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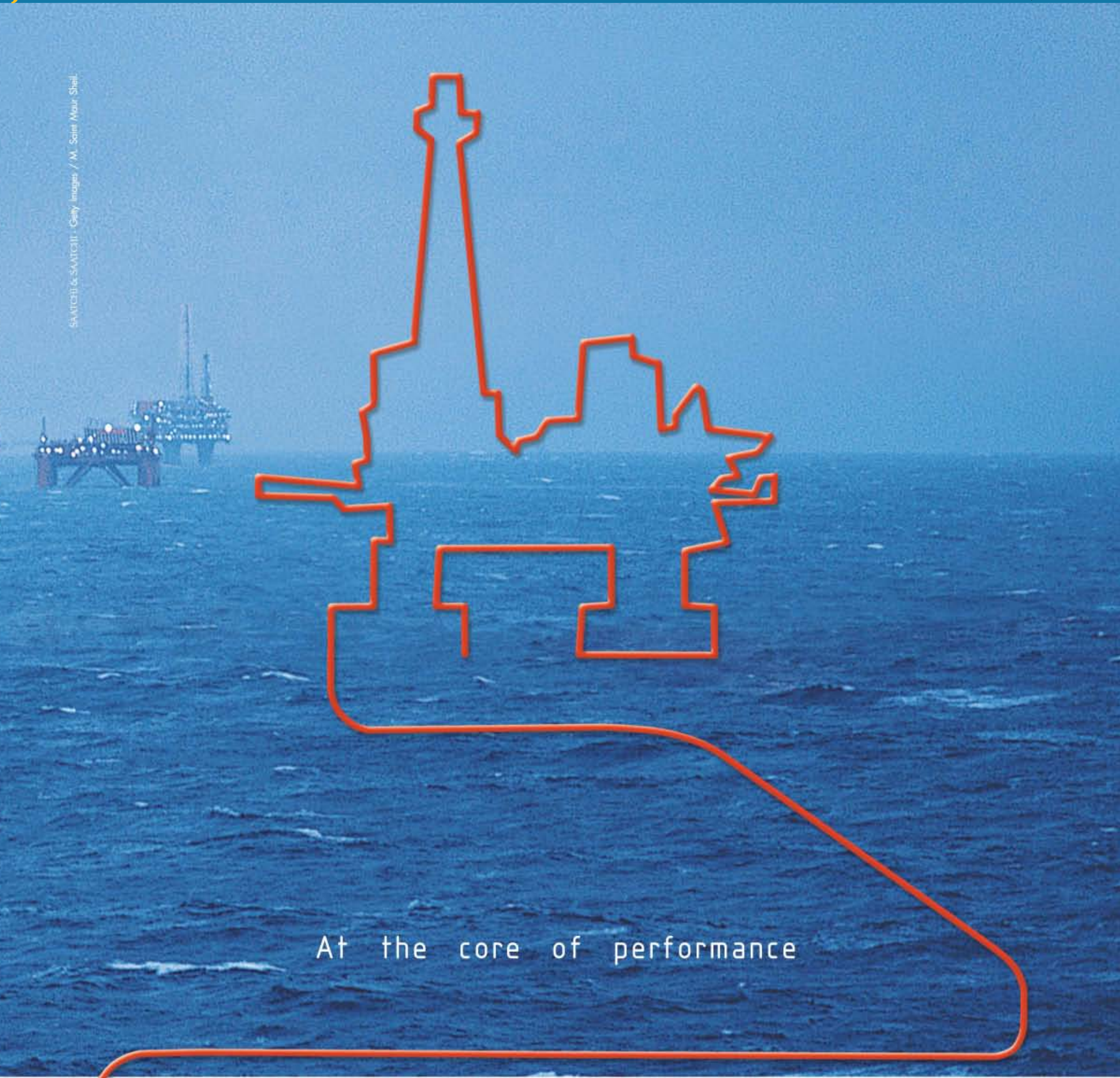
Offshore Technology Roundup

Second discovery indicated in Central Utah thrust belt
StatoilHydro completes, flows 10-km horizontal well
'Design-build' method useful for refinery project execution
Nearly 30 new US gas transport facilities due by mid-2009



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OIL&GAS JOURNAL

May 12, 2008
Volume 106.12

Offshore Technology Roundup

Regular Features

Cover

New offshore deepwater drilling technologies as well as methane hydrates and acquiring and keeping quality technical personnel were among the top-listed topics being discussed at this year's Offshore Technology Conference in Houston. The cover shows some of the award-winning technologies showcased at this year's 4-day conference. Shown are Delmar Systems Inc.'s OMNI-Max anchor, a gravity-installed vertically loaded anchor for MODU moorings (left) and Baker Hughes-INTEQ's MagTrak logging-while-drilling tool (inset). OTC coverage begins on p. 20. Photos from Delmar Systems and Baker Hughes-INTEQ.


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May 12, 2008

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General Interest — *Quick Takes*

OTC: Roundtable notes NOCs, IOCs lack trust

Business with national oil companies (NOCs) is certain to grow over the next 5 years with 64% of delegates voting that this would happen at the Offshore Technology Conference's Energy Roundtable May 7 in Houston. But this new dynamic is threatened by a lack of trust between international oil companies (IOCs) and NOCs, which could hinder oil and gas investment according to 64% of the attendees at the panel.

Global energy demand is expected to rise by 1.2%/year until 2030 with NOCs and IOCs committed to meeting those needs: hydrocarbons will have an important role in doing so.

Oil executives on the panel agreed that there was a new energy equation with constrained supplies, steep growth in the world's energy demand, geopolitical tensions, and new challenging energy resources such as oil sands.

Patrick Poyanne, senior vice-president of strategy, business development, and research and development at Total SA, said IOCs and NOCs should cooperate because IOCs have operational excellence and offer a diversified experience in handling large and complex developments. However, Poyanne also acknowledged that IOCs need to address the socioeconomic needs of producing countries and boost the intellectual capacity of its people.

"There is a lack of trust now between NOCs and IOCs. NOCs feel that IOCs benefit from excessive profits. We accept that contracts can be revised in today's market, but it needs to be on a win-win basis," he said.

Increased competition between NOCs, IOCs, and independent exploration and production companies for acreage necessitates a focused and disciplined strategy, said Jean Claude Gandur, president and chief executive of Addax Petroleum. "Resource pressures include personnel, service providers, and capital."

OTC: Oil-producing nations balance supply, demand

Tensions are developing in some oil-producing nations with citizenship demanding an improved standard of living and economic growth rather than a government with its focus on export markets, Energy Roundtable panelists said May 7 at OTC in Houston.

Emmanuel Egbogah, special advisor to Nigeria's president on petroleum affairs, said that security of demand and supply are complimentary and it was necessary to strike the right balance between local demand and high values in the export markets. Nigeria is changing its stance by aggressively monetizing its gas resources under its Gas Master Plan for the domestic market.

"The domestic market's demand is expected to be at 10-11 bcfd by 2010 but supply will be at 4 bcfd and export demand at 25 bcfd. This unprecedented growth is due to the power and LNG export capacity," he said.

Robert Ryan, vice-president of global upstream exploration at Chevron Corp., was optimistic that oil companies can meet growing global demand provided it can find new ways to enhance recovery from mature fields, deliver technological breakthroughs in the deep water and ultradeep water, and turn to unconventional resources.

"We have always had limited access, remote locations, technological challenges, and escalating costs. These are all relative because one of these factors has always been a problem at some point, but we have found ways to overcome them."

OTC: Industry looks to solve personnel shortage

Thierry Pilenko, chairman and chief executive of Technip SA, warned that oil and gas megaprojects will take longer to implement because of a shortage of experienced management. Speaking May 7 at OTC's Energy Roundtable, Pilenko said there were 190 major projects worldwide in 2008 that have an average size of 1.6 billion boe and require investments of $8.7 billion, according to a report by Goldman Sachs. Most of the reserves will come from deep and ultradeep water, which poses significant technological challenges.

"As the complexity of project rises, soft skills and attitudes will make the difference as well as the finance and technical skills," Pilenko said.

Greater societal and governmental pressure on oil companies to reduce emissions and stem climate change means that they must become more transparent in their practices, predicted Mark Lee, chief executive of industry think tank SustainAbility. Oil and gas prices are likely to be volatile with export quotas and resource nationalism all having an impact on energy supplies. "Leadership from the industry needs to become more sophisticated and I think there will be a massive technological acceleration until 2050, particularly in alternative energy."

Holly settles Woods Cross refinery pollution charges

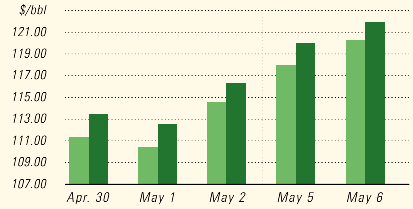
Holly Refining & Marketing Co. settled federal air pollution charges involving its Woods Cross, Utah, refinery by agreeing to spend more than $17 million on new and upgraded pollution controls, the US Department of Justice and Environmental Protection Agency said on Apr. 21.

The Holly Corp. subsidiary also agreed to pay a $120,000 civil penalty that EPA and the state of Utah will share. It also will spend $130,000 on a supplemental environmental project to help fund the purchase of new emergency response equipment for the South Davis Metro Fire Agency, DOJ and EPA jointly announced.

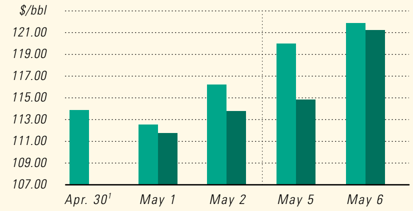
They said that the settlement requires Holly to install pollution controls which will reduce sulfur dioxide emissions by 315 tons/year and nitrogen oxides by more than 105 tons/year. The new

Industry Scoreboard

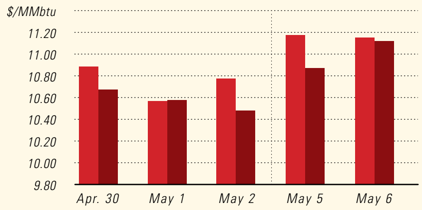
IPE BRENT / NYMEX LIGHT SWEET CRUDE



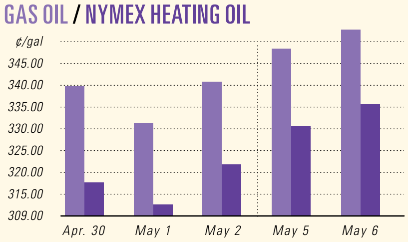
WTI CUSHING / BRENT SPOT



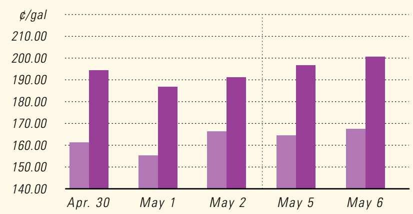
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



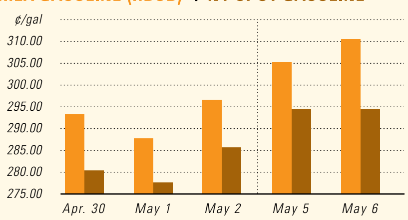
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

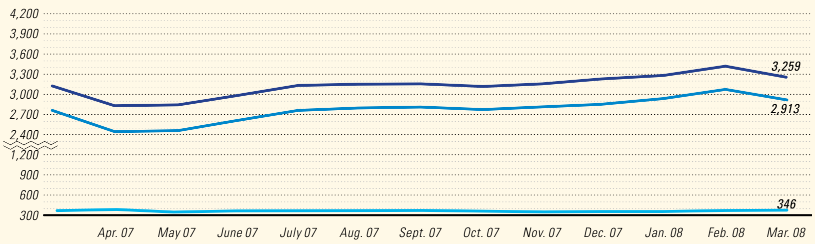
US INDUSTRY SCOREBOARD — 5/12

Latest week 4/25	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,257	9,223	0.4	9,068	9,071	—
Distillate	4,257	4,229	0.7	4,266	4,354	–2.0
Jet fuel	1,569	1,637	–4.2	1,571	1,611	–2.5
Residual	795	724	9.8	674	795	–15.2
Other products	4,801	4,759	0.9	4,906	4,896	0.2
TOTAL DEMAND	20,679	20,572	0.5	20,400	20,730	–1.6
Supply, 1,000 b/d						
Crude production	5,098	5,212	–2.2	5,083	5,184	–1.9
NGL production[2]	2,423	2,401	0.9	2,411	2,323	3.8
Crude imports	9,512	10,203	–6.8	9,786	9,947	–1.6
Product imports	3,445	3,691	–6.7	3,392	3,445	–1.5
Other supply[3]	1,358	676	100.9	1,177	643	39.6
TOTAL SUPPLY	21,836	22,183	–1.6	21,849	21,742	0.5
Refining, 1,000 b/d						
Crude runs to stills	14,640	15,020	–2.5	14,640	14,828	–1.3
Input to crude stills	14,822	15,362	–3.5	14,822	15,188	–2.4
% utilization	84.8	88.1	—	84.8	87.0	—

Latest week 4/25	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	319,929	316,081	3,848	335,648	–15,719	–4.7
Motor gasoline	211,089	212,572	–1,483	193,099	17,990	9.3
Distillate	105,831	104,702	1,129	117,134	–11,303	–9.6
Jet fuel-kerosine	38,738	38,283	455	39,657	–919	–2.3
Residual	39,522	39,415	107	40,850	–1,328	–3.3
Stock cover (days)[4]			**Change, %**		**Change, %**	
Crude	22.0	21.9	0.5	22.1	–0.5	
Motor gasoline	22.8	22.9	–0.4	20.8	9.6	
Distillate	24.9	24.5	1.6	27.1	–8.1	
Propane	27.5	24.6	11.8	27.1	1.5	
Futures prices[5] **5/2**			**Change**		**Change**	**%**
Light sweet crude, $/bbl	115.34	117.95	–2.61	65.49	49.85	76.1
Natural gas, $/MMbtu	10.86	10.78	0.09	7.64	3.22	42.2

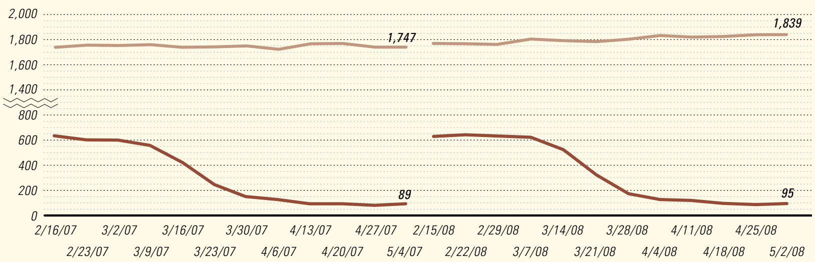
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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controls also will further reduce emissions of volatile organic compounds and particulate matter, the federal agencies said.

The consent decree, which was lodged in US District Court for Utah, is subject to a 30-day comment period and final approval by the federal court, DOJ and EPA said.

Holly acquired the refinery north of Salt Lake City from ConocoPhillips Co. in 2003 and increased its capacity in early 2005 to 26,000 b/d from 25,000 b/d, according to information at the company's web site.

Nigerian refinery legislation to be passed soon

Nigeria is aiming to pass legislation that will require international oil companies working in the country to refine a percentage of their crude oil production there.

"Everybody producing in the country will be mandated to refine a percentage in Nigeria," said Sola Alabi, group general manager for refinery projects at Nigeria National Petroleum Corp.

Alabi told a refinery conference in Barcelona that the legislation had been under discussion for 2 years and was due for approval soon. He said Nigeria is proposing the move as a way to reduce its dependence on imported fuel.

Nigeria can produce only 445,000 b/d of oil products, while demand is currently around 600,000 b/d, Alabi said. Nigeria has four state-owned refineries and NNPC hopes to build two refineries with 200,000-300,000 b/d of capacity each.

NNPC plans to take a 30-49% stake in each refinery, Alabi said, and it hopes oil majors will take 21-30% stakes, given the proper incentives. One of the fiscal incentives to be offered will be pricing crude at international market levels, Alabi said. ✦

Exploration & Development — *Quick Takes*

Eni, partners find oil off Angola with Sangos-1 well

Eni Angola SPA and its partners made an oil discovery on deepwater Block 15/06 off Angola—the first well to be drilled on the block—reported 5% block partner StatoilHydro.

The Sangos-1 discovery well, which was drilled in 1,349 m of water to a total vertical depth of 3,343 m, found a 127-m oil column in high-permeability Miocene sands. The well tested for high-quality oil in excess of 30° gravity and at higher than forecasted rates, StatoilHydro reported.

The Sangos discovery well was drilled 350 km from Luanda and will soon be followed by other exploration wells in nearby structures "with significant potential with the aim of achieving synergic development of the western area of the block," StatoilHydro said.

Block 15/06 lies within the Lower Congo basin and covers 2,984 sq km in 300-1,600 m of water.

Indonesia approves deepwater block for Chevron

Indonesia has approved a proposal by Chevron Corp. to develop natural gas fields on the deepwater Galan Block off East Kalimantan.

"The current price of oil has reduced the risks of developing deepsea gas blocks," said Energy and Mineral Resources Minister Purnomo Yusgiantoro. He said the price of natural gas is expected to increase in line with the price of oil.

According to ministry documents, Chevron committed to spend $311.6 million to develop the block, which is believed to have the potential to produce an average of 800 MMcfd. Chevron holds an 80% stake in the block, while Eni SPA holds the remaining 20%.

Chile awards eight exploration blocks

Chile has signed contracts with four international oil companies for exploration of eight blocks in the southern Magallanes region.

Apache Corp., Pan American Energy LLC, Greymouth Petroleum Holding Ltd., and IPR-Manas collectively will invest some $222 million for seismic surveys and exploratory drilling over a 3-7 year period. Work is due to begin within 6 months.

IPR-Manas won the Tranquilo Block and will invest $33.2 million. Apache won the Russfin and Lenga blocks, where it will invest $23.4 million and $24.9 million respectively.

Greymouth won the Porvenir, Brotula, Isla Magdalena, and Caupolican blocks and will invest a total of $107 million, while Pan American Energy won the Coiron Block, where it will invest $34 million. Brotula and Isla Magdalena are offshore, while Otway is onshore and offshore. The remaining blocks are onshore.

Chile's state-run oil company Empresa Nacional del Petroleos (Enap) holds a 50% stake in the Coiron, Caupolican, and Lenga blocks, with the remaining 50% in each block held respectively by Pan American Energy, Greymouth, and Apache. The other blocks will be 100%-held by the winning companies.

For reasons that remain unclear, Total SA, which last October won the Otway Block where it was expected to invest some $44.5 million, did not attend the contract-signing ceremony.

Chile's Mining Minister Santiago Gonzalez said the government was surprised at Total's absence and that negotiations would start with the next company on the list—a consortium comprised of Wintershall, GeoPark Holdings Ltd., and Methanex Corp.

Analyst BMI said it is still possible that a deal might be worked out with Total before the contact is awarded to another company. ✦

Drilling & Production — *Quick Takes*

EXCO presses Vernon gas field development

Gas production from Vernon field in Jackson Parish, La., has stabilized at a net 130 MMcfd of gas equivalent for the past 8 months since EXCO Resources Inc., Dallas, acquired the field from Anadarko Petroleum Corp. in March 2007 for $1.5 billion.

EXCO said it has 280 drilling locations at Vernon compared with 15 identified at the time of the acquisition. The field produces from the Jurassic Lower Cotton Valley formation.

One recent completion flowed 10.3 MMcfd of gas equivalent, the highest initial production rate from a new well since the acquisition, EXCO said. Six wells drilled and completed in the quarter ended Mar. 31 averaged initial production rates of 6.5 MMcfd of gas equivalent.

EXCO is adding a fourth rig at Vernon and plans to drill 31 wells there in 2008. It has expanded the field's southern and western limits and is reprocessing seismic as it evaluates another 65,000 net prospective acres.

Reliance contracts for new Transocean drillship

Reliance Industries Ltd., India's largest private sector conglomerate, signed a 5-year drilling contract with Transocean Inc. for a newbuild enhanced Enterprise-class design drillship.

A Transocean subsidiary executed a shipyard contract with Daewoo Shipbuilding & Marine Engineering Co. Ltd. for construction of the dynamically positioned, double-hull drillship in Okpo, South Korea, where four of Transocean's previously announced enhanced Enterprise-class drillships are being built. Total capital costs for the drillship are estimated at $730 million, excluding capitalized interest.

The 5-year drilling contract is expected to commence during fourth quarter 2010, following shipyard construction, sea trials, mobilization, and customer acceptance. The term of the contract may be extended to 7-10 years at the client's election up to a week after mobilization. The 5-year contract provides for day rates of $537,000 for the first 6 months, escalating to $557,000/day for the next 4 ½ years. The 7 and 10 year contract terms would be $1.35 billion and $1.85 billion, respectively if Reliance Industries elects to keep the operating day rate fixed for the full 10 years and does not terminate the contract early.

If Reliance Industries extends the contract to 10 years, then it may have the operating day rate for the second 5 years fluctuate based on crude prices. The operating day rate for the second 5 years would not be adjusted if crude is priced at $75/bbl but would be raised on a straightline basis if crude is then priced between $75-100/bbl, with a maximum 10% increase if crude is at or above $100/bbl. It would be lowered on a straightline basis if crude is selling at $50-75/bbl, with a maximum 10% reduction if crude is priced below $50/bbl at that time.

Reliance Industries retains the right to terminate the contract for convenience. But the termination mechanism is designed to keep Transocean economically whole for the remaining term of the contract.

The proposed rig will feature Transocean's patented dual-activity drilling technology, allowing for parallel drilling operations designed to save time and money in deepwater well construction. It will have a variable deckload of 20,000 metric tons, and the capability of drilling in 10,000 ft of water depth, up to a water depth of 12,000 ft, and a total drilling depth of 40,000 ft with additional equipment. ✦

Processing — *Quick Takes*

Iran starts $1.2 billion Sri Lanka refinery upgrade

Iranian President Mahmoud Ahmadinejad launched a $1.2 billion project to upgrade Sri Lanka's sole refinery at Sapugaskande, outside Colombo, the island nation's capital.

Sri Lanka's petroleum minister A.H.M. Fowzie said the 4-year upgrade will triple his country's refinery capacity to 150,000 b/d from the current 50,000 b/d. Earlier plans had called for an increase to 100,000 b/d.

Iran, which supplies 70% of Sri Lanka's oil needs, agreed to finance $700 million of the upgrade in the form of a 10-year loan, with a 5-year exemption period from payment of the loan's installments. Sri Lanka will provide the remaining $500,000 for the project.

In March, Saudi Arabia expressed its willingness to assist Sri Lanka with its oil needs—including the Sapugaskande refinery—following a meeting in Riyadh between Fowsie and his Saudi counterpart, oil minister Ali al-Naimi.

"We have plans to improve our refining capacity from 50,000 b/d to 100,000 b/d and getting Saudi expertise for the proposed expansion will facilitate the successful implementation of the project," said Fowzie.

The Sri Lankan minister added that his country also needed a cracker to convert crude oil into diesel and gasoline which would cost the government some $400 million. He asked the Saudi oil minister to request funds from the Organization of Petroleum Exporting Countries to enable Sri Lanka to purchase the facility.

The importance of the refinery upgrade was underlined in January when Sri Lanka, which has to import all of its oil needs, saw its trade deficit double to $610.8 million as higher oil import costs exceeded export gains.

Sri Lanka bought $302.1 million worth of oil in January, when the island's sole refinery shut down for upkeep work, compared to $54.2 million a year earlier.

In February, the Sri Lankan central bank said the country's trade deficit widened to $3.56 billion in 2007 from $3.37 billion in 2006 due to the high cost of importing petroleum products. It said the country's oil import bill stood at $2.49 billion for 2007, a 20.6% increase over the cost of imports in 2006.

Gulf Petroleum gets nod for Malaysian complex

Qatar's privately held Gulf Petroleum Ltd. won regulatory approval from the Malaysian government to develop a $5 billion oil and petrochemical complex on a 1,000-hectare site in the northern state of Perak, according to state media.

Malaysia's Bernama news agency said the International Trade and Industry Ministry approved the request by Gulf Petroleum, which seeks to build a complex encompassing a refinery, a petrochemicals plant, and storage facilities.

Gulf Petroleum, which wants the proposed facility to serve as a regional hub for Asia-Pacific, plans to invest $1.5-2 billion in the project's first phase—a refinery with a capacity of 100,000 b/d-150,000 b/d.

The Qatar firm foresees further large investments for additional phases of the project: $1.5-2 billion for the petrochemical plant and about $1 billion for the storage facilities.

Gulf Petroleum said at least two Middle East national companies also will participate in the project, along with major energy, banking, and insurance groups from Qatar, Saudi Arabia, Kuwait, Oman, Bahrain, the UAE, and Egypt.

It is not clear if Gulf Petroleum's proposed Perak complex would connect with the bigger transpeninsular pipeline and related refinery projects announced by Malaysia last year (OGJ Online, May 4, 2007).

The transpeninsular pipeline, intended as an alternative transport route to the busy Straits of Malacca, will cross the states of Kedah, Perak, and Kelantan to carry oil from West Asia to East Asia. ✦

Transportation — *Quick Takes*

Italy gives environmental approval for LNG terminal

Italy's environment ministry has approved plans by Compagnie Industriali Riunite SPA's energy unit Sorgenia SPA and northwest utility Iride SPA for construction of an LNG terminal at Gioia in Calabria.

The two firms have a 70% controlling stake in the Gioia Tauro plant, which will have a regasification capacity of 12 billion cu m/year. The proposed terminal is due on stream in 2013 pending approval by other Italian government authorities.

Meanwhile, Sorgenia is considering construction of an 8-12 billion cu m/year regasification terminal at Trinitapoli in southern Italy—one of several LNG projects in the planning stages or before Italian environmental authorities.

In February, Snam Rete Gas SPA CEO Carlo Malacarne said the firm plans to build a pipeline linking the country's transmission system to an 8 billion cu m /year LNG receiving terminal near the northeastern port of Trieste to be built by Spain's Gas Natural SA.

Malacarne also said Snam Rete Gas plans to boost the annual capacity of its Panigaglia LNG terminal in northwest Italy to 8 billion cu m from the current 3.5 billion cu m. Construction is due to start at yearend 2010, after receipt of necessary permits.

Also in February, however, BG Group PLC said the Italian environment ministry had requested more information regarding the group's application for environmental clearance to build an LNG terminal at Brindisi (OGJ, Nov. 12, 2007, Newsletter).

Ministry Director General Bruno Agricola said BG's environmental impact assessment (EIA), delivered on Jan. 15, did not contain any assessment of risk factors regarding a possible industrial accident.

Even if BG's environmental problems are resolved, Agricola said Italy's national gas grid operator Snam Rete Gas SPA does not have enough capacity to transport the gas from more than one LNG terminal in the area.

Last October the Italian government suspended BG's permits to build the facility until BG completed the new EIA report. The Brindisi project was scheduled to start up in 2010 but the firm now thinks that target could be "challenging."

Qatar, Dutch firms to jointly upgrade energy ports

State-owned Qatar Petroleum and Dutch port operator Havenbedrijf Rotterdam NV have signed a long-term agreement on strategy and development in port management.

QP said it wants to develop its port at Ras Laffan to the highest international standards, while Havenbedrijf wants to strengthen its position as Europe's main energy port, especially for LNG and associated hydrocarbons.

The cooperation was laid out in a memorandum of understanding during a visit of Qatar's Prime Minister Sheikh Hamad bin Jassim bin Jabr al-Thani to the Netherlands.

The sheikh's visit followed a visit days earlier by Algerian officials who expressed interest in developing an LNG terminal at Maasvlakte, near Rotterdam, along with storage facilities for LNG.

The Dutch government said it will send a delegation to Algeria in the autumn for further discussion of the project.

The meetings underline new policy developments concerning energy in The Netherlands, which is said to be shifting its natural gas policy toward increased imports in an effort to retain its declining reserves, Europe's second-largest after Norway's.

In that new policy, the Dutch government put forward legislation in February to fast-track procedures for large energy infrastructure projects, including LNG installations, along the Rotterdam-Amsterdam corridor as well as around the Port of Eemshaven.

Rockies gas pipeline open season to start

Alliance Pipeline Inc. and Questar Overthrust Pipeline Co. plan to launch a binding open season May 12 to assess interest in shipping natural gas on the companies' proposed Rockies Alliance Pipeline.

They have altered the planned route. Based on discussions with shippers, the proposed route now runs from Wamsutter, Wyo., to Ventura, Iowa. The initial route when the pipeline was announced Mar. 25, 2008, was from Wamsutter to the US-Canada border at the northwest corner of Minnesota.

As reproposed, Rockies Alliance will be a 900-mile, 42-in., 1.2 bcfd system expandable to 1.8 bcfd. The open season ends June 16.

Rockies Alliance would allow shippers to transport gas from the Greater Green River, Piceance, and Powder River basins to Midwestern and eastern markets. It would connect with Alliance Pipeline and Northern Natural Gas at Ventura.

Questar said its Overthrust pipeline can be expanded at low cost to connect multiple receipt points between Opal, Wyo., and Wamsutter. In a separate open season, Overthrust Pipeline is proposing to add as much as 1 bcfd of incremental capacity from Opal to Wamsutter and construct the proposed new White River lateral from the White River hub at Meeker, Colo., in the Piceance basin, to Wamsutter.

With minor modifications, Alliance can enhance downstream capacity on its system, which connects to the Guardian, Vector, Peoples, Nicor, ANR, NGPL, and Midwestern systems.

Rockies Alliance would compete with TransCanada's proposed Pathfinder pipeline from Wamsutter to a connection with Northern Border in North Dakota (OGJ, Apr. 18, 2008, Newsletter).

Subject to obtaining shipper commitments and regulatory approvals, Rockies Alliance could be in service as early as third-quarter 2011. ✦

Letters

Decline rates?

There has been an abundance of studies and letters to the editor on oil decline rates in recent weeks. The latest article, based on a report from the International Energy Agency, was motivated because "failure since 2004 of non-OPEC production to achieve predicted output gains has created the impression that decline rates are accelerating (OGJ, Apr. 7, 2008, p. 34)." IEA studied hundreds of oil fields in decline and concluded that the net decline rate is 4-5%/year. In February, Cambridge Energy Research Associates presented the results of a decline study of 811 fields and came up with an average global decline rate of 4.5%/year. The key conclusion was that "there is no evidence that oil field decline rates will increase suddenly." They claimed the study had filled in the missing link! The Uppsala Hydrocarbon Depletion Group studied 333 giant oil fields and came up with an average of 4.5%/year.

