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Capital Spending Outlook

Giant field discovery patterns show gas bent, active decade
Multiphase flowmeter optimizes heavy oil production off Congo
Method correlates solubilities of crude hydrocarbons in water
REX pipeline start affects regional natural gas pricing

OIL&GAS JOURNAL

Apr. 2, 2007
Volume 105.13

Capital Spending Outlook

Regular Features

Cover

Capital expenditures in the US and Canada will head in different directions this year, according to OGJ's annual outlook of upstream and downstream oil and gas outlays. In the US, budgets call for capital spending for exploration and production, refining, and other segments to climb. In Canada, oil sands development is one of the few growth areas for budgets this year. Meanwhile, spending for both upstream and downstream projects will continue to climb this year outside North America.

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OGJ Newsletter

Apr. 2, 2007

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General Interest — Quick Takes

ROV industry to see increased spending

The work-class remotely operated underwater vehicle (ROV) industry has had strong growth as a result of recent sustained high oil prices. Particularly since 2002, expenditure on work-class ROV operations has more than doubled, and further strong growth is expected over the next 5 years, said Douglas-Westwood Ltd. analysts in a recent report.

Total expenditures for the ROV market is forecast to reach $1.46 billion/year by 2011, according to the report entitled "The World ROV Report 2007-11," which is based on analysis of demand drivers. "Offshore utilization and ROV dayrates have increased dramatically over the past 5 years and stand at an all-time high," said lead analyst Rod Westwood. "Between 2002 and 2006 alone, the work-class dayrate increase was around 30%," he said.

In 2006, Westwood estimates, $827 million was spent on the operation of work-class ROV units worldwide, an increase of 86% on the 2002 value. This is forecast to increase by a further 76% to a 2011 value of about $1.46 billion—more than three times the market over the 10-year period, he said.

The study suggests that North America and Western Europe are expected to account for the largest proportion of ROV activity. About half of the total ROV units expected to operate in 2007 are associated with these regions, the report said.

High oil prices have resulted in high levels of drilling activity and increased installations of subsea wells, pipelines, control cables, and other hardware. Increasing underwater resources, therefore, are required to service the growing numbers of underwater installations, progressively more in deep waters beyond the economic reach of manned intervention. This all manifests itself in the building of new drilling rigs and offshore construction vessels, all of which use ROVs in subsea operations, Westwood said.

The report contends that by the end of the period, more than 120 work-class ROVs/year will need to be built to meet demands of market growth and attrition of the existing fleet.

"Based on an average cost per unit" the study predicts that "work-class ROV capex will increase from its 2006 level of $186 million to $247 million by 2011—an increase of 33% over the period." Cumulative expenditures, meanwhile, are expected to be slightly higher than $1 billion over the forecast period.

RIK gas sale to bring in $1 billion in revenues

The US Treasury will gain more than $1 billion in revenues following the latest federal royalty in-kind natural gas sale, the Minerals Management Service said on Mar. 27.

Ten companies submitted successful bids in the Mar. 8 sale for the 13 contracts involving 137.5 bcf of gas produced from federal leases in the Gulf of Mexico. The gas will be delivered over 7-month or 12-month terms beginning Apr. 1, MMS said.

Winning bidders included Bear Energy LP, Eagle Energy Partners, Coral Energy LP, Louis Dreyfus Energy Services, National Energy & Trade LLC, Williams Power Co., BG Group, Total Gas & Power North America Inc., Fortis Energy Marketing & Trading, and Constellation Energy Commodities Group Inc.

MMS said bidding was strong in the sale, as 20 companies submitted 152 offers for the RIK gas. It said it based its revenues estimate on the current $7.50/Mcf gas price.

Chavez, Manning sign cross-border gas treaty

Trinidad and Tobago has signed a cross-border treaty with Venezuela, following an agreement concluded in March to jointly develop an estimated 30 tcf of natural gas in offshore fields straddling the borders of the two nations (OGJ, Mar. 12, 2007, Newsletter). It is the first such agreement in the Western Hemisphere and is designed to provide for the production of gas out of the Deltana area.

Venezuela President Hugo Chavez and Trinidad and Tobago Prime Minister Patrick Manning, who signed the agreement in Caracas, hailed the treaty as a major step forward, allowing the countries to develop one of the world's most prolific gas regions.

The first fields to be developed will be Loran and Manatee, which are estimated to hold 10 tcf of gas—7.3 tcf on the Venezuelan side and 2.7 tcf on the Trinidad and Tobago side. Chevron Corp. operates Loran and is a partner with BG Group on the Trinidad side (Manatee), which BG Group operates.

The treaty sets the framework for taxation and other production issues. However markets for the gas have yet to be determined.

The two countries will decide by mid-April where Loran-Manatee gas will be piped for processing. Manning wants it processed as LNG in the Caribbean island nation, where it would form the basis for an additional LNG train.

"We are a producer of LNG at this time and can do it much quicker than in any other route," Manning explained. The country is conducting talks with BG about adding another LNG train at Point Fortin (OGJ Online, Mar. 23, 2007). ✦

Exploration & Development — Quick Takes

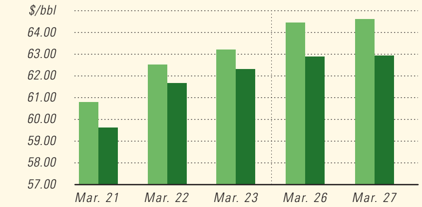
Royale targets Rio Bravo Monterey shale oil

Royale Energy Inc., San Diego, plans to begin work by the end of May to further develop Rio Bravo field west of Bakersfield in Kern County, Calif.

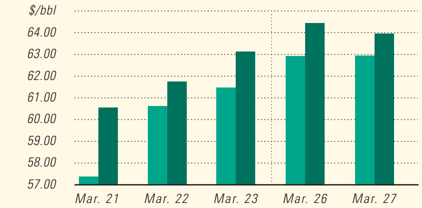
Royale signed a letter agreement with Matris Exploration Co. LP to acquire 50% of Matris's interest in the field and fund future

Industry Scoreboard

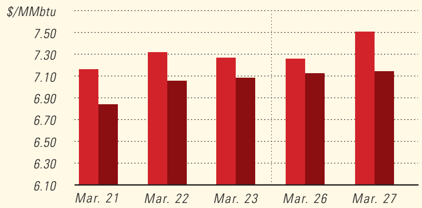
IPE BRENT / NYMEX LIGHT SWEET CRUDE



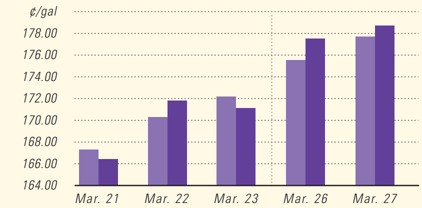
WTI CUSHING / BRENT SPOT



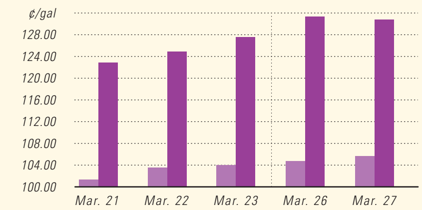
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



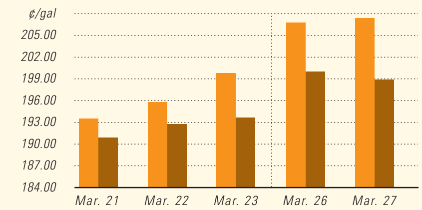
IPE GAS OIL / NYMEX HEATING OIL



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.

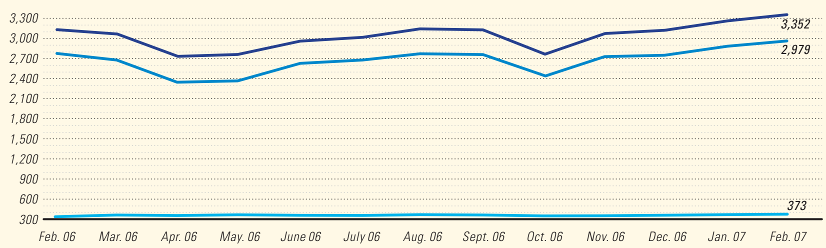
US INDUSTRY SCOREBOARD — 4/2

Latest week 3/23	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	9,044	9,077	–0.4	9,074	8,897	2.0
Distillate	4,534	4,452	1.8	4,450	4,320	3.0
Jet fuel	1,592	1,562	1.9	1,613	1,545	4.4
Residual	905	820	10.4	743	821	–9.6
Other products	5,190	4,716	10.0	5,015	4,790	4.7
TOTAL DEMAND	21,265	20,628	3.1	20,893	20,374	2.6
Supply, 1,000 b/d						
Crude production	5,261	5,022	4.8	5,298	5,037	5.2
NGL production	2,456	1,686	45.7	2,417	1,683	43.6
Crude imports	9,603	9,838	–2.4	9,630	9,806	–1.8
Product imports	3,120	3,124	–0.1	3,094	3,449	–10.3
Other supply[2]	858	913	–6.1	946	1,182	–20.0
TOTAL SUPPLY	21,297	20,583	3.5	21,385	21,157	1.1
Refining, 1,000 b/d						
Crude runs to stills	14,430	14,580	–1.0	14,602	14,658	–0.4
Input to crude stills	14,916	14,924	–0.1	15,038	14,995	0.3
% utilization	86.1	85.8	—	86.8	86.4	—

Latest week 3/23	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	335,296	329,357	5,939	336,850	1,554	–0.5
Motor gasoline	202,471	204,694	–2,223	212,059	–9,588	–4.5
Distillate	119,239	123,342	–4,103	124,137	–4,898	–3.9
Jet fuel	40,619	38,617	2,002	42,800	–2,181	–5.1
Residual	38,237	38,427	–190	39,324	–1,087	–2.8
Stock cover (days)[3] **3/16**			**Change, %**		**Change, %**	
Crude	22.4	22.3	0.4	23.5	–4.7	
Motor gasoline	22.9	23.3	–1.7	24.5	–6.5	
Distillate	26.2	26.2	—	29.6	–11.5	
Propane	17.1	17.2	–0.6	21.0	–18.6	
Futures prices[4] **3/23**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	60.08	57.69	2.39	62.19	–2.11	–3.4
Natural gas, $/MMbtu	7.10	6.95	0.15	7.05	0.05	0.7

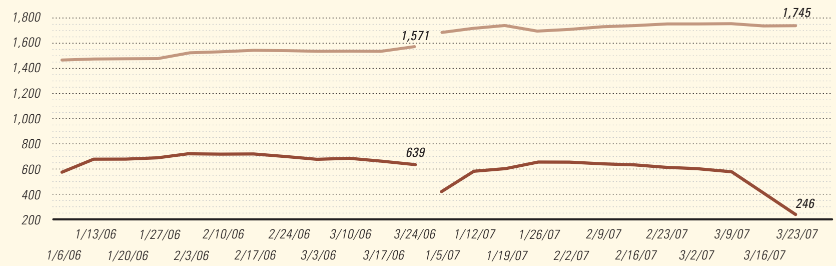
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [3]Stocks divided by average daily product supplied for the prior 4 weeks. [4]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, American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

development. Royale will target the shallow, unconventional Monterey shale and more-conventional deeper reservoirs.

The first project is to complete the Weber 27-27 well in Monterey shale, source rock for the San Joaquin basin. The vertical well had good oil and gas shows in several intervals before being drilled horizontally in the deepest of the show zones.

Texas Crude, EOG Resources, and Chevron have produced more than 7 million bbl of light, sweet oil from Monterey shale in North Shafter field, the closest analog to Rio Bravo, Royale said.

Pacific Stratus details Colombian finds

Pacific Stratus Energy Ltd., Toronto, started production tests at a Llanos basin multizone oil discovery and reported final drillstem test results at a gas discovery in the Lower Magdalena basin.

The company, operator of the Moriche Block, said the Mauritia Norte-1 wildcat went to 10,000 ft TMD and cut 6 ft of net pay in Carbonera C7 topped at 8,726 ft, 5 ft of net pay in Mirador topped at 8,973 ft, 9 ft of net pay in Gacheta topped at 9,520 ft, and 23 ft of net pay in Ubaque topped at 9,693 ft.

Oil quality is 38.5° gravity in Mirador and 12.8° gravity in Ubaque. The Carbonera C7, Gacheta, and Ubaque reservoirs had 253, 214, and 296 ft of gross thickness, respectively.

Pressure gradients were made based on repeat formation test data, and well-defined water oil contacts were confirmed in Ubaque and Mirador.

Meanwhile, Pacific Stratus plans to spud the La Creciente-2 appraisal well in early April. Calculated absolute open flow at the discovery well was 208.1 MMcfd of gas based on reservoir depth pressure data vs. the initially estimated 71.8 MMcfd based on wellhead surface pressure from Tertiary Cienaga de Oro at 10,933-11,572 ft.

Colombia's National Hydrocarbons Agency awarded Pacific Stratus 100% working interest in the 216,123-acre Guama Block near La Creciente.

The company committed to reprocess 300 line-km of seismic surveys and shoot 200 line-km of new 2D surveys in the first 18 months. The commitment for the second phase is to drill a well.

Pacific Stratus has mapped five gas and oil prospects in the block. One prospect was proved almost 20 years ago when the Ligia-1 well flowed 500 Mcfd of gas and 450 b/d of 39° gravity oil on short tests.

Chevron, partners awarded acreage off Australia

Chevron Australia Pty. Ltd., Perth, and partners have been awarded exploration rights to the W06-12 permit area in the Carnarvon basin off northwestern Australia.

The acreage, in the Greater Gorgon area of the basin, covers 1,150 sq miles and lies about 60 miles offshore.

Chevron will serve as operator, with a 50% interest in the permit, while partners Shell Development Australia and Mobil Australia Resources Co. Pty. Ltd. each will hold a 25% interest.

The 3-year work program for the permit includes geotechnical studies, the shooting of 110 miles of 2D seismic, and the drilling of an exploration well. Seismic work will begin this year.

Chevron said there also is potential for an additional 3-year work program.

Tower Resources to drill two wells in Uganda

Tower Resources PLC plans to drill two exploration wells on Block EA5 in western Uganda by 2008 and may also drill a contingent well under the second exploration phase of its Ugandan license. The government also has extended the company's initial exploration period for another 6 months, meaning the license will now end on Mar. 28, 2008.

Tower Resources will shoot a 250 km, 2D seismic survey in July and hopes to drill the exploration wells in first half 2008. The extension of its license will "facilitate optimum management of the seismic program and implementation of an early exploration well," Tower said.

Tower said the drilling program was appropriate, given the recent success in other similar licenses in the Rift Valley, in reference to Heritage Oil Corp.'s oil find in nearby acreage; Heritage is operator of the Kingfisher-1 exploration well in Uganda (OGJ Online, Feb. 16, 2007).

Tower's onshore block covers 6,040 sq km and has Tertiary rift sediments that hold oil and gas-bearing segments to the south. The company said the main exploration risk for the unexplored block is the thermal maturity of source rocks.

Statoil, Sonatrach gauge Hassi Mouina well

Operator Statoil ASA reported its Hassi Mouina exploration and appraisal well in Algeria has produced gas at 7,083 standard cu m/hr from a depth of 1,131-42 m. About 9,012 standard cu m/hr of gas flowed at 1,113-29 m, Statoil said. These results were achieved through a 32⁄64-in. choke.

Hassi Mouina, drilled to a TD of 3,200 m, is the first onshore well for Statoil in Algeria. The Norwegian state company partnered with Algeria's Sonatrach. The well targeted Devonian reservoir rocks.

The Hassi Mouina license was awarded in June 2004. It comprises four blocks within an area of 23,000 sq km in the Gourara basin. The area lies in Algeria's western desert, northwest of the In Salah gas field, where Statoil has a 31.85% share.

Statoil and Sonatrach are now drilling their second well, Hassi Tidjerane West 1 (HTJW-1), in the Sahara Desert. Statoil's share in Hassi Mouina is 75% and Sonatrach holds the other 25%.

ExxonMobil signs PSC for Mandar block

ExxonMobil Exploration & Production Indonesia (Mandar) Ltd. has signed a production-sharing contract with Indonesia for Mandar block in the Makassar Straits off West Sulawesi.

ExxonMobil was the successful bidder for block in Indonesia's 2006 exploration tender round; the company holds 100% participating interest.

Mandar block, which covers 4,200 sq km, is in the Southern Makassar basin in water as deep as 2,000 m.

ExxonMobil said Mandar block ownership augments its acreage position in the Makassar Straits, where it also has a PSC in place for Surumana block from a previous tender round.

BHP to explore deepwater blocks off Malaysia

Malaysia's state-owned Petronas awarded BHP Billiton two deepwater blocks, Block N and Block Q, which lie 175 km off Sabah

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state capital Koto Kinabalu in 1,600-2,800 m of water.

In contracts signed with Petronas, BHP holds a 60% interest in both blocks and will serve as operator. Petronas Carigali holds 40% interest.

The 7-year exploration period includes a schedule for seismic acquisition, seismic data reprocessing, and exploration drilling. ✦

Drilling & Production — *Quick Takes*

Timan-Pechora joint venture producing oil

The OOO Naryanmarneftegaz (NMNG) joint venture has begun oil production from six wells in Yuzhno Khylchuyu field in the northern Timan-Pechora basin of the Russian Arctic.

Unspecified volumes of oil are being trucked to an existing terminal on Varandey Bay on the Barents Sea for export via tanker to international markets. An 80-mile pipeline to replace the truck shipments is due for completion this winter or next winter.

Interests in the joint venture formed in 2005 are OAO Lukoil 70% and ConocoPhillips 30% (OGJ Online, July 1, 2005). ConocoPhillips also has an equity interest in Lukoil.

ConocoPhillips said it expects to spend $1 billion in 2007 in Russia, split evenly between NMNG and its 9.3% interest in supergiant, Eni-operated Kashagan field in the Caspian Sea.

ConocoPhillips has booked 170 million bbl of reserves or 15% of the combined ultimate expected bookings from the two projects. Yuzhno Khylchuyu field is the anchor field on the NMNG acreage block.

The terminal is to be expanded to 240,000 b/d capacity by the end of 2007. NMNG is expected to be producing and shipping about 200,000 b/d of oil at peak.

GOSP work starts in Shaybah expansion

Construction has begun on a gas-oil separation plant (GOSP) that will boost production capacity of Saudi Arabia's Shaybah oil field to 750,000 b/d from 500,000 b/d.

SNC Lavalin Group Inc., Montreal, is designing and building Shaybah Central Processing Facilities GOSP-4 under a contract let by Saudi Aramco last year (OGJ, Apr. 24, 2006, Newsletter). Other contractors and subcontractors are Hyundai Heavy Industries, NEC, and Saudi firms NESMA, NCC, and Al-Falak.

Completion of the expansion project is due in 2008. Shaybah field is 900 km southeast of Dhahran in Saudi Arabia's Empty Quarter.

Total expects production from Jura field in 2008

Total SA reported that production from Jura gas-condensate field in the UK North Sea is expected to start in second quarter 2008.

The company will produce 45,000 boe/d at plateau and will connect the field via a 3-km pipeline to the Forvie North subsea wellhead, itself connected to the Alwyn North processing platform. "The additional output should enable the Alwyn facilities to continue producing at full capacity until early next decade," Total said.

Jura, discovered 4 months ago, holds more than 170 million boe of proved and probable reserves in the Alwyn area, 160 km east of the Shetland Islands and 440 km northeast of Aberdeen. The Alwyn area holds the Alwyn North, Dunbar, Ellon, Grant, and Nuggets fields.

Total is continuing exploration in the UK North Sea with an appraisal well on Kessog, a high-temperature, high-pressure field near Elgin Franklin, followed by another exploration well on the Jura East prospect. Recent discoveries lifted Total's proved and probable reserves in the UK to over 1 billion boe in 2006.

Pokohura platform off New Zealand on stream

Gas and condensate production from the first of six planned offshore wells in Pokohura field off New Zealand has begun.

The other wells will be drilled from the production platform, completed, and tied in to the pipeline to shore during the next 12 months. After drilling, the platform will be unmanned and controlled from onshore facilities.

Three extended-reach wells drilled from onshore locations into the southern part of the Taranaki basin field started up last September.

Pokohura output will bring the onshore processing plant near New Plymouth in the North Island to its full capacity of 20 MMcfd of gas plus condensate during first-quarter 2008.

Pokohura has an estimated 750 bcf of gas reserves. The condensate content is rich, believed to be around 50 million bbl.

The field is operated by Shell Exploration New Zealand Ltd. with 48% interest. Todd Energy and OMV New Zealand hold 26% each.

Aramco lets contracts for ancillary platforms

Saudi Aramco has let contract to National Petroleum Construction Co. (NPCC) of the UAE for ancillary platforms in Zuluf and Marjan oil fields off Saudi Arabia.

NPCC will fabricate, transport, and install two tie-in platforms in Zuluf field, including two bridges, pipe spools, and associated work, and three scraper decks, two in Zuluf and one in Marjan.

Completion is due by January 2009. ✦

Processing — *Quick Takes*

Eni, Petrobras sign MOU for biofuel production

Italy's Eni SPA and Brazil's Petroleo Brasileiro SA (Petrobras) plan to assess developing a partnership to produce biofuels in Brazil and worldwide.

Under a memorandum of understanding signed Mar. 27, the companies will combine their proprietary technologies to jointly produce biofuels in other countries and may work together in commercializing biofuels in the international market.

Petrobras is experienced in large-scale production of bioethanol in Brazil. Eni plans to construct at its Livorno refinery a 250,000 tonne/year plant that would produce high-quality biodiesel. Eni also is looking to develop biofuel projects in other countries.

Eni said the two companies will study joint projects to assess together the application of the Eni Slurry Technology in Brazil in the framework of a broader partnership involving both upstream and downstream joint initiatives. EST will allow deep conversion of residues and heavy oils—typical of those produced in Brazil—into diesel and gasoline.

Holly lets EPC contract for hydrocracker unit

Holly Corp., Dallas, has let a $53 million engineering, procurement, and construction (EPC) services contract to Benham Constructors for a gas oil mild hydrocracker at its 26,000 b/cd Woods Cross, Utah, refinery.

The new unit will have a capacity of 15,000 b/d of gas oil. The unit is a major component of an expansion project at the refinery and, when combined with the desalting equipment, will expand the facility's crude processing capabilities to 31,000 b/d enabling the refinery to process a wider slate of crude oils.

Holly recently awarded the license and process design package of the unit to Process Dynamics Inc. (OGJ, Mar. 19, 2007, Newsletter).

Nova, Aux Sable to build ethane extraction plant

Nova Chemicals Corp. and Aux Sable Canada Ltd. have signed a letter of intent to jointly develop a 40,000 b/d ethane extraction plant in Fort Saskatchewan, Alta. The plant would have a capacity to process as much as 1.2 bcfd of natural gas, which will be transported via the Alliance Pipeline system.

The ethane will be piped to Nova Chemicals' Joffre, Alta., petrochemical complex to be used as a feedstock.

Aux Sable will own and operate the plant, which is expected to begin operating in mid-2010.

EPC contract let for Bavarian refinery upgrades

BP PLC subsidiary Bayernoil has let a detailed engineering, procurement, and construction management services contract to Jacobs Engineering Group Inc. for work related to a $60 million upgrade project at the Vohburg refinery in Bavaria.

The contract calls for Jacobs to provide logistics and revamp an existing Merox unit.

The project is scheduled for completion in early 2009. ✦

Transportation — *Quick Takes*

Oneok to lay NGL pipeline in Oklahoma, Texas

Oneok Partners LP plans to build a $260 million natural gas liquids pipeline from southern Oklahoma through the Barnett shale gas play in northern Texas and continuing on to the Texas Gulf Coast.

The proposed 440-mile Arbuckle Pipeline will originate in Stephens County, Okla., and be designed to initially transport 160,000 b/d of raw NGL for delivery into Mont Belvieu, Tex.

The line will interconnect with Oneok Partners' existing fractionation facility at Mont Belvieu and other Gulf Coast-area fractionators.

Following receipt of permits, construction of the 12-in. and 16-in. line is currently expected to be complete by early 2009.

Last year Oneok Partners proposed another NGL line, Overland Pass, which will be a 750-mile line extending from southwestern Wyoming to Conway, Kan. (OGJ Online, May 5, 2006). The $433 million project is a joint venture of units of Oneok and Williams Cos. Inc.

BG eyes Trinidad and Tobago LNG export train

BG Group has signed a memorandum of understanding with Trinidad and Tobago for a joint study to determine the feasibility for an additional LNG export train at the liquefaction plant at Point Fortin, Trinidad (OGJ, Feb. 19, 2007, Newsletter).

"We have an unrivalled ability to put together gas chains: working with the government, our [Trinidad & Tobago LNG] joint venture will open up new possibilities for the country's gas—and perhaps also Venezuelan gas—to reach markets," said BG Chairman Robert Wilson.

Wilson delivered the keynote address at a luncheon hosted by BG in Trinidad, where the entire BG Group board assembled to hold its first ever meeting outside London—"to understand the importance of [Trinidad and Tobago] in the global gas market and the part that we play here," said Wilson.

He also said BG has just concluded a heads of agreement with National Gas Co. of Trinidad & Tobago LLC to commit an additional 1.2 tcf of gas to the domestic market.

Wilson said BG is awaiting the result of its bid to develop shallow-water Block 2 in the North Coast Marine Area. The company declined to bid for deepwater acreage under current terms, but Wilson said he "believes that future investment will demand exploration of these areas" in order to meet the needs of new downstream industries.

GCLP selects operator for Calhoun LNG project

Gulf Coast LNG Partners LP (GCLP), Houston, has signed a memorandum of understanding for Port Lavaca LNG Services LLC to become operator of the Calhoun LNG terminal under development at Port Lavaca-Point Comfort in Calhoun County, Tex.

Port Lavaca LNG Services has also agreed to participate as an equity owner in the project.

Pending regulatory approvals, full operation of the terminal is scheduled for late 2009 to early 2010 (OGJ Online, Jan. 26, 2006).

Port Lavaca LNG is a consortium of Korea Gas Corp., LG International Corp., and EMS Group of Houston. ✦

Correction

Incorrect units of measure were given throughout a story about Indonesian gas production. All "MMscf" and "bcf" units should have been expressed in "MMscfd" and "bcfd" (OGJ, Mar. 12, 2007, Newsletter).

Calendar

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

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2007

APRIL

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

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

PIRA Natural Gas and LNG Markets Conference, Houston, 212-686-6808, 212-686-6628 (Fax), e-mail: sales@pira.com, website: www.pira.com. 2-3.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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), 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.

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Energy and venture capital

Paula Dittrick
Senior Staff Writer

As a business reporter covering the peak of the dot-com craze years ago, I wondered how start-up companies intent on making a fortune off the internet could attract millions of venture capital dollars while oil and gas companies could raise little, if any, VC financing.

Today, renewable and alternative energy is attracting VC dollars. US Energy Sec. Samuel W. Bodman acknowledged this during his February speech to a Cambridge Energy Research Associates conference in Houston.

"I can honestly say that for the first time in my life we are seeing the venture capital community put sizable amounts of money into energy," Bodman said. "This is real money. They are betting, if you will, that clean, safe, affordable energy represents the new innovation frontier." Formerly, Bodman worked for a VC firm before he was chief operating officer of Fidelity Investments.

VC contributions

The National Venture Capital Association is forming a committee of its members who invest in alternative energy. One committee goal will be to educate lawmakers about VC's contribution to energy-related innovations, a NVCA spokeswoman said.

Although representing a fraction of today's energy supply mix, renewable and alternative energy is generating growing revenues and attracting escalating investments, reports Clean Edge Inc., a research and consulting firm.

Clean Edge collaborated with Nth Power LLC, an energy technology VC firm, on Clean Edge's annual report "Clean Energy Trends." Both firms are in San Francisco.

The report shows US VC investments in energy technologies rose to $2.4 billion in 2006 from $917 million in 2005. Of total VC investments, energy tech increased to 9.4% in 2006 from 4.2% in 2005. Over the last 7 years, investments in energy technologies have increased from less than 1% of total VC investments to nearly 10% (see table).

US VENTURE CAPITAL ACTIVITY

	2004	2005	2006
		Million $	
Batteries	73	52	120
Biofuels	0.8	20.5	813
Energy intelligence	192	272	476
Fuel cells	131	86	175
Solar	68	156	264

Sources: Nth Power LLC and Clean Edge Inc.

Nth Power principal Rodrigo Prudencio said many VC funds have found ways to apply their skills and knowledge to energy-tech deals in solar and batteries "without straying too far from their IT and biotech roots."

"Biofuels, at $813 million, grabbed the lion's share of energy-tech dollars as investors clamored for an opportunity to play in ethanol and biodiesel against the rising price of petroleum-derived fuel," Prudencio said of 2006 investments. Solar attracted $264 million, and fuel cells raised $175 million. An energy-tech bubble is unlikely because investors appear to be realistic about valuations, Prudencio said. One "curious" trend last year was that VC firms invested $1 billion primarily for infrastructure plays associated with ethanol, biodiesel, and solar rather than for technology development, he said.

The Clean Edge report said global annual revenue for four benchmark technologies—solar photovoltaic (PV), wind power, biofuels, and fuel cells—"ramped up nearly 39% in 1 year—from $40 billion in 2005 to $55 billion in 2006. We forecast that they will continue on this trajectory to become a $226 billion [worldwide] market by 2016."

