Week of April 23, 2007/US$10.00

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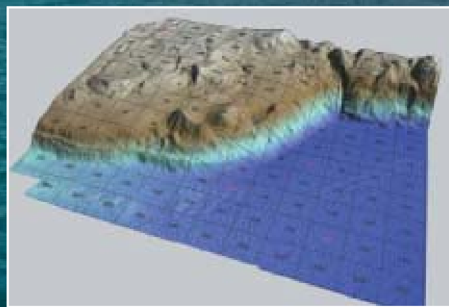
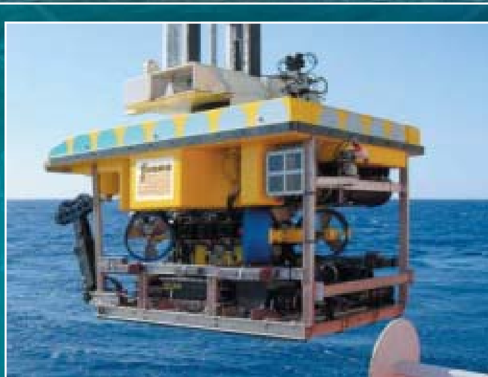
International Petroleum News and Technology / www.ogjonline.com

Offshore Petroleum Operations

China expands energy mix, seeks investment
World oil production to peak in 15-25 years, AAPG told
Study updates refinery investment cost curves





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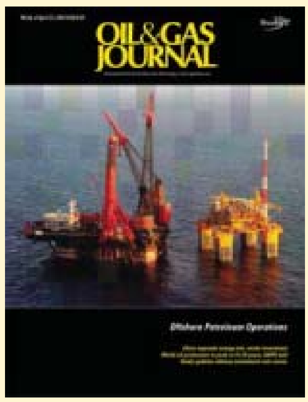
Apr. 23, 2007
Volume 105.16

Offshore Petroleum Operations

Regular Features

Cover



Independence Hub LLC, a venture of Enterprise Field Services LLC (80%) and Helix Energy Solutions (20%), owns the Independence Hub (IHUB) semisubmersible natural gas processing platform. Anadarko Petroleum Corp. will operate processing on the hub on behalf of gas field owners that include Anadarko, Dominion Exploration & Production, Devon Energy Corp., Hydro Gulf of Mexico, and Murphy Oil Corp. Production from the fields served by IHUB, stationed in water 8,000 ft deep on Mississippi Canyon Block 920, is to begin in second-half 2007. Enterprise hired Heerema Marine Contractors Nederland BV for installation of the IHUB, including all risers. Heerema used its Deepwater Construction Vessel Balder for the IHUB installation. More on the installation of IHUB's export riser, the largest steel catenary riser ever installed, forms part of Oil & Gas Journal's exclusive annual report on Offshore Petroleum Operations that begins on p. 57. Photo from Enterprise Products Partners LP.

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General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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General Interest — Quick Takes

Iraq study sees output hike, confirms reserves

Iraq could double oil production capacity to 4 million b/d in 5 years with little effort, according to a 12-month study of its reservoirs by IHS Inc., London.

The study, to be published in May as an Iraq Atlas, confirmed longstanding conventional wisdom that Iraq has 116 billion bbl of proved and probable oil reserves and 100 tcf of gas reserves. Basin studies indicated that another 100 billion bbl of oil and a large volume of gas can be recovered from the country's hardly explored western desert.

The study group assessed 435 undrilled prospects and noncommercial discoveries and 81 producing fields and commercial discoveries. The group evaluated the reservoirs using new information and reassessed and validated all field reserves and production numbers.

The government, which needs $20-25 billion in investment in its E&P sector, is expected to launch a bid round for 65 exploration blocks and 78 fields in 2007.

The western desert estimate, which IHS said has a large error margin, was developed from new play concepts generated in a recent study of the Western Arabian platform. Iraq has made only one discovery in the region, which is expected to hold oil in Silurian rocks and gas in Ordovician formations.

Given a stable political and civil environment, Iraq could boost its capacity from just under 2 million b/d presently by restoring shut-in wells to production in northern fields and drilling infill wells in southern fields without using new technology or enhanced oil recovery methods, the group found.

IEA raises China's 2007 product demand estimate

The International Energy Agency, Paris, has revised upwards its forecast for China's 2007 total oil product demand by 6.1% to 7.6 million b/d due to refining and trade data showing stronger-than-expected apparent demand in the first 2 months.

IEA said its projections for Chinese apparent demand in the first quarter have also been revised upward by 300,000 b/d to 7.61 million b/d. The agency also said it lowered its second quarter demand projection by 600,000 b/d to 7.7 million b/d.

According to preliminary data, January's apparent demand increased by 4.1% on an annual basis, IEA said. Apparent demand is defined as refinery output plus net oil product imports adjusted for fuel oil and direct crude burning, smuggling, and stock changes.

The Asian giant's demand increases were driven mostly by naphtha (up 12.4%), gasoline (up 3.3%), gas oil (up 5.9%), and other products (up 27%).

"Following further revisions to last year's monthly data, particularly in fourth-quarter 2006, we estimate that demand in 2006 averaged 7.2 million b/d, slightly higher than in our last report, bringing yearly growth to 6.9%," IEA said.

The agency said January's relatively modest—by Chinese standards—pace of growth is explained by the fact that oil product demand was particularly strong in January 2006, buoyed by Lunar New Year festivities, which prompt a surge in demand, particularly of gas oil as many Chinese citizens travel home.

The 2007 celebrations, by contrast, took place in February. In anticipation, the government ordered refiners to cut gas oil exports in February to meet the surge of domestic demand that month.

In late January, the government also reduced jet fuel surcharges for domestic airlines by 17-20% to encourage air travel—the surcharges had been raised in August 2006.

Meanwhile, citing recently released data from the China Electric Power News, IEA said that over the next few years the country is unlikely to see a repeat of its 2004 oil demand surge, when electricity shortages were met mostly by small diesel generators, especially in rural areas.

China expanded its generating capacity by 102 Gw in 2006 to a total of 520 Gw, IEA said. As a result, China's generating margin—the spare capacity available to meet peak demand—is "likely to reach some 10 Gw this summer, compared with [a] 40 Gw shortfall in 2004."

However, IEA said, 90% of China's new power plants are coal-fired, while hydropower accounts for another 9%. It said nuclear and other forms of energy represent less than 1% of China's capacity.

APPEA: Macfarlane nixes Aussie tax breaks

Australia Resources Minister Ian Macfarlane has rejected calls from the oil and gas industry for government to provide tax breaks to stimulate investment in LNG projects (OGJ Online, Apr. 17, 2007).

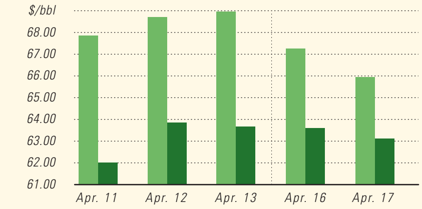
The minister told delegates to the Australian Petroleum Production & Exploration Association (APPEA) conference in Adelaide that the industry should seize the opportunity to expand its gas programs before overseas customers decided to "leapfrog" this fuel and go straight to the nuclear solution to greenhouse-gas emissions.

He said the Australian industry already has plenty of incentive in high world oil and gas prices, and that the government has given industry accelerated depreciation on upstream assets already and provided a 150% tax break for working in frontier exploration areas.

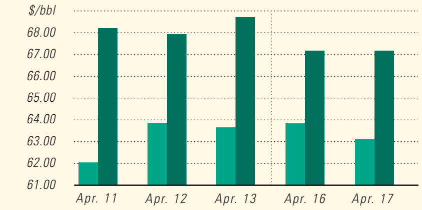
"If the industry does not get down and go hard, companies may find customers go straight to the one proven base-load, zero-emission technology for the production of electricity," he said. "That's nuclear."

Industry Scoreboard

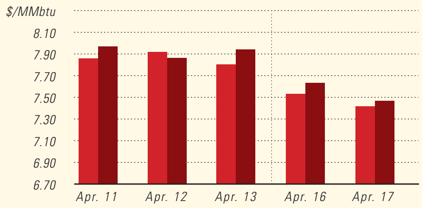
IPE BRENT / NYMEX LIGHT SWEET CRUDE



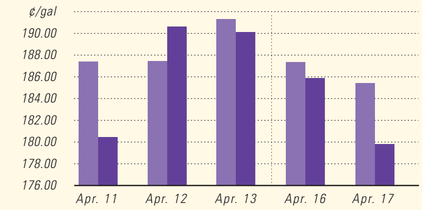
WTI CUSHING / BRENT SPOT



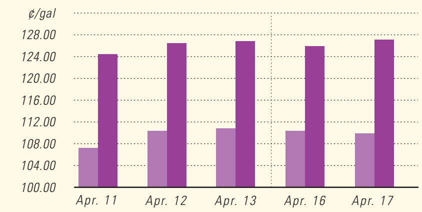
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



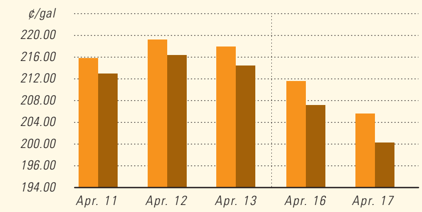
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[1] / NY SPOT GASOLINE[2]



[1]Reformulated gasoline blendstock for oxygen blending
[2]Nonoxygenated regular unleaded.

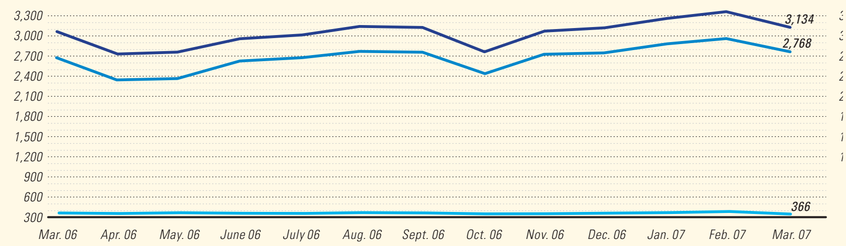
US INDUSTRY SCOREBOARD — 4/23

Latest week 4/13	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	9,236	9,134	1.1	9,122	8,958	1.8
Distillate	4,455	4,290	3.8	4,429	4,257	4.0
Jet fuel	1,576	1,604	–1.8	1,622	1,571	3.3
Residual	813	761	6.8	745	786	–5.3
Other products	4,944	4,668	5.9	4,994	4,754	5.1
TOTAL DEMAND	21,021	20,457	2.8	20,911	20,326	2.9
Supply, 1,000 b/d						
Crude production	5,212	5,040	3.4	5,279	5,045	4.7
NGL production	2,460	1,707	44.1	2,426	1,695	43.1
Crude imports	9,608	9,814	–2.1	9,662	9,804	–1.4
Product imports	3,363	3,277	2.6	3,145	3,469	–9.4
Other supply[2]	830	979	–15.3	925	1,192	–22.4
TOTAL SUPPLY	21,472	20,817	3.1	21,436	21,204	1.1
Refining, 1,000 b/d						
Crude runs to stills	14,715	14,746	–0.2	14,634	14,727	–0.6
Input to crude stills	15,173	15,098	0.5	15,074	15,076	—
% utilization	87.5	86.8	—	86.9	86.8	—

Latest week 4/13	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	333,884	337,164	–3,280	341,281	–7,397	–2.2
Motor gasoline	198,587	198,829	–242	205,706	–7,119	–3.5
Distillate	118,540	119,251	–711	115,091	3,449	3.0
Jet fuel	39,347	40,540	–1,193	41,125	–1,778	–4.3
Residual	40,145	38,720	1,425	42,586	–2,441	–5.7
Stock cover (days)[3] **4/6**			**Change, %**		**Change, %**	
Crude	22.4	22.5	–0.4	23.6	–5.1	
Motor gasoline	21.3	22.1	–3.6	22.8	–6.6	
Distillate	27.1	26.8	1.1	28.5	–4.9	
Propane	20.6	18.5	11.4	25.1	–17.9	
Futures prices[4] **4/13**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	62.85	64.51	–1.66	68.92	–6.07	–8.8
Natural gas, $/MMbtu	7.80	7.54	0.26	6.93	0.87	12.5

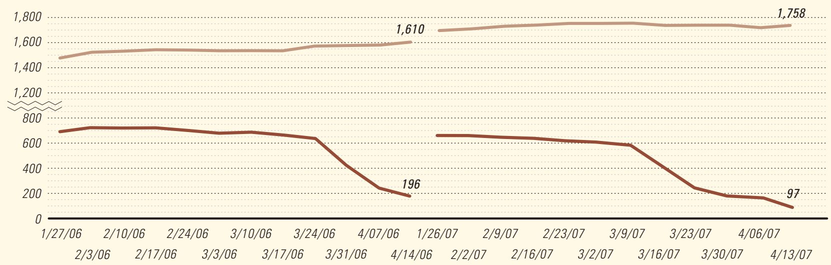
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Stocks divided by average daily product supplied for the prior 4 weeks. [4]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, American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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

He said, "The oil and gas industry needs to ensure it develops projects quickly to optimize the high gas prices, particularly for LNG, that we are now seeing around the Asia-Pacific Rim."

Macfarlane was responding to a 64-point strategy document released on the eve of the conference that called for stimulation of the industry by providing tax relief and depreciation allowances.

He said his comments were delivered to industry as a caution rather than a warning.

Chevron, Weyerhaeuser jointly assessing biofuels

Chevron Corp. and Weyerhaeuser Co. agreed to jointly assess the feasibility of commercializing biofuels production from cellulose sources. The companies will focus on developing technology that can transform wood fiber and other nonfood sources of cellulose into biofuels for cars and trucks.

The venture combines Chevron's technology capabilities in molecular conversion, product engineering, advanced fuel manufacturing, and fuels distribution with Weyerhaeuser's expertise in the collection and transformation of cellulosics into engineered materials, land stewardship, crop management, and biomass conversion.

Feedstock options include a wide range of materials from Weyerhaeuser's existing forest and mill system and cellulosic crops planted on its managed forest plantations.

Chevron already was involved with biofuels research through alliances with the Georgia Institute of Technology, the University of California at Davis, the Colorado Center for Biorefining and Biofuels, and the US Department of Energy's National Renewable Energy Laboratory. ✦

Exploration & Development — *Quick Takes*

Apache tests Zaina-2 oil well in Egypt

Apache Corp.'s Zaina-2 well in Egypt's Western Desert tested 1,067 b/d of oil from 12 ft of pay in the Abu Roash G-10 sand, the company reported. Zaina field, which Apache operates, is in the company's East Bahariya concession.

The discovery well, Zaina-1, flowed on test 1,165 b/d of oil in July 2005 from 55 ft of oil pay in the Upper Bahariya sand. The Abu Roash G-10 sand is a new producing zone in the field. The Abu Roash G-10 and G-20 sands, with 39 ft of total indicated oil pay, are behind-pipe recompletion targets for Zaina-1, which currently produces 560 b/d of oil.

Apache, which had acquired a 50% interest in the East Bahariya concession in 1997, became operator and gained its 100% contractor interest in 2001. Apache and Repsol YPF SA made the first discovery on the concession, the Karama-1X, in early 1997. The concession has produced 21 million bbl of oil since Apache began operations, with 18,500 b/d currently flowing. The company plans to drill 39 development wells there this year.

Egypt continues Meleiha concession until 2024

Egypt has extended until 2024 the length of its concession agreement with the group developing Meleiha Block in the Western Desert. The group plans to produce 840,000 tonnes of oil in 2007 compared with 800,000 tonnes in 2006.

Melehia holds 34 million tonnes of initial oil reserves. On the block are 129 operating wells that have produced more than 17 million tonnes of oil during the past 30 years.

Partners in the Meleiha production-sharing agreement are ENI Group unit IEOC Production 56%, Lukoil Overseas 24%, and International Finance Co. 20%.

Agiba—a joint venture of state-owned Egyptian General Petroleum Corp., IEOC, and IFC—operates the development project.

Partners spud Golitza-1 well in Bulgaria

JKX Bulgaria Ltd., a wholly owned subsidiary of JKX Oil & Gas PLC, has spudded the Golitza-1 exploration well targeting Jurassic sands, Triassic limestones, and Triassic sands on the B-Golitza exploration permit in Bulgaria, said Aurelian Oil & Gas PLC. Aurelian's wholly owned subsidiary Balkan Explorers Bulgaria Ltd. is 50% partner on the permit.

The onshore well aims to reach 4,900 m TD and will hit a large tilted fault block through near vertical drilling during the next 120 days, Aurelian said. Romanian driller Dafora SA will use a 2,000-hp rig to drill Golitza-1.

B-Golitza is on the southern edge of the Moesian platform where the Miocene Balkan Thrust Front strikes east-west across Bulgaria. A number of wells have been drilled in the area, but none has penetrated the target formations in a comparable structural setting, according to Aurelian.

Aurelian said nothing has been tested to date along the trend that Golitza-1 will target. "We are therefore not underestimating the risk of the play," it said. "However, all the required elements for a discovery are interpreted to be present." ✦

Drilling & Production — *Quick Takes*

ExxonMobil to maintain Bass Strait output

Bass Strait's future as a major oil province will continue for some years, according to operator ExxonMobil Corp. The company's lead country manager Mark Nolan said he is confident that the area's 140,000 b/d of liquids output can be held steady.

Speaking at the Australian Petroleum Production & Exploration Association conference in Adelaide, Nolan said ExxonMobil and its 50% partner BHP Billiton were under constant production pressure because of Bass Strait's annual 20%-plus natural production decline rate.

Thanks to high oil prices, however, production from wells flowing as little as 1,000 b/d has become attractive.

After completing a $100 million (Aus.) 3D seismic program early this decade, ExxonMobil has carried out extensive infill drilling in Bass Strait.

Nolan said the company was still working with BHP Billiton on proposals to develop Scarborough gas field on the Exmouth Plateau off Western Australia.

The project has not been affected by California's rejection of BHP's proposals to build an LNG terminal at Cabrillo Port off Malibu, he said.

Contracts let for work in Ursa, Princess fields

Shell Offshore Inc. has selected Technip to install water injection flowlines and risers for deepwater Ursa and Princess oil fields. They lie in the Gulf of Mexico's Mars basin 140 miles southeast of New Orleans.

The work is scheduled to start in the fourth quarter and will take a month to complete.

Separately, Shell has let a $30 million contract to Technip to tie back four subsea water injection wells to the Ursa platform, anchored on Mississippi Canyon Block 854 in 3,780 ft of water. Princess also lies in water deeper than 3,000 ft.

The contract covers project management, engineering, fabrication, and installation of flowlines and steel catenary risers, and installation of pipeline end terminations.

A Shell spokeswoman said the work will boost production and extend the life of the field. Peak production during Princess's initial development stage is pegged at 55,000 b/d of oil and 110 MMcfd of gas (OGJ Online, Jan. 6, 2004). Shell estimates that the Princess project will yield the ultimate recovery of 175 million total gross boe.

The partners in Princess and Ursa are Shell, operator, with 45%, BP PLC 23%, ExxonMobil Corp. 16%, and ConocoPhillips 16%.

Tabu field production begins off Malaysia

ExxonMobil Exploration & Production Malaysia Inc. has begun production of nonassociated gas from Tabu field, 200 km off Terengganu, Malaysia. Production is expected to peak at 150 MMcfd.

Gas from the unmanned facility will be transported via a new 16-in. full-well-stream, corrosion-resistant alloy pipeline to the manned Jerneh A platform for compression and processing.

ExxonMobil said the $182 million project was developed under its gas production-sharing contract with 50% joint venture partner Petronas to help meet increasing gas demand in Malaysia.

The announcement coincides with other recently announced developments aimed at increasing Malaysia's gas production.

In late March Kejuruteraan Samudra Timur Bhd. said ExxonMobil awarded it a 4-year contract valued at $17.4-20.4 million to provide tubular handling equipment and services.

In early March ExxonMobil awarded a 52 million-ringgits ($15 million) contract to Brooke Dockyard & Engineering Works Corp., Sarawak, for construction of the Jerneh B gas production platform 230 km off eastern Peninsular Malaysia.

The Malaysian company will fabricate and construct the platform jacket and topsides and undertake associated host tie-ins and offshore hook-up and commissioning works.

Anadarko lets FEED study contract for K2 Unit

Anadarko Petroleum Corp. has let a contract to Intec Engineering to perform the conceptual engineering and front-end engineering and design study phases of a proposed single-well tieback in the Gulf of Mexico Green Canyon area from Block 606 to Anadarko's K2 Unit on Block 562.

The flowline will connect to K2 at an existing connection at the south fault block. The addition to the K2 Unit will be controlled from the Marco Polo platform on Block 608, which also is operated by Anadarko.

Intec will provide flow assurance analysis and operability planning, system design and vender coordination for the flowline, manifolds, jumpers, subsea tree, and production control system. Intec also will assist in the regulatory and permitting process.

Last month, Anadarko agreed to sell a 23.2% portion of its interest in the K2 Unit for $1.2 billion to two undisclosed companies (OGJ Online, Mar. 13, 2007).

K2 currently averages 37,100 boe/d of production from six wells. Anadarko retains a 41.8% working interest in K2 and serves as operator.

Petrobras lets subsea contract to Cameron

Petroleo Brasileiro SA (Petrobras) let a $127 million contract to Cameron for the supply of subsea systems for the Gas Production Anticipation Plan (Plangas) project, which aims to increase "significantly" domestic natural gas production in southeastern Brazil, Petrobras said.

Cameron's contract scope covers the supply of 22 subsea christmas trees, control systems, and related equipment.

Initial delivery and installation is expected to begin in second quarter 2008, with additional deliveries to continue through 2009.

The trees for the project will be manufactured in Cameron's facility in Taubate, Brazil, Cameron said. ✦

Processing — *Quick Takes*

BP lets contract for Whiting refinery upgrades

BP Products North America Inc. has let two major engineering, procurement, and fabrication packages to Jacobs Engineering Group Inc. for work associated with a planned upgrade project to increase Canadian heavy crude processing at BP's 399,000 b/cd refinery in Whiting, Ind.

The $3 billion upgrade project is scheduled for completion in 2011 (OGJ Online, Oct. 26, 2006).

Jacobs' work scope for one of the packages includes licensing, design, and fabrication of sulfur recovery facilities. Jacobs will execute the licensing portion of this award from its offices in Leiden, the Netherlands, and will use its Comprimo Sulfur Solution technology. The modular fabrication portion will be executed through the company's facility in Charleston, SC. The scope of the second package includes revamping several hydroprocessing units, which Jacobs will execute from its Houston location.

Federal judge fines Sinclair Tulsa Refining

A federal judge ordered Sinclair Tulsa Refining Co. on Apr. 4 to pay a $5 million criminal fine and sentenced two of its former managers to 6 months of home detention and 3 years of probation for violating provisions of the US Clean Water Act (OGJ Online, Dec. 19, 2006).

US District Judge Claire V. Eagan also ordered the Sinclair Oil Corp. subsidiary to make a $500,000 community service payment to the River Parks Authority, which strives to maintain, preserve, and develop the Arkansas River and adjacent land. She also sentenced the company to 2 years of probation. Eagan fined one former manager, Harmon Connell, $160,000 and ordered him to provide 100 hr of community service. The other, John Kapura, was fined $50,000 and ordered to provide 50 hr of community service.

The company and its two former employees previously admitted to knowingly manipulating refinery processes and wastewater flows and discharges to create unrepresentative samplings during mandatory sampling under the National Pollutant Discharge Elimination System permit program. The US Department of Justice said the manipulated samples were intended to influence analytical testing results reported to the Oklahoma Department of Environmental Quality and the US Environmental Protection Agency. ✦

Transportation — *Quick Takes*

Consortium plans Papua New Guinea LNG plant

Santos Ltd. has joined a consortium of ExxonMobil Corp., Oil Search Ltd., and Nippon Oil in planning a 5-6.5 million tonne/year gas liquefaction plant in Papua New Guinea.

In joining the consortium, Santos signed a cost-sharing agreement to carry out a preliminary front-end engineering and design study for the stand-alone LNG plant that would rely primarily on gas feedstock from Hides field in the central highlands.

The $60 million pre-FEED phase, to be completed by yearend, will evaluate the technical and commercial merits of establishing the LNG facility, planned to come on stream by 2012-13.

The study also will determine the best development concept, select a preferred site—likely to be on the Papuan Gulf coast—determine the best field configuration and unitization framework, and examine fiscal terms with the Papua New Guinea government.

Although Hides would be the primary gas supply, additional feedstock could come from nearby Angore and Juha fields (OGJ Online, Apr. 3, 2007).

Santos agreed to buy FEED data previously undertaken for the upstream part of the now-defunct Papua New Guniea gas pipeline to Queensland and to reimburse ExxonMobil for a proportionate share of costs already incurred for LNG studies.

ExxonMobil, which holds 49% interest, will operate the plant. Oil Search will have a 32% interest, Santos 17%, and Nippon Oil 2%.

Petrobras unit to add to oil tanker fleet

Petroleo Brasileiro SA (Petrobras) shipping subsidiary Transpetro, following a favorable court order last month, has signed contracts valued at $866 million for the construction of nine oil tankers.

Petrobras said the Rio Naval consortium will build five Aframax tankers for $517 million and four Panamax tankers for $349 million. The ships, part of a $2.48 billion program to buy 26 oil vessels, will join Transpetro's fleet in 2009-11.

The signing was enabled by a Mar. 23 ruling of Brazil's Tribunal de Contas da Uni'o (TCU), which lifted an earlier suspension of contracts for 16 tankers. The court reversed its earlier decision after consideration of a detailed submission presented to Brazil's internal auditor on Mar. 9, as well as a presentation by Transpetro Pres. Sergio Machado on Mar. 12.

Aroldo Cedraz, the minister responsible for the TCU, had blocked the contracts at the end of February, claiming that was a clear possibility of damage to the company due to the absence of detail of the indirect costs and inadequate criteria to fight and forecast any readjustment in prices.

Petrobras wants to increase the number of its oil vessels to 42 under a plan financed by Brazil's National Development Bank. Under the plan, BNDES aims to reduce Petrobras's costs for chartering foreign ships and revitalize Brazil's shipbuilding industry.

The Rio Naval consortium comprises Brazilian shipbuilders MPE, IESA, and Sermetal, in partnership with South Korea's Hyundai Heavy Industries.

China mulls formation of two LNG shipping JVs

Chinese authorities are considering plans to establish two LNG shipping ventures, both to be under the supervision of the state-owned Assets Supervision and Administration Commission (SASAC).

The official Shanghai Securities News said China Shipping (Group) Co. Ltd., China National Petroleum Corp. (CNPC), and China Petroleum & Chemical Corp. (Sinopec) plan to set up an LNG shipping joint venture, with an initial agreement to be reached by the end of June, according to China Shipping Group Pres. Li Shaode.

Li told the newspaper the JV will order carriers from Hudong Shipyard, which is controlled by China State Shipbuilding Corp.

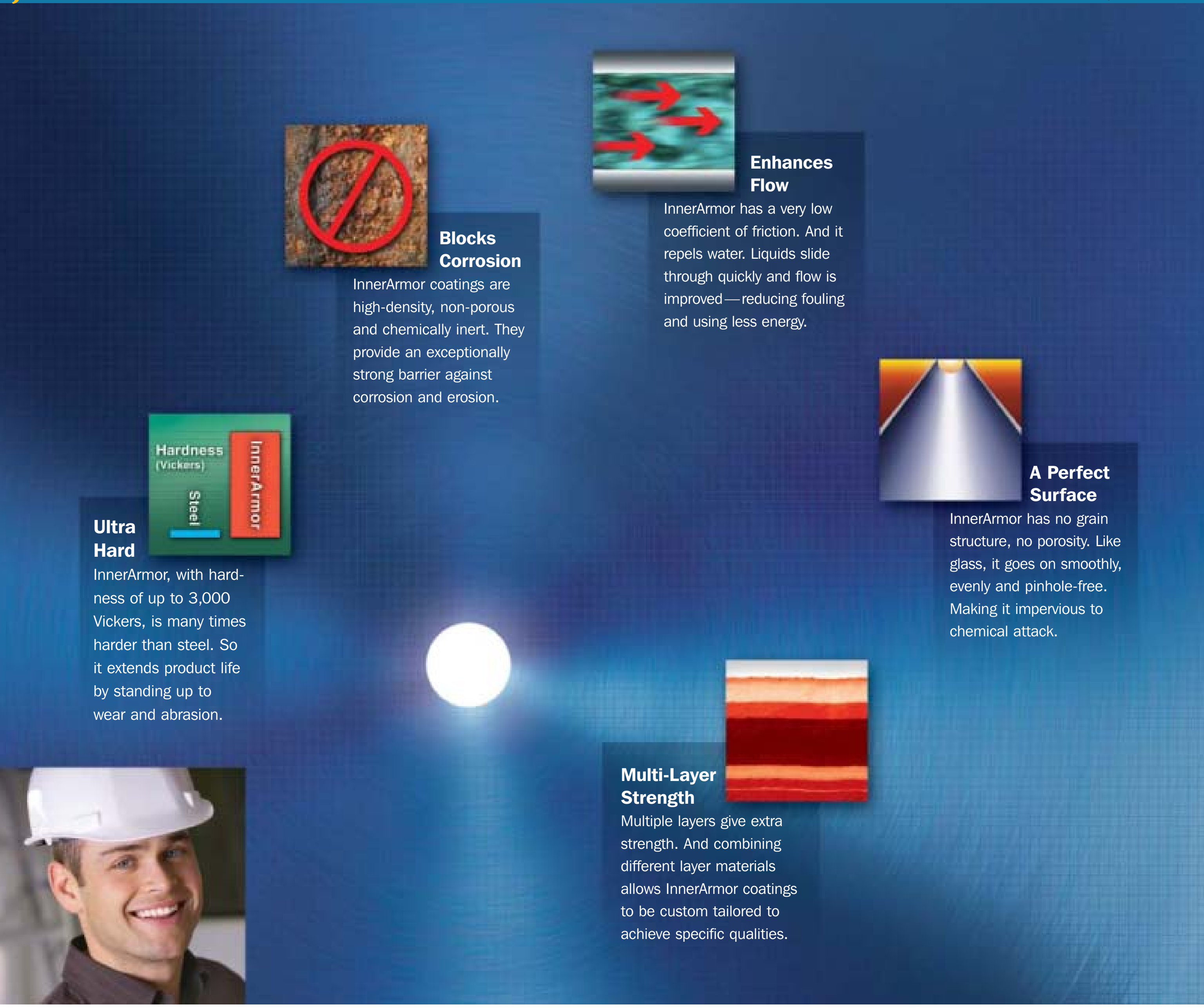
The second JV, Hong Kong-based China LNG Shipping Holdings Co. Ltd. (CLNG)—a JV of China Ocean Shipping (Group) Co. and China Merchants Group—is talking with China National Offshore Oil Corp. (CNOOC), the newspaper said.

CLNG has ordered five LNG shipping vessels from Hudong Shipyard, one of which is due for delivery in November, the paper said. Current plans call for three of the vessels to ship LNG imported from Australia to Guangdong, while the other two will ship LNG imported from Indonesia to Fujian.

The paper said that under SASAC requirements, the two JV firms will supply different regions of the country.

The China Shipping, CNPC, and Sinopec JV will ship imported LNG to terminals in northern China such as Qingdao, Dalian, and Yingkou.

The CLNG and CNOOC JV will ship imported LNG to terminals in Shanghai and the southern provinces, including Guangdong, Fujian, and Zhejiang. ✦



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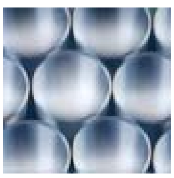

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2007

APRIL

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

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

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

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

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

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

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

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

MAY

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

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

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

Middle East Influence on Global Energy and Petrochemical Markets Conference, Manama, (281) 531-9966 (fax), website: www.cmaiglobal.com/EvConferences.aspx?eventid=Q6UJ9A008E3S. 7-9.

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

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

AchemAsia Exhibition and Conference, Beijing, +49 (0) 69 7564 249, +49 (0) 69 7564 201 (fax),

Calendar

e-mail: achemasia@dechema.de, website: www.achemasia.de. 14-18.

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

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

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

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

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

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

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

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

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

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

Contract Risk Management for the Oil & Gas Industry Conference, Jakarta, +00 603 2723 6745, +00 603 2723 6699 (fax), e-mail: CindyC@marcusevanskl.com, website: www.marcusevans.com/events/CFEventinfo.asp?EventID=12204. 28-29

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

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

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

JUNE

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

GazChem Conference, Port of Spain, +44 20 7903 2444, +44 20 7903 2432 (fax), e-mail: conferences@crugroup.com, website: www.britishsulphurevents.com/Gazchem07_prog.htm. 17-20.

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

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

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

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

Russia & CIS Refining & Petrochemicals Business Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 25-26.

✦Purvin & Gertz Annual *Asia LPG Seminar*, Singapore, (713) 236-0318, (713) 236-8490 (fax), e-mail: glrodriguez@purvingertz.com, website: www.purvingertz.com. 25-28.

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

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

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

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

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

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

JULY

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

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

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

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

AUGUST

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

Remembering Lloyd N. Unsell

Nick Snow
Washington Correspondent

Lloyd N. Unsell, who rose from reporting for a small Oklahoma newspaper to become one of the US oil and gas industry's most influential leaders in Washington, DC, as president of the Independent Petroleum Association of America, died on Apr. 7. He was 84.

Unsell joined IPAA in 1948 and retired in 1987.

In a foreword to memoirs he had begun (the early chapters of which appear on the American Oil and Gas Historical Society's web site at www.aoghs.org), he wrote:

"The domestic oil and gas industry historically has been the target of as much unfounded criticism and counterproductive intrusion by government as any economic entity in America, and most assuredly has been shaped in part by misguided political actions and effluvium. I hasten to add, because I'm not an apologist for oil and gas, that the industry at times clearly invited some lumps by its own mistakes. I should add too that it has been the beneficiary of positive policies put in place by legislative leaders concerned for the country's energy future."

Oklahoma roots

Born in Henryetta, Okla., Unsell became a reporter for the Seminole [Okla.] Daily Producer in 1945 after military service during World War II. He later worked at the Tulsa World.