As the IEA report states, the fields selected had to be in sustained decline for at least 12-18 months. This is a general condition to apply the standard hyperbolic decline algorithms to wells, reservoirs, and fields. What if crude oil production has been flat, as has been the case worldwide since 2004? The decline rate is zero, according to the typical decline approximation normally used: $(q_i - q)/q$, where q_i and q are the production rates during the interval (year) of interest. But it's a simple fact that the reserves continue to be depleted at a higher rate than if the production had dropped over the interval. The proper definition for aggregate decline rate must replace the production rates with the cumulative production values over the interval. In the case of the US, the approximation (using production rates) gives an annual decline rate estimate of 2%, whereas the proper rate is less than 1%. Worldwide, the aggregate decline rate is 2.5%/year. Physically, the decline rate declines linearly with depletion—it never increases—and much less suddenly (Sandrea, OGJ, May 22, 2006, p. 30).

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President
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Tulsa

C a l e n d a r

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

OIL&GAS JOURNAL online

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

2008

MAY

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

Oil and Gas Pipelines in the Middle East Conference, Abu Dhabi, +44 (0) 1242 529 090, e-mail: c.pallen@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/mepipes8/mepipes8register.html. 12-14.

GPA Houston Midstream Conference, Houston, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 13-14.

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

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

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

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

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

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

Calendar

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

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

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

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

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

The CIS Oil and Gas Summit, Paris, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: l.hannant@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/summit8/summit8register.html. 28-30.

JUNE

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Russia and CIS Oil & Gas Investment and Finance Forum, London, +44 (0)20 7878 6888, website: www.C5-Online.com/OilGasFinance. 16-17.

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

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

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

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

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

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

✦Purvin & Gertz Annual Asia LPG Seminar, Singapore, (713) 331-4000, (713) 236-8490 (fax), e-mail: glrodriguez@purvingertz.com, website: www.purvingertz.com. 23-26.

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

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

Russian Petroleum & Gas Congress, Moscow, +44 207 596 5016, e-mail: oilgas@

ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

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

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

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

Russian Oil and Gas Exports International Forum, Amsterdam, +44 (0)20 7878 6888, website: www.C5-Online.com/OilGasExport. 26-27.

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

JULY

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

Annual Rocky Mountain Natural Gas Strategy Conference & Investment Forum, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: conference@coga.org, website: www.coga.org. 9-11.

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

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

AUGUST

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

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

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

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

SEPTEMBER

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

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

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

Rocky Mountain GPA Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), email: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 10.

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

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

Poll wants government action

Sam Fletcher
Senior Writer

World Public Opinion.org, an international collaborative internet project to "give voice to public opinion" on international issues, released the results of a recent poll that claimed, "Majorities in 15 of 16 nations surveyed around the world think that oil is running out and governments should make a major effort to find new sources of energy."

Governments should find new energy sources? A statement like that is enough to bring tears to the glass eye of a practicing capitalist. When did a government official, especially one elected to office, ever bring a single btu to the energy market? Even in those countries where the dominant oil company is still owned by the state, energy resources are discovered and developed by geologists and engineers. Lack of fiscal autonomy has constrained production and increased the financial leverage of state-run companies like Petroleos Mexicanos. Venezuela's production dropped sharply as President Hugo Chavez restructured participation by Western companies and squeezed cash out of Petroleos de Venezuela SA to fund social programs. Even the biggest oil producing countries in the Middle East are looking for outside investors to fund exploration and development.

Upfront investment costs are high for any energy project, with a long wait for a payoff. At the Offshore Technology Conference in Houston, Matthew Simmons, chairman of Simmons & Co. International, said the oil and gas industry will need to invest $50-100 trillion to rebuild its ageing infrastructure within the next 7 years (see OTC, p. 20). During the last boom in the 1970s, the US government underwrote financing for experiments in turning coal into methane gas. The sole commercial result was the massive Great Plains Coal Gasification Plant in Beulah, ND. When the government lifted price controls on natural gas, large gas supplies returned to the market, and it had to buy back the plant at pennies on the dollar. The US government also had to buy back many of the offshore rigs that it helped finance in that period. It could have been worse, however. Some government employee in the last energy boom floated the suggestion that the US government drill all of its offshore leases to determine how much oil and gas were there to be sure the government was getting a fair return when it sells those leases to private producers.

Poll findings

According to the poll, "A majority in the US (57%), the world's biggest consumer of oil, believes their government is acting on the assumption that oil can remain a primary source of energy. This is also true in Nigeria (63%). However, while most Americans believe their governments' assumptions are incorrect, most Nigerians think it is correct." Guess it depends on the time frame in which oil can remain a primary energy source. Two years after the first oil well was drilled in 1859, an employee at the US Geological Survey announced that all the oil in the world had by then been discovered. People have been making wrong predictions about the end of oil ever since.

Respondents in 12 of the 16 nations polled said the various governments assume oil is running out and needs to be replaced. "This is especially true in South Korea (79%), China (70%), and Egypt (67%). In Iran, which is developing a controversial nuclear energy program, 63% say that oil must be replaced, while only 12%—the lowest percentage among the countries polled—say their government assumes enough oil can be found," said the report. Azerbaijanis, by a margin of 50% to 31%, say their government assumes enough oil will be found. Russians are divided: 37% think their government assumes there will be enough oil and 34% do not.

"In 4 of 5 countries that are net oil exporters," the report said, "the perception that their government is planning for oil running out is below the average of 53%. These include Azerbaijan (31%), Nigeria (32%), Russia (34%), and Mexico (49%). The exception is Iran, which is well above the average, with 63% believing that their government is planning for oil running out."

Some 15,000 people were polled in 16 nations representing 58% of world population. These included China, India, the US, Indonesia, Nigeria, Russia, Mexico, Iran, the UK, France, Azerbaijan, Ukraine, Egypt, Turkey, South Korea and "the Palestinian Territories." World Public Opinion.org is managed by the Program on International Policy Attitudes at the University of Maryland. ✦

Editorial

Those oil subsidies

To hear some US politicians tell the story, "Big Oil" soaks up much of the national wealth through "subsidies." In a period of wildly elevated oil and gas prices and consequently high profits of major oil companies, the story sounds scandalous indeed. This scandal, though, doesn't bear up to facts.

Oil companies in the US do receive federal benefits that qualify as subsidies. But they're not as large as they're reputed to be. Most such help goes to small producers, not the integrated companies connoted by the expression "Big Oil." And oil subsidies, as a new analysis by the Energy Information Administration makes clear, are smaller than those available for energy forms yielding much less supply.

The nonsubsidy subsidy

In current discussions, the phrase "oil subsidies" frequently attaches without a time reference to the number "$18 billion" to imply an annual benefit unique to oil. In fact, the number represents the sum of the estimated value over 10 years of two general tax breaks that a bill passed by the House would deny large oil companies.

The larger of the two, the "Section 199" tax credit passed in 2005, encourages investment by all US manufacturers while tax rates on non-US competitors are falling. Denial of the Section 199 would cost oil companies $14 billion over a decade and hamper their ability to compete with companies in other industries for capital. The other provision, relating to treatment of foreign tax payments, also would deny oil companies a benefit available to others. Neither of these provisions, because of their general applicability, can be called an oil subsidy.

According to EIA, federal provisions more properly considered oil and gas subsidies amounted in 2007 to $2.149 billion. Energy categories receiving larger subsidy totals last year were renewables, $4.875 billion; end uses, $2.828 billion; and refined, or chemically enhanced, coal, $2.37 billion. Each of the categories with greater subsidies represents a fraction of the total energy supplied by oil and gas. Receiving less total subsidies than oil and gas last year were coal, $932 million; nuclear, $1.267 billion; electricity unrelated to fuel, $1.235 billion; and conservation, $926 million.

Of the 2007 oil and gas subsidies, nearly all, $2.09 billion, took the form of tax measures. The small remainder was research and development funding and federal electricity support.

Two oil and gas tax measures dominated: expensing of exploration and development costs (E&D; mostly intangible drilling costs, or IDCs) and the excess of percentage over cost depletion. Both are tax deferrals, as opposed to credits or deductions, which are much more valuable subsidies.

The recent history of IDC expensing shows why the "deferral" distinction is important. The alternative to expensing is writing down costs from a capital account year by year. With expensing, the producer can deduct costs for tax purposes in the year they're incurred. Then, however, no write-down is available for that property in later years. The advantage is timing of the tax payment rather than escape from the liability.

EIA points out that in most years during the drilling slump of 1987-99 the government's revenue losses were negative. "The negative values imply a payment to the federal government of funds that it had loaned (tax deferrals), mostly to oil companies, in earlier periods," it explains. No one then complained about subsidies.

Distorting discourse

EIA estimates the value of IDC expensing last year at $860 million. Integrated companies can charge only 70% of their IDCs to expense and must write down the remainder over 5 years. The benefit of percentage vs. cost depletion, worth a total of $790 billion last year, is available only to small independent producers and is limited even to them. The next largest subsidy in the oil and gas category, and the only nondeferral type, is $260 million and doesn't go to oil and gas companies. It's a package of credits and deductions for clean-fuel vehicles.

The perspective available from EIA's report won't stop politicians from braying about oil subsidies, of course. It does, however, show how opportunistic falsehood distorts energy discourse in an election year. ✦

OTC speakers highlight offshore industry's future

This report was reported and written by Paula Dittrick, senior staff writer, and Uchenna Izundu, international editor.

The oil and gas industry continues to develop new technologies and adapt others to keep pace with the rising need worldwide for energy. Diversified energy supplies, energy security, market uncertainty, and the recent strength of oil and gas prices all have played a part in fueling these "Waves of Change"—the theme of the Offshore Technology Conference in Houston May 5-8.

Industry continues to search for resources in deeper waters, speakers at OTC said. The Gulf of Mexico's deep water (to 400 m) and ultradeep water (deeper than 1,600 m) continue to be a vital part of the gulf's total production, providing about 72% of the oil and 38% of the gas in the region, said the US Minerals Management Service in a report released May 6 at OTC.

At the end of 2007, there were 130 producing projects in the deepwater

gulf, up from 122 at the end of 2006, said Lars Herbst, MMS regional director for the gulf's Outer Continental Shelf. Fifteen deepwater fields, including Atlantis, Shenzi, and several associated with Independence Hub, began production last year.

Production from the Independence Hub in the eastern Gulf of Mexico exceeded expectations in the quarter ended Mar. 31, averaging 841 MMcfd, said operator Anadarko Petroleum Corp. However, a leak from a stainless steel o-ring gasket located on the flex joint that connects an export pipeline to the platform in about 85 ft of water forced the shutdown of operations in April, pending repair. When Independence Hub reaches full capacity, Herbst said, it will represent more than 10% of the total gulf gas production.

Proved deepwater fields now number 125, representing a 44% increase from the end of 2006. For the first time in history, all 20 of the highest producing blocks in the gulf were in deep water.

Ultradeepwater activity

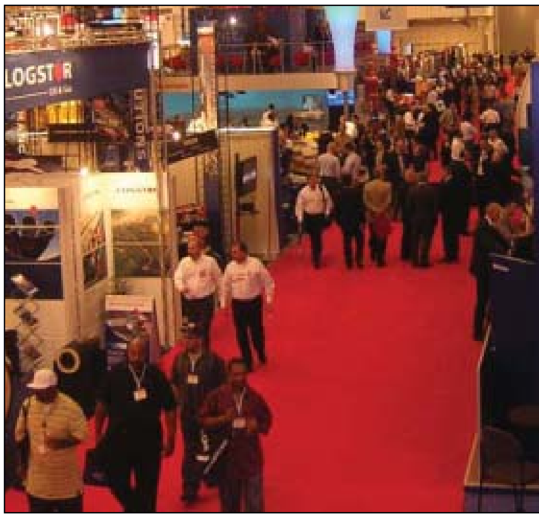
According to Randall Luthi, MMS director, more than a dozen new ultradeepwater rigs, capable of drilling in 12,000 ft of water, are expected to enter the gulf in the next few years. "Continued advancement into this deepwater frontier is important to our nation's energy security," Luthi said. "The Gulf of Mexico is a key energy producer, and the safe and environmentally responsible development of our resources is vital to the economy and our way of life."

In 2007, 54% of all gulf leases were in 1,000 ft of water or deeper, the report said. In the two lease sales that year, Western Gulf Lease Sale 204 and Central Gulf Lease Sale 205, nearly 70% of the tracts receiving bids were in deep water.

This year saw a record-setting lease offering in Central Gulf Sale 206, which attracted $3.7 billion in high bids—the largest sum since federal offshore leasing began in 1954 (OGJ Online, Mar. 19, 2008). About 67% of the blocks receiving bids were in deep water with about 34% in ultradeep water.

"As we look at the data, it's clear that deepwater advancement is occurring in all areas—leasing, drilling, and production," Luthi said. By yearend 2007, he said, there were 130 producing projects in deepwater, double the amount from 5 years ago.

Attendance at the 39th annual Offshore Technology Conference in Houston continued to show strength this year, as last week's conference at presstime was on pace to exceed last year's final tally of 67,155 attendees—a 25-year high—according to organizers.



Energy security

Energy security must incorporate social acceptance of technology, available diverse energy sources, and environmental sustainability, said speakers in a May 6 panel discussion at OTC.

Robert Fryklund, IHS Inc. vice-president of industry relations, said society in general, including the oil and gas industry, is working to achieve a balance between energy security and climate security. "Unfortunately, this puzzle has a couple missing pieces," Fryklund said, "There is a lot that we know, but there is a lot that we don't know. In the corporate world, we ask how much is it going to cost? As individuals, we ask how much more are we going to have to pay at the pump?"

Amy Jaffe of Rice University's Baker Institute, Houston, said the concept of energy security varies over time and geography. Europeans generally talk about natural gas when they discuss energy security while US citizens generally talk about gasoline. "So, different parts of the world are not even talking about the same commodity," Jaffe said.

The definition of energy security also changes with perceived threats to energy supplies. Such threats include political instability and civil unrest in some producing countries, severe storms, and work stoppages. "On top of that, we have to worry about a new producer climate. National oil companies feel empowered by oil supply shortages, and this will tempt them to flex their geopolitical muscle," Jaffe said.

Not all types of energy are well received, she added, noting that oil sands are perceived by some as being good for energy security but bad for climate security. Saying that she does not view energy security and climate security "as two sides of the same coin," Jaffe acknowledged "a growing sense of urgency about climate change and security of supply." New fuel efficiency standards will reduce US oil demand and emphasize greater fuel diversity, she said.

Trade offs will have to be made when determining the future energy mix, and Jeffe questioned whether many people yet realize the ramifications of such decisions. "If we move to greater use of natural gas, what is that going to mean for US energy security," she asked. "In a carbon-constrained scenario, LNG becomes quite more dramatic. It makes the US more dependent on imported LNG."

MMS view

MMS Director Luthi said environmental security needs to be considered along with energy security and climate security. "The price of gasoline is only part of our energy equation," Luthi said. "Without increased domestic production, imports will have to increase."

US energy production must be increased from all sources, including alternative and renewable energy, he said. "We do have to look at all possibilities: new sources of energy as well as more efficient use of existing sources," Luthi said. "It needs to be a worldwide effort. The US is a key part, but other emerging economies need to be a part as well."

Kevin Leahy, Duke Energy Corp.'s managing director for climate policy and economics, said climate change will rework the energy supply and distribution system in the US, particularly for transportation fuels. He said the power sector is going to drive carbon dioxide prices in a global carbon-trading scenario and natural gas prices, too.

Regarding the future role of hydrocarbons, Leahy said, "I could see where electrons would become energy carrier for wealthy countries, and liquid fuel would still provide the energy in countries with emerging economies."

Key considerations for expanding the role of clean energy involve more than cost, said Robert LaCount of Cambridge Energy Research Associates, Massachusetts. Other factors are scale, reliability, timing, integration, and unintended consequences. "When we look over the next couple decades, we would recommend keeping our eye on many different aspects" to see how acceptance of different energy sources develops, LaCount said.

International perspective

Fatih Birol, chief economist for the International Energy Agency, Paris, sees a "new world energy order" with some new actors coming into the picture, and some actors exiting.

China and India are transforming global energy markets, Birol said, adding those two countries are expected to contribute almost half of the increase in global energy and 60% of carbon dioxide emissions by 2030. China's oil imports are expected to reach 13 million b/d in 2030, and car ownership there is forecast to jump to 140 vehicles/1,000 people compared with 20 vehicles/1,000 people today.

"Carbon capture and storage would be good for energy security and climate security, but we are not yet there," Birol said.

Carbon dioxide

Both onshore and offshore sequestration options are under study to find large capacity storage for CO_2 emitted from the use of fossil fuels, said participants at another OTC panel. Sally M. Benson of Stanford University said improved understanding of multiphase flow and trapping in CO_2-brine systems is needed to predict the storage capacity of saline aquifers.

Daniel P. Schrag, a professor at Harvard University's Department of Earth and Planetary Sciences, believes deepsea sediments in 3,000 m of water could provide permanent offshore storage by gravitational trapping.

Sequestration of CO_2 would keep it out of the atmosphere, where it could contribute to global warming, scientists say. Benson is studying monitoring methods "to provide a quantitative assessment of the fate and transport of injected CO_2" over time. Physical and chemical properties of the storage reservoir and seal are key to the permanent containment of sequestered CO_2, she said.

Performance standards regarding leakage have yet to be established, Benson said. Detection methods include seismic monitoring and atmospheric flux monitoring. A recent experiment proved releases of sequestered CO_2 are detectable and can be measured. More testing is pending, she said.

The public demands a better understanding of what might happen to CO_2 injected into a saline aquifer, she said, calling monitoring a key element of any sequestration project. "This interest is driven in part by concerns about long-term stewardship and liability. After the injection phase of the project is completed, and the wells have been abandoned, there are unanswered questions," Benson said.

Benson said unanswered questions include:

- How long and how much monitoring is required?
- What can be done to stop a detected leak?

Schlumberger's ResInject injection control device is one of 14 technologies recognized in the OTC Spotlight on Technology (see story, p. 25). Photo from Schlumberger.

- Who is responsible for monitoring and potential remediation?
- Can long-term liability be transferred to a shared risk pool?
- Will state or federal governments assume long-term liability?

Offshore sequestration

Schrag is evaluating the potential for subsea CO_2 storage in deepsea sediments. "At high pressures and low-temperatures common in deepsea sediments a few hundred meters below sea floor, CO_2 will be in its liquid phase and will be denser than the overlying pore fluid," he said. "The lower density of the pore fluid provides a cap to the denser CO_2 and ensures gravitational trapping in the short term."

Thermal modeling and laboratory calculations show injected high-density liquid CO_2—combined with its potential to form CO_2 hydrates—will impede upward migration. Schrag has yet to do field tests on his calculations but is working with Shell Oil Co. to develop a system that could be field-tested. Schrag believes his proposed offshore sequestration will prove to be "essentially a leak-proof method."

Heavy oil

In an earlier OTC session, David Bairrington, general manger of nonconventional resources at ConocoPhillips, said water management in developing heavy oil resources is a bigger problem than handling carbon emissions. Bairrington told delegates May 5 his company uses 2.5 bbl of water and 1 Mcf of gas to obtain 1 bbl of bitumen when applying the steam-assisted gravity drainage process. About 30,000 b/d of production is typical under this method.

Production of heavy oil—touted as the future of the industry—produces a high volume of carbon emissions because of the intensive techniques required to develop it, and regulators are pressuring operators to reduce the emissions to address climate change. About 63% of the world's heavy oil resources is in North and South America. It is only within the last 5 years that its production has become economically viable, with heavy oil operators breaking even at a market price of $50-55/bbl for conventional oil.

Meanwhile, operators in Abathasca, Canada, report development costs have soared.

"It is a high cost resource from the production standpoint, so we're looking at using solvents to accelerate the viscosity," Bairrington said. Other upgrading options include thermal cracking, removing carbon, and hydrogen additions. "Carbon taxes and dealing with CO_2 emissions will be a burden to the

industry as a whole," he said, stressing that carbon capture is problematic.

Scale in developing unconventional petroleum resources is crucial in managing costs, said Timothy Parker, chief executive officer at HighMount Exploration & Production LLC. HighMount operates the Sonora field in West Texas, which has 20 tcf of gas originally in place. Parker criticized the industry for focusing on repeatability as a key success factor, stressing that this may not be the criteria for success in tomorrow's operating environment.

He said HighMount regularly carries out controlled experiments to identify areas where costs can be slashed and other improvements made. Compared with its peers, he said, the company has drilled identical wells for 70% of the cost others incur. HighMount has 15,000 development locations and plans an aggressive drilling program in the field to sustain gas production over the coming years.

Replacing equipment

The oil and gas industry will need to invest $50-100 trillion to rebuild its ageing infrastructure within the next 7 years to stave off a serious drop in oil and gas production, said Matt Simmons, chairman of Simmons & Co. International, May 5 at OTC. In a worst-case scenario, Simmons said, oil and gas output could fall by 10-20% by 2013 if industry does not replace its rusting, corroded assets. Spare capacity has run out because earlier cheap prices for oil and gas precluded upgrading and construction of new facilities.

The average age of offshore rigs is 25 years, and oil companies have not addressed the problem because of low energy prices during the past few decades. "The industry's tool kit for corrosion is old, and painting over rust creates an illusion. Few parts of oil infrastructure have been replaced," said Simmons. Leaks, stains, oil streaks, metal fatigue, and brittle steel are all signs of ageing pipelines, platforms, wells, and other assets.

However, the upward trend in prices can help pay for the rebuilding of the energy system, Simmons stated. Still, he said, "There is no blueprint in place, and this is a global problem. The longer the blueprint is postponed, the more acute the crisis will get."

The reconstruction problem is compounded by the shortage of skilled engineers to carry out the work and the scarcity of raw materials.

"Peak oil is a reality. In 2005 we had peak production and this fell by 265,000 b/d in 2007. There is a high likelihood that production will continue to fall," Simmons said. He forecast oil prices could hit $200/bbl as global demand increases. That same day in New York, Goldman Sachs Group Inc., the world's largest securities firm, predicted crude costs could escalate to $150-200/bbl within 2 years. The front-month price for benchmark US crudes soared past $120/bbl in intraday trading May 5, up from $62/bbl a year ago. On May 6, the intraday price hit a new high of $122.73/bbl before closing at a record $121.84/bbl.

Mexico

With subsalt plays and poor recovery efficiency for existing fields, Mexico needs improved oil recovery and innovative technology to extend the productive life of its reservoirs, said Mexican Petroleum Institute Chief Executive Heber Cinco Ley on May 5 at OTC. Operators are finding Mexico's fractured reservoirs challenging because they are difficult to characterize, model, and simulate. "We need a new generation of reservoir simulators," Ley said.

The country's oil and natural gas industry is crucial to its economy, accounting for 40% of Mexico's federal budget. But production is on the wane: oil output is 3.1 million b/d, and gas is 6 bcfd. Cantarell, Mexico's largest oil field, generates half of the output of state-owned oil company Petroleos Mexicanos (Pemex). Cantarell had been producing an average of 1.58 million b/d, but production began falling last November to 1.3 million b/d, and it is expected to drop to 600,000 b/d by 2013. Ley said the challenge with Cantarell is accessing oil that is trapped under the gas cap.

Onshore Chicontepec field will require $14.5 billion to develop. Pemex expects to drill 5,421 development wells in the field by 2012. Oil production is expected to hit 1 million b/d. However, according to Ley, Chicontepec has a primary recovery factor of only 5-7%.

Deep water will be the future source of oil production in Mexico, but expertise is needed in flow assurance, control pipelines, subsea systems, and other areas, Ley added. Pemex has assembled its first deepwater asset team, Coatzacoalcos, which hopes to produce 400 MMcfd of gas under a $40-70 billion investment program. The company also has contracted three semisubmersible drilling rigs for deepwater activity. Two of the rigs can drill in water as deep as 2,100 m, and the third can work in water 3,000 m deep.

Water management from producing reservoirs is another major challenge, as it takes 3 bbl of water to produce every barrel of oil, Ley added. "We need to predict this accurately, as it can affect hydrocarbon production. We need to develop efficient drilling at lower costs."

Angola

Angola has prequalified 40 oil companies under its latest licensing round, which lists 10 blocks as available, Syanga Abilio, vice-president of Sonangol, told OGJ in an exclusive interview May 6 at OTC. The qualified candidates include majors Royal Dutch Shell PLC and ExxonMobil Corp., independent oil companies, and private Angolan firms.

As so many Angolan companies have applied for licensing permits, the government needs more time to evaluate them, Abilio said. So the country has postponed the previous deadline for companies to submit proposals for blocks. "A new deadline has not yet been given, but we plan to announce that shortly," Abilio said.

About 200 companies participated in the licensing round, which offers both deepwater and ultradeepwater blocks. "We don't know what kind of interest the prequalified companies had in the blocks as they had not yet given us a plan for the ones that they wanted," Abilio said.

The government invited companies to bid for onshore blocks Cabinda Centro in the Cabinda Centra basin and KON11 and KON12 in the Kwanza basin. In shallow water, Block 9 was offered. Three blocks, 19, 20, and 21, are in deep water and Blocks 46, 47, and 48 are in ultradeep water.

Angola's recent admission into the Organization of Petroleum Exporting Countries should not dissuade potential investors from coming to the country, Abilio said. "We joined the institution that works to protect price, and it was important to be part of that; we were an observer at OPEC for a long time. We have a quota of 1.9 million b/d but that does not bind us on further exploration and production. We had our oil infrastructure destroyed during our civil war, and there is nothing to fear with future investment."

Sonangol aims to become a fully integrated petroleum company by 2010. It bought a 20% stake in Societe Ivoirienne de Raffinage's 64,000 b/d refinery at Vridi, Abidjan, in Ivory Coast. Abilio declined to give the value of the investment.

"We are also building a new refinery in Lobito, which will cost about $7 billion," he said, adding, "It will have a 200,000 b/d capacity and we may seek technical partners in the future. For now, we are doing the project by ourselves."

Sonangol originally planned to develop the refinery with China's Sinopec, but talks broke down last year following disagreement on what products the refinery would make. It will process heavy acidic oil (such as Kuito and Dalia) and have a high conversion with crude, vacuum, fluid cracking, and delayed coking units. Construction of the refinery will start by yearend and operations in 2010.

Nigeria

Nigeria is seeking $20-25 billion of private investment to build natural gas pipelines, processing plants, and other infrastructure under its gas master plan, which has just been approved by the federal council. The plan will help Nigeria become a major gas consumer and monetize its 182 tcf of proved gas reserves, said David Ige, group general manager at Nigeria National Petroleum Corp. Ige told OTC on May 6 the plan would help connect the resources to Nigeria's domestic and export markets.

"The US Geological Survey puts undiscovered reserves at 600 tcf, and our gas reserves are those found so far in exploring for oil. We have not had any gas exploration program on its own," Ige added. "The commercial framework and the lack of infrastructure have made it difficult to bring the resources to market."

The plan anticipates an aggressive demand increase of 20-25% in the midterm because of domestic projects such as methanol plants, gas-to-liquids plants, fertilizer plants, independent power projects, and other LNG export plants such as Brass LNG.

Nigeria aims to have a market-driven gas sector by 2014 where the domestic and export market will come together, Ige said. "We did the mistake with oil where exports were preferred over the domestic market and we don't want to make that mistake with gas." President Umaru Yar'Adua has called on companies to set aside gas production for local use and Ige told OGJ that the new domestic market supply obligation launched in February would see 1 bcfd of natural gas directed to consumers in Nigeria. This would rise to 4-5 bcfd over the next 5 years.

By January 2011, Nigeria hopes to see a commercial domestic market and commercial pricing for gas to power. By January 2013, it expects to have a GTL market. Nigeria will give presentations in May in Abuja, London, and Singapore to provide more details on how investors can become involved in its gas development. ✦

OTC Spotlight on Technology recognizes 14 technologies

Nina M. Rach
Drilling Editor

Guntis Moritis
Production Editor

The Offshore Technology Conference of 2008 recognized 14 diverse technologies in its Spotlight on New Technology Awards. The award program, which began in 2004, highlights new technologies in offshore drilling and production.

This year OTC recognized:

- ABB AS for its wireless vibration sensor.
- Baker Hughes Inc.-Baker Oil Tools for its RAM rotatable, self-aligning, multilateral system.
- Baker Hughes-INTEQ for the MagTrak logging-while-drilling (LWD) tool.
- Cubility AS for its MudCube drilling fluid-cleaning system.
- Delmar Systems Inc. for the OMNI-Max anchor for deepwater mobile offshore drilling unit (MODU) mooring.
- Expro International Group PLC for the ViewMax sideview camera.
- FMC Technologies Inc. for

its enhanced vertical deepwater tree (EVDT).

- Schlumberger Ltd. for FUTUR active-set cement technology.
- Schlumberger for ResInject injection control device.
- Versabar Inc. for the "Bottom Feeder" heavy-lift system.
- Weatherford International Ltd. for its MetalSkin monobore openhole liner system.
- Weatherford for the motorized cutting tool (MCT).
- Welltec AS for the Well Miller reverse circulating bit.
- Yantai Raffles Shipyard Ltd. for the Taisun 20,000-tonne gantry crane.

To be considered, each technology had to be less than 2 years old, be proven through full-scale application or successful prototype testing, have broad interest and appeal, and provide significant benefits beyond existing technologies.

AC motor monitoring

ABB received an award for its microelectromechanical system (MEMS) accelerometer for wireless vibration measurements on AC motors.

The wireless vibration sensor is a small, autonomous sensor mounted on a motor close to a bearing. The unit has a vibration sensor (accelerometer), a temperature sensor, and provides wireless communication to a central computer for data analysis and storage.

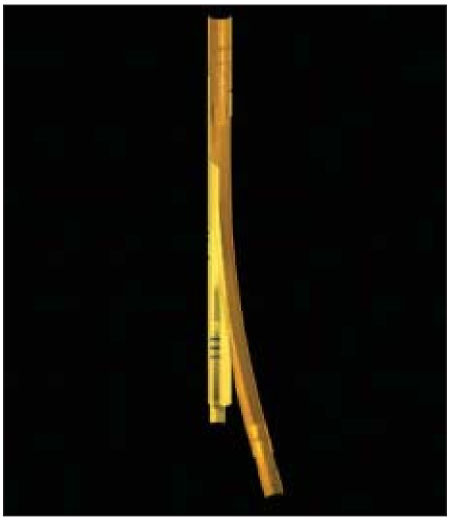
The prototype sensor is cylindrical with a diameter of less than 1.5 in. and a height of less than 4 in. ABB says the frequency response is ideal for early detection of bearing failures. The sensor uses the Wireless HART standard for transferring data.

