some businesses closed.

However, energy prices had rebounded earlier partially in anticipation of holiday travel. More people travel over the Thanksgiving holiday than any during other US holiday. Some 31.7 million motorists were expected to take to US roads and highways, representing 83% of total travelers expected over the 4-day holiday.

US inventories

The Energy Information Administration said US commercial inventories of crude jumped by 5.1 million bbl to 341.1 million bbl during the week ended Nov. 17. Gasoline stocks increased by 1.4 million bbl to 201.7 million bbl during the same period. Distillate fuel inventories fell by 1.2 million bbl to 133.8 million.

Imports of crude grew by 1 million b/d to 10.5 million b/d in the same week. Input of crude into US refineries increased by 60,000 b/d to 15 million b/d, with refineries operating at 87.1% of capacity.

EIA also reported the withdrawal of 1 bcf of natural gas from US underground storage in the same week, compared with a 5 bcf injection the previous week and a 9 bcf withdrawal during the same period last year. US gas storage now stands at 3.4 tcf, up by 174 bcf from year-ago levels and 240 bcf above the 5-year average.

The latest withdrawal of gas "does not appear to reflect any new incremental 'backed-out' demand or change in our view of the supply-demand fundamentals," said Robert S. Morris, Banc of America Securities LLC, New York. US weather Nov. 1-17 was nearly 10% warmer than the 10-year average for that period. Since November accounts for only 15% of a normal winter's heating demand, the month "has historically not been a precursor" for the full winter. "If temperatures for the rest of the winter match the 10-year average, we project that natural gas storage levels will end March at about 1.35 tcf vs. last year's record high [of] 1.7 tcf, and the 5-year average of roughly 1.2 tcf," Morris said.

To accomplish that, however, the pace of gas withdrawals this winter would have to average 13.9 bcfd in November-March vs. 9.9 bcfd last winter, in the face of increased supply relative to the hurricane curtailment of offshore production in 2005 and some increase in "organic" production, he acknowledged.

Raymond James analysts said, "On the natural gas front, prices have held within a 98¢/Mcfe range during [most of] November (with a high of $8.26), after months of intense volatility. Frigid weather is the most likely catalyst needed for oil and gas prices to break out of their respective trading ranges."

(Online Nov. 27, 2006; author's e-mail: samf@ogjonline.com)

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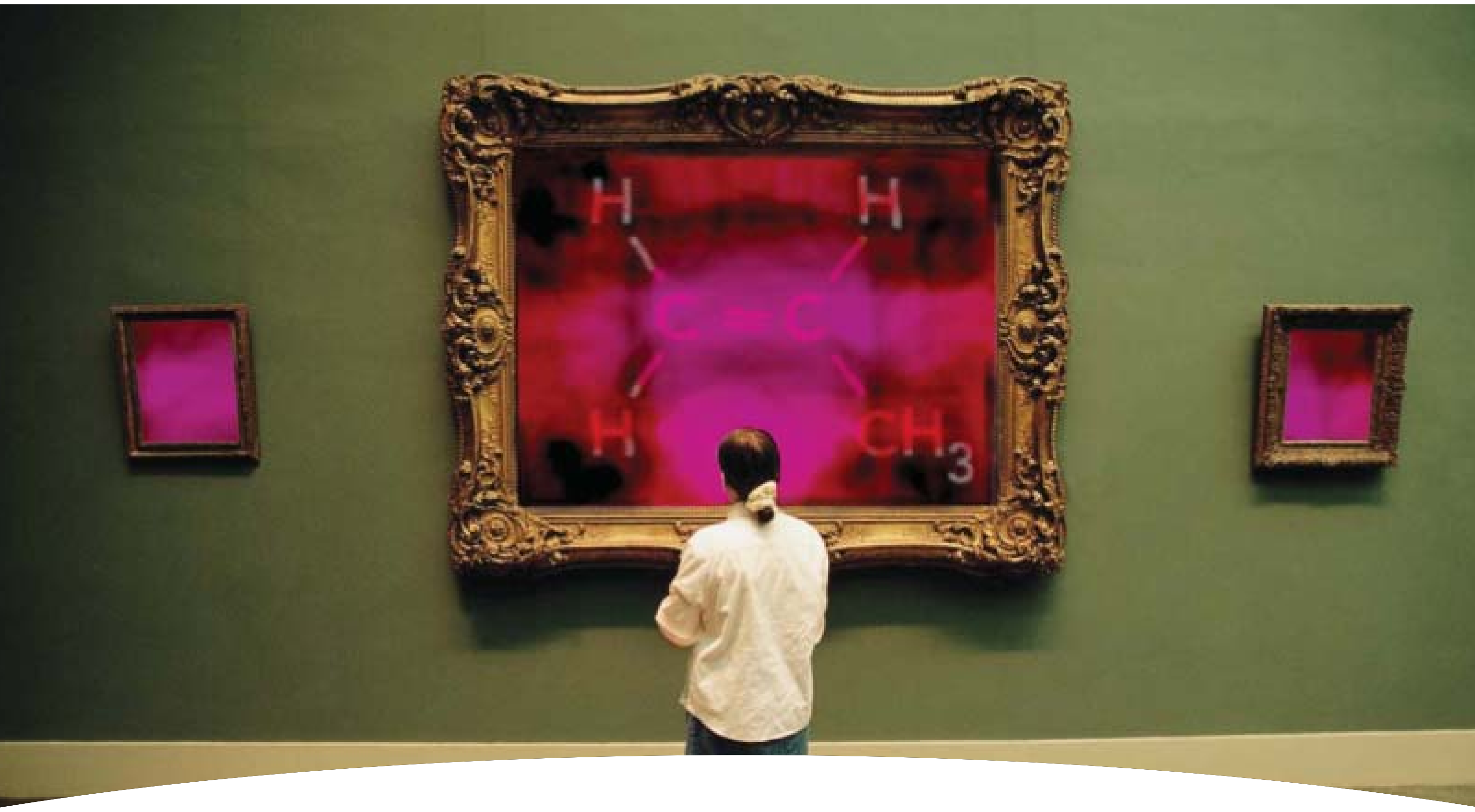