He joined IPAA as a staff writer for its monthly magazine, Petroleum Independent, and rose through the association as vice-president of public affairs to become executive vice-president in 1976, a job title changed to president in 1985.

During Unsell's tenure, IPAA and its members worked to end price controls on interstate natural gas, which had existed since 1954, and on crude oil, which US President Richard M. Nixon imposed as part of an effort to fight inflation in the mid-1970s. Gas price controls changed when the Natural Gas Policy Act became law in 1978 and ended in 1985. President Ronald Reagan lifted oil price controls soon after taking office in 1981, but the industry had to endure a crude oil windfall profit tax, which independent producers vigorously opposed, from 1980 to 1988.

Under Unsell's leadership, IPAA's committees grew in stature. The cost study panel tracked drilling and oil field service prices. The natural gas group worked to remove market controls and improve relations with pipelines. And the supply-demand committee's twice-yearly forecasting sessions attracted economists and planners from major oil companies to debate industry trends with leading independent producers.

Formed coalitions

Unsell was not bashful about confronting issues important to independent producers. But he also formed coalitions with leaders from other oil and gas industry segments, as well as other businesses, to address matters of broader importance.

"He was incredible. He was a giant," recalled Gene Ames, a former IPAA chairman and chief executive of Venus Oil Co., San Antonio. "You could thank Lloyd for the stripper well producers' exemption from price controls. He worked with [Sen.] Lloyd Bentsen [D-Tex.] on that. He also worked to preserve the intangible drilling costs exemption when it came under attack in the 1980s."

"In a way," said Barry Russell, IPAA's current president, "he was a throwback to a time when there was much more power with committee chairmen in Congress. You always had the sense you were in the presence of a statesman, even though he wasn't an elected official or part of the government, because he cared so much about this country and its energy policies."

Unsell worked with other groups on issues like tax reform and energy policy, said Russell, who joined IPAA in 1980, adding: "He never talked negatively about anybody, even political adversaries."

'Environmental purism'

In the foreword to his memoirs, Unsell recalled the industry's political critics since World War II, "some who could justify industry-bashing as a strategy to advance their controlling philosophies, and some who were opportunists adept at recognizing any vulnerable target when it entered their field of vision."

He wrote, "Much of that has changed now. In fact, sheer antioil demagoguery once rampant in Washington has all but disappeared, but environmental purism has become so identified with the public weal that political actions addressing the nation's energy policy dilemmas seem less likely than ever."

Less known than Unsell's IPAA leadership was his work for the Vietnam Veterans Memorial on the National Mall in the early 1980s. He was cochair of the corporate advisory committee, which raised more than $1 million in contributions. The US petroleum industry provided more than any other business. ✦

Editorial

The painful climate step

ConocoPhillips has adopted a thoughtful approach to climate change that comes up one step short of comprehensive. Room remains for argument about whether the US truly needs the "mandatory national framework to address greenhouse-gas emissions" for which the company declares support. Yet political pressure has intensified to the point that some form of mandatory action seems inevitable. If nothing else, such a move would end the uncertainty now plaguing business decisions. It might even quell the extremism that has made reasoned discussion about a complex issue impossible.

Mandatory action on greenhouse-gas emissions must be thoughtful action. Toward this hope, ConocoPhillips's Apr. 11 statement sets useful standards.

Avoids alarmism

In general, the statement avoids the alarmism typical of most calls for action on climate change. ConocoPhillips makes no wild claims about melting ice caps, dwindling polar-bear populations, coastal inundation, or malaria plagues. It doesn't insist that people, as an act of political will, can substantially alter trends in global average temperature. Instead, the ConocoPhillips statement confines itself to the observable increase in greenhouse gases in the atmosphere that has accompanied industrialization. To argue that this increase warrants moderation of emissions, as a precaution against unknown and possibly malign consequences, is sound. And to argue in this manner, confining the discussion to what's mostly certain and possibly achievable, avoids the all-or-nothing nuttiness of most climate-change debate.

With specifics, too, ConocoPhillips constructs a useful standard for the emissions-reduction framework it espouses. "Any such framework," said company Chairman and Chief Executive Officer Jim Mulva, "should be transparent, clearly communicate the cost of carbon to consumers, be structured to avoid the volatility of energy prices, and encourage energy efficiency. It also should be paced to match the speed at which technology can be developed and deployed in order to avoid undue impact on the economy, including any impact on the number and location of jobs." These criteria suggest flexibility and attention to economics. They are more sophisticated than mandatory targets for volumetric cuts in emissions by specific dates—the state-centered approach of the foundering Kyoto Treaty. They are more likely than Kyoto is to produce successful policy.

The step ConocoPhillips didn't take is a difficult one. But it's inescapable for any company—such as members of the US Climate Action Partnership, which ConocoPhillips has joined—deciding to support regulation of greenhouse gases. In fact, such companies should take the step sooner rather than later. It's the only way to assure the transparency, cost visibility, and efficiency upheld by ConocoPhillips.

For oil companies, however, the step requires crossing what should be a painful line. It's support for a carbon tax. As a matter of principle, companies should be loath to call for new taxation of their customers. Before they do so, they should be certain that societal benefits warrant the economic costs and inevitably frayed trust. Then, in service to honest disclosure, they should make carbon taxation prominent in their greenhouse-gas reduction campaigns.

Contrary to popular propaganda, any major effort to lower greenhouse-gas emission rates will impose costs on people. The climate-change issue has ridden into public acceptance on the back of a colossal bluff, according to which governments can immunize individuals against mitigation costs by aiming directives at companies. This is deceitful. Reducing greenhouse-gas emissions means emitting less carbon dioxide, which means using expensive energy in place of cheaper hydrocarbons. Somebody has to pay the difference. Companies don't pay such costs. Governments don't, either. People do.

All options

People, not bureaucrats or companies, should decide how much to pay for greenhouse-gas mitigation. They should be able to accommodate mitigation to affordability. They should have the option to consider other, possibly more-affordable responses to feared warming, such as adaptation. They must have the freedom—scandalously denied so far in climate-change politics—to consider all choices.

First, though, they must know the potential cost. Taxation offers the best illumination. Mitigation without taxation wears too much camouflage. Companies supporting mandatory mitigation therefore must be willing to support new taxes on their customers—and to say so. Anything less is camouflage, too. ✦

THE OIL MARKET'S HARD CHARGERS—1

China expands energy mix, seeks investment

Gawdat Bahgat
Indiana University of Pennsylvania
Indiana, Pa.

About this series

China and India have charged into the oil market with consumption growth well above global average rates and with keen interest in securing supply. This article examines China's energy needs and its approaches to meeting them. On May 21, in the second part of this two-part series, the author will profile India.

Since the early 1990s China's skyrocketing demand for energy has dramatically affected global markets and international policy. To close the growing gap between stagnant domestic production and expanding consumption, Beijing has sought to reform its energy sector and diversify its energy mix and sources. Improvements are still needed in Chinese energy governance, however, to enhance energy conservation and diversify the energy mix.

Chinese companies have sought to operate mostly in countries where Western companies are absent or have withdrawn.

Furthermore, Beijing's aggressive pursuit of energy security on the international scene has become a global concern. Securing supplies from abroad has become a major component of the country's foreign policy.

Swift economic growth

Following the establishment of the People's Republic of China (PRC) in 1949, the nation was largely self-sufficient in energy. The largest oil field, Daqing, was discovered in 1959 and largely met China's petroleum demand. Thus, the first two "oil shocks" (1973-74 and 1979-80) had little impact on the Chinese economy and energy sector. Indeed, China exported crude oil to several of its Asian neighbors during this period.

Since the early 1980s, however, China's economy has grown impressively. This growth, in conjunction with a population of more than a billion people, demanded more energy than domestic production could provide.

In 1993 China became a net importer of oil, and by 2006 it was the world's third-largest net importer of oil behind the US and Japan.

This gap between stagnant energy production and fast-growing consumption is projected to expand even further in the next 2 decades. According to the Energy Information Administration (EIA), China's oil consumption is projected to rise to 15 million b/d by 2030 from 5.6 million b/d in 2003 (a 3.8% average annual change—the highest in the world). Similarly, natural gas consumption will jump during the same period to 7 tcf from 1.2 tcf (a 6.8% average annual change—again the highest in the world).

China's limited oil and gas reserves further complicate its energy outlook. In 2006 proved oil reserves were 16 billion bbl (1.3% of the world's total), and gas reserves were 83 tcf (also 1.3% of the world's total).

This combination of limited indigenous energy resources and rising demand has prompted Chinese leaders to adopt a multifaceted energy strategy.

CHINA'S 2000-20 ENERGY MIX

Fuel	Annual growth rate, 2000-20	Energy mix 2000	Energy mix 2010	Energy mix 2020
		%		
Coal	4.22	69.9	66.7	63.2
Oil	5.10	25.0	25.2	26.7
Gas	9.44	2.8	5.2	6.7
Other	—	2.3	2.9	3.4

Source: Development Research Center of the State Council, Overview of the National Energy Strategy, 2006

Three elements of this strategy can be identified:

- Reforming the energy sector to maximize domestic production and attract foreign investment.
- Diversifying the energy mix to reduce the nation's dependency on fossil fuels and contain pollution.

• Diversifying energy sources to restrain dependence on one or a few producing regions.

Energy sector reform

Chinese leaders agree that a viable and aggressive energy policy is essential to maintain and further expand the high economic growth of the last 2 decades. However, unlike many other countries, China lacks a national energy agency to draw and implement such a policy. Several national agencies have been established and dissolved since the PRC's founding.

The Ministry of Fuel Industries was abolished in 1955, when separate ministries for coal, electricity, and oil were established. In 1970 a new Ministry of Fuel and Chemical Industries combined the functions of those three ministries, but it was dissolved 5 years later.

In 1988 a Ministry of Energy was launched to oversee coal, oil, nuclear, and hydroelectric development, but it was dissolved in 1993.[1] In the early 2000s the central government created the Energy Bureau under the National Development and Reform Commission as an integrated central authority responsible for developing long-term energy strategies.[2] In June 2005 this bureau was replaced by the Energy Leading Group, a cabinet minister organization chaired by the prime minister. The purpose of this new agency is to strengthen energy policy planning and implementation.[3] These continuing changes suggest that China lacks a strong national mechanism to oversee its energy sector.

Institutional instability aside, oil and gas resources are controlled by three state firms: China National Petroleum Corp. (CNPC), China Petroleum & Chemical Corp. (Sinopec), and China National Offshore Oil Corp. (CNOOC). The Chinese government maintains a majority stake in all of them. CNPC and Sinopec operate almost all of China's refineries and the domestic pipeline network, while CNOOC has the most expertise with international transactions.

The country's first private sector company, the Great Wall Petroleum Group, was founded in 2005.

These corporations seek to enhance China's energy security by investing in domestic exploration and development and securing foreign supplies. In addition, Beijing seeks to neutralize threats to oil and gas shipments and to build a strategic petroleum reserve (SPR). The idea of building an SPR has been considered since the late 1990s, and a proposal to build one was approved in the tenth 5-year plan (2000-05). Several important issues such as the amount of oil to be stored and the time to start the reserve have been under intense debate. Chinese officials assert that eventually the SPR will hold oil covering about 90 days' supply.

Central Asian producers can reduce dependence on Russia by exporting some of their oil and gas to China, while imports from Central Asia would reduce China's dependence on the Middle East.

Energy diversification

China's energy consumption is dominated by fossil fuels, particularly coal. This energy mix has caused serious pollution and threatens the sustainable energy supply. Indeed, many of China's cities are among the most polluted in the world.

Production from Daqing oil field peaked in the 1970s, and has fallen since 2004. Chinese authorities have sought assistance from international oil companies to boost oil recovery and extend the life of producing fields. Furthermore, heavy investments have been made in exploration and development, particularly offshore.

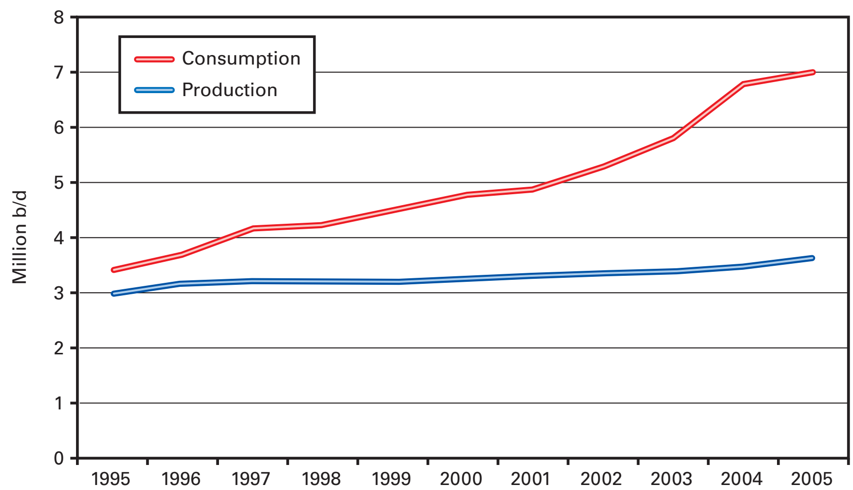
In the mid-2000s Daqing, Shengli, Liaohe, Xinjiang, Changqing, Sinopec Star, and Zhongyuan fields provided most of China's oil production. Since the early 1990s domestic production has failed to keep up with demand.

Figures in the table show two important trends:

• Natural gas represents a small proportion of China's energy mix.

• Gas consumption is growing faster than that of coal and oil. Several discoveries have been made in recent years, including Puguang, Sulige, and Kela-2 gas fields.

CHINA'S OIL CONSUMPTION VS. PRODUCTION



Most of China's gas fields are in the western and north-central areas away from the population and industrial centers in the east and southeast. To offset this imbalance, the Chinese government built the West-East gas pipeline.

Other pipelines from Kazakhstan and Russia are under consideration. In addition, two LNG import terminals, one in Guangdong and the other in Fujian, have been built, and several others have been proposed. China's gas development is still in its infancy, hence it has great potential.

Future consumption will draw on three sources: higher domestic gas production, emerging LNG import terminals, and proposed international pipeline projects.

While China is the world's largest producer and consumer of coal—its primary energy source—its dependence on the substance is projected to decline slightly.

In recent years, Chinese authorities have sought foreign investment to expand coal liquefaction projects. The goal is to reduce dependence on oil and to increase energy efficiency and environmental benefits.

Almost a third of China's imported oil now comes from Africa. In 2006 Angola overtook Saudi Arabia as China's single largest oil supplier.

Chinese authorities also have shown strong interest in other sources of energy, particularly renewables and nuclear power.

In January 2006 the Renewable Energy Law took effect. It establishes a regulatory framework for renewable energy development and provides economic incentives and financial support for research and development. Similarly, China has stepped up the pace of nuclear power plant construction and has one of the most ambitious plans for nuclear power in the world.

Source diversification

Securing future energy supplies has become a key aim of China's energy and foreign policies. Beijing officially joined the World Trade Organization in December 2001. Around this time, then-Premier Zhu Rongji, and Hu Jintao, general secretary of the Communist Party, called on Chinese companies to pursue a Zou Chu Qu or "going-out" policy, which should be seen as part of a broader policy of global economic engagement.[4]

Three major characteristics of this policy can be identified:

- Chinese oil companies have only a short history of mergers and acquisitions abroad. The policy was launched and gained momentum only in the last several years. In the mid-1990s most of China's oil deals were in three countries—Indonesia, Oman, and Yemen. A decade later Chinese companies are actively pursuing oil deals in North and

South America, Africa, Asia, and the Middle East.

- Chinese companies have sought to establish presence mostly in countries where American and European companies are absent or have withdrawn. These targeted countries, such as Iran, Sudan, Uzbekistan, and Venezuela, have adopted domestic and foreign policies that are largely in contrast with the interests of Western powers.
- Despite conscious efforts to diversify import sources, China's oil suppliers are heavily concentrated in the Middle East and Africa. These regions are likely to continue providing the bulk of China's oil needs.

Following are profiles of countries and regions in which China has shown special interest:

Russia

On the bilateral level, China's relations with Russia have substantially improved since the early 1990s. Close cooperation between the nations was enshrined in the Friendship and Cooperation Treaty of July 2001.

Since June 2005, Russia and China signed the final demarcation of their long borders. Bilateral trade has experienced exponential growth. China has become Russia's second-largest trading partner after the European Union.

Despite similar perceptions and joint interests, some Russian policy-makers are concerned about China's rising economic and strategic power. In addition, Russia's Pacific provinces are vulnerable to China's legal and illegal immigration. Finally, Beijing's and Moscow's interests differ in Central Asia, where both seek influence.

These contradictory strategic trends have restrained energy cooperation between China and Russia. In 2006 CNPC wanted to buy $3 billion of the shares in the Russian energy giant Rosneft, but it was allocated a bloc of shares valued at $500 million.

However construction has begun on parts of the long oil pipeline Russia is laying between Taishet in Eastern Siberia to Skovorodino on the border with China.

Central Asia

Central Asia is particularly attractive to China for many reasons: The region is known to have large hydrocarbon reserves; imports from Central Asia would reduce China's overwhelming dependence on the Middle East; and shipping oil and gas by land from Central Asia would help China avoid sea lanes largely dominated by the US navy.

Central Asian producers, for their part, can reduce their equally overwhelming dependence on Russia by exporting some of their oil and gas to China.

Within this context, China and Central Asian producers have pursued their mutually beneficial energy interests. In April 2006 Chinese President Hu Jintao signed agreements with the late Turkmen President Saparmurat Niyazov for Turkmenistan to sell gas to China and to build a pipeline to deliver it. In June 1997 CNPC purchased 60% of Kazakhstan's Aktyubinsk Oil Co. for $4.3 billion. In October 2005 CNPC finalized the purchase of Petrokazakhstan, whose assets include 11 oil fields and licenses to seven exploration blocks.

In May 2006 China began receiving crude oil from its first transnational oil pipeline. The pipeline was developed by the Sino-Kazakh Pipeline Co., a 50-50 joint venture of CNPC and Kazakhstan's KazTransOil. The Kazakh and Chinese governments also have explored the possibility of laying a gas pipeline parallel to the oil pipeline.[5]

Africa

The Chinese role in Africa has dramatically changed in the last half-century. In the 1960s and 1970s Beijing's interest centered on repelling Western imperialism and on building ideological solidarity with other underdeveloped nations to advance Chinese-style communism. Following the Cold War, Chinese interests evolved into more pragmatic pursuits such as trade, investment, and energy.

Unlike their Western counterparts, Chinese leaders avoid controversial political issues such as human rights, promoting democracy, and proliferation of weapons of mass destruction. Instead, China's approach towards Africa is almost exclusively based on and driven by commercial interests.

In November 2006 Chinese and African leaders adopted an action plan in which the two sides "resolved" to bolster joint energy and resources exploration and exploitation under the principle of reciprocity and common development. The document noted that China and Africa are "highly complementary" in energy and resources and that better information-sharing and pragmatic cooperation in these sectors serve the long-term interests of both sides. Beijing confirmed its intention to help African countries turn their advantages in energy and resources into development strengths.

In the last several years Africa has become a major oil supplier to China. In the mid-2000s Africa supplies almost a third of China's oil imports. Most of this oil comes from Angola and Sudan. In 2006 Angola overtook Saudi Arabia as China's single largest oil supplier.

The Middle East

Like African states, Middle Eastern oil producers share significant commercial and strategic interests with China. With oil, Middle Eastern producers want to secure a buyer, and China wants to secure a reliable supplier.

For the last several years China has taken an assertive role in developing Iran's hydrocarbon resources. In October 2004 Sinopec signed a memorandum of understanding to buy 250 tonnes of LNG from Iran over the next 25 years in exchange for the development of Iran's Yadavaran oil field. This agreement, estimated at $70-100 billion, would offer Sinopec a 51% stake in Yadavaran and deliver 150,000 b/d of Iranian crude oil to China in the same time period.

In June 1997 a consortium of Chinese energy companies signed a 22-year production-sharing agreement with Saddam Hussein's regime to develop Iraq's oil fields after the lifting of UN sanctions. In the post-Hussein period, the status of this agreement remains uncertain.

Relations between Beijing and Riyadh have improved in recent years. Visits by top officials from both countries illustrate this close and growing partnership. In 1999, then-President Jiang Zemin visited Saudi Arabia and signed several trade and energy agreements.

Since then the kingdom has become a major oil supplier to China. After long and unsuccessful negotiations with American oil companies to develop Saudi Arabia's gas, Riyadh awarded concessions to European, Russian, and Chinese companies in 2004.

On the other hand, China has attracted Saudi investment in joint ventures to expand and upgrade Chinese refining capacity. In January 2006 King Abdullah visited China on his first trip outside the Middle East since becoming the Saudi ruler. This was the first visit by a Saudi king to China since the two countries established diplomatic relations in 1990. Four months later, President Hu Jintao made his first state visit to Saudi Arabia. ✦

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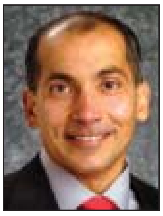
The author



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DDB Oslo KF 20 Photo: Billy Bonkers Ill: Commando Group

IEA sees 2.6 million-b/d near-term gain in OPEC capacity

Members of the Organization of Petroleum Exporting Countries, led by Angola and Saudi Arabia, will increase total capacity to produce crude oil this year and next by a net 2.6 million b/d.

The International Energy Agency made that forecast in its April Oil Market Report, warning of uncertainty about developments in Nigeria, Venezuela, and Iraq and noting that the crude streams due on stream will be "relatively sweet."

Net of assumed declines in existing fields, OPEC production capacity will rise to 34.8 million b/d by the end of this year from 33.9 million b/d at the end of 2006, IEA said. By yearend 2008 it will reach 36.5 million b/d.

The assessment assumes decline rates ranging from 1-5%/year for onshore fields in the Persian Gulf region to 12-15%/year for deepwater fields.

The projected increase for 2008 assumes partial resumption of the 450,000 b/d of production in Nigeria now shut in by political violence. The projection for both years assumes no change in capacities of Venezuela and Iraq.

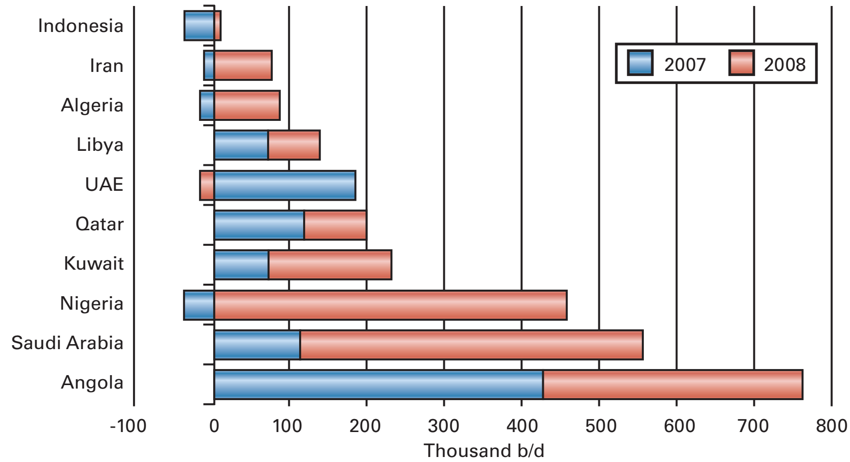
"Clearly, developments in all three of these countries are surrounded by risks both on the downside and the upside," IEA said. The agency also warned of development delays that might result from tight service and drilling markets.

Of nearly 4 million b/d of new crude supply coming onto production from OPEC members through 2008, 56% will have sulfur content of less than 1%, IEA said. Crude containing more than 2% sulfur will account for less than 20% of the new supplies.

The increment will be about evenly split between light, medium, and heavy grades. The high crude quality largely reflects increases in African crudes, some of which have high wax and acid contents.

A LOOK AT NET CHANGE IN PRODUCTION CAPACITY

Fig. 1



Source: International Energy Agency

Al Hamli: OPEC 'fully committed' to continuous oil supply

Eric Watkins
Senior Correspondent

The Organization of Petroleum Exporting Countries, while seeking security of demand, is fully committed to a continuous supply of oil on the international market, according to the group's president.

"There should be no doubt that OPEC members are fully committed to ensure regular supplies to consumers and maintain market stability," said Mohamed Al Hamli, who also serves as UAE's energy minister.

Al Hamli told an oil conference in Dubai that the organization's commitment has been proven "time and again, during crises brought about by severe weather conditions, geopolitical tensions, or disruption of supplies caused by unrest."

But he said the 12-member group is concerned by subsidies given by consuming nations to competing fuels that seek to "divert investments away" from the oil industry or "discriminate" against oil.

"Producing countries cannot spend precious funds needed elsewhere on expanding facilities when their customers are telling them that they intend to reduce dependence on OPEC oil," he warned.

Underlining the global need for energy security, Al Hamli said OPEC members, as a condition of their investment in capacity expansion, want to know that consuming nations are committed to the purchase of oil.

"This would greatly strengthen producing countries' resolve to invest in future capacity expansion. The result would be greater energy security for all," he told the conference.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Growth leaders

Angola and Saudi Arabia account for half of the projected net increase in OPEC production capacity (Figs. 1 and 2).

For Angola, IEA has lowered its estimate of current crude-production capacity to 1.6 million b/d by accounting for 50,000-100,000 b/d of output from Bomboco field as condensate. Condensate flow will not count against Angola's quota when OPEC assigns one to its new member, possibly as early as September.

IEA expects Angolan crude-production capacity to jump to 2 million b/d by mid-2008 and 2.14 million b/d by late 2008 and to stay at 2-2.2 million b/d through 2011.

Capacity increases will come from the Dalia, BBLT, Rosa, Greater Plutonia, and Kizomba C projects.

In Saudi Arabia, capacity increases this year and next will come from Khursaniyah, Nuayyim, and Shaybah fields, pushing the total to 11.4 million b/d by the end of 2008 from 10.8 million b/d at present.

IEA excludes from its capacity estimates crude from Abu Safah field, which Saudi Arabia produces on behalf of Bahrain, and condensates added to crude streams.

It expects Saudi capacity to reach 12.5 million b/d by 2012. Later capacity additions will involve lower-quality crude than those due on stream by yearend 2008.

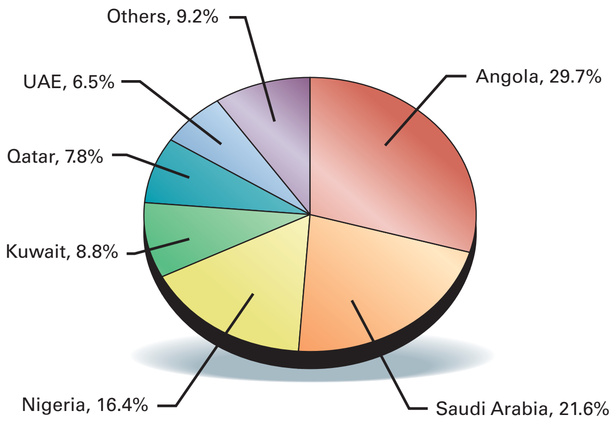
Because many of the new developments are linked with associated-gas projects, IEA said Saudi NGL and condensate output might increase by 500,000 in the next 2 years.

Other growth

In Nigeria, IEA said, capacity will rebound to 2.9 million b/d by 2008 from 2.5 million b/d at the end of 2006, with all the growth occurring next year.

The agency assumes that EA and Forcados production of 450,000 b/d remains offline this year but phases back online next year and in 2009. After late next year, Chevron Corp.'s deepwater Agbami field is expected to add to capacity growth.

SHARES OF OPEC PRODUCTION CAPACITY GROWTH, 2007-08 Fig. 2



Source: International Energy Agency

"Nigeria's new, lower capacity target of 3.2 million b/d by 2011 in our opinion represents a more realistic level (compared with an earlier 4.1 million b/d), assuming deepwater projects such as Bosi, Usan, Akpo, and Bonga Southwest proceed," IEA said.

The agency expects capacity gains of 200,000 b/d each from Kuwait, Qatar, and the UAE in 2007-08.

Expansion and refurbishment in Minagish and Burgan fields account for most of the expected Kuwaiti growth. Expansion of Sabriyah field has been approved but isn't likely to boost capacity until 2010, IEA said.

The agency added that continuing bans on direct foreign participation in Kuwaiti exploration and production will limit capacity to 3 million b/d, although the emirate has a long-term goal of 4 million b/d.

Qatar's increase will come from expansion of Al-Shaheen oil field to 240,000 b/d, taking total crude-production capacity to 1.1 million b/d by late 2008.

In the UAE, most capacity growth in the next 2 years will occur in onshore Abu Dhabi fields, which might raise the emirate's total to 2.9 million b/d by the end of 2007.

Capacity will stay at that level through 2010, after which growth in offshore fields will raise the total to 3.4 million b/d by 2012.

Limits on growth

IEA sees limits on near-term expansion of production capacity in Algeria, Libya, and Iran.

"There has been an apparent change in tone in the past couple of years from Algeria and Libya as regards receptiveness to capacity expansion itself and license terms in particular," it said, adding that Iran's prospects are limited by unattractive investment climate and political problems.

Each country will have capacity growth of 70,000-135,000 b/d during 2007-08. Algeria's growth will come from Hassi Messaoud field, Libya's from Elephant and El Shahara fields.

Iran has expansions under way in Darkhovin, Masjid e Suleiman, Rag e Safid, Salman, Foroozan, Doroud, and Abuzar fields, but total growth of 350,000 b/d will be offset by declines elsewhere and leave the country's capacity at 4 million b/d through the end of next year. Declines are possible after that.

"Any step change in Iranian capacity would require greater outside investment at fields such as Azadegan, Yadavaran, and South Pars," IEA said. It called a government capacity target of 5.2 million b/d by 2011 "wholly unrealistic in the current political and regulatory environment." ✦

Oil summit notes industry challenges, uncertainties

Doris Leblond
OGJ Correspondent

Three main challenges facing the oil industry—stable and reasonable prices, security of both demand and supply, and the relationship between national oil companies (NOCs) and international oil companies (IOCs)—were the predominant themes of the 8th International Oil Summit held Apr. 5 in Paris.

The general stated consensus on the need for "stable and reasonable oil prices" was marred by controversy between the Organization of Petroleum Exporting Countries and the Organization for Economic Cooperation and Development (OECD) countries on whether oil production and demand are being properly balanced.

Claude Mandil, executive director of the International Energy Agency, said: "Demand growth has exceeded the capacities put on the market, which currently are barely balanced." This is especially true, he said, with refinery upgrading capacity, which "reduces the usefulness of even the small crude buffer.

"Alongside strong economic growth and concerns in the upstream, the downward trend in oil refining spare capacity has pushed oil prices to current high levels," he said, adding that the bulk of new capacity will be in the Middle East and Asia but only if investments are sustained.

Concerning crude capacity, Mandil noted: "Even if we are happy with increasing investments in Middle East countries of OPEC, we think the rate of investment and capacity growth is not enough to meet future oil demand."

However OPEC Pres. and UAE Energy Minister Mohamed Al Hamli countered that the oil market is much better balanced and that this year the world economic performance will remain at the same level as in 2006 and will be "correctly supplied." He said recent high oil prices have been pulled along by geopolitics, and there is no need for OPEC to meet before the scheduled September meeting.

Demand security needed

Nevertheless, Al Hamli was concerned about what he called the "mixed message" on future oil demand during 2010-20. OPEC's crude capacity is to increase to nearly 40 million b/d in 2010 from 35 million b/d in 2006. He insisted that oil-producing countries need "a backup of [demand] security" to engage in further investments to increase oil production.

Besides soaring costs, which are inflated so much that producers must scrap some projects, demand security is being eroded by the widely publicized environmental concerns that are leading consumer countries to reduce fossil fuel dependence by switching to renewables and biofuels, by energy conservation, and by increasing strategic petroleum reserves. "We cannot produce more oil than the world will buy," Al Hamli said. He added that OPEC strongly supports carbon dioxide capture and storage, which he described as "a win-win technology" for sustainable development.

Qatar's Second Deputy Premier and Minister of Energy and Industry Abdullah Bin Hamad Al Attiyah, also expressed concern for the future when he asked consuming countries to consider demand security and not create constraints such as high taxes on fossil fuels or establish subsidies to promote alternative energy supplies that "are not

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Tension: the Iranian view

Iran's First Vice-President Parviz Davudi last week said that his country would do its level best to prepare a proper ground free from tension for attraction of foreign investment in the oil, gas, and petrochemical industries.

Davudi made the statement at the inaugural ceremony of the 12th oil, gas, and petrochemical exhibition in Tehran. Oil Minister Kazem Vaziri-Hamaneh also attended the inaugural ceremony of the 5-day exhibition.

Reports said that 797 domestic and 510 foreign companies from 35 countries participated in the event. The Iranians were pleased to say the number of participants in the event increased by 15 foreign and 7 domestic companies from the previous round.

Growth observed

The exhibition was held in a total area of more than 37,000 sq m, of which some 8,720 and 28,500 sq m were allocated to foreign and domestic companies, respectively.

Growth was the watchword of the day, with the first vice-president purring that over the past 2 years considerable growth has been observed in Iran's joint economic commission meetings with other countries. "The messages of Iranian officials, including that of the president, to various countries, shows reduction of tension and growing trend of cooperation in the field of investment in oil projects," added Davudi.

That's meant to be the good news coming out of an event whose main objectives included attracting foreign investments, introducing final products, increasing market share, studying marketing, identifying opportunities for joint ventures, and holding meetings with final consumers of products as well as current purchasers.

Unveiled threat

Under the gun of United Nations sanctions, of course, the Iranians need all of the friends they can muster. But the Iranians have a funny way of trying to reduce tension in their effort to attract more foreign investment. No one said a word about the country's stepping away from its nuclear ambitions. Nor, for that matter, did anyone talk of negotiations with the UN Security Council.

To the contrary—and to the amazement of world observers—at the conference, the Iranian government actually refused to rule out the option of withholding supplies of oil as a weapon if the current standoff with the West over its nuclear program intensifies.