ABB developed the sensor prototype together with SKF and SINTEF under a program sponsored by the Research Council of Norway.

Deepwater tree

FMC Technologies was recognized for its EVDT, which is a slimbore, vertical subsea completion system. The EVDT accommodates 7-in. tubing completions in a 13⅝-in. BOP stack, and is tested to 15,000 psi. It can be installed in ultradeep water using a small rig.

The EVDT system includes an ROV tree cap, subsea tree, retrievable flow module and flow meter, and tubing hangar. The tubing hangar can be installed with or without a tubing head.



Baker Hughes Inc.-Baker Oil Tools' RAM system was among 14 technologies that received recognition at the OTC Spotlight on Technology. Photo from Baker Oil Tools.

Shell has adopted the EVDT as its global standard (OGJ, May 5, 2008, p. 53).

Liners, multilaterals

Two awards went to liners and multilaterals.

Baker Oil Tools was recognized for its RAM system, the first and only system that allows continuous rotation of a lateral liner while landing a completion system.

The RAM system is based on the HOOK hangar platform and can deliver multilateral junctions for Level 3 and Level 5 completions. The RAM system can support, control, and access all lateral junctions joining cased and cemented main bores with screened or lined openhole laterals.

Baker developed and tested the system with an IOC and first installed it on Alaska's North Slope in 2007.

Weatherford received an award for the MetalSkin liner that allows the drilling of larger boreholes.

Setting the liner requires the running of an oversized shoe with the 13⅜-in. casing string. After the next hole section is drilled, the completion involves running the expandable liner and expanding it back into the oversized shoe. This provides an expanded casing string with the same drift as the 13⅜-in. casing; thereby, adding casing without losing hole size.

The design provides a full bore in the overlap between the monobore openhole liner and the 13⅜-in. casing string.

Drilling tools, fluids

Three awards went to drilling tools and fluids.

Welltec was recognized for its Well Miller bit, characterized as a "tunnel power drill" used to mill out hard materials, retrieve them to surface, in order to reestablish flow in well bores using E-line intervention without need for a rig.

The bit works in conjunction with the Well Tractor, which provides WOB and controls the reactive torque. The tool includes a basic rotational unit (pressure compensator, electric motor), which drives an impeller that creates a vacuum flow that drags sand into intake holes, tapping it in sand trap bailers. Different numbers of bailer sections can be mounted, depending on the tool configuration.

INTEQ was recognized for its MagTrak LWD tool, which does not require a radioactive source.

MagTrak provides magnetic resonance data to determine formation porosity (independent of lithology), bound and free fluid volumes, permeability, hydrocarbon detection, and T1-T2 distribution spectrums (T2 in real-time).

The LWD service is combinable with rotary steerable systems and is available as a 6¾-in. collar-based tool for use in borehole diameters from 8⅜-in to 9⅞-in.

Cubility was recognized for its MudCube system. MudCube is a closed, under-pressured system that produces low noise and vibration and emits no gas or oil vapor.

Fluid enters a continuous, rotating screen belt with a vacuum beneath the screen. Solids remain atop the screen, fall off the end as a dry mass, and the screen cleaned with an air knife. Fluid is vacuumed through screen apertures and enters a closed-loop system. The fluid is degassed and evacuated or vented.

The MudCube system was tested at the StatoilHydro-Cubility test center.

Downhole tools

Two awards went to downhole tools.

Expro was recognized for its downhole tool incorporating the ViewMax sideview camera for inspecting conditions downhole, such as suspected casing failures.

The tool allows an operator to switch between a downview camera and the new side camera. The operator can also rotate the tool 360° to provide a circumferential view of the pipe or look ahead.

Operators can run the tool on both fiber optic wireline or on conventional electric line. Clear fluid is still a prerequisite for optimum viewing.

The tool has a 12.4-ft length, 2⅛-in. diameter and weighs 65 lb. It is rated for 257° F. and 10,000 psi.

Weatherford was recognized for its MCT, which allows multiple cuts through tubing.

Weatherford says the tool cuts downhole tubulars without needing chemicals or explosives and facilitates fishing by displacing tubing cleanly, whether in tension or compression, with no flaring and no debris left in the well.

The tool allows rigless interventions and is operated on an electric line for depth control.

Downhole cement, injection

Two awards, both to Schlumberger, went to downhole cement and injection technologies.

Schlumberger was awarded for its FUTUR technology, which can automatically self-heal in the presence of hydrocarbon leaks. FUTUR is used as an additional isolation barrier above the reservoir and reacts to applied stress when the cement sheath is damaged.

It has been used to prevent sustained casing pressure, to mitigate surface casing vent flow and gas migration, and to contain leaks and enhance zonal isolation in underground gas storage wells.

Schlumberger also received an award for its ResInject device for distributing injection fluids along an entire wellbore section, such as long

laterals in horizontal wells.

The device is a sister tool of the ResFlow device for production wells although the injection device has a different nozzle configuration to avoid erosion. The ceramic nozzles in the injection device form a ring around the base pipe directing fluid flow longitudinally to the base pipe of the wire-wrapped sand-screen.

By including different nozzle sizes, an operator can have low-permeability zones receive more injection fluid.

Mooring, lifting

Three awards went to mooring and lifting technologies.

Delmar Systems was recognized for its OMNI-Max anchor, a gravity-installed, vertically-loaded anchor for deepwater MODU mooring.

The OMNI-Max can be loaded in any direction and the load angle can change without adversely affecting its foundation capacity. This could be a critical factor in station-keeping in the event of multiple line failure.

The first OMNI-Max anchor used in this industry was installed in December 2007 in the Gulf of Mexico.

Versabar was recognized for its Bottom Feeder, a new heavy-lift system designed, built, and operated by Versabar affiliate Versabuild for retrieving hurricane-toppled platform topsides from the seabed (OGJ, May 4, 2008, p. 70).

Each of the six eight-leg topsides retrieved to date by the system was in a single lift with peak lift weights of up to 1,600 tons. Cargo barges hauled the retrieved topsides ashore for scrapping.

The system has a rated lifting capacity of 4,000 tons and includes four independent lift blocks that provide control during the lifting of large unbalanced structures for which accurate weight data is unavailable.

Yantai Raffles received an award for its Taisun crane, which is designed to sit across a 380 m by 120 m dry dock.

The crane has two fixed beams placed horizontally across the dock floor on four columns. Spanning an overall length of 120 m, the beams, with lifting capacity of 10,000 tonnes each, are at 89 m and 119 m heights and have 83 m and 113 m lifting height.

The shipyard installation of 96 lifting devices will enable the mating of an entire outfitted deck box of a semi-submersible rig onto its hull-pontoons in one step, reducing work hazards at high heights and in the open sea. Yantai Raffles says the 1-day mating process, compared to conventional methods, will reduce both risks and time while improving quality. ✦

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House diesel price hearing targets market speculators

Nick Snow
Washington Editor

A US House subcommittee's hearing to examine the adverse impacts of rising diesel fuel prices on truckers became the latest forum for Democrats to demand crackdowns on oil market speculators and Republicans to call for expanded access to remaining domestic resources.

Members of the House Transportation and Infrastructure Committee's Highways and Transit Subcommittee generally agreed that diesel prices have risen faster than gasoline prices, and that increases are reflected in higher food and merchandise costs. But they broke along party lines in suggesting ways to address the problem.

"The conventional wisdom is that speculation provides liquidity to the market. But when you have a huge entry of people who have no intention of taking delivery of a commodity but are merely interested in making money by bidding prices higher, that's a different matter," Rep. Peter A. DeFazio (D-Ore.), the subcommittee's chairman, said in his opening statement.

The hearing's stated purpose was to discuss fuel surcharges that many motor carriers, independent drivers, and fuel brokers have imposed in response to higher diesel prices. DeFazio has introduced a bill, the Trust in Reliable Understanding of Consumer Costs (TRUCC) Act, which would require that fuel surcharges be passed on to the persons who actually buy the fuel, and to disclose that surcharge and other charges in writing.

But DeFazio decided to set the stage for this discussion with an examination of possible causes for recent dramatic increases in oil and product prices. Oil industry executives who have appeared before other congressional committees have said that supply and demand account for only part of the soaring prices, the subcommittee chairman told the first panel of witnesses.

Oversight weakened

US energy commodity market oversight was seriously weakened with passage of the 2000 Commodity Futures Modernization Act, which set the stage for speculators to take large positions and push prices up, DeFazio said. The housing market collapse and declining dollar has pushed more traders into energy commodities and prices have climbed, he said.

But two of the three witnesses said growing oil demand in a market with dwindling surplus production capacity has had a bigger impact. "This week, refiners were paying as much as $2.86 for the gallon of crude oil they need to make a gallon of gasoline or diesel. That's most of the price at the pump. When you add about 74¢ in gasoline taxes (or almost 54¢ in diesel taxes) to each gallon, you've accounted for the vast majority of what people are paying," said American Petroleum Institute Chief Economist John C. Felmy.

Felmy said while overall US petroleum demand, including demand for gasoline, has flattened, demand for diesel has remained strong, continuing a long-term trend both globally and domestically. "Demand for diesel has remained strong in the face of higher prices at the pump in large part because its use is less discretionary," Felmy testified. "Consumption is mostly business-related. Fuel is an indispensable cost component and just one of the costs in the manufacturing-distribution chain. Also, keep in mind that, unlike Europe, taxes on diesel in the US are higher than on gasoline, and the new ultralow-sulfur diesel formulations cost more to produce too," he said.

Ryan Todd, an oil analyst who covers major US oil companies and independent refiners for Deutsche Bank Securities Inc. in New York, suggested that continued congressional efforts to blame high crude and product prices on speculators diverts attention from the real cause. "The problem with conspiracy theories or talk of price gouging is that it gives the oil companies far more control than they actually have. Certainly, during the recent run in crude oil and gasoline prices, the oil companies have become much more price takers than price makers," Todd said.

Trying to catch up

Decades of low returns and underinvestment during the 1980s and 1990s when oil prices were lower has made it necessary for the industry to try and catch up, both in terms of resources under development and qualified personnel, Todd said. "Higher prices, rather than increasing supply, have actually constrained it. While new unconventional sources have become economic, resource nationalism around the globe has restricted international oil company access to less than 20% of the world's reserves. Rising fiscal takes, including the US, have driven up the cost of doing business or eliminated access altogether in some cases. An incredibly tight global service and construction industry has further exaggerated the cost and time of doing business," Todd said.

But Tyson Slocum, energy program director at the consumer advocacy group Public Citizen, agreed with DeFazio that speculators are exerting an unhealthy influence on energy commodity markets. "A certain amount of speculation or hedging is essential. But we have a financial bubble resulting from too much speculation. About 95% of the trades today do not involve taking delivery," he said.

Slocum said other parts of the federal government have not upheld their responsibilities, including the Federal Trade Commission, which he said allowed oil companies to merge and restrain growth in refining capacity. "In just the last few years, mergers between giant oil companies such as Exxon and Mobil, Chevron and Texaco, and Conoco and Phillips, have resulted in just a few companies controlling a significant amount of America's gasoline, squelching competition," he said in his written statement.

Recent record oil company profits justify reimposition of a windfall profits tax, particularly since several of those companies spend more money buying back stock than increasing exploration and production or refining capacity, Slocum said. The levy that existed from 1980 through 1988 was ineffective not because of the tax itself but because oil prices fell shortly after it was enacted, he said.

Felmy and Todd disagreed. The windfall levy of the 1980s simply reduced domestic supplies and increased imports, Felmy said. "Siphoning away earnings from the industry for new tax schemes won't help address the current market situation. It won't increase investments, it won't produce more supply and it won't help consumers. It will hurt oil and natural gas com-

FTC starts process to consider rule on oil market manipulation

Nick Snow
Washington Editor

Using authority it received in energy legislation late last year, the US Federal Trade Commission on May 1 took the first step to determine whether it should develop a formal rule defining and prohibiting oil market manipulation.

The commission announced that it has approved an advanced notice of proposed rulemaking (ANPR) to seek public comments on the appropriate way to interpret and enforce provisions in the 2007 Energy Independence and Security Act (EISA 2007) aimed at preventing market manipulation in the oil industry.

"We understand that consumers are being hurt by high [gasoline] prices," said FTC Chairman William E. Kovacic. "The commission remains vigilant in using its full authority to prevent unlawful behavior that affects gas prices. Today's request for public comments is an important part of our efforts to assess, quickly and thoughtfully, how the commission's new market manipulation authority may be used to protect the American people."

US House Speaker Nancy Pelosi (D-Calif.), who complained a week earlier with several of her colleagues that the FTC was dragging its feet in exercising its new authority, said May 1 that the action was long overdue. "I thank the FTC for heeding our call to protect consumers by using this new authority to probe oil and gasoline prices and punish those who manipulate prices at the pump," she said.

In a letter to Pelosi that she released, Kovacic said the commission's staff "has worked hard to move as speedily as possible." The letter continued: "To date, an FTC task force has examined the development and use of antimanipulation authority by other federal agencies, as well as by the states; met with other government officials (including the Commodity Futures Trading Commission, the Federal Energy Regulatory Commission, and the Securities and Exchange Commission), and undertaken other tasks, both substantive and administrative, in connection with this legislation."

Section 811

Two sections of EISA 2007 gave the FTC this new authority. The agency is seeking public comment on Section 811, which deals with petroleum market manipulation. But FTC said it already is able to seek relief through federal courts for violations of Section 812, which prohibits the reporting of false price information to a federal agency, because it received this authority when EISA 2007 became law.

Following the advance notice's 30-day comment period, Kovacic told Pelosi that the commission "expects to expeditiously analyze the comments received, draft a proposed rule and issue a notice of proposed rulemaking (NPR) with a 30-day comment period."

The learning during this process will be crucial, Kovacic said. "The commission has not previously sought to develop a legal definition of the term 'manipulation' or prosecuted a case alleging manipulation. Moreover, there are challenges involved in appropriately applying this broad concept to markets that, unlike electricity or natural gas, are not subject to comprehensive regulatory disclosure or reporting regimes," he said.

"The pursuit of a case alleging manipulation in wholesale markets for crude oil, gasoline, or distillates may encounter other complexities arising from the differences between such products and the other markets in which manipulation cases have been brought, but we hope to overcome these challenges as we avail ourselves of the methods and opportunities contemplated by the ANPR/NPR procedures, Kovacic said, adding, "Specifically, we believe that there is no better way to generate meaningful comments that will assist in our development of a workable rule for the benefit of the American public."

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Windfall profits tax re-emerges

How serious are the prospects of Congress' reviving the windfall profits tax? Serious enough for US Sen. Pete V. Domenici (R-NM) to ask the chief executives of the five largest US oil companies for detailed explanations of how they use their profits to reinvest in energy production.

Domenici, the ranking minority member on the Energy and Natural Resources Committee, asked the leaders of BP America, ExxonMobil Corp., Chevron Corp., ConocoPhillips, and Shell Oil Co. in an Apr. 30 letter to assess how proposals to increase taxes on domestic production would affect their companies.

"In order to help me gain a better understanding of your investments and your activities related to helping meet our nation's future energy needs, I am writing to request a summary of all public information in this area," Domenici said in his letter.

"In your summary, please include the amounts that you are re-investing in domestic and international oil and gas production. Additionally, I am particularly interested in the extent of your investment in clean energy sources such as wind, solar, biomass, and geothermal energy," he continued.

Gasoline tax proposal

Domenici's letter came two days after Sen. Hillary R. Clinton (D-NY), in her campaign for the Democratic presidential nomination, proposed using a windfall profits tax to pay for suspending the federal tax of 18.4¢/gal for gasoline and 24.4¢/gal for diesel fuel during this summer's driving season.

Clinton said on Apr. 28 that she also would like to repeal $7.5 billion in incentives that were part of the 2005 Energy Policy Act, stop filling the Strategic Petroleum Reserve, crack down on speculation and market manipulation, and press the Organization of Petroleum Exporting Countries to increase production.

"We have a choice. We can choose to have you continue to pay the federal gas tax this summer or we can choose to have the oil companies pay for it out of their record profits," she said at a May 2 "Get Out the Vote" event in Hendersonville, NC.

Obama's response

Obama responded on Apr. 29 in Winston-Salem, NC, that suspending federal motor fuel taxes this summer, which was first proposed by presumed Republican presidential nominee Sen. John McCain (Ariz.), was an election year gimmick. But he added that he also favors taxing oil companies' excess profits.

Oil and gas industry associations are trying to counter what clearly is election year rhetoric. "Siphoning away earnings from the industry through new tax schemes won't help address the current market situation. It won't increase investments, it won't produce more supply, and it won't help consumers," American Petroleum Institute Chief Economist John C. Felmy said on May 6.

"It will hurt oil and natural gas company owners, 98.5% of whom have no connection with the oil industry other than through the pensions they receive invested in oil company stock, or through their 401(k) programs, individual retirement accounts, and other stock holdings," he told a House Transportation and Infrastructure subcommittee. ✦

pany owners, 98.5% of whom have no connection with the oil industry other than through the pensions they receive invested in oil company stock, or through their 401(k) programs, individual retirement accounts and other stock holdings," Felmy said.

Government intervention impacts

Todd said a windfall profits tax would simply be another example of government intervention producing unintended consequences. "In a tight global balance, the government, through ultralow-sulfur diesel and ethanol, has mandated tougher-to-make fuels, requiring more refining and plant maintenance. Suggestions for windfall profit taxes would further raise the cost of supply, while a suspension of the gasoline tax in summertime would only artificially increase the demand for gasoline while robbing the government of infrastructure revenue," he said.

Slocum maintained that a windfall profits tax would not reduce production unless it was excessively punitive. "The proposals I've seen would reduce executives' bonuses and shareholders' dividends but not materially affect production," he said.

DeFazio still was interested in the possible impact of speculators on oil prices. "What would it hurt to have trades no longer opaque and off the books?" he asked Felmy.

Felmy replied, "API has not taken a position on this matter. I would have to defer to the Commodity Futures Trading Commission, which regulates commodities trading and is better acquainted with it."

DeFazio declared, "But it's part of an administration that's opposed to regulation."

Todd suggested that speculation can exaggerate trends, but it doesn't create them. "There's some fear volatility built into the market. A certain amount of increased visibility would show that tight markets and not speculation are the primary cause of higher oil prices," he said. ✦

API: Lieberman-Warner bill could reduce domestic gas supply

Nick Snow
Washington Editor

A climate change bill headed for the US Senate floor in early June could greatly reduce domestic natural gas production and send refining production and jobs overseas, according to a new report commissioned by the American Petroleum Institute.

ICF International report, which API released May 5, says that S. 2191, which Sens. Joseph I. Lieberman (I-Conn.) and John W. Warner (R-Va.) introduced Oct. 18, 2007, would raise the $25,000 estimated annual cost of operating a domestic gas well by some $12,500/year by 2012 and $25,600/year by 2030 because producers would be required to buy greenhouse gas (GHG) emission allowances.

Even though methane emissions from upstream oil and gas operations represent only about 1% of the national total, the impact on investment in new wells would be substantial because the estimated cost of allowances is high relative to gas well operating costs, the report says in its executive summary.

Higher costs would reduce the incentive to drill for gas, and it is estimated that gas drilling "would decline, relative to the base case and depending on assumptions about potential additional mitigation efforts, by about 18-22% over 2012-20 and about 31-40% over 2021-30," the report maintains.

Domestic gas production could be reduced (from the level estimated without the bill's enactment) by 3-4% in 2012, by 5-6% in 2020, and 7-12% in 2030, it indicates. "Over the entire 2012-30 period, lost natural gas production is estimated at 20.4-30.8 tcf, which is roughly equal to 1 1/2 years worth of production," it says.

Less for refining in US

The report also warns that refinery investment would move overseas because US plants would be required to obtain GHG allowances for emissions when most foreign refineries would not. Domestic refinery investment could drop by more than $3 billion/year by 2012 and $11.5 billion/year by 2020, it says.

US refinery throughput could drop by an estimated 3 million b/d in 2020 from a level of about 18.5 million b/d under the study's base case, it continues. Imports of refined products could increase in 2020 to about 29% from 15% under the base case, the report says.

Refiners and gas processors would feel additional negative impacts because they would be required to buy emissions allowances for their customers that would cost much more than the allowances for their own operations.

For refiners, consumer emissions allowance costs would total an estimated $90.21 billion in 2012 (compared with more than $10.37 billion for emissions allowances from their own operations) and nearly $123.45 billion in 2020 (vs. more than $13.59 billion). Gas processors could pay $39.62 billion for consumers' emission allowances (compared with nearly $1.86 billion for their own operations' allowances) in 2012 and $59.89 billion (vs. nearly $2.2 billion for refiners allowances) in 2020, the study projects. The study does not consider how the cost of consumer emissions allowances for gas processors could affect domestic gas supplies if the Lieberman-Warner bill is enacted.

To the extent that any of the consumer allowance costs are borne by gas processors or producers, the adverse impact on US natural gas supplies would be greater than estimated in the report, it says in its executive summary. The report did not examine that scenario because it could have created antitrust problems, API policy analyst Russell Jones said. But the American Exploration & Production Council and American Gas Association have both raised the question with senators and their staffs.

Focus on supplies

"When we started this study, the question was what the impact would be under the Lieberman-Warner bill's mandated requirements. We thought it would be better to look at supplies, which had not been done previously," Jones told reporters during a May 5 teleconference.

Other industries have suggested that requirements of the Lieberman-Warner bill would send jobs overseas, he said.

"This study convinced us that our industry also has to worry about international leakage [of refining jobs]," Jones said. When a refiner would plan to increase capacity, "some accountant would ask why the money shouldn't be spent overseas where greenhouse gas emission allowances aren't required. Tankers [that] transport products instead of crude oil, would be required, but the same pipelines and terminals would be used," he said.

"Refineries are very long-lived assets that require huge investments. Signals such as those which Lieberman-Warner would send are causes for concern because they would make executives in board rooms consider where they will invest for additional capacity," noted API Pres. Red Cavaney, who participated in the teleconference with API Chief Economist John C. Felmy and Lou Hayden, another API policy analyst.

Hayden said Lieberman and Warner's staffs have been receptive to possible gas-cost impacts of the bill and the need to increase access to more domestic supplies. But he suggested that a bigger question is how extensive mandatory measures must be because the 2007 Energy Independence and Security Act and other existing laws already may be having a negative impact on GHG emissions.

API released a second report May 5 that shows that the US oil and gas industry invested about $42 billion in GHG emission mitigation technologies during 2000-06. This represents 45% of an estimated $94 billion spent on such technologies by all US industries and the federal government, according to the report by T-Squared & Associates and the Center for Energy Economics at the University of Texas at Austin.

Cavaney suggested that the upcoming debate on S. 2191 may not lead to passage of major climate change legislation this year but could set the stage for action in 2009.

"We anticipate Congress coming together with a climate change bill, and we want to be a part of it. We think that while the debate has gone on for a long period, starting to look at details is just beginning," he said. Cavaney also expects this Congress to debate the issue but that the next one will actually discuss details. ✦

Republican senators offer bill to increase US supplies

Nick Snow
Washington Editor

US Senate Republicans responded May 1 to near record-high oil prices with a bill to authorize leasing within the Arctic National Wildlife Refuge and increase access to the Outer Continental Shelf.

S. 2958, the American Energy Production Act, would produce as much as 24 billion bbl of oil from ANWR and the OCS, enough to supply domestic needs for 5 years, according to bill sponsor Pete V. Domenici (R-NM), who also is ranking minority member of the Senate Energy and Natural Resource Committee. Seventeen other Senate Republicans are cosponsors.

"For years now, I have been trying to develop more domestic production of oil and gas, and for years, with one exception in the Gulf of Mexico, I have been blocked for political reasons. Consumers are now paying the price for those years of obstruction," Domenici said.

The bill would allow governors of states on the Atlantic and Pacific coasts to petition for leasing and have federal moratoriums and withdrawals lifted. New federal leases would operate under a revenue-sharing agreement in which states would receive 37.5%, the federal treasury 50%, and the Land and Water Conservation Fund 12.5%.

It also would repeal the $4,000 fee for onshore drilling permit applications, a 2% reduction of states' shares of federal mineral royalties and a 1-year moratorium on funding formulation of regulations for commercial oil shale leasing. The three provisions were inserted into the Omnibus Appropriations Bill late last year.

Refinery permit provision

It also would grant the US Environmental Protection Agency authority to accept consolidated applications for permits required to construct new refineries. Financial assistance to states and Indian tribes for hiring employees to process permit applications also would be authorized. Application decision deadlines of 360 days for constructing new refineries and 120 days for expanding existing plants would be established.

S. 2958 also would suspend crude oil purchases for the Strategic Petroleum Reserve for 180 days. It also would repeal Section 526 of the 2007 Energy Independence and Security Act that bars federal agencies from contracting for alternative fuels with longer greenhouse gas lifecycle emissions than the conventional fuels they would replace. The provision's author, House Oversight and Investigations Committee Chairman Henry A. Waxman (D-Calif.), has said that it would apply to any contract for a coal-to-liquids or other alternative fuel or for "a fuel produced from a non-conventional petroleum source such as tar sands."

The bill also would authorize research to study transportation needs for renewable fuel blends, mandate that 6 billion gal of coal-derived fuels be produced by 2022, launch a study of diesel-fueled vehicles' environmental and energy attributes, and extend US Department of Defense contract limits for synthetic fuels to 25 years from 5 years.

'Produce more at home'

"Congress has spent billions to research and develop clean sources of energy," Domenici said, adding, "I've been a leader in those efforts and I will continue to be. However, we must face the fact that no matter what we do, America will still need oil, and without action, an increasingly large portion of that oil will come from unstable regions. With gas prices soaring higher and higher, we must produce more at home and this bill allows us to do that in an environmentally responsible manner."

Sen. John Barraso (R-Wyo.), one of the measure's cosponsors, said, "Record oil prices are a burden whether it is for transportation, home heating, or groceries. The issues of high prices and foreign dependence go hand-in-hand. This bill hits the nail on the head when it comes to addressing America's energy needs."

Another cosponsor, Sen. Lisa Murkowski (R-Alas.), said the US has the resources to produce more oil and gas. "We just need the policies that will allow us to develop those resources. We have the technology to not only safeguard the environment while developing resources, but also safeguard Americans' bank accounts at a time when they are struggling to meet rising energy costs," she said.

But the bill faces an uncertain future in the Senate and House since Democrats hold a majority in both and many have said they believe development of alternative fuels and renewable technologies would be more beneficial environmentally and economically.

Bingaman lashes at Bush for oil, gas supply inaction

Nick Snow
Washington Editor

President George W. Bush and his administration share part of the blame for the US not having increased its domestic oil and natural gas supplies, the chairman of the US Senate Energy and Natural Resources Committee said May 2.

Sen. Jeff Bingaman (D-NM) also disputed Bush's contention in an Apr. 29 press conference that Congress has impeded efforts to add new production. He cited the 2006 Gulf of Mexico Security Act, which he said made an estimated 4.74 tcf of gas and 1.26 billion bbl of oil available.

"Ironically, Congress needed to pass this law because of steps taken by the Bush administration," Bingaman continued.

He said then-US Interior Secretary Gale A. Norton, during her first year in office in 2001, cut the size of a scheduled lease sale in the area by 75%. "With the stroke of a pen, she put off limits over 6 tcf of natural gas and over a billion bbl of oil from an area that had been proposed for leasing by the Clinton administration," he said.

Bingaman suggested that while this was a politically popular stance for the administration of then-Florida Gov. Jeb Bush, the president's brother, it did not increase domestic oil and gas production. "In fact, large areas of the OCS are currently off-limits to oil and gas development, not just because of congressional moratoria but also because of presidential withdrawals—first put in place in 1990 by then-President [George H.W.] Bush," the senator said.

Taking the first step

"This President Bush could exercise real leadership by eliminating those presidential withdrawals. As it stands now, some 574 million acres of the [Outer Continental Shelf] are unavailable for leasing." These contain "estimated undiscovered, technically recoverable resources of approximately 18 billion bbl of oil and 76 tcf of natural gas. The president could take the first step toward making these resources available any time he chooses by simply issuing the appropriate order revoking the presidential withdrawals," Bingaman maintained.

Although Bingaman's extended May 2 statement was framed as a response to Bush's statements 4 days earlier, it also presented likely arguments against the bill that the Energy and Natural Resources Committee's ranking minority member Sen. Pete V. Domenici (R-NM) and 17 cosponsors introduced May 1 to increase domestic oil and gas supplies. Its provisions include authorizing leasing within the Arctic National Wildlife Refuge as well as making more of the OCS along the Atlantic and Pacific coasts available.

"If opened for development, not one drop of oil will come from the Arctic Refuge for 10 years, and we will have to wait 20 years for maximum production," Bingaman said. "The Energy Information Administration (EIA) has estimated that production from the Arctic Refuge would, at its peak, reduce our reliance on imports by only 4%, from 68% to 64%."

Other federal acreage can and should be drilled, he argued, noting that of the 45.5 million onshore acres currently leased, more than 31 million acres are not producing. "Likewise, there are 33 million acres of the federal OCS that are under lease but not producing. Processing of federal drilling permits has surged over the past several years, more than doubling from 2001 to 2006. At the same time, the administration reported that in five key basins in the Rocky Mountain states, 85% of oil resources and 88% of natural gas resources are available for leasing and development," he said.

"Congress has also funded important research and development programs to enhance domestic production. It is simply inaccurate finger-pointing to say that Congress is impeding oil and gas development and production in our nation," Bingaman said.

Short-term actions

He said the US could take a number of short-term actions to reduce upward pressure on oil prices, starting with suspending crude oil purchases for the Strategic Petroleum Reserve. "It simply makes no sense to be putting $120 oil underground," he observed.

Consumers also need to understand that they increase their motor vehicle's fuel efficiency by about 7.5% for every 5-mph reduction in speed, by about 4% when the vehicle's tires are properly inflated, and by about 2% with regular maintenance, according to Bingaman.

"Americans could use about 10-15% less gasoline just by adopting these common-sense measures. But they won't ever do so unless there is a lot of publicity that makes clear that they can save the equivalent of 50¢/gal by taking these simple steps," he said.

Bingaman outlined two medium-term steps he said would ensure adequate government oversight of oil markets. First, he said, the US Secretary of Energy should have a role. "It troubles me that the people at the New York Mercantile Exchange, on which oil is traded, and the Commodity Futures Trading Commission, which regulates that exchange, seem to be the only people who think that speculators are not influencing oil prices," Bingaman said.