Clean Edge cofounder and principal Ron Pernick attributed annual revenue growth rates in these technologies to various factors, including growing concern about response to climate change. He said market growth for solar and wind has been "more akin to the computer, wireless, and internet than traditional energy sectors like coal, natural gas, oil, and nuclear."

Costs rising

Pernick noted increased production costs for some energy-tech elements. "Solar PV companies saw momentary increases in their prices as the high cost of silicon raised module pricing. And profit margins for ethanol in the US all but collapsed in 2006 as the price of corn nearly doubled in just 2 years."

This reporter sees numerous economic, regulatory, and technical challenges for renewable and alternative energy firms. To avoid the fate of defunct dot-com companies, energy-tech companies must hold their own in a competitive business environment worldwide amid evolving US and international government policies. It's a fascinating time to be covering the energy industry. ✦

Editorial

SUSTAINABLE ENERGY—1

The economic dimension

In discussions about world energy systems, sustainable development properly has become the central topic. While the subject is a vital concern, however, the phrase itself can mean nearly anything. Phrases that mean nearly anything too readily become tools of propaganda.

Well-meaning groups have defined "sustainable development" in many and mostly constructive ways. The classic statement came from former Norwegian Prime Minister Gro Harlem Brundtland, who said sustainable development "meets the needs of the present without compromising the ability of future generations to meet their own needs." Little improvement is needed.

'Not hydrocarbon'

Applied to energy, however, Brundtland's statement too readily comes to mean "not hydrocarbon." In popular judgment, an energy form is unsustainable if it comes from a depleting resource or alters the environment when produced or used, especially if it emits carbon dioxide. So if it's oil, gas, or coal, it's unsustainable. Anything else is sustainable and therefore preferable. This reasoning, motivated by a wholesome yearning for sustainability, explains the frantic political favor now bestowed around the world on renewable and other alternative energy forms. It also sometimes conflicts with good sense.

Both the lack of sustainability ascribed to fossil energy and the sustainability attributed to everything else tend to be exaggerated. The ambiguity allows propagandists to bend the concept to suit political and commercial agendas.

For example, hydrogen enthusiasts contrast the virtually limitless supply of their favorite energy carrier with the finite nature of fossil energy resources. Yet depletion isn't the only limit applicable to energy forms. Hydrogen itself has a daunting constraint: the need to detach it from other atoms and to use large amounts of energy to do the job. Similarly, the supply of plant wastes that might someday be feedstock for ethanol can seem limitless, too. But accumulating the material into concentrations useful for energy-intensive processing requires external work comparable to what nature already has performed for fossil energy. If fossil forms are unsustainable because they come from depleting resources, alternatives that require more energy to make usable than they yield are no less so.

Just as all energy forms have limits that in some way compromise sustainability, all energy sources affect the environment when produced and converted into work. The allure of hydrogen—to cite that example again—is that its combustion or use in a fuel cell yields only water. But the same can't be said of the energy required to liberate hydrogen from carbon or oxygen. And nearly every energy form that substitutes for CO_2-emitting fossil energy has oil, gas, or coal burning somewhere in its background.

Sustainability distortions typically fail to account fully for the economic imperatives of meeting current and future needs of people. A fuel cell that propels a passenger vehicle seems more sustainable than a gasoline engine when the analysis considers only vehicle emissions. But if hydrogen for the fuel cell costs more than gasoline and represents more energy used in processing than reaches the vehicle, the fuel cell is in no way sustainable. It can't compete. To be sustainable, an energy form has to be affordable to use and profitable to produce—preferably without subsidies, which are to sustainable energy what bribes are to responsive government.

Macro sustainability

Furthermore, the economic dimension of sustainability applies at the macro level. Developed economies usually pollute less overall than undeveloped ones do; economies that use fossil energy develop faster than those that do not. Ideas about sustainability must accommodate the proposition that people who drive to work in automobiles tend not to be people who must burn dung in their homes to cook and stay warm. Both economic systems pollute; the mobile one supports life better. Sustainable energy thus might be said to meet present needs efficiently while bequeathing future generations economic progress, social stability, and technical advance—everything any generation should need to solve its problems, environmental and otherwise.

Lately, the global energy system has taken some unsustainable turns, about which more will be written here next week. ✦

Oil and gas capital spending to rise in US, fall in Canada

Marilyn Radler
Senior Editor-Economics

Capital spending for oil and gas activities in the US will rise this year but at a slower rate than last year. In 2006, upstream spending surged as a result of increased activity and high costs as oil prices held firm.

Meanwhile, total capital spending in Canada will decline this year, but spending for oil sands development there will continue to climb.

Total capital expenditures for upstream and downstream oil and gas projects in the US during 2007 will be $183 billion, up from $176 billion last year. In 2005 spending totaled $135 billion.

In Canada, total capital spending will dip to $50 billion from $53 billion last year and $45 billion 2 years ago.

Upstream spending outside the US and Canada will also increase, but indications are that such expenditures will grow much more slowly than they did a year ago. Oil and gas activity in Asia remains heavy, with a wealth of upstream and downstream projects under way and planned.

OGJ's 2007 upstream spending forecast is based on estimates of drilling activity and costs, as well as what companies report for their upcoming budgets and past capital expenditures. Annual changes to downstream spending are determined by the capital budget plans reported by refiners, petrochemical plants, pipeline operators, and others, in addition to individual project announcements.

All amounts reported are in US dollars unless otherwise indicated.

US upstream spending

Upstream oil and gas expenditures in the US this year will climb nearly 4%. Total spending for exploration, drilling, and production activity will total almost $162 billion, OGJ forecasts.

The basis of this estimate is OGJ's drilling forecast, which projected that the total number of well completions in the US will be 47,003 this year (OGJ, Jan. 15, 2007, p. 31).

Outlays for drilling and exploration in the US this year will be $135.1 billion, compared with $130.5 billion last year and $96.7 billion in 2005.

Included in that total are geological and geophysical expenditures, which this year will amount to $12.6 billion.

Capital outlays for production also will climb 3.5% this year to $25.7 billion.

Companies collectively will spend less on bonus payments related to Outer Continental Shelf lease sales this year. OGJ forecasts that such payments will total $850 million, down from $914 million last year.

The US Minerals Management Service has scheduled three lease sales for 2007. One each is scheduled for tracts in the Western Gulf of Mexico, the Central Gulf of Mexico, and the Beaufort Sea.

During 2006, the MMS held two lease sales. The first one, for acreage in the Central Gulf of Mexico, resulted in $582 million in bonus payments. The other sale, for the Western Gulf of Mexico, produced $332 million in bonus payments.

The 2007 capital budgets of large integrated oil and gas companies based in the US show that much of these firms' upstream spending will occur outside the US. At the same time, most US-based independent producers will devote the majority of their expenditures to projects in the US.

Chevron Corp. has budgeted $19.6 billion for capital and exploratory expenditures during 2007, with $14.6 billion earmarked for upstream spending. The majority of this is likely to be spent on projects outside the US. During 2006, Chevron spent 68% of its upstream capital outlays on projects outside the US.

ExxonMobil Corp., which has announced a 2007 budget of $16 billion for worldwide upstream capital expenditures, last year spent just 15% of such outlays in the US.

In contrast, Marathon Oil Corp. announced that it has allocated the majority of its exploration and production (E&P) spending to projects in the US. With total upstream spending set at $2.23 billion this year, Marathon will spend 60% on US projects.

Meanwhile, large independent producer Anadarko Petroleum Corp. has budgeted $4 billion to this year's capital program and plans to spend 25% of it in the deepwater Gulf of Mexico and 28% in the Rocky Mountain area. The company plans to spend up to 16% of its budget outside the US.

Where funds will go for 2007 US projects

Table 1

	2007, million $	Change 2007–2006, %	2006, million $	Change 2006–2005, %	2005, million $
Exploration-production					
Drilling-exploration	135,135	3.5	130,520	34.9	96,733
Production	25,675	3.5	24,800	34.9	18,379
OCS lease bonus	850	–7.0	914	34.6	679
Subtotal	**161,660**	**3.5**	**156,234**	**34.9**	**115,791**
Other					
Refining	8,280	–8.0	9,000	25.0	7,200
Petrochemicals	840	7.7	780	7.6	725
Marketing	1,930	–3.5	2,000	5.3	1,900
Crude and products pipelines	970	498.8	162	–80.4	828
Natural gas pipelines	3,607	49.7	2,410	–31.5	3,517
Other transportation	970	14.1	850	11.8	760
Mining, other energy	1,000	0.0	1,000	0.0	1,000
Miscellaneous	4,100	10.8	3,700	12.1	3,300
Subtotal	**21,697**	**9.0**	**19,902**	**3.5**	**19,230**
Total	**183,357**	**4.1**	**176,136**	**30.5**	**135,021**

Processing expenditures

OGJ forecasts that capital spending in the US in all other oil and gas categories will grow 9% from last year. These categories include refining, petrochemicals, pipelines, LNG, corporate, and others.

Refining expenditures will decline following an upsurge during 2006. OGJ projects that capital spending at US refineries this year will decline to $8.3 billion from 2006 spending of $9 billion.

Last year, capital improvements at refineries to meet clean-fuels requirements caused a 25% surge in outlays. This year spending will shift toward expanding capacity at existing refineries. There still are no advanced plans to build a new refinery in the US.

Holly Corp. will expand the crude capacity at its Navajo refinery in New Mexico and at its Woods Cross refinery in Utah with revamps to existing units and new equipment.

And Marathon will increase the crude processing capacity at its Garyville, La., refinery by 180,000 b/d in a project expected to cost $3.2 billion.

Valero Energy Corp. has estimated its capital budget for 2007 at $3.5 billion, down from $3.73 billion last year. In 2005, the refiner's capital spending totaled $2.6 billion. This year's declines are due to a $775 million drop in clean-fuels and other regulatory outlays as its strategic and sustaining expenditures climb 25% from a year ago.

Other US outlays

Pipeline expenditures in the US will grow following last year's big decline. OGJ forecasts that spending for US natural gas lines will climb 50%. Meanwhile, outlays for crude and product lines will total $970 million, up from $162 million last year.

Plans call for a total of 2,050 miles of gas pipelines to be completed this year, mostly larger than 30 in. in diameter (OGJ, Feb. 19, 2007, p. 48). These projects are expected to cost $3.6 billion. In addition, plans call for the construction of 813 miles of crude and product lines in the US this year. The majority of these lines will be 12-20 in. in diameter.

Capital expenditures at petrochemical plants will total $840 million this year, up nearly 8%. In 2006, petrochemical spending in the US moved up at about the same rate, but the big growth area for petrochemicals is Asia, especially China.

Last year ExxonMobil increased its capital spending for US petrochemicals to $280 million from $243 million in 2005. Also last year, Chevron's petrochemical capital spending in the US climbed 35% to $146 million.

Huntsman Corp. plans to spend $40 million in the first half of this year on its US base chemicals and polymers business and will require additional outlays to repair its olefins plant in Port Arthur, Tex., which was damaged by a fire in April 2006. The total cost of the clean-up, engineering, and rebuild was estimated at $110 million.

Marketing expenditures in the US this year will decline 3.5%. Marathon and ConocoPhillips have announced plans to reduce these expenditures from a year ago, while Hess will leave such outlays unchanged. Hess plans to expand its retail network and add convenience stores to existing retail gasoline stations.

CANADIAN SPENDING PLANS* Table 2

	2007, million $	Change 2007–2006, %	2006, million $	Change 2006–2005, %	2005, million $
Exploration-production					
Drilling-exploration	23,500	–10.0	26,115	20.0	21,762
Production	9,750	–10.0	10,835	20.0	9,028
Subtotal	**33,250**	**–10.0**	**36,950**	**20.0**	**30,790**
Oil sands	12,000	9.1	11,000	22.2	9,000
Other					
Refining	3,050	–1.0	3,080	–2.2	3,150
Petrochemicals	300	11.1	270	–28.0	375
Marketing	585	–3.3	605	5.0	576
Crude and products pipelines	78	–84.7	510	–22.7	660
Natural gas pipelines	0	–100.0	20	—	0
Other transportation	250	4.2	240	9.1	220
Miscellaneous	550	7.8	510	6.3	480
Subtotal	**4,813**	**–8.1**	**5,235**	**–4.1**	**5,461**
Total	**50,063**	**–5.9**	**53,185**	**17.5**	**45,251**

*US dollars.

Miscellaneous expenditures, which include capital expenditures for LNG terminals, will climb this year to $4 billion. Four LNG terminals are currently under construction in the US. The total costs of these projects are reported to range from $400 million to $1 billion each.

Corporate costs and other nonpetroleum activities are also included in the miscellaneous category. OGJ forecasts that the total of these expenditures will increase more than 10% from last year.

Expenditures in Canada

Total oil and gas industry capital expenditures in Canada will decline 6% this year.

E&P spending will be down 10% as rising costs and a shortage of labor and equipment suppress activity. Allocations for spending in most upstream and downstream categories are lower from a year ago, but oil sands spending will continue to increase.

OGJ forecasts that exploration and drilling capital expenditures in Canada this year will be $23.5 billion. This compares to the all-time high of $26.1 billion last year and $21.8 billion spent 2 years ago. Production costs will decline at the same rate, totaling $9.75 billion this year.

In 2005 there were 26,951 well completions in Canada, according to the Canadian Association of Petroleum Producers (CAPP). Of this total, 59% were gas wells.

OGJ's most recent drilling forecast estimates that well completions in Canada during 2006 totaled 24,185. The forecast called for 22,233 well completions this year.

CAPP's latest figures also show that in 2005 capital expenditures for oil sands development in Canada totaled $10.4 billion (Can.). That was up 69% from a year earlier. These figures include capital expenditures for in situ developments, mining, and upgraders.

OGJ forecasts that capital spending for oil sands in Canada this year will rise to $12 billion from $11 billion last year.

Downstream capital expenditures in Canada will decline 8% from last year. Refining outlays are the largest component of this group but will be little changed from a year ago. Pipeline spending is the most flexible component in the group.

Canadian refinery outlays will decline 1% to $3.05 billion. Last year, such outlays were a bit lower than during 2005, when projects to meet clean-fuels regulations were gearing up.

One firm that has budgeted more money this year than last for capital spending at its refineries is Petro-Canada. The company has earmarked funds for a conversion of its Edmonton refinery and for engineering a coker at its Montreal refinery.

Pipeline spending in Canada will post the biggest decline of all expenditures this year, as plans call for little construction. OGJ forecasts that outlays for crude and products pipelines this year will be $78 million, down from $510 million last year and $660 million 2 years ago. No capital outlays are expected for gas pipelines in Canada this year.

Petrochemical capital expenditures will grow to $300 million from $270 million last year, mostly due to projects required to meet environmental regulations.

Nova Chemicals, for example, estimates that its 2007 environmental capital spending will be $32 million for pollution abatement and remedial programs. This is up from $8 million last year and $12 million in 2005.

Spending elsewhere

Capital spending outside the US and Canada will grow again this year, spurred by international oil companies and national oil companies ramping up production.

ConocoPhillips announced that its 2007 E&P capital program in Europe, Asia, Africa, and the Middle East will be about $4.9 billion. The company's projects in the North Sea include continued development of Britannia field in the UK and development of Alvheim and Statfjord fields, as well as ongoing development of existing and new opportunities in Norway's Ekofisk area.

In the Asia Pacific region, most of the funding will support ConocoPhillips's continued development of Bohai Bay in China, oil and gas reserves offshore in Block B and onshore South Sumatra in Indonesia, and fields off Malaysia and Vietnam.

ConocoPhillips also said its funding in Africa is primarily for the ongoing development of its Waha concession in Libya and several oil leases in Nigeria. And in the Middle East, the company will focus its spending on the Qatargas III LNG facility in Qatar.

Hess announced that of its $3.5 bil-

lion worldwide E&P capital budget this year, it will spend $650 million in Europe, $600 million in Africa, and $960 million in Asia and other areas. Most of the production expenditures will be directed to improve the performance of producing fields.

Investments at the company's Okume offshore oil development in Equatorial Guinea will primarily be focused on completion of production facilities and the drilling of 18 development wells.

The most recent E&P spending survey from Lehman Bros. indicates that 2007 upstream spending growth outside the US and Canada will slow to 13% from a 28% surge in 2006 (OGJ, Jan. 1, 2007, p. 25).

The survey revealed that companies greatly overspent their 2006 capital budgets, especially on projects outside North America. Lehman reported that 60% of the companies it surveyed spent more than 10% over their original E&P budgets last year.

Meanwhile, downstream activity remains elevated in Asia, Latin America, and the Middle East this year, according to OGJ's latest Worldwide Construction Update (OGJ, Nov. 20, 2006, p. 20).

The report details numerous refining, petrochemical, and LNG terminal projects under construction this year and planned for the next several years, with a flurry of activity in China, India, Qatar, and Saudi Arabia. ✦

Part 2: Relationships changing as NOC, IOC roles evolve

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International oil companies (IOCs) find themselves in new and complex relationships with their government-owned counterparts. As noted in the first part of this two-part series, national oil companies (NOCs) have gained regulatory and commercial influence from the combination of resource ownership and finances strengthened by elevated oil and gas prices. Many of them are using that influence to change terms of participation with IOCs and, in some cases, to become international competitors in their own right (OGJ, Mar. 26, 2007, p. 18).

This is part 2 of a two-part series.

Increasingly, IOCs work with NOCs as primary contractors on projects to provide technical and oil field management expertise as well as financing. They also compete with entrepreneurial NOCs—those that have been partly privatized and that, being run like commercial entities, have joined the global search for reserves and other assets.

In the future, IOCs and NOCs will collaborate and compete with each other on two fronts: The first is the international market, where NOCs can be competitors and sometimes collaborators with IOCs. The second is the country-specific market, where NOCs represent the state and where IOCs act more than before as contractors and partners and less as resource owners in developing host-country resources.

IOCs must plan for the unfair advantage NOCs receive from host-government backing. During the bidding war over Unocal, for instance, Chevron complained that China National Offshore Oil Corp. could offer more money because the Chinese government was helping finance the bid by providing low and no-interest loans.

There is no doubt that with NOCs controlling over three fourths of the word's oil and gas resources, markets will become more politicized. Oil markets have been politicized for a long time, but the actions of groups such as the Organization of Petroleum Exporting Countries are constrained by the demand for oil and long-term supply responses to price.

'IOCs may be expected to provide end-to-end service on oil field development.'

Recently, gas markets have become increasingly politicized in response to European concern over energy security due to curtailments in supplies from Russia that appear politically motivated. Venezuela clearly would like to use oil as a political weapon and has been courting allies throughout South America with varied success.

Some NOCs are also moving down the supply chain, expanding downstream into refining, distribution, and retail, particularly in Europe and the US, to secure markets for their oil and gas and to provide insulation from upstream price volatility. Cases in point are Gazprom's movement into European wholesale gas markets and the takeover of Getty service stations in the US by Lukoil. This provides greater competition to IOCs in traditional markets as they become increasingly squeezed in both production as well as downstream and in wholesale and retail markets.

IOC responses

IOCs are responding and adapting to the challenges laid down by NOCs in a number of ways. For example:

• IOCs are focusing exploration and production (E&P) activities in regions where they can operate outside NOC territory, such as the Gulf of Mexico, Australia, and in areas with favorable partners such as Africa.

• As their equity-share production declines, IOCs are changing their role from suppliers of energy to suppliers of technology. NOCs seek to collaborate with IOCs on projects that clearly need the IOCs' technological and financial expertise.

• IOCs will need to continuously develop upstream and downstream technologies to remain valuable to NOCs as partners or contractors.

'IOCs will adjust their focus, increase collaboration with NOCs, and move further into downstream activities.'

• IOCs will adjust their focus further down the supply chain and move more into downstream activities, building and expanding refineries and retail operations outside the US to capture wholesale and retail markets in Europe and Asia.

• IOCs will be involved in greater collaboration with NOCs and other commercial companies in downstream activities in order to increase global refinery capacity. This will reduce bottlenecks that have become apparent in some major consumer markets and are putting upward pressure on oil prices.

• IOCs will move from their traditional role as operators of oil and gas fields to oil-field managers and primary contractors for developing major projects. NOCs will tend to place greater reliance on IOC expertise in coordinating all aspects of complex project execution. IOCs may be expected to preselect traditional service companies, experts, local manpower, consultants, and miscellaneous service providers in order to provide end-to-end service on oil field development.

• IOCs and NOCs will have to work as partners in order to provide sustainable long-term development within the host country. This means IOCs will have to put much greater emphasis on understanding the long-term needs of NOCs. This may involve IOCs providing a supporting role for NOCs in maximizing the benefits for the country economy as well as optimizing resource development for the benefit of future generations.

Currently, IOCs' equity stakes and, by extension, reserves replacement are the primary bases for market evaluation. As IOC roles change in response to NOC changes, however, Wall Street likely will consider other yardsticks. They may, for example, focus less on short-term revenue maximization and more on value creation for NOCs, long-term sustained partnerships with NOCs, and new technology development. These factors may become more important indicators of future profitability and sustained revenue growth for IOCs.

NOC strategies

Working less as equity owners and operators and more as partners and technology providers, IOCs will find familiarity with NOCs' energy as well as economic needs increasingly important. Following are descriptions of the strategies of four of the most aggressive NOCs:

Gazprom

As the world's largest integrated natural gas producer, reserves holder, and exporter, Gazprom explores for, produces, transports, processes, and markets gas in the Russian Federation and is a product of the Soviet-era, state-owned company of the same name. Gazprom was privatized in the mid-1990s, but the Russian government is still the largest shareholder, with 38%. The company has over 103 tcf of proved gas reserves and access to almost 1,200 tcf of potential gas resources. It produces about 19 tcf/year, almost 86% of Russia's gas production and 20% of global gas production.

'Wall Street likely will consider yardsticks other than equity stakes and reserves replacement in determining IOCs' market value.'

Gazprom's goal is to complete its transformation from a Soviet-era gas monopoly to a world-class, international gas company able to compete globally. Its major goals are to:

• Develop new fields in Russia and Asia and new export routes to Europe and Asia via pipelines and LNG.

• Invest in downstream distribution, trading, and power assets in Europe and Asia.

• Realize greater value by raising gas prices to international norms.

Gazprom plans to improve production from existing fields and develop new fields on the Yamal Peninsula, on the shelf of the Arctic seas (Shtokman), and in East Siberia (Kovytka and Sakhalin-2).

Internationally, Gazprom is active in Central Asia, India, Vietnam, and Venezuela. The company also conducts European trading operations as a way to integrate its operations along the entire value chain. Gazprom has talked about entering the US market via LNG from Shtokman and Sakhalin-2. These plans appear to be on hold, given the slowdown in Shtokman development and the effort currently expended on selling Sakhalin LNG to China, Japan, and other Asian countries.

Central Asia is a point of major competition between Gazprom and IOCs over control of export routes. Gazprom's preference is to exert market control by shipping Central Asian gas through Russia. IOCs are backing alternative routes through the Caspian Sea area to Turkey.

Most of Gazprom's new developments must wait for major export pipelines or LNG facilities to be built, including:

• The Yamal-Europe gas pipeline, a 2,500-mile pipeline to Germany across Belarus and Poland, with a projected capacity of 1.2 tcf/year.

• The Nord Stream pipeline, [formerly called North-European Gas pipeline], a submerged pipeline that will cross the Baltic Sea from Vyborg to the German coast and possibly to the UK, with a projected capacity of 700 bcf-1 tcf/year.

• Central Asia–Center (CAC) gas transportation system delivering up to1.6 tcf/year from Central Asia to supplement Russian gas production in Russia, elsewhere in the Former Soviet Union, and China. This system was built during 1967-85 and needs upgrades. Gazprom currently is making direct investment in the system.

PDVSA

Petroleos de Venezuela SA (PDVSA) is the eighth largest oil producer in the world and is 100% owned by the Venezuelan government. It is also the third largest seller of crude and products to the US.

PDVSA is a classic state-owned oil company in the mold of Mexico's Petroleos Mexicanos (Pemex) in that it has a dual business and social role. Revenues from PDVSA's energy activities are reinvested in nonenergy sectors and in promoting Venezuelan government policy. Initiatives include construction of hydro and thermoelectric power plants, a new national airline, housing and infrastructure developments, agricultural development projects, education, and health care.

PDVSA also is making political rather than economic investments in the oil and gas infrastructure of Cuba. Consequently, like Pemex, PDVSA doesn't generate enough revenue to cover needed oil and gas activities as well as meet its other obligations, and it increasingly will become a finance and technology seeker.

PDVSA has large downstream investments overseas, including refineries and service stations that serve as outlets for its oil production. Major investments include:

• Citgo—the American refining and distribution company 100% owned by PDVSA.

• Ruhr Oel GMBH—in which PDVSA controls 50% in association with Deutsche BP AG.

• AB Nynas Petroleum—in which PDVSA and Neste Corp. of Finland hold equal interests. The company runs refineries in Sweden, Belgium, and the UK.

• Isla Refinery—a 335,000 b/d PDVSA-affiliated refinery 36 miles north of Venezuela in Curacao, part of the Netherlands Antilles. Isla processes PDVSA heavy crude and exports products to American, Central American, and Caribbean markets.

• Bahamas Oil Refining Co. International Ltd. (BORCO).

A major thrust of PDVSA investments over the next several years is its "Oil Sowing Plan." The plan includes six development projects and consists of two stages—one to be executed in 2005-12 and the other during 2012-30. PDVSA estimates an investment of $56 billion in the first phase, of which PDVSA will finance 70% and private investors, the balance.

PDVSA's Oil Sowing Plan 2005-12 includes:

• Development of heavy-oil reserves in the Orinoco Belt.

• The Delta-Caribbean project to develop gas reserves on the Deltana Platforma off eastern Venezuela and in the Paraguana Peninsula in the northwest area of the country. The Deltana Platforma development would be linked to PDVSA's joint venture with Petrobras to develop the Mariscal Sucre LNG export project.

• Increasing refining capacity to 700,000 b/d.

• Construction of domestic filling stations and oil and gas pipelines.

Venezuela's efforts to nationalize four heavy oil projects in the Orinoco basin will give PDVSA a majority stake in the projects, and IOCs will have to relinquish their stake or stay on as minority partners. At the present time, the terms of the takeovers are being negotiated, but it is doubtful that IOCs will obtain the full value of their investment so far.

Petrobras

Petroleo Brasileiro SA (Petrobras) is a publicly traded, integrated oil and gas company and a leading player in Latin America's oil and gas industry. The company was founded in 1953 as a government monopoly, although the government has since reduced its share of ownership to 32%. The Brazilian government is still the largest shareholder, and Petrobras continues to enjoy monopoly status in many aspects of Brazil's oil and gas industry.

This entrepreneurial NOC is expanding internationally through large exploration and development ventures in the Gulf of Mexico, West Africa, and Latin America. Petrobras has become a technology leader and provider in deepwater operations and directional drilling, which it has applied successfully off Brazil and is now deploying in deep waters of the Gulf of Mexico and off West Africa.

Petrobras's 2006-10 business plan allocates 87% of investment capital to the domestic market, including E&P ($28 billion); refining, processing, and retail ($12.9 billion); and gas pipelines and power generation.

'Analysts will place a premium on strategies for long-term sustained relations with NOCs.'

Active in South America's gas markets, Petrobras has new offshore finds and major investments in Bolivian and Argentine upstream gas assets and pipelines. Petrobras also has new upstream investments in most other Latin American countries, West Africa, Iran, and China.

In 2004, Petrobras acquired major deepwater exploration prospects in the Gulf of Mexico and has explored for deep gas in shallow water. In the gulf, Petrobras holds 36 million boe of reserves and produces 6,700 boe/d of oil and gas.

Earlier this year, Petrobras started production from its Cottonwood gas field in the Gulf of Mexico. Cottonwood represents Petrobras's largest producing field in the US and is its first operated Gulf of Mexico deepwater field to achieve production.

In West Africa, Petrobras has deepwater projects off Angola and Nigeria where it has teamed with IOCs such as ConocoPhillips and Shell. Petrobras also operates in deep waters off Libya where it was successful in the first round of bids held by the Libyan NOC.

Statoil

Partially privatized Statoil of Norway has interests around the globe as well as in the Norwegian North Sea. The company conducts exploration, production, transportation, refining, and marketing.

Its international E&P activities include operations in or off the coasts of Azerbaijan, Algeria, Venezuela, Western Europe, Angola, and Nigeria. Russian Gazprom has recently shown interest in working with Statoil in developing Shtokman gas and condensate field in the Barents Sea.

Statoil is considered a leader in arctic offshore operations, subsea production technology, and deepwater LNG facilities. It developed its LNG expertise in the North Sea and with the Snøhvit liquefaction plant.

Statoil has several key operational objectives:

- Maintain oil production at 1 million b/d from the Norwegian continental shelf beyond 2010 through improved recovery in existing fields and exploration in the northern Norwegian North Sea and in the Barents Sea.
- Build up an international portfolio of prospects and producing fields, which will help the company achieve a long-term production growth rate of 2-4%/year in 2007-10.
- Double sales of natural gas to Europe to around 1.8 tcf/year by 2015 through investments in new fields and infrastructure. Statoil expects to supply European gas markets from several sources, including the North Sea, North Africa, and the Caspian Sea. Statoil also expects to supply US markets from the new Snøhvit LNG terminal, providing LNG to the Cove Point terminal.
- Use its comparative advantage in the development of offshore technologies to develop new projects in deep waters and LNG. ✦

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BP, OSHA, API draw fire in hearing about refinery blast

Nick Snow
Washington Correspondent

Questions during a US House committee hearing about the fatal 2005 refinery explosion in Texas City, Tex., hinted at toughened plant inspections and an end to voluntary industry standards.