"The Islamic Republic of Iran's policy is to supply energy as a responsibility. We are never seeking to cut the energy supplies to the world," said Oil Minister Kazem Vaziri-Hamaneh. "But, naturally, every country which is subject to danger or attack should use all its possibilities to defend itself, and this is every country's right." His comments came in response to a question over whether Iran would use oil as a "weapon" if the UN Security Council passed a third resolution imposing more sanctions against Tehran. The minister may think it entirely natural to threaten use of the oil weapon, but such a threat could not be considered assuring by potential investors. ✦

economically viable."

He called on OECD countries to invest in downstream supply chains such as refineries and LNG receiving terminals to complement producing countries' efforts.

To achieve OPEC's mission of a stable and sustainable energy market, Al Attiyah said, "We are implementing important projects aiming at increasing our crude oil production capacity from approximately 800,000 b/d to 1 million b/d."

Al Hamli said he believed, like Al Attiyah, that "there is enough oil and gas to last for many years." He said, "The instability we have faced in the past is because of not recognizing the linkages in the energy markets."

Listing "three key uncertainties in the oil outlook," Fatih Birol, IEA chief economist and head of the agency's economic analysis division, examined the pace and nature of China's economic growth. If China's GDP growth should fall to 7% from the current 9%, the country would need 11 million b/d of oil over the next 10 years, up from the past year's 7 million b/d. If growth should remain at 9%, oil needs would jump to 14 million b/d, Birol said.

Other uncertainties he listed were the expected 8%/year production decline in mature oil fields during 2007-30 and oil demand coming from regions where there are subsidies on oil products.

IOCs and NOCs

The third challenge facing the industry is the changing relationship between IOCs and NOCs, which is impacting oil production via access to reserves. Representatives from the four OPEC countries attending the summit—Qatar, Algeria, the UAE, and Saudi Arabia—expressed the necessity and advantages of maintaining partnerships with IOCs, even through new ways might be found to suit each of the partners.

Sonatrach's Pres. and CEO Mohammed Meziane said the concept of partnership "is central to Sonatrach's vision and strategy." The challenge to compete successfully in today's business environment "is prompting both NOCs and IOCs to join their efforts along the value chain for more close cooperation," he said.

Ibrahim Al-Muhanna, advisor to Saudi Arabia's energy minister, maintained that mutual cooperation is needed, adding that Saudi Aramco is itself "an IOC working closely with oil companies in different parts of the world."

But Nader Hamad Sultan, chairman of Ikarus Petroleum Holdings and former chief executive of Kuwait Petroleum Corp., was more confrontational, charging that the "new Seven Sisters" are now the rule makers and want to control everything. "Are the NOCs competing with the old Seven Sisters, or don't they need them? Have IOCs become too big with more riches than the [gross domestic product] of the countries they work in?" he asked.

Hard-line resource nationalists such as Venezuela, Bolivia, and Russia did not attend the summit, but representatives from two IOCs invited as keynote speakers—Royal Dutch Shell's Chief Executive Jeroen van der Veer and Total's Chief Executive Christophe de Margerie—favored cooperation with NOCs rather than competition.

"Easy oil doesn't need Shell and is not for IOCs, said Van der Veer. "Difficulties provide more than a number of opportunities for Shell and room for others."

De Margerie also said NOC-IOC cooperation is needed. New production "will be largely based on huge high-tech projects," and NOCs should bring their investment effort more in line with IOCs, or be more open to let them invest "because new developments are an industrial, financial, political, and human challenge." What is needed, he said, is confidence based on "mutual understanding and respect." ✦

GAO: Deepwater royalty relief impact hard to pin down

Nick Snow
Washington Correspondent

Deepwater royalty relief will cost the US government billions of dollars, but uncertainty about prices and production levels make precise estimates impossible at this time, the Government Accountability Office said in an Apr. 12 report.

It nevertheless found that the US Minerals Management Service produced reasonable estimates of future potential royalties that were lost because deepwater leases in the Gulf of Mexico in 1998-99 were issued without price thresholds. It said MMS estimated in February that the amounts lost could reach $6.4-9.8 billion in addition to the $1 billion that has already been lost.

GAO saw "considerably more uncertainty" regarding the amount of lease revenues potentially lost from leases issued in 1996, 1997, and 2000 because of Kerr-McGee's challenge of the US Interior Dept. agency's authority to include price thresholds.

"Although MMS has not yet updated its 2004 estimate of the future potential royalty losses on the leases at issue in the Kerr-McGee suit, it is clear that such an update could differ significantly from its earlier estimate because of likely changes to price and production assumptions," the congressional watchdog service said.

Congress will need more current information, it continued. It recommended that MMS report the status of leases and annual amount of royalties lost from the 1998-99 deepwater leases until the issue is resolved. GAO also suggested that MMS supply similar estimates for leases involved in the Kerr-McGee lawsuit to Congress (OGJ Online, July 5, 2006).

GAO prepared the report in response to a January 2006 request from US Sen. Jeff Bingaman (D-NM), then-chief minority member and current chairman of the Energy and Natural Resources Committee. "My fundamental goal in moving ahead on this serious matter is to recover the lost funds. I plan to carefully review the report and will soon introduce legislation that builds on GAO's recommendations," Bingaman said Apr. 12. ✦

Senate panel considers carbon sequestration strategy

Nick Snow
Washington Correspondent

Enhanced oil recovery is merely the first step in a national effort to capture and store or reuse industrially produced carbon dioxide, witnesses told the US Senate Energy and Natural Resources Committee on Apr. 16.

The CO_2 already used for EOR in the US is dwarfed by future requirements, said Thomas D. Shope, acting assistant secretary for fossil energy at the US Department of Energy. But US Geological Survey Director Mark D. Myers said such applications in oil and gas fields could supply important information about other carbon storage applications.

Myers said, "Outside the traditional oil and gas reservoirs, there's very little data. Obtaining it will require a collaborative effort with states and other entities."

Another federal government witness on a second panel said the US already has extensive carbon sequestration experience from its enhanced

recovery applications so far. "Power plant-scale volumes of CO_2 have been handled, transported, and injected into geologic reservoirs for more than 30 years as part of EOR operations in the Permian basin of West Texas," said George Guthrie, fossil energy and development programs director at the Los Alamos National Laboratory (LANL) in New Mexico.

Analog sites can provide information on long-term concerns such as the fate and impact of CO_2 storage, Guthrie said. "Wellbores are an excellent example. They are a critical component of the containment system. They are used to place the buoyant CO_2 below an impermeable barrier. The problem is that wellbores use cement which may degrade when exposed to CO_2 and water," he said.

Field-based study

As part of the LANL's support of DOE's carbon sequestration program, Guthrie said the laboratory recently completed the first field-based study of this issue using samples from a mature EOR site.

"The results show that interactions do occur, but complete degradation may not be an issue for some geologic environments," Guthrie said. "In fact, in some cases, beneficial reactions may actually improve the integrity of the wellbore. We need more studies, but these results demonstrate the importance of field observations in developing a reliable risk framework."

A major question that emerged during the hearing was whether to fund pilot projects using available technologies and information or identify future storage locations and carbon capture, transmission, and storage techniques. Another involved liability and whether treating industrially produced CO_2 as a waste would limit its reuse beyond EOR.

DOE's Shope said the department's regional carbon sequestration partnerships have identified potential Canadian and US sites where more than 3,500 billion tons of CO_2 might be stored. But Myers of USGS said more rigorous research, with a full scientific peer review, is needed. He said it would take a year to develop the methodology, another year to conduct the peer review, and 2-3 additional years to complete.

That led committee member Craig Thomas (R-Wyo.) to observe: "Sometimes, we get so taken up with research that we don't move forward with information we already have."

Chairman Jeff Bingaman (D-NM) called the hearing to discuss two bills before the committee. S. 731 would request the Interior secretary to oversee a USGS study that would develop a methodology for, and completion of, a national assessment of geological

storage capacity for CO_2. S. 962 would amend the 2005 Energy Policy Act to reauthorize and improve DOE's carbon capture and storage research, development, and demonstration program.

'Move forward'

Bingaman said, "It's my purpose, and the purpose of this committee, to move forward as aggressively as possible to see how extensively sequestration can be used to handle CO_2 which is produced."

Shope and Myers said while the administration of President George W. Bush supports the bills' goals, the measures must compete with others for federal funding. Myers said while S. 731, the CO_2 storage capacity assessment bill, would supply critical information, "we cannot commit to meeting the time frames it establishes."

Shope said the $86 million requested by DOE will fully support its carbon sequestration program for fiscal 2008. "You need to develop the capture and transmission technologies along with storage," he said, adding that initial applications could occur around 2025 with full-scale commercialization taking place 20 years later.

David G. Hawkins, climate center director at the Natural Resources Defense Council, said this should happen sooner. "We do not need to delay large-scale demonstrations for a national data base but can move ahead with them now," he said. Early efforts should be focused on actual carbon capture techniques, he added.

Shope said while future US carbon sequestration volumes are significantly greater than the amount used for EOR, "the oil and gas industry is considerably more experienced in this matter than utilities."

But Myers said while CO_2 injection for EOR is understood, its behavior in saline and other formations is not. "You may not know what the geologic downdip of the reservoir is so you don't know the capacity. You also don't know how long you will need to store it," he said.

Guthrie concluded: "We are at a point where many of the remaining questions can only be answered by larger field efforts. We know we can handle and inject CO_2 safely at large volumes. But we need to show that CO_2 capture at power plants works. We need to improve our estimates on the overall capacity for geologic storage. And we need to develop the confidence that CO_2 storage is a safe and effective option for the long term." ✦

Report: Offshore spending to reach $275 billion by 2011

Steady increases in offshore oil and gas production will drive up industry's annual spending to more than $275 billion by 2011 from $219 billion in 2006, according to a forecast published by Douglas-Westwood and Energyfiles.

The report, World Offshore Oil & Gas Production and Spend Forecast 2007-11, said offshore oil production has risen by more than a third since 1991 and is forecast to continue to rise at about the same rate, reaching 35 million b/d in 2011. Offshore gas production, meanwhile, has more than doubled in the same period—to 867 billion cu m in 2006, or 14.9 million boe/d. It will almost double again by 2011, forecast the report.

While offshore oil and gas fields are distributed across the world, only three regions—the North Sea, the Gulf of Mexico, and the South China Sea—attract more than half of this spending, said report author Michael R. Smith. "Yet relative shares are changing, with growth forecast everywhere except Western Europe," he said.

"Expensive deepwater projects in West Africa and the Gulf of Mexico as well as projects in the Caspian Sea and Sakhalin and new activity in the Persian Gulf are disproportionately increasing spending shares in these regions," Smith said. Offshore oil output is expected to peak within 10 years at less than 40 million b/d but the global peak for gas is not predicted until at least 2030, he said.

Price effects

The recent spending surge, said Smith, was driven by a shortage of spare oil and gas production capacity. "From 2002, prices significantly increased for equipment, consumables, and services, and this was especially so in 2005 and 2006 as demand rose and fuel costs escalated," he said. "The magnitude of growth, especially in rig rates, was attributable to intense competition within the service sector over the previous years of relatively low oil prices, which led to underinvestment in higher-specification rigs, new production systems and associated hardware, and in personnel."

Over the next 5 years, the forecast for oil prices is expected to be "erratic," the report said, but "generally lower in 2007 as oil demand growth is forced down by higher oil prices, as new non-OPEC production enters the market, and as LNG and coal continue to replace oil use in Asia along with modest amounts of other alternative energy sources everywhere."

Oil prices are expected to escalate from 2009, however, eventually leading to more cost inflation. "But, not all cost escalation can be ascribed to inflation," Smith said, adding, "Costs are also going up as more advanced rigs, production systems, and services are used for deeper and more complex reservoirs and more extreme conditions."

Operational sector

Although high oil and gas prices over the period to 2011 will result in continued strong growth in all parts of

the offshore oil and gas sector over the next 5 years, the report continued, "the prime mover will be the less-alluring operational sector."

Smith said capital spending (capex) has nearly doubled since 2002, with most of the growth occurring in the last 2 years. This spending has been dominated by drilling and platforms. "But hardly any capex growth is forecast for the 5 years to 2011, although floating and subsea production solutions, especially in deep waters, are likely to continue to expand their shares," Smith said.

Conversely, he said, operational expenditures (opex) "will likely increase by more than 50% to 2011 as a result of increasing output and a higher share of more expensive oil." Last year, Smith said, opex accounted for 40% of global offshore spending, "but its share is forecast to begin rising again in 2007, and by 2011 spending on capex and opex could be approximately equal."

Smith said this report is "unique" in that it determines capex levels based on "production additions." He said, "Every year new production comes on stream, which both adds capacity and replaces lost capacity as older fields deplete. The expected volume of new production is modeled using these two increments of output—'growth' and 'replacement'—the sum of which corresponds to the amount and cost of new capacity that is added each year."

He said, "Shallow-water production additions are only forecast to increase in the Middle East and will continue to increase until at least 2010 as the region strives to meet global oil and gas demand. They are also increasing in the Caspian Sea and Sakhalin."

Deepwater production additions meanwhile are increasing in all regions where deepwater prospects exist, Smith said. "In particular, additions in West Africa are expected to show considerable growth, [while] deepwater oil additions in Brazil and the Gulf of Mexico will modestly decline towards the end of the period" but will be supported by new marketed gas production.

Constraints

Many sectors of the offshore industry up to 2011 will continue to be constrained by shortages of equipment and people resources, the report said. "Consequently, day rates will remain high, especially for capital assets such as high-specification drilling rigs and other vessels," the report said. "The experienced personnel needed to design, build, and operate drilling and production equipment will also command a growing premium."

Starting to enter the market, however are new, high-specification rigs and vessels, which are serving to moder-

ate day rate growth. Smith said, "These restraints are reinforced by limits on exploration opportunities in offshore regions available to private oil and gas companies. Moreover, only the most demanding environments in ultradeep waters and Arctic regions are expected to offer new large scale opportunities by the end of the period." ✦

APPEA: Energy production trends toward decarbonization

Rick Wilkinson
OGJ Correspondent

The most important trend in energy production over the last two centuries is decarbonization, a trend that will see methane overtake oil and coal to become the next two generation's primary fuel, said Jesse Ausubel, director of Rockefeller University's Program for the Human Environment. Ausubel spoke at the Australian Petroleum Production & Exploration Association (APPEA) 2007 Conference in Adelaide.

"On average, when one removes the water, biomass fuels have a ratio of 40 carbon atoms to 4 hydrogen," he said.

"Coal typically has about 8 Cs for each 4 Hs. Gasoline and jet fuel average about 2 Cs for each 4 Hs. Methane burns only 1C for each 4 Hs—one-fortieth the ratio of wood."

Ausubel and his colleagues plotted the history of fuel in terms of the ratio of carbon to hydrogen and found a strong trend towards decarbonisation, with carbon losing market share to hydrogen. "The slow process to get from 90% C to 90% H in the fuel mix should take about 300 years and culminate about 2100," Ausubel told the conference. "Some decades have lagged and some accelerated, but the inexorable decline of carbon seems clear."

This trend is driven by the ever-increasing need for spatial density of energy consumption by the end-user, that is, the energy consumed per square meter, especially in urban areas.

"Fuels must conform to what the end-user will accept, and constraints become more stringent as spatial density of consumption rises," he said.

Green energy metrics

Ausubel also questions the green credentials of renewable energy forms. "They may be renewable, but calculating spatial density proves they are not green," he said.

"The best way to understand the

scale of destruction that hydro, biomass, wind, and solar promise is to denominate each in watts per square meter that the source would produce. In a well-watered area like Ontario, Canada, a square kilometer produces enough hydroelectricity for about 12 Canadians, while severely damaging life in its rivers," Ausubel said. "A biomass power plant requires about 2,500 sq km of prime Iowa farmland to equal the output of a single 1,000-Mw nuclear plant on a few hectares. Windmills to equal the same nuclear plant cover about 800 sq km in a very favorable climate," he said.

"Photovoltaics require less, but still a carpet of 150 sq km to match the nuclear plant. And a car requires a pasture of a hectare or two to run on biofuels—unwise, as the world's vehicle population heads towards one billion." Ausubel concluded, "No economies of scale adhere to any of the solar and renewable sources, so trying to supply India or eastern China would require increases in infrastructure that would overwhelm these already crowded lands." ✦

Problems for European refiners seen in EC sulfur-cut proposals

European refiners face new investment requirements at a difficult time, warns the International Energy Agency.

A Jan. 31 proposal of the European Commission on fuel quality would impose new sulfur specifications in a relatively short period and necessitate investment in hydrotreating, hydrocracking, and hydrogen production capacity, IEA says in its April Oil Market Report.

The move comes while "anecdotal evidence suggests refinery reliability is deteriorating due to existing sulfur-removal requirements, lowering average utilization rates," the agency says. Regulations are limiting sulfur content of gasoline, diesel fuel, and other distillates, or gas oil.

The EC's proposal would:

- Confirm the mandatory date for a 10 ppm sulfur limit in diesel as 2009.
- Reduce to 8% the maximum polyaromatic hydrocarbon content of diesel, beginning in 2009.
- Cut maximum sulfur content of nonroad gas oil to 10 ppm from 1,000 ppm for land uses and to 300 ppm from 1,000 ppm for inland waterways.
- Increase the allowable oxygenate content of gasoline to encourage use of biofuels, including gasoline containing as much as 10% ethanol, and increase the vapor-pressure limit of gasoline to accommodate ethanol.
- Require refiners to monitor greenhouse gas emissions and to cut emissions of greenhouse gases by 1%/year beginning in 2011.
- Adjust vapor-pressure standards to encourage development of a biofuels industry.

Desulfurization hike

The EC proposal responds to requirements in the European Union for greenhouse-gas emission cuts and for a 10% biofuel share of the transportation-fuels market by 2020.

IEA notes discussions about displacement of fuel oil by distillate in marine bunkers and points out that Germany soon will cap the sulfur content of heating oil at 50 ppm.

"The changes to gas oil specifications in Europe would effectively increase European desulfurization requirements by 50%," it says.

Refiners would have to increase high-severity hydrotreating or hydrocracking of high-sulfur gas oil from cokers and catalytic crackers.

"These processes involve significant amounts of hydrogen and energy, neither of which is inexpensive or without significant greenhouse-gas emissions," IEA notes.

Under current regulations, refiners are increasing the frequency of maintenance shutdowns to keep hydrotreaters able to meet product specifications. Operation of the units at high severity and high capacity utilization has increased failure rates.

Hydrotreating problems can lower overall throughputs temporarily because refiners have less spare hydrotreating capacity than before new sulfur limits took effect and fewer outlets for off-specification product.

Refiners also are less able than before to perform partial turnarounds.

While the proposed changes would further lower sulfur levels in gas oil, IEA says, "they could have far-reaching and possibly unintended consequences in terms of reduced product supply and higher greenhouse-gas emissions." ✦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World oil production to peak in 15-25 years, AAPG told

Alan Petzet
Chief Editor-Exploration

The world is consuming oil at a rate that will result in oil production peaking in 15 to 25 years, a group of geoscientists told the American Association of Petroleum Geologists' annual convention in Long Beach, Calif.

When world oil production reaches the peak by 2020-40, the rate will be 90-100 million b/d, only 10-20% higher than it was in 2005. Depending on the level of world oil resources, which is highly uncertain, that peak is likely to last 20-30 years before production begins its ultimate decline.

The estimates are released for the first time following an AAPG Hedberg Research Conference on Understanding World Oil Resources held in November 2006 in Colorado Springs.

Richard Nehring, chairman of that conference, said present estimates of conventional and unconventional world oil resources range from 3.4 to 5 trillion bbl. "These estimates of technologically and economically feasible world oil potential fall in the optimistic range of published estimates of world oil resources," Nehring said.

The world took more than 140 years to consume the first trillion barrels produced since the Drake well in Pennsylvania in 1859. Consumption of the second trillion barrels will occur within only 30 years.

Additions to world oil resources will come from three sources: recovery growth, undiscovered, and unconventional.

Recovery growth from existing fields, not discoveries, has been the major contributor to world oil production in the last 25 years. Growth in recovery from existing fields is also likely to be the largest source of future additions to world oil supply.

Worldwide, about 300 billion bbl of known oil, or about a 10-year supply, is either being developed or planned for future development.

About 50% of the world's oil has characteristics acceptable for enhanced oil recovery application, but EOR is currently applied to about 11%. More intensive development, either through tighter well spacing or the extensive use of horizontal and multilateral wells, also promises to increase recovery.

Extrapolating past trends of recovery growth from existing fields adds about 1 trillion bbl to the overall ultimate production expectation, about 200 billion bbl of which would come from EOR.

Undiscovered resources are the best understood source of future additions. They are the most thoroughly studied, a study that increasingly has strong theoretical support.

Worldwide estimates of undiscovered oil resources presented at the AAPG Convention, drawn from an augmented version of the USGS Worldwide Assessment, range from 480 to 1,550 billion bbl.

Nine geologic provinces (each with a mean estimate of 25 billion bbl or more) account for 65% of the mean world estimate.

Given the locations of the undiscovered potential, most is 15-40 years away from initial production.

Unconventional resources—tar sands and extra-heavy oil, oil shale, and oil from mature source rocks—provide a massive in-place resource. Each is known to have at least 3-4 trillion bbl.

The problem with these unconventional resources is recoverability. Each faces a major challenge, whether poor quality oil (extra-heavy oil), poor quality reservoirs (oil from source rocks), or both (oil shale).

Production of extra heavy oils and oil shale also requires substantial energy, enough so that oil shale production may be severely constrained by being mostly uneconomic due to a low net energy gain.

The 75 Hedberg conference participants came from 18 countries on all six populated continents. ✦


Complete cabling solutions for complex projects

Apache lists Argentina plans, budget shift

Apache Corp. plans to drill 120 wells in 2007 in Argentina, where its early-year production averaged 11,000 b/d of oil and 200 MMcfd of gas.

The company holds 2.5 million acres onshore in the Cuyo, Neuquen, San Jorge, and Austral basins.

The 2007 plan calls for shooting more than 2,000 sq km of 3D seismic surveys in the Austral basin in Tierra del Fuego, where 21 of the wells will be drilled. Two rigs will work there in the second quarter.

The company also expressed interest in exploring to the west in Chilean part of Tierra del Fuego, where a licensing round may be in prospect.

Overall, Apache will shift $500 million—adjusted from $600 million estimated in February—of its preliminary $4.1 billion 2007 exploration and production budget away from North America because of rising costs and the maturing of US fields. Instead, the company will spend those funds mainly on its existing projects Australia and Egypt. ✦

Tullow to spud well in Kudu field off Namibia

Tullow Oil PLC, London, said it has reached agreement to sell to Japan's Itochu Corp. a 20% interest in its Republic of Namibia Production License No. 001, which contains giant Kudu gas field, off Namibia.

Itochu will pay 40% of the cost of two appraisal wells planned this month to probe the upside potential of Kudu field and will provide other development financing, including further financial payments depending on the ultimate volume of reserves developed.

The transaction is subject to partner preemption rights and Namibia's approval, Tullow said.

The two-well appraisal program is to establish commercially productive flow rates from the extensive Kudu East reservoir originally tested by the Kudu-5 well (OGJ Online, Sept. 6, 2006).

If the flow rates can be established, Tullow said, "a multi-tcf upside potential will be demonstrated," thereby expanding Kudu field's development options.

Pride International's Pride South Seas semisubmersible is scheduled to arrive on location in late April. Each well is expected to take 80 days to drill.

In 2004 Tullow's subsidiary Energy Africa, which operates Kudu, concluded a joint development agreement with National Petroleum Corp. of Namibia and state-owned utility NamPower, calling for field development and piping of the gas to shore. There it will be treated

Gain Competitive Advantage through Global Collaboration

By Chuck Pol, President, BT Americas

Success in today's marketplace requires companies to take advantage of global resources to gain competitive advantage. Collaborating across regions and organizational boundaries injects innovation into your operations and helps you bring the right skill sets to bear on business issues while enabling the sharing of institutional knowledge. Collaboration also reduces costs and enhances your efficiency by reducing travel time and expenses.

The Challenge
Until recently, real-time global collaboration has been hampered by many factors including technology limitations. Communications networks were unable to support the services needed to enable real-time collaboration. Huge, data-intensive applications overwhelmed available bandwidth.

But that's changing. BT, with extensive experience in network design and management, can optimize the flow of massive data files with audio and video, enabling teams in different regions, and even different companies, to collaborate in real-time.

Today, BT is uniquely positioned to help companies deploy and manage global collaboration for competitive advantage.

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BT's Global Collaboration Room suite of services allows companies to share institutional knowledge in real time, which stimulates innovation. Massive files, such as computer aided engineering files, can be seamlessly transmitted around the globe to expedite the design process. Teams on separate continents can collaborate in real time to solve problems, generate creative ideas and advance the speed of doing business.

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Why BT?
BT's network capability is world-class. But when operating globally, implementing new operational models or supporting new business models, it is about more than just the network – it's about experience, expertise and commitment.

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BRPC's Gwydyr Bay well apparent success

Brooks Range Petroleum Corp. (BRPC), operator of the ADL 47468 lease on Alaska's North Slope, has made an apparent discovery with one of two wells in the Gwydyr Bay Prospect Area.

The North Shore No. 1 well was drilled to 10,319 ft TVD (13,309 ft MD) through Triassic Ivishak sandstone.

BRPC's partner TG World Energy Corp. said the well appears comparable to Mobil Oil Corp.'s 1974 Gwydyr Bay South No. 1 well, which also intersected Ivishak. That undeveloped discovery, 1,100 ft east of BRPC's well, averaged 2,263 b/d of oil.

The North Shore No. 1 well is scheduled to be tested next winter after reservoir evaluation using recently acquired 3D seismic data. BRPC will case the well as a potential oil producer.

A second well—Sak River No. 1—was a dry hole. It was drilled to 11,348 ft TVD (13,110 ft MD) and suspended for the possible drilling of an exploratory sidetrack next winter. Information from this well will be integrated with proprietary 3D seismic data to evaluate the sidetrack.

Nabors Drilling Alaska Rig No. 16E drilled both wells (OGJ Online, Feb. 19, 2007). ✦

IPR, OVL find oil on North Ramadan block

IPR Inc., Irving, Tex., and ONGC Videsh Ltd. (OVL), Mumbai, have made an oil discovery with the first exploration well on the North Ramadan concession in the Gulf of Suez.

The North Ramadan-1A discovery was drilled 6 km west of IPR's North July oil field, which has been producing since 1991. IPR said the offshore infrastructure at the adjacent North July development lease will provide options for expedited development of the discovery.

North Ramadan-1A was drilled to 10,050 ft TD in the Lower Miocene Mheiherrat formation. The well perforated a total of 133 ft over a gross interval of 174 ft of interbedded sandstones, shales, and limestones in the Miocene Asl formation. The well tested at a naturally flowing rate of 2,979 b/d of 36.5° gravity oil and 1.5 MMscfd of gas. No water was produced.

Operator IPR expects additional

zones to be prospective and will focus on the tested zones and the upside potential during the upcoming drilling campaign.

IPR and OVL are in the first phase of exploration on the 290 sq km North Ramadan concession, believed to hold potential resources exceeding 200 million bbl of oil. The work program during this 3-year period requires that the companies shoot 3D seismic and drill two more exploratory wells. The first-phase budget is estimated at $45 million. ✦

Niger

CNPC International Tenere Ltd. spudded the Fachi West-1 exploration well on the 17.3 million acre Tenere Block in Niger. The drillsite is 27 km north of Saha-1, where one formation tested noncommercial oil and a second interval was tight.

The well established the existence of a working hydrocarbon system on the block, said 20% interest holder TG World Energy Corp., Calgary. It found reservoir sandstones in the primary objective Eocene Sokor and Cretaceous-Tertiary Madama formations and sandstones in the Cretaceous Donga formation. Once Saha-1 is drilled, the operator plans to rerisk the existing prospect inventory and choose a third exploration drillsite.

Meanwhile, CNPCIT is acquiring a seismic survey on the adjacent Bilma concession, where TG World does not hold an interest. Afterward, the crew will acquire 700 line-km of 2D seismic surveys on Tenere.

UK

U.S. Energy Systems Inc., New York, said its UK subsidiary completed and tested the first of three planned wells at undeveloped Ebberston Moor gas field on PL007 in the Cleveland basin west of Scarborough.

The unit, UK Energy Systems Ltd., also finished a 3D seismic survey over Ebberston Moor, largest of six fields in the companies' North Yorkshire gas development project.

Logs at Ebberston Moor-1 indicate 116-123 ft of net pay at 5,341 ft true vertical depth subsea in the primary reservoir. It stabilized at 5 MMcfd of gas on a 5-day test at 1,440 psi maximum flowing wellhead pressure.

A secondary reservoir has 177 ft of gross pay, and a 78-ft section of this interval flowed 1.32 MMcfd in an offset well. A pipeline to the natural gas grid will be required.

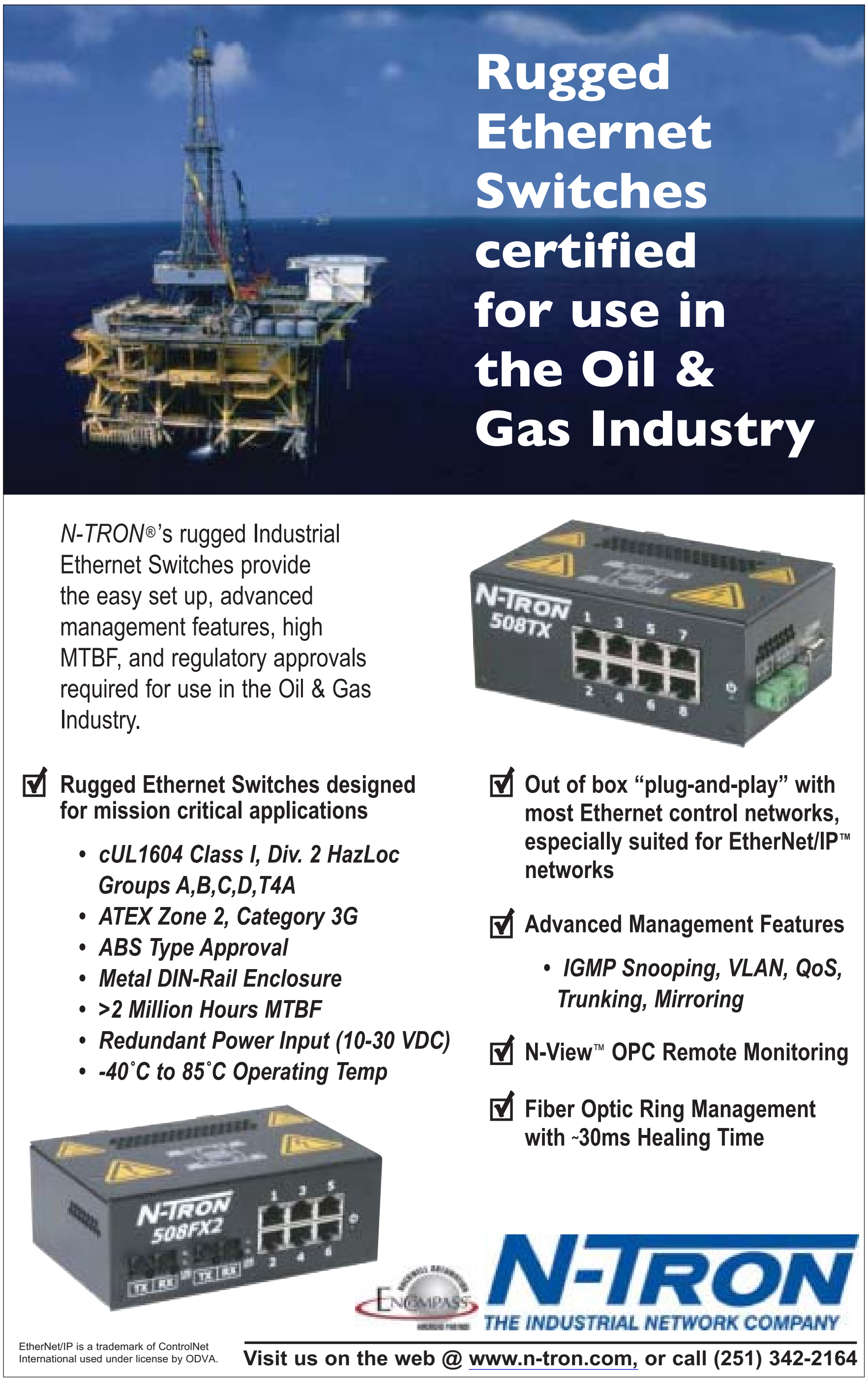
Thailand

Coastal Energy Co., London, reported reserves increases as of Jan. 1, 2007, from a year earlier of 42% to 220 bcf proved and probable and 55% to 272 bcf proved, probable, and possible in its holdings in Thailand.

The company has 12.6% interest in blocks EU1 and E5N that include Hess Corp.-operated Phu Horm field, producing 100 MMcfd of gas in northeastern Thailand.

It also holds 100% interest in Songkhla basin block G5/43 in the Gulf of Thailand with three successful appraisal wells drilled in 2005, two other discoveries awaiting appraisal, and untested exploration potential.

Other land holdings include 36.1% interest in Block L27/43 that contains undeveloped Dong Mun gas field and 21.7% interest in Block L13/48, adjacent to blocks L15/43 and L27/43, that contains the Si That gas discovery.



Newfoundland

Shoal Point Energy Ltd. took a farmout from Canadian Imperial Venture Corp., St. John's, covering the Garden Hill South area in western Newfoundland.

SPEL plans to reenter the Port au Port-2 well and drill to 3,470 m true vertical depth or a depth sufficient to test the uppermost Ordovician St. George Group. The well's subsurface target is 750 m north of the Port au Port-1 well in a separate fault block as defined by a 2D seismic survey.

Drilling the well will earn SPEL 50% of CIVC's interest in the farmout lands. CIVC spudded Port au Port-2 in 2001, drilled to 500 m, and cased and suspended it.

If it doesn't drill the well, SPEL will have the right to earn a partial interest by participating in any recompletion or workover in Sidetrack No. 2 to return the well to production.