The energy secretary and the more than 500 employees at EIA who analyze data and develop forecasts should at least provide market insights and advice to CFTC regulators, he suggested. "Perhaps this could help the CFTC come to

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

A new flag of convenience

The US and French governments, deeply concerned about attacks on oil tankers, have introduced a draft United Nations resolution that would allow countries to pursue pirates from the high seas and into territorial waters to arrest them.

While the draft resolution would specifically authorize action only against pirates off Somalia, it contains the possibility of extending the antipiracy mandate elsewhere.

The draft resolution expresses concern at reports from the International Maritime Organization providing "evidence of continuing piracy and armed robbery in regions crucial to international navigation, including the western Indian Ocean and the Gulf of Guinea."

It cites the hijacking off Somalia of the Panamanian-flagged vessel Fiesty Gas Apr. 10, the French-flagged passenger ship Le Ponant Apr. 4, the Spanish fishing vessel Playa de Bakio Apr. 20, and the attempted hijacking of the Japanese oil tanker Takayama Apr. 21.

Al Qaeda speaks up

Ominously, the Al Qaeda terrorist organization recently issued a resolution of its own calling for maritime jihad, or "holy war." It cites the very same attacks as examples of its recent successes against the West.

The group referred to "the operations by the gunmen who seized the French yacht and struck the Japanese oil tanker, the Spanish yacht, and commercial ships that ply between the coast of Somalia and Yemen...."

The group underlined its successes in the region, recalling that the mujahidin, or holy warriors, succeeded in Yemen twice: "The first was the preparation for the two blessed conquests in New York and Washington by striking the American destroyer Cole in October 2000; then, there was the French oil tanker Limburg in 2002."

The group explained why the area is so important to their larger strategic aims: "The beaches of Yemen are considered the links between the Arabian Sea and the Gulf of Aden. The latter overlooks the Strait of Bab al-Mandab in the Red Sea and the Indian Ocean.

"This region represents a strategic point to expel the enemy from the most important pillars of its battle. If [the enemy] is unable to protect itself in this strategic region, then it cannot protect itself on the ground and its naval bases under the blows of the mujahidin."

Terrorists, not "pirates"

It can hardly be a coincidence that the Al Qaeda statement and the proposed UN resolution have come at the same time. In fact, both sides seem to have declared open warfare on each other, with the high seas now the battleground.

But there's much more going on in this war than the mere "pirate" attacks that are mentioned in the UN resolution sponsored by the US and France.

We sense that the international war on terror is being taken to the sea, but we also sense that the resolution is flying a flag of convenience: instead of being called "the war on maritime terrorists" it's called "the war on piracy." ✦

understand the role of speculators in the market in a manner that is more in line with conventional thinking among oil analysts," he said.

Second, said Bingaman, markets that trade US oil or are located in the US should be subject to US regulation. "It is unacceptable that an exchange based in Atlanta, Ga., [trading] US crude oil that is delivered in Oklahoma is regulated in the United Kingdom [and is] not subject to the laws and regulations that we in Congress put in place to regulate the futures industry. It is also unacceptable that over-the-counter markets are regulated neither here in the US nor in the UK. There is no regulatory body that can see these over-the-counter transactions," he said.

He said the proposal initially offered by Sen. John McCain (R-Ariz.) to suspend federal gasoline and diesel fuel taxes through the summer would come at the expense of fiscal common sense and sound energy policy. "We need to get serious about energy policy. It is an election year, and while there is a tendency to take rhetorical stands in the run-up to an election, the American people understand that. That's one reason why they don't always hold Congress in the highest esteem. Proposals that are mostly feel-good propositions will not fool voters for long, if at all," Bingaman said. ✦

Second discovery indicated in Central Utah thrust belt

Covenant oil field in the Central Utah thrust belt may have a companion soon.

Covenant field, discovered by private Wolverine Gas & Oil Corp., Grand Rapids, Mich., produced its 5 millionth bbl of oil in early 2008, and a press report indicates that a second discovery may be announced soon pending test results.

A Wolverine official is quoted in a Utah newspaper saying that the company could be producing oil later in May from a second discovery well. He said geologic indicators look good at the well, Arapien Valley 24-1, in 24-20s-1e, near Mayfield in Sanpete County, Utah.

The wellsite is about 20 miles north-northeast of Covenant field in 23s-1w, Sevier County. A completion unit was working as of this writing in early May.

Despite the "tite-hole" nature of the play, Wolverine seems to have lent credence to the report by applying to Sanpete County to build a temporary storage/treatment facility and loading station.

Since discovering Covenant in May 2004, Wolverine has drilled five exploration wells in and near the thrust belt, four of which it lists as dry or temporarily abandoned. The fifth, if it is determined to be a discovery, could be named Providence field.

Sources said several of the play's "unsuccessful" exploratory wells may be on the edge of potentially productive structures and may be sidetracked later.

Oxy USA Inc., Houston, a subsidiary of Occidental Petroleum Corp., Los Angeles, acquired major interests from Wolverine and its partners in seven counties in the play last year (OGJ, Oct. 22, 2007, p. 37).

Covenant's status

Cumulative production from Covenant field was 4.9 million bbl through the end of 2007, state figures show.

The field, which doesn't produce gas, also has made 1.24 million bbl of water.

The December 2007 average was 4,636 b/d of oil and 1,695 b/d of water from 10 wells. Most of the oil comes from Jurassic Navajo sandstone at 6,200 ft.

Wolverine reported completing the 17-8 well producing 145 b/d of oil and 450 b/d of water from the subthrust Jurassic Twin Creek formation. This and the 17-9 well have raised the number of wells capable of production at Covenant to 12.

Eight more Covenant wells are permitted, three of which have spud.

Wolverine and Oxy plan to shoot a large 3D seismic survey later this year over Covenant field and the surrounding area about 8 miles northeast of Richfield, Utah.

Refinery utilization in Salt Lake City is at capacity, and it is difficult to see how production on the thrust belt could be increased much absent additions in refining or pipeline capacity.

Exploration outlook

Sources said that as many as three exploratory dry holes in the play might be sidetracked based on positive post-drilling seismic reevaluations.

These include one by Wolverine in 18-19s-1e, Sanpete County, and one by Petro-Hunt LLC, Dallas, in 15s-2e.

Oxy and Wolverine, meanwhile, have obtained permits to shoot 280 line-miles of 2D seismic later this year in Sevier and Sanpete counties.

Sources said the companies plan to drill two to three more exploratory wells in the play this year.

In addition to taking interests in Wolverine and partners' original acreage, Oxy purchased 50-100% working interests in about 65,000 acres in the thrust belt from Plains Exploration & Production Co., Houston.

Overall, Occidental said it invested $743 million in 2007 to acquire several new properties in California, the Rocky Mountains, and the Permian basin, collectively increasing its proved reserves by 50 million boe.

Other operators

Numerous other large and small companies are attempting to establish footholds in the play.

Private Anschutz Exploration Corp. of Denver is active at the north end of the play and is permitting a follow-up to a dry hole it drilled 2 years ago.

Petro-Hunt drilled a well west of Ephraim, Utah, that encountered the Twin Creek formation three times. It is comtemplating reentry and directionally drilling to the west. Petro-Hunt staked a location just south of Wales, Utah, about 6 miles north of its temporarily abandoned well, that may be drilled.

Private Freedom Oil & Gas has acreage north of Petro-Hunt and is trying to raise funds for drilling.

Pioneer Natural Resources Inc., Dallas, is shooting seismic on a separate thrust west of the Arapien Valley 1-24 well. It bought a major working interest from private Burnett Oil Co., Dallas.

Far to the south, Delta Petroleum Corp., Denver, drilled a well in Iron County west of Parowan, Utah, and plans to test shows in the Twin Creek this fall. The company also plans to drill in Beaver County just south of Beaver, Utah.

Delta disclosed that it has identified at least 20 prospects between Parowan and the Arapien Valley 1-24 well that it would like to drill eventually.

Delta drilled its first well southwest of Covenant field anticipating Navajo at 5,000 ft. Instead, it cut igneous rocks from near surface to 11,000 ft and penetrated Navajo below that. The well was 1½ miles low structurally and dry.

Talisman Energy Inc., Calgary, has purchased some acreage in the thrust belt and has done some 2D seismic.

Private Chief Oil & Gas LLC, Dallas, purchased 50% working interest in 180,000 acres in the thrust belt. The other 50% is owned half by private International Petroleum LLC, Salt Lake City, and half by Pioneer Oil & Gas, South Jordan, Utah.

Utah Great Eagle hopes to drill a location 2 miles east of Covenant field this year. ✦

Federal judge orders polar bear decision soon

Eric Watkins
Senior Correspondent

Offshore oil and gas exploration in Alaska's Chukchi Sea could face delays or even be halted after a US federal judge ordered the Department of Interior to decide within 2 weeks whether to list polar bears as an endangered species.

US District Judge Claudia Wilken said oil industry operations in Alaska's Chukchi Sea, where one fifth of all polar bears live, "could jeopardize the continued existence of the species" unless it is protected under the Endangered Species Act.

She rejected the DOI argument that waiting longer to consider the ESA listing would not pose a threat to the bears because the species is already protected under the US Marine Mammal Protection Act (OGJ, Feb. 11, 2008, p. 28). However, Wilken noted that the ESA protections "far surpass" those under the MMPA because the ESA also protects a species' habitat.

Wilken ordered the DOI to reach a decision by May 15 that would take effect immediately, without the usual 30-day waiting period. The department had sought to wait until June 30, with a decision effective 30 days later.

In rendering her decision, Wilken said the DOI admitted ignoring a Jan. 9 deadline for a final decision, and offered "no specific facts that would justify the existing delay, much less further delay." In listing threatened species, Wilken said, "time is of the essence."

The DOI will evaluate its legal options, according to a spokesperson. It could ask a federal appeals court for an emergency order extending its deadline, or it could issue a decision by May 15 granting or denying protection to the polar bear, or granting it in some areas while denying it in others.

The DOI's Fish and Wildlife Service, in response to a 2005 environmental lawsuit, proposed listing the polar bear as a threatened species in January 2007, an action that required a final decision within a year.

But in January 2008 the agency said it would need a further 30 days to study new scientific data; 4 weeks later, with that decision still pending, the DOI's Minerals Management Service sold $2.6 billion in oil leases covering 46,000 sq miles of the Chukchi Sea (see map, OGJ, Apr. 14, 2008, p. 43). ✦

Australia

Sentry Petroleum Ltd., Denver, acquired from Medina Group of China the rights to explore ATP 865, a 1.68 million acre permit in Queensland's Adavale basin 1,000 km west of Brisbane.

The company identified the Sherwood Park prospect and numerous leads. The basin covers 14 million acres and has a proven petroleum system but is lightly explored with fewer than 60 exploration wells.

ATP 865 is within 30 km of a 13 bcf gas field and 40 km east of fields that contain more than 15 million bbl of recoverable oil. The block acquisition is subject to regulatory approval and the assignor's retention of a 0.5% royalty after the transaction.

Chile

The government signed a special operating contract on Apr. 30 on the 6,700 sq km Tranquilo Block in the Magellan basin with Improved Petroleum Recovery Traquilo Chile, Dallas, and Manas Petroleum Corp., Baar, Switzerland.

IPR and Manas committed a three-phase, $33.24 million exploration program. It calls for spending $14.36 million the first 3 years for 360 km of

2D and 160 sq km of 3D seismic and drilling six wells.

Tranquilo is the largest of 10 blocks awarded in Chile's November 2007 licensing round (see map, OGJ, Dec. 24, 2007, p. 36). IPR, operator, and Manas hold the block 50-50.

The block's petroleum system is proved with Tranquilo gas field and the Esperanza and Manzano wells. Four wells on the Esperanza structure had gas-condensate shows.

The basin has 417 km network of gas pipelines that connect the main fields to consumption centers, such us Methanex, the world's largest methanol plant, and Chile's state ENAP has four gas processing plants in the basin.

Denmark

Danica Resources AS, Copenhagen, was awarded a 6-year exploration and production license covering 6,429 sq km in the Danish Baltic Sea that includes Lolland and Falster islands.

Preliminary evaluation of the license, which covers Block 5410 and parts of 5411 and 5412, revealed several large structures similar to hydrocarbon producing structures in northern Poland and Germany. The Danish state has a 20% interest in the license.

Greenland

TGS-NOPEC Geophysical Co. launched more than 140,000 km of geophysical surveys in two areas off Greenland.

The company is running 80,000 km of aeromagnetic and aerogravity surveys in the Labrador Sea/Ungava basin and 58,000 km off northeast Greenland. Data are to be available in the fourth quarter. An 8,300-km 2D seismic shoot is planned in Baffin Bay early in the third quarter to infill the company's 60 by 60-km grid acquired in 2007.

Papua New Guinea

InterOil Corp., Whitehorse, Yukon, said its Elk-4 well established the presence of gas-condensate on the Antelope structure beneath the Elk structure on PPL 238 in Papua New Guinea.

The well intersected the Antelope structure at 7,402 ft and experienced a kick, and gas-condensate flowed to surface and was flared. InterOil plans to deepen the well.

British Columbia

Subsidiaries of Imperial Oil Ltd. and ExxonMobil Canada Ltd. have acquired 115,000 acres of exploration rights in the Horn River basin in Northeast British Columbia.

The acquisitions came at land sales since September 2007. The interests are held 50-50. The licenses are 70 km northeast of Fort Nelson, BC. Imperial Oil will act as operator.

California

Ormat Technologies Inc., Reno, Nev., brought the Heber South geothermal project to commercial operation in mid-April in southern California's Imperial Valley.

Integrated into the existing Heber Complex, Heber South is supplied by three wells 4,000 ft deep and brings the total output supplied from the complex to 92 Mw.

Nevada

Eden Energy Corp., Vancouver, BC, reported a dry hole at the Noah Federal-1 wildcat in White Pine County, Nev.

The well, operated by a Midland, Tex., independent in 31-26n-55e, 18 miles southeast of Blackburn oil field, was plugged and abandoned at TD 7,080 ft. It encountered its target formation, Devonian Simonson dolomite, at 5,058 ft or within 200 ft of the company's prognosis based on seismic interpretation and structural model.

Eden Energy has more than 190,000 acres in the area with numerous structural leads and plans to merge the well results into its geologic model before deciding how to proceed.

Texas

Gulf Coast

Harvest Natural Resources Inc., Houston, and a private company formed an area of mutual interest to explore and develop deeper Frio, Vicksburg, and Yegua prospects in the Texas and Louisiana Upper Gulf Coast.

The AMI covers 20 counties from Nueces County to Cameron Parish and includes state waters. Harvest, with 55% operated interest in the AMI, will fund the first $20 million of new lease acquisitions, geology and geophysical studies, seismic reprocessing, and drilling costs.

The private company has contributed two prospects, including leases and proprietary 3D data sets, and numerous leads generated in the last 3 decades. Harvest and Fusion Geophysical LLC's technical staff reviewed the prospects.

A prospect in Calcasieu Parish is to spud early in the third quarter of 2008. The private company's geological team includes John Amoruso and Denny and Larry Bartell, who discovered Amoruso (Deep Bossier) field in 2005.

Energy Corp. of America, private Denver operator, plans to spud the BSMC-1 well on its Austin Bayou prospect in Brazoria County, Tex., in early May.

The well targets Lower Frio/Vicksburg sands at 19,700 ft with an expected drilling time of 80 days. Greywolf Drilling Co. has the contract. ECA is operator with 76.75% working interest.

The rig will then return to Brazos Belle gas-condensate field in Fort Bend County, where ECA as operator with 100% working interest just completed its fourth horizontal Wilcox producer at 19,280 ft measured depth.

The company has begun targeting gas in Devonian Marcellus shale with horizontal and vertical development wells in the Appalachian basin, where it holds 750,000 acres.

StatoilHydro completes, flows 10-km horizontal Gulltopp well

Nina M. Rach
Drilling Editor

StatoilHydro drilled and completed a long horizontal well off the Gullfaks-A platform, increasing the possibility of platform drilling to remote prospects. The Gulltopp well began flowing oil from 9,910 m TD on Apr. 8.

In early 2004, Statoil ASA announced that it would deepen an existing producing well from the Gullfaks A platform to reach the Gulltopp accumulation 10 km away (OGJ, Feb. 9, 2004, p. 8).

Last month, StatoilHydro characterized it as the longest producing well in the world drilled from an offshore platform.

Gulltopp has recoverable reserves of 4 million std. cu m of oil and 500 million std. cu m of gas and the company expects a production plateau of 16,000 bo/d.[1]

The reservoir pressure was 316 bar when the field was discovered (50 bar depleted), and the permeabilities are medium (50 md) to high (5 Darcy).[2]

'Dolly'

Previously named the Dolly prospect, Gulltopp field is in the Tampen area of the northern Norwegian North Sea, 5 km north of Gullfaks satellite fields Gullveig and Rimfaks (Fig. 1). The field is operated by majority owner StatoilHydro (70%), on behalf of license partner Petoro AS (30%).

In 2002, the Deepsea Trym semisubmerible rig, owned by Odfjell Drilling AS, drilled the 34/10-47ST2 wildcat on Dolly (OGJ, Dec. 9, 2002, p. 8).

In January 2007, Odfjell sold the Deepsea Trym, a second-generation semisub, of modified Aker H-3 design, to Songa Trym AS (Songa Offshore), and it was renamed the Songa Trym. The rig continues to drill for StatoilHydro in the North Sea.

Operations

Before Gulltopp, Statoil's longest production well was the 34/10-A-47T2, which reached 9,052 m MD and was sidetracked to 8,835 m MD. It was drilled in 2001 to Gullfaks South from the Gullfaks A platform.[2]

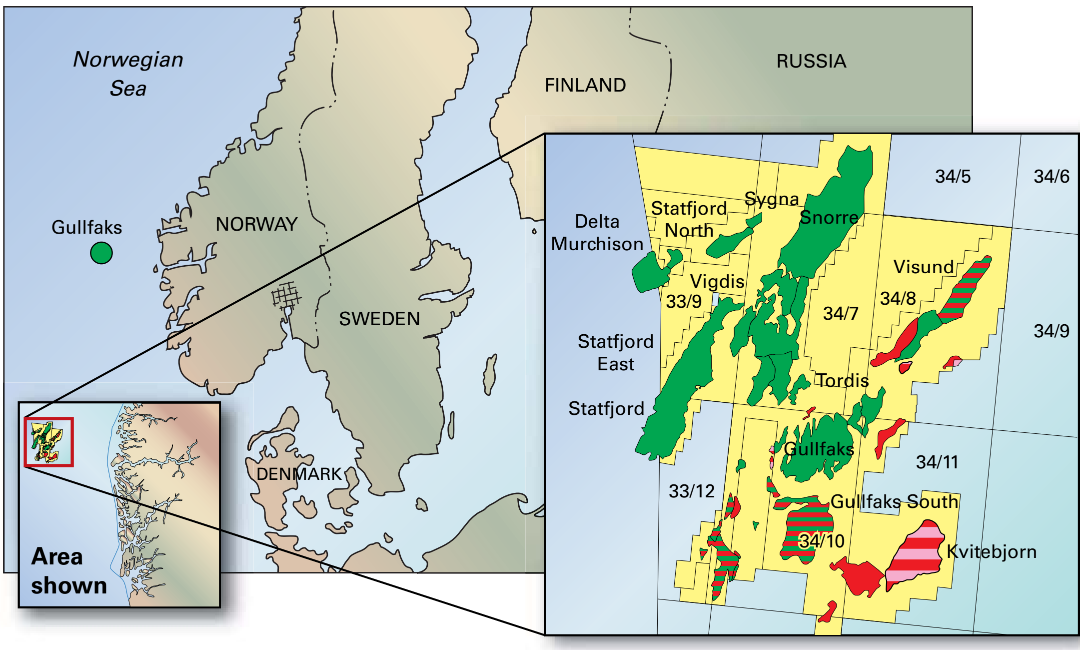
A year later, Statoil drilled the Dolly discovery well on Gulltopp.

In 2004, Statoil considered both a subsea solution and long reach drilling to exploit the Gulltopp field.[2]

Statoil began directional drilling toward Gulltopp in April 2005 and ultimately drilled nearly 900 m farther than its 2001 record. In order to produce the field, the company faced

GULLTOPP FIELD, PL 050/B, NORWEGIAN SECTOR, NORTH SEA

Fig. 1



either drilling and producing through a subsea template or attempting to drill production wells from the nearest platform. Statoil initially estimated the cost of drilling the extended reach well at $43.9 million, about 25% of the cost it estimated necessary to develop Gulltopp with a subsea template and dedicated multiphase flowlines (OGJ, Feb. 9, 2004, p. 8).

Last month, after completing the 3-year project, StatoilHydro said the well was "considerably more expensive than initially assumed."

The rig on the Gullfaks A platform is in 439-ft water and StatoilHydro describes the Gulltopp oil as "exceptionally shallow." The reservoir is 2,430 m below the sea surface.[1]

The company planned to deviate the Gullfaks A sidetrack to 83° from vertical to reach the Brent reservoir and then deviate to 90° through the formation (OGJ, Feb. 9, 2004, p. 8).

ERD

Drilling contractor Seawell Ltd. has managed platform rigs in the North Sea since 1977, with about 35% of the market off Norway and experience in extended-reach drilling. In 1995, Seawell drilled an extended-reach, world record well from Oseberg C to a total depth 9,327 m for Hydro.

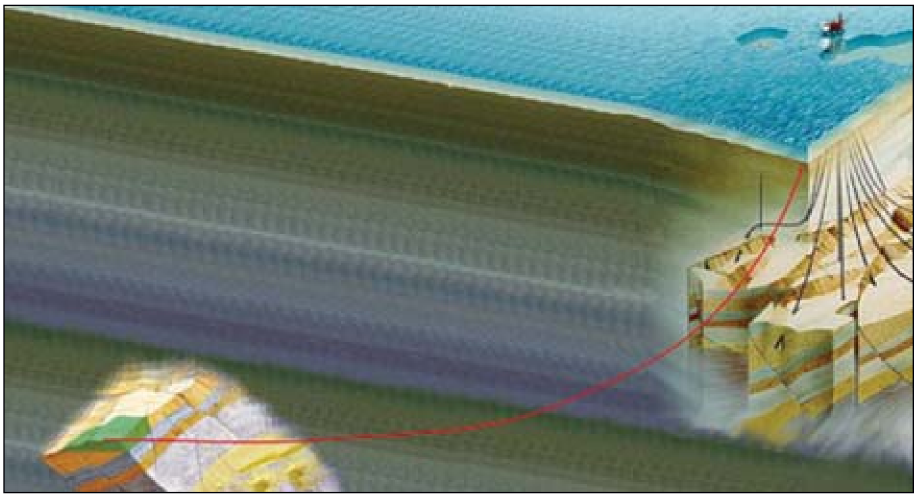
In August 2004, Statoil awarded Seawell the Tampen production drilling operations contract for Statfjord and Gullfaks fields.

StatoilHydro renewed the contract in March 2008; the 2-year extension begins Oct. 1 (OGJ Online, Mar. 13, 2008). Gullfaks A and B have 42 wells each, and C has 52, totaling 136. Seawell has performed managed pressure and through-tubing drilling at Gullfaks.

It is involved in planning and upgrading of the equipment for extended-reach drilling. Seawell says that StatoilHydro is considering wells with 12,000-15,000 m reach on Gullfaks A and C for the future.[3]

Key to success

To reach Gulltopp, StatoilHydro had to drill about 4 m horizontally for each 1 m vertically; most of the well path had an inclination of 7° (Fig. 2).



StatoilHydro had to reinforce the drilling equipment on Gullfaks A platform several times while drilling the nearly horizontal Gulltopp well (Fig. 2; photo from StatoilHydro).

The shallow angle meant there was a great deal of friction while drilling and running casing. StatoilHydro chose to fill the 8-km casing with air, instead of drilling mud, in order to reduce drag and "float" the casing in the nearly horizontal well. "This was the key to success," the company said.[1]

The extreme drilling required StatoilHydro to upgrade the brake system on the drilling rig and the power supply for the platform.

Arne Sigve Nylund, head of operations west at StatoilHydro, described it as "the company's most demanding drilling operation."

Among the new technologies Statoil used to drill the well were newly designed 7-in. polymer control line protectors, beginning in October 2005 (OGJ, Aug. 15, 2005, p. 44).

Geir Slora, head of drilling and wells at StatoilHydro, said that the suppliers involved made a "crucial contribution" to the success of the Gulltopp well.

Production

The main Gullfaks field lies in Block 34/10 in the northern part of the Norwegian North Sea and has been developed with three large concrete production platforms (A, B, C).

Gullfaks A is used for storing and exporting stabilized crude from Vigdis and Visund fields.

Production at Gullfaks is commingled from the Gullfaks A/B/C, Gullfaks satellites, Vigdis, Visund, and Tordis fields. Gullfaks blend is a light, low sulfur North Sea crude oil, 37.5° API.[4]

Oil is loaded into shuttle tankers, and associated gas is piped to the Kårstø gas treatment plant north of Stavanger and then on to continental Europe. ✦

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Subsea gas compression hydrate formation analyzed

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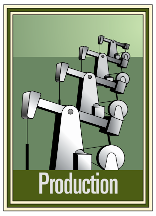


A study focused on potential hydrate formation in the pipe that connects the separator to the planned Ormen Lange subsea compressor.

Subsea gas compression is a new technology, and this article summarizes the results of an analysis of the potential for hydrate formation in the subsea compression station when it operates at steady conditions.

To maintain production levels in the future, Ormen Lange will require offshore gas compression, and the field's operator has selected subsea gas compression as an alternative to the base-case of having compression on a floating platform.

StatoilHydro and its partners are now designing and building a full-scale pilot unit that will operate for a minimum 2 years in a seawater filled basin at the Ormen Lange onshore plant at Nyhamna.

In subsea gas compression, gas-liquid separation takes place upstream of the compressor unit, and thus this study will assess the hydrate inhibition strategy with respect to the Ormen Lange subsea compressor station.

Based on a presentation to the Deep Offshore Technology International Conference & Exhibition, Houston, Feb. 12-14, 2008.

Ormen Lange

Ormen Lange gas field is about 100 km off Norway in 250-1,100 m of water. StatoilHydro ASA, AS Norske Shell, Petoro AS, BP Norge AS and Esso Exploration and Production Norway AS are partners in the development.

The field started producing in September 2007 from subsea facilities tied back to an onshore processing facility at Nyhamna, on Norway's west coast. It is the second largest gas discovery off Norway, with estimated initial recoverable gas reserves of 375 billion cu m (dry sales gas volumes).[1,2]

Production from the field will satisfy eventually about 20% of the UK's gas consumption.

Ormen Lange is in a prehistoric slide area with an uneven sea bottom that has local 60-80 m high summits. The slide's back wall is steep, up to 26°. Environmental conditions are also severe.

Hydrate formation

Subsea compression in recent years has been the subject of several studies.[3-5] Reference 5 provides a detailed description of the subsea compression planned at Ormen Lange (Fig. 1).

Gas hydrates are crystalline ice-like structures wherein gas molecules are trapped in cages formed from hydrogen-bonded water molecules.[6]

Hydrate crystal morphology differs for various hydrocarbon mixtures. This means that in some cases the hydrocarbon liquid phase transports the crystals as dispersed particles, while in other cases the hydrate crystals form deposits on the pipe walls.

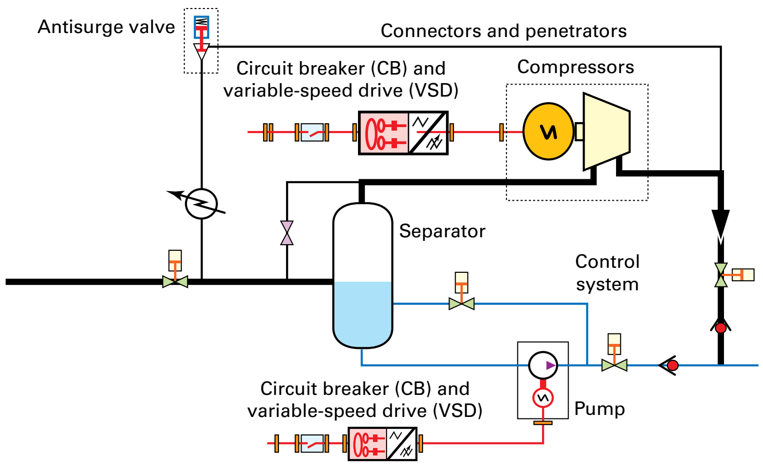
Hydrate formation is a major threat for forming blockages in long flowlines transporting unprocessed gas along the seabed.[7,8] The threat can be controlled by adding hydrate inhibiting chemicals but the ultimate solution is to maintain flow without using chemicals or at least with using a minimum amount.

Extensive research on underinhibited systems or systems operating within the hydrate region without inhibitors is ongoing currently.[9]

No compression system in the world is designed to compress water-wet hydrocarbon gas at a temperature below the hydrate formation temperature. The Ormen Lange subsea compression system has to do this; so that the process design and hydrate formation proper-

ORMEN LANGE SUBSEA COMPRESSION STATION

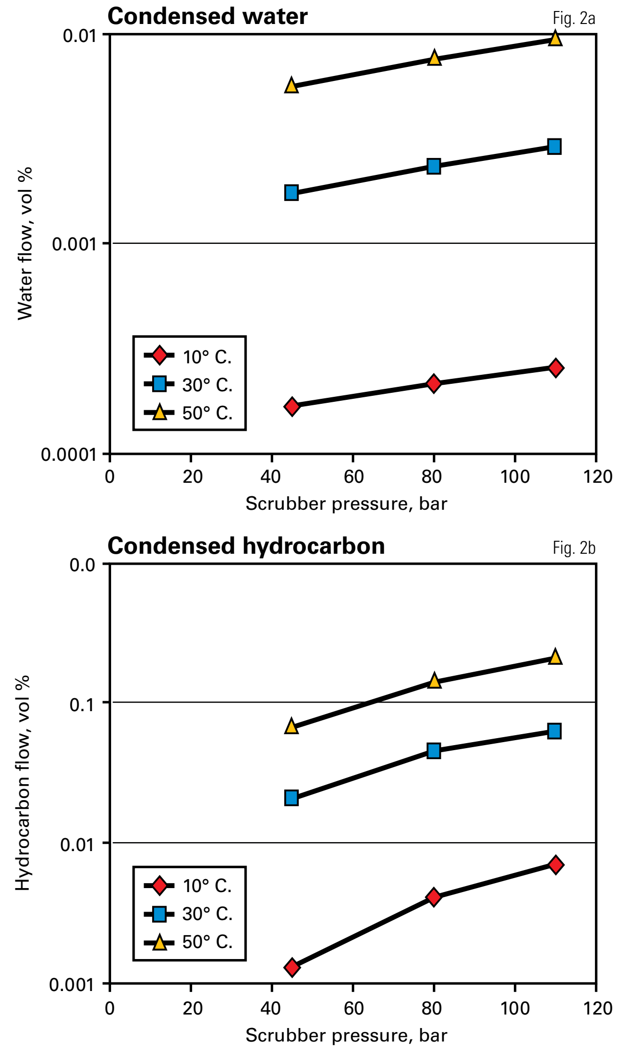
Fig. 1



Note: Separator includes slug handling, liquid separation, fines handling, and gas scrubbing.