Members of the Education and Labor Committee criticized BP America Inc.'s failure to implement process safety procedures developed by the oil industry at the company's 446,500 b/cd Texas City refinery and the US Occupational Safety and Health Administration's enforcement of federal workplace safety laws. They also slapped American Petroleum Institute safety standards with which members can choose not to comply.

The Mar. 23, 2005, accident, involving C5-C6 isomerization unit, killed 15 workers and injured 180.

"The BP explosion was the biggest workplace disaster in 18 years, yet it received very little congressional scrutiny until today. Even more upsetting is that 2 years after this catastrophe, we're still seeing a disturbing pattern of major fires and explosions at US refineries," said Chairman George Miller (D-Calif.).

He said that over several months the committee will examine issues including "OSHA's failure to issue important standards to protect American workers, the Bush administration's transformation of OSHA from a law enforcement organization into a so-called 'voluntary compliance organization,'... the chronic under-reporting of workplace injuries and illnesses, and the agency's ineffective penalty structure."

Howard P. "Buck" McKeon (R-Calif.), the committee's senior minority member, said primary responsibility for the accident rests with BP. "The repeated accidents and number of citations at the Texas City facility should have alerted management to the potential for imminent danger," he said. BP "cannot be—and, indeed, has not been—given a pass for its failings," McKeon said, noting that the company will pay "the largest fine in OSHA's history."

Recurring problems

In its final report issued on Mar. 20 about the accident, the US Chemical Safety Board said many recurring safety problems previously identified in BP internal audits, reports, and investigations led to the accident (OGJ Online, Mar. 20, 2007).

The refinery is regulated under OSHA's Process Safety Management (PSM) standard, which was issued in 1992 as a result of chemical accident provisions included in the 1990 Clean Air Act amendments, CSB Chairwoman Carolyn W. Merritt told the committee. The accident likely would not have occurred if the standard, which requires covered facilities to implement 14 management elements to prevent catastrophic releases of hazardous substances, had been applied, she explained.

"Federal regulators did not conduct any comprehensive, planned process safety inspections at the Texas City refinery. In fact, our investigation found that in the 10 years from 1995 to 2005, federal OSHA only conducted nine such inspections anywhere in the country, and none in the refining sector," Merritt said.

Other witnesses included API Pres. Red Cavaney; Nuclear Safety Institute Pres. Frank "Skip" Bowman, who served on the independent panel chaired by former US Sec. of State James A. Baker III which BP assembled to investigate the fire and explosion; Kim Nibarger, health and safety specialist with the United Steelworkers of America; and Eva Rowe, whose parents died in the accident.

The panel did not include representatives of either BP or OSHA. Edwin D. Foulke Jr., assistant US labor secretary for OSHA, said in a statement on the day CSB issued its final report that it confirmed OSHA's findings.

The agency will conduct more than 100 refinery inspections this year and is implementing a national emphasis program "to ensure that every refinery under its jurisdiction is inspected and all employees are protected," Foulk said.

Plant safety under review

More than 2 years later, shock waves from the Mar. 23, 2005, blast and fire that killed 15 people and injured 180 at BP America's Texas City installation are increasingly being felt in plant safety. Everyone agrees that improvements are needed.

The most likely results include stronger enforcement of existing rules and enactment of additional regulations. Witnesses at the US House Education and Labor Committee's Mar. 22 hearing criticized the Occupational Safety and Health Administration for not conducting more planned process safety management (PSM) inspections at the Texas City refinery and other refineries and chemical plants. OSHA announced the same day that it is hiring more inspectors and doing more inspections.

Proper inspections take time and money. When the federal PSM standard was created in the 1990s, OSHA envisioned a highly technical, complex, and lengthy process called a program quality verification inspection for regulated facilities, according to US Chemical Safety Board Chairwoman Carolyn W. Merritt. "The inspections would take weeks or months at each facility and would be conducted by a select, well-trained, and experienced team. Indeed, thoroughly inspecting a 1,200-acre complex with 30 major process units, such as the Texas City refinery, is no small undertaking and requires at least that level of effort," she said.

Near misses

Several witnesses want more. Kim Nibarger, a health and safety specialist with United Steelworkers, estimated that 98% of all releases of hazardous substances, especially hydrocarbons, never result in ignition. "Any number of these releases, had they found an ignition source, could have resulted in consequences as tragic as Texas City," Nibarger said.

Such "near-misses" troubled committee members because they are not always formally reported. They may be discussed in oil industry forums such as the American Petroleum Institute's standards and practices committees. But the procedures that emerge are recommendations, not requirements. API Pres. Red Cavaney told the committee that the existing program works because it is voluntary.

Other initiatives

Cavaney said API is part of the OSHA Alliance, which has brought stakeholders together to examine process safety issues. He also said the industry will join the steelworkers union in studying worker fatigue, which CSB said contributed to the Texas City accident. "Safety is a continuous improvement process," he observed. Committee members want more enforcement. "A terrific case has been made this morning about why we need mandatory oversight from OSHA and how we should give it the necessary resources," said Rep. John P. Sarbanes (D-Md.).

President George W. Bush has requested from Congress an increase to $490.3 million for OSHA in fiscal 2008 from the agency's $472.4 million budget under the 2007 continuing resolution. The enforcement budget would increase to $183 million from $172.6 million. ✦

Infrequent inspections

But committee member Phil Hare (D-Ill.) said it was inexcusable that OSHA had not conducted frequent inspections at the Texas City refinery before the accident. "What is the problem? Does it have enough inspectors?" he asked Merritt. "The rule is there for inspections to be done," Merritt replied. "OSHA intended to do this every few months or years, but it was never able to implement its plan. We've found states and local governments, including Contra Costa County in California, that do a better job, including inspections every 3 years."

Cavaney said he agreed that more frequent inspections would be an improvement because situations at refineries and chemical plants change over time. He also said the US oil industry has an active program of 500 recommended standards and practices, including approximately 110 related to refinery process safety.

While these did not include recommendations for safe placement of contractors' trailers in a refinery before the fire and explosion at the Texas City refinery, API began to develop one as soon as this was identified as a major factor in the accident. The association expects to be ready to adopt the recommendation later this spring, Cavaney said.

'No teeth'

Other committee members and witnesses wondered if this voluntary approach is sufficient.

"I'm deeply disturbed that one of your members can decide not to implement your practices while still getting the benefit of being part of your organization with its high standards," said Rep. Carol Shea-Porter (D-NH). "Basically, your organization has no teeth."

Merritt observed, "The problem with voluntary programs is that not everybody volunteers." She noted that in its other investigations and examinations of refineries, CSB has found some that surpass API's standards, others that meet them, and others that ignore them.

Responding to an inquiry by Miller, Bowman said the Nuclear Safety Institute requires its members to follow standards or be expelled. The group adopted this policy following the 1979 incident at the Three Mile Island power plant in Pennsylvania. Bowman said the Baker report recommends that oil refiners implement a similar approach.

Refiners already are applying recommendations from the Baker and CSB investigations to their operations, according to Cavaney. He said API intends to work with the United Steelworkers to develop new refining workplace safety procedures as CSB has recommended.

But Rep. Rush D. Holt (D-NJ) was skeptical. He asked Cavaney if API would support increasing OSHA's staff, training, and general resources; making OSHA require reporting of close calls and warning events; requiring that injury reports be kept for each site, including for contractors and others involved in dangerous activities; implementing a process to review audits; and requiring OSHA to devote its resources to enforcement instead of voluntary programs and partnerships. Cavaney said he would supply answers as soon as he could get them.

Miller also was critical. "Companies can say they belong to an organization that's on the cutting edge of technology and safety but not follow its recommendations," he said. "I think we're reaching a point where API could become an enabler of very bad behavior." ✦

Consultant sees surplus of oil, gas workers in 5 years

Sam Fletcher
Senior Writer

Despite current emphasis on "talent gaps" within the petroleum industry due to the loss of experienced older workers, global labor trends indicate an adequate—or even excess—supply of entry-level workers over the next 5 years, said Bob Orr, Houston-based director of oil and gas consulting practice for Mercer Management Consulting Inc.

Energy companies participating in a recent survey by MMC said they anticipate shortages across all critical occupational groups. However, according to other sources uncovered by MMC, the entry rate of new workers in petroleum engineering and geoscientist occupations will just keep pace with retirement losses and increased demand for employees in those fields. On a global scale however, a large number of young workers will be entering the work force, creating a surplus of applicants with "at least entry-level skills and knowledge" for other jobs in the oil and gas industry.

"If you break it down by countries and geography, we see the sub-Sahara Africa region as having the greatest number of worker shortages. There clearly are some in the US, Canada, and the former Soviet Union, too. But we see a surplus of skilled workers in Asia and the Middle East," Orr said. "In some positions such as upstream technicians, if the current productivity levels continue to progress the way they are, we could see an excess supply of technicians within 5-7 years." There also "could be spot shortages in places, based on geographic factors," he said.

Enrollments in geological and petroleum engineering schools have been increasing "for the last year or so, even in US schools," Orr said. "Many schools have diligent programs to reposition petroleum engineering as an attractive career path. Whether they are at the level they need to be, whether all of those candidates matriculate and actually go into the oil and gas fields, remains to be seen."

Changing labor regulations in Europe will spark an increase in retirements over the next 5-10 years. Among firms surveyed by MMC, the service companies project the highest percentage of retirement losses, with 20% of that workforce due to retire over the next 10 years. "The ability to acquire significant wealth in recent years is leading many employees to take early retirement," the study reported.

"The problem is, a lot of entry-level talent is coming into the marketplace and a lot of very experienced talent is exiting the marketplace. So what we really have is an experience gap," Orr said. "It's really not an issue of numbers for numbers' sake. It's an issue of the quality of experience, which will continue to drive competition for experienced workers certainly over the next 5 years."

That means companies competing for those workers "need to be quite serious about their talent management strategies for both the retention of experienced workers and to make sure they're bringing in the best new entries into the system that they can—coaching them, training them, and bringing them along as fast as they can with the transfer of knowledge," said Orr. The most successful companies will be those with an integrated set of talent management strategies.

International workforce

Companies now gravitate towards internal solutions to regional talent shortages, but that approach may not be sustainable over the long term, Orr said. In the future, the petroleum industry's work force will be even more international. "There are a couple of reasons for that," Orr reported. "We're seeing more trained engineers, project managers, and other experts coming out of schools in countries outside the US, especially in Asia and in some cases the Middle East. Also, there is growing demand for them over there, and many companies try to build national work forces in countries they're working. While in the past there have been a lot of [western] expatriates, as we interviewed companies and talked about their strategies, what we heard more was very definitive plans and strategies to build those national workforces." US and European companies are recruiting experienced professionals from other parts of the world "because that is good for them in the work that they're doing in those countries but also because that's where some of the newer talent is coming from," he said.

"Good project mangers are the new rock stars of the industry," said David Hobbs, vice-president and managing director of global research at Cambridge Energy Research Associates, during the group's annual energy conference in Houston in early February.

At that same meeting, Farouk Al Zanki, chairman and managing director, Kuwait Oil Co. said his company plans to increase its oil production to 4 million b/d by 2020, which means finding new ways to develop relationships with international oil companies. He also emphasized the need for a highly skilled workforce; KOC expects to have 8,000 employees by 2015, up from 5,000 today.

MMC did an external labor market analysis of the current population of workers on a global basis to understand the trends for people entering engineering and other programs. The purpose is "to understand what the trends will be over time" compared with "companies' perceptions of where their own labor forces are going," Orr said.

The study found that employers need to be looking to provide more challenge to younger employees. Oil and gas companies are able to recruit new employees, although "they have to pay them a surfeit of money these days, but the real challenge is in holding onto experienced workers," said Orr. "So once folks have been there some years and salary levels tend to plateau, those workers are looking for more challenges in their careers. They want more responsibility. They want to move up to next level. And often when they are leaving one company for another, they're not leaving only for more money but for what they think is going to be a better opportunity."

To cope with such problems, companies are developing more structured career paths, especially for skilled workers or those approaching managerial levels. Under such systems, Orr said, "Workers can understand where they may go over a 15-year period, what kind of moves might they actually make over that time, so they continue to be excited and continue to see that company as a good place to stay."

He said, "It may sound intuitive, but I think that in the past only a few companies have done a really good job at that, with maybe the service companies doing a better job than some of the big oil companies."

When it comes to retaining experienced workers, Orr said, "I think there's a common perception that it is all about money. I think the reality is you have to be competitive [in pay], but what you also have to provide is the right culture, the right opportunity for growth over time, and the flexibil-

ity that allows for career advancement."

He said, "Money is not the driving interest, at least in the US. Now in Canada and its [developing] oil sands areas, I think that's a different story. I think people are putting themselves up for the highest price" to compensate for working in remote frontier areas with extreme climates. However, Orr said, "The story heard in the interviews we did was one of people switching [jobs] primarily to get more responsibility over time and shifting from places where their career paths might have been unclear.

Job remuneration is not going to be the only criteria, and new employees will look for a better lifestyle balance—"having the right geographic situation so they are not being sent overseas to inhospitable places for too long and maybe doing more of their work from Houston offices," even though the projects they are working may be in distant places.

Management strategies

Orr advocates three basic "buckets" of management strategies: The first is sourcing and recruiting of employees; the second, the development and management of workers; and the third, rewarding and retaining the firm's best producers.

The wrong strategy would be to focus "on one area as a silver bullet" to resolve the experience gap, Orr said. For instance, companies addressing retirement issues often put their emphasis on retaining older workers rather than rehiring them after retirement. The right approach, said Orr, is to determine first where a firm will have the greatest shortages and to refine and enhance its integrated strategies across all three key levels.

The first step is "getting the right recruits through the door," he said. "Am I going to the right schools to recruit? Do I have the right recruitment policy? Is it better than my competition's? What will convince the best people to come with me, other than money?"

Then, Orr said, "Once I have them in door, do I have the best training program, the best coaching and mentoring, the best career path opportunities for them? How do I put together the best performance management strategies in terms of supervision, in terms of leadership development, in terms of performance assessment, so they know where they stand, and we know where they stand, and we can manage those the right way and be very serious about it?"

On the "reward and retention side, compensation and incentives have got to be competitive, for sure," said Orr. "But also on the retention side, what other programs do I have? How am I managing and adapting my [corporate] culture to help with retention? How do I build flexibility into my system to do that? And what other talent management tools and strategies am I going to use to keep folks there? It's important to manage the full life-cycle of the workforce at each level across each position, as well as geography in a coordinated and rigorous way to insure that I'm going to have the right kind of experience when and where I need it. The solution is not to throw more money at people but maybe to put some investment dollars into talent management strategies," he said.

Many—"but not all"—of the leading companies now recognize this is no longer a human resources issue only, he said. "It is a senior management issue, an operational issue, and the general management strategies need to be linked across all the operational processes in a company," Orr said. "It makes sense, but when you get inside some of these companies, they're not managed that way." Too often recruitment and training are left to the human resources department.

"People are going to be more attracted to companies providing the best representation of what their future could look like—those companies that are really actively involved in recruiting and not just making spot appearances," Orr said.

An integrated application of all the strategies in advancing workers to their next levels "allows companies to do a better job of recruiting people, but also in keeping the people they have, keeping them happy and motivated relative to their competition," he said. That then translates into development of a corporate culture "that will be self-perpetuating, in people wanting to stay, wanting to excel, and wanting to push the company forward. Some companies are beginning to do this; others are just now starting to recognize this and to put some programs and priorities into place."

A number of companies are establishing training centers in countries where they want to build national workforces, establishing coordinated programs with local universities, and integrating that national workforce into the international company's broader workforce. What that may mean for those companies and their employees "is something that companies are just now starting to consider in their career paths. Do those national workforces just stay there [in their native countries]? Do they get integrated into the company over time? Do they become expatriates in other places?" Orr asked.

"I think the industry has a large opportunity to have a culture shift to allow it to be more successful on the people front. Industry has lot of smart people who recognize this as well but who need to focus their efforts and attention," he said. "There are a lot of dollars at stake, so it benefits companies to make sure their dollars are spent wisely by testing some of these things before committing those dollars to it."

It is not a simple matter of putting equal money into each "bucket," he said. "It's about setting priorities and dealing with them in order." Most companies have strength in some areas and should invest more in the areas where they are weak. Some employers have the perception "that it is all about the aging workforce," said Orr. Loss of workers through retirement is certainly an issue in the US. "But it is not a global issue," he said. "While we may expect to see larger experience gaps in the US, in places such as Asia, that is not the case."

More mergers and acquisitions are likely over the next few years. "But I think that has settled some," said Orr. "Related to that, one of the areas where companies probably are not doing as good today is effective integration of workforce planning with operation plans." He said, "A number of companies know what they want to do within the next year and have plans for that. But if you ask them where they are going to be 3-5 years from now in terms of the fields they are going to be operating in, they may have some ideas but they probably have not yet linked it back to the resources they need to do it, including the people."

Orr said, "Acquiring the people resources as well as rigs and other infrastructure becomes a longer planning horizon in terms of what companies need to do. That means they need better development of strategic planning capabilities and linking those to resource requirements and securing those requirements much earlier."

Performance simulation

Performance simulation "is one way to capture the loss of experience and transfer it to new employees," said Parrish K. Potts, a partner in Accenture, at the Cambridge Energy Research Associates annual energy conference in Houston in early February.

Performance simulation is similar to a flight simulator applied to business situations, enabling users to gain "job experience" in the same way that a flight simulator allows a pilot to gain "flight experience" on the ground that will improve his performance at the controls of a real airplane. Accenture's website quotes one satisfied client as saying, "Twenty-four hours on a performance simulator is equal to 4 years of job experience." Learners are challenged to achieve specific, real-world business objectives and master the fundamentals of general business skills or those unique to their business, said company officials.

It can teach sales staff the best practice behaviors for traditional and nontraditional interactions with customers that result in increased sales and sales conversion rates. It generally can improve the efficiency and effectiveness of customer service representatives, resulting in increased sales, reduced cost, and greater customer satisfaction. The company provides several ready-to-use simulations available in supply chain management, customer relationship management, leadership development, and other general business operations. ✦

Exhibition - EQUIPMENT SAVES LIVES

OSHA to train more refinery inspectors

Nick Snow
Washington Correspondent

The US Occupational Safety and Health Administration expects to have 280 staff members trained to conduct process safety management inspections by August, Assistant Labor Secretary for OSHA Edwin L. Foulke Jr. announced.

So far, the federal workplace safety agency has more than 160 employees who are qualified to conduct the inspections, Foulke said on Mar. 22. Adding inspectors will ensure that every refinery will be inspected under OSHA's new national emphasis program, he said.

His announcement came the same day that witnesses and members of the House Education and Labor Committee charged that OSHA failed to adequately inspect BP America Inc.'s Texas City, Tex., refinery for years prior to a Mar. 23, 2005, fire and explosion which killed 15 workers and injured 180 there.

In a final report on the accident that it issued on Mar. 20, the US Chemical Safety Board said that OSHA conducted only one planned PSM inspection at the refinery in 1998 despite numerous fatal incidents occurring there from 1985 to 2005. Other unplanned inspections, which typically are narrower in scope and shorter in duration than planned inspections, occurred in response to accidents, complaints, or referrals, CSB said.

It said that OSHA levied $270,255 in fines and collected a net $77,860 during the 20-year period in which 10 people were killed at the refinery preceding the accident. The agency fined BP more than $21 million on Sept. 22, 2005, for what CSB termed "more than 300 egregious and willful violations" at the plant. It was the largest penalty in OSHA's history.

CSB recommendations

CSB's final report on the Texas City fire and explosion called on OSHA to identify refineries and chemical plants at the greatest risk of a catastrophic accident and to conduct comprehensive inspections of those facilities. It also recommended that the US Department of Labor division hire or develop new, specialized inspectors and expand the PSM training curriculum at its national training institute.

"The refinery industry has been a major focus for OSHA, and the CSB report confirms we are on the right track," Foulke said on Mar. 22. "OSHA already has implemented two of CSB's three major recommendations and increased our inspections in the refining industry." The agency and its state partners conducted more than 100 refinery inspections during the 12 months ending Sept. 30, 2006, and already has conducted 50 more in fiscal 2007, he said.

Meanwhile, Texas state Sen. Mario V. Gallegos Jr. (R-Houston) and Rep. Craig Eiland (R-Austin) and representatives from the United Steelworkers Union and the AFL-CIO were scheduled to join Eva Rowe, whose parents died in the Texas City refinery's fire and explosion, and her attorney, Brent W. Coon, at a press conference in Austin on the Texas capitol's south steps on Mar. 23 to mark the accident's second anniversary and announce legislation which would:

- Ban trailers and other temporary buildings from refineries and chemical plants in the state.
- End the use of blowdown drums and other open-air release systems in Texas refineries.
- Involve state agencies directly in Texas petrochemical plant inspections.
- Ensure all employees and contract workers at Texas refineries and chemical plants are properly trained by requiring meaningful competency testing and certification for everyone working there. ✦

UK bill aims to lower carbon emissions

Uchenna Izundu
International Editor

David Miliband, the UK environmental secretary, has proposed legislation to enforce a 26-32% cut in carbon emissions by 2020 which could have significant implications for energy companies. The bill aims to slash emissions by 60% by 2050 and would create a legal framework for transition to a low-carbon economy.

In 2005, about 22.6 million tonnes of carbon emissions were produced from the UK continental shelf compared with 22.9 million tonnes in 2004.

Under the climate change bill, the UK would set legally binding 5-year "carbon budgets" to give businesses guidance on key targets and encourage investments in low-carbon technologies at least 15 years in advance. The first period would be in 2008-12.

The bill would require the government to inform on current and predicted impacts of climate change and on its proposals and policy for adapting to climate change and its progress in meeting the 5-year carbon budget and the 2020 and 2050 targets.

To achieve its targets, the government would receive guidance and expert advice from a new statutory body, the Committee on Climate Change. The bill would empower the government to drive through policies to reduce emissions.

The proposed bill would pose challenges for the industry because the UK North Sea is mature, and emissions could rise as companies use more energy to produce the remaining resources, which are estimated at 27 billion bbl.

"With climate change we can't just

close our eyes and cross our fingers," Miliband said. We need to step up our action to tackle it, building on our considerable progress so far. And time isn't on our side. Government must rightly lead from the front on this, but we want everyone—the public, industry, Parliament—to have their say to help us ensure that the bill really delivers."

A spokeswoman from the UK Offshore Operators' Association (UKOOA) said the industry was already moving to reduce emissions, particularly the growing switch from coal and oil to gas, which has helped the UK meet its Kyoto target.

"Despite an increase in energy demand of 10% over the last 15 years and a slight increase in CO_2 emissions since 2002, overall the UK has recorded a reduction in CO_2 emissions since 1990," she added.

Many oil companies are involved in the EU Emissions Trading Scheme. "Carbon capture and storage in a geological structure such as a suitable mature oil or gas reservoir under the North Sea is being promoted as a possible method of enabling low-carbon electricity production. This is emerging technology, and there are still not insignificant economic and operational hurdles to overcome," the UKOOA spokeswoman said.

Critics have scorned establishing another independent body to produce reports and monitor progress on reaching carbon targets, and it is unlikely that the government can get the bill through Parliament without changes.

Michael Woods, head of the environment group at Stephenson Harwood law firm, told OGJ that many more details were needed before businesses could plan their future operations with certainty. "It is important for business to engage and influence the outcome because they will be significantly affected."

Woods said one very contentious issue is whether the 5-year cycles to reduce emissions should be transformed into annual targets. "Under the bill, the emissions-trading element is set up with enabling powers, but it doesn't go into the nitty-gritty of the social and economic effects; it's one thing to target big polluters, but quite another to look at big businesses, retail, and the general public."

The government's public consultation period closes Jun. 12, but whether Parliament can enact the bill any time soon remains to be seen, as the ruling Labour Party faces difficult times ahead when its leader Tony Blair leaves later this year, opening the door to a possible leadership contest. ✦

Watching the World

Eric Watkins, Senior Correspondent

Archeology or oil?

We recently were talking with a Turkish friend who said intelligent oil people are not going to be fooled by the latest efforts of the Greeks. According to our friend, under the guise of conducting yet another archaeological investigation of Homer, their great epic poet, the Greeks have really authorized a search for oil.

The Turk was agitated last week when word broke of a geological engineering company agreeing to help in an archaeological project to find the island of Ithaca, which Homer's legendary hero Odysseus was supposed to have ruled.

Although the western Greek island of Ithaki is generally accepted as the Homeric site, scholars have long been troubled by a mismatch between its location and geography and those of the Ithaca described by Homer.

Seeking Ithaca

In fact, Robert Bittlestone, a management consultant, believes that the peninsula of Paliki on the Ionian island of Cephallonia, near Ithaki, is the real location of Odysseus' homeland. Bittlestone thinks that Paliki used to form a separate island before earthquakes and landslides filled in a narrow sea channel dividing it from Cephallonia.

To test Bittlestone's theory, engineers and geologists will examine rock where Bittlestone believes a narrow sea channel once existed.

Our Turk, though, said we need to consider a little more about Bittlestone and Odysseus Unbound, the book he has written with two other people. In our Turk's narrow-eyed view of the Greek enterprise, the evidence points to conspiracy.

Bittlestone was educated in classics and science before reading economics at the University of Cambridge. But he also is the founder of Metapraxis Ltd., a company specializing in the detection of early warnings for multinational companies.

Seeking signs

Our Turkish friend raised his eyebrows at that expression, "early warnings for multinational companies" and gave the nod-nod, wink-wink to let us know the signs the archaeologists are seeking: hydrocarbons under the Mediterranean.

As evidence of that, he said John Underhill, one of Bittlestone's coauthors, is chair of stratigraphy at the University of Edinburgh and associate professor in the department of petroleum engineering, Heriot-Watt University.

He then began to tell us how Fugro Group, along with Bittlestone and the Greek Geological Society, will use high-tech surveying equipment that might be used in oil-and-gas exploration for the Ithaca project.

Personally, I think our Turk was a little overexcited due to the issue of oil in waters off Cyprus, which Turkey disputes, where international oil companies are lining up for lucrative permits.

He also may have read that Mediterranean Oil & Gas PLC swung to a first half pretax profit and expects to spud its key Monte Gross and Ombrina Mare wells in 2007. Who knows what Homer found on Ithaca, wherever it may lie. But in the search for Ithaca, pace our Turk, should we worry if a lot of oil is found along the way? ✦

AGA: US gas reserves 205 tcf at yearend 2006

Nick Snow
Washington Correspondent

US natural gas reserves increased for the eighth consecutive year in 2006 as producers drilled a record 30,000 wells, the American Gas Association reported in its latest annual estimate of domestic supplies.

Reserves grew to more than 205 tcf at yearend 2006 from 204 tcf a year earlier, placing them at their highest point since 1978, according to AGA.

Its annual estimate is based on reported figures from a sample of 30 reserves holders representing more than half of the total US booked reserves and slightly less than half of all US production, AGA said. Noting that 2006's total US gas completions were a record last year, Chris McGill, AGA's managing director of policy analysis and the report's author, said most of the wells were drilled onshore in shales, tight sands, and coal seams.

"It takes many of these smaller wells to sustain production. Growing reserves inventories do not necessarily mean that domestic production capacity is dramatically increasing," he said.

AGA's latest analysis predicts that annual US gas production capacity will remain at 18-19 tcf for the foreseeable future without significant policy decision to open access to more potential gas resources.

McGill also said the "shelf life" of current US gas reserves has increased to an estimated 11 years in 2006 from about 9 years in 2001. He attributed this to a marked shift to lower-yield reservoirs such as shales and coal seams from traditional producing wells.

"The good news is that a solid productive capacity baseline is being established. The bad news is that it takes many more wells to sustain productive capacity as more traditional production is depleted," he pointed out. ✦

GIANT FIELD TRENDS—1

Giant field discovery patterns show gas bent, active decade

M.K. Horn
Independent Geologist
Tulsa

Giant fields (estimated ultimate recovery of 500 million bbl of oil and-or 3 tcf of gas or more) exist in every major region of the world, and have been discovered throughout the history of the petroleum industry (Figs. 1a to 1g).

The seven world regional maps represent 15 decades. The period extends from 19th century discoveries dependent on oil seeps and surface structures, drilled and produced with minimal technology; to 21st century discoveries dependent upon sophisticated geophysical tools and elegant geologic models and highly technical drilling and production techniques.

No better example of the application of modern production technology is found than at the largest oil discovery of the present decade: Kashagan field in the Caspian Sea off Kazakhstan,[1] presently being developed under harsh conditions of the environment, complicated by high concentrations of hydrogen sulfide.[2]

Kashagan is expected to recover 13 billion bbl of oil. To be developed in phases, its expected production steps are 75,000 b/d at first, gradually increasing to 450,000 b/d, and ultimately reaching 1.2 million b/d.