Meanwhile, the farmee in the December 2006 Shoal Point/Garden Hill North deal, Tectonics Inc., has transferred its rights to SPEL, a private Calgary company whose president, George Langdon, is an expert in western Newfoundland geology.

Pakistan

The government provisionally awarded International Sovereign Energy Corp., Calgary, the Injra oil and gas block that straddles the Potwar and Kohat basins in Pakistan.

On the Potwar side of the 1,465 sq km block, target formations are Eocene Chorgali and Sakesar limestones, Jurassic Datta sandstone, and Cambrian Khewra sandstone.

Targets on the Kohat side are Paleocene Lockhart limestone, Lower Cretaceous Lumshiwal sandstone, Datta sandstone, Paleocene Hangu limestone, and Khewra sandstone.

Long intelligent completion assemblies save rig time

Jack Burman
Exploitation Technologies LLC
Houston

Ricardo Tirado
Baker Oil Tools
Houston

Mark Teague
Baker Oil Tools
The Woodlands, Tex.

Production

Running extra-long intelligent bottomhole assemblies (BHAs) reduced rig time for completing wells in the ultradeepwater Independence project in the eastern Gulf of Mexico.

Anadarko Petroleum Corp. operates the project that will bring on line 1 bcf/day of previously stranded gas.

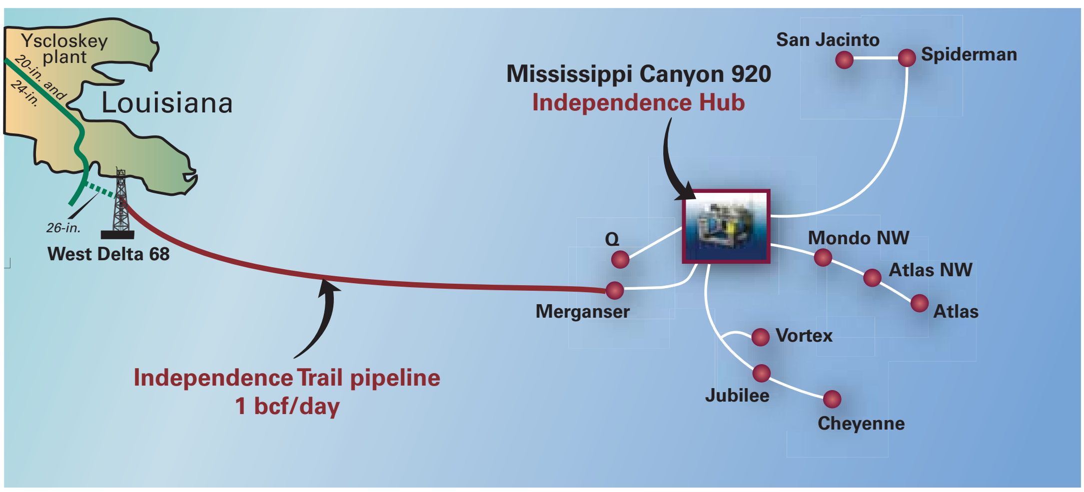
The $2 billion project, scheduled to begin production in fall 2007, will tie together 10 gas fields in record-setting water depths of 8,000-9,000 ft (Fig. 1). These fields would be uneconomical to develop on a standalone basis (OGJ, Nov. 27, 2006, p. 43).

The project's production will add about 2% to the US supply of natural gas and account for about 10% of the natural gas produced from the Gulf of Mexico.

Anadarko selected Baker Oil Tools' InForce intelligent well systems (IWS) with HCM-Plus shrouded and non-shrouded hydraulic flow control valves, Premier removable production packers, and Neptune safety valves to complete the project's high rate, subsea, multizone wells.

INDEPENDENCE PROJECT FIELDS

Fig. 1



To reduce installation time, Anadarko became the first operating company successfully to pre-assemble and test 90-ft plus completion assemblies and install them as a single unit rather than multiple components.

Anadarko and Baker Oil Tools devoted 18 months to project planning that involved equipment design, as well as designing and implementing lifting and transportation devices. This work thus far has enabled five successful intelligent well completions in four fields, while saving 12-14 hr of rig time/installation.

Fewer connections and pre-assembling and testing in controlled shop conditions away from the rig have improved reliability and assembly integrity, as well as reduced risk.

Extending technology

The Independence project is one of the industry's most ambitious attempts to extend the limits of production technology. The fields are in deeper water than any other offshore development, and they will produce through a floating production system, subsea tieback, and pipelines installed in the deepest water to date.

The subsea umbilicals will contain about 1,100 miles of steel tubing, and flowlines will exceed 200 miles in length.

Flow-assurance measures will include chemical injection to control paraffin and scale, with hydrates controlled from subsea trees. Subsea wells will be frac-packed for sand management and production optimization.

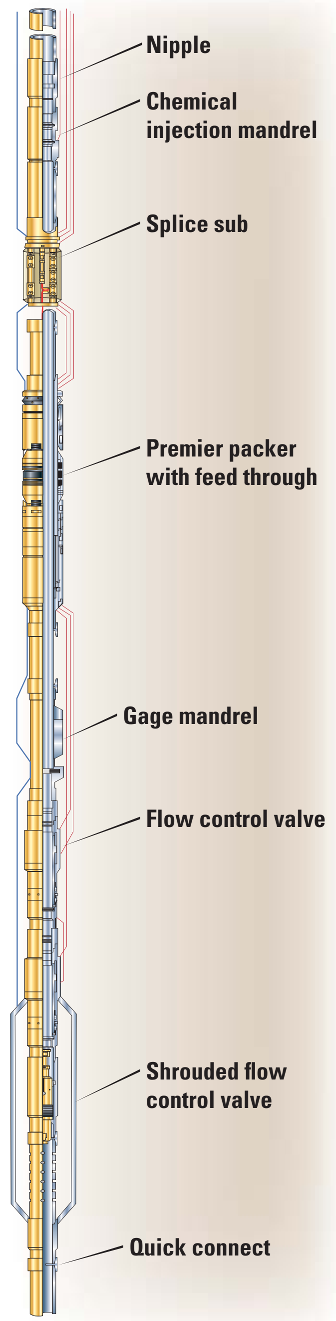
For Anadarko and its partners (Dominion Exploration & Production, Devon Energy Corp., Murphy Oil Corp., and Hydro Gulf of Mexico), water depths and subsea infrastructure required team members to reach new levels of collaboration and technical innovation. The project complexity was heightened by the fact that the development involved contracts with several different service companies rather than a single vendor.

Anadarko as project operator developed a coordinated plan with one hub facility and a single hydraulic power unit (HPU) to power the control systems for all subsea wells in the project.

Studies of wells throughout the area formed the basis of a standardized development plan designed around a single set of parameters and standardized equipment for all wells rather than specific sets of parameters and equipment for each well.

The intelligent well completions with extra-long-assemblies were developed in keeping with the standardization philosophy and as a way to minimize BHA handling time.

BOTTOMHOLE ASSEMBLY Fig. 2



Completion design

Spiderman field will be one of the first to come on stream, in fall 2007.

The dynamically positioned Transocean Deepwater Millennium drillship drilled and completed the wells in Spiderman.

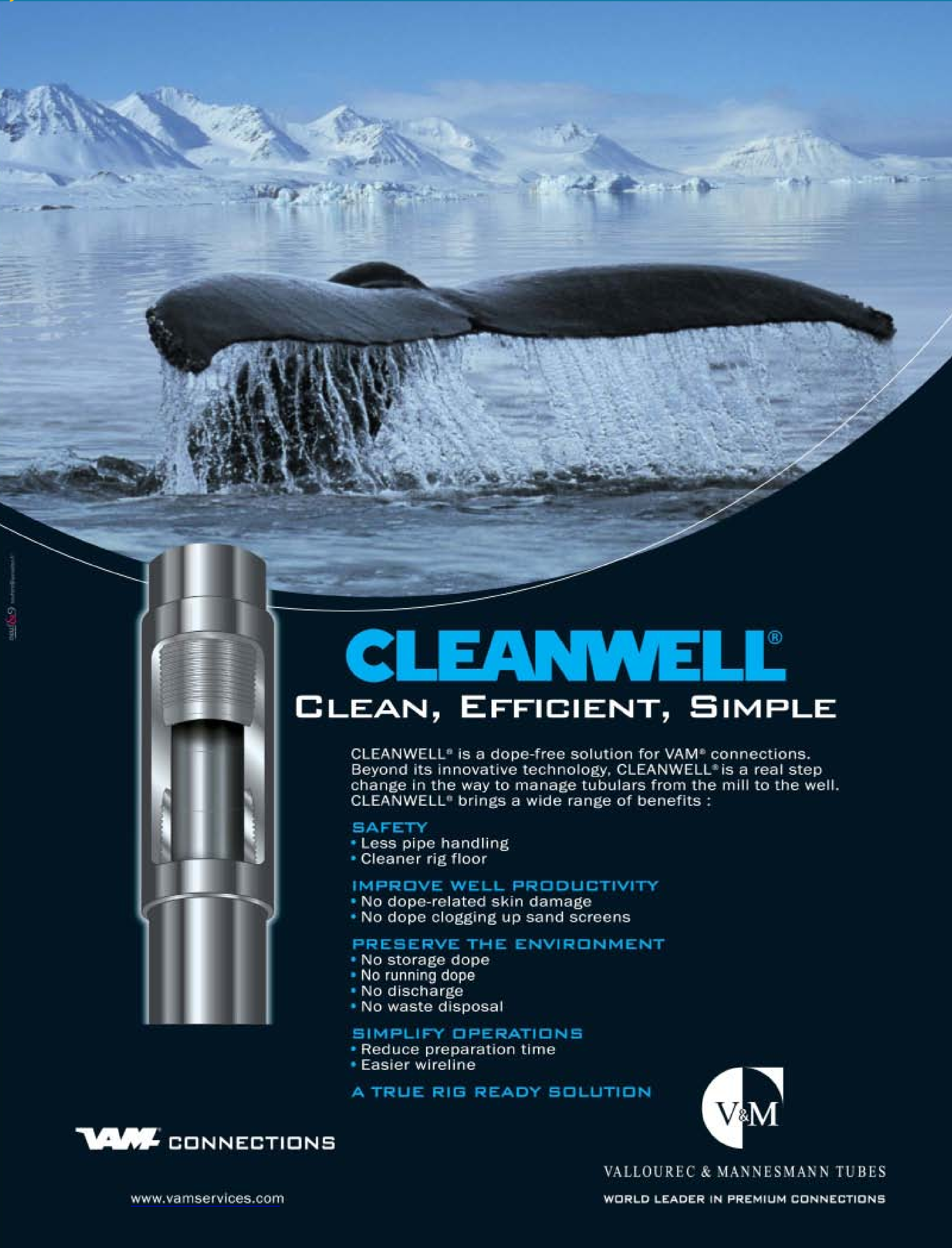
The operator based the well completion design on the need to remotely control two frac-packed zones, produce the zones sequentially, monitor downhole conditions, and provide flow assurance. In addition, reducing rig time and ensuring reliability and safety were other critical needs for optimizing the installation.

The selection of the InForce intelligent well system (IWS) was based on its functionality, inherent simplicity, and proven reliability. The selected intelligent control system (Fig. 2) includes:

- Two $4\frac{1}{2}$-in. flow control valves: one shrouded to control flow from the lower zone, and the other nonshrouded to control the upper zone.
- A $9\frac{7}{8} \times 4\frac{1}{2}$-in. feed-through removable production packer V0 (zero gas leakage) rated as per ISO 14310.
- A splice sub above the packer to house all control lines and cable splices.

The hydraulically operated control valves are controlled from surface and provide open-close functionality for multizone applications. The system includes a subsea control unit with hydraulic control lines that operates a balanced hydraulic piston for actuating the sliding insert in the valves. The piston develops an axial load exceeding 15,000 lb in both upward and downward directions to help overcome debris and scale buildup.

The valves have a diffuser ring system and equalizing slots that allow repetitive opening under high differen-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tial pressures, and a testable jam-nut connection ensures sealing integrity of the control chamber under extreme conditions. The valves' gas-tight, chemically inert seal system protects them from erosion.

The removable production packer has no body movement during setting, which protects control lines fed through the packer during packer setting. A slip-element-slip configuration provides permanent packer-like performance, but with removability.

In addition to the IWS system, the single 93-ft BHA has a triple-gauge mandrel, chemical-injection mandrel, and depth-correlation sub and pup joints.

The triple-gauge mandrel holds three downhole permanent pressure-temperature gauges, provided by another supplier. These three gauges provide real-time pressure and temperature monitoring of each zone, as well as the tubing.

The dual chemical-injection system, also from another supplier, provides a method for treating the well against potential scale and paraffin accumulation.

The single 93-ft long BHA expedites the installation process and saves valuable rig time.

The installation process includes connecting and testing all control lines, cables, and chemical-injection lines before lifting the assembly to the rig floor. Having all lines attached to the BHA before its make-up to the production tubing meant that the BHA could not be rotated.

The assembly, therefore, has a Baker quick connect for connecting the assembly to the tailpipe without the need for rotation.

The water depth (deepest of any intelligent well system installation to date) required installation of a deep-set safety valve, which in this case was Baker's nitrogen-charged Neptune safety valve.

The safety valves throughout the field were set with a standardized common pressure charge in the nitrogen chamber.

In addition to safety valve selection, deep water complicates completion string space-out. To compensate for any potential space-out error, the completion string included a 40-ft seal assembly in combination with a 20-ft seal-bore extension.

Onshore lift tests ensured the functionality of the compensating sling used for lifting the long bottomhole assembly offshore (Fig, 3).

Rehearsing the process several times onshore proved valuable when lifting the BHA at the rig site (Fig. 4).

Installation approach

Intelligent well systems require several control lines and cable connections that are normally pressure tested after make-up. This process requires considerable time, which varies depending on the number of zones completed and instruments used.

In deepwater and ultradeepwater operations, rig time is expensive. Eliminating or reducing rig critical path time is paramount for project economics.

Working from this premise, Anadarko instituted the new installation approach of using the extra-long completion assembly. The rationale behind the approach was that the single-activity Deepwater Millennium could handle 90-ft joints of riser; thus, it had the ability to handle extremely long BHAs.

The risk-reward relationship promised big dividends if the approach succeeded. But the approach did required careful planning to mitigate any additional risk.

The planning revolved around addressing several concerns:

- Would it be possible to safely pick up long assemblies on the single-activity drillship?
- Would it be possible to eliminate bending and damage to intelligent well components?
- Could components be tested on deck prior to going in hole?
- Could logistics, such as transportation, be addressed satisfactorily?

Handling of the BHA required compensating slings. To ensure the functionality of these slings, the project team developed proper procedures and performed lift tests before shipping the equipment offshore (Fig, 3). Finding the balance point for the subassemblies and rehearsing the process several times onshore proved valuable when performing the job at the rig site (Fig. 4).

The work also included building an extra-long tool basket for transporting the subassembly and providing protection and stability during handling operations.

Another key complication addressed during subassembly make-up was the alignment of key components to facilitate installation of multiple lines through by-pass slots and control-line ports. Utilization of timed couplings, provided by another supplier, solved this problem.

The assembly also had all control lines fed through the packers and connections made up and tested before shipment offshore. Pretesting also enhanced reliability because the connections were made in a controlled shop environment without time constraints.

Subsea interfacing

The functionality of IWS downhole equipment depends in great part on the surface control and data acquisition systems. Because the Independence project is a subsea field development, the intelligent completion systems must be monitored and controlled through the subsea control system.

A system integration test (SIT) before installation ensured a problem-free interface between downhole and subsea components. The SIT included the intelligent flow control valves, downhole gauges, control-line flat pack, tubing hanger, and subsea control module. The SIT proved out system compatibility and measured the response time of the control valves.

Planning pays off

Planning the first Spiderman IWS completion required 18 months, including time to design and test the long subassembly installation approach. During this time, the well was completed on paper with a focus on multidisciplinary teamwork. Involvement of rig personnel in advance of the installation also contributed to the success of the operation.

On Aug. 6, 2006, the rig team installed the first Anadarko Independence intelligent well system with no problems. The 93-ft completion assembly had six control lines (one electric and five hydraulic) that were terminated and tested on the riser skate before lifting.

The actual installation required 2 hr, during which the rig team tested the functioning of the sleeves and pressure tested the quick connect.

Initial well tests exceeded expectations, and the installation saved an estimated 12 hr of rig time.

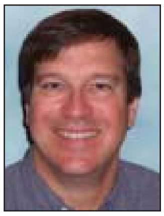
Riser skate testing of four subsequent IWS wells in Spiderman, Jubilee, Mondo NW, and Atlas fields was a shorter 1.25 hr, with pickup and stabbing requiring as little as 15 min.

Working from a riser skate and using 30-ft assemblies where possible has been expanded to BHAs for wellbore cleanout, tubing-conveyed perforating, pulling packer plugs, and wear bushings, gravel-pack assemblies, safety valves, and tubing hangers.

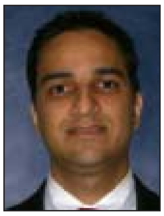
Thus far, the project is on schedule for first production this fall, and under budget.

Independence is massive and ambitious.✦

The authors



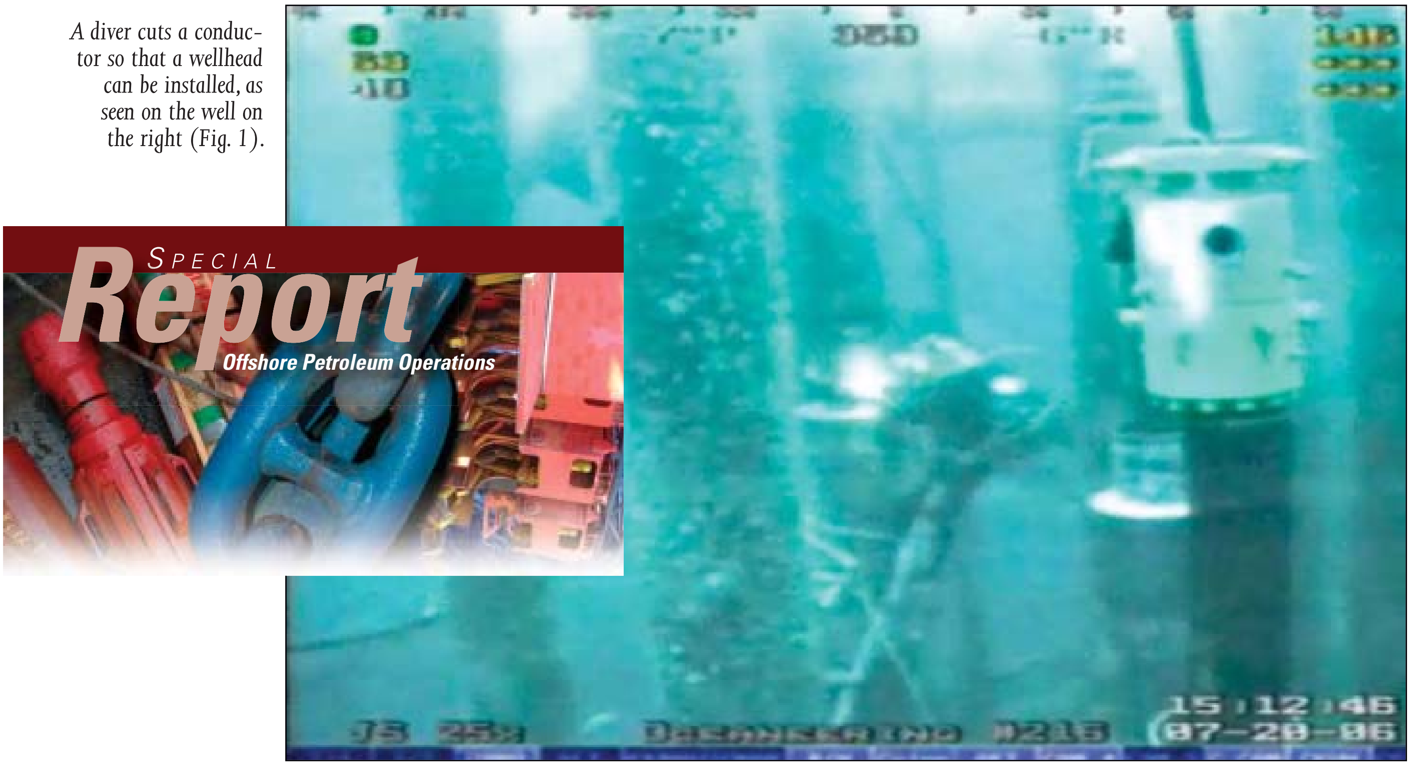
Jack Burman is manager for Exploitation Technologies LLC, Houston. He specializes in worldwide deepwater and shelf well completion, production engineering, and field implementation. Before forming Exploitation Technologies in 1999, he held various positions at Chevron Corp., Conoco Inc., Newfield Exploration Co., and Snyder Oil Corp. Burman has a BS in mining engineering from Virginia Tech and an MS in petroleum engineering from University of Wyoming. He is a licensed professional petroleum engineer and an SPE member.



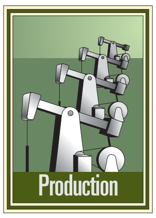
Ricardo Tirado is business development manager for Baker Oil Tools intelligent well systems. With Baker Oil Tools, he has held several positions in sales, operations, and marketing. Tirado has a BS in electrical engineering from Universidad Rafael Urdaneta, Venezuela and an MBA from University of Houston. He is an SPE member.

Mark Teague is a project manager with Baker Oil Tools and is currently embedded with an independent operator providing in house technical, operational, and logistical support for cased-hole completions. Since joining Baker Oil Tools, he has held various positions as a technical specialist, district manager, and sales and applications engineer.

A diver cuts a conductor so that a wellhead can be installed, as seen on the well on the right (Fig. 1).



Wellheads provide means for abandoning hurricane-damaged wells



Diver-installed wellheads facilitate plugging and abandoning wells damaged in recent storms in the Gulf of Mexico.

Storms and hurricanes in 2004 and again in 2005 extensively damaged many platforms in the gulf. The US Minerals Management Service estimates that in 2005 Hurricane Katrina destroyed 46 platforms and extensively damaged 20, while Rita destroyed 69 platforms and extensively damaged 32. Accurate numbers of damaged wells are unavailable, but one estimate is that the industry will have to plug and abandon more than 1,000 wells because of these storms.

Most of these damaged and destroyed platforms and wells were in water depth less than 400 ft and installed in the late 1960s and 1970s.

Wellhead design

One approach to abandoning these wells is for divers to install a new wellhead such as that designed and development by Superior Wellhead Inc., Houston.

In June 2005, Wild Well Control Inc., Houston, approached Superior Wellhead (SWI) about developing the wellheads for abandoning wells damaged by Hurricane Ivan in 2004. SWI said that it developed the diver and remotely operated vehicle (ROV) friendly system in less than 3 months, with the first one installed in August 2005.

SWI designed the system to work with existing hand tools in the diver's current standard kit. The system can accommodate multiple strings and multiple casing and tubing sizes and has all the external functional parts such as tie-down screws and slip-activating pins with an oversized design for easy handling, requiring only diving gloves.

The system also includes a sealing assembly that employs a noninterference packoff type seal, in lieu of the standard interference-type seal.

SWI says companies may leave the wellheads on the wells in areas that allow the structures to be reefed in placed.

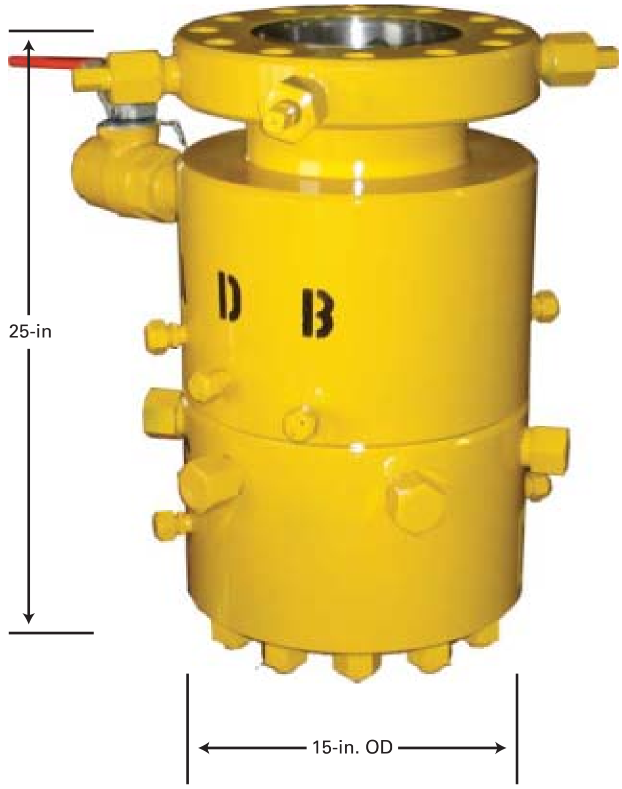
In other areas, MMS requires the conductor and casing to be cut below the mud line. In these cases, the wellheads are used during the plugging work, such as wireline and cementing, and removed later on.

Well abandonment

In abandonment of damaged wells, the first step is to remove platform debris. After this, divers aided by surface cranes on work vessels can cut the casings in a "wedding cake" fashion and install the wellheads (Fig. 1). Because well conductors are often close together, work with an ROV is not possible. In most cases the wellhead installation

SINGLE-STAGE WELLHEAD

Fig. 2



requires saturation divers for work in water depths in excess of 100 ft.

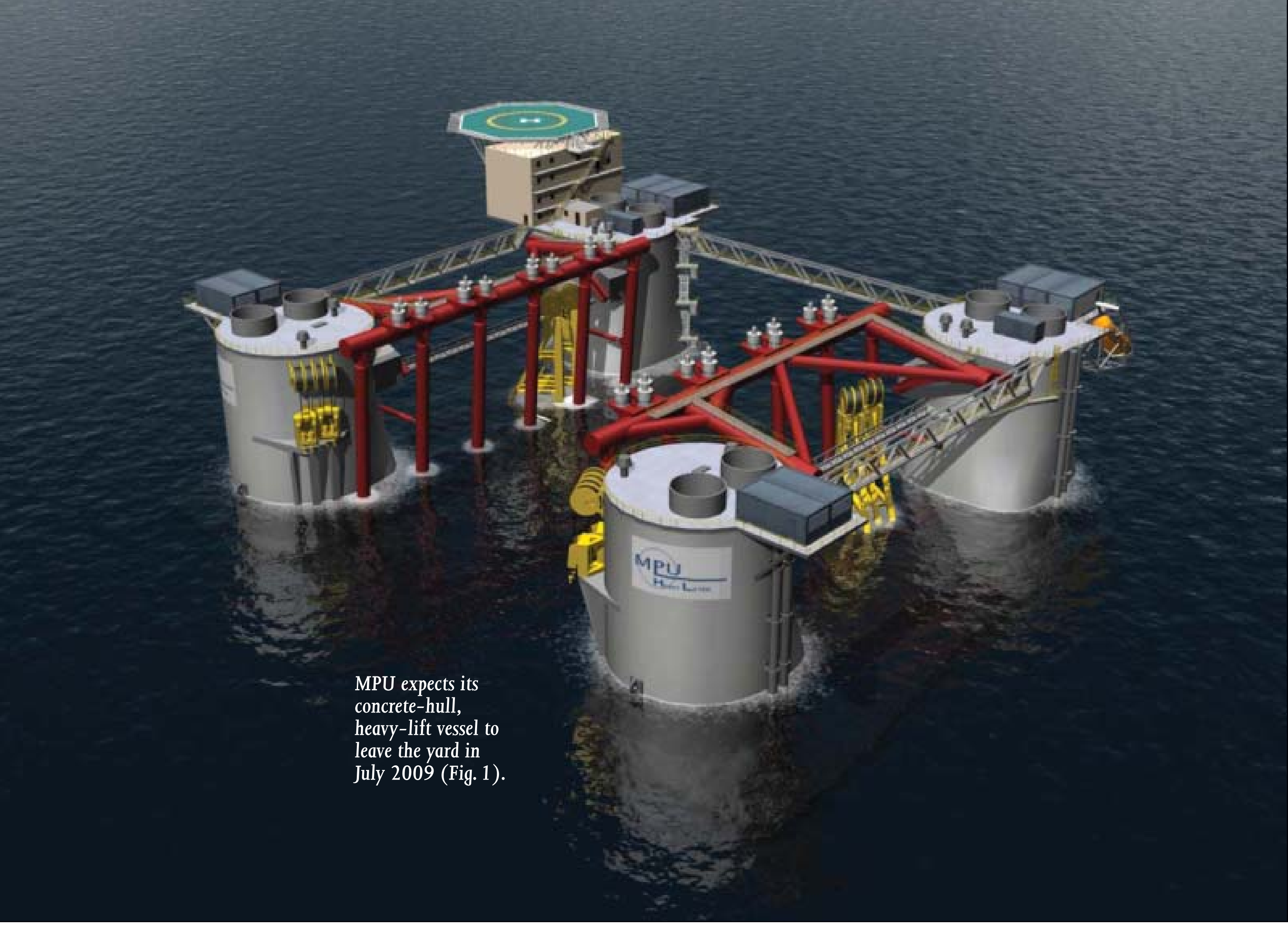
With the casing strings prepped, divers can then test the annulus string with a strip-over or wrap-around tester. The wellhead is then installed to isolate the production or surface strings. The wrap-around annulus isolation tool also has been used to meet additional MMS test requirements without the removal of the wellhead.

Time is a critical element because work vessels can cost more than $250,000/day. SWI says that with its Express Connect system divers have completed a typical installation in less than 1 hr.

The Express Connect wellhead (Fig. 2) has a full bore access and is for casing ranging from 7 to 13⅜-in. in size, with pressure ratings of 3,000, 5,000, and 10,000 psi. The wellhead has a standard bowl profile for the tubing hanger and recessed seals.

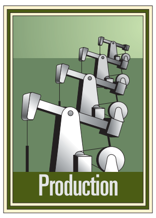
The tubing hanger can accommodate single, dual, or triple strings and has a control-line option.

SWI says that to date operators have installed more than 120 of its wellheads. ✦



MPU expects its concrete-hull, heavy-lift vessel to leave the yard in July 2009 (Fig. 1).

Construction start nears for concrete-hull, heavy-lift vessel



To satisfy demand for new lifting capacity for offshore decommissioning and installation, MPU Offshore Lift ASA in July will begin construction of a concrete hull vessel at the Keppel Verolme dry-dock in Rotterdam.

MPU says the vessel has been tailor made for single-lift removal and installation of platforms in the North Sea and elsewhere (Fig. 1). For MPU this concludes 8 years of conceptual development, model tank testing, design, and verifications.

Since mid-December, MPU has worked together with Van Hattum en Blankevoort BV (VHB) to test and document the lightweight aggregate concrete (LWAC) for the hull. MPU says a mock-up test under supervision of Sintef in Norway and Intron and the University of Delft in the Netherlands was successful.

Contractors for construction of the concrete hull, €55 million portion of the project are a joint venture of VHB and BAM Civiel BV.

MPU signed the first €165 million contract for outfitting the vessel in December 2006 with Keppel Verolme BV. MPU says detail design and engineering are on schedule for vessel delivery from the yard in mid-January 2009. ✦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Elvary Neftegaz plans riserless system for Sakhalin drilling program

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In 2006, CJSC Elvary Neftegaz deployed a riserless mud-recovery (RMR) system off Sakhalin Island.

An RMR system enables dual-gradient subsea drilling operations to take place with the well open at the seabed. There are no pressure-containment devices at the wellhead, but as with earlier systems developed for deepwater drilling, mud and cuttings are returned to the rig by a subsea pumping system, fluid recovery hose, and umbilical.[1] The system was field tested as part of the Norwegian DEMO2000 project.[2] Subsequently, it was used in a multiwell drilling campaign in the Caspian Sea.

SAKHALIN RMR—1

This two-part series describes how the riserless mud-recovery system was implemented in a remote exploration drilling operation off Sakhalin Island. The first part covers project planning and engineering. The concluding part, to be published May 7, discusses the RMR system installation and operation.

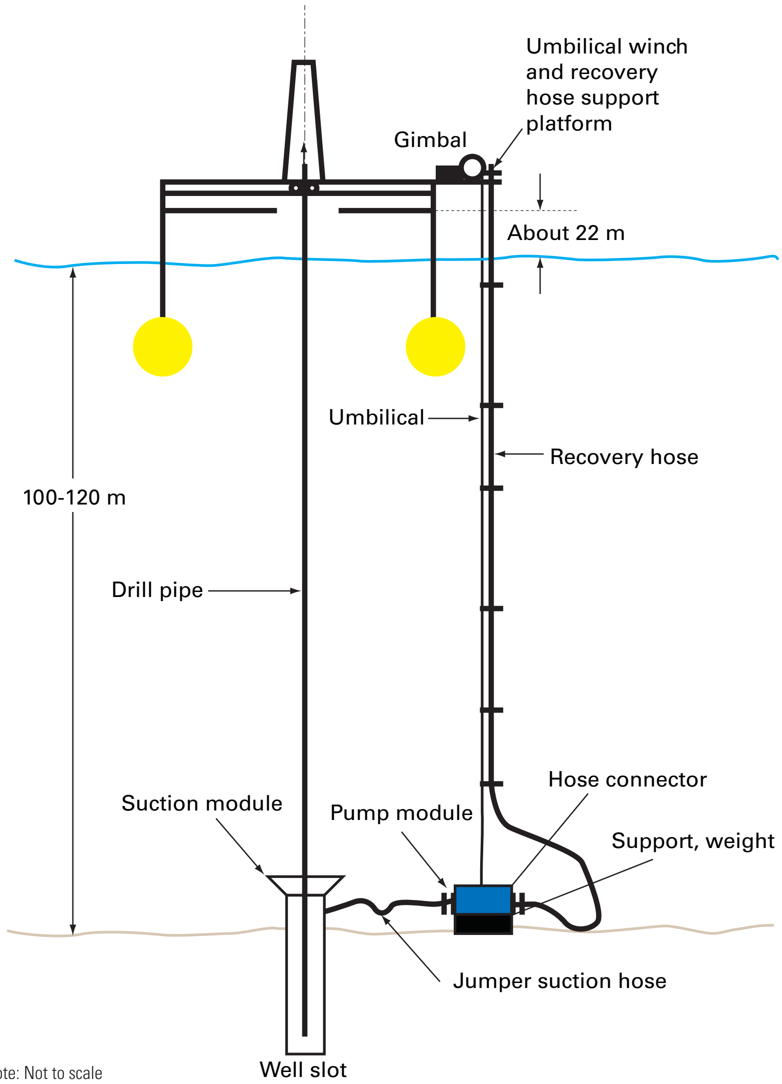
After the company's Sakhalin experiences in 2004-05, a clear business case emerged with the underlying drivers of limited weather window, shallow gas, and stringent discharge regulations.[3]

Accordingly, a formal project was established and several critical risk-reduction studies were carried out in relation to shallow gas and integrity of the return hose under high current conditions. Correct interfacing aboard the rig required careful choice of location, power supply, wellhead, and remotely operated subsea vehicle. There, changes were verified by means of a formal hazard and operability review.