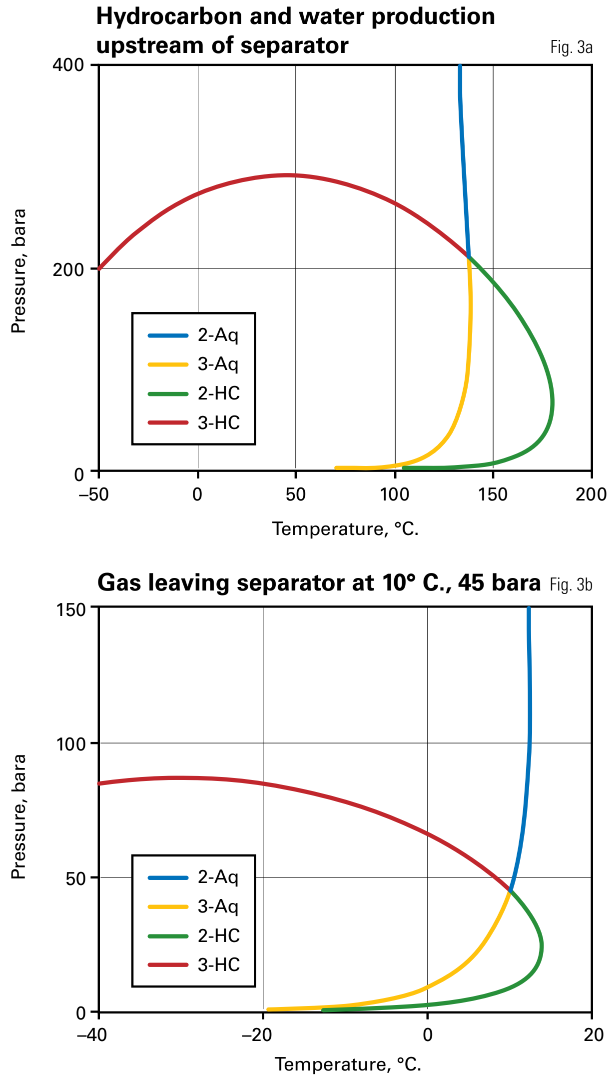
Condensed liquid in outlet piping

Fig. 2



Ormen Lange phase envelopes

Fig. 3



ties for the field are different than for any existing compression operation.

This study aimed to secure efficient and effective long-term full scale (single train) pilot testing in Nyhamna to avoid for example long delays in testing due to hydrate problems.

The Ormen Lange subsea compression project identified that hydrate formation inside the compression station might lead to operational problems. Upstream of the compression station there is no problem because the Ormen Lange flow assurance strategy creates conditions in which the flow is always sufficiently inhibited against hydrates.

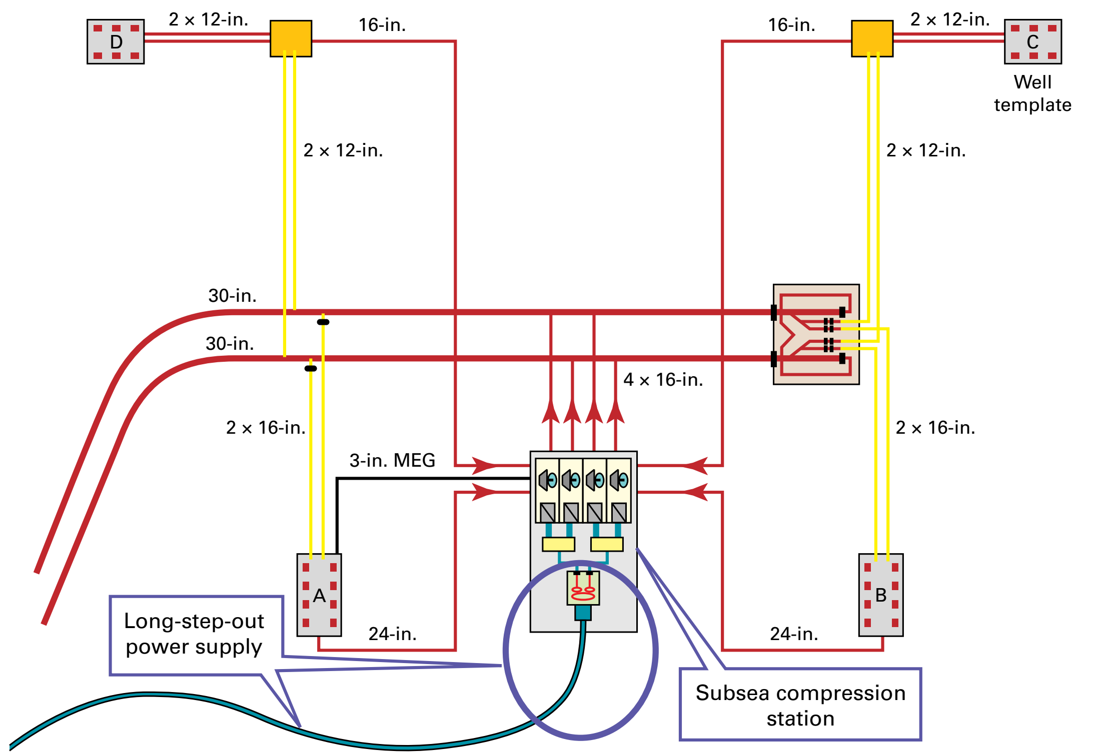
Monoethylene glycol (MEG) is added to the well stream (gas at dewpoint) at the templates to prevent the condensed water from forming gas hydrates. The design concentration is 60 wt % at the pipe outlet, which means that the concentration of the lean MEG at the wellhead is significantly higher (90 wt %) to make up for the dilution by the condensed water along the flowline. Formation water breakthrough is not expected, but should it appear, the well needs to be shut in. If the MEG injection is reduced, stopped, or insufficient with respect to concentration, the well also needs to be shut in.[2]

The hydrate strategy needs to be verified for a subsea compressor station placed near the wellhead. This means that normal operation (no formation water) with respect to hydrate formation and remediation should be verified. All calculations and conclusions discussed in this article are related to normal operating conditions. Shut down and start-up situations represent transients that will be addressed in the design of the compressor system. For example, at start-up and after a shut-down, the compressor system requires inhibition with MEG for the existing temperature and pressure conditions. Hence, the system will be designed accordingly.

The main question answered in this

FIELD LAYOUT

Fig. 4



study is:

Is the separator and piping from the separator to the compressor inhibited with respect to hydrate formation under normal operating conditions?

The initial assumption was that the system was not inhibited. Hence, to prevent the Nyhamna Subsea Compression Station (SCSt) pilot from early failure it was proposed to build a test separator and install it on the multiphase-flow test facility in StatoilHydro's research centre in Porsgrunn for hydrate formation and remediation studies.[10]

Verification

A separator that prevents damage to the compressor removes from the gas the condensed liquids such as water, hydrocarbon condensate, and the added glycol solution. This is the point that required attention with respect to verification of the existing hydrate strategy. Uninhibited conditions with high pressure combined with low temperature and the presence of water will form hydrates either in the separator or in the outlet pipe.

Initially it was assumed that the separation was perfect (as flash separation) with only gas leaving the separator top outlet pipe and only liquid leaving the separator bottom outlet pipe (Fig. 1).

In such a case, further cooling of the gas, which is at its dewpoint or in equilibrium with the liquid, would lead to water condensing with almost no glycol present. Hence, the condensed water in the outlet pipe would form a hazard with respect to hydrate formation, even at normal operation.

The gas is in thermodynamic equilibrium and glycol exists in small amounts in the gas. This means that the condensed water in the separator and gas outlet pipe from the separator will have only minor amounts of glycol if it is assumed that the separation is perfect (100% efficiency).

DISTANCES FROM TEMPLATES TO COMPRESSOR STATION

Template	Diameter, in.	Length, m
A	24	2,000
B	24	1,800
C	16	9,700
D	16	14,200

Fluid system

The Ormen Lange wells produce gas at the reservoir dewpoint. At the wellheads, the reduced temperature and pressure have caused the formation of a small amount of condensed water and condensate, typically 0.5-1.0 vol% liquid with about a 5% water cut.

The well fluid is mixed with a 90 wt %/10 wt % MEG/water mixture at the wellhead for inhibiting hydrates.

Water originates from two sources; water from the reservoir (condensed water and produced water) and water added from the lean MEG injection.

As the temperature and pressure decrease further downstream of the wellheads more liquid condenses from the gas phase and the condensed water dilutes the MEG concentration in the system.

The system is designed for a minimum 60 wt % MEG concentration at the land arrival point.

The liquid loading on the separator depends on operating pressure and temperature. The lower the temperature and pressure, the more liquid will condense. The gas leaving the separator through the gas outlet will be dry saturated gas. Some liquid will also flow through the gas outlet because the separation efficiency is slightly less than 100%.

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The selected pressure and temperature for the base-case calculation was 45 bar and 10° C. The separator operating temperature and pressure can have large variations. Pressure can vary from 155 bars down to 35 bars. The temperature can be higher or lower during start-up or shut-down.

The base case calculation represents conditions late in the field life.

Calculations show that the temperature drop from the separator to the compressor inlet is only a few degrees, and this temperature drop will be small at whatever temperature the separator operates at.

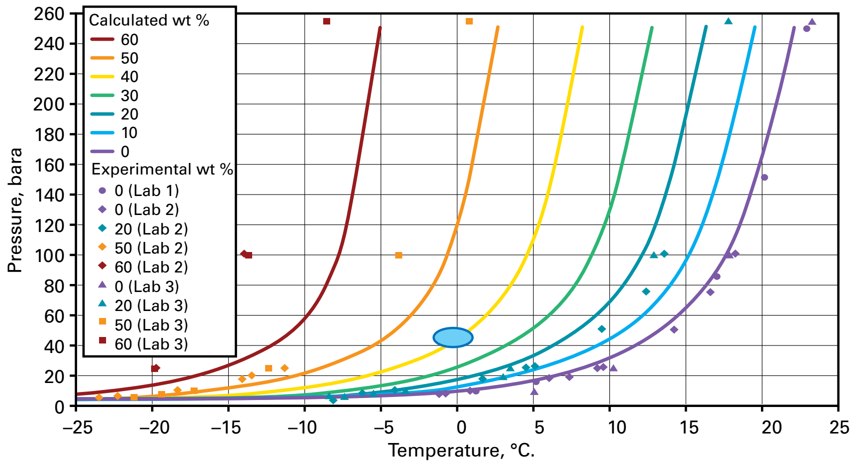
If the system shuts down and cools to –1° C., however, then the amount of condensed liquid will be greater at higher operating temperatures. In this case, however, the system will be provided with local inhibition, thus ensuring a safe shut-down.

For different separator operating conditions, Fig. 2 shows the resulting condensed liquids when the temperature decreases by –1° C. It is seen that the temperature has the largest impact on the resulting amount of condensed liquids.

Phase envelopes (Fig. 3) indicate the fluid behavior in the separator and in the gas outlet piping at a 45 bara and 10° C. separator operating condition.

Hydrate formation

Fig. 5



Note: Simulations using Ormen Lange composition and PVT simulation pakage PVTSim.

Equilibrium considerations

The distance from the wellheads to the compressor station varies from 1,800 to 14,200 m, and the flowlines have a 24-in. diameter from templates A and B and 16-in. from templates C and D (Fig. 4).

The residence time in the flowlines from the wellheads to the compressor station inlet is typically 3-20 min, based on a velocity of about 10 m/sec. The residence time is for the vapor phase because liquid travels slower.

The liquid phase in these flowlines mainly will flow at the pipe walls, resulting in a large contact area between the gas phase and the liquid phase.

Because the pipe length from the wellheads to the subsea compressor station is long (Table 1), it is reasonable to assume that the fluid is close to thermodynamic equilibrium with regard to phase compositions when it reaches the compressor station.

This means that one can consider the multiphase fluid entering the separator at the subsea compressor station as an equilibrium mixture. The gas phase leaving the separator will be at the dewpoint for both hydrocarbon liquid and water. The liquid phases leaving the separator will be at their boiling points.

Fig. 5 shows the calculated hydrate formation curves for the Ormen Lange fluid system. The curves indicate that the Ormen Lange well fluids at a 45 bar pressure are fully inhibited with 40 wt % MEG in the aqueous phase.

MEG flowing conditions

The study assumed MEG (90 wt % MEG, 10 wt % water) being injected at the wellheads with a 1,500 cu m/day maximum capacity. The MEG concentration decreases as more water condenses from the gas phase, and when the fluid reaches land, the MEG concentration still will be 60 wt %.

The MEG concentration in the separator will be between 60 and 90 wt %. A calculation based on a maximum lean 1,500 cu m/day MEG flow rate, a 455 cu m/day water flow rate from the reservoir, and a 600 kg/sec production flow rate gives a 70 wt % MEG concentration in the MEG/water system when the separator operates at 45 bara and 10° C.

Carry over

The computer program PVTSim,[11] can calculate the amount of condensed liquids in the gas outlet piping from the separator. The calculation assumes that the gas-liquid mixture in the separator is at thermal equilibrium and that the gas phase leaving the separator is at the dewpoint with respect to both water and hydrocarbons.

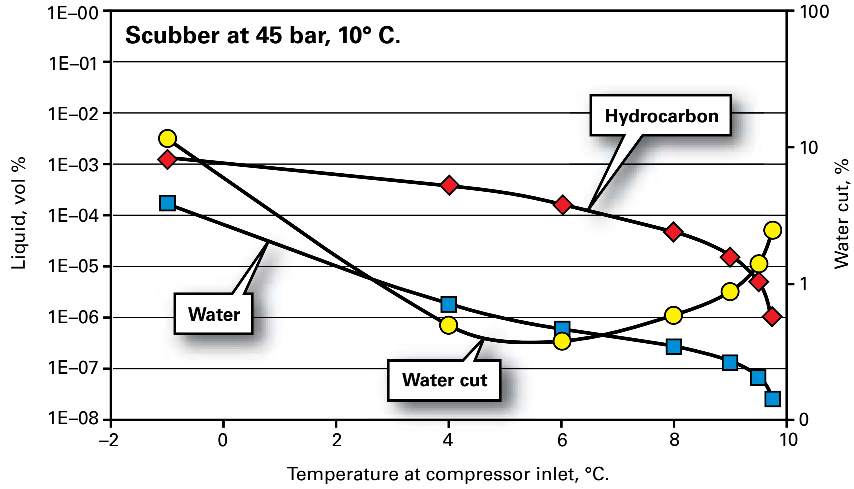
The temperature and pressure decrease as the gas stream flows towards the compressor inlet. With a surrounding temperature of –1° C., the calculations show that the steady-state normal operating temperature at the compressor gas inlet will not be more than 1° below the separator temperature.

The calculations show that the minimum steady state wall temperature is 9° C. The liquid will condense at the wall, but only a part of the gas will be in contact with the wall and temporarily be cooled down to a temperature below the average bulk value. The condensed liquid may therefore be somewhat greater than the calculated bulk temperature level would indicate.

The study made flash calculations with PVTSim at a 45 bara constant pres-

Condensed liquid in gas outlet pipe

Fig. 6



sure and different temperatures on a gas mixture taken from a separator operating at 45 bara and 10° C. This condition was selected for the calculation case since the amount of condensed liquid is greatest at the lower pressure, and the 10° C. temperature is the normal operating condition.

Fig. 6 shows that the condensed water cut is generally lower than 10%, and small amounts of liquid condense when the temperature decreases below 10° C.

The amount of condensed liquid at 9° C. is about 10 times less than the amount of condensed liquid at –1° C.; however, only the condensed water dilutes the MEG.

The specified separator efficiency (liquid carry over) is 0.013 cu m/million standard cu m,12 and this represents a 99.993% volumetric efficiency at the 45 bara and 10° C. operating condition. This efficiency value is high, and if the separator efficiency is lower, then even more MEG will flow through the gas outlet.

The maximum design flow rate for the subsea compressor station is 70 million standard cu m/day, which corresponds to a total mass flow rate of about 600 kg/sec. The specified 0.013 cu m/million standard cu m separator efficiency indicates that the liquid carry over will be about 38 l./hr in total (not per train).

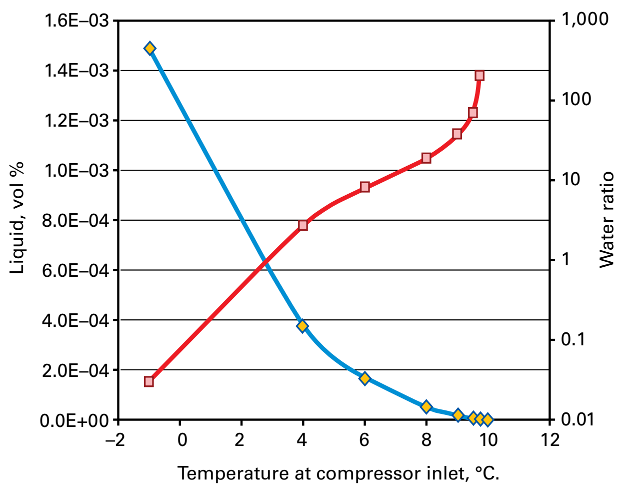
Fig. 7 shows the liquid volume% in the gas outlet piping and the volumetric ratio of water from separator to condensed water. The figure indicates that the water/MEG mixture from the separator is much greater than the condensed water for normal operating conditions.

Calculations with PVTSim on a separator operating condition of 45 bara and 10° C., show that the condensed liquid at a temperature of 9° C. is 4.5 l./hr. The volumetric ratio of water from the separator to condensed water is in this case 37.

The liquid carry over, containing about 70 wt % MEG is, therefore, only slightly diluted by the condensing water. As an example, in 37 l. of water (about 37 kg of water), the amount of MEG is 25.9 kg (corresponding to 70 wt %). Adding 1 l. or 1 kg of water reduces the MEG concentration to 68 wt %. Hence, the fluid system remains inhibited.

Carryover from separator to condensed water

Fig. 7



Other results

Other results from this study are:

• The liquid carry over from the separator contains 60-90 wt % MEG, depending on operating pressure and temperature.

• The condensed liquids in the gas outlet have a low water cut; less than 2% down to a temperature of 3° C.

• The condensed water in the gas outlet dilutes the MEG/water mixture in the carry over from the separator, but the dilution is small at normal operating conditions.

• If the liquid carry over is larger than 0.013 cu m/million standard cu m, then this is beneficial from an inhibition point of view.

• It is recommended to measure the separator efficiency and to test the hydrate remediation system such as MEG flushing at Nyhamna over a wide range of operating conditions.

• It is further recommended that to ensure a successful pilot test at Nyhamna with respect to the hydrate strategy, the test program should be planned carefully with quality input from hydrate and flow-assurance specialists. ✦

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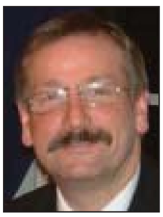

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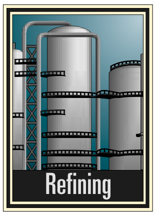
'Design-build' method useful for refinery project execution

James W. Jones
Turner, Mason & Co.
Dallas



Refiners can execute many projects at a lower cost and in less time using a "design-build" approach that bypasses the front-end engineering and design (FEED) package.

Refinery managers should take a fresh look at how they evaluate and execute new projects due to dramatic increases in operating margins and asset values of refining companies. The current economic environment requires refiners to rethink the traditional approach of evaluating and executing projects.

Refiners should expend much more effort in the initial stages of project development to ensure they select the best project for execution. Those projects selected for execution should either strategically fit the refiner's core business or meet a higher selection standard than the customary standard used for projects that are a strategic fit.

We believe current industry practices regarding development and execution of projects rose from leaner times and are no longer the "blueprint" for future projects.

Based on a presentation to the 2008 National Petrochemical & Refiners Association Annual Meeting, San Diego, Mar. 9-11, 2008.

Background

During the past 20 years, refiners have approached projects, for the most part, in a singular manner. Refinery or corporate staffs defined the basic process facilities to be added. They then contracted with an engineering firm to develop a FEED package from which bids were obtained from engineering, procurement, and construction (EPC) contractors. A definitive cost estimate was then prepared and the project was either approved, canceled, or placed on hold.

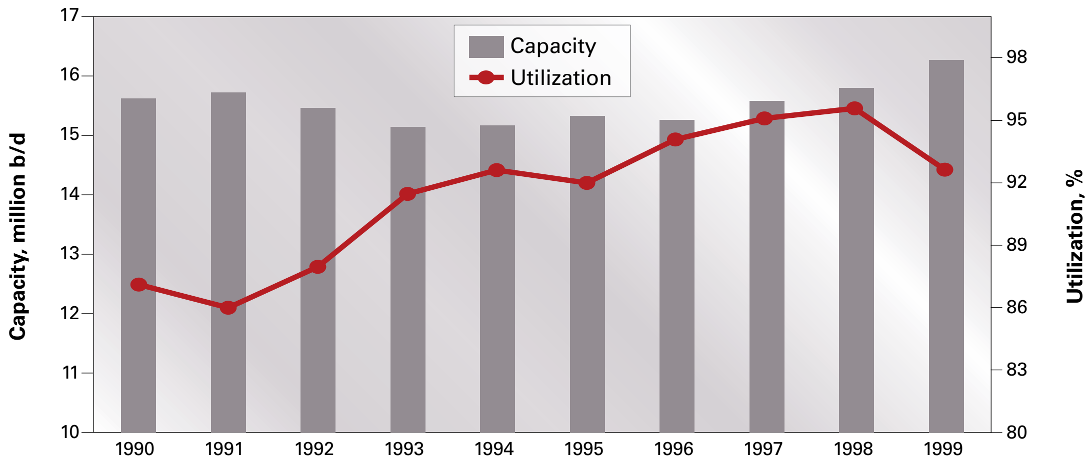
In most cases in which the project went forward, the refiner used a rather extensive project-controls mechanism to track project cost even when lump sum, turnkey (LSTK) contracts were in place with the EPC contractors.

The significant time and engineering resources used to ensure that the project was executed according to the FEED package and within the predicted cost was deemed necessary due to the economic environment during the 1990s.

In the 1990s, refined product supply exceeded demand, which led to underutilized refinery capacity (Fig. 1) and relatively low volumes of long-haul im-

US REFINING, 1990S

Fig. 1



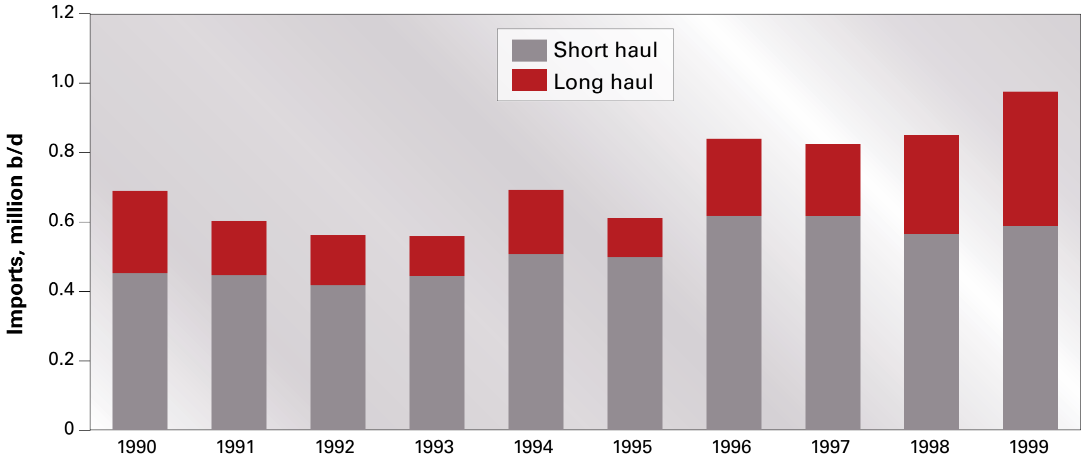
Source: US Energy Information Administration ports (Fig. 2) from export refineries not specifically targeted for the US. Refining margins were narrow during this period. Wall Street held a dim view of the refining business and many integrated companies were selling their domestic refineries for cents on the dollar (Table 1).

The percentage of a refinery's replacement cost to the seller of an existing facility was extremely low (Fig. 3); therefore, any new capital expended on refineries instantly depreciated by as much as 70-90%.

Most capital projects executed during this period were to satisfy regulatory changes to specifications for gasoline and diesel (Table 2).

US GASOLINE, DISTILLATE IMPORTS, 1990S

Fig. 2



Source: US Energy Information Administration

REFINERY SALES*

Table 1

Year	Seller	Buyer	Location
1990	Exxon	Tosco	Linden, NJ
1993	BP	Tosco	Ferndale, Wash.
1994	Chevron	Sun	Philadelphia
1995	Chevron	Clark Oil	Port Arthur, Tex.
1997	Unocal	Tosco	Los Angeles, San Francisco
1998	Mobil	Valero	Paulsboro, NJ
1998	BP	Clark Oil	Lima, Ohio
1999	Equilon	Frontier	El Dorado, Kan.

*Sales for 15% or less of replacement cost.

KEY REGULATORY CHANGES

Table 2

Year	Requirement
1990	rvp reduction
1993	Low-sulfur diesel
1995	Reformulated gasoline
2004	Ultralow-sulfur gasoline
2006	Ultralow-sulfur diesel

The primary economic projects were geared toward substituting of heavier, sour feedstocks for lighter crude oils. The driving force behind these projects was the attractive heavy-light cost spread, which frequently exceeded the crack spread (Fig. 4), and the belief that having the cheapest feedstock was the key to remaining competitive. Almost all of these projects involved delayed coking capacity, but only a few significantly increased clean fuels production.

The remainder of refinery projects executed during the 1990s involved a slew of minor debottlenecking efforts implemented in-house that collectively became known as capacity creep. For most of these projects, forces other than broad refining economics defined the general refinery configuration. Regulatory-driven projects usually required hydrotreating units or other universally accepted approaches for compliance.

Because refinery capital was in short supply, there was little need or emphasis for company staffs thoroughly to evaluate multiple technology options and refinery configurations in search of maximizing refinery profitability. Minimizing capital spending was generally the company's primary goal.

Furthermore, due to Wall Street's increased scrutiny of industry performance, achieving the budgeted capital cost for these projects became as or more important than whether the budgeted cost was reasonable and if additional spending could further enhance refinery performance. It was logical, therefore, for refining companies to focus on the execution phase of these projects, especially maintaining tight control of spending.

New 'Golden Age'

The refining environment of the past few years is dramatically different from the period that gave rise to the FEED-package-driven approach. Since 2005, refining margins have been robust; recent crack spreads of $10-14/bbl are much higher than in the past.

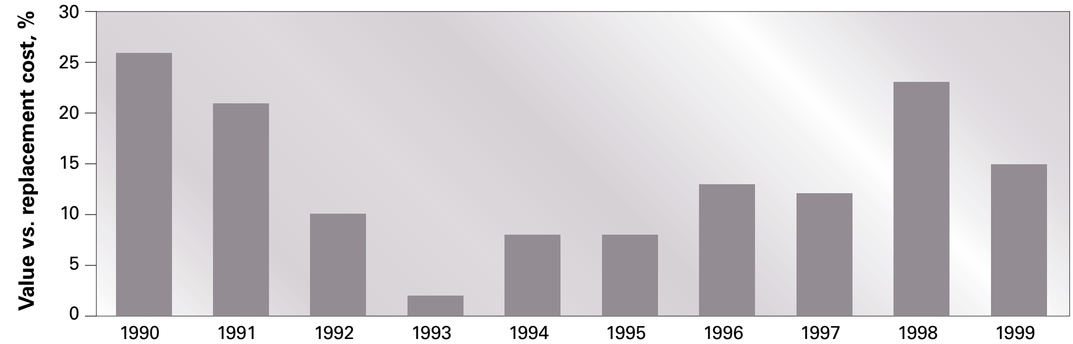
Additionally, refining netback margins for light crude far exceed the additional margin associated with substitution of heavy, sour feedstocks (Fig. 5) that spawned the numerous delayed-coking projects during the 1990s. Furthermore, fair market values for existing refineries have risen significantly and now approach full replacement cost (Fig. 6).

In the current economic environment, capital improvements for increasing capacity or improving yield structure of existing refineries will contribute additional income, and will increase the facility's value by a near-equivalent amount. Another indication of this turnaround is a reduction in refinery sales by integrated oil companies.

Although none can predict how long

US REFINERY TRANSACTION VALUES, 1990S

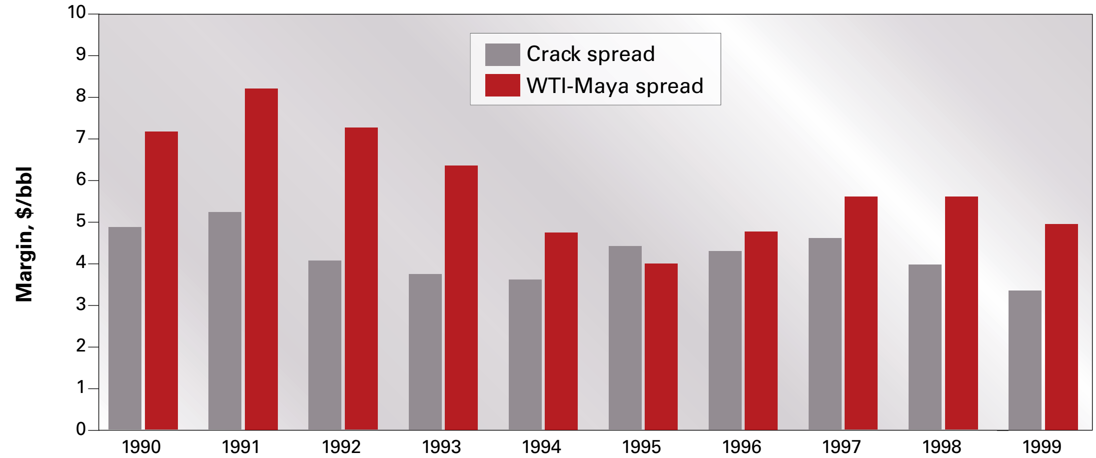
Fig. 3



Source: Turner, Mason & Co. proprietary database

US REFINING MARGINS

Fig. 4



Sources: NYMEX and Platt's Oilgram

this new era will last, we believe there are many indicators that it will not be short-lived:

• Demand for clean fuels in the US exceeds the current supply and modest growth in demand appears to exceed likely capacity additions. Capacity creep may have run its course. Even though distillation capacity continues to rise slowly, utilization appears to have peaked (Fig. 7) and has actually declined a bit.