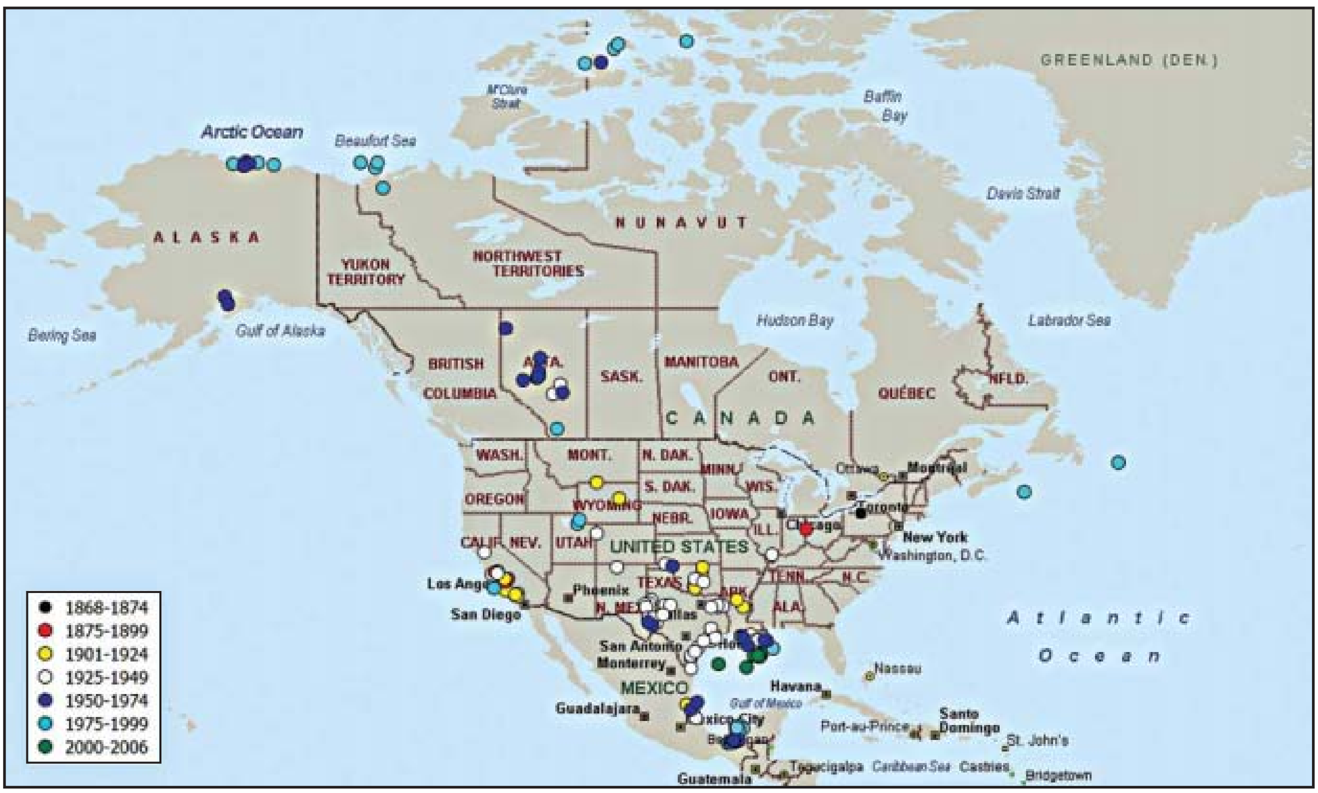
Of the 33 giant oil field discoveries in the decade that began with the year 2000 in addition to Kashagan, the following are the most important: Block 15 Complex, including Kizomba, Angola; Hosseinieh, Iran: combined fields of the deepwater Lower Tertiary (Walker Ridge) Trend, Gulf of Mexico, US; Kushk, Iran; and Southwest Bonga, Nigeria.

One of the largest giant gas discoveries this decade, Jansz field off Northwest Australia, illustrates application of modern day exploration techniques, in this case to detect stratigraphically trapped dry gas by targeting amplitude-supported seismic anomalies.[3]

Of the 39 giant gas field discoveries

NORTH AMERICAN GIANT FIELDS BY DISCOVERY YEAR QUARTILE

Fig. 1a



South American giant fields by discovery year quartile

Fig. 1b

West European giant fields by discovery year quartile

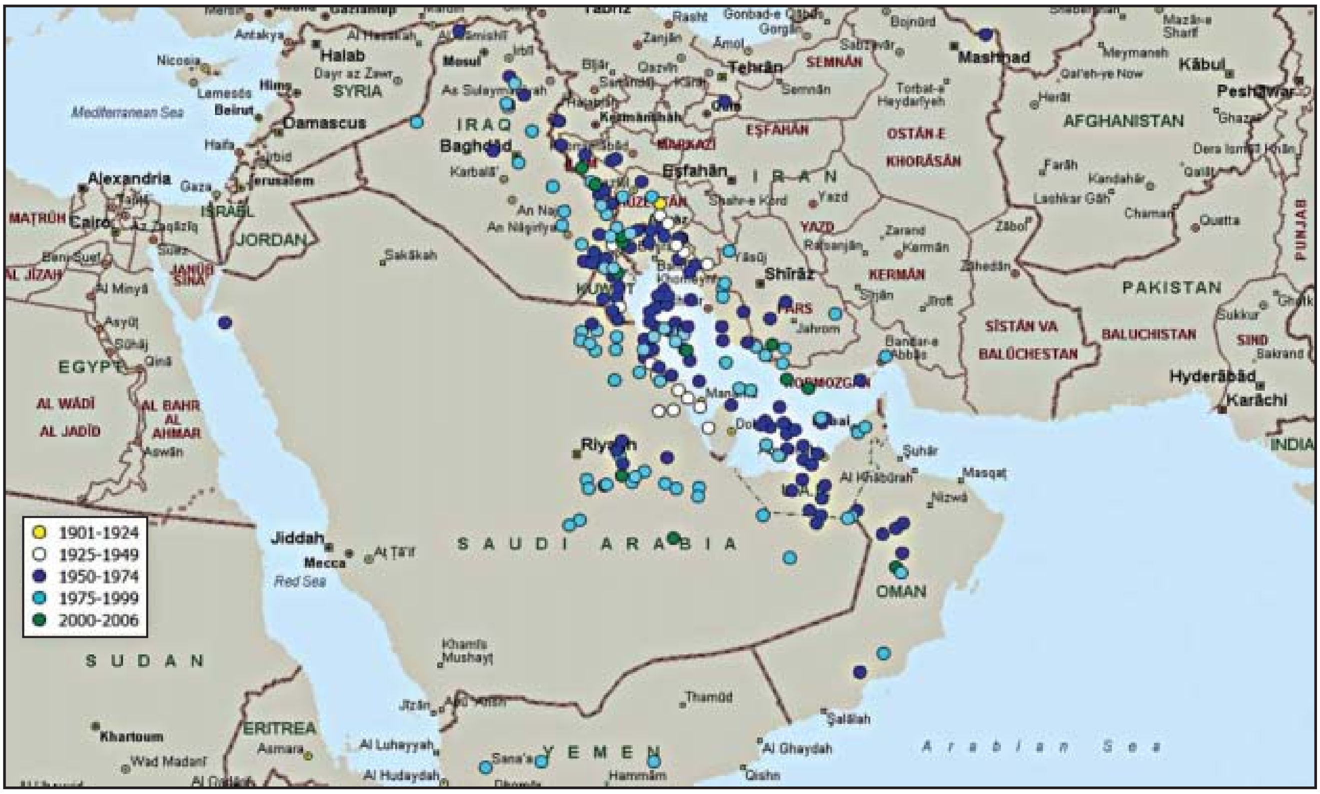
Fig. 1c

East European and former USSR giant fields by discovery year quartile

Fig. 1d

Middle East giant fields by discovery year quartile

Fig. 1e



this decade in addition to Jansz, the following are the most important: Kish and Lavan, both in Iran; Sulige, China; Karan, Saudi Arabia; and Mexilhao, Brazil.

Most of the 72 giant fields discovered this decade owe their status to the application of technologies that were not available in the early and middle history of the industry.

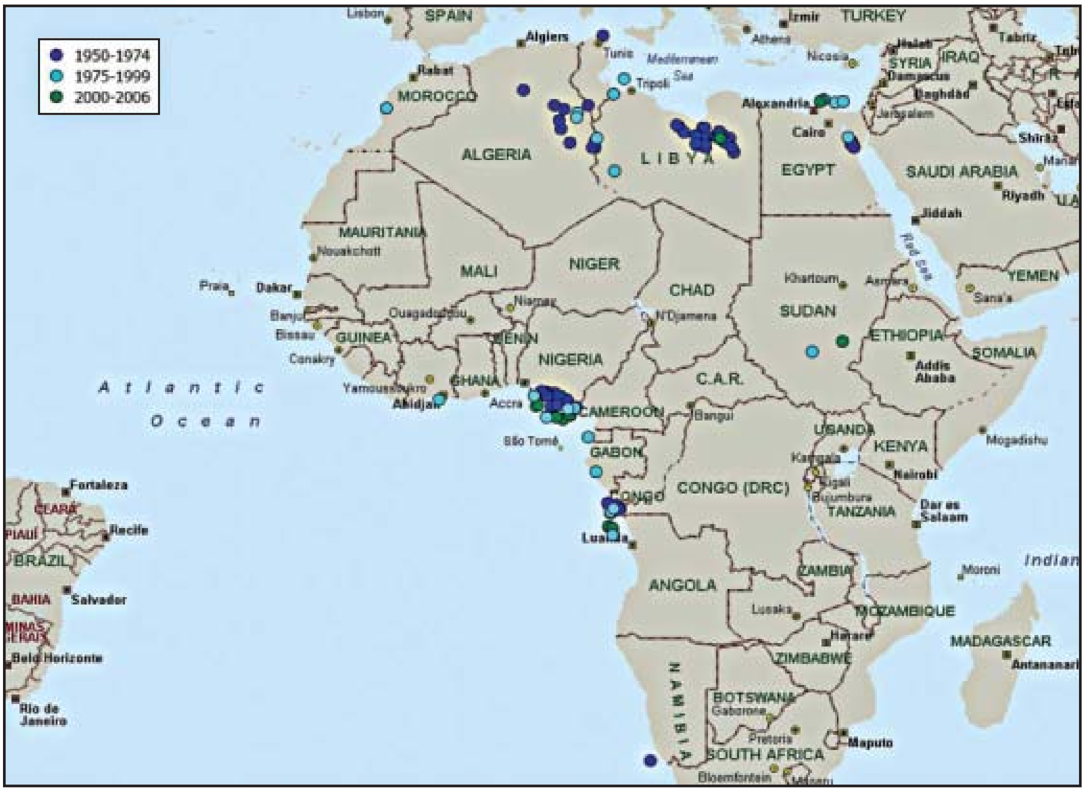
The objective of this study, which will be presented next week in the second and final part of this article, is to show in mostly graphical form the major patterns in decade-by-decade format of giant field discoveries, ultimate reserves, and average field size. Estimates of giant field percentage contribution to the global hydrocarbon inventory will also be presented.

The major source of data for this study is Horn[4] supplemented with additional information for the present decade.

Next: Giant fields are likely to supply more than 40% of the world's oil and gas. ✦

Africa giant fields by discovery year quartile

Fig. 1f



Asia and Oceania fields by discovery year quartile

Fig. 1g

Production

Multiphase flowmeter optimizes heavy oil production off Congo

Bruno Pinguet
Schumberger
Paris

Jean-Philippe Hussenet
Didier Bardin
Schlumberger
Pointe-Noire, Congo (Brazzaville)

Eric Blouin
Eric Faillenet
Perenco SA
Pointe-Noire, Congo (Brazzaville)

A multiphase meter used for testing wells producing heavy oil led to increased production and improved the understanding of reservoirs in the Yombo field, off Congo (Brazzaville).

A unit of Perenco SA operates the field that produces an average 17° gravity oil with a 2,200 cp viscosity at 80° F.

Well testing of heavy oil production is complex because most conventional surface testing equipment provides unreliable measurements. This unreliability derives from test-vessel instability (low GOR), foaming, or fluid separation problems.

Well tests in the off-Congo field before use of multiphase meters overestimated oil production by more than 25% even when total liquid flow rate was more or less acceptable.

Based on a presentation to PennWell's Multiphase Pumping & Technologies Conference and Exhibition, Abu Dhabi, Feb. 11-13, 2007.

Perenco operations

Off Congo, Perenco operates Yombo and Emeraude fields (Fig. 1). Yombo fields has a relative simple anticlinal dome structure with little faulting. Halokinetic movement of underlying salt created the structures.

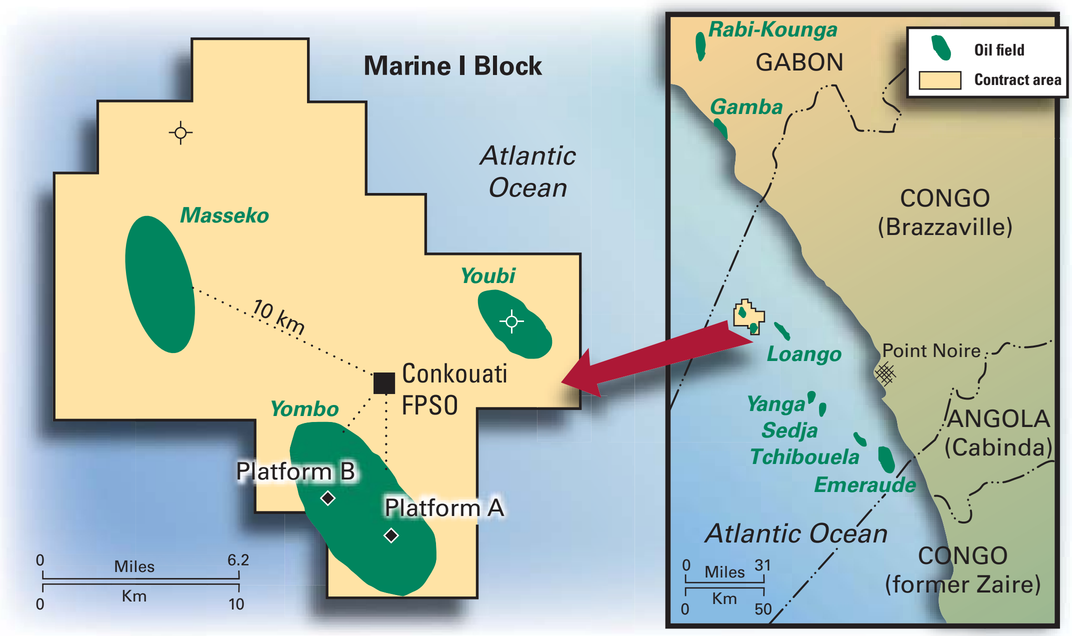
The Sendji carbonate is the primary reservoir. This reservoir is heterogeneous with very variable permeability. The variability creates uncertainties in predicting the performance of this single layer reservoir that is predominantly sandy dolomite with sand interbeds. The reservoir has good 20-25% porosity and permeability up to 3,000 md, but the low reservoir pressure makes production difficult.

Another secondary reservoir is the Tchala sandstone, composed predominantly of dolomitic sands with 25-30% porosity and permeabilities up to 2,000 md. The Tchala has multiple layers in which Perenco has identified all oil-water contacts.

The Yombo field, discovered in 1989, began producing in 1991. Perenco acquired the field in 2003 and began producing it from two platforms tied to a floating production, storage, and offloading (FPSO) vessel (Fig. 2).

PERENCO FIELDS OFF CONGO

Fig. 1



The field produces 16-31° gravity oil with 100-200 cp viscosity at 130° F. reservoir temperature. Surface oil viscosity is about 2,200 cp at 80° F., with liquid viscosity being more than 5,500 cp at surface conditions even with a very high water cut.

Conventional equipment

Production from the fields during the last 4 years has decreased by more than 35% to the current 10,000 bo/d, while bs&w increased to 80% from 70% (Fig. 3).

Perenco, therefore, needed a strategy to monitor the wells in real time and decrease the rapid oil production decline, which was assumed to be caused by numerous electric submersible pump (ESP) failures, bs&w increases, difficulty in managing the reservoir due to tight emulsions, impossibility of monitoring well performance with a test separator, problems with test repeatability, and large flow fluctuations in some wells.

The company first tried conventional periodic testing of the wells, but this showed large variations between real production and well tests of up to 25% (Fig. 4).

The centrifuge-measured bs&w from the separator was much less than the actual value. A mass balance indicated that the bs&w should be about 83% instead of the 75% obtained with the centrifuge. Bs&w measurements were also not repeatable, with some various between two measurements greater than 25%.

Because of the inconsistent data, Perenco could not fine tune production parameters for each well. It was impossible to select the best size of ESP for each well. This led to oversizing the pumps and higher electrical consumption. Overall it was impossible to optimize consistently the production on a well-to-well basis. Perenco had to find an innovative solution for this high viscosity, high-emulsion production.

Three possible solutions could handle this problem:

1. Install a gauge tank. This requires space that was already a constraint on these platforms. Also rapid flow rate variation from the different producers would remain. And this option would require a desmulsifier to break the emulsion and work to get the best retention time.

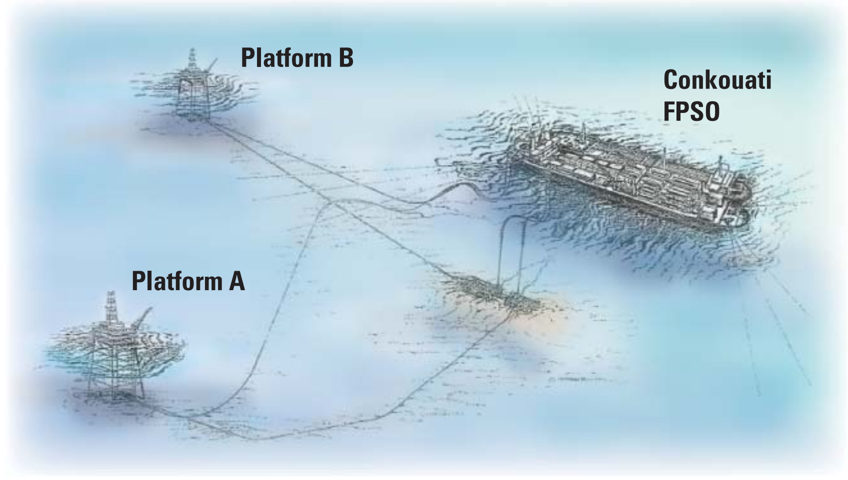
2. Install a static mixer on the separator liquid line with an automatic sampler. This will increase the emulsion, but production fluctuating (bs&w) would remain a main concern. Moreover, this would increase moving parts, leading to problems with accuracy and maintenance. And this option would not obtain the high accuracy needed on long-term tests.

3. Install a multiphase flowmeter capable of handling heavy and viscous oil. This option eliminated the need for flow stabilization and separation. The meter eliminates phase dispersion, which means that flow would remain in a continuous oil or water phase and allow accurate measurements of water/liquid ratios (WLRs) or bs&w. The meter also provides for proper real-time monitoring.

Other benefits include accurate and

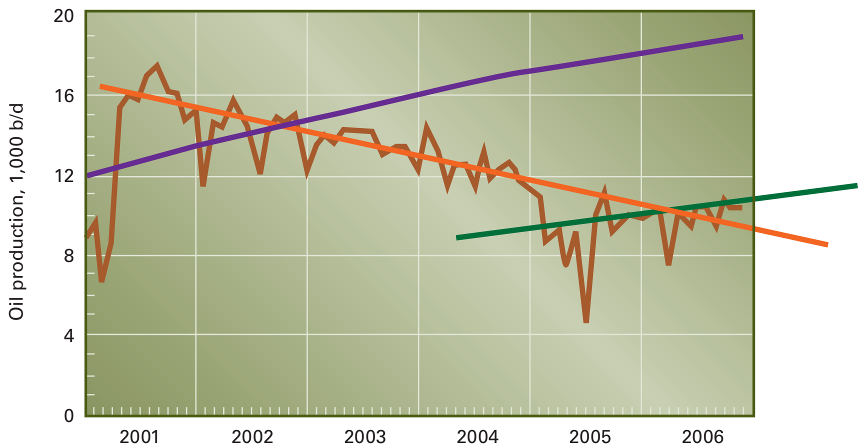
Yombo field development

Fig. 2



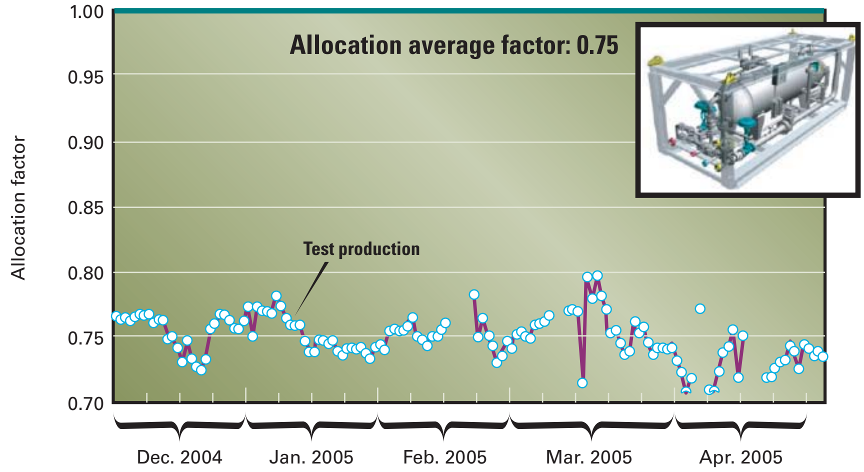
Production decline

Fig. 3



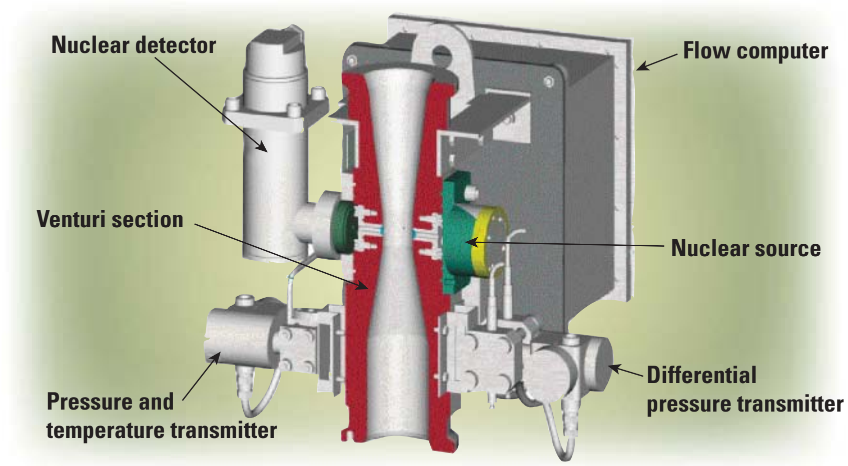
CONVENTIONAL EQUIPMENT PERFORMANCE

Fig. 4



PHASEWATCHER VX

Fig. 5



repeatable flow measurement, shorter well stabilization (more tests per day), high resolution to detect small flow events, and reduced pressure drop (test at producing conditions).

It also was possible to test technology with the Schlumberger's PhaseTester Vx (periodic unit) before purchasing the permanent multiphase flowmeter called PhaseWatcher Vx.

Vx technology

Schlumberger's Vx meter measures the total mass or total volumetric flow rates and then the oil, water, and gas flow rates of a producing well at line conditions (Fig. 5). Pressure-volume-temperature (PVT) software then converts these line-condition measurements to standard conditions.

The meter has four simple sensors:

1. A sensor measures the differential pressure between the inlet and throat of the Venturi. This measurement provides the total mass flow rate, Q, and the total volumetric flow rate, q.

2. A nuclear dual energy fraction meter measures the count rate of gamma ray transmitted from source to detector at two different photon energies. The nuclear gamma-ray fraction meter obtains the fraction of each constituent in the flow based on knowledge of each phase's constituents (density and mass attenuation). This allows calculation of mixture density (the density of the three phases flowing in the main pipe).

3. The process-fluid pressure sensor measures the line pressure at the Venturi throat.

4. The process-fluid temperature sensor measures the fluid temperature upstream of the Venturi section, including an ambient temperature TAMB, for increased safety.

The Vx technology is based on the

PRODUCTION TESTS

Table 1

		Multiphase meter					Separator			Change			
Well No.	Duration, hr:min	bo/d	b/d fluid	%bs&w	GOR	Sample %bs&w	bo/d	b/d fluid	%bs&w	bo/d	b/d fluid	%bs&w	meter/separator, %
1	4:20	484	2,467	80.4	24	84.3	494	2,508	80.3	–10	–41	3.9	0.1
1	0:54	547	2,595	78.9	24.2	81.1	487	2,508	80.6	60	87	2.2	–1.7
2	12:31	288	3,736	92.3	107.9	94.4	385	4,010	90.4	–97	–274	2.1	1.9
2	11:06	289	3,623	92	104.6	94.3	270	3,910	93.1	19	–287	2.3	–1.1
4	11:27	698	4,102	83	117	82	895	4,261	79	–197	–159	–1	4
4	7:13	808	4,310	81.3	118.9	82.5	930	4,516	79.4	–122	–206	1.2	1.9
4	3:17	504	3,498	85.6	118.9	86.9	581	3,522	83.5	–77	–24	1.3	2.1
4	3:52	571	3,860	85.2	124.7	85	600	3,920	84.7	–29	–60	–0.02	0.5
4	13:16	784	4,304	18.8	125.1	85	667	4,600	85.5	117	–296	3.2	–3.7
Total		**4,628**	**10,821**	**88.7**	**56.0**	**88.4**	**6,213**	**42,156**	**85.3**	**–1,585**	**–1,335**	**–0.3**	**3.4**

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following premises:

• No slippage inside the liquid phase.

• An empirical approach of the gas-liquid slippage law based on experiments conducted at low pressures (2-30 bara) with immiscible fluid.[1-3]

• A shape factor model for multiphase flows.

The primary outputs are at line conditions. Direct outputs of the combination nuclear and Venturi measurements are gas fraction (GF) or gas holdup, WLR, total mass flow rate, and the mixture density.

Secondary outputs from the meter are gas volume fraction (GVF) and volumetric flow rates (oil, water, and gas) at line conditions. The combination of the previous primary outputs is the basis for these calculations.

Volumetric flow rates at standard conditions are the most valuable outputs. A PVT software package computes these from flow rates at line conditions.

Perenco installed permanent PhaseWatcher Vx29 multiphase meters on the Yombo platforms (Fig. 6).

Trial test

Perenco tested the meter first on only one platform and used the portable PhaseTester Vx instead of the permanently installed PhaseWatcher (Fig. 6).

Perenco's main aim was to control water production because the FPSO has limited water-handling capabilities. Total liquid production accuracy was also important for selecting the best producing wells and having a good allocation factor for the total production measured on the FPSO. These two values need to be very accurate for calculating net oil.

Table 1 shows the test results, which had an absolute error for bs&w of better than 0.5% between the manual measurements done as recommended by Schlumberger against the Vx measurements.

The test also confirmed that previous tests on the platform and bs&w sampling techniques were invalid. These measurements had errors of 3-5%. The Vx total liquid flow rate had better than 3% relative error.

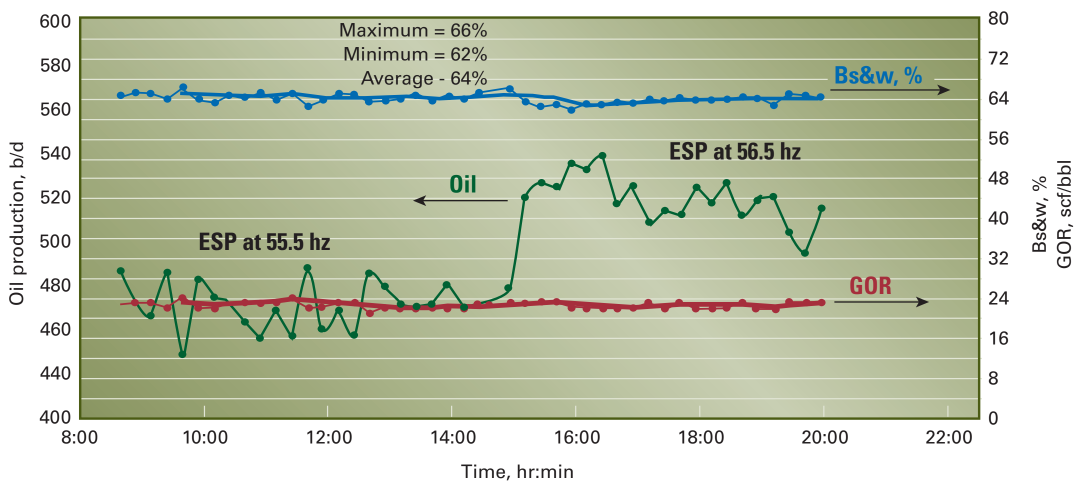
Finally, cumulative oil flow rate on the platform was representative of that measured at the FPSO.

For a gassy well with a high GOR, the gas-flow rate measurement was more realistic with actual production. For a low GOR well, it was usually impossible to measure gas flow rate at the separator.

Overall performance of the meter was very good. Tests were repeatable and reproducible. During the 13-day

Yombo well A5 ESP frequency change

Fig. 7



trial, Perenco was able to get more than 3.7 tests/day with the longest lasting more than 14 hr and the shortest lasting less than 10 min. This demonstrated the meter's repeatability and the fact that the meter needed no stabilization.

Real-time production

In the field, Perenco wanted to increase oil production without increasing water production because of processing constraints on the FPSO.

Real time production data allowed Perenco to do quicker intervention in some wells for changing the ESP and upsizing the equipment. In Well A8, an upsized pump increased production by more than 350 b/d and also lowered water production.