A significant part of the effort involved gaining certification of the

GENERAL SCHEMATIC, RISERLESS MUD RECOVERY SYSTEM

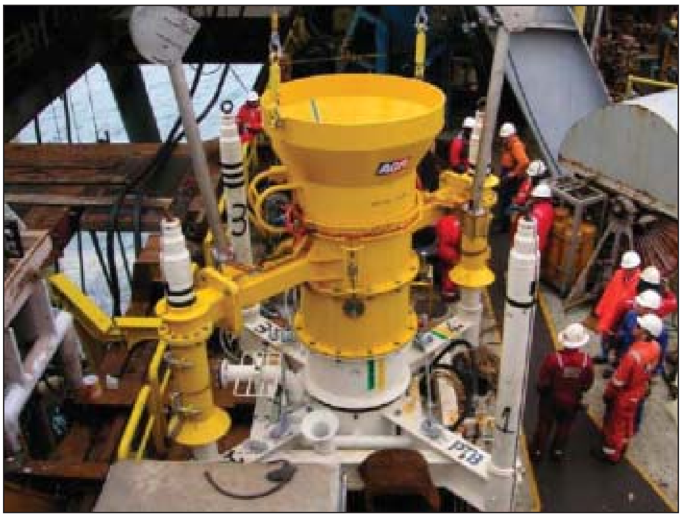
Fig. 1



Note: Not to scale

Based on a presentation to the 2007 SPE/IADC Drilling Conference, Amsterdam, Feb. 20-22, 2007.

equipment for use in the Russian Federation in parallel with fabrication, acceptance testing, mobilization, offshore installation, and commissioning of the system. The article concludes with a review of operational experience from the 2006 drilling season along with associated lessons learned and forward plan.



The wellhead suction module is stacked on a permanent guide base (Fig. 2).

Sakhalin shelf

CJSC Elvary Neftegaz, a joint venture between OAO Rosneft and BP Exploration Operating Co. Ltd., drilled wells on the northeast Sakhalin shelf during the summers of 2004, 2005, and 2006. The operation encountered numerous challenges in logistics, schedule, location, harsh environment, limited weather window, environmental sensitivities, and stringent regulations.[3]

Discharges of drilling waste, even water-based fluids and cuttings are prohibited in waters off Sakhalin once the 30-in. conductor is set. In the surface hole, before the blowout preventers are run, mud and cuttings must be returned to the rig by attachment of a marine riser directly to the 30-in. wellhead with a hydraulic latch connector. With this arrangement, the only protection against shallow gas blowouts is the rig's diverter system. This practice was the cause of a number of serious incidents during the 1980s.[4]

As a result, industry has moved away from using a riser when drilling surface holes; the present practice is to drill with returns to seabed whenever possible.

Elvary Neftegaz carried out a risk assessment on running the riser system to satisfy discharge regulations, in accordance with company policy. The outcome of the assessment was that a pilot hole should be drilled to surface-casing depth to prove that shallow gas was absent before the riser system was installed. Clearly, this is a time-consuming and potentially hazardous way of operating; an alternative and safer means had to be investigated.

In Sakhalin, there is a clearly defined weather window within which operations can be conducted. Although satellite images suggest that ice begins to clear from locations in early May, the area still sees drifting pack ice until late June. Severe storms and rapidly decreasing air temperatures in autumn result in a very clear cut-off date in mid-October for nonwinterized drilling units.

Effectively, the weather window lasts for 4 months, about June 21-Oct. 21. Clearly, elimination of activities from the critical path would enable more to be achieved within a strictly limited period.

Several factors drove the urgent search for a different approach, including being compelled to:

- Recover cuttings from the surface hole.
- Eliminate discharges associated with the pilot hole.
- Mitigate the risks posed by shallow gas.
- Maximize productive activity within the rigidly constrained weather window.

A riserless mud-recovery system developed by AGR Subsea AS, Bergen, Norway, and actively used in the Caspian was identified as a possible candidate to achieve all the desired objectives.[2] Accordingly, Elvary Neftegaz initiated a phased project to review the feasibility of the technology and, if viable, proceed with implementation.

System description

The riserless mud-recovery system is a very simple form of a dual-gradient drilling system.[1 2] Fig. 1 shows a schematic of the system, together with photographs of the different components in Figs. 2, 3, and 4. The system consists of seven major components:

1. *Suction module.* The suction module (Fig. 2) functions as a collection funnel for mud returns from the well. It provides connections to the suction hose that permit mud and cuttings to be removed from the well. It houses the video cameras, lighting, and the mud-level control system. The suction module is deployed through the rig's moon pool on the drillstring.

2. *Pump and motor module.* The pump module (Fig. 3) provides a support frame for the motor and pump. It is connected to the suction module by a flexible hose that is made up by the remotely operated vehicle. Power to the cameras, lamps, and level sensor on the suction module comes via a separate jumper umbilical line, also connected by the remotely operated vehicle.

The module includes a remotely controlled flow valve on the discharge side, a side outlet on discharge side for cement-return disposal, and an interface to the control system. The system has only a few, well-proven components. The Pleuger subsea motor is filled with a water-glycol mixture. Motor speed, and hence pump output, is controlled by a variable frequency drive. The Discflo pump has undergone extensive development with efficiency enhanced to 50%, high for this type of pump. A single pump drawing up to 300 kW is sufficient for water depths up to 200 m.

3. *Umbilical and winch.* The umbilical winch (Fig. 3) provides the power

supply and control connection between the control container and the pump module. The umbilical winch is designed to enable launching and retrieval of the pump module over the side of the rig. Total length of the umbilical is optimized to the deployment depth for the pump module. The umbilical winch is built to Norsok Z-015 and DNV 2.7.1 standards.

4. *Recovery hose system including handling platform.* The recovery line provides for return of drilling fluid to the rig. It is made up in 15-m sections of 6-in. diameter heavy-duty hose joined by quick-connect couplings. The tensile strength of the hose is enhanced with a pair of load-bearing wires strung from integral lugs on each connector.

A special hose coupling and load-bearing wires enable efficient deployment and retrieval of the mud-recovery line. A remotely operated vehicle-friendly connector connects the recovery line to the pump module. The recovery-hose handling platform (Fig. 3) includes a safe handling system for deployment and retrieval of the recovery hose and a hang-off shoulder to take the weight of the recovery hose during operations. Hard piping connects the return hose landing platform manifold to the shale shaker header box.

5. *Control containers and power supply.* Two purpose-built containers (Fig. 4) were installed. One pressurized unit is a crew work area and operator workstation. The second pressurized unit contains the variable speed drive, transformer, filter, and control system to provide the interface between the rig and the system. A 3-kv transformer provides the high voltages to enable cable sizes to be optimized.

The container is the hub to which all control systems are interfaced. The control system monitors pump speed and pressures and also monitors and maintains a stable mud level in the wellhead suction module. The containers are fabricated to Norsok Z-015 and DNV 2.7.1 standards.

6. *Control system.* The control system controls the speed of the pump motor to keep the mud level below the top of the wellhead suction module, thus preventing escape of fluids to the sea. The control system is distributed between the control container and the subsea pump module. The system is controlled from a dedicated explosion-proof computer in the driller's cabin.

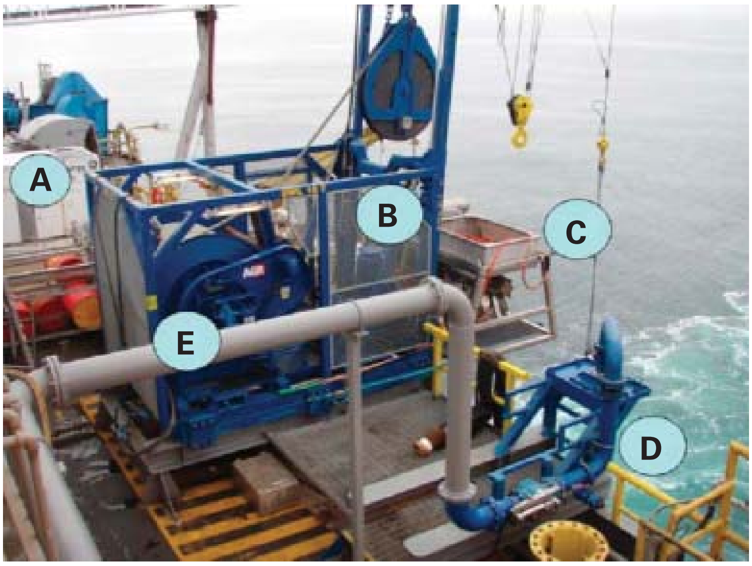
7. *Shutdown system.* Emergency shutdown elements are part of the control system. The system was configured with two shutdown buttons, one on the drill floor, the other in the control container.

Project description

Modern project-management practice emphasizes the correct phasing of

DETAIL OF WINCH, PUMP, HOSE PLATFORM

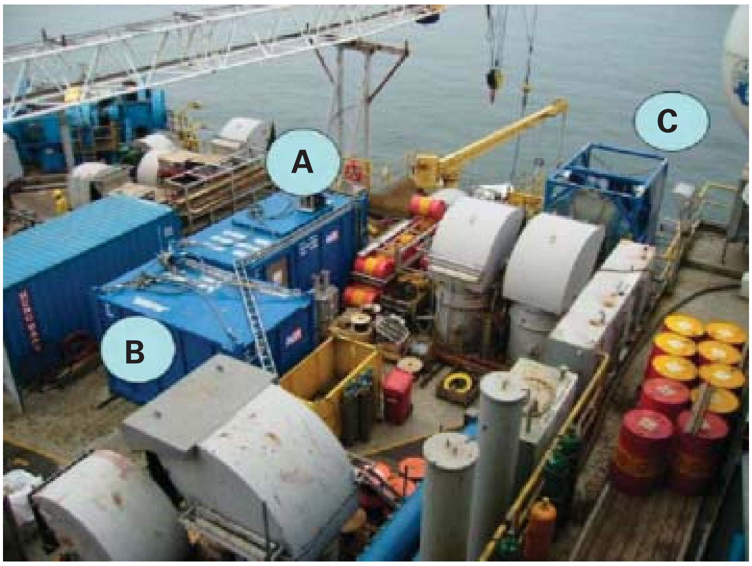
Fig. 3



A – Generator
B – Winch unit
C – Subsea pump and motor
D – Hose landing platform
E – Mud and cuttings return line

GENERAL LAYOUT OF WINCH, CONTROL UNITS

Fig. 4



A – Pressurized control cabin
B – Crew cabin
C – Winch unit

Note: Hose landing platform is out of sight, to right of winch

projects. Experience repeatedly demonstrates the benefits of a careful review of options and assessment of risks in the early stages of a project. Accordingly, the Sakhalin RMR project was broken into five steps with a formal "stage gate" review required before the project could progress to the next step.

• *Appraise*. The objective of this stage was to assess the feasibility of the concept. A review of available literature pointed to a candidate system. Discussions with the manufacturer suggested that a system could be developed and mobilized to commence operations in June 2006. A high-level risk assessment was carried out, a preliminary schedule prepared, and cost estimate developed.

Further work showed that the risks could be overcome and a system delivered within the required timeframe. This plan was networked with other business units and technical specialists who endorsed the viability of the project in June 2005. Funding was approved to carry out the necessary risk-reduction studies.

• *Select*. The purpose of this stage was to develop sufficient confidence in the concept to allow a commitment to be made to proceed with detailed engineering design and then, potentially, to full-scale system procurement and mobilization. Building on the risk assessment, planners visited the rig and carried out a series of preliminary risk reduction studies, specifically in relation to shallow gas and integrity of the recovery hose in the high currents.

During this phase, regular contact was maintained with another BP business unit employing the system as part of a template drilling operation in the Caspian Sea. An outline design of the system was developed with input of actual rig data, actual environmental data, and a rigorous input of operational procedures based on likely well designs. The output from this stage was a frozen design that demonstrated how the major risks were to be mitigated, how the system eliminated the need for pilot hole, and what effect it had on the chosen waste-handling method.

A detailed execution plan, budget, and commercial proposal were prepared and externally reviewed and approved in August 2005. At this stage the concept was de-risked to the point that funding for long-lead procurement items was approved.

• *Define*. The purpose of this stage was to develop a detailed design and specification of the system in order to proceed with manufacturing, certification, and installation. Given the schedule, it was necessary to identify and order long-lead items before the design freeze. The work to date had been carried out under a study contract, thus an agreement for the operational phase had to be developed.


They work 12 hour shifts,
73 miles offshore in all kinds
of weather.

Of critical importance early on was investigating matters relating to Russian certification and importation and developing the necessary action plan. Building on earlier work, the team completed detailed risk-reduction studies on the hose system and shallow gas behavior. Following the preliminary rig visit, Elvary Neftegaz held a series of meetings with the wellhead vendor and the remotely operated vehicle operator.

Once these initial studies were complete and preliminary plans devised, they were subject to a detailed operational hazard and operability review. After this review's actions were identified, Elvary Neftegaz conducted a formal peer review of operational procedures involving shallow hazards specialists and senior technical authorities from drilling and completions. Formal approval to use the system in the 2006 drilling campaign was given in January 2006.

- *Execute.* The object of this phase was to deliver a working system to the rig in Busan, South Korea. It was necessary to procure the equipment, fabricate, and commission the system in Norway before disassembly and shipment to South Korea. Once in South Korea, in May 2006, the system was installed aboard the rig and commissioned. Detailed procedures for deployment and operation were developed and integrated with the main drilling operations plans for the wells. At this point, the RMR system was handed over to the well operations team.
- *Operate.* Use procedures for drilling operations, evaluate performance, capture lessons learned, and plan for next season.
- *Project organization.* Personnel in the UK coordinated the technical risk-reduction studies and contracting activities, but overall program administration and supervision was carried out in Sakhalin. Special consultancies in the UK and Norway performed the risk-reduction studies. The contractor in Bergen carried out the bulk of the engineering activity.

Interfaces between drilling contractor, wellsite supervision, wellsite service companies, and wellhead vendor were critically important. They were managed through a series of meetings in Singapore and South Korea. High-level peer reviews took place in Sakhalin and Houston.

- *Key project risks.* An initial high-level project risk assessment, carried out during the appraisal stage, formed the basis for a number of activities during the remainder of the project. The key risks and their mitigations were:
- Shallow gas: detailed engineering analysis.
- Integrity of umbilical in high current conditions: detailed engineering analysis.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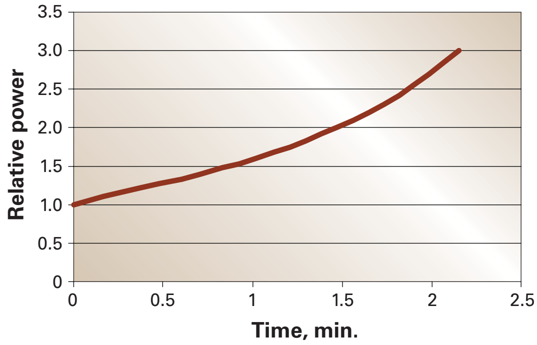
- Use of the system in the Russian Federation: early start to permitting.
- Equipment lead-time: commitment of funds to enable procurement of critical items.
- Rig interface: early site visits, involvement of all parties, detailed hazard and operability review.
- New technology: extensive discussion and visits to other users.

RELATIVE PUMP POWER*

Fig. 5



*with increasing influx volume, after SPE102579

Risk-reduction studies

Although BP had considerable experience using the system in the Caspian Sea, the metocean conditions off Sakhalin, with its strong current regime, posed significant problems. Elvary Neftegaz was concerned about system deployment, hose integrity, and the need to ensure the topsides equipment's design rating would not be exceeded.

Elvary Neftegaz chose UK-based 2H Offshore Engineering Ltd. for the work based on its experience designing solutions for drilling and production riser systems. Environmental data for the study were derived from metocean data gathered in 2004, including current data recorded throughout the drilling operation with a seabed acoustic Doppler current profiler.

The resulting output endorsed selection of flexible riser material and validated design loadings for the umbilical winch and return line handling platform. Transocean Inc. the used these topside loadings to design and build the deck-strengthened foundations to mount the winch and handling platform, located starboard aft of the semisubmersible rig's main deck.

Offshore systems team at BP's technology center in the UK reviewed the study. There was some concern that internal abrasion of the riser hose might occur, given the large volumes of sand

anticipated during drilling of top-hole sections. Calculations indicated that breaching of the hose liner was unlikely to occur before 1,000 hr of circulation at maximum pump rates. As the operation period was estimated to last some 2-5 days (100 hr maximum), this risk was considered negligible.

Concern was also expressed about the possibility of the hose kinking while in service. Kinking would not lead to damage of the hose, but simply a blockage of the recovery hose. Therefore, this was regarded as matter to be addressed through operational procedures as opposed to being an issue of fundamental technical integrity.

The possibility of gas entering the pump and recovery hose during a shallow gas blowout was evaluated even though the dual-gradient nature of the system, with the ability to control mud weight, makes it almost impossible for conditions to develop under which an influx can occur.

The Norwegian technology company, SINTEF, had already carried out some general scoping studies of this problem as part of the initial system development.[5] SINTEF carried out a further, more detailed study using input data specifically related to the well design, hole sizes, mud properties, operational procedures, and anticipated geological conditions. The results of the analysis showed that:

1. Use of the system in conjunction with a suitably weighted drilling fluid would greatly reduce the likelihood of a gas kick because of the "dual-gradient" behavior of the system.

2. With a conventional influx volume of 3 cu m (20 bbl) as the detection threshold, kick detection is possible before gas reached the wellhead for all the kick scenarios and hole size combinations likely to be encountered.

3. Subsea pump power consumption is a sensitive method of detecting an influx. Fig. 5 illustrates the case of a 26-in. hole, in which it takes 2 min for the influx volume to reach 3 cu m, by which time the power demand has increased by a factor of 3. The control system is set to trip out following a 10% increase in power, in this case triggering a kick alarm within 15 sec.

4. With kick development times ranging from 30 to 300 sec, ensuring no gas is taken into the pump and recovery hose demands a high degree of alertness and prompt action by the crew. The most rapid influx times were associated with pilot-hole configurations.

Further details of Elvary Neftegaz's work with a riserless mud recovery system off Sakhalin will be published in the concluding part of this series. ✦

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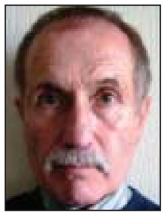
The authors



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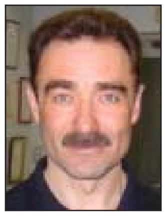

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Study updates refinery investment cost curves

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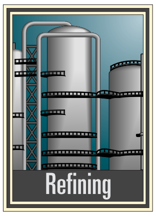


In this article, we have updated and extended the refinery investment cost curves presented in Gary and Handwerk's "Petroleum Refining: Technology and Economics."[1 2] This article presents the methodological framework, data sources, and normalization procedures used for cost estimation, along with a discussion of the limitations of analysis.

Cost functions are summarized for the main refinery processes.

Data sources

Many different data sources are available to estimate the construction cost of a refinery unit, including government organizations, private and public companies, commercial databases, trade and academic publications, and press releases for licensors and companies.

Oil & Gas Journal and Hydrocarbon Processing semiannually report planned capacity expansions for refineries (OGJ Apr. 16, 2007, p. 18). The data coverage is similar in both surveys and provides information on refining capacity that will be added at each location by project type (increment of capacity added; total capacity after construction; revamping, modernization or debottlenecking; expansion); licensor, engineering company, and constructor; estimated completion date; estimated cost; and project status (abandoned, engineering, feed, completed, maintenance, planning, under construction).

The data are subject to availability, and because project descriptions are not provided, are of limited use for cost estimation.

The best public sources of information for cost data are technical articles found in OGJ and other trade publications, material presented at such professional conferences as National Petrochemical and Refining Association's annual meeting, and industry studies.

Robert Meyer's "Handbook of Petroleum Refining Processes" is an excellent source of process and economic data for a wide compendium of technologies. Maples, Raseev, Sadeghbeigi, and various other texts provide cost estimates for mid-1990 and earlier configurations and technologies.[3-6]

Commercial databases from Baker & O'Brien Inc.; Purvin & Gertz Inc.; Solomon Associates LLC; Turner, Mason & Co.; and other consultancies such as Independent Project Analysis Inc. are widely used throughout industry for benchmarking and policy studies. Cost information in commercial sources is some of the best available, having been collected from projects and other assignments over an extended period of time and at various levels of detail.

Each agency considers its database and modeling software proprietary, however, and so the quality, reliability, and consistency of commercial sources remain difficult to assess and compare.

Process technologies

Table 1 shows the primary process technologies used in petroleum refining. For each process, one or more subcategories are typically defined, based on technology attributes, operating conditions, or feedstock.

Function specification

Capital costs for refining units are frequently specified as a function of capacity and scaled using the power-law relation as shown in Equation 1 (see accompanying equation box).

The value of x varies with each unit and is frequently assumed to vary between 0.5 and 0.7.[7 8] To estimate x, data are collected for units of comparable design and technology, and then the value is determined empirically through regression analysis.

EQUATIONS

$$\frac{C(U_i, Q_1)}{C(U_i, Q_2)} = \left(\frac{Q_1}{Q_2}\right)^x \quad (1)$$

$$C(t_2) = C(t_1)\left(\frac{I(t_2)}{I(t_1)}\right) \quad (2)$$

$$\gamma(U_i) = \frac{C(U_i, Q_i)}{C(U_0, Q_0)} \quad (3)$$

$$\gamma(R) = \sum_i \frac{Q_i}{Q_0}\gamma(U_i) \quad (4)$$

$$\gamma(\Gamma) = \frac{1}{Q(\Gamma)}\sum_i Q(R_i)\,\gamma(R_i) \quad (5)$$

Nomenclature
C = Cost of process unit, $
I = Cost index
Q = Capacity of process unit, b/d
t = Time
U_i = Type of process unit
U_0 = Atmospheric distillation unit
x = Exponent that varies by type of process unit
$\gamma(U_i)$ = Complexity index for a given process unit
$\gamma(R)$ = Complexity index for overall refinery
$\gamma(\Gamma)$ = Complexity index of category Γ

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

For some units, it is not possible to develop useful curves from its feed capacity, while in other cases, if a large number of factors influence the design parameters, unrealistic uncertainty bounds may result. To manage these issues we frequently cross-correlated cost data, based on two or more process descriptors, and in cases where data were extremely sparse, (unit) cost data on a per-barrel basis are presented.

Analysis limitations

Many engineering estimates are available, but the actual (finished) cost is preferred to avoid estimator bias and to assess actual system performance. Ideally, we would only use actual cost data in our analysis, but the sample sets in most cases would be too sparse. We therefore, found it necessary when building cost curves to base the assessment on both engineering estimates and actual cost records.

Cost curves are meant to represent typical, or average, values and stand as point estimates rather than in terms of intervals or ranges. Cost functions represent an "average" refinery, which of course does not exist as an actual plant but is useful in developing conceptual cost estimates in early stages of assessment and design.

Every cost estimate involves uncertainty due to differing qualities of equipment fabrication, design differences, market conditions, vendor profit, and other considerations. The cost curves can be assumed to have an accuracy limited to ±25%.

Working capital, inventories, start-up expense, the cost of land, site preparation, taxes, licenses, permits and duties are not considered in the estimation. The cost curves that we established are inappropriate for benchmarking studies.

The level of uncertainty in estimation can be reduced through a detailed front-end engineering design based on site-specific information. For definitive economic comparisons and estimations, other factors such as feedstock, production specification, operating conditions, design options, and technology options must be considered.

Utility requirements

Utility requirements for each process are usually presented on a per-barrel unit feed or product basis and correspond to average characteristics associated with the mid-point of the construction cost curve. Wide variability in utility values can result, depending upon the capacity of the unit and other process-specific factors.

Table 2 shows typical utility cost data.

Normalization

The cost data of units of roughly comparable design and technology are normalized with respect to construction requirements, process specifications, location, and time of installation:

- *Dependent variable.* The normal basis in computing construction cost is the liquid-volume fraction of the crude that is fed to each process, but in several units (alkylation, polymerization, aromatics manufacture), a better descriptor is the barrels of product rather than the feed.

In other units (isomerization, hydrotreating, catalytic reforming, hydrogen production), it is necessary to cross-correlate the cost with other factors, while in gas processing and sulfur manufacture, the liquid-volume basis needs to be replaced with the measures cubic feet (gas) and long tons (sulfur).

REFINING PROCESS TECHNOLOGIES

Table 1

Process operation	Technology
Coking	Fluid coking, delayed coking, other
Thermal process	Thermal cracking, visbreaking
Catalytic cracking	Fluid, other
Catalytic reforming	Semiregenerative, cycle, continuous regeneration, other
Catalytic hydrocracking	Distillate, upgrading residual, upgrading lube oil, other
Catalytic hydrotreating	Pretreatment of cat reformer feeds, other naphtha desulfurization, naphtha aromatics saturation, kerosine/jet desulfurization, diesel desulfurization, distillate aromatics saturation, other distillates, pretreatment of cat cracker feeds, other heavy gas oil hydrotreating, resid hydrotreating, lube oil polishing, post-hydrotreating of FCC naphtha, other
Alkylation	Sulfuric acid, hydrofluoric acid
Polymerization/dimerization	Polymerization, dimerization
Aromatics	BTX, hydrodealkylation, cyclohexane, cumene
Isomerization	C_4 feed, C_5 feed, C_5 and C_6 feed
Oxygenates	MTBE, ETBE, TAME
Hydrogen production	Steam methane reforming, steam naphtha reforming, partial oxidation
Hydrogen recovery	Pressure swing adsorption, cryogenic, membrane, other

TYPICAL UTILITY COST DATA, 2005

Table 2

	Cost, $	
Utility	English units	SI units
Steam, 450 psig	5.50/1,000 lb	12.10/1,000 kg
Steam, 150 psig	4.40/1,000 lb	8.80/1,000 kg
Steam, 50 psig	2.50/1,000 lb	5.50/1,000 kg
Electricity	0.04/kw-hr	0.04/kw-hr
Cooling water	0.05/1,000 gal	0.013/cu m
Process water	0.05/1,000 gal	0.13/cu m
Boiler feed water	1.50/1,000 gal	0.40/cu m
Chilled water, 40° F.	1.00/ton-day	3.30/GJ
Natural gas	5.40/1,000 scf	0.226/cu m
Fuel oil	0.75/gal	200/cu

Source: Reference 8

NELSON-FARRAR REFINERY OPERATING COST INDICES

Table 3

	2000	2001	2002	2003	2004	2005
Fuel and power cost	780	704	667	935	972	1,360
Labor cost	249	221	211	201	192	202
Wage rate	1,094	1,007	968	972	984	1,007
Productivity of labor	441	456	459	485	513	501
Investment related	589	594	620	643	687	716
Chemicals and catalyst	224	222	221	238	268	311
Refineries	444	429	433	465	487	542
Processes	554	521	514	613	638	787

• *Project type.* Projects are classified according to new capacity, expansion of existing capacity, or a revamp or modernization of existing facilities. Cost estimates in this article pertain exclusively to grassroots construction, limited to equipment inside the battery limits (ISBL) of each process, and including materials and labor; design, engineering, and contractor's fees; overheads; and expense allowance.

• *Off-site expenses.* These include the cost and site preparation of land, power generation, electrical substations, off-site tankage, or marine terminals. Off-site costs vary widely with the location and existing infrastructure at the site and depend on the process unit. ISBL costs do not include off-site expenses.

• *Location.* It is common practice to state cost estimates relative to the US Gulf Coast because this location has favorable construction costs relative to other domestic and international markets. Design requirements, climate, regulations, codes, taxes, and availability and productivity of labor all influence the cost of construction, and to some extent, the operating cost of a facility.

• *Time.* The purchase cost of processing equipment in refining is generally obtained from charts, equations, or quotes from vendors at a particular date, usually month and year. Factors such as regulatory requirements, heavy feedstock, and the cost of materials may increase costs and inflate refinery investment over time, while other factors may act to lower cost, such as improvements due to a technological and process nature like improved catalyst, control and instrumentation, and materials technology.

Time captures both long-term dynamics such as improvements in technology and operational efficiency, as well as local effects such as the cost of steel, permit requirements, and pollution control.

Nelson-Farrar cost indexes

An estimate of the purchase cost at a given time t_2 is obtained by multiplying the original (quoted) cost at time t_1 by a ratio of cost indexes (Equation 2).

The Nelson-Farrar (NF) construction cost index normalizes cost during the time required to construct a process unit. The NF cost index is unsuitable for determining the cost for refineries or process units that are more than 3-5 years old. The NF cost index also does not account for productivity attained in design, construction, or management skills.

The NF construction cost index (Fig. 1) is published in OGJ in the first issue of each month.

The NF operating cost indices compare operating costs over time (Table 3). Unlike the construction index, the operating cost indices are normalized for the productivity of labor, changes in the amounts and kinds of fuel used, productivity in the design and construction of refineries, and the amounts and kinds of chemicals and catalysts used (OGJ, Dec. 30, 1985, p. 145; OGJ, Oct. 2, 1989, p. 90)

Comparisons of operating indices can be made for any two periods of time.

Unit complexity

The Energy Information Administration division of the US Department of Energy publishes data on US refineries that are similar in format to those published annually by OGJ.[9]

Crude distillation, vacuum distillation, coking, thermal processes, catalytic cracking, catalytic reforming, catalytic hydrocracking and catalytic hydrocracking are described in terms of charge capacity, which describes the input (feed) capacity of the facilities. Production capacity represents the maximum amount of product that can be pro-

TRENDS IN COMPLEXITY FACTORS

Table 4

Process operation	1946	1961-72	1976	1989
Atmospheric distillation	1	1	1	1
Vacuum distillation	2	2	2	2
Vacuum flash	1	1	1	1
Thermal processes				
Thermal cracking	4.5	3	3	3
Visbreaking	2	2	2	2
Coking	5	5	5.5	5.5
Calcining		63	108	108
Catalytic cracking				
60% conversion	4	5	5	5
80% conversion		6	6	6
Catalytic reforming	5	4	5	5
Catalytic hydrocracking		6	6	6
Catalytic hydrorefining		4	3	3
Catalytic hydrotreating		2	2	1.7
Alkylation	9	9	11	11
Aromatics, BTX		40-70	20	20
Isomerization		3	3	3
Polymerization	9	9	9	9
Lubes				60
Asphalt	2		3.5	1.5
Hydrogen, MMscfd				
Manufacturing		1.2	1.2	1
Recovery		0.7	0.7	1
Oxygenates				10
Sulfur, long ton/day				
Manufacturing		85	85	85
Manufacturing from dilute gas		250-300	220-600	220-600

Sources: Reference 10, OGJ, Dec. 30, 1985, p. 145

EXXON-MOBIL'S LOUISIANA REFINERIES, 2005

Table 5

	Capacity, b/cd							
Location	Crude	Vacuum distillation	Delayed coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating
Baton Rouge	501,000	227,000	112,500	—	229,000	75,500	24,000	333,500
Chalmette	188,000	112,000	33,000	—	68,000	47,000	18,500	172,500
Total	**689,000**	**335,000**	**145,500**	—	**297,000**	**122,500**	**42,500**	**506,000**

Source: OGJ Worldwide Refining Survey, Dec. 19, 2005.

duced and are presented for alkylation, polymerization/dimerization, aromatics, isomerization, lubricants, oxygenates, hydrogen, coke, sulfur, and asphalt facilities.

Wilbur Nelson introduced the concept of complexity factor to quantify the relative cost of components that make up a refinery (OGJ, Nov. 29, 1976, p. 68; OGJ, Jan. 10, 1977, p. 86). Nelson assigned a complexity factor of 1 to the atmospheric distillation unit and expressed the cost of all other units in terms of their cost relative to distillation.

For example, if a crude distillation unit of 100,000 b/d capacity cost $10 million to build, then the unit cost/daily barrel of throughput would be $100/b/d. If a 20,000 b/d catalytic reforming unit cost $10 million to construct, then the unit cost is $500/b/d of throughput and the "complexity" of the catalytic reforming unit would be 500/100 = 5.

The complexity factor of process unit U_i of capacity Q_i is defined in Equation 3.

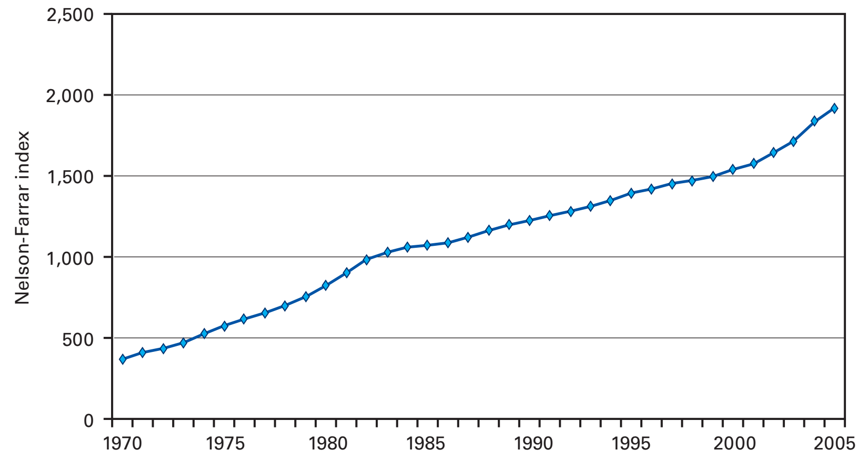
Various methodological issues limit the use of complexity factors in estimating cost. For example, complexity factors do not account for the impact of capacity on cost because the complexity factor is capacity-invariant, and trends in complexity factors change slowly (or not at all) over time (Table 4), making their application suspect.