• Capacity creep will play an insignificant role in future capacity gains. Most easy and inexpensive debottlenecking projects have already been implemented. Furthermore, US Environmental Protection Agency and Justice Department initiatives to pursue legal action against refiners for expanding process units without formal permitting have dampened enthusiasm for these types of projects.

• Reformulated gasoline and ultralow-sulfur fuels requirements have added significant new complexity to refinery operation and undoubtedly contributed to the decline in distillation capacity utilization.

To supply rising demand adequately and consistently, US refiners have imported more gasoline and distillate (Fig. 8) and have increased dependence on long-haul imports. Demand for gasoline and diesel will continue to grow (Fig. 9), which will extend the favorable refining environment created by the domestic supply shortfall.

Although imports may ultimately decline, long-haul imports will not disappear in the foreseeable future even with the effect of recently enacted corporate average fuel economy (CAFE) and renewable fuels legislation, and a pessimistic view of demand (Table 3).

New project approach

US refiners need to add significant production capacity and the options for doing so appear infinite. Indeed, a few large expansions of existing refineries—Marathon's Garyville, Ill., expansion, for example—are in progress.

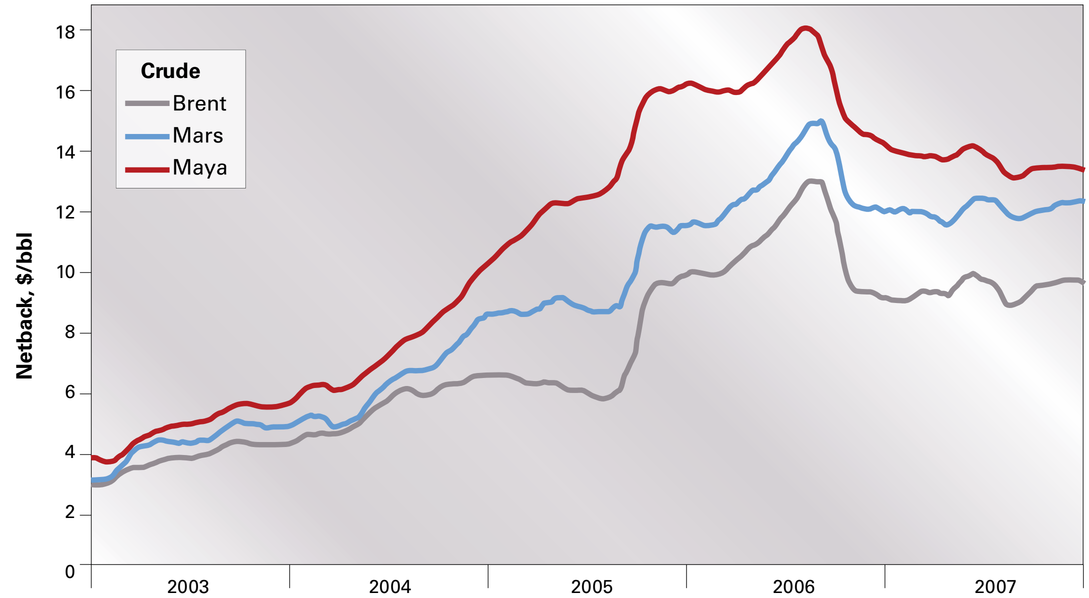
All of the announced likely expansions will not balance refinery supply and demand short of a reversal of the rather modest, but consistent, growth in gasoline and distillate demand in the US. Refiners therefore face developing and executing their own best combination of economic-driven projects for existing facilities.

Unlike the 1970s, however, which was the last time this type of environment existed, refining companies no longer have large home office and local technical staffs adequately to explore their various options. Additionally, most of the "veterans" from this prior era have left the industry via retirement or downsizing. Furthermore, controlling capital costs will no longer be the only focus during execution of future projects.

The current economic environment

US GULF COAST COKING REFINERY NETBACKS*

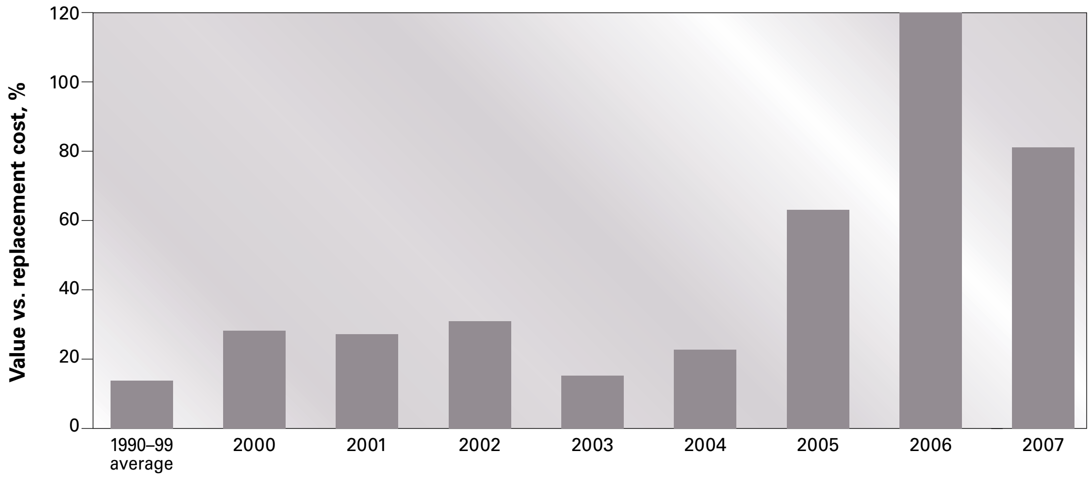
Fig. 5



*Based on data provided to Turner, Mason & Co. and published by Platt's Oilgram. Rolling 12-month average.

RECENT US REFINERY TRANSACTION VALUES

Fig. 6



dictates that refiners devote more attention and more resources, including outside parties such as consultants and EPC contractors, to screening the many opportunities and selecting the best mix of projects that can maximize earnings and asset value. One important element is the whether a project under consideration is consistent with the company's strategic interests.

Identification and prioritization of all available options, including those options that are commercial, are important. Finally, given the attractive refining margins currently available, getting the selected project on stream more quickly can be more valuable than reducing the amount of capital used in an excessive project definition and for spending controls.

Strategic importance

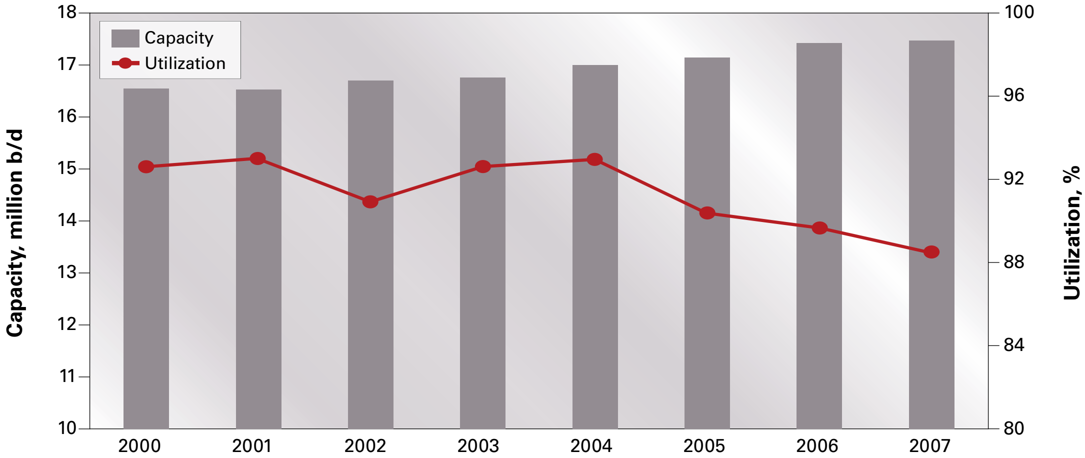
Projects that fall outside a refiner's core business, even if they appear to add value, should be carefully considered relative to competing options that may be a better fit. Although the lack of strategic value should not disqualify a good project, it should force the project to meet a high standard for approval, including a thorough, and possibly independent, assessment of any overlooked or rejected alternatives.

Perhaps no better example of the importance of strategic fit is the major addition by a nonfuels, inland refinery that occurred in the early 1990s. The refinery staff was determined to add processing units to convert certain salable by-products into transportation fuels. The staff considered these streams to be undervalued by its current customers.

The proposed project cost about five times the fair market value of the existing refinery and it did not enhance the refinery's non-fuels core business. In addition, the project team adopted a narrow "Case A" vs. "Case B" evaluation methodology that did not consider different commercial options nor the acquisition of another regional refinery (two would have been available) that

US REFINING, 2000S

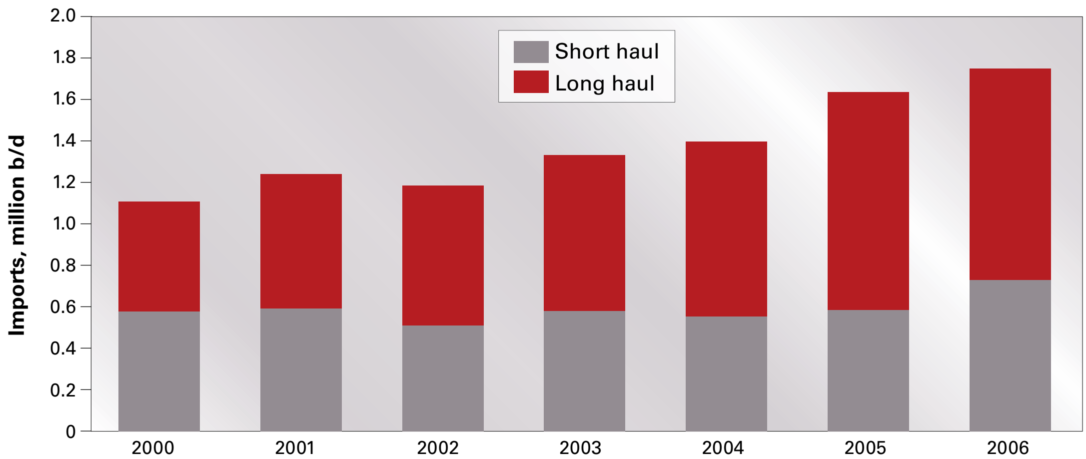
Fig. 7



Source: US Energy Information Administration

US GASOLINE, DISTILLATE IMPORTS, 2000S

Fig. 8



Source: US Energy Information Administration

would have cost much less than the project and provided the opportunity to expand the refinery's core business product slate in a cost-effective manner.

A few years after the project was completed, the refinery closed. It has since been restarted by a different company after being purchased for a minor sum. The facilities added in this project, however, remain idle with no firm plan in place to restart them.

A similar mistake was narrowly avoided by a US Gulf Coast refinery that was considering an expensive desulfurization project in response to pending low-sulfur-diesel regulations. The project would cost about one to two times the refinery's fair market value.

Although the projected economic benefit was reasonable, it was based on a predicted price differential for a new product (low-sulfur diesel) relative to the price for high sulfur off-road diesel and heating oil. The project team evidently ignored the fact that the refinery was pipeline connected to the primary common carrier serving the Northeast heating oil market and that production of on-road diesel was not required at the team's location.

The project was canceled, a decision that was correct in hindsight because the predicted price differential needed for an economic return on investment never materialized and the refinery had no problem selling its entire distillate production as high-sulfur material.

The 'best' options

Many refinery projects executed during the past 20 years were either regulatory compliance-driven or were heavy oil substitution projects centered on delayed-coking additions. In most cases, the project-development stage consisted of little more than licensor evaluations followed by some refinery optimization.

Regulations or, as for heavy oil projects, a universally accepted approach dictated the basic conceptual design to be used. Local and corporate technical staffs had little need, and were therefore never challenged, to evaluate multiple refinery configurations and process technologies.

The current economic environment requires a thorough review of the numerous routes for converting a broad range of available feedstocks into additional clean fuels. Refinery technical staffs have limited experience with this degree of conceptual review and generally lack the broad knowledge necessary to identify, evaluate, and accurately select and prioritize all of the potential options available for adding the most value to their refining companies.

A diverse group, including consultants and EPC companies familiar with issues such as construction cost and constructability, is needed during the project development phase to ensure that all options are identified, their economics accurately quantified, and that the best are selected for execution.

A recent strategic review conducted by a large single refinery company that serves US Gulf Coast and East Cost markets shows how to implement this approach. The company enlisted the assistance of our staff and a well-known engineering company, both of which had knowledge of the refinery and a history of working with the company's staff.

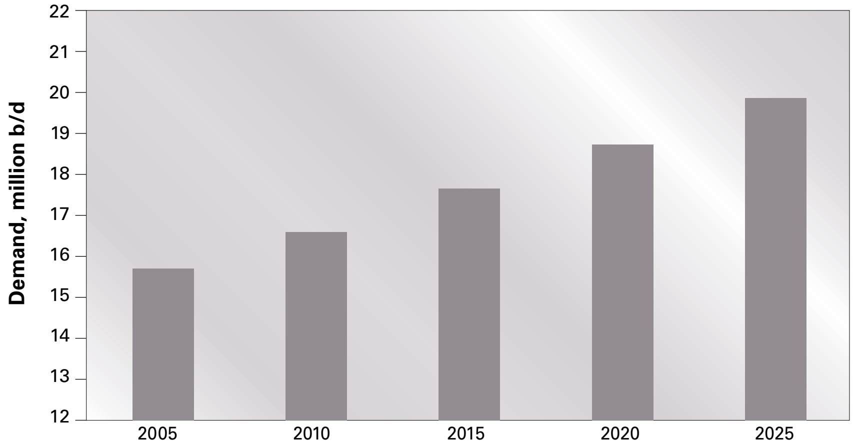
Members of the refinery's technical staff and representatives from the two outside companies formed a review team to develop what might be best described as a 5-year capital plan for the refinery. The team identified and screened more than two dozen options for increasing the company's profitability. Several potential refinery configurations involved technologies whose details were unfamiliar to the company's staff.

We then selected the most interesting options for more detailed evaluation. Surprisingly, the company's original presumption of a major crude oil expansion was only marginally attractive and given a low priority for execution. The review team correctly identified a cost-effective expansion of an existing delayed coker to be the highest value-added project for the facility and the one project that could be implemented in the shortest possible time.

Although the crude expansion remains a possibility, it is unlikely it will move forward until the delayed coker expansion is complete. It is unlikely that the company could have satisfactorily performed such an extensive review and developed a recommendation so different from their original presumption without the participation of outside parties.

US GASOLINE, DISTILLATE DEMAND FORECAST

Fig. 9



Source: "The Outlook," mid-year 2007, Turner, Mason & Co.

Project execution

After the best project is selected, there are many approaches to executing design and construction. The current industry standard approach is to select an engineering company to prepare a FEED package from which bids are obtained from various EPC contractors. Companies are reluctant to deviate from this approach.

The FEED package approach can hinder a project as much as it can help. By relying on the FEED package for the basis of bids, the refiner has eliminated from competition any knowledge, expertise, and creativity available from the EPC contractor. In addition, extra implementation time and cost are required relative to a "design-build" approach where a limited bid basis is provided from which EPC contractors submit LSTK bids that achieve the refiner's goals but may not use identical designs.

Refinery projects that are essentially the same can vary significantly in cost depending on the refining company and EPC contractor involved. We witnessed the construction of two CCR reformers with the same licensor and of reasonably similar size for two different companies by somewhat similar LSTK EPC contractors. In fact, the successful bidder for one unit was a close runner-up for the other.

The costs for these units, both being built in US Gulf Coast refineries during the same time period, were significantly different. The unit built using the FEED package approach cost about $3,500/bbl of capacity. The other slightly smaller unit was competitively bid with the design-build approach and cost about $2,000/bbl.

Refiners using the design-build approach for LSTK construction usually rely upon the EPC contractor's standard specifications, albeit with some minor modifications for specific refiner circumstances. Refiners also cede a certain degree of project control when following the LSTK route in return for reduced price risk.

Individual refiner specifications and the desire to control every aspect of the EPC process, however, tend to inflate project cost. This added cost returns little incremental benefit.

During a recent project in which we helped develop and execute a refinery expansion involving a new vacuum distillation unit and a new ultralow-sulfur distillate hydrotreater, we used the design-build approach to achieve a much more cost-effective project. We first developed the project in January 2005 and presented it to the company the following month.

Because of the relative quick pretax payout estimated for the project (slightly less than 2 years), the company approved our plan to obtain LSTK bids for the two major process units in a "fast track" manner via the design-build approach. We screened five potential EPC contractors and requested bids from the top three candidates in May 2005.

Unlike the FEED package approach, which would have cost more than $1 million and consumed 12 weeks, two of the three bidders agreed to submit LSTK bids at the same time at no cost to the refiner. The third bidder, who also agreed to the desired time frame, did negotiate a small "loser's fee" in the event their proposal was not selected.

Interestingly, none of the three EPC bidders chose to use the same fractionation scheme for the full-range distillate hydrotreater, nor did any propose the same diameter for the vacuum tower. The cost from each bidder also varied significantly for essentially identical units. We jointly reviewed the bids with the refiner, and the winning bid was accepted in late August 2005.

The fast-track approach was invaluable because the refiner obtained a LSTK price immediately before the economic disruption caused by Hurricanes Katrina and Rita. The project, which also included a reformer expansion, hydrocracker fractionation additions, and related infrastructure, was successfully completed in January 2008 for less than $6,000/bbl of added refinery capacity. Projects such as the one being implemented at Marathon-Garyville are reported to cost about $15,000-20,000/bbl.

The fast-track approach created no significant cost overruns or large change orders. The largest overrun was associated with the fractionation addition to the hydrocracker, which was not fast tracked, and became exposed to escalation associated with the post Katrina-Rita period.

Overall, the entire project cost was 15% more than the original feasibility-stage cost estimate. The cost for the two grassroots units covered in the original LSTK contracts, including change orders, additional contractor charges, and force majeure items, was less than 10% more than the feasibility study estimate and well below the amount of the runner-up bidder's proposed cost.

The estimated pretax payout using 2007 actual prices calculates to be less than 1 year. ✦

PROJECTED GASOLINE, DISTILLATE SUPPLY, 2015 Table 3

	[1]2006	Turner, Mason outlook	Pessimistic demand
		1,000 b/d	
Demand	15,790	[2]17,690	[2]16,885
Refinery supply	13,865	[3]15,010	[3]15,010
Less exports	(385)	[4](385)	[4](385)
MTBE	64	0	0
Domestic renewable fuels	49	[5]1,195	[5]1,195
Short-haul imports	730	[4]730	[4]730
Long-haul imports	1,025	[6]1,140	[6]335

[1]Actual data from EIA. [2]"The Outlook," 2007 midyear. [3]Turner, Mason estimate. [4]Assumed to be constant. [5]Arbitrarily limited. [6]Calculated by difference.

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US NATURAL GAS—Conclusion

Gulf, Southeast to see many new transport facilities by mid-2009

Porter Bennett
E. Russell Braziel
Jim Simpson
Bentek Energy LLC
Golden, Colo.

Pipelines

Between January 2008 and the end of second-quarter 2009, 29 pipeline and LNG terminal projects are scheduled to be completed in and around the Southeast US-Gulf Coast.

These projects represent pipeline capacity and LNG sendout additions totaling 25.4 bcfd. For purposes of this analysis, the projects are segmented into four groups:

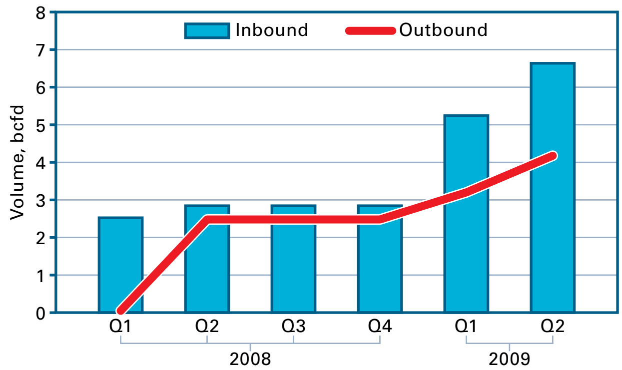
- Inbound projects bringing natural gas into the region. These seven projects are increasing capacity from major domestic producing regions into the Southeast-gulf. Fig. 1 shows inbound projects increasing deliverability into the region by 6.6 bcfd during this time.
- Outbound pipeline projects transporting natural gas through the region. These five projects (totaling 4.2 bcfd) either increase capacity west-to-east across the region or are designed to facilitate such movement by other pipelines (Fig. 1). Most of these projects are positioned to move gas out of the region, but downstream constraints on connecting pipelines will frustrate this intent until 2010 or later when debottlenecking projects start to relieve some of the downstream issues.
- New LNG terminals bringing supplies into the region. Four new gulf-region LNG terminals will increase LNG sendout capacity by 7.1 bcfd. Although it is unlikely these facilities will see more than a few nominal cargoes in the near term, the potential for additional internationally sourced supplies into the region is enormous.
- West-of-region expansions, feeder projects. During the 18-month timeframe of this analysis, 13 projects are scheduled to expand capacity out of the highest-growth producing regions by 7.4 bcfd (Fig. 2). These projects will bring either gas to inbound pipeline projects described above, relieve constraints out of producing areas, or achieve some combination of these objectives.

Figs. 1-2 show projects increasing inbound capacity and potential LNG deliveries into the Southeast-gulf far exceed incremental capacity to move gas across the region. Through the 18-month horizon of this analysis, it becomes apparent there is little synchronization between in-service dates of inbound and outbound projects. Net capacity additions to the region will come in successive waves, with an increment of inbound capacity coming online in one timeframe and a lesser increment of outbound capacity coming online at a later date.

The first article of this two-part series (OGJ, Apr. 28, 2008, p. 57) provided the background driving these expansions. This concluding article

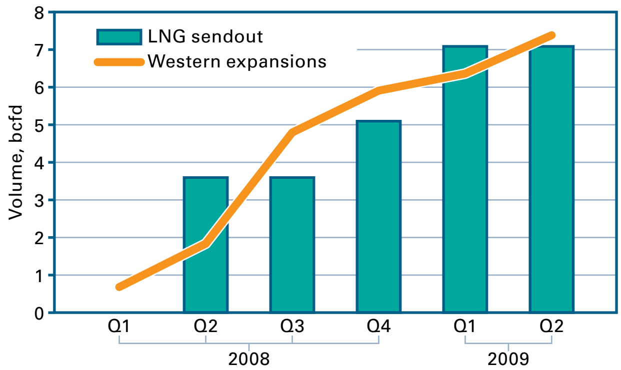
CUMULATIVE PIPELINE PROJECTS

Fig. 1



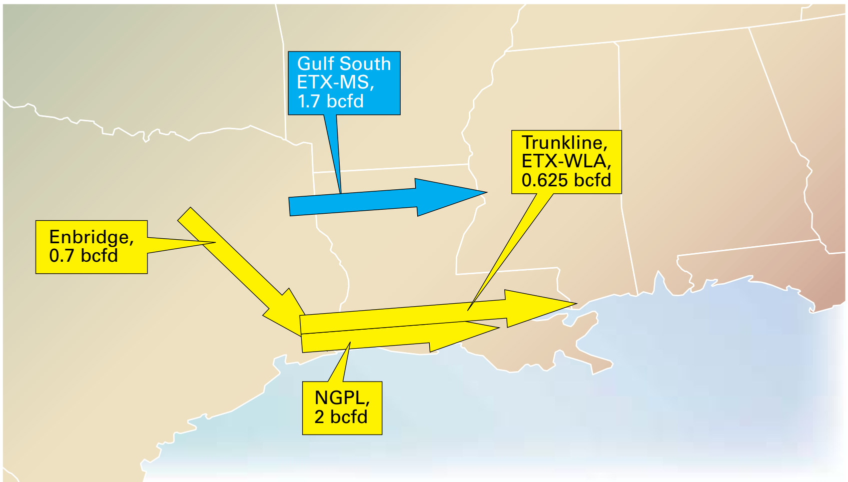
CUMULATIVE INPUT EXPANSION

Fig. 2



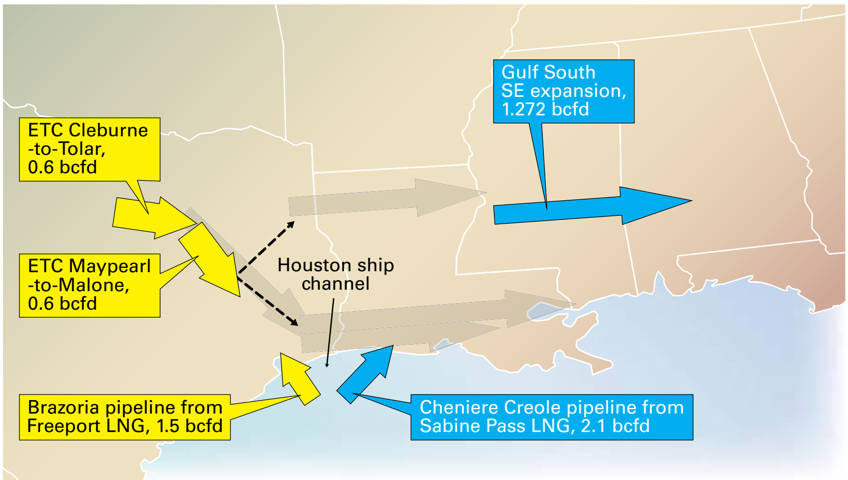
Early 2008 projects

Fig. 3



Second-quarter 2008, initial expansion

Fig. 4



details capacity additions on a quarter-by-quarter basis, showing location of projects, size of capacity additions, and timeline of start-up dates. Each quarterly graphic builds on previous quarters to provide a sense of the magnitude of all projects as a group.

First-quarter 2008

Four projects entered service in the first few weeks of 2008. Three projects from Trunkline, NGPL, and Gulf South will increase capacity out of Texas and into the region by 2.5 bcfd. The Enbridge East Texas Pipeline project will feed into the Trunkline project as well as bringing incremental supply into South Texas from the Bossier Sands of East Texas. Fig. 3 shows these projects.

• Trunkline Field Zone-Henry lateral (625 MMcfd). Southern Union's Trunkline system completed its 625,000-MMbtu expansion from South Texas to Henry Hub on Jan. 16. Known as the Trunkline Field Zone Expansion Project, the 58-mile pipeline (originally announced June 2006), expanded the line's capacity to move gas from Jasper County, Tex., to Henry Hub.

• Gulf South ETX-to-MS pipeline (1.7 bcfd). Boardwalk's 242-mile Gulf South East Texas to Mississippi expansion began service in the first week of January. This 1.7 bcfd expansion brings supplies from sources near Carthage, Tex., through Perryville, La., and then on to Harrisville, Miss.

• NGPL Louisiana Line expansion (200 MMcfd). The Kinder Morgan NGPL Louisiana Line Expansion consists of a 5-mile looping project increasing the system's capacity from the gulf coast mainline to Henry Hub by 200,000 MMbtu/day. It also declares Compressor Station 304 as bidirectional to facilitate gas supplies flowing south along NGPL's Gulf Coast system into the Louisiana line. Expansion finished in early February 2008.

• Enbridge East Texas pipeline (700 MMcfd). Completed in first-quarter 2008, Enbridge Energy Partners' East Texas Pipeline expansion project consists of a 36-in. intrastate pipeline with a capacity of 700,000 MMbtu/day. This pipeline is a feeder project, designed to move East Texas production, primarily from the Bossier Sands, into the Trunkline project described earlier, as well as intrastate pipelines in the Houston Ship Channel-Beaumont area.

Second-quarter 2008

Regional expansions continue during second-quarter 2008 (Fig. 4). These include:

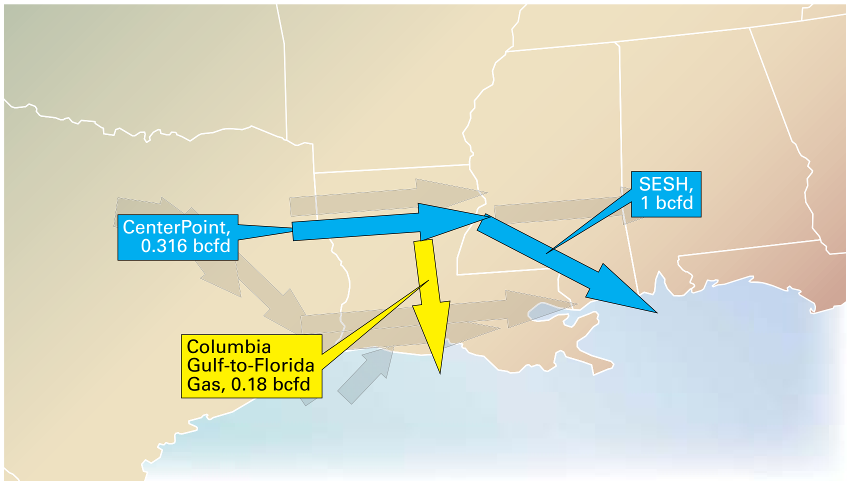
• Gulf South Southeast Expansion pipeline (1.272 bcfd). The second phase of Boardwalk's Gulf South project, known as the Southeast Expansion, was scheduled to be in service April 2008. This pipeline project begins at the existing Gulf South pipeline terminus in Simpson County, Miss., and runs 112 miles to Transco Station 85 in West Butler, Ala.

The project will move gas from CenterPoint's Perryville Hub to premium Southeast locations that can access eastern markets. In addition to the west-end CenterPoint connection and east-end Transco connection, the expansion will connect to Sonat, Destin, and Tennessee.