Perenco also observed increased production in other wells that produced several zones with one tubing string. Because the zones had different permeabilities and fluid mobility, the upsized ESP decreased the pump-intake pressure. This allowed for better oil recovery from some zones, thereby reducing WLR.

Changing pump frequency was another way for adjusting ESP pump intake pressure.

Because of complex reservoir lithology with many layers, some wells produced more oil and less water with reduced pump intake pressure, while others produced less oil and more water. To find the optimum intake pressure, each well was tested at different pump intake pressures, starting with a low frequency and increasing it gradually, while the meter recorded liquid and oil flow rates continuously.

The optimum point occurred when liquid flow rate is the lowest possible for the highest oil flow rate.

Changing the pump to a larger or smaller one improved production. In one well, a production pump change increased oil production to 850 b/d from 500 b/d.

Also changes in pump frequency by only 1 hz, based on physical measurement, from the Vx meter led to improved production (Fig. 7).

Some wells had an outstanding gain in production after adjustments. For instance, before adjustment, Well B1 produced more than 3,000 b/d with nearly 99% bs&w, suggesting water invasion from one layer. With this amount of water, the well was uneconomic and would have been shut down except for test data from another well.

In July 2006, an increase in pump frequency to 60 hz from 45 hz led to Well B1 increasing total production. Oil production increased nearly 500 b/d from less than 60 b/d before. The bs&w also decreased to 90% from the previous 99%.

Currently the well produces 3,300 b/d of liquid with about 88% bs&w.

Based on this success, changes in several other wells increased oil production to 338 b/d from 98 b/d with bs&w decreasing to 86% from 95%.

Real-time data also helped determine if the wells needed to be choked down to avoid slugging and improve flow rates. Reduced slugging would increase ESP life by avoiding large fluctuations on the motor.

Allocation factor

One key to optimizing the wells is monitoring of the allocation factor. Before installation of the multiphase meter, an allocation factor of 0.75 was needed to account for the 2,700 bo/d difference in test separator measurements on wells in the Yombo field and measurements on the FPSO.

The discrepancy with the multiphase meter is now less than 300 bo/d and the overall allocation factor is better than 0.97.

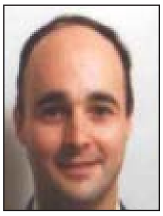
Improved production

Fig. 3 shows that production declined during 2001-04 to about 9,000 bo/d. With installation of multiphase meters, adjustments of the ESPs, and shut in of some high-water-cut wells, production has improved during the last 16 months and is currently almost 10,500 bo/d.

This increase translates into an additional $90,000/day in earnings, indicating that the cost of installing several multiphase flowmeters on both platforms was paid out in a few days.

The meters provide bs&w and net oil accuracies better than 1% (abso-

The authors



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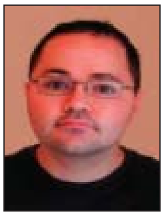

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lute error) compared with the 25% with the conventional test separator. The bs&w is measured every 10 sec compared with the hourly readings previously taken.

With the meters, tests on a well are close to production conditions, with pressure drop through the meter much less than through a test separator.

Acknowledgments

The authors thank the various teams involved in the data acquisition and both companies for their permission to publish this article. ✦

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KAZAKHSTAN

Fig. 1

Petro Kazakhstan improves processes for 2006 hydraulic fracture campaign

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Drilling

Petro Kazakhstan Kumkol Resources (PKKR) has increased oil production in five Kazakhstan fields through a hydraulic fracturing program. The wells had not been fractured when initially brought on line.

Evaluation of current fractured wells, the candidate selection process, and postfracture completion practices are believed by PKKR and Halliburton to be keys in achieving the sought-after result of significant oil-production increases. PKKR used hydraulic fracture stimulation in five fields, all located just north of the city Kzyl Orda (Fig. 1). Production from the Mayburak field rose 100% immediately afterward (Fig. 2).

This article presents the methodology followed by PKKR and Halliburton to evaluate, select, and prioritize fracture-candidate wells for the PKKR 2006 fracture campaign.

As of February 2007, PKKR had drilled and completed 591 wells in five Kazahkstan fields that it manages (Kumkol South, South Kumkol, Kyzykiva, Aryskum, and Maybulak), including 74 wells in the past year. The company fracture stimulated 92 of the wells as part of the initial completion process. Of the remaining wells, PKKR selected and fracture stimulated 52 wells (45 producers, 7 injectors) during its 2006 campaign.

Candidate selection

The following steps guided selection of wells for fracture stimulation:

1. Before expending resources selecting individual wells for hydraulic fracturing, first determine the potential of the field to yield an adequate return on investment (ROI).

- Calculate the current, radial, and fractured-well productivity index (PI). The PI is the ratio of liquid production rate to the pressure drop at the center of the completed interval.

PI is a measure of the well's potential and can be extrapolated to estimate field potential. Conditions such as relative permeability, skin factor, reservoir pressure, and oil viscosity can change throughout well or reservoir life, and can change PI.[1]

- Establish cutoff criteria for minimum oil-production increase and water cut.
- Review nearby wells using well and reservoir analysis software, bubble map, and injection-well locations.
- Review nearby wells using Halliburton's OFM well and reservoir analysis software, bubble map, injection-well locations.

2. Analyze production data from current wells and determine current PI, then estimate postfrac PI.

- Review current production data,

taking note of liquid rate and water cut for the past 2-3 months.

• Obtain current reservoir pressure from each well, from pressure build up if available, and from fluid dynamic level, from nodal analysis on flowing well, or with direct measurement.

• Estimate current prefrac PI from liquid rate, reservoir pressure, and bottomhole flowing pressure (BHFP).

• Calculate the postfrac PI. The prefrac PI can be influenced by well damage, but this is not accounted for in hydraulic-fracture candidate selection. If the well is damaged, the actual incremental increase will be higher than estimated, with the frac treatment more economically attractive.

Preselection criteria

Hydraulic-fracture candidate selection should include only wells that have not been fractured and wells with less than 35% water cut. Other considerations include:

• Completion history.

• Workover history.

• Water-oil contact (WOC), gas/oil ratio (GOR), and bubble point (Pb). If GOR is high and Pb is lower, the well could produce primarily gas and create gas coning.

• Well location (close to WOC, gas-oil contact, end of reservoir, etc.).

• Pressure maintenance.

• Wellbore deviation and azimuth.

• Fracture plane.

• Injector-well locations.

• Oil viscosity. High oil viscosity may cause more drawdown and sand production after frac.

• Location of faults, natural fissures, or fractures, etc.

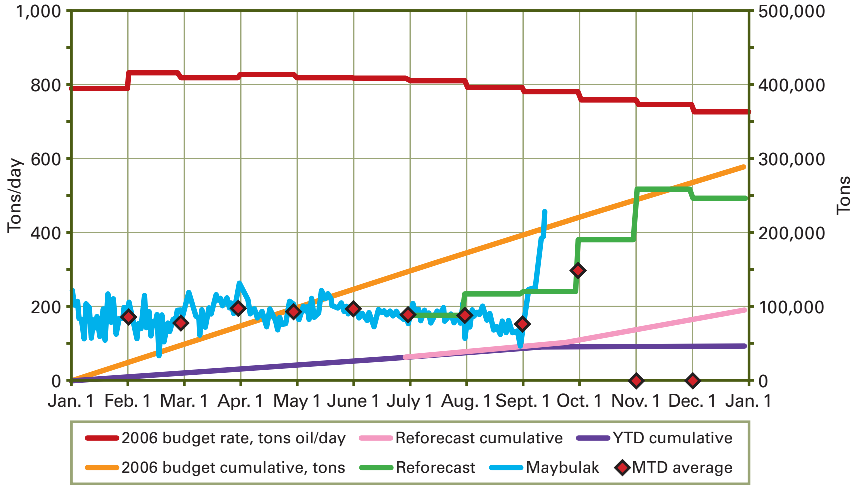
Note that if a well is completed in multiple zones or has poor cement bonding across a zone suspected of being water-productive, a workover, including zonal isolation or repair, can possibly allow for an efficient frac in an oil-bearing formation.

Next, calculate the increment increase of oil keeping the water cut value identical to the pre-frac value. (Water cut will normally be higher during the cleanup phase due to losses during workover.)

Finally, sort the wells in order of decreasing tons of incremental oil calculated.

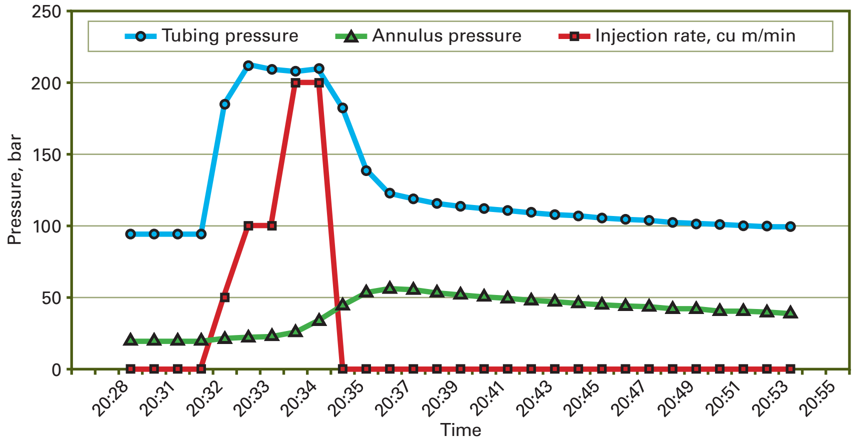
PRODUCTION INCREASES, MAYBULAK FIELD

Fig. 2



MICROFRAC INJECTION TEST*

Fig. 3



*Used to establish the fracture closure pressure gradient in one of the PKKR fields. The value is still in use to define the shale stress for the wells of the field.

Evaluating logs, maps

Use logs and field maps to evaluate the following information:

Log review of mechanical well condition:

• Verify operator knowledge of hardware weaknesses that could affect pressure application, such as wellhead limitations, casing leaks, casing weakness, and improperly functioning packers.

• Verify location of perforated intervals and distance between intervals.

• Determine presence of water zones or flooded zones near the targeted frac interval.

• Determine condition of cement to sustain fracture operations.

Review offset wells with field map:

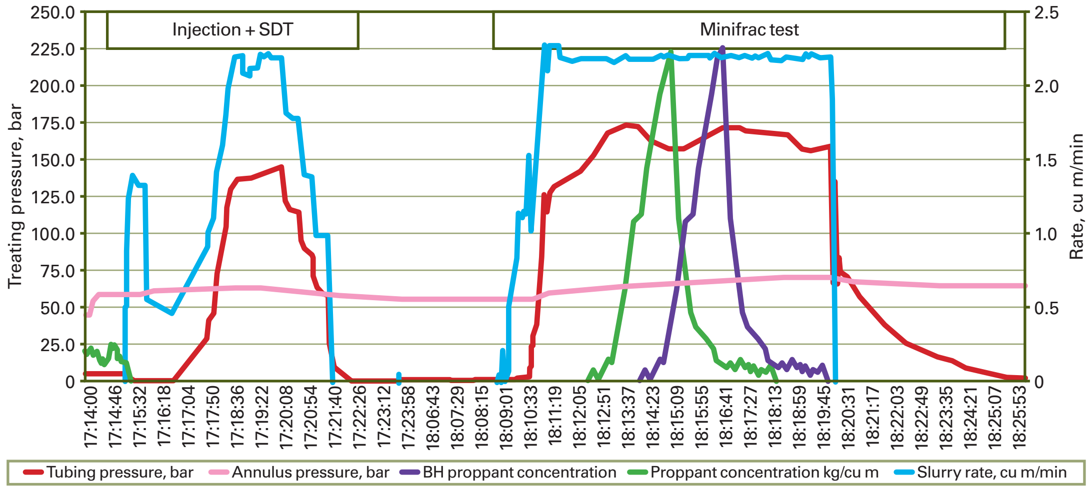
• Study condition of water-front advancement from nearby wells.

• Determine whether pressure support is available from injectors in the area.

Table 1 summarizes reservoir proper-

TYPICAL WELL TESTS

Fig. 4



TYPICAL PKKR FIELD

Table 1

Age	Developed in 1990
Production formations	Six separate sandstones
Field area	75 sq km
Trap	Structural anticline
Reservoir properties:	
Permeability, per range	20-3,000 md, variable fluid efficiency 15-45%
Net pay	20-30 m
Porosity	20-27%
Original water saturation	20-30%
Original reservoir pressure*	11.1-13.5 Mpa, different formations
BHST	48.9-57.8° C.

*Current reservoir pressure is lower than original pressure because most reservoirs are partially depleted.

ties for a typical Kazakhstan field operated by PKKR.

Frac design considerations

PKKR completes most wells with 146-mm production casing and uses wellhead isolation tools to protect the wellhead on the surface. Combining retrievable packers and sand plugs enables multiple-zone fracturing, working from the bottom zone upward.

The primary frac fluid used is 30 to 35-lb borate-crosslinked guar/1,000 gal (Mgal) water. If the pay zone is of low porosity or is near a wet sand, however, a 25-lb/Mgal, borate-crosslinked guar fluid is used.

PKKR used an intermediate-strength ceramic, 16/30-mesh proppant, and the proppant schedule was adjusted to optimize the frac design. PKKR ran 35 frac treatments in five PKKR fields in the 2006 campaign.

A microfrac treatment was run on a well to determine the closure pressures for a shale formation. The procedure provided stress data in one of the fields where the frac campaign would be conducted. Fracture-closure pressure gradient in the shale was found to be 0.184 bar/m. This value is still in use to define shale stress in fracture designs for wells in the field (Fig. 3).

An injection plus stepdown test (SDT) is normally performed for every job (Fig. 4) in order to:

- Determine whether the packer is holding frac pressure.
- Check the communication between wellbore and formation.
- Determine near-wellbore (tortuosity) friction and perforation friction.
- Determine closure pressure.
- Determine the fluid efficiency of the frac-fluid system.
- Optimize the main frac treatment based on all parameters obtained from injection followed by SDT and minifrac tests.

Pumping a sand slug has proven helpful in removing near-wellbore friction, both from the perforations and near-wellbore area, to help ensure success in placing the main fracturing treatment.

Postfrac procedures

Postfrac completion procedures differ between wells that screen out prematurely and wells that do not screen out early.

Early screen-out wells—if a premature screen-out occurs, begin completion procedures immediately. The worst-case scenario is a screen-out with proppant in suspension from the perforations all the way up to surface.

The gel holding the proppant in suspension will begin to break. Breaking will occur more slowly from the surface to some distance down the wellbore, however, because the temperatures near surface are generally lower than in the reservoir.

When running in the hole with the 42-mm production tubing, PKKR made stops at 300-m increments and reverse-circulated bottoms-up to remove all proppant to that depth. The company repeated this procedure until the tubing had been cleaned out to the tubing shoe.

If the well treatment screens out as planned, PKKR gains several benefits by its postfrac completion procedures that:

- Reduce production downtime.
- Limit loss of fluids to the reservoir.
- Simplify removal of proppant from the wellbore.

The procedures below benefited PKKR's fracture program.

1. Shut the well in for a minimum of 12 hr after fracture treatment to allow gelled fluids to break before pulling the packer and swabbing back the injected treatment fluids.

When closure pressure has declined to a point low enough below the surface pressure to allow fractures to close, completion operations can be started. Note that at this point, there should be no pumping into the formation, nor swabbing from the formation.

2. Remove the wellhead isolation tool and immediately pull the packer, run tubing in, and begin removal of proppant from the wellbore. Frac fluid may not have completely broken by this time; however, that can be an advantage because less fluid will be lost to the formation during circulation.

3. To help ensure there is no proppant in suspension in tubing above the shoe, inject into the annulus at least 11/2 tubing volumes of diluted frac fluid, after the packer is released, to circulate proppant that may still be in suspension.

4. Use leftover 25-30 lb/Mgal base gel and 10-lb/Mgal linear gel to wash proppant out of the wellbore instead of simply disposing the gel. Dilute the base gel with water to about 10 lb/Mgal; this will leave the KCl concentration of 3-4% for the total diluted gel.

Using diluted gel instead of 2% KCl water as a washout fluid has these advantages:

- Better proppant-carrying capability.
- Limited amount of fluid lost to the formation.
- Lower pumping friction and more efficient proppant cleanout.
- The high percentage (7%) of KCl in the base gel raises the washout fluid KCl concentration to 3-4%.

5. Add 1 l. surfactant for every 1 cu m of all fluids used to kill wells and to all fracturing fluids to aid in recovery of fluids lost and help prevent formation of emulsions from mixing of formation oil with completion fluids.

Learnings

PKKR believes that the keys to its successful fracture-stimulation program are well evaluation, candidate selection, and the postfracture completion practices outlined above. The first order of business was to determine the field potential to yield an adequate ROI. Determining the current PI and estimating the postfrac PI were critical steps.

In its 2006 fracture stimulation campaign, PKKR did not include any wells that had been fractured before or wells that had water cut higher than 35%. ✦

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Method correlates solubilities of crude hydrocarbons in water

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Gas Processing

A new correlation calculates the water solubility for a wide variety of hydrocarbons found in a typical crude oil—alkanes, olefins, diolefins, acetylenes, cyclopentanes, cyclohexanes, benzenes, mercaptans, thiophenes, and sulfides.

The correlation provides reliable solubility values down to extremely low concentrations, in the ppm range. It agrees favorably with experimental data.

Results from the new correlation are useful for process engineering for wastewater minimization.

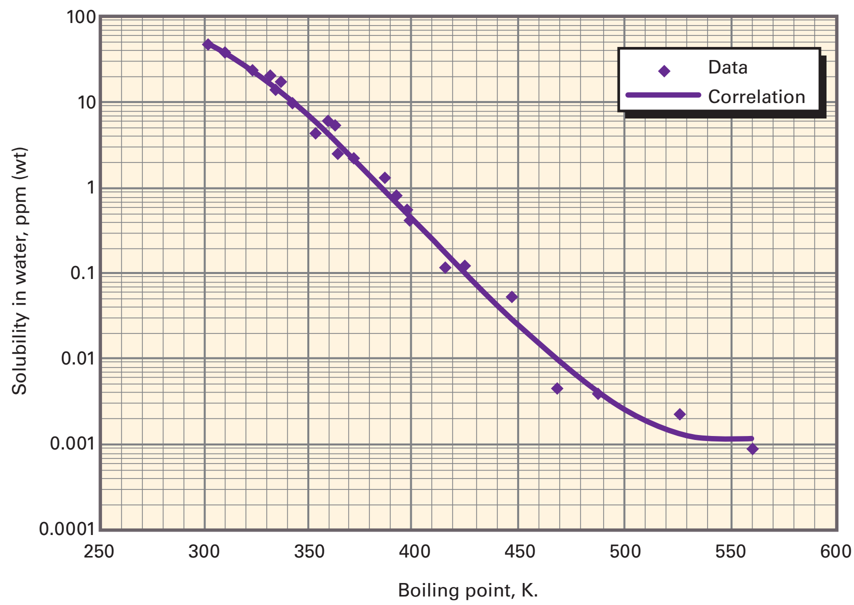
Importance of water solubility

Knowing the solubility of crude oil hydrocarbons in water is important for health, safety, and environmental considerations, an importance that will only increase with time.

For health involving human exposure to substances in air, the threshold limit value (TLV) for pentane in air is 600 ppm (vol), according to the US Occupational Safety and Health Ad-

ALKANES

Fig. 1



SOLUBILITIES IN WATER

Table 1

Chemical family	Equation 1 coefficients A	B	C	D	Minimum boiling temperature, K	Maximum boiling temperature, K	Formula
Alkanes	–17.652	1.77811E-01	–5.00907E-04	4.11124E-07	298	560	C_nH_{2n+2}
Olefins	–17.030	1.77811E-01	–5.00907E-04	4.11124E-07	298	560	C_nH_{2n}
Diolefins	–16.561	1.77811E-01	–5.00907E-04	4.11124E-07	298	560	C_nH_{2n-2}
Acetylenes	–15.835	1.77811E-01	–5.00907E-04	4.11124E-07	298	560	$C_{n+2}H_{2n+2}$
Cyclohexanes	–16.700	1.77811E-01	–5.00907E-04	4.11124E-07	298	560	C_nH_{2n}
Cyclopentanes	–16.900	1.77811E-01	–5.00907E-04	4.11124E-07	298	560	C_nH_{2n}
Benzenes, single substitution	–24.008	2.21196E-01	–5.55632E-04	4.1883E-07	298	560	$C_{n+6}H_{2n+6}$
Benzenes, multiple substitution	–23.650	2.21196E-01	–5.55632E-04	4.1883E-07	298	560	$C_{n+6}H_{2n+6}$
Mercaptans	–6.900	1.005E-01	–2.7288E-04	1.9987E-07	298	560	$C_nH_{2n+2}S$
Thiophenes	–6.850	1.005E-01	–2.7288E-04	1.9987E-07	298	560	$C_nH_{2n-4}S$
Sulfides	–6.539	1.005E-01	–2.7288E-04	1.9987E-07	298	560	$C_nH_{2n+2}S$

ministration.[1] A concentration of only 0.0000001 mole fraction of pentane in water will provide about 7,000 ppm (vol) of pentane in air at the air-water interface, which greatly exceeds the 600 ppm (vol) TLV.

To ensure safe operations, a lower explosion limit (LEL) for pentane in air is reportedly 1.4%.[2] A concentration of only 0.000001 mole fraction of pentane in water provides about 7% of pentane in air at the air-water interface.

To illustrate environmental effects, consider a spill of pentane in contact with water. The water will become saturated; at saturation, the solubility of pentane in water is about 0.0000385 weight fraction, or 0.00000916 mole fraction, according to Yalkowski.[3]

This concentration at saturation leads to a pentane level of 64.4% in air at the air-water interface, which is considerably higher than the TLV and LEL.

Correlation for solubility

In an earlier work by Yaws and coworkers, water solubility for various chemical types was correlation as a function of the boiling point temperature of the compound.[2]

For the new correlation, we determined that the boiling point method was also applicable for correlating water solubility of crude oil hydrocarbons. Equation 1 (see accompanying equation box) shows the new correlation.

The range of boiling point temperatures for the hydrocarbons studied was 298-560 K.

Table 1 shows the regression coefficients for a wide variety of hydrocarbons: alkanes, olefins, diolefins, acetylenes, cyclopentanes, cyclohexanes, benzenes, mercaptans, thiophenes, and sulfides. The table also shows the boiling point range (minimum, maximum) for which the correlation is applicable. The correlation should not be used for compounds with boiling points outside the boiling point range.

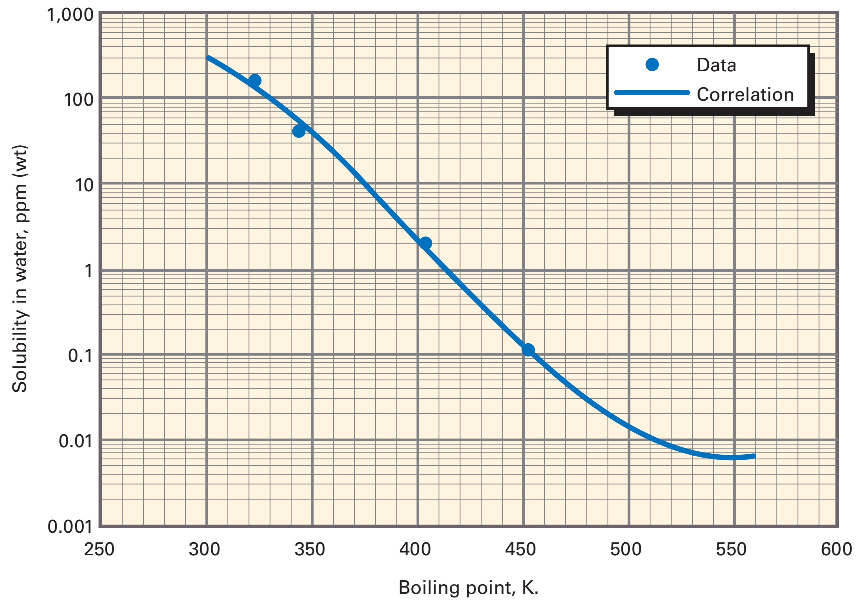
We determined the coefficients using regressions of available data. In preparing the correlation, we conducted a literature search to identify data source publications.[2-12] The excellent compilations by Howard and Meylan;[7] Mackay, Shiu, and Ma;[8] Verschueren;[10] Yalkowski;[3] and Yaws[2] were used extensively for water solubility.

The boiling point temperatures are from compilations from Yaws.[2 11 12]

The publications were screened and copies of the appropriate data were made. These data were then keyed in to the computer to provide a database for which experimental data are available. The database also served as a basis to

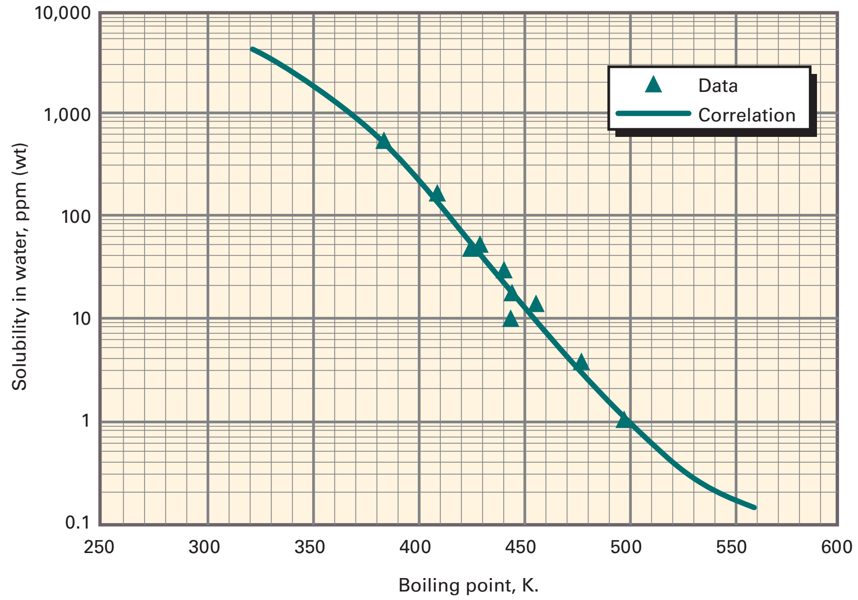
CYCLOPENTANES

Fig. 2



BENZENES

Fig. 3



EQUATION

$$\mathrm{Log}_{10}(S) = A + BT_B + CT_B^2 + DT_B^3 \quad (1)$$

Nomenclature

A, B, C, and D = Regression coefficients
S = Solubility in water at 25° C., ppm (wt)
T_B = Boiling point temperature, K

check the accuracy of the correlation.

Figs. 1-3 show water solubility vs. boiling point temperature for representative hydrocarbon families. The graphs indicate favorable agreement of correlation values and experimental data.

Example

A chemical spill of toluene occurs into a body of water at ambient conditions. Estimate the concentration in the water at saturation.

The correlation for benzenes (single substitution) can be used to determine the solubility in water. Substitution of the coefficients and boiling point temperature of toluene into Equation 1 yields:

$\log^{10}(S) = -24.0080 + 0.221196 \times (383.78) + 5.55632E\text{-}4 \times (383.73)^2 + 4.1883E\text{-}7 \times (383.73)^3$

S = 524.68 ppm (wt)

The calculated value and experimental data compare favorably: 524.68 vs. 542.4. Deviation is (542.4-524.68)/542.4, or 3.3% error. ✦

LNG Observer back in print

With the Apr. 2, 2007, issue of Oil & Gas Journal, the magazine's quarterly supplement ***LNG Observer*** returns to print. It will also remain electronic and accessible at www.lngobserver.

OGJ's ***LNG Observer*** is produced with the widely respected GTI, Des Plaines, Ill. This publication aims at anyone interested or involved in the natural gas and LNG business.

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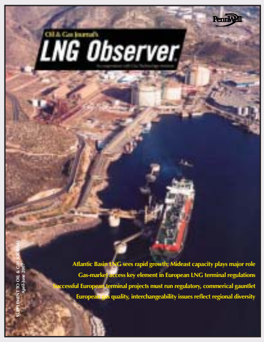

NELSON-FARRAR COST INDEXES

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

	1962	1980	2004	2005	2006	Dec. 2005	Nov. 2006	Dec. 2006
Pumps, compressors, etc.	222.5	777.3	1,581.5	1,685.5	1,758.2	1,721.8	1,787.0	1,791.7
Electrical machinery	189.5	394.7	516.9	513.6	520.2	509.6	527.3	528.2
Internal-comb. engines	183.4	512.6	919.4	931.1	959.7	938.0	963.8	963.8
Instruments	214.8	587.3	1,087.6	1,108.0	1,166.0	1,119.0	1,220.4	1,224.8
Heat exchangers	183.6	618.7	863.8	1,072.3	1,162.7	1,079.2	1,179.4	1,179.4
Misc. equip. average	198.8	578.1	993.8	1,062.1	1,113.3	1,073.5	1,135.6	1,137.6
Materials component	205.9	629.2	1,112.7	1,179.8	1,273.5	1,202.5	1,295.7	1,297.1
Labor component	258.8	951.9	2,314.2	2,411.6	2,479.8	2,467.9	2,550.0	2,557.1
Refinery (Inflation) Index	237.6	822.8	1,833.6	1,918.8	2,008.1	1,961.7	2,048.3	2,053.1

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

	1962	1980	2004	2005	2006	Dec. 2005	Nov. 2006	Dec. 2006
Fuel cost	100.9	810.5	971.9	1,360.2	1,569.0	1,617.1	1,473.1	1,474.0
Labor cost	93.9	200.5	191.8	201.9	204.2	197.1	213.1	198.4
Wages	123.9	439.9	984.0	1,007.4	1,015.4	992.2	1,072.0	1,003.6
Productivity	131.8	226.3	513.3	501.1	497.5	503.3	503.1	505.9
Invest., maint., etc.	121.7	324.8	686.7	716.0	743.7	732.0	758.6	760.4
Chemical costs	96.7	229.2	268.2	310.5	365.4	323.9	363.2	365.7
Operating indexes								
Refinery	103.7	312.7	486.7	542.1	579.0	571.7	580.0	575.5
*Process units**	103.6	457.5	638.1	787.2	870.7	881.3	845.0	841.5

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

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

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

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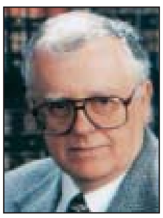
The author



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Indexes for selected equipment show moderate increase

Gary Farrar
Contributing Editor

Costs for six selected equipment items used in refining construction operations have been surveyed for the 3 years, 2004-06. The accompanying table shows Nelson-Farrar equipment indexes for these items of equipment.