Refinery complexity

A refinery's complexity indicates how complex it is in relation to a refinery that performs only crude distillation. The complexity index of a given refinery, R, is determined by the complexity of each individual unit weighted by its percentage of distillation capacity (Equation 4).

A simple refinery is typically defined by $\gamma(R)<5$; a complex refinery by $5\leq\gamma(R)\leq15$; and a very complex refinery by $\gamma(R)>15$. Refinery complexity is an often-cited industry statistic and is a useful tool in comparative analysis, being frequently used as a correlative or descriptive variable in marketing and valuation studies (OGJ, Sept. 19, 2005, p. 43).

Nelson-Farrar refinery construction cost index Fig. 1

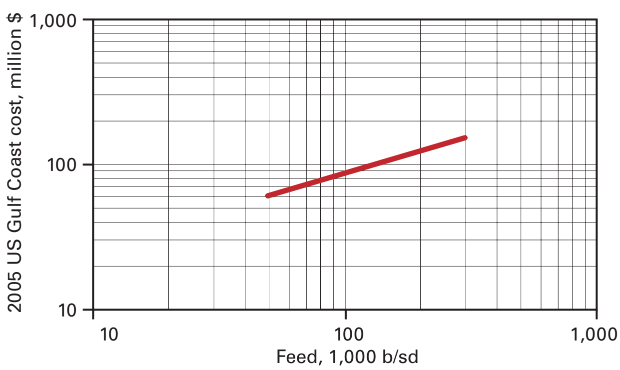


Source: OGJ

Refining example

Tables 5 and 6 show ExxonMobil Corp.'s charge and production capacity of its Louisiana refineries. The complexity index of the Baton Rouge refinery is computed in Table 7 as 13.4, a complex refinery.

Atmospheric distillation investment Fig. 2



Generalized complexity

The complexity index can be generalized across any level of aggregation, such as a company, state, country, or region (Equation 5).

Process cost functions

The first steps in every refining process are desalting and the subsequent separation of crude oil into fractions by atmospheric and

Production from Exxon-Mobil's Louisiana refineries Table 6

Location	Alkylation	Poly/Dim	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen, MMcfd	Coke	Sulfur	Asphalt
	b/cd							tonnes/day		
Baton Rouge	140,000	9,500	—	—	16,000	7,000	12	5,262	690	—
Chalmette	12,500	—	10,000	10,000	—	—	—	2,050	920	—
Total	**152,500**	**9,500**	**10,000**	**10,000**	**16,000**	**7,000**	**12**	**7,312**	**1,619**	**—**

Source: OGJ Worldwide Refining Survey, Dec. 19, 2005

vacuum distillation.

Exxon-Mobil's Baton Rouge complexity index, 2005

Table 7

Process operation	Capacity, b/sd	Ratio to distillation capacity, %	Complexity factor	Complexity index
Atmospheric distillation	501,000	100	1	1
Vacuum distillation	227,000	45.3	2	0.91
Coking	112,500	22.5	5.5	1.20
Catalytic cracking	229,000	45.7	6	2.74
Catalytic reforming	75,500	15.1	5	0.76
Catalytic hydrocracking	24,000	4.8	6	0.29
Catalytic hydrotreating	333,500	66.6	1.7	1.13
Alkylation	140,000	27.9	11	3.07
Polymerization	9,500	1.9	9	0.17
Lubes	16,000	3.2	60	1.92
Oxygenates	7,000	1.4	10	0.14
Hydrogen, MMcfd	12,000	2.4	1	0.02
Refinery complexity index				13.4

Process cost functions

Table 8

Process unit	Cost, $ million = α•capacity^β — α	β	Units of capacity
Desalter	0.44	0.555	1,000 b/sd
Atmospheric distillation	8.20	0.510	1,000 b/sd
Vacuum distillation	8.34	0.493	1,000 b/sd
Delayed coking			
10 bbl feed/ton coke	17.56	0.657	1,000 b/sd
30 bbl feed/ton coke	24.42	0.644	1,000 b/sd
Visbreaking	5.80	0.741	1,000 b/sd
Fluid catalytic cracking			
Distillate feed	24.67	0.461	1,000 b/sd
Resid feed	32.98	0.510	1,000 b/sd
Catalytic hydrocracking			
1,000 scf/bbl H_2	15.65	0.719	1,000 b/sd
3,000 scf/bbl H_2	26.18	0.714	1,000 b/sd
Catalytic hydrotreating			
Naphtha desulfurization	4.96	0.524	1,000 b/sd
Distillate desulfurization	8.62	0.576	1,000 b/sd
Resid desulfurization	8.61	0.834	1,000 b/sd
Catalytic reforming			
Semiregenerative	7.96	0.572	1,000 b/sd
Continuous	12.19	0.547	1,000 b/sd
Isomerization			
Butane	9.57	0.514	1,000 b/sd
Pentane/hexane; once through	3.11	0.565	1,000 b/sd
Pentane/hexane; recycle	6.17	0.599	1,000 b/sd
Alkylation	12.19	0.606	1,000 b/sd
Hydrogen production			
Steam methane reforming	3.35	0.599	MMscfd
Partial oxidation	5.44	0.601	MMscfd
Gas processing			
1 gal/Mscf	1.91	0.627	MMscfd
10 gal/Mscf	4.38	0.593	MMscfd
20 gal/Mscf	5.83	0.610	MMscfd
Amine-gas treating	0.064	0.746	gpm
Sulfur recovery	2.84	0.412	Long ton/day
Sulfur removal			
S-zorb, gasoline	4.77	0.602	1,000 b/sd
S-zorb, diesel	4.62	0.553	1,000 b/sd
Dewaxing	5.82	0.598	1,000 b/sd
Ether production	8.96	0.472	1,000 b/sd

Table 8 summarizes cost functions for different types of refining processes in terms of the function parameters α and β. For example, Cost (desalter) = 0.44•Capacity$^{0.555}$, where α = 0.44 and β = 0.555.

Delayed coking, visbreaking, fluid coking, and flexicoking are common thermal cracking units.

Fig. 1 shows a typical cost curve, in this case, crude distillation.

Catalytic cracking is accomplished through the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil. Fluid catalytic cracking cost curves for distillate and resid feed are given by Cost(Catalytic cracking; distillate feed) = 24.67•Capacity$^{0.461}$ and Cost(Catalytic cracking; resid feed) = 32.98•Capacity$^{0.510}$.

Table 9 also shows:

- Catalytic hydrocracking capital investment costs at 1,000 and 3,000 scf/bbl hydrogen consumption.
- Hydrodesulfurization capital costs processing a naphtha feedstock, a distillate feedstock, and a residual feedstock.
- Semiregenerative and continuous-regeneration catalytic reforming costs. Continuous regeneration has been used in the majority of the new catalytic reformers built in the US, although fixed-bed units are still constructed depending upon product requirements.
- Paraffin isomerization unit capital costs for butane and pentane-hexane feed for once-though and recycle processes.
- Investment cost of alkylation units expressed in terms of alkylate production. Capital costs for sulfuric and hydrofluoric alkylation units are generally comparable, and therefore the investment curve can be applied for either unit. Composition of the costs, however, varies with the technology. The sulfuric acid process has an expensive reactor section and requires refrigeration, whereas HF alkylation uses feed driers, product treating, regeneration equipment, and more exotic metallurgy.
- Investment cost curves for hydrogen-production units that use steam reforming of natural gas, catalytic reforming, and partial oxidation.
- Gas processing and amine-treatment capital investment costs.
- Investment costs for sulfur-removal technologies including the Claus process, which uses both thermal and catalytic-conversion reactions and the S-zorb process.
- Solvent dewaxing capital costs.
- Capital costs and utility consumption for methyl tertiary butyl ether and tertiary amyl methyl ether production based on a one-stage design. The capital costs are expressed in terms of total hydrocarbon feed (excluding alcohol), and therefore the iso-olefin content of the feedstock must be known for cost estimation. ✦

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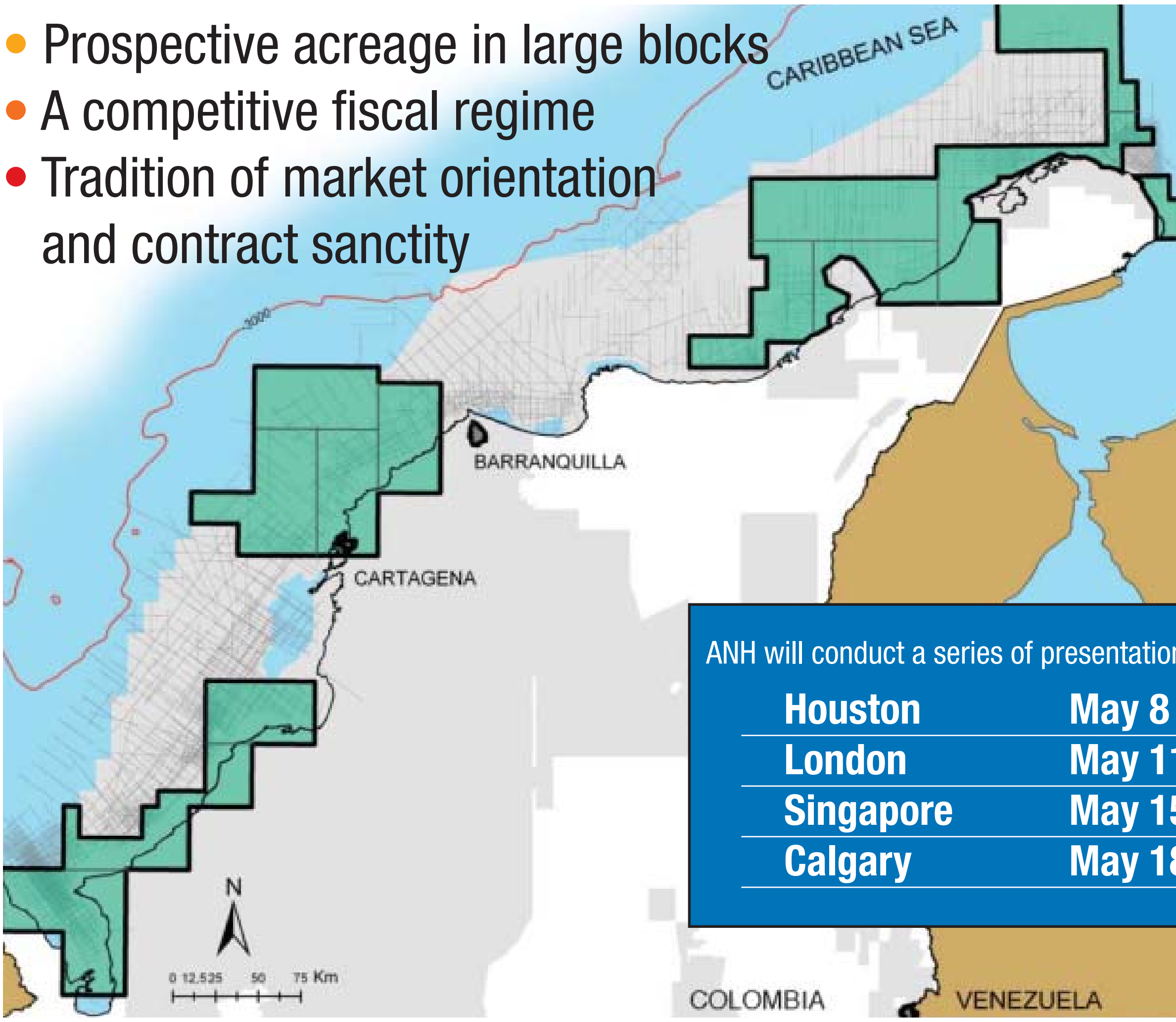

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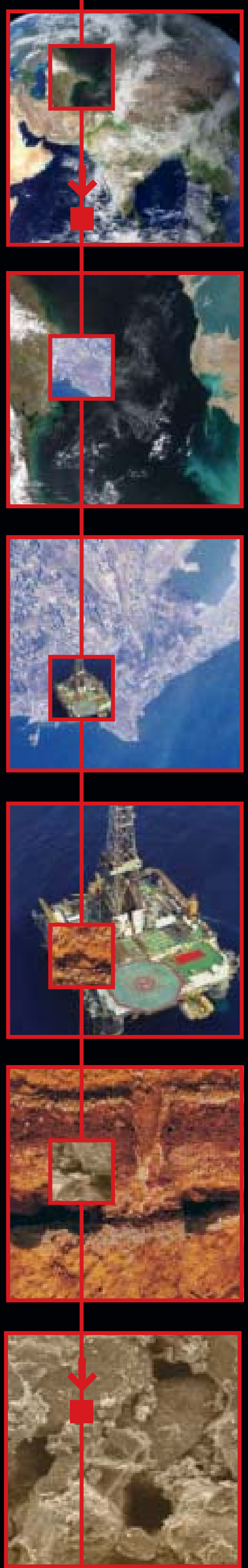
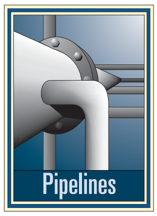


Independence Hub sees record SCR installation

Christopher E. Smith
Pipeline Editor



The 20-in. steel catenary riser, connecting the Independence Hub (IHUB) production platform to the Independence Trail natural gas export pipeline, ranks as the largest and deepest such riser ever installed. Beginning at the IHUB, on Mississippi Canyon Block 920 in water 8,000 ft deep, Independence Trail is also the deepest export pipeline installed to date.

Enterprise hired Heerema Marine Contractors Nederland BV for installation of the IHUB floating production facility, including all risers.

Both the export riser and IHUB's production risers were in temporary storage on the seabed near IHUB when Heerema began work in first-quarter 2007, having previously been installed by Allseas' Solitaire. The export riser lay parallel to one of the production risers but on top of four others and under two. Production risers are 8 and 10-in. OD.

This article outlines the Independence Hub project and details installation of the export SCR.

IHUB

Enterprise announced Mar. 8, 2007,

INDEPENDENCE HUB PROJECT

Fig. 1

OIL&GAS JOURNAL | Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page | qMags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that IHUB had been successfully installed and had started earning demand revenues. Independence Hub LLC, a venture of Enterprise Field Services LLC (80%) and Helix Energy Solutions (20%), owns IHUB. Anadarko Petroleum Corp. will operate processing on the hub on behalf of the gas field owners that include Anadarko, Dominion Exploration & Production, Devon Energy Corp., Hydro Gulf of Mexico, and Murphy Oil Corp. Production from the fields served by IHUB is to begin in second-half 2007.

IHUB is the deepest offshore platform ever installed and, at 1 bcfd, also has the largest production capacity, representing a 10% increase in current natural gas deliveries from the Gulf, according to Heerema.

The Independence Trail Natural Gas Pipeline is a wholly owned affiliate of Enterprise Products Partners LP. The 134 mile, 24-in. pipeline connects Independence Hub to an interconnect with Tennessee Gas Pipeline on West Delta Block 68 (Fig. 1).

Allseas Solitaire completed S-lay of the pipeline in August 2006.

The pipeline has a maximum operating pressure of 3,640 psi and a capacity of 1 bcfd. It has two subsea dual tees of 16-in. and 12-in. in water depths of about 6,500 and 4,500 ft, respectively, for future tie ins.

The 24-in. line consists of API 5L X-65 DSAW (double submerged arc welded) pipe coated with 14-16 mils thin film fusion-bonded epoxy (FBE) and an additional 2-3 mils rough coat FBE (OGJ, Nov. 27, 2006, p. 43).

The export SCR has a 1.21-in. WT, 9,000 ft of vortex induced vibration strakes, a dry recovery weight of 460 tonnes, and a wet recovery weight of 900 tonnes.

Equipment

Heerema used its Deepwater Construction Vessel (DCV) Balder for the IHUB installation. This section focuses on equipment Balder used while installing the export SCR.

Built as semisubmersible crane vessel in 1978, Balder completed conversion into a Class III dynamic positioning system DCV in 2001.

Balder has an overall length of 522 ft, overall breadth of 371 ft, and gross tonnage of 48,511 tons. Its Class III DPS produces 350 tonnes thrust using nine thrusters (2 × 4,400 kw, controllable pitch; 7 × 3,500 kw, 360° azimuth) with seven independent engine rooms. The system can be operated manually, via joystick, autopilot, or in full dynamic-positiong mode. Special DP functions include:

- Track follow.
- Heavy lift.
- Follow floating object.
- External force compensation.
- Pipelay.

Balder also features:

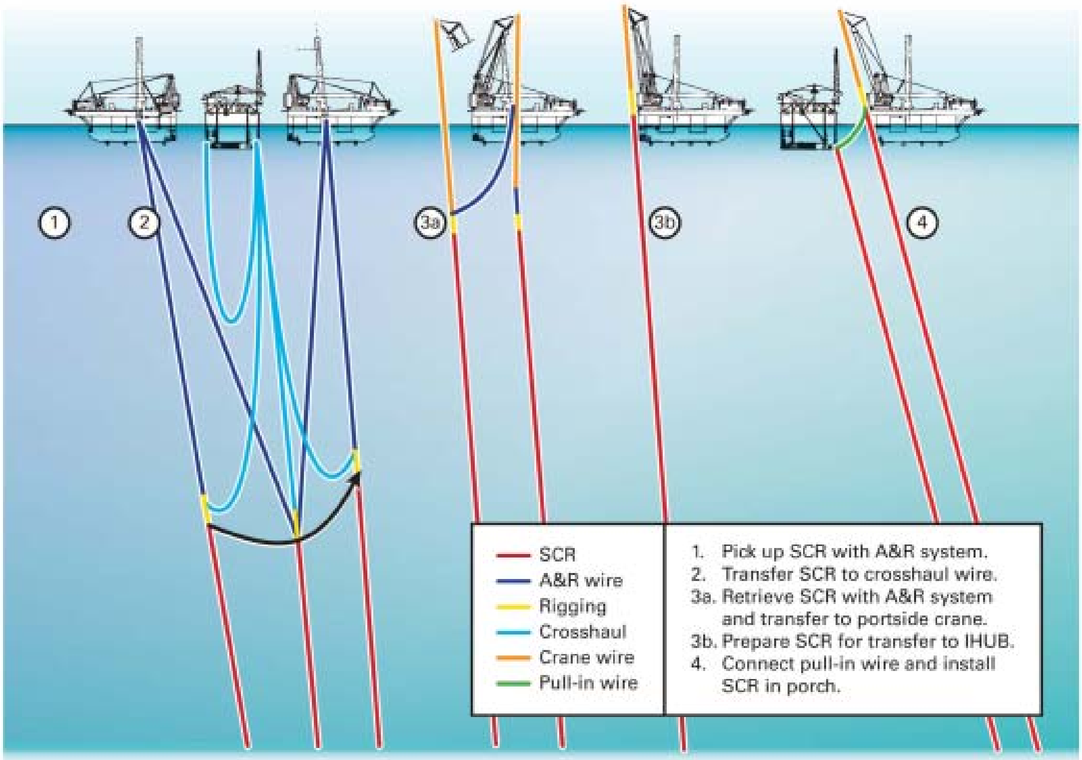
- Two heavy-lift cranes with a combined capacity of 6,300 tonnes at 110-ft radius. The starboard crane includes two traction systems, each with 19 km of steel wire, allowing Balder to manipulate heavy structures at great water depths (e.g., 500-tonne hook load in water 2,200 m deep, 250-tonne hook load in water 3,000 m deep).
- Mooring line deployment winch (MLDW) with a capacity of 310 tonnes (Fig. 2).
- Abandonment and recovery (A&R) winch system with a hoisting capacity of 650 tonnes. The MLDW winch capac-

Heerema Marine Contractors used DCV Balder's starboard crane (right) during cross haul and retrieval of Independence Hub's 20-in. steel catenary export riser. The starboard crane includes two traction systems, each with 19 km of steel wire, allowing Balder to manipulate heavy structures at great water depths. Heerema used Balder's 310-tonne capacity mooring line deployment winch (MDLW) for spooling the SCR's cross-haul wire. The yellow piping and structural components in the background are on the topsides of the Independence Hub platform (Fig. 2). Photo by Christopher E. Smith.

Balder's abandonment and recovery (A&R) winch system, incorporating the ship's J-lay tower (right center), picked up the export SCR from the seabed and also participated in cross haul and retrieval. During retrieval, Balder's portside crane (left center) slewed over the J-lay tower, lowering its 1,000-tonne auxiliary block to the SCR head for connection by ROV before moving the riser head to a work deck at the vessel's stern (Fig. 3). Photo by Christopher E. Smith.

Export SCR installation

Fig. 4



Source: Heerema Marine Contractors Nederland BV.

ity can be added to this if needed. Part of the vessel's J-lay tower on its port side, the A&R winch uses 3,150 m of 138-mm wire (Fig. 3).

SCR installation

Balder's work installing the export SCR involved four steps (Fig. 4):

1. *Pickup.* Balder used its A&R winch to recover the export SCR from the seabed. The A&R wire attached to a deepwater buoy on the SCR's head, with Balder on the south side of IHUB.

After attachment, Balder moved to a 2,200-m distance from IHUB, creating a catenary which raised the SCR's head 25 m above the seafloor. Balder then returned to station next to IHUB; stopping at a distance sufficient to execute cross haul of the SCR under IHUB, while staying within the weight limits of the A&R winch system.

2. *Cross haul.* Balder's starboard crane picked up the cross-haul wire (previously installed and attached to IHUB using the MLDW) from the A&R winch in water 532 m deep and then transferred the SCR underneath IHUB's hull from its south side to its north side. The A&R winch first paid out enough wire to make the transfer and then released after all load had been transferred to the cross-haul wire.

3. *Retrieval.* After cross haul, Balder reconnected the A&R winch to the SCR head for retrieval. Paying in the A&R winch returned the load to it, with the release of a hydraulic shackle swinging the SCR toward IHUB.

Before retrieving the cross-haul wire from IHUB with its starboard crane, Balder returned to a 450-m standoff distance to avoid interfering with mooring lines. During this process, the A&R winch paid in until the SCR reached water 135 m deep.

While retrieval was under way, the portside crane positioned itself over the J-lay tower for connection to the SCR. Once Balder slewed the portside crane to its stern and verified connection, the A&R connection was paid out and disconnected, transferring the full load to the portside crane.

After moving to a point 625 m from IHUB, while at the same time raising the SCR to deck level, Balder prepared the export riser for installation on a work station at its stern. Preparation included:

- Removal of flex joint protection cover.
- Removal of hang-off collar protection.
- Removal of flex joint laydown tool.
- Installation of pull-in wire forerunner.

4. *Installation.* Once preparation work was completed, the Balder positioned itself on IHUB's starboard side for final installation of the export SCR, using its starboard crane to pick up the pull-in wire from IHUB and transfer it to the on-board work station.

Lowering the SCR head and tensioning the IHUB's pull-in wire moved the IHUB toward Balder, with the follow-target mode of the DCV's DPS maintaining a safe distance between the two.

Balder's portside crane lowered the SCR's flex joint into its porch located underwater on one of IHUB's 38 × 26-ft pontoons, transferring the load from the crane to IHUB where final connection of the SCR spool piece took place.

Acknowledgments

The author acknowledges the help of Heerema Marine Contractors Nederland BV and John Bouwman, senior project engineer. ✦

Enhanced diamond protection offered for drillbits

This drillbit supplier has expanded its offering of enhanced diamond protection for customers drilling with the company's roller cone products.

Because of higher drilling rig costs and increased extended reach applications, more diamonds are being used to improve roller cone bit life, the firm notes, adding that the company customizes the bit to the specific application; e.g., builds sections in directional drilling and horizontal applications where maximum abrasive resistance is required. The objective is to keep the cutting structure sharper for better penetration rates and maintain gauge for longer on-bottom time.

Diamond protection occurs during the manufacturing process of the bit, when polycrystalline diamond capped inserts are inserted along the gauge, back row, and-or the leading edge of the shirttails to provide added protection to the bit in abrasive formations. Diamond protection is recommended on motor, directional, and rotary steerable applications, particularly those drilling through abrasive formations such as sandstone, siltstone, granite, and limestone.

These diamond protection options are offered:

- *Enhanced back row* increases gauge holding in abrasive applications—available in varying percentages.
- *Enhanced gauge row* maximizes 100% of gauge rows and provides longer gauge hold in abrasive and directional uses.
- *Enhanced shirttail protection* provides wear resistance in extreme drilling environments.

Enhanced diamond protection packages are available on Challenger tungsten carbide insert bits and steel tooth bits.

Source: **Varel International,** 1434 Patton Pl., Suite 106, Carrollton, TX 75001.

Statistics

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4 4-13 2007	Districts 1-4 [1]4-6 2007	District 5 4-13 2007	District 5 [1]4-6 2007	Total US 4-13 2007	Total US [1]4-6 2007	Total US 4-14 2006
	1,000 b/d						
Total motor gasoline	397	433	92	4	489	437	243
Mo. gas. blending comp.	496	547	42	191	538	738	712
Distillate[2]	324	176	68	14	392	190	178
Residual	360	505	28	30	388	535	285
Jet fuel-kerosine	106	152	141	163	247	315	259
LPG	286	240	6	6	292	246	253
Unfinished oils	629	505	28	5	657	510	609
Other	329	619	27	6	356	625	550
Total products	**2,927**	**3,177**	**432**	**419**	**3,359**	**3,596**	**3,089**
Canadian crude	1,382	1,468	164	191	1,546	1,659	1,708
Other foreign	7,568	7,025	567	534	8,135	7,559	7,974
Total crude	**8,950**	**8,493**	**731**	**725**	**9,681**	**9,218**	**9,682**
Total imports	**11,877**	**11,670**	**1,163**	**1,144**	**13,040**	**12,814**	**12,771**

[1]Revised. [2]Includes No. 4 fuel oil.

PURVIN & GERTZ LNG NETBACKS—APR. 13, 2007

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	6.90	5.00	6.18	4.91	5.55	6.16
Everett	6.44	4.44	6.07	4.53	4.98	6.72
Isle of Grain	1.96	0.27	1.43	0.21	0.65	1.49
Lake Charles	536	3.63	5.12	3.77	3.96	5.94
Sodegaura	4.40	6.37	4.61	6.10	5.49	3.93
Zeebrugge	5.54	3.64	4.98	3.57	4.12	5.00

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

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

OGJ CRACK SPREAD

	*4-13-07	*4-14-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	85.47	87.01	–1.54	–1.8
Brent crude	68.07	68.64	–0.58	–0.8
Crack spread	17.41	18.37	–0.96	–5.2
FUTURES MARKET PRICES				
One month				
Product value	85.60	85.06	0.53	0.6
Light sweet crude	62.58	68.92	–6.34	–9.2
Crack spread	23.02	16.15	6.87	42.6
Six month				
Product value	81.65	82.71	–1.06	–1.3
Light sweet crude	69.15	72.18	–3.03	–4.2
Crack spread	12.50	10.52	1.97	18.7

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel Kerosine	Fuel oils Distillate	Fuel oils Residual	Unfinished oils
	1,000 bbl						
PAD I	14,632	53,430	26,895	9,454	41,880	15,389	7,474
PAD II	74,588	48,158	15,896	7,928	28,002	1,336	15,313
PAD III	178,624	63,308	26,936	12,637	32,597	17,028	46,391
PAD IV	13,949	5,916	1,785	541	2,922	354	3,515
PAD V	[1]52,091	27,775	20,199	8,787	13,139	6,038	22,577
Apr. 13, 2007	**[1]333,884**	**198,587**	**91,711**	**39,347**	**118,540**	**40,145**	**95,270**
Apr. 6, 2007[3]	**337,164**	**198,829**	**91,173**	**40,540**	**119,251**	**38,720**	**94,384**
Apr. 14, 2006	**341,281**	**205,706**	**87,001**	**41,125**	**115,091**	**42,586**	**93,672**

[1]Included in total motor gasoline. [2]Includes 4.220 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—APR. 13, 2007

District	Refinery operations: Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Refinery output: Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual
	1,000 b/d					1,000 b/d			
East Coast	3,283	1,406	1,409	1,618	87.1	1,645	89	568	141
App. Dist. 1	11	5	6	95	6.3	28	0	3	0
Dist. 1 total	**3,294**	**1,411**	**1,415**	**1,713**	**82.6**	**1,673**	**89**	**571**	**141**
Ind., Ill., Ky.	2,214	2,131	2,152	2,355	91.4	1,156	116	586	65
Minn., Wis., Dak.	387	380	385	442	87.1	342	31	125	11
Okla., Kan., Mo.	833	629	631	786	80.3	469	23	241	1
Dist. 2 total	**3,434**	**3,140**	**3,168**	**3,583**	**88.4**	**1,967**	**170**	**952**	**77**
Inland Texas	960	624	644	647	99.5	433	41	182	7
Texas Gulf Coast	3,702	3,302	3,420	4,031	84.8	1,329	318	923	167
La. Gulf Coast	3,576	3,293	3,295	3,264	101.0	1,309	323	905	142
N. La. and Ark.	222	168	195	215	90.7	99	13	43	8
New Mexico	171	106	106	113	93.8	109	3	43	0
Dist. 3 total	**8,631**	**7,493**	**7,660**	**8,270**	**92.6**	**3,279**	**698**	**2,096**	**324**
Dist. 4 total	**656**	**524**	**542**	**596**	**90.9**	**228**	**29**	**159**	**16**
Dist. 5 total	**2,663**	**2,372**	**2,630**	**3,173**	**82.9**	**1,677**	**371**	**481**	**148**
Apr. 13, 2007	**18,678**	**14,940**	**15,415**	**17,335**	**88.9**	**8,824**	**1,357**	**4,259**	**706**
Apr. 6, 2007*	**18,120**	**14,688**	**15,158**	**17,335**	**87.4**	**8,680**	**1,365**	**4,203**	**669**
Apr. 14, 2006	**16,674**	**14,423**	**14,822**	**17,115**	**86.6**	**8,214**	**1,482**	**3,617**	**635**

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

OGJ GASOLINE PRICES

	Price ex tax 4-11-07	Pump price* 4-11-07	Pump price 4-12-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	232.9	272.6	258.1
Baltimore	235.8	277.7	259.7
Boston	226.6	268.5	252.8
Buffalo	224.7	284.8	263.3
Miami	240.9	291.2	276.0
Newark	225.1	258.0	243.9
New York	216.8	276.9	262.4
Norfolk	230.9	268.5	252.7
Philadelphia	232.2	282.9	263.1
Pittsburgh	222.2	272.9	257.9
Wash., DC	246.6	285.0	270.9
PAD I avg	225.4	271.2	260.1
Chicago	254.6	305.5	285.4
Cleveland	225.6	272.0	250.9
Des Moines	227.6	268.0	250.3
Detroit	226.2	275.4	257.7
Indianapolis	231.8	276.8	261.7
Kansas City	226.5	262.5	243.6
Louisville	241.3	278.2	263.9
Memphis	227.0	266.8	252.9
Milwaukee	233.8	285.1	262.4
Minn.-St. Paul	227.6	268.0	261.5
Oklahoma City	227.9	263.3	243.5
Omaha	227.0	273.4	256.5
St. Louis	232.6	268.6	248.8
Tulsa	229.5	264.9	248.2
Wichita	223.7	267.1	245.9
PAD II avg	225.0	267.2	255.6
Albuquerque	237.2	273.6	264.0
Birmingham	229.1	267.8	255.7
Dallas-Fort Worth	233.9	272.3	264.7
Houston	230.1	268.5	260.4
Little Rock	225.9	266.1	250.1
New Orleans	227.6	266.0	258.1
San Antonio	217.8	256.2	247.2
PAD III avg	222.6	261.0	257.2
Cheyenne	224.9	257.3	234.6
Denver	230.6	271.0	247.4
Salt Lake City	220.1	263.0	225.8
PAD IV avg.	222.2	260.8	235.9
Los Angeles	266.0	324.5	283.1
Phoenix	247.7	285.1	252.5
Portland	258.9	302.2	256.4
San Diego	275.5	334.0	285.4
San Francisco	290.4	348.9	285.9
Seattle	256.7	309.1	273.5
PAD V avg.	265.9	317.3	272.8
Week's avg.	**235.0**	**278.6**	**258.1**
Mar. avg.	**210.4**	**254.0**	**235.4**
Feb. avg.	**184.4**	**228.0**	**229.6**
2007 to date	**196.8**	**240.4**	—
2006 to date	**192.1**	**234.5**	—

*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

	4-6-07 ¢/gal		4-6-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil, No. 2	
New York Harbor	209.75	New York Harbor	185.85
Gulf Coast	213.25	Gulf Coast	181.97
Los Angeles	237.75	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	190.79	ARA	187.05
Singapore	197.14	Singapore	179.76
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	208.25	New York Harbor	106.26
Gulf Coast	221.50	Gulf Coast	109.52
Los Angeles	246.25	Los Angeles	130.03
		ARA	104.78
		Singapore	128.88

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

BAKER HUGHES RIG COUNT

	4-13-07	4-14-06
Alabama	3	4
Alaska	11	9
Arkansas	43	22
California	32	33
Land	31	29
Offshore	1	4
Colorado	107	88
Florida	0	0
Illinois	0	0
Indiana	2	0
Kansas	14	7
Kentucky	9	6
Louisiana	189	184
N. Land	59	56
S. Inland waters	27	18
S. Land	38	33
Offshore	65	77
Maryland	0	0
Michigan	2	2
Mississippi	21	8
Montana	23	24
Nebraska	0	0
New Mexico	76	95
New York	6	5
North Dakota	30	29
Ohio	14	7
Oklahoma	178	173
Pennsylvania	17	15
South Dakota	2	1
Texas	828	730
Offshore	10	13
Inland waters	1	4
Dist. 1	21	22
Dist. 2	33	20
Dist. 3	53	72
Dist. 4	90	79
Dist. 5	171	130
Dist. 6	127	102
Dist. 7B	48	40
Dist. 7C	61	38
Dist. 8	110	85
Dist. 8A	23	29
Dist. 9	30	30
Dist. 10	50	66
Utah	43	32
West Virginia	29	27
Wyoming	70	106
Others—ID-1; NV-2; TN-4; VA-2	9	3
Total US	**1,758**	**1,610**
Total Canada	**97**	**196**
Grand total	**1,855**	**1,806**
Oil rigs	282	259
Gas rigs	1,472	1,349
Total offshore	76	94
Total cum. avg. YTD	**1,735**	**1,531**

Rotary rigs from spudding in to total depth. Definitions, see OGJ Sept. 18, 2006, p. 42.