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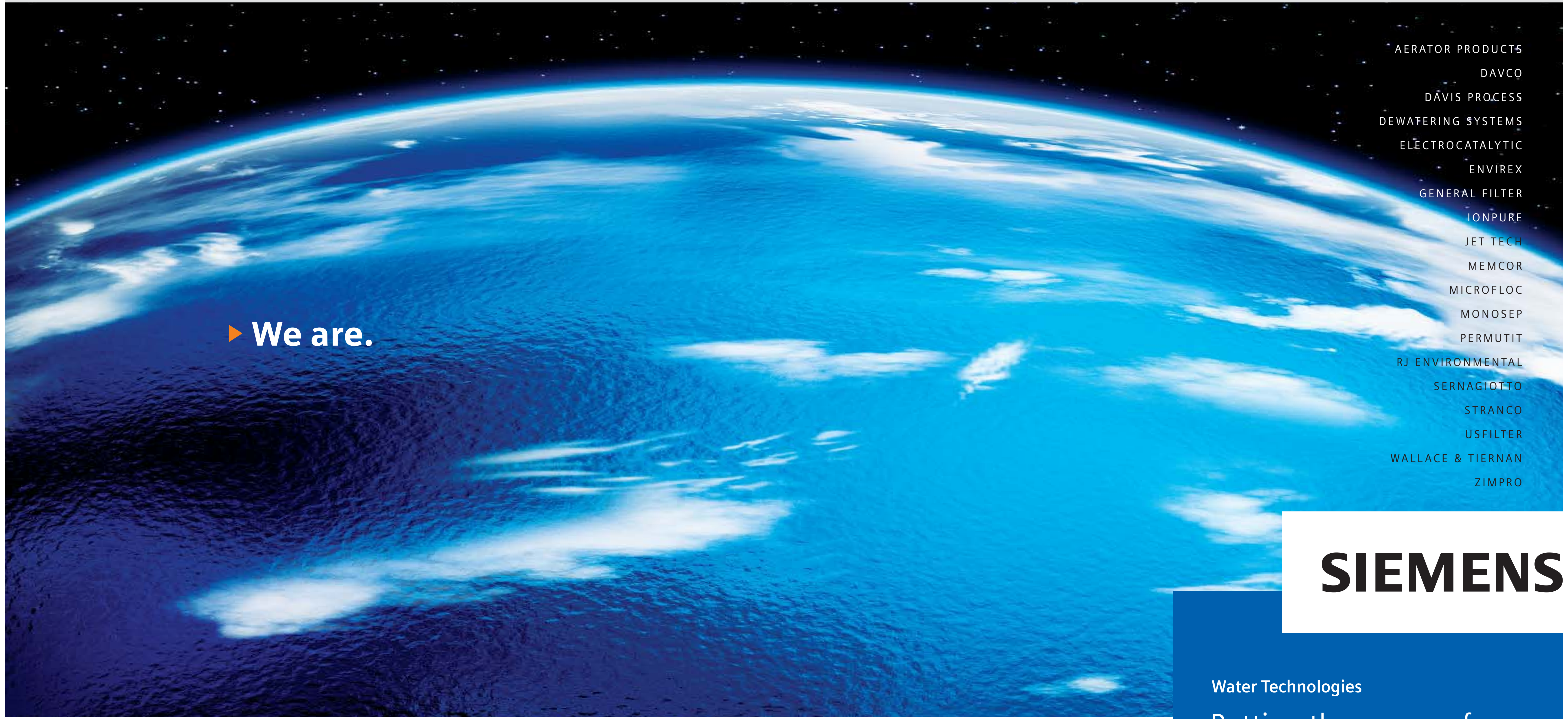

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