Bubble trays showed the greatest increases in cost, rising from 1,227.8 in first-quarter 2004 fourth-quarter 2006.

Four other items showed more modest increases. The tanks and pressure vessels category rose to 1,030.3 from 804.6 during the 36-month span. Tube stills increased to 600.3 from 439.9. Valves and fittings showed an index gain to 1,883.1 from 1,624.1. Fractionating towers showed a 235-point gain, increasing to 1,233.1 from 998.2 over the 3-year period.

The final category, nonmetallic building materials, showed the least gain during the data compilation period. Beginning index value was 810.1, while the final value was 984.8. ✦

Indexes for selected equipment items

Quarter	Bubble trays	Fraction-ating towers	Tube stills	Valves, fittings	Tanks, pressure vessels	Nonmetallic building materials
2004						
1st	1,227.8	998.2	439.9	1,624.1	804.6	810.1
2nd	1,308.5	1,046.2	492.5	1,660.6	848.5	818.7
3rd	1,370.6	1,092.2	531.6	1,675.5	896.7	831.7
4th	1,411.3	1,124.1	549.9	1,682.1	924.9	843.0
Year	**1,329.6**	**1,065.2**	**503.5**	**1,660.6**	**868.7**	**825.9**
2005						
1st	1,429.5	1,152.1	560.0	1,694.2	962.3	864.0
2nd	1,405.2	1,149.0	541.5	1,742.8	965.9	875.4
3rd	1,371.1	1,150.6	513.8	1,752.2	979.7	892.6
4th	1,431.9	1,177.0	546.9	1,763.4	989.9	913.6
Year	**1,409.4**	**1,157.2**	**540.6**	**1,738.2**	**974.5**	**886.4**
2006						
1st	1,434.6	1,184.2	549.5	1,796.1	1,000.8	941.2
2nd	1,458.6	1,192.3	566.3	1,813.0	1,003.2	967.6
3rd	1,514.7	1,219.3	603.6	1,866.3	1,023.0	984.8
4th	1,528.2	1,233.1	600.3	1,883.1	1,030.3	984.8
Year	**1,484.0**	**1,207.2**	**579.9**	**1,839.6**	**1,014.3**	**969.6**

Itemized refining cost indexes

The cost indexes may be used to convert prices at any date to prices at other dates by ratios to the cost indexes of the same date. Item indexes are published each quarter (first week issue of January, April, July, and October). In addition the Nelson Construction and Operating Cost Indexes are published in the first issue of each month of Oil and Gas Journal.

Operating cost (based on 1956 = 100.0):	1954	1972	2004	2005	2006	Nov. 2006	*References	Index for earlier year in Costimating and Questions on Technology issues
Power, industrial electrical	98.5	131.2	727.9	771.3	850.2	832.1	Code 0543	No. 13, May 19, 1958
Fuel, refinery price	85.5	152.0	944.5	1,288.9	1,523.6	1,402.0	OGJ	No. 4, Mar. 17, 1958
Gulf cargoes	85.0	130.4	1,250.7	1,635.4	2,023.9	1,656.4	OGJ	No. 4, Mar. 17, 1958
NY barges	82.6	169.6	1,130.7	1,539.6	1,837.5	1,666.3	OGJ	No. 4, Mar. 17, 1958
Chicago low sulfur	—	—	1,478.4	1,478.4	1,765.8	1,498.9	OGJ	July 7, 1975
Western US	84.3	168.1	1,427.7	1,941.5	2,358.1	1,993.1	OGJ	No. 4, Mar. 17, 1958
Central US	60.2	128.1	953.8	1,274.0	1,765.9	2,025.5	OGJ	No. 4, Mar. 17, 1958
Natural gas at wellhead	83.5	190.3	5,322.0	7,010.6	6,306.5	6,647.0	Code 531-10-1	No. 4, Mar. 17, 1958
Inorganic chemicals	96.0	123.1	504.9	562.9	686.8	714.2	Code 613	Oct. 5, 1964
Acid, hydrofluoric	95.5	144.4	414.9	414.9	414.9	414.9	Code 613-0222	Apr. 3, 1963
Acid, sulfuric	100.0	140.7	397.4	397.4	397.4	397.4	Code 613-0281	No. 94, May 15, 1961
Platinum	92.9	121.1	762.1	819.3	1,344.5	1,466.4	Code 1022-02-73	July 5, 1965, p. 117
Sodium carbonate	90.9	119.4	310.3	357.3	452.4	470.5	Code 613-01-03	No. 58, Oct. 12, 1959
Sodium hydroxide	95.5	136.2	529.6	529.6	620.1	644.9	Code 613-01-04	No. 94, May 15, 1961
Sodium phosphate	97.4	107.0	733.7	733.7	733.7	733.7	Code 613-0267	No. 58, Oct. 12, 1959
Organic chemicals	100.0	87.4	587.9	666.5	764.5	745.8	Code 614	Oct. 5, 1964
Furfural	94.5	137.5	848.1	961.9	1,103.1	1,076.7	Chemical Marketing Reporter	No. 58, Oct. 12, 1959
MEK, tank-car lots	82.6	87.5	408.3	625.0	625.0	625.0	Reporter	
Phenol	90.4	47.1	339.1	411.3	374.9	415.5	Code 614-0241	No. 58, Oct. 12, 1959

Itemized refining cost indexes

Operating cost (based on 1956 = 100.0):	1954	1972	2004	2005	2006	Nov. 2006	*References	Index for earlier year in Costimating and Questions on Technology issues
Operating labor cost (1956 = 100)								
Wages & benefits	88.7	210.0	984.0	1,007.0	1,015.4	1,072.0	Employ & Earn	No. 41, Feb. 16, 1969
Productivity	97.2	197.0	513.3	501.1	497.5	503.1	Employ & Earn	No. 41, Feb. 16, 1969
Construction labor cost (1946 = 100)								
Skilled const.	174.6	499.9	2,077.2	2,170.8	2,240.7	2,288.9	Eng. News Record	No. 55, Nov. 3, 1949
Common labor	192.1	630.6	2,747.1	2,863.5	2,971.7	3,034.9	Eng. News Record	No. 55, Nov. 3, 1949
Refinery cost	183.3	545.9	2,314.2	2,411.6	2,497.8	2,550.0	OGJ	May 15, 1967
Equipment or materials (1946 = 100):								
Bubble tray	161.4	324.4	1,329.6	1,409.4	1,484.0	1,528.2	Computed	July 8, 1962, p. 113
Building materials (nonmetallic)	143.6	212.4	825.9	886.4	969.6	984.8	Code 13	No. 61, Dec. 15, 1949
Brick—building	144.7	252.5	1,215.8	1,301.7	1,408.6	1,433.3	Code 1342	No. 20, Mar. 3, 1949
Brick—fireclay	193.1	322.8	1,358.6	1,441.1	1,540.5	1,553.3	Code 135	May 30, 1955
Castings, iron	188.1	274.9	1,192.5	1,290.0	1,351.3	1,370.8	Code 1015	Apr. 1, 1963
Clay products (structural, etc.)	159.1	342.0	843.9	893.8	951.6	963.1	Code 134	No. 20, Mar. 3, 1949
Concrete ingredients	141.1	218.4	908.3	985.5	1,092.0	1,115.9	Code 132	No. 22, March 17, 1949
Concrete products	138.5	199.6	761.9	841.3	921.1	937.1	Code 133	Oct. 2, 1967, p. 112
Electrical machinery	159.9	216.3	516.9	513.6	520.2	527.3	Code 117	May 2, 1955
Motors and generators	157.7	211.0	796.8	839.2	880.3	899.4	Code 1173	May 2, 1955
Switchgear	171.2	271.0	1,045.9	1,090.0	1,147.3	1,182.7	Code 1175	May 2, 1955
Transformers	161.9	149.3	486.0	537.1	612.5	647.1	Code 1174	No. 31, May 19, 1949
Engines (combustion)	150.5	233.3	919.4	931.1	959.7	963.8	Code 1194	No. 36, June 23, 1949
Exchangers (composite)	171.7	274.3	863.8	1,072.3	1,162.7	1,179.4	Manufacturer	Mar. 16, 1964
Copper base	190.7	266.7	816.2	992.1	1,059.4	1,081.8	Manufacturer	Mar. 16, 1964
Carbon steel	156.8	281.9	866.1	1,080.2	1,162.1	1,189.4	Manufacturer	Mar. 16, 1964
Stainless steel (304)	—	—	914.3	1,119.3	1,174.8	1,193.3	Manufacturer	July 1, 1991
Fractionating towers	151.0	278.5	1,065.1	1,157.2	1,207.2	1,233.1	Computed	June 8, 1963, p. 133
Hand tools	173.8	346.5	1,651.7	1,722.1	1,792.5	1,801.9	Code 1042	June 27, 1955
Instruments (composite)	154.6	328.4	1,087.6	1,108.0	1,166.0	1,220.4	Computed	No. 34, June 9, 1949
Insulation (composite)	198.5	272.4	2,230.4	2,228.6	2,257.4	2,308.8	Manufacturer	July 4, 1988, p. 193
Lumber (composite):	197.8	353.4	1,417.9	1,359.6	1,309.8	1,188.3	Code 81	No. 7, Dec. 2, 1948
Southern pine	181.2	303.9	1,040.7	998.6	984.3	820.1	Code 81102	No. 7, Dec. 2, 1948
Redwood, all heart	238.0	310.6	2,145.1	2,057.9	1,948.1	1,690.1	Code 811-0332	July 5, 1965, p. 117
Machinery								
General purpose	159.9	278.5	1,106.7	1,163.6	1,213.7	1,237.3	Code 114	Feb. 17, 1949
Construction	165.9	324.4	1,407.3	1,499.2	1,559.7	1,566.6	Code 112	Apr. 1, 1968, p. 184
Oil field	161.9	269.1	1,333.0	1,454.8	1,599.1	1,650.5	Code 1191	Oct. 10, 1955
Paints—prepared	159.0	231.8	907.4	975.3	1,040.8	1,050.4	Code 621	May 16, 1955
Pipe								
Gray iron pressure	195.0	346.9	2,301.2	2,580.2	2,687.9	2,673.7	Code 1015-0239	Jan. 3, 1983
Standard carbon	182.7	319.9	1,900.0	2,217.3	2,306.9	2,389.0	Code 1017-0611	Jan. 3, 1983
Pumps, compressors, etc.	166.5	337.5	1,581.5	1,685.5	1,758.2	1,787.0	Code 1141	No. 29, May 5, 1949
Steel-mill products	187.1	330.6	1,300.6	1,409.1	1,527.5	1,591.0	Code 1017	Jan. 3, 1983
Alloy bars	198.7	349.4	1,050.1	1,146.8	1,311.8	1,211.0	Code 1017-0831	Apr. 1, 1963
Cold-rolled sheets	187.0	365.5	1,278.4	1,462.5	1,658.4	1,974.3	Code 1017-0711	Jan. 3, 1983
Alloy sheets	177.0	225.9	665.0	760.3	862.4	1,026.7	Code 1017-0733	Jan. 3, 1983
Stainless strip	169.0	221.2	710.0	811.6	920.7	1,095.9	Code 1017-0755	Jan. 3, 1983
Structural carbon, plates	193.4	386.7	1,493.7	1,654.5	1,766.6	1,841.0	Code 1017-0400	Jan. 3, 1983
Welded carbon tubing	180.0	265.5	1,925.0	2,246.8	2,337.3	2,420.8	Code 1017-0622	Jan. 3, 1983
Tanks and pressure vessels	147.3	246.4	868.7	974.4	1,014.3	1,030.3	Code 1072	No. 5, Nov. 18, 1949
Tube stills	123.0	125.3	503.5	540.5	579.9	600.3	Computed	Oct. 1, 1962
Valves and fittings	197.0	350.9	1,660.6	1,738.2	1,839.6	1,883.1	Code 1149	No. 46, Sept. 1, 1940
Nelson-Farrar Refinery (Inflation Index)								
(1946)	179.8	438.5	1,833.6	1,918.8	2,008.1	2,048.3	OGJ	May 15, 1969
Nelson-Farrar Refinery Operation								
(1956)	88.7	118.5	486.7	542.1	579.0	580.0	OGJ	No. 2, Mar. 3, 1958
Nelson-Farrar Refinery Process								
(1956)	88.4	147.0	638.1	787.2	870.7	845.0	OGJ	No. 2, Mar. 3, 1958

*Code refers to the index number of the Bureau of Statistics, US Department of Labor, "Wholesale Prices" Itemized Cost Indexes, Oil & Gas Journal.

REX pipeline start affects regional natural gas pricing

Porter Bennett
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Pipelines

The Feb. 14, 2007, opening of the first leg of Kinder Morgan's Rockies Express (REX) pipeline between Wamsutter, Wyo. and the Cheyenne Hub in northeastern Colorado, will narrow the Opal-to-Cheyenne pricing differential even while increased gas-on-gas competition in the region forces regional price differentials lower until completion of REX Phase III in 2009.

Kinder Morgan began flowing natural gas through the 192-mile section of the Rockies Express pipeline (REX) between Wamsutter and Cheyenne hub on Feb. 14. Completion of this first leg of REX along with several smaller projects extending the western end of the system from Wamsutter to Opal lets producers flow an additional 500 MMcfd from major Rockies basins to Cheyenne.

Since then, about 300 MMcfd of REX receipts from the Uinta-Piceance flowed directly to Cheyenne. At the same time, REX deliveries at Wamsutter dropped to zero. This shift in flows opened capacity on the Wyoming Interstate pipeline (WIC) through Wamsutter, letting WIC increase the flow of Green River (Opal) gas to Cheyenne.

The additional flow of gas into Cheyenne has started to narrow the Opal-to-Cheyenne differential. On Feb. 14 and 15 the differential remained above $0.50/MMbtu due to support for the Cheyenne price resulting from high demand along the front range of Colorado. By Mar.15, the differential had dropped to less than $0.01 MMbtu.

This article examines the reasons behind this compression in differentials and discusses how completion of REX's Wamsutter-to-Cheyenne leg is likely to affect the market.

Geography

REX Phase I's initial segment went into service in February 2006 with completion of the length formerly called Entrega, a 136-mile leg connecting Uinta-Piceance production with WIC and Colorado Interstate Gas (CIG) pipeline at Wamsutter (Fig. 1).

The segment completed in February extends REX east to Cheyenne and west to Questar Corp.'s Overthrust pipeline at Kanda.

Through a long-term lease with Overthrust Pipeline, REX Phase I also can move up to 1.5 bcfd from the Green River-Overthrust area (around Opal) to Kanda and on to Cheyenne Hub.

REX Phase I is the first phase of a project that will become the largest natural gas pipeline built in the US in the last 20 years. REX West (Phase II) will begin operations in early 2008 and extend the system to Mexico, Mo. Addition of compression will also increase capacity at Cheyenne to 1.6 bcfd. REX East (Phase III), planned for completion in 2009, will extend the pipeline to Clarington, Ohio, and increase overall

DELIVERIES FROM REX

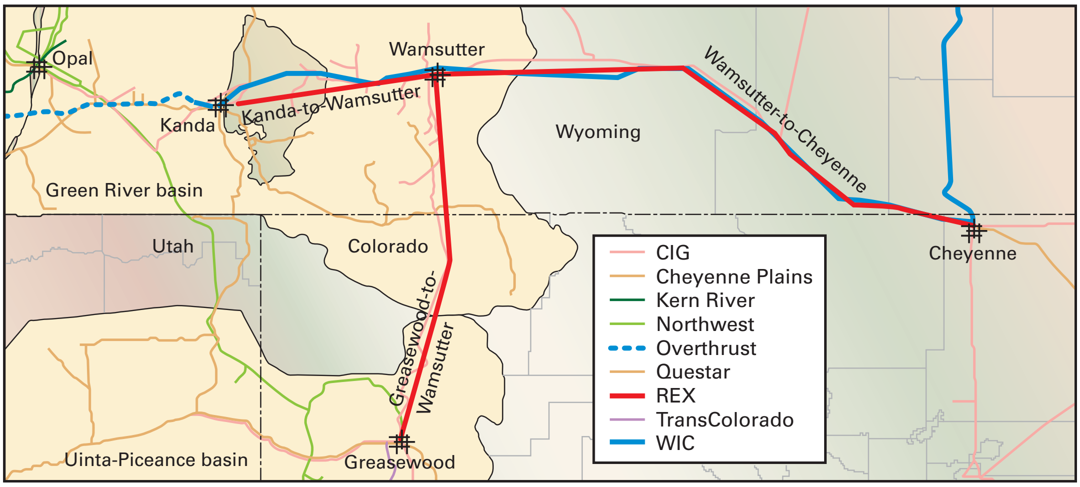
Table 1

2007	MMcfd — February 13	14	15	16	17	Week average — Feb. 18-24	Feb. 23-Mar. 3	Mar. 7	30-day average
Cycle	12	12	12	12	12	12	12	E	12
Into Wamsutter									
To CIG at Bitter Creek	139	89	54	20	21	22	1	0	48
To WIC at Frewan Lake	170	80	47	0	7	11	7	0	56
Total, Wamsutter	**309**	**169**	**101**	**20**	**27**	**33**	**8**	**0**	**104**
Into Cheyenne Hub									
To CIG at Crazy Horse	0	4	17	5	12	12	11	2	9
To Cheyenne Plains at Crazy Bear	0	63	115	200	188	195	208	224	174
To PSCC at Chalk Bluffs	0	23	20	20	28	19	19	0	19
To Trailblazer at Owl Creek	0	43	41	79	78	60	74	84	62
Total, Cheyenne Hub	**0**	**134**	**194**	**305**	**307**	**287**	**312**	**310**	**264**

capacity to 1.8 bcfd. When completed, REX will span 1,663 miles and be one of the nation's longest interstate pipelines.

Rex phase 1

Fig. 1



Context

Seven other major interstate pipelines operate near REX:

• *Cheyenne Plains.* Owned by El Paso Corp., it carries gas from the Cheyenne Hub in Weld County, Colo., to Greensburg, Kan., interconnecting with Kinder Morgan Interstate Gas Transmission (KMIT), Natural Gas Pipeline Company of America (NGPL), ANR Pipeline Co., Southern Star Central Gas Pipeline Inc., Northern Natural Gas, Kansas Gas Service, and Panhandle Energy.

• *CIG.* Also owned by El Paso, it flows gas from the Uinta-Piceance basin in Utah and Colorado, the D-J in Colorado, and the Green River, Wind River, and Powder River basins in Wyoming, primarily to markets in Colorado and the Midwest. CIG can also deliver gas through Kern River Gas Transmission Co. (to Nevada-California) and Northwest Pipeline Corp. (NWP).

• *NWP.* Owned by Williams Companies, it carries gas from the Uinta-Piceance and Green River-Overthrust basins to the Pacific Northwest.

• *Overthrust.* Owned by Questar Corp., it extends from Whitney Canyon, southwest of Opal, to Kanda, where it connects with Questar, Kern River, CIG, and WIC.

• *Questar Pipeline (QP).* Also owned by Questar, it operates like a hub in northeastern Utah, western Colorado, and southwestern Wyoming. Questar connects with CIG, NWP, and TransColorado Gas Transmission to move gas south to El Paso and Transwestern Pipeline Co. LLC. Through connections to Kern River, gas can also move to California markets, and through connections with NWP it can move to Oregon and Washington and occasionally to the east via CIG and WIC.

• *WIC.* A subsidiary of CIG, it is also the middle section of the Overthrust-WIC-Trailblazer system designed to deliver gas from western Wyoming and the Powder River to eastern markets.

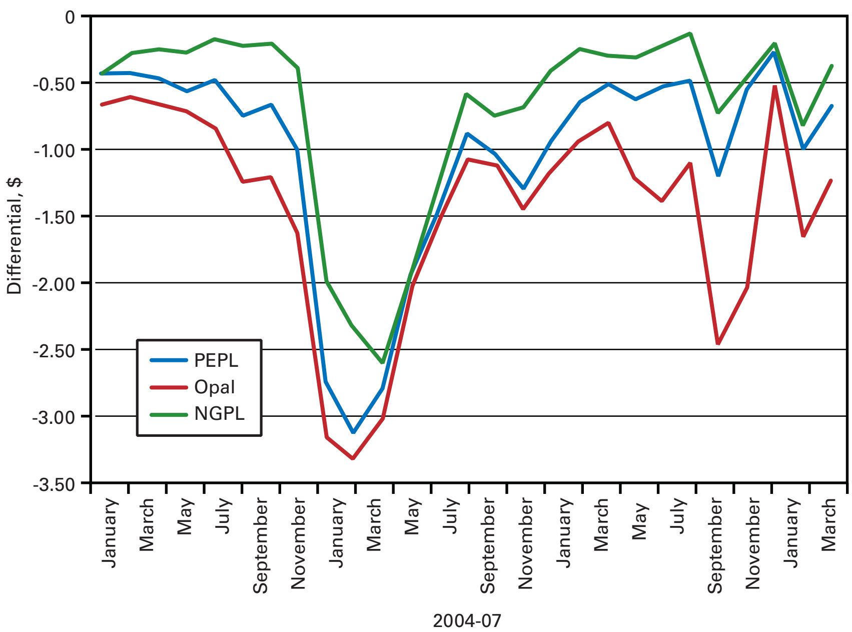
• *TransColorado.* Owned and operated by Kinder Morgan, it runs from the Greasewood Hub in Rio Blanco County, Colo. to the Blanco Hub in New Mexico.

Price, basis

REX is designed to expand export capacity for Rockies producers. The expectation that REX will improve Rockies pricing significantly, relative to prices in other producing regions of North

Monthly prices bases, average

Fig. 2



America, underpins these expansion plans.

Opal, in southwestern Wyoming, and CIG Rockies are the primary pricing points for Rockies production. Cheyenne Hub is the primary pricing point for natural gas flowing east of Wyoming and Colorado.

Prices at Opal and Cheyenne historically have lagged prices in other production areas, primarily because of the limited ability to export gas, a problem compounded by rate stacking when gas enters the Midwest, and the rapidly expanding Rockies production base.

Earlier in this decade, severely constrained export capacity saw netbacks in the western Colorado, Utah, and Wyoming basins fall to $1.10/MMbtu. A 2004 expansion of Kern River that added 1 bcfd of export capacity to California initially addressed the capacity shortfall. Then, in January 2005, Cheyenne Plains began service, eventually adding more than 760 MMcfd of new capacity from Cheyenne to the Midwest. Although this new capacity prevented further pricing disasters in the Rockies, Opal and CIG Rockies prices continued to lag other production areas.

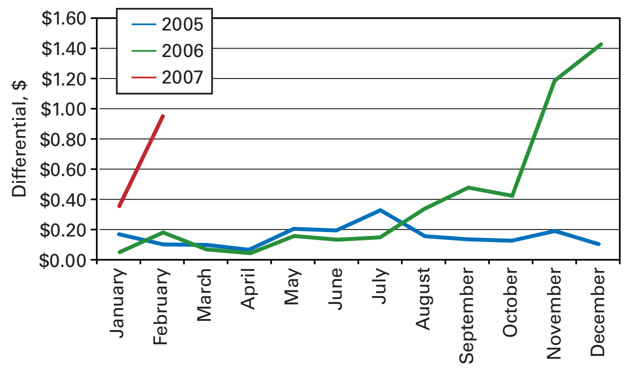
Fig. 2 shows the average basis at Opal about $0.73 below Henry Hub from January 2004 through the early summer of 2005. This value averaged $0.27/MMbtu below Panhandle Eastern and $0.49/MMbtu below NGPL during the same period. By August 2005, a price spike in Louisiana due to hurricanes Katrina and Rita caused these basis differentials to widen significantly. By spring, Opal basis again settled into a range averaging about $1.00 below Henry.

But in the summer of 2006, the specter of transportation curtailments started to rear its head. Unrelenting increases in production had again tightened capacity out of the region. By November 2006, Opal was running $2.50/MMbtu under Henry, spiking to $5.00/MMbtu below Henry Nov. 14 due to mechanical problems at Opal.

It is this kind of pricing pressure that REX will ultimately relieve.

Cheyenne-Opal differential

Fig. 3



Opal vs. Cheyenne

REX will also equalize pricing pressures within the Rockies region, reducing, if not eliminating, the differential that exists between Opal and Cheyenne.

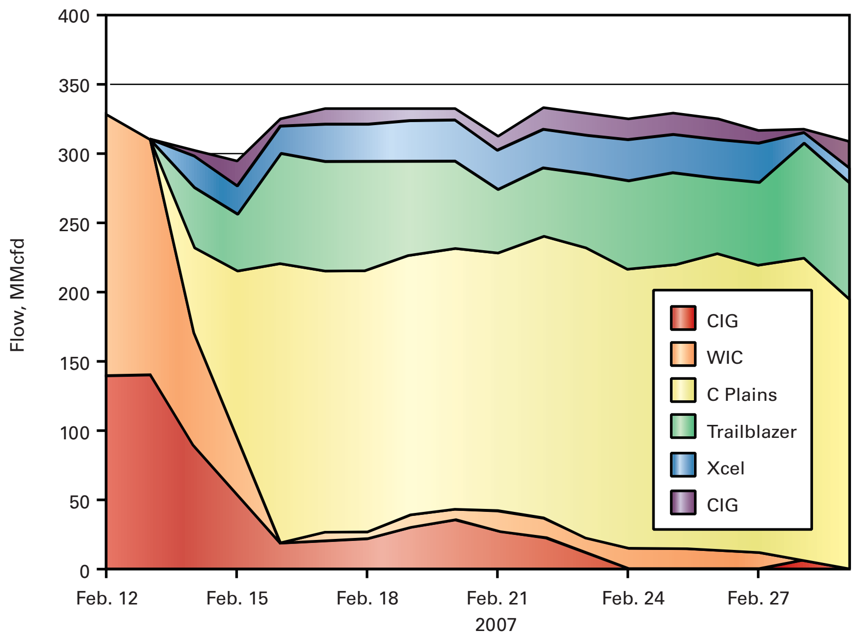
Opal typically trades below Cheyenne Hub. During 2005, Cheyenne exceeded Opal by an average of $0.16/MMbtu, increasing to $0.39/MMbtu in 2006 (Fig. 3). The differential has continued to grow in recent months, averaging $0.81/MMbtu since Sept. 1, 2006.

Cheyenne Hub connects to multiple Midwestern markets as well as markets along the front range of Colorado. Particularly with the completion of Cheyenne Plains in 2005, gas from Cheyenne has significantly improved access to Midwest and Eastern markets, which provide the highest value market for Rockies gas most of the time. Demand at Cheyenne Hub is typically strong, drawing supply from Rockies producing basins.

REX Phase I gives producers the opportunity to move more gas to the Cheyenne Hub, thereby increasing supply relative to demand and narrowing the differential between Opal and Cheyenne.

Deliveries from REX

Fig. 4



Gas flow effect

REX pulled volumes from WIC. Fig. 4 shows deliveries from REX to other pipelines from Feb. 12 through Mar. 1. Before Feb. 14, Uinta-Piceance gas received into REX in the Greasewood area moved to Wamsutter where there are two delivery options: Gas could be delivered into CIG at Bitter Creek or to WIC at Frewen Lake. Gas received at these two points either moved west to Kern River and Questar or east to Cheyenne.

New REX capacity has significantly affected these two points. By Feb. 16, volumes delivered to WIC fell to zero and CIG only received about 20 MMcfd at Bitter Creek (6% of REX's total deliveries). By Mar. 7, both points had fallen to zero. Gas flows received at these two interconnects stayed on REX and moved to Cheyenne, delivering into Cheyenne Plains Gas Pipeline Co. at Crazy Bear, Trailblazer Pipeline Co. at Owl Creek, Xcel Energy at Chalk Bluffs, and CIG at Crazy Horse (Fig. 4, Table 1).