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

SMITH RIG COUNT

Proposed depth, ft	4-13-07 Rig count	4-13-07 Percent footage*	4-14-06 Rig count	4-14-06 Percent footage*
0-2,500	62	6.4	42	4.7
2,501-5,000	100	61.0	82	48.7
5,001-7,500	201	23.8	203	19.7
7,501-10,000	421	3.8	343	2.9
10,001-12,500	420	3.8	370	1.3
12,501-15,000	256	—	274	—
15,001-17,500	112	0.8	121	0.8
17,501-20,000	72	—	71	—
20,001-over	38	—	16	—
Total	**1,682**	**8.6**	**1,522**	**6.4**
INLAND	35		42	
LAND	1,587		1,418	
OFFSHORE	60		62	

*Rigs employed under footage contracts.
Definitions, see OGJ, Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]4-13-07	[2]4-14-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	17	22
Alaska	770	776
California	670	684
Colorado	51	61
Florida	6	6
Illinois	30	28
Kansas	95	93
Louisiana	1,363	1,211
Michigan	14	15
Mississippi	51	48
Montana	90	97
New Mexico	163	158
North Dakota	103	105
Oklahoma	169	172
Texas	1,337	1,295
Utah	42	48
Wyoming	140	144
All others	63	73
Total	**5,174**	**5,036**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	4-13-07
Alaska-North Slope 27°	50.46
South Louisiana Sweet	65.00
California-Kern River 13°	53.15
Lost Hills 30°	60.90
Wyoming Sweet	59.63
East Texas Sweet	61.03
West Texas Sour 34°	53.40
West Texas Intermediate	60.25
Oklahoma Sweet	60.25
Texas Upper Gulf Coast	57.00
Michigan Sour	53.25
Kansas Common	59.25
North Dakota Sweet	53.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	4-6-07
United Kingdom-Brent 38°	68.57
Russia-Urals 32°	65.65
Saudi Light 34°	63.25
Dubai Fateh 32°	63.41
Algeria Saharan 44°	70.28
Nigeria-Bonny Light 37°	70.80
Indonesia-Minas 34°	68.25
Venezuela-Tia Juana Light 31°	62.98
Mexico-Isthmus 33°	62.87
OPEC basket	65.98
Total OPEC[2]	64.73
Total non-OPEC[2]	65.19
Total world[2]	64.93
US imports[3]	60.53

[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]

	4-6-07	3-30-07	Change
	Bcf		
Producing region	642	629	13
Consuming region east	706	702	4
Consuming region west	244	238	6
Total US	**1,592**	**1,569**	**23**
	Jan. 07	**Jan. 06**	**Change, %**
Total US[2]	**2,379**	**2,371**	**0.3**

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

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

Statistics

World oil balance

	2006 4th qtr.	2006 3rd qtr.	2006 2nd qtr.	2006 1st qtr.	2005 4th qtr.	2005 3rd qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	21.02	21.15	20.88	20.76	21.16	21.24
Canada	2.22	2.27	2.14	2.18	2.26	2.28
Mexico	2.03	1.99	2.02	2.08	2.10	2.06
Japan	5.35	4.81	4.78	5.96	5.46	5.03
South Korea	2.30	2.02	2.03	2.28	2.23	2.01
France	1.96	1.95	1.89	2.10	1.96	2.00
Italy	1.69	1.66	1.63	1.86	1.78	1.68
United Kingdom	1.79	1.76	1.81	1.90	1.84	1.82
Germany	2.69	2.71	2.55	2.56	2.63	2.75
Other OECD Europe	7.41	7.36	7.16	7.35	7.49	7.31
Australia & New Zealand	1.11	1.07	1.06	1.06	1.10	1.04
Total OECD	**49.57**	**48.75**	**47.95**	**50.09**	**50.01**	**49.22**
NON-OECD						
China	7.62	7.33	7.42	7.05	7.14	6.93
FSU	4.42	4.22	4.59	4.68	4.60	4.04
Non-OECD Europe	0.70	0.65	0.69	0.74	0.69	0.64
Other Asia	8.99	8.62	8.70	8.63	9.06	8.43
Other non-OECD	15.21	15.04	14.14	14.26	15.14	15.14
Total non-OECD	**36.94**	**35.86**	**35.54**	**35.36**	**36.63**	**35.18**
TOTAL DEMAND	**86.51**	**84.61**	**83.49**	**85.45**	**86.64**	**84.40**
SUPPLY						
OECD						
US	8.46	8.48	8.35	8.18	7.74	7.95
Canada	3.40	3.32	3.16	3.29	3.28	3.02
Mexico	3.52	3.71	3.79	3.80	3.75	3.72
North Sea	4.75	4.51	4.71	5.11	5.05	4.95
Other OECD	1.54	1.52	1.41	1.41	1.51	1.55
Total OECD	**21.67**	**21.54**	**21.42**	**21.79**	**21.33**	**21.19**
NON-OECD						
FSU	12.41	12.18	11.98	11.74	11.97	11.72
China	3.83	3.83	3.85	3.83	3.75	3.80
Other non-OECD	11.77	11.98	11.76	11.56	11.81	11.86
Total non-OECD, non-OPEC	**28.01**	**27.99**	**27.59**	**27.13**	**27.53**	**27.38**
OPEC	**34.98**	**35.65**	**35.18**	**35.33**	**35.69**	**35.88**
TOTAL SUPPLY	**84.66**	**85.18**	**84.19**	**84.25**	**84.55**	**84.45**
Stock change	**–1.85**	**0.57**	**0.70**	**–1.20**	**–2.09**	**0.05**

Source: DOE International Petroleum Monthly.
Data available in OGJ Online Research Center.

OECD total net oil imports

	Dec. 2006	Nov. 2006	Oct. 2006	Dec. 2005	Chg. vs. previous year Volume	%
	Million b/d					
Canada	–1,547	–1,412	–1,349	–1,352	–195	14.4
US	11,525	11,568	11,804	12,422	–917	–7.4
Mexico	–1,374	–1,650	–1,549	–1,714	340	–19.8
France	1,986	1,943	1,860	1,866	120	6.4
Germany	2,326	2,505	2,605	2,585	–259	–10.0
Italy	1,725	1,749	1,678	1,532	193	12.6
Netherlands	1,009	830	1,071	972	37	3.8
Spain	1,582	1,631	1,518	1,513	69	4.6
Other importers	3,911	4,124	4,064	4,152	–241	–5.8
Norway	–2,311	–2,540	–2,614	–2,793	482	–17.3
United Kingdom	–2	336	248	–229	227	–99.1
Total OECD Europe	**10,226**	**10,578**	**10,430**	**9,598**	**628**	**6.5**
Japan	5,306	5,180	4,888	5,565	–259	–4.7
South Korea	2,272	2,322	1,903	2,222	50	2.3
Other OECD	727	718	644	757	–30	–4.0
Total OECD	**27,135**	**27,304**	**26,771**	**27,518**	**–383**	**–1.4**

Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD* total gross imports from OPEC

	Dec. 2006	Nov. 2006	Oct. 2006	Dec. 2005	Chg. vs. previous year Volume	%
	Million b/d					
Canada	381	456	357	372	9	2.4
US	5,232	5,153	5,525	5,431	–199	–3.7
Mexico	43	33	10	27	16	59.3
France	819	764	836	955	–136	–14.2
Germany	337	440	490	414	–77	–18.6
Italy	1,372	1,399	1,387	1,325	47	3.5
Netherlands	594	700	582	753	–159	–21.1
Spain	744	744	798	784	–40	–5.1
Other importers	1,423	1,272	1,351	1,341	82	6.1
United Kingdom	182	294	220	214	–32	–15.0
Total OECD Europe	**5,471**	**5,613**	**5,664**	**5,786**	**–315**	**–5.4**
Japan	4,591	4,480	4,181	4,944	–353	–7.1
South Korea	2,213	2,476	2,181	2,404	–191	–7.9
Other OECD	761	714	689	676	85	12.6
Total OECD	**18,692**	**18,925**	**18,607**	**19,640**	**–948**	**–4.8**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly.
Data available in OGJ Online Research Center.

US petroleum imports from source country

	Dec. 2006	Nov. 2006	Average YTD 2006	Average YTD 2005	Chg. vs. previous year Volume	%
	1,000 b/d					
Algeria	677	462	650	478	172	36.0
Kuwait	169	259	184	243	–59	–24.3
Nigeria	1,066	972	1,119	1,166	–47	–4.0
Saudi Arabia	1,491	1,491	1,461	1,537	–76	–4.9
Venezuela	1,271	1,275	1,409	1,529	–120	–7.8
Other OPEC	558	694	676	634	42	6.6
Total OPEC	**5,232**	**5,153**	**5,499**	**5,587**	**–88**	**–1.6**
Angola	620	521	534	473	61	12.9
Canada	2,412	2,598	2,303	2,181	122	5.6
Mexico	1,366	1,584	1,700	1,662	38	2.3
Norway	178	174	195	233	–38	–16.3
United Kingdom	199	291	271	396	–125	–31.6
Virgin Islands	334	331	326	328	–2	–0.6
Other non-OPEC	2,370	2,303	2,784	2,854	–70	–2.5
Total non-OPEC	**7,479**	**7,802**	**8,133**	**8,127**	**–14**	**–0.2**
TOTAL IMPORTS	**12,711**	**12,955**	**13,612**	**13,714**	**–102**	**–0.7**

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

Oil stocks in OECD countries*

	Dec. 2006	Nov. 2006	Oct. 2006	Dec. 2005	Chg. vs. previous year Volume	%
	Million bbl					
France	192	190	188	196	–4	–2.0
Germany	277	277	278	283	–6	–2.1
Italy	133	133	130	132	1	0.8
United Kingdom	107	106	103	95	12	12.6
Other OECD Europe	679	663	665	645	34	5.3
Total OECD Europe	**1,388**	**1,369**	**1,364**	**1,351**	**37**	**2.7**
Canada	176	177	177	178	–2	–1.1
US	1,721	1,746	1,767	1,698	23	1.4
Japan	631	650	654	612	19	3.1
South Korea	152	158	156	135	17	12.6
Other OECD	103	109	110	104	–1	–1.0
Total OECD	**4,171**	**4,209**	**4,228**	**4,078**	**93**	**2.3**

*End of period.
Source: DOE International Petroleum Monthly Report.
Data available in OGJ Online Research Center.

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World Bank chief loses ground in corruption fight

The Editor's Perspective

by Bob Tippee, Editor

To the oil and gas industry's detriment, World Bank Pres. Paul Wolfowitz has sustained a blow likely to destroy his effectiveness in a crucial fight.

Normally, Wolfowitz can take a punch. Before moving to the World Bank in 2005, the former university professor and longtime federal official was deputy defense secretary in the administration of President George W. Bush. Because he helped plan the invasion of Iraq, the president's political antagonists regularly depict Wolfowitz as a demon.

Political pressure followed him to the World Bank, where he is said to have angered much of the staff for imposing change and exercising an apparently unbeloved style of management.

He also irked staffers and many governments by acting on his conviction that the bank can't fight poverty without also fighting corruption (OGJ, Dec. 18, 2006, p. 19).

That position deserves the oil and gas industry's full support. Expatriate companies need their presence to benefit host-country populations. Where corruption dissipates wealth generated by resource development, the popular welcome of resource developers suffers. It's Wolfowitz's commendable and controversial stance against corruption that now teeters.

The World Bank chief acknowledges that he participated in negotiations that helped a former bank worker with whom he is romantically involved make a lucrative transfer to the State Department.

The move occurred because Wolfowitz properly raised concerns about the conflict of interest that developed when he became World Bank president while the woman was a bank employee. To some extent, though, he involved himself in dealings that financially benefited his girlfriend.

That's enough to have agitated his detractors at the World Bank, who by Apr. 12 were calling for his resignation. Opponents of Bush, especially of his policies on Iraq, will see political opportunity in Wolfowitz's troubles. The biggest question, however, should be whether the World Bank chief can effectively pursue his already beleaguered campaign against corruption after these disclosures.

Seriousness of the offense doesn't matter. The indiscretion will make it impossible for the World Bank president to confront corrupt governments effectively.

Wolfowitz should recognize how seriously his potency in an important campaign has been hurt and act accordingly.

(Online Apr. 13, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Supply outlook pressures prices

Energy prices fluctuated Apr. 9-13 with fast-paced changes in US inventories and political threats to Middle East crude supplies.

The May contract for benchmark US light, sweet crudes fell $2.77 to $61.51/bbl Apr. 9 on the New York Mercantile Exchange following Iran's release of 15 UK sailors and marines. It was the biggest price reduction for a front-month crude contract in 3 months. Yet an Apr. 10 rally in gasoline and heating oil boosted May crude to $61.89/bbl for its first gain in five sessions on NYMEX. The price inched up to $62.01/bbl Apr. 11 as US gasoline stocks fell for the 9th consecutive week, plunging 5.5 million bbl to a below-average level of 333.4 million bbl during the week ended Apr. 6, the lowest level since 2001. The crude price escalated to $63.85/bbl Apr. 12 on evidence that US gasoline inventories had gone from adequate to tight in less than a month. It slipped to $63.63/bbl Apr. 13, resulting in roughly a 1% loss in volatile trading that week.

"The US gasoline crack is taking back its driving position. Demand is holding well. Geopolitics moved to the back seat," said analysts at the Société Générale Group in an Apr. 16 report. Members of the Organization of Petroleum Exporting Countries won't increase supply until crude prices climb above $70/bbl, said Société Générale.

Analysts in the Houston office of Raymond James & Associates Inc. said, "It is not often that a single refinery outage has a material impact on the US oil market, but that is precisely what has happened in the wake of the fire at the Sunray, Tex., refinery. The temporary glut of crude oil at Cushing, Okla., has kept the price of West Texas Intermediate stagnant year-to-date, even as global oil prices surged higher." Valero Energy Corp.'s 158,000 b/d Sunray refinery in the Texas Panhandle is expected to restart this month. Once that happens, Raymond James analysts said, "We believe that WTI prices could rise by up to 10% within the next 6 weeks."

Raymond James analysts said refinery shutdowns have led to a build-up of crude oil in inventory and depressed WTI prices compared with Brent Sea crude prices on the London Stock Exchange. "Iran remains a catalyst for high oil prices, however. The country asserts it is enriching uranium on an industrial scale in defiance of global sanctions," they said.

Refinery problems in the Midwest helped inflate the local stock build, while Canadian crude exports to the same area made market prices for WTI "incredibly weak" vs. North Sea Brent crude. The primary problem, said Société Générale was "not enough crude on the Atlantic Basin and too much in Cushing." Crude supplies in Cushing surged by 12% in the week ended Mar. 30.

Gasoline inventories

With the official the start of the summer driving season approaching on May 28, Société Générale analysts were expecting the first seasonal build of gasoline stocks after an "unrealistic" draw of 5 million bbl to 205.2 million bbl during the week ended Mar. 30. Instead, the Energy Information Administration reported Apr. 11 that US gasoline stocks fell for the ninth consecutive week, plunging 5.5 million bbl to a below-average level of 333.4 million bbl during the week ended Apr. 6, the lowest level since 2001.

Commercial US crude inventories increased by 700,000 bbl to 333.4 million bbl during the same period, well below the jump some analysts had expected in the face of recent refining outages. Distillate fuel inventories inched up just 100,000 bbl to 118.1 million bbl, with a modest gain in diesel offsetting a drop in heating oil. Propane and propylene inventories rose 700,000 bbl to 25.8 million bbl in the same week.

Imports of crude into the US fell 441,000 b/d to 9.8 million b/d during that period. However, the input of crude into US refineries increased by 231,000 b/d to 15.1 million b/d, with units operating at 88.4% of capacity. Gasoline production declined to 8.5 million b/d while distillate fuel production increased to 4.2 million b/d.

The International Energy Agency in Paris said Apr. 12 that inventories of crude and petroleum products among member countries of the Organization for Economic Cooperation and Development fell by 80 million bbl in February due to seasonal refinery maintenance in North America.

IEA estimated that members of the Organization of Petroleum Exporting Countries (excluding Iraq and Angola) reduced their total production by 200,000 b/d to 26.5 million b/d in March. That was 1.2 million b/d below September 2006 levels and contributed to declining crude stocks. EIA revised its 2007 "call-on-OPEC" down by 200,000 b/d to 31.5 million b/d.

(Online Apr. 16, 2007; author's e-mail: samf@ogjonline.com)


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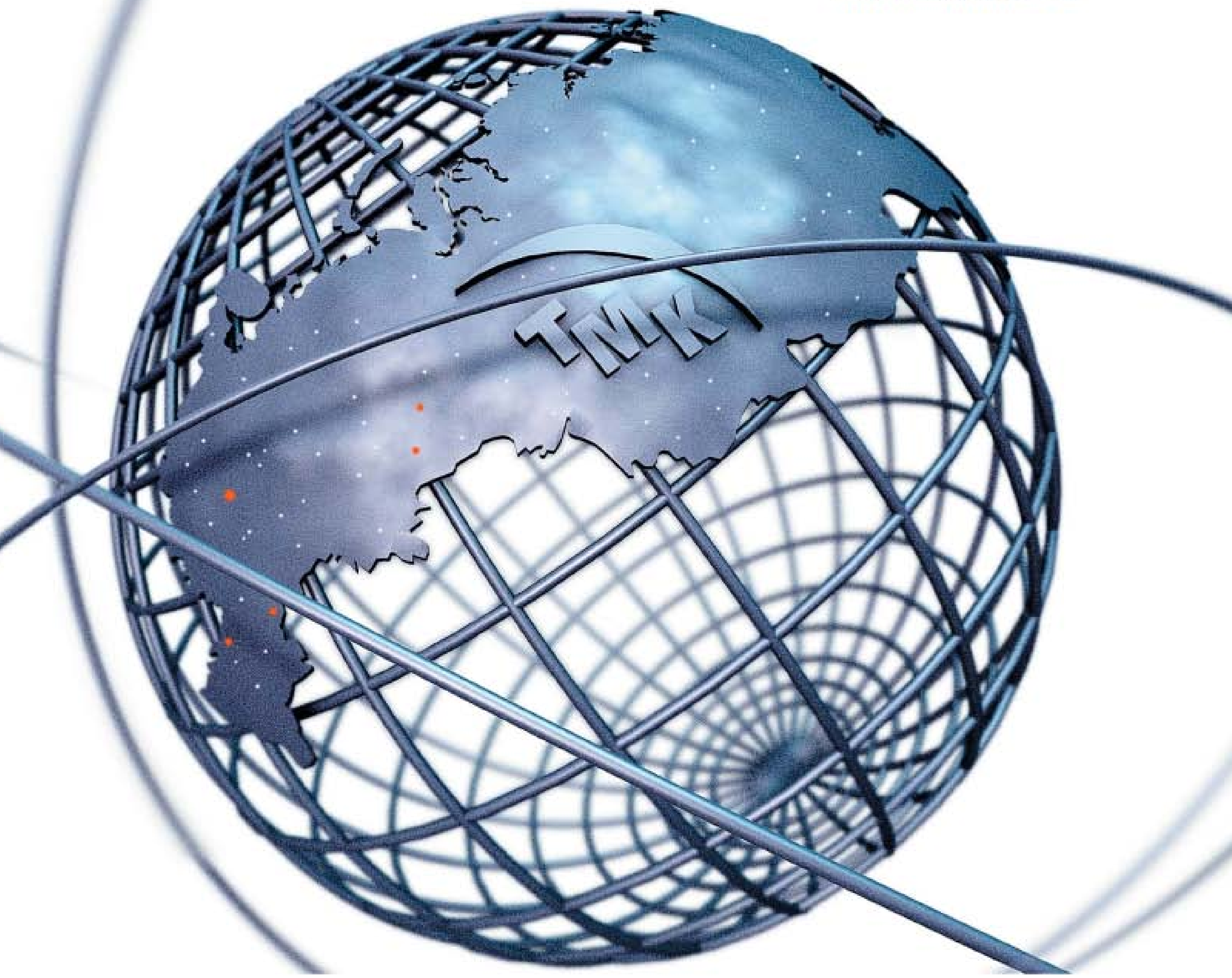
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New types of TMK thread connections

TMK consists of five Russian and two Romanian enterprises and has long become a remarkable player in the world pipe market and the leader on the Russian market. In 2006 the enterprises of the Company have manufactured 3.01 million tons of pipes, over 1 million tons of which being welded pipes, and about 2 million tons – seamless pipes.

The major activity of the Company is production of seamless pipes – first of all, hi-tech oil country tubular goods – drill pipes, casing pipes, oil-well tubing used directly at extraction of hydrocarbon raw material and at oil fields (so-called OCTG pipes). In the sphere of this activity TMK pays special attention to development and implementation of the high technologies conforming not only to all modern quality standards, but also designed for perspective conditions keeping ahead the up-to-date requirements of consumers.

In this connection TMK has been actively developing technologies for production of highly impermeable thread connections and upset tubing. Oil-and-gas pipes with similar connections are used for drilling and extraction of hydrocarbons in difficult geological conditions, which requires the pipes to have uprated specifications. This refers to axial tension and compression, internal and external pressure, bend, possibility to work in a aggressive environment (high temperature and thermal fluctuations, high content of hydrogen disulfide, carbon dioxide gas).

Connections of "Premium" class also are widely used at technologically complex horizontal extended-reach drilling at high drift angles, sea drilling, drilling of geothermal wells, at rotation of boring casing during running-in. Today TMK is the only owner in Russia of a full set of similar technical solutions, which are not only highly competitive with foreign analogues, but even surpass them. Achievement of such results was promoted much by close cooperation of TMK with the leading Scientific Research Institute for the Tube and Pipe Industries in Russia – Open Company "RosNITI", as well as the Scientific Center for development of thread connections at the Taganrog Metallurgical Works (Tagmet, Taganrog, Rostov area), which is a part of TMK.

TMK carries on major activities on development of new kinds of thread connections of "Premium" class.

This relates to highly impermeable gasproof thread connections for casing pipes TMK-GF, TMK-FM, TMK-FMC, TMK-TTL-01, TMK-CS, TMK-1, as well as new highly impermeable connection for oil-well tubing TMK-FMT.

In 2005 experts of the Scientific Center on development and assimilation of new thread connections of Tagmet started development of two new thread connections of "Premium" class for seamless pipes: TMK-GF and TMK-FMT.

Highly impermeable connections of "Premium" class for casing pipes TMK-GF (for deviant directional and horizontal well casing) and oil-well tubing TMK-FMT allow to increase efficiency of extraction of hydrocarbon raw material, which is achieved by their application at directional and horizontal drilling. It should be noted that such connections have never been produced in Russia previously. The design of a highly impermeable thread connection of oilwell tubing TMK-FMT utilizes the trapezoidal thread profile, which has a tip clearance for better coupling of connections and uses "metal-metal" grummets. It provides reliable hermetic sealing after repeated screwing-unscrewing. One of the advantages of such connection is the extended collar, which improves connection characteristics when bending.

Thread connection TMK-GF was developed for deviant directional and horizontal well casing with inclination intensity up to 400 per 30 meters. The range of used sizes of tubulars is from 114.3 mm to 339.72 mm.

Benchmark tests of full-scale specimen of oil-well tubing with TMK-FMT thread connection were already conducted in the Scientific Research Institute of Gazprom-VNIIGAS. Connections developed by TMK have been tested in this institute on gas tightness by temperature cycling. Besides TMK-FMT has also passed tests in the Scientific Research Institute of Oil where the connection has undergone 55 cycles of screwing and unscrewing without losing its tightness and was highly estimated. TMK-GF thread connection has also successfully passed tests in VNIIGAS and filed approbation on deposits of Open Society "Gazprom". In addition to these connections experts of the Scientific Center of Tagmet conduct works on development of new drill pipe joints and several more types of thread connections.

Subsea Equipment and Services

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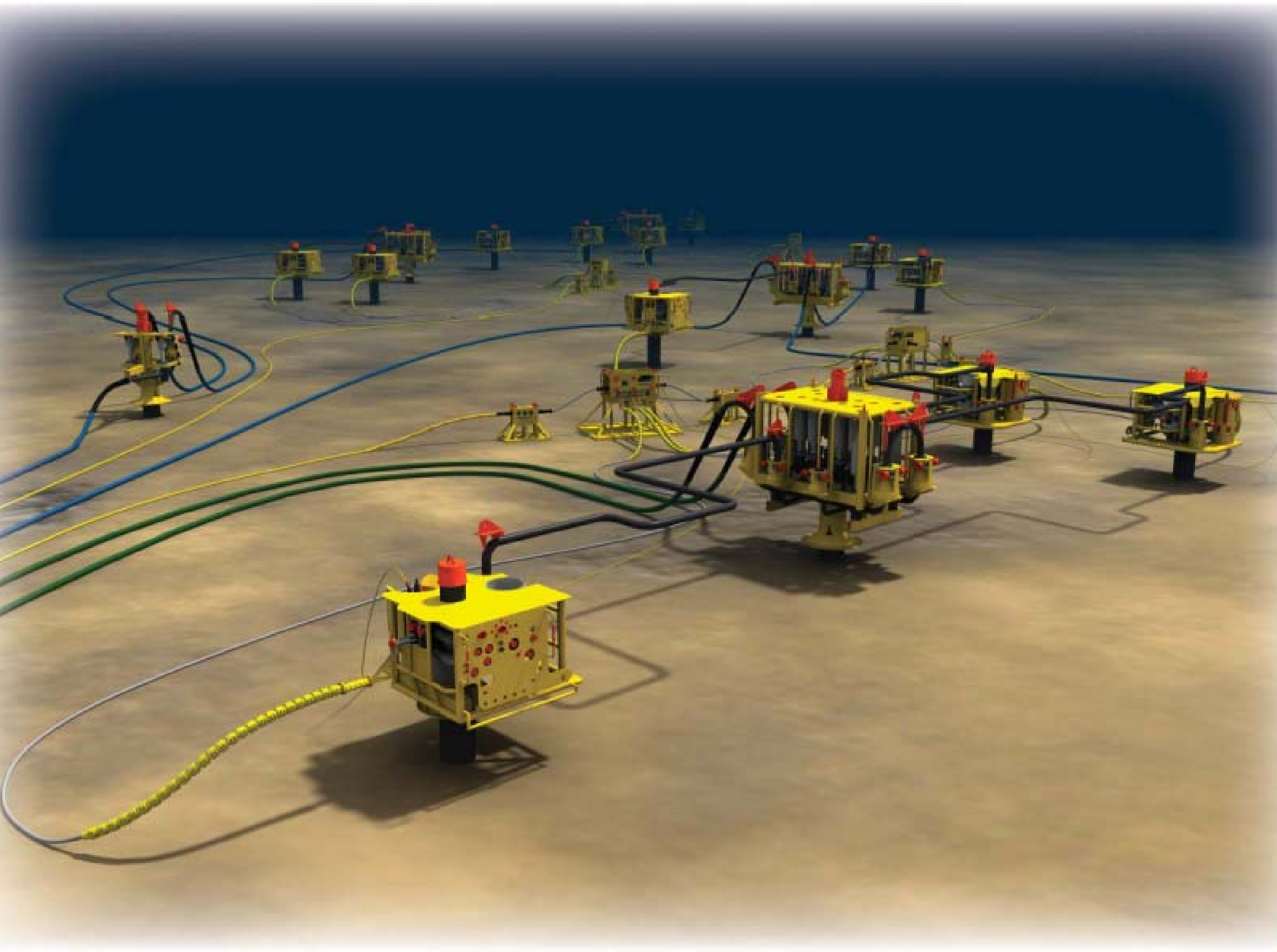

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Technology Forum

Subsea Equipment and Services

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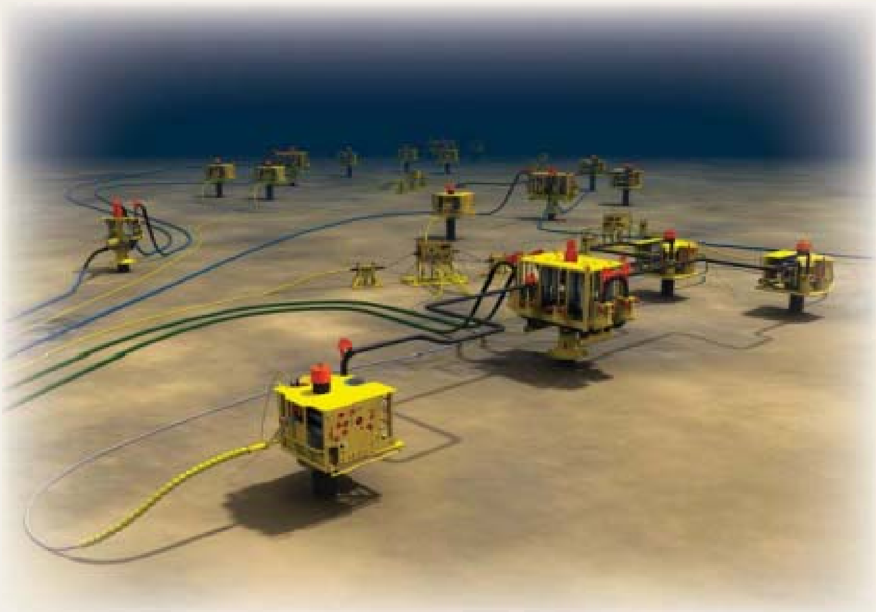

Shown on the cover is an illustration of the Kikeh subsea development planned off Malaysia, the first deepwater development of its kind in the Asia-Pacific region. Aker Kvaerner is providing engineering, procurement, construction, and commissioning assistance for the project, operated by Murphy Sabah Oil Co. Ltd. in partnership with Petronas Carigali Sdn. Bhd. The subsea production system consists of 16 subsea christmas tree systems, five manifolds, a production control system, and umbilicals. The project is expected to go on stream in second half 2007. Image courtesy of Aker Kvaerner.

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.

Subsea sector facing challenges amid booming demand

Subsea oil and natural gas field development has mushroomed in size from its status just a few years ago as a minor niche in the offshore industry to a major market category in its own right.

The numbers tell the story, according to London-based analysis group Infield Systems Ltd. Infield forecasts that worldwide capital spending on subsea systems will explode to $44.6 billion by 2010. That represents a 94% increase from 2005 levels.

Infield estimates that subsea spending will rocket to $16.5 billion in Africa from $5 billion in 2005 and to $15.8 billion in the Americas, a rise of 58% in the same timeframe. In Asia and Australia, subsea outlays are expected to jump to almost $5 billion in 2010 from $1 billion in 2005. In Europe, spending on subsea installations will remain steady at $6.9 billion.

Infield predicts that a total of 2,060 subsea wells will be installed during 2006–10, compared with 1,204 such wells in 2005.

The drivers are a frantic search for new hydrocarbon plays by major oil companies plunging into ever-deeper waters and advances in technology that are enabling drilling and production in water depths that were unassailable just a decade or so ago.

> "The subsea sector has perhaps experienced higher inflation rates in its raw material supply than any other industry, simply because it is consistently delivering equipment with high-grade materials. The requirements set by operators in terms of quality, reliability, and service life will not be compromised. That means the delivery costs for the subsea industry will remain sensitive to market fluctuations as they apply to raw materials."
>
> *— Jarl Kosberg, Aker Kvaerner*

The demographics are already changing in this young industry. With activity previously limited mainly to deepwater areas of Brazil, West Africa, and the Gulf of Mexico, subsea installations are cropping up off 47 countries today, and Infield expects this number to grow to 59 by 2010.

Another demographic change is occurring among subsea well operators as well. Once mainly the arena of international oil companies (IOCs), subsea operations are now headed increasingly by independents and state-owned national oil companies (NOCs). Infield notes that, in its 2002 5-year forecast, it predicted that IOCs would account for 68% of the deepwater wells brought online in the Gulf of Mexico in 2007, with independents responsible for 29% and NOCs 3%. What happened in the intervening 5 years was a surprise to Infield: During 2002–07, independent operators accounted 52% of the deepwater wells brought on stream in the gulf vs. 44% for majors.

The subsea story is one of technology advances, and more are needed as plays move further into ultradeep waters and into deep waters of the Arctic.

Meeting those technology challenges will be an industry already constrained by rising costs and shortages of qualified personnel.

In addition, heightened concern over the fragility of ocean ecosystems has service and supply companies pursuing new technological innovations to ensure subsea installations are environmentally friendly.

Cost issues

The specialized nature of subsea operations is a contributing factor to the high costs affecting that industry sector today, says Jarl Kosberg, senior vice-president of trees/processing and boosting for Aker Kvaerner.

"The subsea sector has perhaps experienced higher inflation rates in its raw material supply than any other industry, simply because it is consistently delivering equipment with high-grade materials," he says. "The requirements set by operators in terms of quality, reliability, and service life will not be compromised. That means the delivery costs for the subsea industry will remain sensitive to market fluctuations as they apply to raw materials.

"Furthermore, the pool of niche subsea resources is fairly small and highly specialized, and therefore in high demand. As such, we have seen greater increases in man-hour costs compared to other industries."

Kosberg sees cost-reduction initiatives countering this trend to some extent, but "overall, we can expect to see costs fluctuating in the current market climate. However, subsea hardware is only a small portion of field development cost, and other equipment and services, I suspect, are increasing more."

Costs will continue to rise as demand increases for more sophisticated equipment and solutions, according to Robert Carter, president and general manager, Antares Offshore LLC.

"There are economies associated with increased equipment and production volumes, but there is also the cost of developing the new

and improved technologies," he says. "The new technologies strive to improve productivity and project economics.