• Energy Transfer Maypearl-to-Malone pipeline (600 MMcfd). The Energy

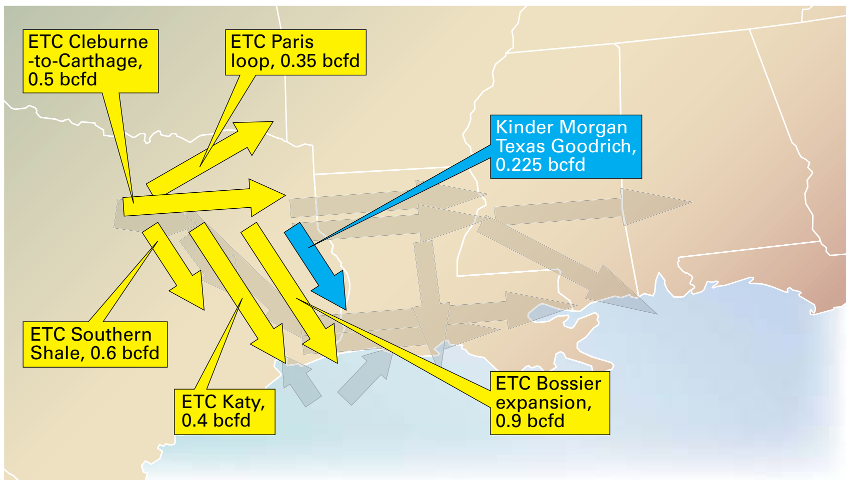
SECOND-QUARTER 2008, ADDITIONAL EXPANSIONS

Fig. 5



THIRD-QUARTER 2008 EXPANSIONS

Fig. 6



Transfer Maypearl-to-Malone expansion is designed to move supplies out of the Fort Worth basin to feed Carthage and South Texas, reaching as far as the Houston Ship Channel.

• Energy Transfer Cleburne-to-Tolar (600 MMcfd). The ETC Cleburne-to-Tolar expansion is designed to feed gas from the Fort Worth basin into the Maypearl-to-Malone expansion and other parts of the ETC system.

• Cheniere Sabine Pass, Creole pipeline (2.1 bcfd sendout). Phase I of Cheniere's Sabine Pass LNG facility in Cameron Parish, La., will be completed in second-quarter 2008. Phase I will have 10.1 bcf of LNG storage in three tanks, each with storage capacity of 160,000 cu m and a sendout rate of 2.1 bcfd.

First approval foresaw connection of the LNG terminal to four pipelines via Cheniere's Sabine Pass Pipeline project. After approval of its Creole Trail LNG terminal only 18 miles to the east, however, Cheniere received FERC approval to merge Sabine Pass Pipeline with its proposed Creole Trail pipeline. This is a 153-mile, 42-in. line designed to move gas from the Sabine Pass terminal to NGPL, Transco, Tennessee, FGT, Bridgeline, TETCO, and Trunkline.

By the end of the quarter, a number of other projects will enter service (Fig. 5). These include:

• Freeport, Brazoria pipeline (1.5 bcfd sendout). Freeport LNG lies about 70 miles south of Houston on Quintana Island. The first phase of development will have sendout capacity of 1.5 bcfd. At start-up, ConocoPhillips will hold 500 MMcfd. On Sept. 30, 2009, ConocoPhillips' capacity will increase to 1 bcfd. The Brazoria Interconnector pipeline transporting gas out of the Freeport terminal has 2.5 bcfd of capacity and is connected to Enterprise, TETCO, FGT, Channel, Kinder Morgan Tejas, Energy Transfer, and the Dow-Enterprise DT pipeline.

• CenterPoint's C-P pipeline (316 MMcfd). The final expansion of CenterPoint's Carthage-to-Perryville line is scheduled for April 2008. When the 316,000-MMbtu/day expansion is completed, the pipeline will deliver 1.5 bcfd from Carthage to Perryville into Columbia, Trunkline, Texas Gas, Tennessee, Sonat, and ANR. The Carthage-to-Perryville line receives gas primarily from Energy Transfer-HPL in the Carthage, Tex, area.

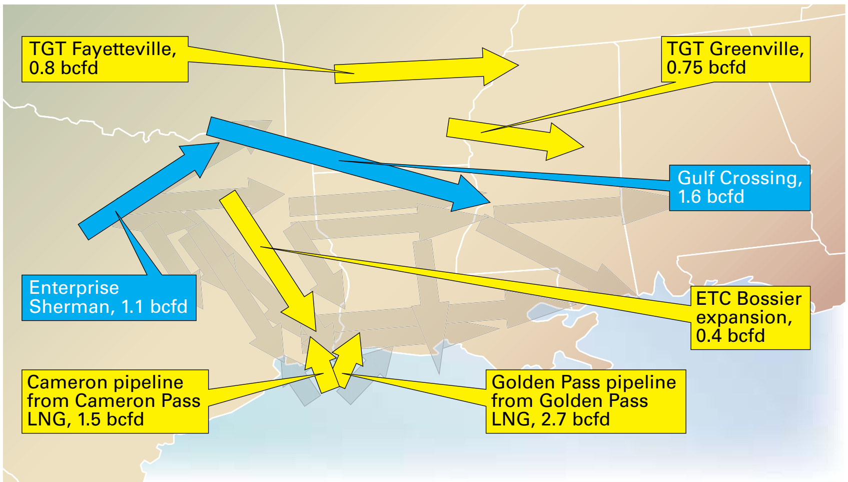
• Columbia Gulf FGT Interconnect expansion (180 MMcfd). The NiSource-Columbia Gulf FGT Expansion Pipeline is small capacity but has large regional implications, expanding CGT's existing facilities near Lafayette, La., by 180,000 MMbtu/day for total southward deliverability of 300,000 MMbtu/day. Columbia Gulf expects service beginning in June 2008.

• CenterPoint-Spectra Southeast Supply Header (1 bcfd). The 36 and 42-in.-OD Southeast Supply Header extends 270 miles from the Perryville hub to the Gulfstream Pipeline (50% owned by Spectra) near Mobile, Ala. SESH's subscribed capacity totals 945 MMcfd. SESH sold an equity stake in the upstream 115 miles of the system to El Paso-Sonat, which has an expanded design capacity of 1.5 bcfd from Perryville to a connection with Sonat in Mississippi.

While the SESH system focuses on

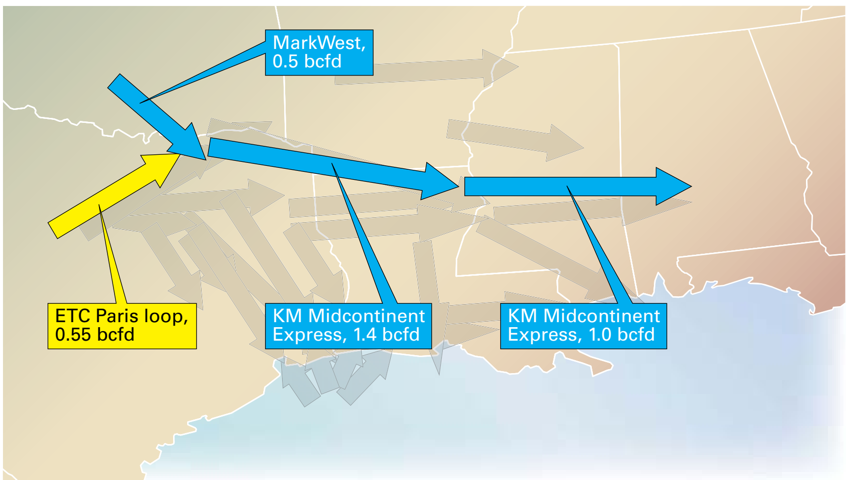
FIRST-QUARTER 2009 EXPANSIONS

Fig. 7



SECOND-QUARTER 2009 EXPANSIONS

Fig. 8



moving more gas into Florida, capacity constraints exist at the east end of the system not unlike those at Transco Stations 85 and 180, with 100% capacity already used on peak days. Any gas moving from Perryville into SESH will thus displace gas from traditional supply routes into Florida.

Third-quarter 2008

Third-quarter additions to regional capacity include (Fig. 6):

- Energy Transfer SE Bossier-HPL pipeline (900 MMcfd initially, growing to 1.3 bcfd by first quarter 2009). The 165-mile, 42-in. OD line will move more than 1 bcfd of natural gas from the heart of the Bossier play in East Texas southeast to a connection with the Houston Pipe Line system. The line will be part of the Katy Transportation and Storage system.
- Energy Transfer Cleburne-to-Carthage pipeline (500 MMcfd). The Cleburne-to-Carthage project will add about 90,000 hp on ETC's Cleburne-to-Carthage pipeline, increasing natural gas deliverability at the Carthage hub to more than 2 bcfd.
- Energy Transfer Paris loop (350 MMcfd). The Paris loop consists of 145 miles of 36-in. OD pipeline running out of the Barnett shale to the northern most point of ETC's Texoma pipeline. This pipeline will function as a header for the Midcontinent Express pipeline.
- Kinder Morgan Texas Goodrich pipeline (225 MMcfd). The 58-mile, 24-in. Kinder Morgan Goodrich pipeline will connect the Kinder Morgan Tejas system in Houston County (Station 7) to the Kinder Morgan Texas system in Polk County, Tex. CenterPoint has contracted a large portion of the initial project capacity.
- Energy Transfer Katy Pipeline expansion (400 MMcfd). This project will expand the 700 MMcfd ETC Katy Pipeline in Southeast Texas. The Katy Expansion will use 56 miles of 36-in. pipeline and 20,000 hp of compression to increase capacity to 1.1 bcfd.
- Energy Transfer Southern Shale pipeline (600 MMcfd). The Southern Shale natural gas pipeline consists of a 36-in. OD, 30-mile pipeline originating in southern Tarrant County, Tex., delivering Barnett shale production to ETC's previously announced Maypearl-to-Malone pipeline expansion project.

First-quarter 2009

As 2009 begins, even larger expansions will enter service (Fig. 7). These include:

- Enterprise Sherman extension (1.1 bcfd). This 178-mile extension of the Enterprise intrastate system will deliver up to 1.1 bcfd from the Barnett shale area into Boardwalk's Gulf Crossing project. Devon stands as the primary capacity holder in the system. Enterprise has the option to acquire up to a 49% interest in the Gulf Crossing project.
- Cameron LNG, Cameron pipeline (1.5 bcfd). Sempra's Cameron LNG terminal in Hackberry, La. (on the Calcasieu channel in Cameron Parish), will have 1.5 bcfd of initial sendout capacity. The project includes the 35-mile Cameron Pipeline, delivering as much as 1.5 bcfd of natural gas to connections with Liberty Gas Storage, FGT, Tennessee Gas, Texas Eastern, and Transco Z3.

An extension or expansion of the pipeline could include other interconnections with ANR, Columbia Gulf, and Sempra's proposed Port Arthur Pipeline. Eni SPA holds a 20-year contract for 600 MMcf/d (40%) of the terminal's sendout capacity and Suez-Tractebel has a 20-year agreement for up to 33% of sendout capacity.

• Boardwalk's Gulf Crossing pipeline (1.6 bcfd). Gulf Crossing is Boardwalk's 355-mile, 42-in. OD interstate pipeline beginning near Sherman, Tex., and terminating near Tallulah, La. Boardwalk designed this pipeline to move Barnett shale, Bossier sand, and Woodford shale gas to the Perryville area.

This project will increase capacity into Perryville without a corresponding increase in capacity out of Perryville. Boardwalk's Gulf South subsidiary is also constructing a 17-mile parallel line called the Mississippi Loop crossing Hinds, Copiah, and Simpson counties.

• Texas Gas Fayetteville lateral (800 MMcfd, increasing to 1.1 bcfd). This Boardwalk project consists of about 165 miles of up to 42-in. OD pipeline with an initial capacity of 800 MMcfd. The addition of up to 14,000 hp of compression will increase capacity to 1.1 bcfd. The proposed route of the pipeline begins in Conway County, Ark., and extends through Faulkner, Cleburne, White, Woodruff, St. Francis, Lee, and Phillips counties in Arkansas, crossing the Mississippi river near Helena, Ark., before interconnecting with Texas Gas in Coahoma County, Miss. Injecting 1.1 bcfd into the Texas Gas system at this point will improve capacity out of the Fayetteville shale.

• Texas Gas Greenville lateral (750 MMcfd). The 95-mile Greenville lateral will move up to 750 MMcfd from the Texas Gas compressor station at Greenville, Miss., to an interconnect with Boardwalk Pipelines's subsidiary, Gulf South Pipeline Co., in Attala County, Miss.

• Golden Pass LNG, Golden Pass pipeline (2.7 bcfd). Golden Pass LNG is a joint venture among Qatar Petroleum, ExxonMobil, and ConocoPhillips. The facility is 10 miles south of Port Arthur and 2 miles northwest of Sabine Pass, Tex., along the Sabine-Neches waterway. Sendout capacity can average 2 bcfd and peak at 2.7 bcfd.

The terminal is connected to 11 regional pipeline systems via a new 2.5 bcfd, 75-mile pipeline. An additional 2-mile, 24-in. diameter pipeline will move gas to ExxonMobil's Beaumont refinery. Qatar Petroleum has committed 15.6 million tons/year (2 bcfd) of LNG to the facility for 25 years.

Second-quarter 2009

Projects entering service during second-quarter 2009 include:

• MarkWest Arkoma Connector (500 MMcfd). The 30-in. MarkWest Arkoma Connector pipeline will extend about 50 miles from an interconnect with MarkWest's gathering system in the Woodford shale in southeastern Oklahoma to an interconnect with the Midcontinent Express pipeline in Bennington, Okla. MarkWest has a one-time right to acquire 10% of MEP after construction is complete.

• Kinder Morgan Midcontinent Express—Carthage-to-Perryville (1.4 bcfd). The Midcontinent Express pipeline project is a joint venture among Kinder Morgan Energy Partners and Energy Transfer Partners designed to move gas from the Barnett shale, Woodford shale, Fayetteville shale, Anadarko basin, Arkoma basin, and Bossier Sands through Perryville and ultimately to Transco Station 85.

The project will have an initial capacity of 1.4 bcfd, connecting to NGPL, Energy Transfer, Columbia Gulf, and Transco. Midcontinent Express brings 1.4 bcfd into Perryville but moves only 1 bcfd out to Station 85 (Fig. 8). This mismatch increases pressure on overall regional capacity. ✦

Statistics

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.

IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4 4-25 2008	Districts 1-4 4-18 2008	District 5 4-25 2008	District 5 4-18 2008	Total US 4-25 2008	Total US 4-18 2008	Total US *4-27 2007
	1,000 b/d						
Total motor gasoline	1,329	988	56	18	1,385	1,006	1,152
Mo. gas. blending comp.	907	591	47	18	954	609	675
Distillate	272	259	1	2	273	261	337
Residual	261	501	164	107	425	608	302
Jet fuel-kerosine	54	82	60	96	114	178	233
Propane-propylene	119	232	14	22	133	254	139
Other	442	551	48	153	490	704	680
Total products	**3,384**	**3,204**	**390**	**416**	**3,774**	**3,620**	**3,518**
Total crude	**9,182**	**8,840**	**1,033**	**1,201**	**10,215**	**10,041**	**10,264**
Total imports	**12,566**	**12,044**	**1,423**	**1,617**	**13,989**	**13,661**	**13,782**

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

OGJ CRACK SPREAD

	*5-2-08	*5-4-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	125.96	87.07	38.89	44.7
Brent crude	115.36	66.50	48.86	73.5
Crack spread	10.60	20.57	–9.97	–48.5
FUTURES MARKET PRICES				
One month				
Product value	128.28	88.70	39.58	44.6
Light sweet crude	115.34	63.78	51.56	80.8
Crack spread	12.94	24.92	–11.98	–48.1
Six month				
Product value	123.58	80.78	42.80	53.0
Light sweet crude	112.12	68.55	43.57	63.6
Crack spread	11.46	12.23	–0.77	–6.3

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

PURVIN & GERTZ LNG NETBACKS—MAY 2, 2008

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant $/MMbtu					
Barcelona	8.51	6.41	7.56	6.29	6.84	7.47
Everett	8.72	7.22	8.32	6.48	7.06	9.05
Isle of Grain	10.42	7.86	10.21	7.74	8.57	9.67
Lake Charles	8.12	5.78	7.84	5.98	6.36	8.88
Sodegaura	7.14	8.42	6.63	8.43	7.68	5.64
Zeebrugge	9.00	5.60	7.20	5.54	6.29	7.20

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
Data available in OGJ Online Research Center.

CRUDE AND PRODUCT STOCKS

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 bbl						
PADD 1	14,711	56,326	29,729	8,935	31,539	13,481	2,913
PADD 2	65,481	49,632	17,727	7,298	28,701	1,359	9,892
PADD 3	168,499	70,495	32,540	12,332	29,923	17,967	14,891
PADD 4	13,773	5,873	1,814	562	3,182	252	[1]760
PADD 5	57,465	28,763	21,341	9,611	12,486	6,463	—
Apr. 25, 2008	**319,929**	**211,089**	**103,151**	**38,738**	**105,831**	**39,522**	**28,456**
Apr. 18, 2008	**316,081**	**212,572**	**105,173**	**38,283**	**104,702**	**39,415**	**27,562**
Apr. 27, 2007[2]	**335,648**	**193,099**	**89,354**	**39,657**	**117,134**	**40,850**	**27,921**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

REFINERY REPORT—APR. 25, 2008

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,370	1,354	2,015	117	435	147	65
PADD 2	3,299	3,263	2,247	235	1,013	45	203
PADD 3	7,416	7,283	3,072	677	2,093	301	610
PADD 4	531	530	281	23	169	12	[1]115
PADD 5	2,405	2,318	1,349	419	528	151	—
Apr. 25, 2008	**15,021**	**14,748**	**8,964**	**1,471**	**4,238**	**656**	**993**
Apr. 18, 2008	**15,058**	**14,827**	**8,867**	**1,429**	**4,116**	**771**	**1,048**
Apr. 27, 2007[2]	**15,404**	**15,132**	**8,777**	**1,334**	**4,090**	**671**	**1,069**
	17,588 operable capacity		**85.4% utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

OGJ GASOLINE PRICES

	Price ex tax 4-30-08	Pump price* 4-30-08	Pump price 5-2-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	329.1	368.8	292.0
Baltimore	313.5	355.4	297.2
Boston	308.5	350.4	287.3
Buffalo	312.6	372.7	303.3
Miami	327.5	377.8	310.3
Newark	309.4	342.3	276.4
New York	298.5	358.6	295.3
Norfolk	304.2	341.8	284.9
Philadelphia	309.1	359.8	298.0
Pittsburgh	307.6	358.3	288.0
Wash., DC	328.3	366.7	301.8
PAD I avg.	313.5	359.3	294.0
Chicago	343.3	394.2	321.9
Cleveland	304.4	350.8	287.9
Des Moines	306.9	347.3	283.9
Detroit	310.9	360.1	291.0
Indianapolis	312.1	357.1	292.9
Kansas City	303.8	339.8	278.0
Louisville	330.8	367.7	294.8
Memphis	305.8	345.6	282.9
Milwaukee	320.7	372.0	301.8
Minn.-St. Paul	310.7	351.1	283.0
Oklahoma City	306.7	342.1	278.9
Omaha	303.7	350.1	289.0
St. Louis	319.2	355.2	284.9
Tulsa	301.8	337.2	280.9
Wichita	298.4	341.8	282.9
PAD II avg.	311.9	354.1	289.0
Albuquerque	309.8	346.2	289.9
Birmingham	312.8	351.5	283.9
Dallas-Fort Worth	314.3	352.7	288.8
Houston	310.1	348.5	284.9
Little Rock	310.0	350.2	281.9
New Orleans	309.1	347.5	281.9
San Antonio	304.7	343.1	271.9
PAD III avg.	310.1	348.5	283.3
Cheyenne	301.8	334.2	275.6
Denver	322.7	363.1	294.2
Salt Lake City	303.0	345.9	285.4
PAD IV avg.	309.2	347.7	285.1
Los Angeles	329.9	388.4	339.1
Phoenix	301.1	338.5	300.9
Portland	322.9	366.2	317.0
San Diego	338.6	397.1	349.0
San Francisco	345.9	404.4	363.1
Seattle	322.8	375.2	324.9
PAD V avg.	326.9	378.3	332.4
Week's avg.	**314.0**	**357.5**	**295.3**
Apr. avg.	**296.4**	**339.3**	**278.3**
Mar. avg.	**276.1**	**319.7**	**254.0**
2008 to date	**273.8**	**317.4**	—
2007 to date	**204.3**	**247.9**	—

*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

	4-25-08 ¢/gal		4-25-08 ¢/gal
Spot market product prices			
Motor gasoline		Heating oil No. 2	
(Conventional-regular)		New York Harbor	331.25
New York Harbor	294.75	Gulf Coast	326.08
Gulf Coast	295.08	Gas oil	
Los Angeles	306.63	ARA	347.54
Amsterdam-Rotterdam-Antwerp (ARA)	284.13	Singapore	336.81
Singapore	285.50	Residual fuel oil	
Motor gasoline		New York Harbor	200.31
(Reformulated-regular)		Gulf Coast	203.88
New York Harbor	305.00	Los Angeles	214.84
Gulf Coast	316.63	ARA	214.66
Los Angeles	317.13	Singapore	207.57

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

BAKER HUGHES RIG COUNT

	5-2-08	5-4-07
Alabama	6	3
Alaska	5	7
Arkansas	43	43
California	36	33
Land	34	32
Offshore	2	1
Colorado	123	107
Florida	0	0
Illinois	0	0
Indiana	2	3
Kansas	9	13
Kentucky	10	8
Louisiana	153	181
N. Land	54	60
S. Inland waters	22	26
S. Land	20	32
Offshore	57	63
Maryland	0	0
Michigan	1	2
Mississippi	12	16
Montana	10	20
Nebraska	0	0
New Mexico	79	74
New York	8	5
North Dakota	65	33
Ohio	12	13
Oklahoma	210	186
Pennsylvania	19	15
South Dakota	3	2
Texas	882	831
Offshore	10	10
Inland waters	1	1
Dist. 1	27	20
Dist. 2	36	31
Dist. 3	60	56
Dist. 4	84	93
Dist. 5	183	169
Dist. 6	119	122
Dist. 7B	27	43
Dist. 7C	66	61
Dist. 8	133	106
Dist. 8A	25	25
Dist. 9	36	39
Dist. 10	75	55
Utah	39	41
West Virginia	26	32
Wyoming	70	70
Others—AZ-1; NV-3; OR-1; TN-5; VA-6	16	9
Total US	**1,839**	**1,747**
Total Canada	**95**	**89**
Grand total	**1,934**	**1,836**
Oil rigs	357	282
Gas rigs	1,473	1,462
Total offshore	69	74
Total cum. avg. YTD	**1,787**	**1,738**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 46.

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

SMITH RIG COUNT

Proposed depth, ft	5-2-08 Rig count	5-2-08 Percent footage*	5-4-07 Rig count	5-4-07 Percent footage*
0-2,500	76	5.2	57	7.0
2,501-5,000	119	52.9	109	53.2
5,001-7,500	216	16.2	223	15.6
7,501-10,000	432	3.4	400	2.5
10,001-12,500	474	4.2	439	4.1
12,501-15,000	287	—	253	0.7
15,001-17,500	126	—	105	0.9
17,501-20,000	75	—	77	—
20,001-over	37	—	35	—
Total	**1,842**	**7.4**	**1,698**	**7.5**
INLAND	29		37	
LAND	1,755		1,596	
OFFSHORE	58		65	

*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]5-2-08	[2]5-4-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	15	20
Alaska	714	750
California	650	669
Colorado	43	59
Florida	6	6
Illinois	24	26
Kansas	93	99
Louisiana	1,350	1,332
Michigan	15	17
Mississippi	50	49
Montana	91	89
New Mexico	161	164
North Dakota	115	117
Oklahoma	169	170
Texas	1,340	1,350
Utah	44	50
Wyoming	143	146
All others	61	72
Total	**5,084**	**5,185**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

	5-2-08 $/bbl*
Alaska-North Slope 32°	96.05
South Louisiana Sweet	118.50
California-Kern River 13°	103.80
Lost Hills 30°	111.95
Southwest Wyoming Sweet	107.82
East Texas Sweet	112.25
West Texas Sour 34°	105.25
West Texas Intermediate	112.75
Oklahoma Sweet	112.75
Texas Upper Gulf Coast	109.25
Michigan Sour	105.75
Kansas Common	111.75
North Dakota Sweet	105.50

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

	4-25-08 $/bbl[1]
United Kingdom-Brent 38°	114.64
Russia-Urals 32°	109.46
Saudi Light 34°	110.52
Dubai Fateh 32°	108.11
Algeria Saharan 44°	116.31
Nigeria-Bonny Light 37°	118.10
Indonesia-Minas 34°	113.47
Venezuela-Tia Juana Light 31°	111.53
Mexico-Isthmus 33°	111.42
OPEC basket	112.78
Total OPEC[2]	110.96
Total non-OPEC[2]	111.12
Total world[2]	111.03
US imports[3]	109.25

[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]

	4-25-08	4-18-08	4-25-07	Change, %
	bcf			
Producing region	531	506	665	–20.2
Consuming region east	652	598	701	–7.0
Consuming region west	188	181	260	–27.7
Total US	**1,371**	**1,285**	**1,626**	**–15.7**

	Feb. 08	Feb. 07	Change, %
Total US[2]	**1,465**	**1,649**	**–11.2**

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

Worldwide crude oil and gas production

	Feb. 2008	Jan. 2008	2 month average production 2008	2 month average production 2007	Change vs. previous year Volume	Change vs. previous year %	Feb. 2008	Jan. 2008	Cum. 2008
	Crude, 1,000 b/d						Gas, bcf		
Argentina	640	614	627	630	–3	–0.5	130.0	122.2	252.18
Bolivia	42	42	42	44	–2	–4.5	39.0	42.0	81.00
Brazil	1,772	1,776	1,774	1,747	27	1.5	35.0	34.0	69.00
Canada	2,586	2,538	2,562	2,570	–8	–0.3	478.0	522.5	1,000.48
Colombia	568	554	561	519	42	8.1	20.0	22.0	42.00
Ecuador	500	500	500	508	–8	–1.5	1.0	1.0	2.00
Mexico	2,929	2,957	2,943	3,146	–203	–6.4	189.7	202.6	392.30
Peru	114	107	111	117	–6	–5.5	7.5	7.0	14.50
Trinidad	116	115	115	122	–7	–5.5	107.6	130.0	237.58
United States	5,045	5,093	5,069	5,172	–103	–2.0	1,695.0	1,784.0	3,479.00
Venezuela[1]	2,410	2,440	2,425	2,460	–35	–1.4	70.0	75.0	145.00
Other Latin America	80	80	80	80	1	0.9	5.2	5.5	10.78
Western Hemisphere	**16,802**	**16,816**	**16,809**	**17,113**	**–304**	**–1.8**	**2,778.0**	**2,947.8**	**5,725.82**
Austria	17	16	17	17	–1	–4.9	4.9	5.2	10.10
Denmark	286	300	293	312	–19	–6.1	29.4	31.5	60.90
France	22	20	21	18	3	16.8	3.0	3.1	6.10
Germany	63	64	64	70	–6	–8.6	47.4	51.3	98.71
Italy	114	108	111	110	1	0.9	25.0	27.0	52.00
Netherlands	40	40	40	44	–4	–9.1	355.0	380.0	735.00
Norway	2,176	2,229	2,203	2,443	–241	–9.8	324.8	325.7	650.50
Turkey	39	39	39	39	—	–0.7	—	—	—
United Kingdom	1,492	1,460	1,476	1,603	–127	–7.9	229.5	256.4	485.88
Other Western Europe	4	4	4	5	—	–5.5	3.7	4.2	7.94
Western Europe	**4,253**	**4,281**	**4,267**	**4,661**	**–394**	**–8.5**	**1,022.8**	**1,084.4**	**2,107.12**
Azerbaijan	950	900	925	850	75	8.8	30.0	31.0	61.00
Croatia	15	16	15	16	–1	–6.1	5.7	5.0	10.74
Hungary	15	14	14	17	–2	–14.7	6.7	7.6	14.30
Kazakhstan	1,250	1,200	1,225	1,075	150	14.0	70.0	68.0	138.00
Romania	95	95	95	98	–3	–2.6	17.0	18.0	35.00
Russia	9,760	9,800	9,780	9,900	–120	–1.2	2,000.0	2,100.0	4,100.00
Other FSU	400	400	400	400	—	—	500.0	550.0	1,050.00
Other Eastern Europe	47	48	47	49	–1	–3.0	17.7	18.9	36.65
Eastern Europe and FSU	**12,532**	**12,472**	**12,502**	**12,404**	**98**	**0.8**	**2,647.1**	**2,798.6**	**5,445.68**
Algeria[1]	1,380	1,400	1,390	1,330	60	4.5	260.0	285.0	545.00
Angola[1]	1,919	1,895	1,907	1,599	308	19.3	4.7	5.0	9.70
Cameroon	86	90	88	86	2	2.6	—	—	—
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	630	630	630	660	–30	–4.5	40.0	42.0	82.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.12
Gabon	240	230	235	230	5	2.2	0.3	0.3	0.61
Libya[1]	1,760	1,770	1,765	1,695	70	4.1	21.0	23.0	44.00
Nigeria[1]	2,060	2,060	2,060	2,265	–205	–9.1	65.0	70.0	135.00
Sudan	480	480	480	450	30	6.7	—	—	—
Tunisia	80	84	82	90	–9	–9.4	6.0	6.7	12.72
Other Africa	232	232	232	232	—	—	9.5	10.2	19.60
Africa	**9,447**	**9,450**	**9,448**	**9,217**	**232**	**2.5**	**406.5**	**442.2**	**848.75**
Bahrain	169	169	169	170	–1	–0.4	22.3	23.5	45.84
Iran[1]	3,950	4,100	4,025	3,840	185	4.8	225.0	245.0	470.00
Iraq[1]	2,450	2,290	2,370	1,840	530	28.8	4.0	4.0	8.00
Kuwait[1,2]	2,580	2,570	2,575	2,440	135	5.5	33.0	35.0	68.00
Oman	700	700	700	725	–25	–3.4	55.0	58.0	113.00
Qatar[1]	830	850	840	805	35	4.3	160.0	170.0	330.00
Saudi Arabia[1,2]	8,960	9,010	8,985	8,510	475	5.6	170.0	180.0	350.00
Syria	390	390	390	395	–5	–1.3	17.0	18.0	35.00
United Arab Emirates[1]	2,650	2,670	2,660	2,570	90	3.5	130.0	140.0	270.00
Yemen	320	320	320	355	–35	–9.9	—	—	—
Other Middle East	—	—	—	—	—	–66.5	11.1	11.5	22.60
Middle East	**22,999**	**23,069**	**23,034**	**21,650**	**1,384**	**6.4**	**827.4**	**885.1**	**1,712.43**
Australia	404	334	369	466	–97	–20.8	107.3	99.1	206.40
Brunei	193	169	181	188	–8	–4.1	35.0	36.9	71.89
China	3,757	3,778	3,768	3,786	–18	–0.5	231.6	229.5	461.10
India	647	686	667	694	–28	–4.0	81.8	83.8	165.57
Indonesia[1]	870	830	850	850	—	—	190.0	200.0	390.00
Japan	20	20	20	19	1	7.7	12.0	13.0	25.00
Malaysia	770	780	775	760	15	2.0	140.0	150.0	290.00
New Zealand	60	65	63	15	48	316.7	11.0	11.9	22.90
Pakistan	68	68	68	65	3	5.0	119.5	128.4	247.93
Papua New Guinea	10	10	10	25	–15	–60.0	0.9	1.0	1.90
Thailand	214	217	216	201	15	7.3	42.0	46.0	88.00
Vietnam	300	300	300	340	–40	–11.8	14.0	15.0	29.00
Other Asia-Pacific	28	31	30	36	–6	–17.0	88.7	95.5	184.17
Asia-Pacific	**7,341**	**7,288**	**7,315**	**7,444**	**–129**	**–1.7**	**1,073.7**	**1,110.2**	**2,183.86**
TOTAL WORLD	**73,374**	**73,377**	**73,376**	**72,489**	**887**	**1.2**	**8,755.5**	**9,268.2**	**18,023.67**
OPEC	32,319	32,385	32,352	30,204	2,148	7.1	1,333.7	1,433.0	2,766.70
North Sea	3,971	4,007	3,989	4,374	–385	–8.8	689.9	727.1	1,417.04

[1]OPEC member. [2]Kuwait and Saudi Arabia production each include half of Neutral Zone. Totals may not add due to rounding.
Source: Oil & Gas Journal. Data available in OGJ Online Research Center.