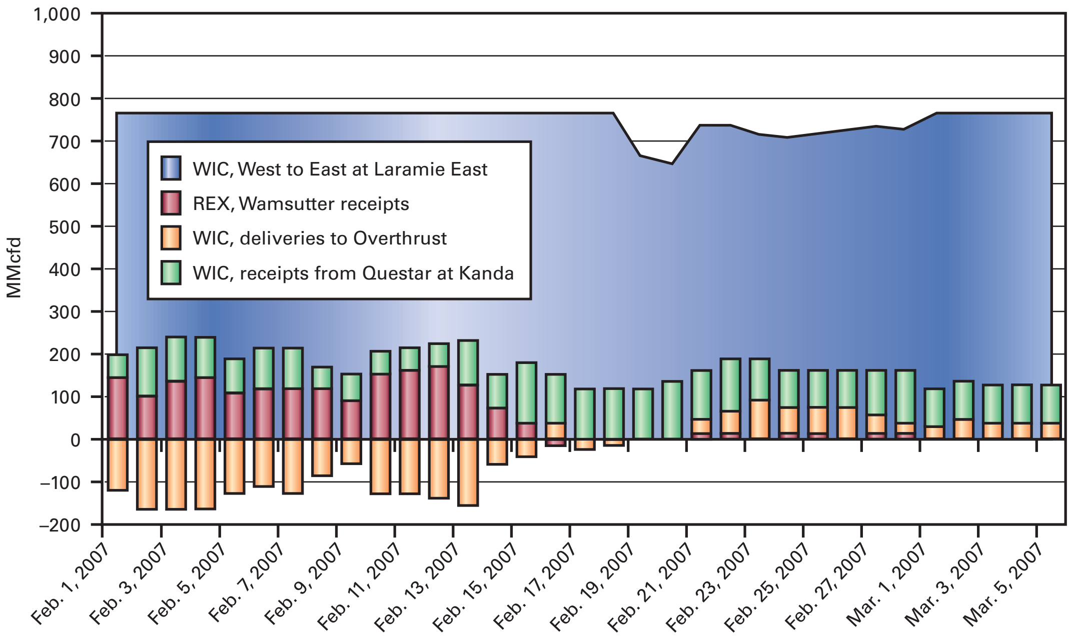
While REX captured volumes that had moved east on WIC prior to Feb. 14, total WIC continued to flow about the same volume west to Cheyenne Hub. The blue area in Fig. 5 shows WIC flows west through the Laramie East point between Wamsutter and Cheyenne Hub were essentially flat at 770 MMcfd.

The bars in Fig. 5 show the shift in certain WIC receipts since REX Phase 1 went into service. Receipts from REX at Wamsutter (the maroon bar) dropped to zero, while receipts from Questar at Kanda (shown in green) increased.

At the same time, WIC reversed deliveries into Overthrust and started receiving gas from Overthrust at the same point (Fig. 5, orange bars). The volumes received from Questar and Overthrust offset volumes lost to REX, maintaining the volume moving west through Laramie East at maximum capacity.

From these early results it seems clear that REX's deliveries of Uinta-Piceance gas into Cheyenne has effectively increased WIC's capacity to deliver incremental Green River Basin (Opal area) gas to Cheyenne. Thus, the total volume of Rockies gas that can move to Cheyenne and then on to markets in the Midwest and East has already increased.

WIC RECEIPTS, INTERSTATE PIPELINES Fig. 5



Basis effect

After three weeks of operation, the anticipated compression of Opal and Cheyenne differentials became evident. Fig. 6 compares the average price at Cheyenne Hub and Opal from Feb. 13 to Mar. 7. Just after the pipeline went into service, Cheyenne prices remained high relative to Opal, but by Feb. 16 the premium had begun to shrink. During the next two weeks, the differential narrowed to less than $0.10/MMbtu.

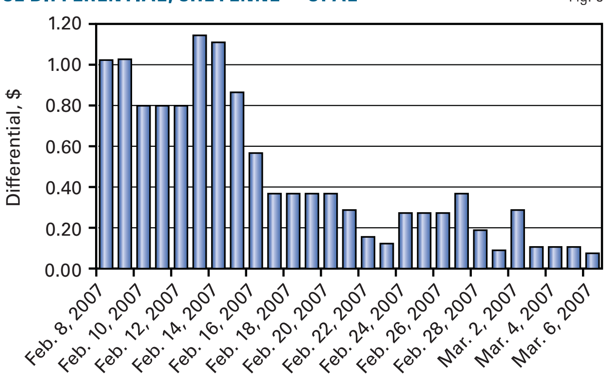
The premium for the first few days portends an inter-Rockies pricing trend that will likely persist: local Rockies demand will swing the Opal to Cheyenne differential.

The price at Cheyenne will likely stay strong relative to Opal in spite of REX when it is cold along the front range of Colorado.

This is not just a winter phenomenon. During the summer, hot weather will also increase front-range demand, likely with the same result.

When Colorado needs gas, the extra demand still drives the price upward at Chey-

PRICE DIFFERENTIAL, CHEYENNE – OPAL Fig. 6



enne. Conversely, when weather reaches extremes along the Wasatch Front, the differential may reverse.

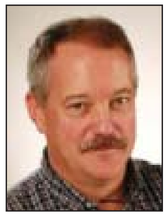
The longer term implications of REX are less clear than its short-term effects. The changes in pipeline flow patterns since REX brought the Wamsutter-to-Cheyenne section online make clear at least two immediate benefits will accrue: improved ability to flow gas from southwest Wyoming to Cheyenne and a narrowing of the basis differentials between Opal and Cheyenne.

Whether REX drives a reduction in the spread between Rockies production and production in other regions of the country will depend on takeaway capacity east of Cheyenne, northwest and west of Opal, south of Greasewood, and local demand. In this regard, Rockies producers may be their own worst enemy.

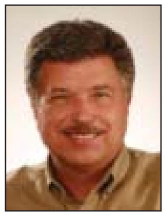
Bentek estimates that between 2001 and 2006, the Rockies region generated 441 MMcfd/year of incremental production. During the last 6 months of 2006, incremental growth in the region exceeded 656 MMcfd. Bentek also estimates that all of the export options combined will create only 150-250 MMcfd of unused takeaway capacity. Weather along the Wasatch front and front range that is either hotter than last summer or colder than this winter might absorb another 100-150 MMcfd.

Bentek believes that by summer 2007 the disparity between production growth and unused takeaway capacity will cause gas-on-gas competition to intensify at Opal and Cheyenne, forcing cash prices lower. Once this situation develops, it is likely to persist until REX reaches Clarington in 2009. ✦

The authors



Porter Bennett is president and CEO of Bentek Energy LLC in Golden, Colo. In his early career, Bennett held positions with consulting companies specializing in energy market analysis. He holds an MS in mineral economics from the Colorado School of Mines and an MA in international affairs from Columbia University in New York. He received a BA in history from Lewis & Clark College in Portland, Ore.



E. Russell Braziel is vice-president, marketing and sales, and chief technology officer for Bentek. He was previously vice-president of business development for the Williams Cos., vice-president of energy marketing and trading for Texaco, and president of Altra Energy Technologies. Braziel holds BBA and MBA degrees in business and finance from Stephen F. Austin University, Nacogdoches, Tex.

Jim Simpson is vice-president, operations for Bentek. Before joining Bentek, Simpson modeled large structured transactions in both gas and power for Enron North America. Subsequently he led natural gas marketing and trading at MarkWest Hydrocarbon Inc. Simpson holds a BBA in finance from Texas A &M University.

Pipe basket transports drillstem components safely

Here's an advanced level pipe basket that promises safe and secure transportation of drillstem components.

The pipe safety basket features integral ratchet straps, helping to ensure a safe and secure load. The elevated and enclosed bottom frame of the safety basket also complies with newer dockside mandates for Dropped Object Regulations.

The basket is proof full-load tested to 55,000 lb—or 2.5 times the maximum weight limit of 22,000 lb. The rigging components of the basket are rated to 1.5 times the maximum load weight. And the baskets are postload tested with full magparticle inspection of all lifting points.

Units are designed for single-line lifts on offshore locations.

Because the safety baskets can be stacked two high, their dimensions and maximum weight limits allow for the transportation of two baskets on a standard 18-wheeler float, the company points out.

The basket also includes a protective enclosure—helping reduce damages that often occur during shipping. Reinforced end area enclosures shield connections and offer protection from load shifts during handling and shipping.

The safety basket also allows for crane or forklift accessibility for loading and unloading.

Source: **Knight Oil Tools**, 2727 SE Evangeline Thruway, Lafayette, LA 70508.

BJ Services Co.

Houston, has announced the appointments of David D. Dunlap as executive vice-president and chief operating officer, and Ronald F. Coleman as vice-president, North America pressure pumping operations.

Dunlap, who has been with BJ for 22 years, most recently served as vice-president of international operations.

Coleman has been with the company for 29 years, with responsibility for the company's US/Mexico operations since 1998.

BJ Services Co. is a leading provider of pressure pumping and other oil field services.

SulphCo

Sparks, Nev., has announced the appointment of Brian Savino as president.

Savino earned a BS from the US Merchant Marine Academy, a master's degree in finance from Long Island University, and a master's degree in transportation from New York University. He has over 25 years of experience in the energy sector, including service with Pierson Capital LLC, RWE Americas, William Energy, Texaco Trading, and Avant Petroleum.

SulphCo has developed technologies to desulfurize and hydrogenate crude oil and other oil-related products.

Technip

Paris, has selected Thierry Pilenko to succeed Daniel Valot as chairman and chief executive officer upon Valot's retirement. During a transition period, Pilenko has been named deputy general manager.

Pilenko received degrees from the Ecole Nationale Supérieure de Géologie, and the Ecole du Pétrole et des Moteurs. He spent 20 years with Schlumberger, before being named chairman and CEO of Veritas DGC in 2004.

Technip is a leading provider of oil, gas, and petrochemical engineering, construction, and services. In support of its activities, the company manufactures flexible pipes and umbilicals, builds offshore platforms, and has a fleet of vessels for pipeline installation and subsea construction.

Cameron

Houston, has announced its acquisition of DES Operations Ltd., a supplier of production enhancement technology for the oil and gas industry, based in Aberdeen, Scotland.

DES' multiple-application reinjection system (MARS) technology enables the installation of multiple processing technologies directly onto a subsea completion. This and other technologies will provide Cameron with increased capability to simplify subsea processing for both on- and off-the-wellhead applications.

Cameron is a leading provider of flow equipment products, systems, and services to the worldwide oil, gas, and process industries.

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4 3-23 2007	Districts 1-4 [1]3-16 2007	District 5 3-23 2007	District 5 [1]3-16 2007	Total US 3-23 2007	Total US [1]3-16 2007	Total US 3-24 2006
	1,000 b/d						
Total motor gasoline	203	335	40	42	243	377	279
Mo. gas. blending comp.	562	382	23	94	585	476	570
Distillate[2]	314	316	38	46	352	362	171
Residual	492	334	48	84	540	418	463
Jet fuel-kerosine	162	80	59	84	221	164	192
LPG	274	199	4	3	287	202	293
Unfinished oils	629	453	34	17	663	470	493
Other	523	421	10	9	533	430	440
Total products	**3,159**	**2,520**	**256**	**379**	**3,415**	**2,899**	**2,901**
Canadian crude	1,661	1,533	314	103	1,975	1,636	1,433
Other foreign	6,774	7,848	309	679	7,083	8,527	9,118
Total crude	**8,435**	**9,381**	**623**	**782**	**9,058**	**10,163**	**10,551**
Total imports	**11,594**	**11,901**	**879**	**1,161**	**12,473**	**13,062**	**13,452**

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

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

OIL&GAS JOURNAL online research center

OGJ CRACK SPREAD

	*3-23-07	*3-24-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	77.04	74.54	2.51	3.4
Brent crude	60.85	61.57	–0.72	–1.2
Crack spread	16.19	12.97	3.22	24.8
FUTURES MARKET PRICES				
One month				
Product value	77.74	75.28	2.46	3.3
Light sweet crude	59.38	62.19	–2.81	–4.5
Crack spread	18.36	13.10	5.26	40.2
Six month				
Product value	76.69	76.11	0.58	0.8
Light sweet crude	64.30	65.63	–1.33	–2.0
Crack spread	12.39	10.49	1.91	18.2

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel Kerosine	Fuel oils Distillate	Fuel oils Residual	Unfinished oils
	1,000 bbl						
PAD I	15,803	55,122	26,925	10,655	42,874	13,436	7,803
PAD II	72,804	50,018	16,252	7,987	27,169	1,570	14,244
PAD III	176,735	64,210	27,601	12,820	33,185	16,781	44,184
PAD IV	14,613	6,285	1,969	452	3,527	426	2,850
PAD V	[1]55,341	26,836	19,623	8,705	12,484	6,024	20,952
Mar. 23, 2007	**[1]335,296**	**202,471**	**92,370**	**40,619**	**119,239**	**38,237**	**90,033**
Mar. 16, 2007[3]	**329,357**	**204,694**	**93,646**	**38,617**	**123,342**	**38,427**	**90,308**
Mar. 24, 2006	**336,850**	**212,059**	**82,536**	**42,800**	**124,137**	**39,324**	**89,973**

[1]Included in total motor gasoline. [2]Includes 6.045 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—MAR.23, 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	3,095	1,260	1,266	1,618	78.2	1,637	88	498	75
App. Dist. 1	31	27	27	95	28.4	22	0	8	0
Dist. 1 total	**3,126**	**1,287**	**1,293**	**1,713**	**75.5**	**1,659**	**88**	**506**	**75**
Ind., Ill., Ky.	2,177	2,085	2,172	2,355	92.2	1,143	145	579	49
Minn., Wis., Dak.	384	372	377	442	85.3	300	29	124	8
Okla., Kan., Mo.	661	526	531	786	67.6	375	27	200	1
Dist. 2 total	**3,222**	**2,983**	**3,080**	**3,583**	**86.0**	**1,818**	**201**	**903**	**58**
Inland Texas	924	602	628	647	97.1	435	38	178	7
Texas Gulf Coast	3,781	3,370	3,466	4,031	86.0	1,424	331	875	234
La. Gulf Coast	3,685	3,286	3,291	3,264	100.8	1,332	419	876	171
N. La. and Ark.	229	192	200	215	93.0	111	10	38	6
New Mexico	145	87	87	113	77.0	110	0	24	0
Dist. 3 total	**8,764**	**7,536**	**7,672**	**8,270**	**92.8**	**3,412**	**798**	**1,991**	**418**
Dist. 4 total	**639**	**549**	**553**	**596**	**92.8**	**289**	**28**	**165**	**13**
Dist. 5 total	**2,467**	**2,224**	**2,450**	**3,173**	**77.2**	**1,597**	**323**	**431**	**106**
Mar 23, 2007	**18,218**	**14,579**	**15,048**	**17,335**	**86.8**	**8,775**	**1,438**	**3,996**	**670**
Mar. 16, 2007*	**18,031**	**14,410**	**14,937**	**17,335**	**86.2**	**8,637**	**1,355**	**4,115**	**662**
Mar. 24, 2006	**17,155**	**14,765**	**15,036**	**17,115**	**97.9**	**8,292**	**1,455**	**3,519**	**689**

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

Statistics

OGJ gasoline prices

	Price ex tax 3-21-07	Pump price* 3-21-07	Pump price 3-22-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	214.0	253.7	235.3
Baltimore	209.9	251.8	232.7
Boston	207.0	248.9	226.9
Buffalo	207.0	267.1	243.0
Miami	218.6	268.9	252.7
Newark	209.3	242.2	218.9
New York	199.7	259.8	243.4
Norfolk	203.5	241.1	225.4
Philadelphia	215.4	266.1	240.9
Pittsburgh	205.1	255.8	231.9
Wash., DC	215.7	254.1	245.9
PAD I avg.	209.6	255.4	236.1
Chicago	227.2	278.1	266.6
Cleveland	202.0	248.4	238.0
Des Moines	203.8	244.2	230.4
Detroit	205.9	255.1	242.2
Indianapolis	206.5	251.5	245.6
Kansas City	207.2	243.2	227.2
Louisville	211.5	248.4	239.1
Memphis	201.3	241.1	227.6
Milwaukee	202.9	254.2	243.5
Minn.-St. Paul	211.7	252.1	243.1
Oklahoma City	206.8	242.2	226.1
Omaha	207.0	253.4	239.3
St. Louis	205.6	241.6	222.2
Tulsa	204.7	240.1	226.3
Wichita	200.9	244.3	232.9
PAD II avg.	207.0	249.2	236.7
Albuquerque	210.6	247.0	239.4
Birmingham	203.4	242.1	228.5
Dallas-Fort Worth	204.7	243.1	236.3
Houston	202.6	241.0	228.5
Little Rock	202.9	243.1	227.6
New Orleans	204.0	242.4	235.8
San Antonio	195.6	234.2	225.4
PAD III avg.	203.4	241.9	231.6
Cheyenne	196.0	228.4	218.4
Denver	202.0	242.4	228.5
Salt Lake City	187.7	230.6	224.9
PAD IV avg.	195.3	233.8	223.9
Los Angeles	249.2	307.7	260.6
Phoenix	221.7	259.1	234.9
Portland	240.5	283.9	237.0
San Diego	257.0	315.5	266.6
San Francisco	276.9	335.4	260.6
Seattle	230.8	283.2	243.6
PAD V avg.	246.0	297.4	250.6
Week's avg.	**211.8**	**255.4**	**236.8**
Feb. avg.	**184.4**	**228.0**	**229.6**
Jan. avg.	**181.7**	**225.3**	**227.3**
2007 to date	**189.6**	**233.1**	—
2006 to date	**187.6**	**230.0**	—

*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

	3-16-07 ¢/gal		3-16-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	192.92	New York Harbor	169.58
Gulf Coast	180.67	Gulf Coast	165.33
Los Angeles	215.67	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	167.70	ARA	167.85
Singapore	178.93	Singapore	172.50
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	188.55	New York Harbor	96.50
Gulf Coast	180.67	Gulf Coast	96.43
Los Angeles	226.67	Los Angeles	126.27
		ARA	94.23
		Singapore	111.48

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

Baker Hughes rig count

	3-23-07	3-24-06
Alabama	3	3
Alaska	12	9
Arkansas	44	21
California	31	37
Land	30	32
Offshore	1	5
Colorado	101	84
Florida	0	0
Illinois	0	0
Indiana	2	0
Kansas	15	5
Kentucky	11	6
Louisiana	191	177
N. Land	57	54
S. Inland waters	26	19
S. Land	43	36
Offshore	65	68
Maryland	0	0
Michigan	2	1
Mississippi	19	6
Montana	22	23
Nebraska	0	0
New Mexico	72	98
New York	8	4
North Dakota	32	27
Ohio	15	7
Oklahoma	178	165
Pennsylvania	14	15
South Dakota	1	0
Texas	818	716
Offshore	8	14
Inland waters	1	2
Dist. 1	26	20
Dist. 2	35	27
Dist. 3	56	65
Dist. 4	91	81
Dist. 5	160	124
Dist. 6	125	100
Dist. 7B	47	39
Dist. 7C	52	41
Dist. 8	102	74
Dist. 8A	27	30
Dist. 9	29	31
Dist. 10	59	68
Utah	44	40
West Virginia	27	26
Wyoming	74	99
Others—ID-1; NV-2; TN-2; VA-2	9	2
Total US	**1,745**	**1,571**
Total Canada	**246**	**639**
Grand total	**1,991**	**2,210**
Oil rigs	281	255
Gas rigs	1,459	1,314
Total offshore	74	87
Total cum. avg. YTD	**1,733**	**1,517**

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

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

Smith rig count

Proposed depth, ft	3-23-07 Rig count	3-23-07 Percent footage*	3-24-06 Rig count	3-24-06 Percent footage*
0-2,500	65	4.6	50	4.0
2,501-5,000	108	62.9	107	42.0
5,001-7,500	227	21.5	210	15.2
7,501-10,000	425	3.2	334	2.0
10,001-12,500	419	3.5	358	1.6
12,501-15,000	270	0.3	267	—
15,001-17,500	103	0.9	112	0.8
17,501-20,000	74	—	76	—
20,001-over	35	—	19	—
Total	**1,726**	**8.7**	**1,553**	**6.0**
INLAND	41		41	
LAND	1,631		1,430	
OFFSHORE	54		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]3-23-07	[2]3-24-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	21
Alaska	783	766
California	682	684
Colorado	51	60
Florida	6	6
Illinois	30	28
Kansas	95	92
Louisiana	1,374	1,201
Michigan	14	14
Mississippi	52	47
Montana	92	98
New Mexico	164	156
North Dakota	104	105
Oklahoma	171	172
Texas	1,343	1,289
Utah	44	45
Wyoming	140	143
All others	64	73
Total	**5,227**	**4,997**

[1]OGJ estimate. [2]Revised.

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

US crude prices

$/bbl*	3-23-07
Alaska-North Slope 27°	44.93
South Louisiana Sweet	63.50
California-Kern River 13°	51.05
Lost Hills 30°	58.95
Wyoming Sweet	58.28
East Texas Sweet	60.42
West Texas Sour 34°	52.65
West Texas Intermediate	58.75
Oklahoma Sweet	58.75
Texas Upper Gulf Coast	55.50
Michigan Sour	51.75
Kansas Common	57.75
North Dakota Sweet	52.00

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

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

World crude prices

$/bbl[1]	3-16-07
United Kingdom-Brent 38°	60.69
Russia-Urals 32°	57.89
Saudi Light 34°	56.60
Dubai Fateh 32°	58.07
Algeria Saharan 44°	62.56
Nigeria-Bonny Light 37°	62.76
Indonesia-Minas 34°	62.16
Venezuela-Tia Juana Light 31°	54.98
Mexico-Isthmus 33°	54.87
OPEC basket	58.86
Total OPEC[2]	57.94
Total non-OPEC[2]	58.15
Total world[2]	58.03
US imports[3]	54.39

[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]

	3-16-07	3-9-07	Change
	Bcf		
Producing region	584	564	20
Consuming region east	718	728	–10
Consuming region west	231	224	7
Total US	**1,533**	**1,516**	**17**
	Dec. 06	**Dec. 05**	**Change, %**
Total US[2]	**3,070**	**2,635**	**16.5**

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

PACE REFINING MARGINS

	Jan. 2007	Feb. 2007	Mar. 2007	Mar. 2006	Change	Change, %
	$/bbl				2007 vs. 2006	
US Gulf Coast						
West Texas Sour	9.46	11.13	15.99	16.56	–0.57	–3.4
Composite US Gulf Refinery	10.44	12.57	16.92	17.16	–0.24	–1.4
Arabian Light	9.71	12.99	17.03	18.43	–1.40	–7.6
Bonny Light	2.80	5.84	9.41	9.66	–0.25	–2.6
US PADD II						
Chicago (WTI)	6.29	11.75	16.19	14.34	1.84	12.9
US East Coast						
NY Harbor (Arab Med)	9.38	12.18	16.89	14.00	2.89	20.7
East Coast Comp-RFG	11.13	14.48	19.58	15.79	3.79	24.0
US West Coast						
Los Angeles (ANS)	17.90	23.96	28.94	17.38	11.55	66.5
NW Europe						
Rotterdam (Brent)	2..58	3.35	3.64	1.99	1.65	82.6
Mediterranean						
Italy (Urals)	7.83	8.60	9.52	9.36	0.16	1.7
Far East						
Singapore (Dubai)	8.28	7.67	8.09	4.76	3.32	69.8

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

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Dec. 2006	Nov. 2006	Dec. 2005	Dec. 2006-2005 change	Total YTD 2006	Total YTD 2005	YTD 2006-2005 change
	bcf						
DEMAND							
Consumption	2,114	1,771	2,348	–234	21,861	22,241	–380
Addition to storage	98	159	99	–1	2,922	3,002	–80
Exports	83	80	46	37	754	728	26
Canada	47	43	23	24	340	358	–18
Mexico	32	32	17	15	353	305	48
LNG	4	5	6	–2	61	65	–4
Total demand	**2,295**	**2,010**	**2,493**	**–198**	**25,537**	**25,971**	**–434**
SUPPLY							
Production (dry gas)	1,610	1,540	1,523	87	18,491	18,074	417
Supplemental gas	6	5	6	—	62	64	–2
Storage withdrawal	441	206	99	342	2,922	3,002	–80
Imports	394	316	408	–14	4,188	4,340	–152
Canada	343	269	353	–10	3,598	3,700	–102
Mexico	0	0	4	–4	6	9	–3
LNG	51	47	51	—	584	631	–47
Total supply	**2,451**	**2,067**	**2,036**	**415**	**25,663**	**25,480**	**183**

NATURAL GAS IN UNDERGROUND STORAGE

	Dec. 2006	Nov. 2006	Oct. 2006	Dec. 2005	Change
	bcf				
Base gas	4,211	4,216	4,217	4,200	11
Working gas	3,070	3,407	3,452	3,635	435
Total gas	**7,281**	**7,623**	**7,669**	**6,835**	**446**

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

WORLDWIDE NGL PRODUCTION

	Dec. 2006	Nov. 2006	12 month average – Production – 2006	2005	Change vs. previous year Volume	%
	1,000 b/d					%
Brazil	87	87	86	79	7	9.0
Canada	671	686	675	679	–4	–0.6
Mexico	396	383	427	427	1	0.2
United States	1,779	1,769	1,739	1,718	21	1.2
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	180	181	175	156	20	12.7
Western Hemisphere	**3,313**	**3,307**	**3,303**	**3,258**	**45**	**1.4**
Norway	322	309	287	268	19	7.1
United Kingdom	164	163	153	168	–15	–9.0
Other Western Europe	19	19	19	21	–2	–9.5
Western Europe	**505**	**491**	**459**	**457**	**2**	**0.4**
Russia	410	420	400	465	–65	–14.0
Other FSU	160	160	160	160	—	—
Other Eastern Europe	18	18	17	18	—	–2.3
Eastern Europe	**588**	**598**	**577**	**643**	**–65**	**–10.2**
Algeria	328	330	310	295	15	5.0
Egypt	65	65	65	65	—	—
Libya	60	60	60	60	—	—
Other Africa	196	196	191	172	20	11.4
Africa	**652**	**651**	**626**	**5992**	**34**	**5.8**
Saudi Arabia	1,490	1,490	1,480	1,460	20	1.4
United Arab Emirates	400	400	400	400	—	—
Other Middle East	670	670	670	571	99	17.3
Middle East	**2,560**	**2,560**	**2,550**	**2,431**	**119**	**4.9**
Australia	75	77	81	81	–1	–0.7
China	180	180	180	180	—	—
India	35	38	41	44	–3	–7.4
Other Asia-Pacific	220	220	220	218	2	0.8
Asia-Pacific	**510**	**516**	**521**	**523**	**–2**	**–0.4**
TOTAL WORLD	**8,127**	**8,123**	**8,037**	**7,905**	**132**	**1.7**

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

OXYGENATES

	Dec. 2006	Nov. 2006	Change	YTD 2006	YTD 2005	Change
	1,000 bbl					
Fuel ethanol						
Production	11,023	10,279	744	115,604	92,952	22,652
Stocks	8,747	9,212	–465	8,747	5,563	3,184
MTBE						
Production	1,503	1,482	21	30,698	46,880	–62,254
Stocks	1,589	1,460	129	1,589	2,860	–1,271

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

US HEATING DEGREE DAYS

	Feb. 2007	Feb. 2006	Normal	2007 % change from normal	Total degree days July 1 through Feb. 28 2007	2006	Normal	% change from normal
New England	1,208	1,028	1,060	14.0	4,435	4,318	4,768	–7.0
Middle Atlantic	936	936	983	–4.8	3,938	3,840	4,332	–9.1
East North Central	1,028	1,028	1,061	–3.1	4,697	4,319	4,835	–2.9
West North Central	1,090	1,090	1,078	1.1	4,995	4,532	5,163	–3.3
South Atlantic	521	521	507	2.8	2,084	2,062	2,233	–6.7
East South Central	669	669	623	7.4	2,800	2,646	2,853	–1.9
West South Central	431	431	414	4.1	1,903	1,648	1,912	–0.5
Mountain	734	734	737	–0.4	3,796	3,401	3,835	–1.0
Pacific	420	420	439	–4.3	2,189	1,977	2,256	–3.0
US average*	**723**	**723**	**732**	**–1.2**	**3,237**	**3,024**	**3,388**	**–4.5**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
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Busy with gotcha games, Congress ignores energy

The best hope for US energy policy these days is embodied in Alberto Gonzales, Valerie Plame, and Al Gore.

Gonzales is the US attorney general, whom congressional Democrats are trying to run out of office.

The Democrats want to know why eight federal prosecutors got fired. When asked about it, Gonzales couldn't manage to say simply that President Bush wanted them to be fired, which is reason enough.

The Editor's Perspective

by Bob Tippee, Editor

So lawmakers have started an inquisition. No crime has appeared yet. Democrats hope to cross up an administration official under oath and score a perjury or obstruction indictment.

Plame is the Central Intelligence Agency something or other whose cover was blown when columnist Robert Novak reported her connection with administration critic Joseph Wilson. The connection: She's his wife and had a hand in his assignment by the CIA to investigate suspected efforts by Iraq to buy uranium from Niger.

Wilson sniffed no Iraqi scent in Niger and wrote articles alleging that Bush juiced intelligence to justify war with Iraq. Attention-grabbing from a CIA-sponsored platform isn't behavior normally associated with a husband concerned about keeping his wife's employment at the agency secret, of course. But when an appropriately curious Novak reported what he learned about it (from the State Department), Washington's scandal machine presumed that the White House outed Plame to punish Wilson.

On Mar. 16, Plame told receptive Democrats in a House committee hearing—only two Republicans showed up—that, sure enough, the Bush folks revealed her secrets "from purely political motives." Nobody asked where she got the information.