"However, mature solutions are available that use proven equipment and processes that are available for lower cost than the latest hardware or processes. For projects, and operators, that utilize these lower-cost solutions, costs can be reined in to some degree. But another major cost contributor is the cost of rigs to drill and complete the wells and vessels to perform marine installation and construction. New construction activities are under way, or planned, to increase the fleets' sizes, and cost is tied to demand—and a fixed supply. Current utilization rates are high—and costs are also high. When the newbuilds arrive, there may be some softening of prices, but that is yet to be seen."

In the end, cost inflation will subside as victim of its own "success."

B.K. Chin, CEO of Global Industries Ltd., contends that "it is likely to be a few years before prices in the subsea world stabilize at a more normal level. The only thing likely to curtail the present inflation in subsea equipment and contracting is deferring major projects, which may occur naturally as costs increase and deliveries slide." Chin adds, "One action that could reduce cost to the industry in the near term would be for oil companies to work cooperatively with suppliers and contractors, sharing schedule information and compromising to allow the best use of available manufacturing and installation equipment and personnel."

"Operators have been standardizing their products for some time now, and subsea drilling systems have been very effective in leading the way. From our perspective, we see operators seemingly recognize the benefits for subsea production and moving towards this in their buying practices to reduce engineering lead time, delivery cycle, and other potential problems caused by variation."

— Dave Lamont, GE VetcoGray

As the subsea industry continues to mature, increasing standardization of products will help rein in costs, according to Dave Lamont, president, Eastern Region & Subsea for VetcoGray, a GE Oil & Gas business. (In January GE agreed to acquire VetcoGray from investor groups Candover, 3i, and JP Morgan Partners for $1.9 billion.)

"Operators have been standardizing their products for some time now, and subsea drilling systems have been very effective in leading the way," he says. "From our perspective, we see operators seemingly recognize the benefits for subsea production and moving towards this in their buying practices to reduce engineering lead time, delivery cycle, and other potential problems caused by variation."

Lamont says that it is worth noting that price increases in the subsea production systems market are modest in comparison to the more robust increases in prices in the drilling rig sector: "Supply in the subsea production market has more or less kept pace with demand."

The industry's changing geographic profile is another factor in holding the line on costs, according to Kosberg.

"Historically, the competence and capacity of the subsea industry has been concentrated in regional hubs—Norway, Houston, and Brazil, for example," he notes. "In recent years, the industry has become increasingly global in nature, and that is a trend that is likely to continue in the future. New markets and requirements for local content drive this development. The transfer of capacity to regions with stronger resource bases and lower cost is also a factor. Asia, which is currently seeing significant subsea development, is a case in point."

Manpower/capacity concerns

The subsea service and supply sector continues to scramble to meet operators' needs as it copes with shortages of manpower and manufacturing capacity.

"Attracting and keeping qualified personnel is the most difficult aspect to address for the subsea service and supply industry," says Carter. "Manufacturing solutions will continue to evolve as new technologies are developed and implemented. But we need people to deliver the solutions to the clients' projects—now and in the future."

The large size of projects and the necessity to develop hydrocarbons in increasingly difficult environments has increased the demand for experienced personnel, notes Chin.

He cites the following steps to mitigate and eventually meet the increasing demand for experienced personnel:

- "An aggressive retention program to encourage experienced engineers to continue to work rather than retire early.
- "Fostering mentoring programs for experienced individuals to transfer their experience and knowledge base to the next generation of employees.
- "Offering excellent compensation and flexible working schedules.
- "Aggressive recruiting of top experienced personnel from other industries, coupled with strong training programs to acquaint those engineers with oil and gas technology and offshore operations.
- "Compelling and imaginative programs, incentives, and encouragement for our young people to enter the engineering and scientific fields and to join the oil and gas industry."

Lamont says it is important for his company to identify all countries that contain candidates for engineering positions.

"Once local resources are identified and hired, we would train them within our company culture," he says. "In addition, the drive for diversity fosters an environment of greater innovation."

Diversity of manufacturing sites also factors into VetcoGray's capacity for meeting customer demand, says Lamont.

"Lean manufacturing is implemented to improve throughput at all our facilities," he says. "For example, we have developed incremental delivery capability in Brazil and Singapore to meet the local demand."

From a manufacturing perspective, additional capacity could be added to ensure that the long-term industry demands are met, Chin points out: "This added capacity will be attained through increased automation and establishment of manufacturing facilities in deepwater oil and gas producing countries dominated by national oil companies, such as [those in] Brazil, Angola, Nigeria, and Malaysia. This will also meet the demand for enhanced 'local content' in these countries."

In addition to its role in holding down costs, standardization of equipment components will help satisfy demand, Lamont notes: "The adoption of standard component or system design effectively increases capacity because it can eliminate the engineering cycle from the delivery process. This is compounded for each area of subsea system technology and each market geographically."

Bruce Crager, president and CEO of Intec Engineering, contends that the subsea service and supply companies must maximize their resources in order to best support the operators' needs and avoid the activities that are counterproductive to that goal.

"It is not necessary to bid out every scope of work for every contract," he says. "There are many cases where the selection of providers, based on capacity or capability in negotiating contracts, will be obvious, and contracting with them on a negotiated basis should be acceptable.

"We are wasting the industry's resources in bidding and tendering. For example, many purchasing departments require a significant amount of company data during a tender, and these same data may have been provided, often in a slightly different requested format, on another tender to the same company. This is exacerbated by the large number of operators and their various purchasing policies. Some standardization in the form of basic bid information would reduce the effort by all suppliers."

Even getting a good feel for the subsea service and supply sector's capacity in certain product and service areas would be a step in the right direction, according to Crager.

"Intec Engineering is currently performing a joint industry project (JIP) looking at subsea processing, pumping, and compression, as well as the associated power and controls. This JIP is currently funded by 14 operators, contractors, manufacturers, and engineering companies and is open to others who are interested in having an up-to-date summary of the industry's current capacity in these areas."

The cure to the limits of capacity in the subsea manufacturing and service industry "will occur naturally if the financial performance of that segment of the industry is acceptable to investors," Chin notes. "This will take time, and in the short term, mitigation requires better scheduling and utilization of available manufacturing facilities and installation equipment."

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— B.K. Chin, Global Industries

Environmental issues

Environmental awareness has long been a major concern for companies operating offshore, even for a subsea sector that has logged an impressive environmental track record.

Subsea well systems have been substantially free from environmental problems, Chin points out: "There has never been a subsea well completion that has blown out. There have been only relatively minor hydrocarbon leaks. This remarkable record is most likely due to the care with which equipment is designed, manufactured, and integrated onshore before moving to offshore installation."

Apart from the usual concerns about operating offshore with environmental awareness, there is a major positive environmental aspect to subsea installations: its low profile and small footprint compared with fixed installations. That aspect, in fact, is one of the key drivers in the subsea industry's growth, contends Lamont.

"One of the advantages of a subsea production system must be the relatively low decommissioning costs, which is but one of many factors tipping the balance in favor of this type of development," he says.

Crager contends the industry must continue to focus on minimizing possible pollution related to subsea equipment.

"This is already a basic design tenet in the industry," he adds, "but we need to keep in mind how our hardware as well as our control systems can meet this goal."

Probably the single most important development in the subsea environmental area is the move away from mineral-based to environmentally sensitive water-based hydraulic control fluids, says Lamont: "We have qualified our systems for these fluids and continue with programs to qualify components as fluid technology continues to evolve.

"Taking this challenge to its obvious conclusion, we would see the complete electrification of the subsea system. While this creates certain challenges, which at present remain unsolved, this is the only technology that will allow us to develop some of the more remote fields."

And even bigger environmental concerns could drive the industry toward a whole new market opportunity: sequestering carbon dioxide amid mounting concern over greenhouse gas emissions.

"In the environmentally sensitive areas of the Barents Sea, we are in the process of delivering the world's longest offset project," notes Lamont: "CO_2 reinjection was one capability demanded of the 145-km offset system."

Pipeline corrosion may be the most worrisome environmental concern for subsea developments.

"In the future, it is likely that the development of pigs with even better data transmission will allow for improved detection of corrosion," Chin says. "Also, autonomous underwater vehicles will allow operation in worse weather conditions and will reduce the cost of inspections of subsea equipment, allowing further improvement of the subsea industry's excellent environmental track record."]

Subsea future: seabed processing, IOR, integrated solutions

What will the optimized subsea installation of the future look like?

Several service and supply company executives weighed in with their speculation about that prospect.

The new technologies tend toward integrated field management systems which, in turn, require highly reliable data acquisition and the ability for precision remote control of subsea equipment, contends Robert Carter, president and general manager of Antares Offshore LLC.

"Certainly the advances in subsea control systems support that course, as does incorporation of subsea flow metering," he says. "The recent promotion of all electrically controlled subsea christmas trees will likely become more common and lead to larger-scale integration of subsea production systems.

> The new technologies tend toward integrated field management systems which, in turn, require highly reliable data acquisition and the ability for precision remote control of subsea equipment.
>
> *— Robert Carter, Antares Offshore LLC.*

"More substantial changes will result from the continued development—and commercial deployment—of subsea pumping, separation, and processing. Each element has its own components, some more optimized than others, but bringing it all together requires subsea control systems that provide the data acquisition and control functions needed for the elements to perform as a single entity—an integrated subsea field development."

However, the use of traditional subsea systems will still be a mainstay for developments that cannot support new technologies and for operators that prefer not to, Carter adds.

"Declining fields, deeper fields, and increasing offset require new and innovative solutions to maximize productivity," notes Dave Lamont, president, Eastern Region & Subsea for VetcoGray, a GE Oil & Gas business. (In January GE agreed to acquire VetcoGray from investor groups Candover, 3i, and JP Morgan Partners for $1.9 billion.) An example is Norway's Ormen Lange development, which entails a compression package for which VetcoGray has supplied both compression technology and the subsea power distribution network.

"Where reservoir pressure is dropping or wells are deteriorating to sand and water, we need to boost subsea flow and process it at the seabed," he says. "It makes no sense to return the water to the surface.

"Furthermore, as deepwater fields move from the technology frontier to developments of strategic importance, the same logic applies. We have had subsea separators working on Troll field in the Norwegian sector for over 5 years and are a leader in the deployment of submersible pumping technology."

Lamont also points out that subsea processing solutions are power-hungry. As such, a big focus of VetcoGray's R&D program is the development of high-voltage connectors, variable speed drives for motors, and subsea transformer technology. "A strong legacy in the world of power systems gives VetcoGray, part of GE's Oil & Gas business, a competitive advantage in this respect," he adds.

Subsea technology will continue to mature as subsea assets do, Lamont says, with an increasing emphasis on equipment monitoring and maintenance.

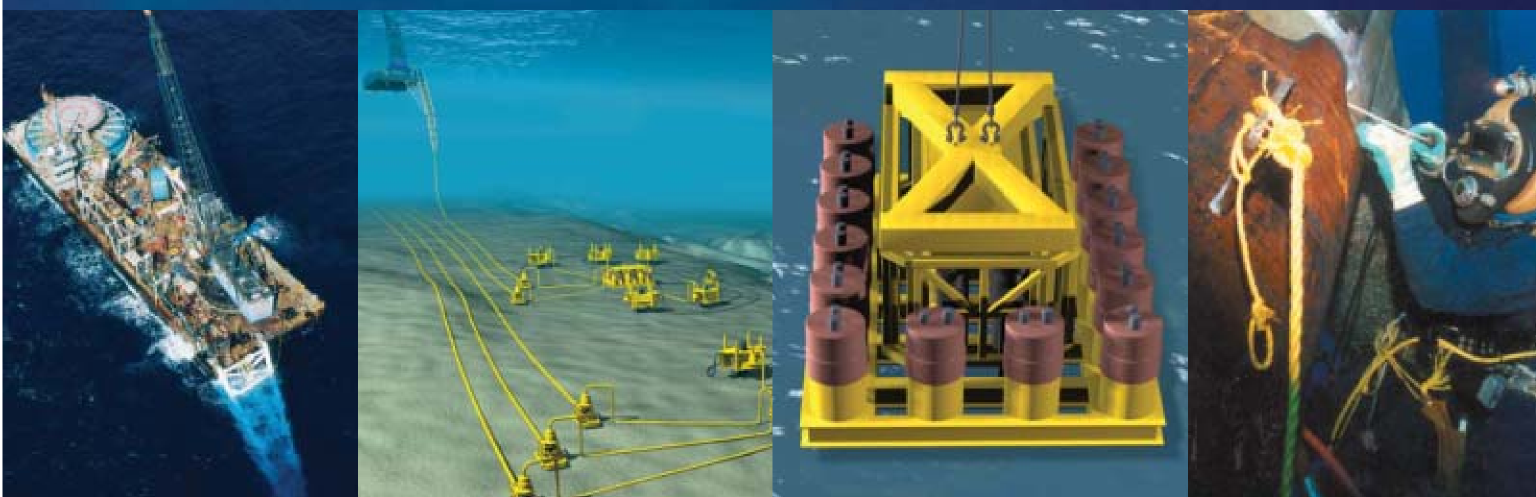
"The increasing age of subsea assets will continue to grow the need for remote health checking and preventative maintenance solutions," he notes. "In addition, at some point in the near future, we will do away with hydraulic circuits and deploy entirely electric solutions."

Look for more improvements in information technology in the subsea installation of the future as well.

"As subsea equipment becomes smarter, using more sophisticated process plant and produced-fluid sensors, the need for sub-sea-to-surface data bandwidth increases," Lamont says. "We are developing networks running this type of communication protocol."

In addition, longer offsets and higher data rate requirements require fiber optic communication.

"We will create more value for asset owners by introducing software applications that improve the quality of information coming from the field. For example, we could deliver a multiphase measurement system running on software for the entire development at the



cost of a single multiphase flowmeter."

Bruce Crager, president and CEO of Intec Engineering, believes that "long-distance tiebacks will become more common, and we will achieve even longer offsets in deeper water."

Integrated solutions based on concept development and careful planning may reduce development time," says Jarl Kosberg, senior vice-president of trees/processing and boosting for Aker Kvaerner. He cites the KG-D6 field development for Reliance Industries off eastern India as an example: "The project is a global-scale gas development with first production within two years of project sanctioning."

In addition, says Kosberg, new technologies are entering the subsea market that allow the operators to better meet their needs: "As an example, new boosting technologies will allow improved oil recovery while not compromising other project drivers."

Subsea separation will continue to be affected by the same reliability problems that surface processing systems experience, contends B.K. Chin, CEO, Global Industries Ltd. "Significant improvements in the subsea realm should follow the improvements on the operational reliability of surface systems," he adds. "Perhaps the visionary 100-mile oil tiebacks with no local surface facility can become a reality, given these advancements."

Chin sees continued success in remote operation of subsea well systems leading to fewer and shared floating surface facilities, such as the Nakika and Independence hub facilities in the deepwater Gulf of Mexico.

"It is also likely that new, less expensive self-standing risers will be developed to separate the installation of the flowlines and risers from installation of the production facility vessel, allowing reduced development cycle times and installation weather risks," he says. "This has happened already on occasion but will become more widespread and will improve deepwater fields' cash flow and production profile."

Chin contends future improvements in equipment and operational reliability databases and the ability to statistically use the information gleaned from them will allow preventative maintenance of subsea equipment: "This will allow seafloor and well intervention to be planned, which will allow lower-cost operations and less-frequent interventions."

In addition, Chin thinks that system integrity processes will continue to improve and gain widespread use.

"This and further development/confidence in automated underwater vehicles will lead to remote underwater inspection and possibly even simple, noninvasive equipment repair, further improving system reliability and reducing overall operating costs," he says.

If subsea installations are to fulfill their ultimate potential, the industry will have to become more accepting of new technology, contends Crager.

"We have a record of being extremely slow to accept first use of new technology, and even after the concept is proven, we are very slow to actually apply that technology," he says. "We should be willing to try out new technologies and accept failure and redesign as a part of technology development.

"In my opinion, Petrobras has been one of the industry leaders in their willingness to try new techniques and have brought out a number of interesting solutions over the last few years, including torpedo piles, torpedo wellheads, subsea boosting improvements, and even better installation methods, such as their pendulous methods for installing manifolds. As an industry, we need to be willing to try these new techniques and technologies and then improve them when they don't fully meet our expectations."

Subsea processing

The critical technology frontier for subsea operations of the future will remain subsea processing.

"Subsea processing—a dream of offshore operators since the 1960s—is finally moving into the mainstream of our industry," says Peter Kinnear, president, FMC Technologies. "FMC's goal is to make it happen; to deliver complete, integrated subsea systems with proven reliability and to provide our clients with direct technical support for the life of the field."

> "Subsea processing—a dream of offshore operators since the 1960s—is finally moving into the mainstream of our industry."
>
> *— Peter Kinnear, FMC Technologies*

Subsea processing, including metering, pumping, compression, and related capabilities, will become more common, notes Crager, and "will allow us to employ subsea systems in deeper water and farther from infrastructure."

FMC involves its clients in its subsea processing design thinking at the outset to help overcome apprehension over this cutting-edge technology area.

"Our designs are simple and robust, so systems should not fail," says Erlend Fjøsna, manager of subsea processing systems for FMC. "But if a primary system does go down, there is always a backup mode and the possibility of reconfiguring the flow so the facility can continue operating."

In many ways, Fjøsna says, the interest in subsea processing "is moving faster than we thought.

"But that really shouldn't be a surprise, because the value cases for subsea processing are so obvious and so strong."

With regard to subsea processing, the subsea installation of the future may be just around the corner. FMC notes that the world's first commercial subsea processing system will be installed in Statoil SA's Tordis field in the Norwegian North Sea. Tordis lies in 200 m of water. The processing system entails a full-scale separation facility and electric pumps on the seabed to reinject bulk water into a nonhydrocarbon reservoir. The oil and gas stream is to be boosted through a multiphase pump back to the Gullfaks C platform.

"Tordis is a perfect application of subsea separation," says Fjøsna. "The field is maturing, so its wells are producing more and more water. That is restricting production, because the flowlines and the surface facilities do not have the capacity to transport and handle all of the extra water."

FMC's design solution that won it the Tordis contract was to take out the gas in the inlet section of the separator, which enabled them to reduce the size of the vessel by almost 50%.

"That made our vessel more compact than what our competitors proposed," Fjøsna added.]

Flow assurance tops subsea technology challenges

The game-changing technologies for subsea installations today center on such challenges as flow assurance, high temperatures and pressures, and control and communications.

Service and supply companies must address these challenges in a way that is both economic and environmentally friendly.

Flow assurance

As industry continues to move into ever-deeper waters, subsea operators continue to grapple with flow assurance concerns posed by hydrate formation and wax and scale deposition.

"The industry continues to improve our capability to analyze flow assurance from a producing reservoir to surface facilities," says Bruce Crager, president and CEO of Intec Engineering. "This has allowed us to minimize operational problems and to properly design pipelines and other key systems, particularly for difficult or unusual reservoirs. The development of hydrate inhibition technologies such as chemical inhibitors, novel techniques such as cold flow, and electric flowline heating will enable very long offsets."

Software solutions are now available to optimize production across a multiwell network, predict hydrate formation, measure multiphase flow, and control slugging, notes Dave Lamont, president, Eastern Region & Subsea for VetcoGray, a GE Oil & Gas business. (In January GE agreed to acquire VetcoGray from investor groups Candover, 3i, and JP Morgan Partners for $1.9 billion.). Other software applications are condition monitoring and the introduction of planned maintenance to the subsea world, he adds.

VetcoGray's Cold Flow technology is an enabling technology for long step-out oil field developments, Lamont points out. It entails cooling the well stream to form tiny hydrate particles from the associated gas and water before they enter the pipeline; the hydrate then flows with the oil in a three-phase flow together with eventual surplus gas, from wellhead to production site.

For gas systems, Lamont contends that methods for controlling hydrates are available and economically viable, and the technology for recycling hydrate inhibitors is available and reliable.

It's a different matter for long step-out oil developments, because the production threats go beyond hydrate formation, Lamont says.

"The methods for controlling hydrates are available and economically viable but not 100% field-proven for this application (subsea separation with back-up chemicals); the use of chemical technology for wax and scale deposition is available but expensive in this application; and the use of thermodynamic technology for wax and scale suspension is available but not field-proven."

For second-generation multiphase flowmeters (MPFM) , the solution is simple, assures Lamont: "Move the computations back to the surface, dumb down the device, and increase reliability by allowing for back-up sensors. The MPFM becomes just another part of a VFM (a 'virtual' flowmeter)."

FMC Technologies developed an innovative flow assurance solution for Ormen Lange, Europe's deepest subsea development, operated by Shell Norway. An especially daunting hurdle was flow assurance in the project's long pipelines, given that the subzero temperatures on the seabed made hydrate formation and icing a constant threat. In addition, the seabed itself is an irregular mix of rocks and soft clay, creating low spots in the gas pipelines that tend to trap liquids that accumulate and freeze.

In response to the challenge, FMC integrated three flow assurance systems based on its FlowManager real-time flow-management software and provides continuous monitoring of Ormen Lange's critical production variables.

Continued, improved confidence in two-phase flow analysis will reduce the contingencies designed into today's subsea systems, according to B.K. Chin, CEO, Global Industries Ltd.: "This will allow confident selection of the most economic method of solids control for a particular system.

"For the hub-and-spoke development and on long subsea tiebacks, flow assurance issues, along with subsea pigging, will be an issue to contend with. There are several design options available to the operator today to mitigate the potential flow assurance issues. These include passive systems such as insulated pipe and pipe-in-pipe solutions, as well as active systems such as DEH (direct electrically heated) pipe and chemical injection."

Long tiebacks

Industry continues to push the envelope on technology for long tiebacks, routinely setting new records for distance every year.

The pipeline and umbilical systems are commonly the key considerations in terms of technology and economics for long tiebacks, notes Jarl Kosberg, senior vice-president of trees/processing and boosting for Aker Kvaerner.

"A technology developed by Aker Kvaerner, the Integrated Production Umbilical, has great potential in making tiebacks economically viable," he says. "It contains a center flowline and umbilical functions covering the area between the center flowline and the circumference. This solution reduces hardware and installation cost significantly."

The improved capability to pump crude oil will extend the range of tiebacks, says Chin: "The ability to supply power to seafloor pumps, improved reliability of downhole pumping, and the ability to install larger casing for the first few thousand feet below the mudline will enable this capability."

Manifolds, tie-in systems

Manifolds are becoming more sophisticated and flexible, notes Crager: "One of the key design aspects of these systems is to try and envision future needs and make sure the capability for future tie-ins is considered during the design process."

Kosberg contends that reliability and simple solutions have always been the main drivers for manifolds and tie-in systems.

"In today's market conditions, reducing installation vessel time and moving away from heavy lift vessels are also important considerations," he says. "In deep water, cost efficiency is achieved by performing operations on the seabed rather than having to move tooling and equipment between the seabed and surface. Wet tow of manifolds is another example where vessel cost is reduced."

Large-bore (30 in. and more) connection systems for gas trunkline systems and next-generation deepwater connection systems are being developed with minimized support infrastructure, Lamont points out.

"Like other subsea equipment manifolds and connection systems, these are being designed for HPHT [high-pressure/high-temperature] applications," he says. "Metal bellows are being used for high piping flexibility in manifolds and jumper applications."

Lamont also notes that manifolds are becoming more intelligent with integrated HIPPS (High-Integrity Pipeline Protection Systems) technology, for pressure protection of export pipelines.

Improved multiphase meters and chemical distribution metering valves will increase the acceptability of comingling multiple reservoirs to common subsea manifolds, contends Chin.

In addition, an improved understanding and detection of solids formation will lead to the development of simpler and more reliable subsea pigging facilities, Chin says: "These will be serviced by free-flying, construction-class autonomous underwater vehicles operating from remote locations without the use of a surface vessel."

Control systems

Increased demand for sensor technologies and functionality of the well, management of the subsea production system, and new technology, such as boosting—"all these require increased power requirements and communication capacity and frequency," cites Kosberg.

There has been some success in standardizing control systems software so various manufacturers' equipment can communicate, notes Crager: "In addition to the common technology of using an umbilical to a subsea system, I believe we will see other solutions, such as floating power/control facilities located near the subsea facility with control signals transmitted by satellite from the beach to this floating control facility. This will greatly reduce the required length of power lines, subsea power systems, and umbilicals with the resulting cost in both [capital expenditure] and installation."

> "The industry continues to improve our capability to analyze flow assurance from a producing reservoir to surface facilities."
>
> *— Bruce Crager, Intec Engineering*

Lamont concurs, noting that control systems are currently being designed "to incorporate IWIS and SIIS for IP communications with subsea and downhole instrumentation. This is a move towards commercially available communication protocols, which reduces the risk of obsolescence associated with proprietary technology. Other developments include fiber optical modems running at 100 Mb/s, and the associated connectors. As the systems open up, a number of software solutions can add additional value to the control system. These include 'virtual' flow metering, optimization, and real-time asset management."

Umbilicals

For production control umbilicals, "the electrification of subsea systems will reduce the size, weight, and cost of the umbilical," Lamont points out. "The use of high-pressure hydraulic intensifiers on the seabed has already removed the need for a high-pressure hydraulic line in the same way."

One interesting development is the use of integrated supply umbilicals (ISU) that might include larger flow passages for chemical injection or even for production, in addition to the power and control functions.

"This makes installation simpler, and it may reduce cost in those cases where an ISU can replace the need for both the flowline and an umbilical," says Crager. "The development and application of all-electric control systems will reduce, but not eliminate, the number of fluid conduits required in umbilicals."

Floating control facilities can significantly reduce capital outlays for umbilicals and their related installation, Crager notes.

"There are five of these in the world, with the sixth currently being installed," he adds. "Combination power/control buoys may also provide functional and cost advantages."

Multiphase pumping, subsea boosting

Kosberg points out that, aside from electric submersible pumps, in use for the last several years, "the market for subsea boosting is predicted to grow from its present emerging state to 100 installations in the next 10-year period.

"The preferred technology for boosting of wellstream pressure is multiphase pumping or a combination of separation and liquid boosting. State-of-the-art multiphase boosting is being installed on BP's King project in 1,700 m in the Gulf of Mexico. Subsea water injection is currently being applied at Statoil's Tyrihans field using 2 by 2.5-MW liquid booster pumps. Subsea wet gas compression has a great potential in extending the useful life of gas fields when the reservoir pressure drops. A 12.5-MW pilot plant is presently being built by Hydro and Aker Kvaerner for testing at a subsea test facility at Aukra, Norway, the purpose being to prove the technology for use at Ormen Lange field in the North Sea."

> "Reliability and simple solutions have always been the main drivers for manifolds and tie-in systems. In today's market conditions, reducing installation vessel time and moving away from heavy lift vessels are also important considerations."
>
> *— Jarl Kosberg, Aker Kvaerner*

Multiphase pumping "is a proven technology and should be applied to more projects in the future, especially for long offsets," contends Crager. "For very deepwater applications, subsea separation coupled with high-differential-pressure, single-phase pumps will also be important."

As it has with subsea boosting, "a subsea variable speed drive solution will be key to enabling parallel high boost pump trains," Lamont says. "This is particularly required for long step-out or deepwater oil."

Crager thinks that the development of subsea separation, pumping, and compression systems is key to success in the ever-farther/ever-deeper trend: "In many cases, the primary factor hindering application is that operators are reluctant to adopt novel technology. In other cases, further development is required. Industry is responding to the need."

Lamont agrees: "As opposed to multiphase pumping, subsea pumping and compression are the big game-changer. VetcoGray is at the forefront of the compression side. The distribution of HV electrical power is key."

Subsea wells

Intelligent wells may be the wave of the future in drilling and producing subsea wells.

With intelligent wells, "a whole range of sensor technologies are available to monitor and better understand well development and behavior," says Kosberg. "The objective is to optimize production rates by, for example, securing high sustainable flows from the well.

"Further, the data can be entered into simulation software to allow optimized production of a whole field, taking into account reservoir characteristics, dependency between wells, and pipeline and processing facility constraints."

Lamont notes that using intelligent wells will increase the need for hydraulic and electrical connections through the subsea completion: "This in turn means more functionality within the control system and increased bandwidth to exchange data and software."

And that adds to costs and complexity, Crager points out.

"While there has been significant discussion on this technology, it is complicated and requires proper installation as well as design," he says. "While this technology brings significant benefit to the operator, it also provides a huge amount of data that must be analyzed and stored in a way that can make the associated capital expenditure cost-effective during the operational phase of the well."

For subsea completions occurring more often in deep reservoirs offshore, equipment will need to be qualified for HPHT wells, according to Lamont.

"Industry requirements will increase the need for robust performance," he says. "With reservoir complexity, the number of penetrations will increase to accommodate the additional downhole pumps, intelligent completions, and instrumentation."

Other technologies

Subsea experts interviewed for this supplement weighed in on other critical technology advances for their sector.

From a surface standpoint, large hub facilities will allow multiple small fields to be tied back to one location and will allow many operators to develop small fields by utilizing these hubs, Crager notes: "Adding subsea processing can allow subsea hubs to replace more expensive surface-piercing hub structures."

Lamont notes the importance of subsea hub design changes that include dual concentric hub configurations for dualbore connections without the need for rotational orientation and multibore designs: "These have a high misalignment capability and enhanced all-metal sealing of smallbore couplers."

Riser designs continue to evolve to accommodate ever larger-sizes, higher pressures, and deeper waters, Crager points out.

"Hybrid riser designs are now being utilized for deepwater projects that utilize rigid, vertical piping topped by a subsurface buoy, and a flexible pipe catenary from the buoy to the floating production facility," he says. "One limitation to hybrid risers has been the capabilities of flexible pipe, but the capability of flexibles is being expanded to handle higher pressures, temperatures, and large sizes."]

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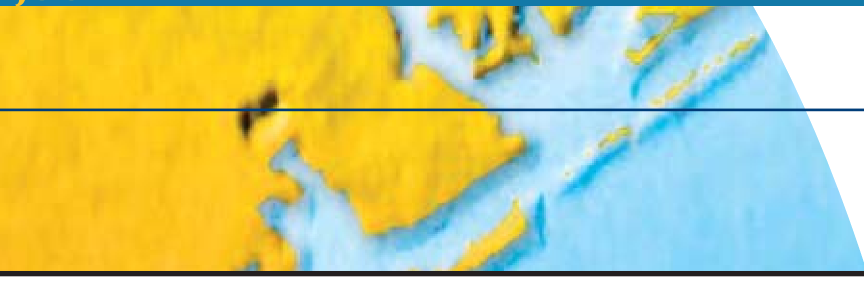

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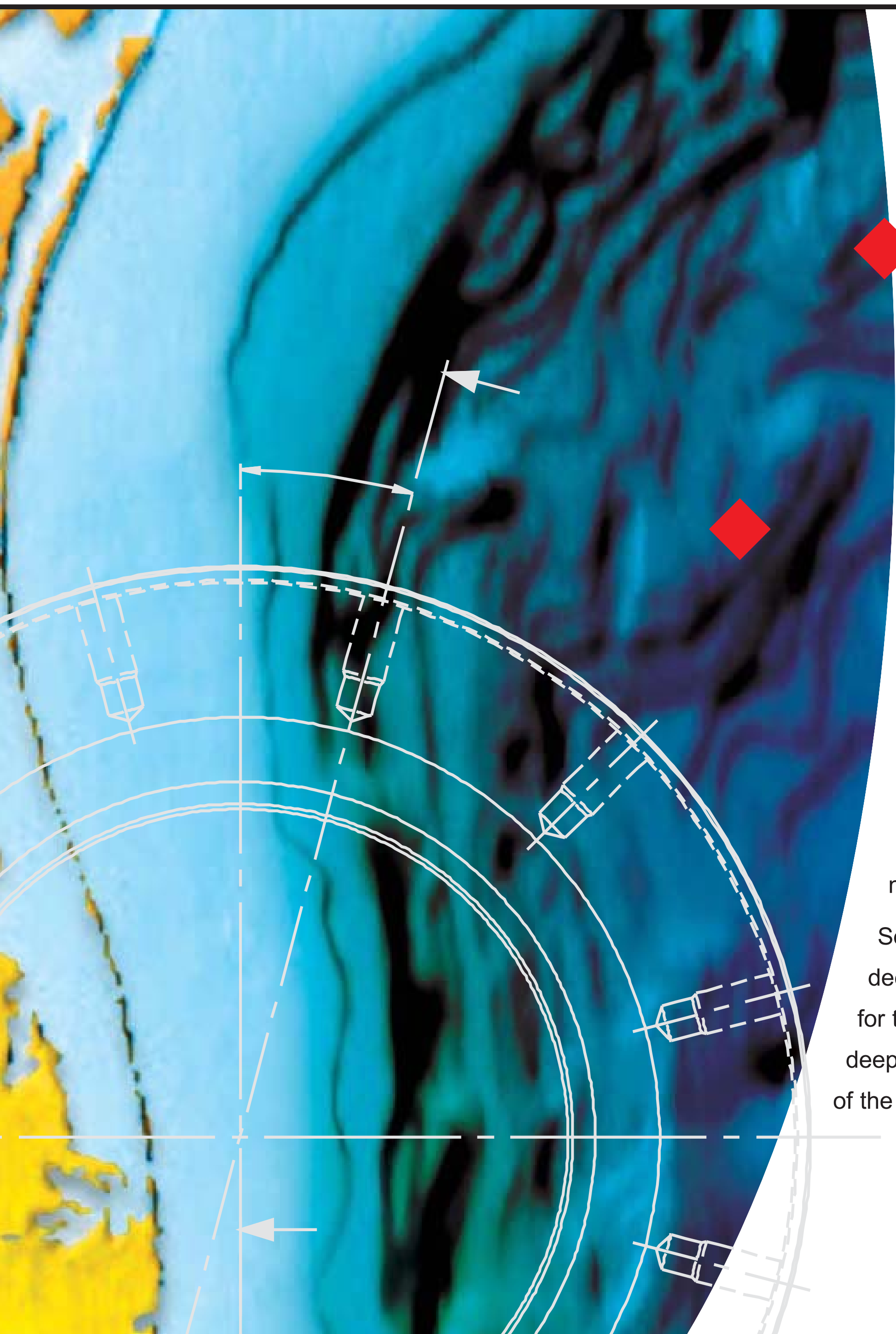

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