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Budget projects and forecast expenses
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Communication and Collaboration
Work with third party engineering consulting firms on more complex projects to ensure facilities meet all applicable standards and specifications.
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Provide engineering technical support, troubleshooting, and problem solving for operating issues relating to pipelines, gas regulating and measurement equipment, electronic automation, and other gas handling facilities.
Participate in studies and projects to enhance the overall safety, reliability, and efficiency of the gas transmission system.

Assist with development and implementation of Company Design Standards and Specifications

Required:

Bachelors Degree in Engineering
Minimum 2 years experience serving as design, construction, or project engineer for natural gas facilities
Intermediate skill level in Microsoft Office applications

Preferred:

Fundamentals of Engineering Certificate
Minimum 2 years experience in Measurement design of Natural gas facilities
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Farm interests strain facts to defend ethanol

Farm interests will say anything to protect the magic money machine that the US government has built for them with fuel ethanol.

They're hard at it now, as global leaders awaken to the push biofuels give the price of food.

In testimony May 1 to the Joint Economic Committee of Congress, National Farmers Union Pres. Tom Buis acknowledged that the US ethanol mandate contributes to the food-price surge but argued that other factors are more influential. He listed $120/bbl oil, the declining value of the US dollar, increased demand from developing countries, and global production shortages, especially for wheat, associated with weather.

The Editor's Perspective

by Bob Tippee, Editor

So far, so good. No one says government support for ethanol and other biofuels is the only reason food prices are high. And there's room for honest disagreement about the relative strengths of forces driving up prices.

But the biofuels push is a deliberate act of government. Hoping to prevent a correction of that mistake, Buis stretched his argument into a realm that should alarm oil and gas companies.

"While critics will say our government is subsidizing and mandating the use of ethanol," he said, "the subsidies pale in comparison to the amount we spend subsidizing the oil companies and protecting the shipping lanes to import oil from the most unstable region of the world."

Oh?

The US will protect shipping lanes no matter how much oil it imports, so that point means nothing.

And the bluster about subsidies is false. Last year, according to the Energy Information Administration, subsidies for oil and gas totaled $2.149 billion, of which $260 million represented tax breaks for clean-fuel vehicles, not oil and gas companies.

The blenders' tax credit alone on the 6.5 billion gal of ethanol blended to gasoline last year was worth $2.92 billion. And ethanol gets other subsidies.

"Instead of cutting the ethanol mandate, maybe Congress should cut the big oil and gas subsidies," Buis said.

Coming from a leader of an industry that enjoys subsidies estimated by the Heritage Foundation at $25 billion/year and favors that raise food prices by a further $12 billion/year, this is hypocrisy.

(Online May 2, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

OPEC's position strengthens

Growing demand for crude combined with the slowdown in production of new supplies in other countries is placing the Organization of Petroleum Exporting Countries in a powerful position, say industry analysts.

"Given the mature characteristics of much of non-OPEC oil production, it does not appear feasible that non-OPEC countries, as a group, will be able to deliver meaningful oil supply growth in the future. A permanent non-OPEC peak seems likely within the next 5 years," said analysts in the Houston office of Raymond James & Associates Inc.

"Non-OPEC growth is highly dependent on Russian growth and, given its current policy environment and recent production declines, Russia would do well to return to 2-3% growth," Raymond James analysts said. "Accordingly, the world is likely to continue in an environment of thin excess capacity for the foreseeable future. Given this tight supply-demand equation, threats of even minor supply disruptions are bound to have a large impact on oil prices."

Adam Sieminski, global energy economist for Deutsche Bank, said, "The oil supply slowdown in the Organization for Economic Cooperation and Development and the former Soviet Union is leaving OPEC in charge. Global oil supplies are under pressure from shrinking production prospects in Russia and across a wide swath of the OECD nations. By definition, demand equals supply, and although we think that demand is rising despite the economic slowdown, supply is struggling to keep up."

Energy conservation in the US and the OECD has not been sufficient to offset demand increases in other parts of the world. Global demand for oil grew by 1.1 million b/d in 2007, while the average of the four estimates for 2008 growth is 1.2 million b/d, according to Deutsche Bank.

"The world has been depending on supply growth from the FSU and other non-OECD countries. Russian production growth has tapered off, biofuel growth is likely to be under pressure from rising concerns about food and environmental impacts, and continuing declines are expected in the OECD," said Sieminski. "Based upon the average estimates we have used here, non-OPEC Africa and Latin America offer some hope for oil supply growth, but not enough to offset the likely rising dependence on OPEC."

Natural gas outlook

Meanwhile, the US Department of Energy report released Apr. 30 "showed US gas production screaming upward, increasing year-to-year by an astounding 5.8 bcfd, although we estimate 1 bcfd was taken offline last year due to wellhead freezes," said Raymond James analysts. "Given the acceleration since last October, driven by exploding growth in resource play activity (Barnett shale), when will the market pull its head out of the sand and start paying attention to this key fundamental driver?" Sieminski said, "The real picture for US natural gas supply and demand is complicated and not as bearish as the February wet gas production jump suggests. We remain bullish." He said DOE analysts have been forecasting that US gas production is likely to flatten out in 2008 at a level slightly below January's estimated output of 54.7 bcfd of dry gas.

The surprise February increase in wet gas "suggests that dry gas production in February might be some 1.2 bcfd higher than [DOE's] Energy Information Administration's estimate of 54.5 bcfd. We believe that there are several good reasons to be cautious about jumping to conclusions about a jump in US gas production" said Sieminski.

Although the Rockies Express pipeline start-up in mid-January (now flowing about 1 bcfd) may be responsible for some of the February gains, the Independence Hub accident in mid-April is temporarily pulling 1 bcfd off the market, he noted.

Further more, said Sieminski, "A jump of 1 bcf in production from January to February seems very implausible in view of the leveling off of the rig count in the third quarter of 2007." He said, "Even if supplies did build consistently by 1 bcfd, that must have been offset by rising demand (or lower imports) because the supply-demand balances can be observed in the storage data, and that is inconsistent with a big supply jump."

The EIA reported May 1 the injection of 86 bcf of natural gas into US underground storage during the week ended Apr. 25. That put the amount of working gas in storage at 1.37 tcf, down 255 bcf from year-ago levels and 3 bcf below the 5-year average for the time of year.

US crude inventories shot up 3.8 million bbl to 319.9 million bbl in the week ended Apr. 25. US gasoline stocks fell 1.5 million bbl to 211.1 million bbl. US distillate fuel inventories gained 1.1 million bbl to 105.8 million bbl.

(Online May 5, 2008; author's e-mail: samf@ogjonline.com)

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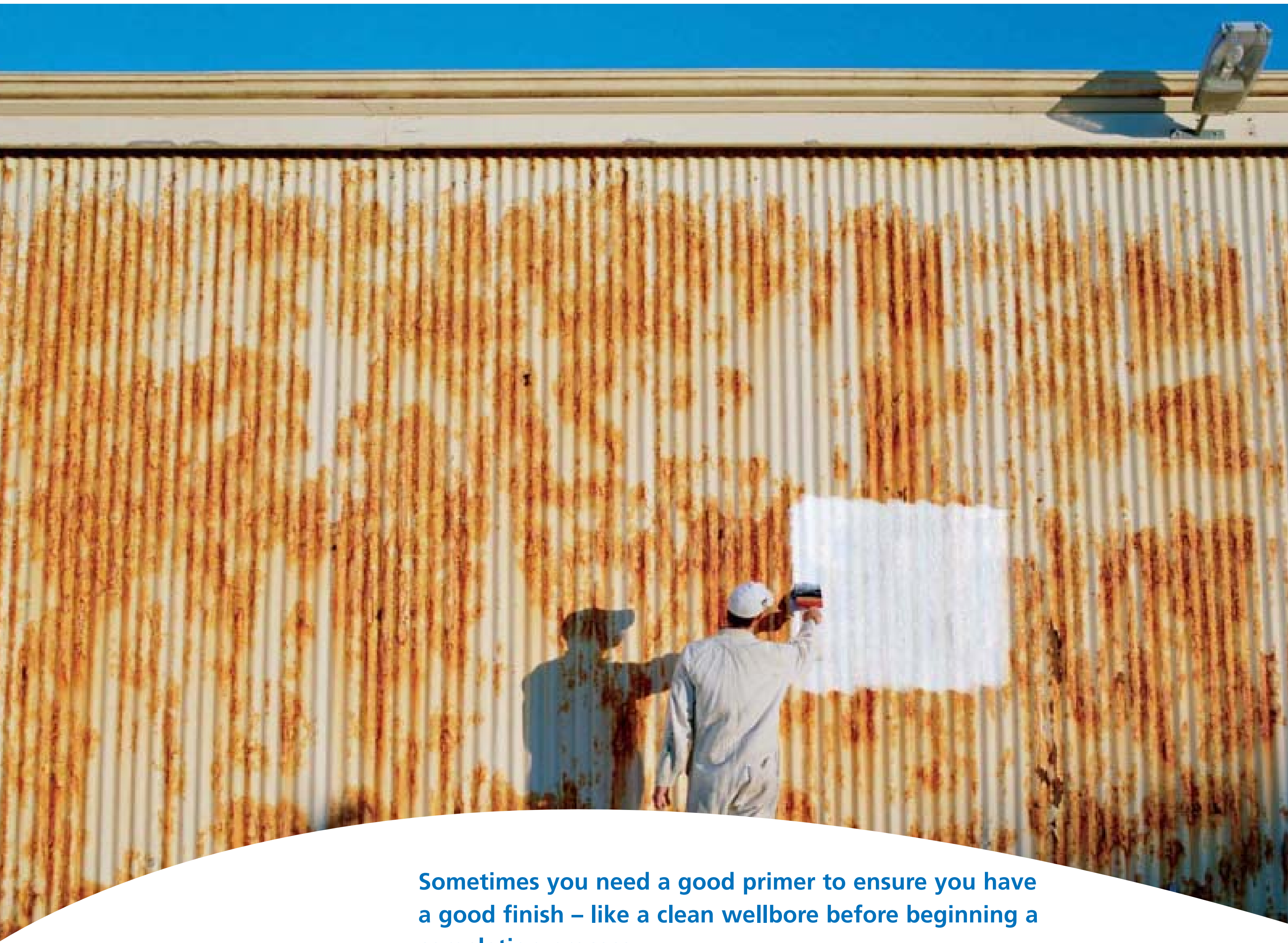
Does Your Wellbore Need a Primer?



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Technology Forum

Downhole Fluids Equipment & Services

Supplement to *Oil & Gas Journal* • May 12, 2008

Managing produced water is one of the controversial environmental issues facing the oil and natural gas industry. This prototype of Wescorp Energy's Total Fluids Solution oil/water separation unit was installed adjacent to storage tanks that are part of the operator's treating facility. Photo courtesy of Wescorp Energy.

Oil & Gas Journal's Technology Forum series, produced by the OGJ Group Publisher, supplements the magazine with topical features on cutting-edge technology, services, and equipment, all expertly written from the technology provider's perspective. Inquiries should be directed to Bill Wageneck, Group Publisher, at billw@pennwell.com.

Managing, optimizing drilling fluids a challenge with deeper drilling

Managing drilling fluids economically and optimizing their effectiveness while still keeping those operations environmentally benign can be among the trickiest balancing acts operators and drilling contractors face today.

Those drilling fluids challenges are getting tougher as industry plunges into ever-deeper waters and penetrates ever-deeper formations.

Specialized applications

As the drilling industry matures and the search for hydrocarbons moves into even more challenging environments, the need for innovative and novel drilling solutions has taken on greater importance, according to Baker Hughes Drilling Fluids: "The utilization of specialized drilling fluid additives is becoming more prevalent, especially in depleted fields and in deep and ultradeep waters. These challenging wells require more than just traditional additives to successfully achieve the goal of moving oil and gas from the reservoir into the refining process."

In response to that need, Baker Hughes has been developing synthetic-based compliant emulsion systems for drilling in challenging downhole conditions, such as deepwater and high-pressure/high-temperature (HPHT) wells, while meeting stringent environmental requirements.

"These developments were driven by the extreme HPHT environment associated with deep shelf drilling in the Gulf of Mexico and the deviated HPHT wells drilled in the North Sea," the company says. "Laboratory testing demonstrates fluid stability at temperatures in excess of 580 °F and pressures exceeding 30,000 psi.

"Since 2001 Baker Hughes Drilling Fluids has been working on perfecting a major change in HPHT emulsion-based systems. Although the revision was initially triggered by environmental legislation changes in the North Sea area, the developments and improved chemistries have demonstrated superior performance in both diesel-based fluids and in the synthetic fluids used in the Gulf of Mexico and other areas of the world. The chemistries chosen deliver minimal impact on the environment and to the health and safety of the personnel involved in the drilling operation."

Baker Hughes Drilling Fluids' high-performance water-based muds (HPWBM) are designed to emulate the performance attributes of invert-emulsion systems. The need for environmentally safe and technically equivalent, water-based alternatives to emulsion systems is increasingly becoming an important consideration in the drilling fluid selection process. Baker Hughes Drilling Fluids was the first service company to introduce HPWBM, starting with the AQUA-DRILL System, based on cloud-point glycols, in the early 1990s.

"We have continually researched technology to constantly improve high performance water-based muds. New technology such as MAX-SHIELD™ and MAX-PLEX™, which improves shale stability by reducing pore pressure transmission, and MAX-GUARD, which suppresses the hydration and dispersion of gumbo and reactive clays, have proven to be significant performance-enhancement products in our HP-WBM product line," the company says.

Deeper drilling

The key word for drilling fluids challenges today is "deeper," says Robin J. Verret, director of research and development for Turbo-Chem International Inc.

"From deeper water to deeper wells, the challenges are daunting," he says. "In the deepwater arena, not only do we have to ensure environmental compatibility with the regulatory agencies, but compatibility also with the harsh and drastic downhole environments that must be drilled, to reach the particular oil or gas commodity the operator is searching for.

"The various drilling fluids must be able to withstand vast temperature fluctuations from near freezing at the seafloor to >450 °F downhole in some cases. This must also be accomplished under the massive pressure changes from atmosphere at the surface to >20,000 psi, depending on the fluid weight, which is where the HPHT systems come into play. Our products must also be compatible with these environments

"The deeper the operators drill, whether in the water or on land, the dynamics will continue to push the envelope of temperature and pressure capabilities of the drilling fluid."

— Robin Verret, Turbo-Chem

"The continued development of environmentally acceptable water-based drilling fluids that match or correlate closely to the high-performance characteristics of invert emulsion fluids is having a very significant impact on the industry."

— *Don McKenzie, M-I Swaco*

and have no negative impact on the fluid make-up that would change the fluid flow properties or chemistry."

The deeper the operators drill, whether in the water or on land, the dynamics will continue to push the envelope of temperature and pressure capabilities of the drilling fluid, contends Verret.

"Actually, any specialty additives must not only be able to withstand these harsh, extreme drilling environmental changes, but these additives should actually contribute to the stability and success of the system as well. That is our task in the research and development department here."

Environmental concerns

The environmental compatibility of drilling, completion, and workover fluids and the additives used in them is an imperative for drilling fluids vendors.

"Much of what we do here at Turbo-Chem is in conjunction with the drilling fluids vendor's system in use in the well at the time," Verret notes. "It is imperative that our additives are environmentally compatible with that system, or in many cases, systems, to prevent any potential regulatory infractions."

Noting the many drilling fluids systems in use worldwide and the large array of regulatory and environmental requirements, Verret adds, "We spend a great amount of time and resources testing our products in the different systems to ensure compatibility."

Don McKenzie, president and CEO of M-I Swaco, contends that the continued development of environmentally acceptable water-based drilling fluids that match or correlate closely to the high-performance characteristics of invert emulsion fluids is having a "very significant impact" on the industry.

Operators benefit from the value-added performance that oil-based muds deliver, while "also removing the environmental obstacles and associated costs that limit the use of oil-based fluids in many operating theaters," he adds.

New technologies

Wellbore stability and preventing or remediating lost circulation will be paramount for the operator's ability to drill with the various drilling fluids systems, according to Verret.

"Each one of the various systems has its own idiosyncrasies regarding compatibility and success of accomplishment, when utilizing specialty additives such as ours," he points out. "Each system has its arena of use, which are as varied as the number of systems. The key for our success is to have products that are 'cross-compatible.' By that I mean products that function as well in most of the water-based, oil-based, and synthetic-based systems. The same product might function as an HPHT additive in one system and as a seepage loss prevention additive in another. Or one particular product might be 'system' compatible with all of these systems. Of course, this is the optimum, but not always achievable. Without some cross-compatibility, the vast array of products that would be necessary to maintain would create quite a warehousing, logistics, and accounting dilemma."

Another growing problem is fluid movement, notes Verret. "The deeper the operators drill and the more extended the reach of directional wells, the more pressure is required to 'move' the drilling fluid efficiently," he says. "This added pressure increases the overall bottomhole pressure, known as equivalent circulating density (ECD). This increase in ECD increases the risk of formation fracturing, leading to lost circulation and possible loss of the wellbore.

"Many of the drilling fluids companies are developing shear-thinning drilling fluids by reducing the strength of the gel structure, to overcome this challenge. However, recent research indicates that lost circulation is influenced by the strength of the gel structure of the fluid. The lower the gel structure strength or the more shear-thinning the fluid, the more prone that fluid is to lost circulation. The solution to one problem actually increases the possibility of another problem. This is another area that we are working in: Testing the compatibility of our current products and working to develop new products that can be used in these shear-thinning fluids without affecting the weaker gel structures, yet preventing the losses from occurring."

One of the major challenges for the industry is developing specialty products for HPHT drilling, says Verret: "As the operators search deeper and more hostile environments, specialized fluid systems and additives will be required to accomplish this task. We are not only working on develop-

As industry continues to press the envelope on drilling in ultradeep formations and ultradeep water, new downhole fluids application and management technology solutions are striving to keep pace. Photo courtesy of Parker Drilling Co.

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As the industry shifts to deeper water, the environment in which we work becomes more complex, hazardous and expensive. Successful companies recognize early the changing conditions and environmental challenges facing the industry. At the Deepwater Operations Conference & Exhibition in 2008, participants and attendees will discuss how to succeed under these extreme conditions.

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Plan to attend, sponsor and exhibit at the 2008 conference and exhibition as the technical focus shifts to "Succeeding in a Changing Environment." As with our past conferences, proceedings will not be published and the press will not be invited to assure confidentiality between the attendees and the speakers allowing the most up–to–date information to be shared.

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ing products to aid in reducing the fluid loss properties of these systems, but we are also looking at ways to make our seepage and lost circulation additives capable of withstanding these environments. Thus far, we have relied on organic materials for many of our additives, but these organic materials can have a weakness: thermal degradation. Our goal has been, and continues to be, finding ways to extend the temperature and pressure range of our existing products and developing new products capable of performing as well as our existing products, in these harsh complex environments, at which I'm happy to say, we've been pretty successful."

Drill-in fluids comprise another area that Turbo-Chem has been investigating.

"These drill-in-fluids, such as Formates, for example, are basically solids-free systems," Verret notes. "While these solids-free systems are very formation friendly, this solids-free state creates a dilemma for the operator. What to do when lost circulation occurs with fluids that cost $900/bbl or greater? We are looking at a number of materials and chemistries that will be able to prevent or control losses without compromising the formation friendliness of these types of fluids."

As the wells have become more complicated, the drilling fluids have followed suit, Verret contends.

"Things are no longer simple, and it's taken some cutting-edge science to get drilling technology to where it is today," he says. "We've had to follow this lead here at Turbo-Chem as well. No longer is it simply putting bagasse or sawdust in the drilling fluid to stop lost circulation. We've had to apply quite a bit of science in our field.

"With all of the new technology has come new opportunities to learn what we are actually dealing with downhole. With MWD, LWD, PWD, and all the other 'WDs,' we now have a better idea of what we are up against when it comes to wellbore stability and lost circulation issues. We've even got actual downhole photographs and videos available, which actually allow us to see the types and size of the fracturing occurring in vertical, directional, and horizontal wells, through various formation types…I believe we're just in the infancy stages of many of these emerging technologies. Just 10 years ago MWD was considered voodoo by many, but today almost no one drills a well without it."

Efficiencies

The most expensive and most difficult to control commodity in the entire drilling arena is time, contends Verret.

"Time isn't getting any cheaper either. There are many time bandits in the drilling of a well, and several that are directly related to the hole, such as rate of penetration, seepage loss or lost circulation, tripping in or out of the hole, etc. As the operators drill deeper, the time cost of these activities rises almost exponentially. That's the real value of the products and services we market. If we can save the operator downtime or help expedite a process, then we've put money back into the operator's drilling budget, which then can be used to drill additional wells. The research and product development that we do is juxtaposed with time. Not only do we need to determine how does what we are adding to the drilling fluid affect the mud and wellbore, but is this effect going to save time? If we can capture all of these in a single product, then we've hit an R&D home run."]

Produced water management: controversy vs. opportunity

One of the most controversial areas of oil and gas production operations today is the handling, treatment, and disposal of produced water.

The oil and gas producing industry generates tens of billions of barrels of produced water every year along with the hydrocarbons it recovers, and with that practice comes mounting concerns about waste and contamination of water.

"The world's population has insatiable demands for two equally precious commodities, potable water and fossil fuels," notes Doug Biles, president and CEO of Wescorp Energy Inc. "Unfortunately, the pursuit of one always seems to be at odds with the pursuit of the other. The perception exists that the demand for fossil fuels comes at the expense of the supplies of potable water in particular and the overall environment in general.

"Put this together with the perception of the petroleum industry as one willing to waste valuable water supplies in its pursuit of massive profits at the expense of the environment and you quickly realize how this subject becomes very emotional, very quickly, and very public."

Contamination concerns

Halina Caravello, Baker Hughes vice-president, health, safety, and environment, notes that "while oil spills are the headline grabbers, release of produced water is, in aggregate, the larg-

"The world's population has insatiable demands for two equally precious commodities, potable water and fossil fuels. Unfortunately, the pursuit of one always seems to be at odds with the pursuit of the other. The perception exists that the demand for fossil fuels comes at the expense of the supplies of potable water in particular and the overall environment in general. Put this together with the perception of the petroleum industry as one willing to waste valuable water supplies in its pursuit of massive profits at the expense of the environment and you quickly realize how this subject becomes very emotional, very quickly, and very public."

— Doug Biles, Wescorp Energy

est liquid discharge from E&P operations, and perhaps, more difficult to manage effectively."

Recent data indicate that worldwide 9 tons of oil were released via produced water for every million tons of produced hydrocarbons, she notes.

"While improper management can lead to detrimental environmental consequences, such as contamination of aquifers, or harm to plant and animal life, managing this stream effectively can have positive environmental impacts." Caravello says.

"Recent activity to increase oil production in new and existing fields has created a more difficult produced water challenge, namely 'high oil-in-water load emulsions,' she notes. "Instead of treating production primarily to remove water from the oil, these fluids must be primarily treated to recover oil from the water. This requires the use of a whole new class of chemicals not used in oil production before—ultra-long-chain polymer flocculants requiring much higher levels of skill and care to apply effectively. This new generation of treatments must be delivered emulsified or dispersed in oil or brine, or diluted in gelatinous solutions."

One particularly difficult class of contaminants to manage in produced water are water-soluble organics, which are insoluble under the acidic conditions in which oil-in-water is measured, Caravello points out.

"New treatment regimes, which employ 'activated hydrophilic acids,' alone or in combination with anionic polymers, reduce the concentrations of these contaminants to acceptably low levels," she notes.

As clean water becomes a scarcer vital resource, the treatment of produced water to allow other uses, such as recycling back to the reservoir as water or steam to enhance production and prevent subsidence, or using for irrigation, washing, or even drinking, may become more important than oil, Caravello adds: 'At ever more wellheads, the most effective approach is 'treat the water first.'"

Because regulators are increasing their requirements on petroleum companies across the globe—a trend that is likely to continue—"the industry must recycle produced water and use it again and again and again, much like how an automatic car wash recycles water," says Biles.

"When hydrocarbons are present in the produced water, other existing technologies—desalinization, desanding, etc.—won't work," he points out. "Today, in the Canadian tar sands area, tailing ponds are so huge they can seen from space with the naked eye.

"If this water treatment issue is not solved, it has the potential of negatively impacting new exploration and production in the United States and Canada."

Biles estimates that it takes 4–20 bbl of water to produce 1 bbl of oil in today's unconventional drilling.

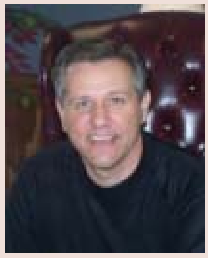
"This water needs to be cleaned so it can be recycled," he adds. "Preserving and remediating water reduces trucking and disposal costs and increases potable water sources."

Michael R. Robicheaux, general manager, oil and gas division, Siemens Water Technologies Corp., concurs that the worldwide E&P sector is currently experiencing several challenging issues pertaining to produced water treatment and discharge criteria. "First, due to higher commodity prices, wells that would have otherwise been shut in are now proving to be commercially viable and are remaining in production for longer periods of time," he points out. "The maturation of these older wells results in higher than initially forecasted water cuts—thus the produced water treatment system being in an overcapacity situation.

"Second, both domestic and international operators of new

"While oil spills are the headline grabbers, release of produced water is, in aggregate, the largest liquid discharge from E&P operations, and perhaps, more difficult to manage effectively."

— Halina Caravello, Baker Hughes



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>
> *— Michael R. Robicheaux, Siemens Water Technologies Corp*

production platforms are demanding smaller equipment footprint and weight reductions while still maintaining the capability to properly treat high volumes of produced water to be discharged while ensuring compliance.

"Third, water-soluble organics (WSOs) are posing a significant challenge to the industry, and economical treatment alternatives have not yet been identified. Overall, the most difficult challenge centers around ever-increasing volumes of produced water requiring treatment, whether on land or offshore."

Robicheaux thinks that dealing with WSOs and mercury contamination loom as the major environmental challenges ahead for industry's efforts centered on managing produced water.

He contends that industry efforts should be focused on three main areas:

- Ultimate compliance with the local, regional or international discharge criteria.
- Reduction in operational cost even at the expense of higher initial capital outlay.
- Point source treatment alternatives.

Cost-effectiveness

The most cost-effective approaches to managing produced water offshore is primary and secondary separation and treatment, followed by discharge into receiving waters within criteria limits and/or reinjection, Robicheaux says.

"Onshore, the most promising beneficial reuse approaches to managing produced water include water reinjection for reservoir/pressure maintenance, reuse of treated water for agricultural purposes (i.e., irrigation), and for miscellaneous applications such as subsequent hydraulic fracturing projects, surface hole drilling, roadway dust suppressant, etc.," he notes.

New technologies

Among new technologies that offer great promise for handling and treating produced water is the dissolved gas flotation (DGF) system patented by Monosep.

Monosep describes the system as follows:

The DGF pump works by using a dual-sided impeller that pulls both water and gas into the pump volute. The backside of the impeller has a "subatmospheric" zone that pulls vapor from the blanket gas source or other means and allows mixing with the incoming fluid. As this occurs the vapor is dissolved into the water, creating microfine bubbles that break out of solution once a pressure drop is experienced. This pressure drop occurs once the fluids and dissolved gas are flowed across a globe valve prior to entrance into the flotation vessel. Due to the close tolerance between the back vanes of the impeller and the back plate of the DGF pump, the vapor is sheared into microfine bubbles piped into a vessel or tank, allowing the fine gas bubbles to attach to the oil droplets. As the gas bubble attaches to the oil droplet, the droplet floats to the surface at an accelerated rate. The DGF technology can produce bubbles that range from 1 micron and greater, according to Monosep.

Robicheaux cites the emergence of subsea separation systems, "a new technology, although not proven on large-scale projects, and there are minimal installations."

Wescorp offers a system it dubs "Total Fluids Solutions."

In the Wescorp system, a unique patented aeration system creates micron-sized gas bubbles that supersaturate the produced water. As the solids are cleaned of hydrocarbons, the heavy solids fall, and the lighter suspended solids rise and are encapsulated in the recovered oil. An innovative tank configuration removes the oil and a slight amount of water from the primary tank. This oil-water mixture flows through the remainder of the system, achieving virtually total separation of the oil and produced water. The recovered oil flows into an oil collection tank and the water, free of oil and solids, is pumped down a disposal well back into the reservoir. Through this process, the hydrocarbon content in the injected water is reduced from the typical 5,000–30,000 ppm to less than 50 ppm.

Biles cites the economic advantages of his company's Total Fluids Solution as:

- Reducing the frequency of expensive remedial work on injection wells.
- Recovering additional reserves from the reservoir.
- Decreasing the amount of surface treating facilities, in some cases.

"These advantages will make a significant difference in the operating costs of an oil field," Biles contends. "This new technology has the ability to significantly help with water shortages in a number of oil and gas producing areas, including the Barnett shale production areas in the US."]


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