On Mar. 21, former Vice-President Al Gore preached his global-warming sermon before a rapt joint House-Senate committee, likening the planet to a baby with a fever—and on and on.

It's all political theater.

"Ten weeks into the new Congress," wrote columnist David Broder recently, "it is clear that revelation, not legislation is going to be its real product."

Good. While busy with gotcha games, Democrats aren't threatening national interests with loopy energy bills like the one that the House passed Jan. 18 and that the Senate, so far, has ignored.

(Online Mar. 23, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Middle East tension hikes oil prices

Escalation of political tensions Mar. 23-25 appeared to threaten Middle East supplies and set the stage for another likely spike in crude prices.

Crude futures prices peaked at $62.65/bbl in intraday trading Mar. 23 in the New York market and settled at $62.28/bbl, up 59¢ for the day, after naval units of Iran's Revolutionary Guard seized eight UK sailors and seven Royal Marines who had boarded a merchant ship for inspection in Iraqi waters of the Persian Gulf.

Meanwhile, Iraqi Deputy Prime Minister Salam Zaubai underwent surgery Mar. 23 at a US military hospital after being injured in a double bombing in Baghdad in which nine people were killed. Iraqi police said a suicide bomber blew himself up and a car bomb exploded as Zaubai was leaving a mosque near his home in the Iraqi capital.

The United Nations Security Council voted unanimously over the weekend to tighten sanctions on Iran after Iranian President Mahmoud Ahmadinejad cancelled his planned appearance to defend his country's uranium enrichment program. The latest resolution embargoed all sales by Iran of conventional weapons and froze the foreign assets of 28 Iranian individuals, institutions, and companies, including Bank Sepah. It called for restriction of new financial grants, credits, and loans to Iran. A Dec. 23 resolution banned trade with Iran in sensitive nuclear materials and ballistic missiles.

Iranian officials said the UN's move will limit their cooperation with the Atomic Energy Agency, the UN's nuclear watchdog. Iran has 60 days to halt its uranium enrichment program or face new sanctions.

Analysts in the Houston office of Raymond James & Associates reported crude futures prices near a 3-month high in early trading Mar. 26. "Geopolitical concerns and supply disruption possibilities are on the forefront of traders' minds," they said. With the proposed build-up of US military forces in the region, analysts said, "The tension is expected to increase in the foreseeable future. Roughly a quarter of the world's oil supply flows through the Strait of Hormuz, a narrow waterway between Iran and Oman. Therefore, any transportation disruptions through that waterway would have a large impact on the world's crude oil supply."

UK demands release

In the interim, UK officials demanded the immediate safe return of military personnel seized as they concluded an inspection for possibly smuggled goods aboard a merchant ship just outside the Shatt al-Arab waterway dividing Iraq and Iran. Jurisdiction in that area has long been contested between the two countries. Iranian officials said they may charge the sailors and marines with violating its waters.

According to UK and US reports, ships of the Iranian Revolutionary Guard naval corps—which operates separately from Iran's navy—darted out of Iranian waters into Iraqi waters to capture the sailors and marines. There was speculation that the seizure might be in retaliation for US detention of five Revolutionary Guard operatives following a January raid on the Iranian consulate in Irbil, Iraq, as part of the effort to counter Iran's growing influence in Iraq.

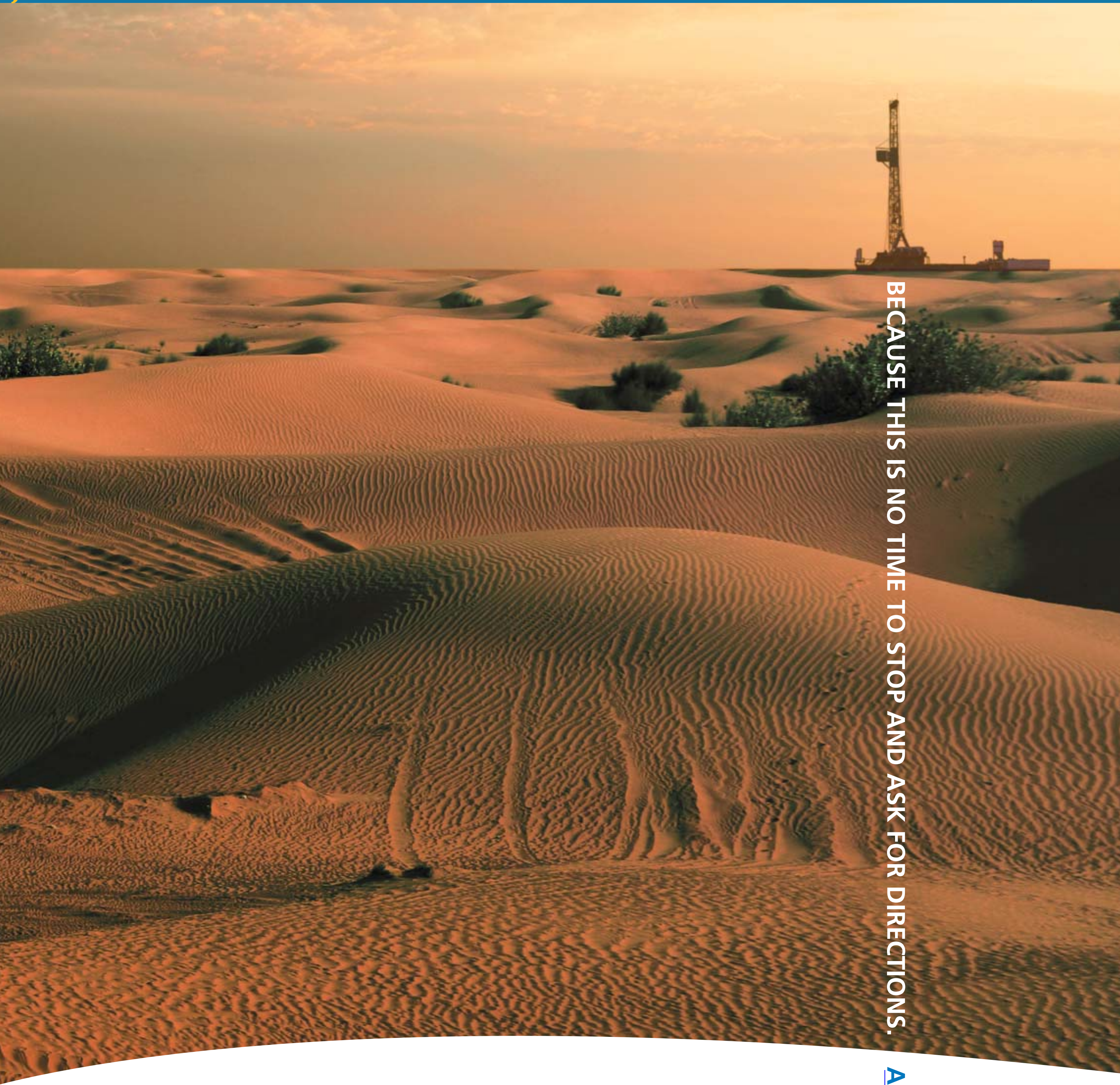
European imports

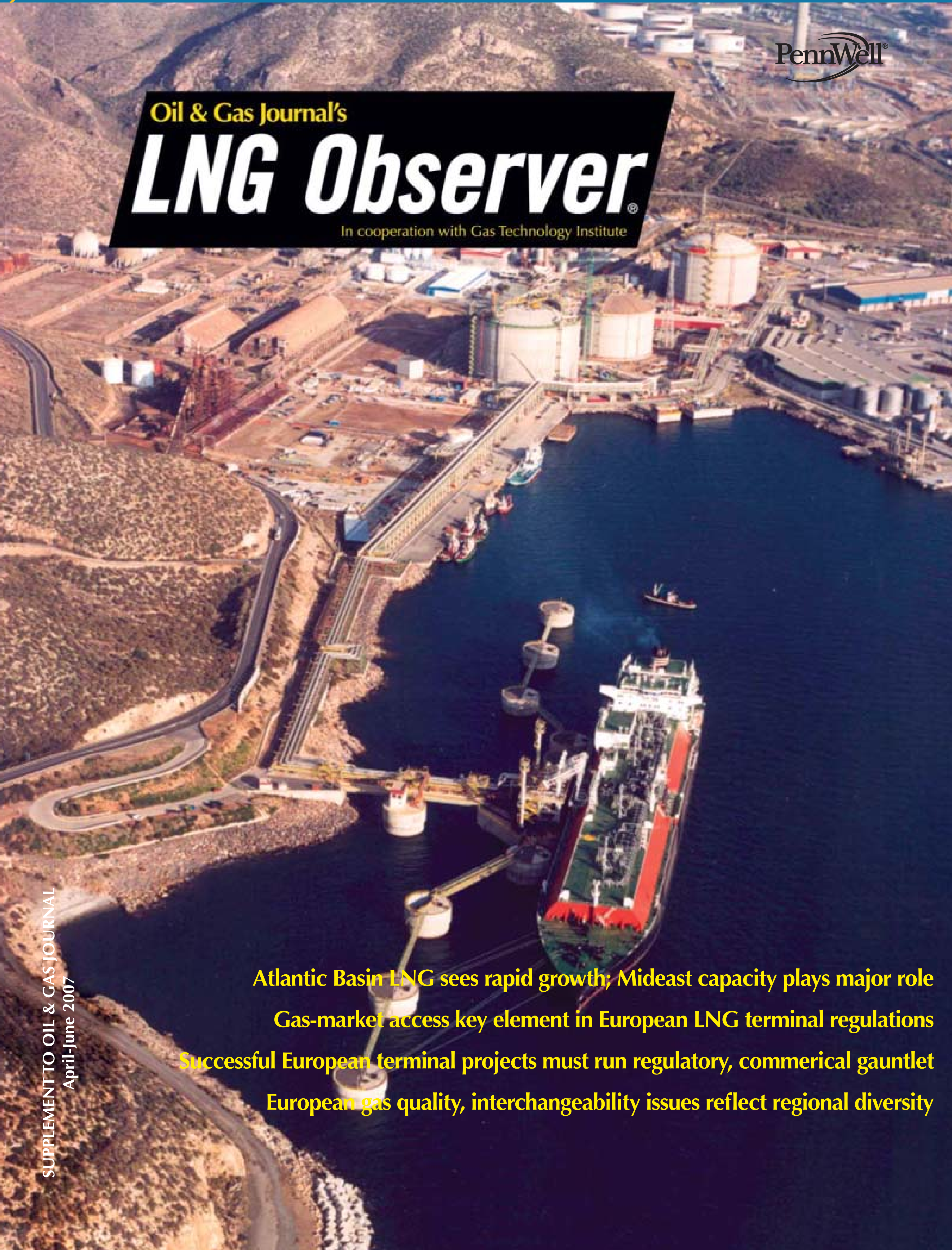
Meanwhile, imports of Saudi Arabian crude by European members of the Organization for Economic Cooperation and Development steadily declined during 2006. Therefore, by keeping its OECD crude exports steady, Libya has taken over Saudi Arabia's former spot as the second largest supplier of crude to Europe OECD, behind Russia. Iraq, Venezuela, and Iran have helped replace former Saudi supplies to those European customers. "Imports from Algeria have dropped and [were] replaced with increases from Azerbaijan," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland, in a Mar. 22 report.

Overall, OECD imports of OPEC crude were essentially unchanged in 2006 from 2005, with the largest difference coming from a drop of Saudi imports (mostly to Europe). "Algeria has decreased flows to Europe to rebalance instead towards North America and the Asia-Pacific. Venezuela on the other hand is reducing its exports to the US and increasing to Europe, while Iran is reducing exports to Asia-Pacific and increasing to Europe," Jakob said.

European imports of gas oil—middle and light distillates—from North America have steadily increased. "While the US is by far the largest importer of European gasoline, European exports to Mexico have seen the largest increase, offsetting slightly lower exports to the US and Nigeria, while exports to Iraq have mostly phased out. Exports to Iran are stable [for] the year but mostly due to shipments in the first half of 2006 while they come down to a trickle in the official statistics for the fourth quarter 2006," Jakob said.

(Online Mar. 26, 2007; author's e-mail: samf@ogjonline.com)


BECAUSE THIS IS NO TIME TO STOP AND ASK FOR DIRECTIONS.



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Atlantic Basin LNG sees rapid growth; Mideast capacity plays major role

Gas-market access key element in European LNG terminal regulations

Successful European terminal projects must run regulatory, commerical gauntlet

European gas quality, interchangeability issues reflect regional diversity

SUPPLEMENT TO OIL & GAS JOURNAL
April-June 2007

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APRIL-JUNE 2007

With LNG Observer's focus on Europe in this issue, its main section (beginning on p. 3) has been expanded to four articles. Each addresses different topics relevant to European LNG development. Spain's terminal at Cartagena (cover) represents the rapid expansion under way in Europe's LNG import system. Operator Enagas added a 127,000-cu m storage tank there in October 2005 and has current plans to increase sendout capacity to 10.5 billion cu m/year from 7.9-billion cu m/year. Photo from Enagas.

Observations

Issues, Trends, Technologies

Project Updates

Statistics

OBSERVATIONS

Interesting times

Warren R. True
Editor
Oil & Gas Journal's
LNG Observer

This issue of LNG Observer recognizes the ascending role of Europe as the world's LNG industry grows and matures. The central section—Issues, Trends, Technologies that begins on p. 3—has expanded to four, rather than the usual three articles.

Each focuses on an area of critical importance for development of Europe's LNG business:

- Its place and function in the growing Atlantic Basin trade.
- The evolution and complexity of Europe's LNG and natural gas regulatory schemes.
- The importance of terminal-use agreements.
- The thorny issues of natural gas quality and regional interchangeability.

These and more concerns fill the agenda for the 15th International Conference and Exhibition on Liquefied Natural Gas ("LNG15"), in late April in Barcelona.

The location is important.

In 2004, for LNG14, industry gathered in Doha, Qatar. That location signified the country's path toward becoming the world's largest producer of LNG, a status it will likely attain before LNG16 in 2010.

For LNG15, a site in Spain, Europe's most prolific LNG importer, and in Europe, a region whose appetite for natural gas draws large pipeline supplies from Russia and Africa, is appropriate as Europe vies with the US to supplant Asia as the world's largest LNG market.

Turning point

And, like Europe, the world's LNG industry gathers at a critical point in its history.

In 2006, more than 20 million tonnes/year of production capacity came on line. 2007 will likely see more than 22 million tpy of production capacity start up. In these 2 years, capacity will have advanced by nearly 30% over what was available in 2005.

Such growth seems striking, until we realize that in 2008 alone, if plans advance on schedule, more capacity will come on line than in both 2006 and 2007.

These numbers alone, however, don't tell the story of industry's evolution. A study released earlier this year by the consultancy PricewaterhouseCoopers notes the changing nature of the industry, saying the world's LNG market has become "characterized by both complexity and globalization, in which the disaggregation of dedicated LNG chains opens up new potential opportunities."

Gone or at least fading is the dominance of LNG trade by single, large Asian suppliers (Indonesia and Malaysia) feeding large Asian markets (Japan and Korea) under long-term contracts.

The report notes that in recent years, a "host of new supply and destination countries [has] emerged, bringing greater volume and dynamism to the LNG market." Of most significance, it says, is the establishment of LNG production in the Middle East, principally among Qatar, Oman, and Egypt. Joining Abu Dhabi, these production centers can serve markets East and West, adding a level of volatility and flexibility unknown in the formative years of industry's growth, 1960s to 1990s.

In the East, as Indonesia struggles to remain an important LNG supplier, new supplies from Australia and Russia are poised to add greater choice and complexity to that area, even as new demand grows in China and India, while Japanese demand flattens.

And as Asia's market landscapes rumble with changing dynamics, Europe and the US stare at each other over the Atlantic Ocean in intense competition for Middle East new supplies as well as volumes from such newly developing Atlantic Basin producers, as Nigeria, Angola, and Equatorial Guinea.

Such evolution of markets and suppliers has sparked intense debate of whether an LNG spot market is developing. PricewaterhouseCoopers is in no doubt: "A short-term 'spot' LNG trading market has developed, accounting for around 11.4% of LNG sales in 2004 if swaps and diversions are included...," adding "the rise of short-term trading in LNG has been dramatic"

The consensus at a session on LNG spot trading at CERAWeek 2007 earlier this year was that spot trading, however defined, would settle at nearly 20% of global LNG trade and that traditional long-term contracts would steadily become less long-term.

It's a curse, remember

These are, no doubt, interesting times. But perhaps we should pause to remember: That saying is a curse, not a blessing.

Living in these interesting times, especially if you are trying to survive and grow commercially, often seems more curse than blessing. But would we have it any other way?

Being only a disinterested watcher and listener as one of the world's great enterprises wrestles with its future ... now that's a privilege. **LNG**

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Atlantic Basin LNG sees rapid growth; Mideast capacity plays major role

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The near-term future of the Atlantic Basin LNG market is exciting, with many new import terminals and several new suppliers set to begin operations.

With Middle East suppliers about to take a prominent role in providing swing supplies to the Atlantic, the definition of the Atlantic Basin LNG market is itself changing. Although the Atlantic and Pacific LNG markets are beginning to blend, significant differences between them continue to exist, however, especially with regard to pricing and contractual terms. Whether these differences will fade in the coming years remains to be seen.

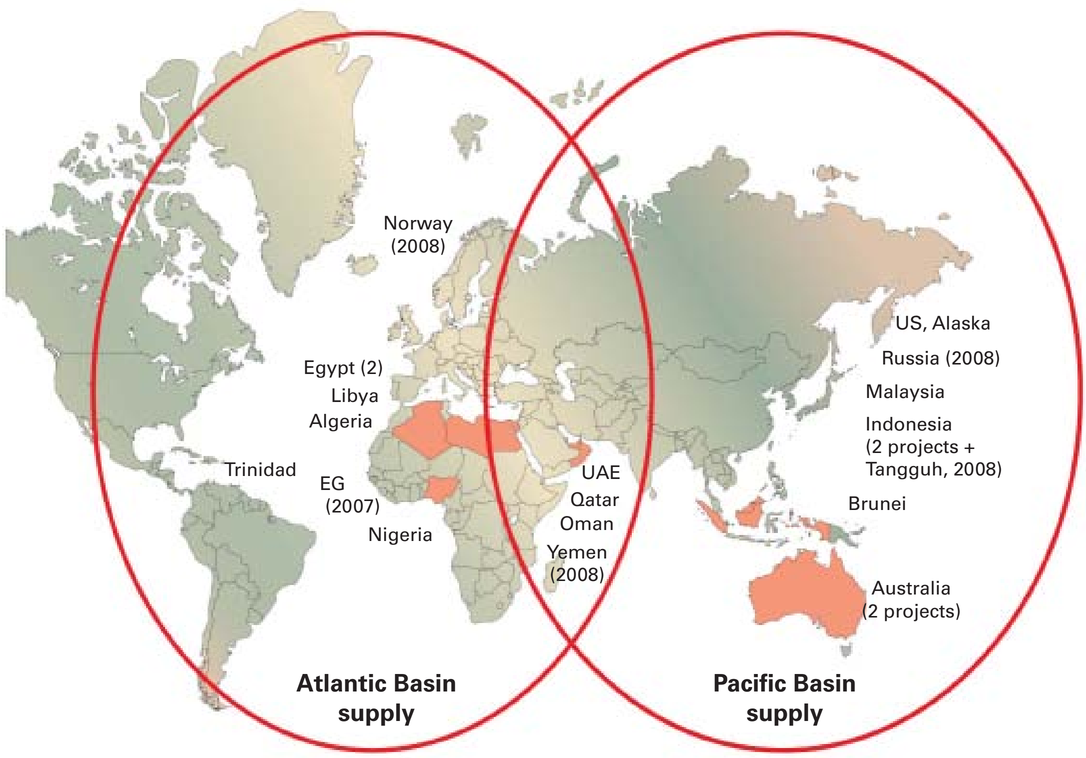
This article will review the origin and current state of the Atlantic Basin LNG market and name some of the drivers shaping this market near-term. It will define the contours of the Atlantic Basin LNG market and highlight key participants, as well as some likely future players. It will examine how this market has risen to prominence in the worldwide LNG industry in a relatively short time.

The discussion will then analyze characteristics of the Atlantic Basin LNG market and how it can be differentiated from the older, more traditional Pacific Basin LNG market. It will examine how geopolitics and other factors are affecting the Atlantic Basin LNG market's continued development and the roles of major Middle East LNG suppliers in serving as swing provider of LNG supply security.

Finally will be a view of how competition between these two primary LNG markets will shape the near-term of the Atlantic Basin LNG market.

TODAY'S LNG SUPPLY, MIDDLE EAST AS SWING PRODUCERS

Fig. 1



Definition

The Atlantic Basin is usually defined as made up of all land masses (including islands) that lie adjacent to or within the Atlantic Ocean and its marginal waters, including the Baltic Sea, North Sea, Black Sea, Davis Strait, Denmark Strait, part of the Drake Passage, Labrador Sea, Mediterranean Sea, Norwegian Sea, almost all of the Scotia Sea, Baffin Bay, Hudson Bay, Gulf of St. Lawrence, Gulf of Mexico, Caribbean Sea and the Weddell Sea, and all navigable rivers and tributaries that empty into any of these bodies of water.

With this rather broad expanse as a reference point, the Atlantic Basin LNG market can be seen as that segment of the world LNG market capable of commercially producing or consuming LNG in or adjacent to the Atlantic Basin.

Others have simply defined this market as all LNG producers and consumers physically located west of the Suez Canal, although this definition excludes the three primary Middle East LNG producers who have been serving and will no doubt continue to serve Atlantic Basin LNG markets.

Under our preferred definition, Atlantic Basin LNG markets specifically include current LNG producing countries Abu Dhabi, Algeria, Egypt, Libya, Nigeria, Oman, Qatar, and Trinidad & Tobago, and LNG consuming countries Belgium, Dominican Republic, France, Greece, Italy, Mexico, Portugal, Spain, Turkey, the UK, and the US (including Puerto Rico), as well as future LNG producers Angola, Equatorial Guinea, Norway, Russia, Venezuela, and Yemen, and possible future LNG consumers Brazil, Canadian East Coast, Germany and the Netherlands.

The Bahamas and Jamaica have also announced plans to join Atlantic Basin LNG market consumers, although both have to date encountered significant political obstacles that have delayed progress.

By way of contrast, the Pacific Basin LNG market consists of present LNG producers Abu Dhabi, Australia, Brunei, Indonesia, Malaysia, Oman, Qatar, and the US (Alaska), producing projects under construction in Peru, Russia (Sakhalin), and Yemen, and current LNG consumers China (including Taiwan), India, Japan, and South Korea, together with future Pacific Basin LNG producers Iran and Papua New Guinea, and future LNG importers Canadian West Coast, Mexico's West Coast, Indonesia, Pakistan, Singapore, Thailand, and the US West Coast.

Atlantic Basin: example terminal-use agreements

Fluxys LNG; Belgium
- Qatar / Exxon (2004)
- Distrigas (2004)

Dragon LNG; UK
- BG (2004)
- Petronas (2004)

Grain LNG (National Grid Transco); UK
- BP/Sonatrach (2004)
- Gaz de France (2005)
- Centrica plc (2005)

Sabine Pass, Cheniere Energy; Louisiana, US
- Total (2004)
- Chevron (2004)
- Cheniere Marketing (2006)

Freeport LNG; Texas, US
- Dow Chemical (2004)
- ConocoPhillips (2004)
- Mitsubishi (2005)

Sempra, Cameron; Louisiana, US
- ENI (2005)
- Merrill Lynch (2006)

As should be evident from both suggested LNG market definitions, Abu Dhabi, Oman, Qatar, and, in future, Yemen and perhaps Iran play an important swing role in forming part of, and being equally capable of serving, both Atlantic Basin and Pacific Basin LNG markets (Fig. 1). Likewise, Mexico and Canada will be future consumers in both the Atlantic Basin and Pacific Basin LNG markets, and the US plays a unique role in being an LNG producer (Alaska), an existing LNG consumer (East and Gulf Coasts), and a future LNG consumer (West Coast).

Atlantic Basin: US perspective

The Atlantic Basin LNG trade began for the US in 1968 when exports from Algeria were delivered to the Boston Gas Co. at the first commercially operational LNG import terminal in the US near Dorchester, Mass. By 1972, Distrigas began importing LNG from Algeria into the newly commissioned Everett terminal near Boston. Between 1968 and 1977, actual LNG imports remained somewhat steady, never exceeding 12 bcf/year.

Then, with commencement of several new long-term Algerian supply contracts between 1977 and 1979, LNG import volumes grew at the fastest rate in US history, peaking at more than 253 bcf/year, which at the time was about 1.3% of total US gas market demand.

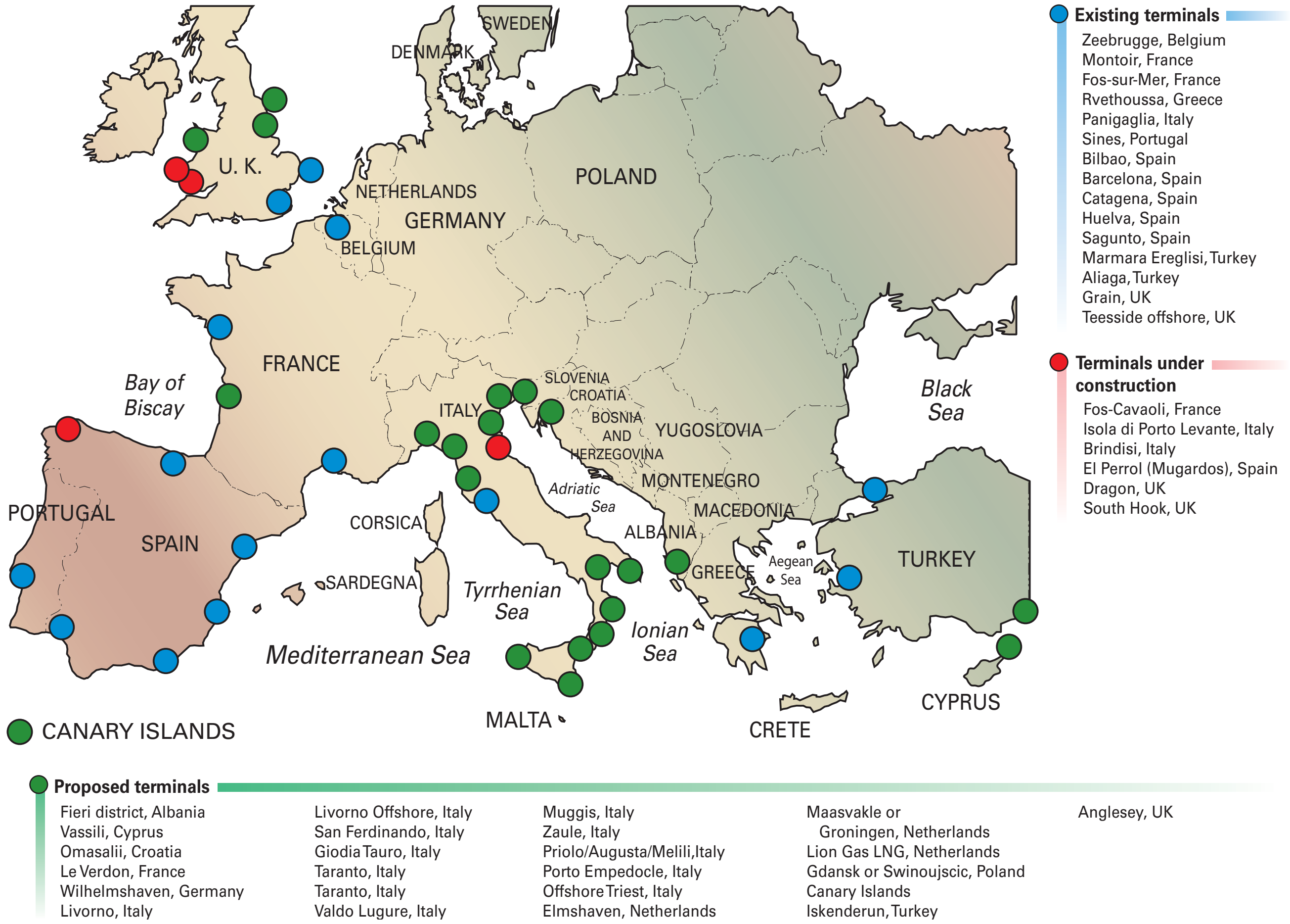
Just as quickly as the market had heated up, the 1980s ushered in a decade of turmoil that featured LNG supply interruptions in April 1980, following a protracted pricing dispute with Sonatrach, and the opening of Trunkline LNG's Lake Charles, La., terminal in September 1982 (with volumes quickly reaching 125 bcf by mid-1983). This was followed by subsequent suspension of imports and mothballing of this terminal in December 1983 when high Algerian LNG supply prices made the dedicated supply contracts uncompetitive in the US gas market.

By 1985, importer Distrigas had filed for bankruptcy due to its inability to reconcile high LNG supply contract prices with the pricing under its customers' gas sales contracts. In 1987, not a single molecule of LNG was imported into the US, which marked the first time since 1974 the US saw no LNG import activity. Shortly thereafter, Distrigas emerged from bankruptcy and resumed its LNG purchases from Algeria, and the Trunkline LNG facility was subsequently re-opened and began receiving LNG cargoes once again in December of 1989.

The early 1990s showed a somewhat healthy return of LNG imports with

European terminals

Fig. 2



volumes ranging between 75 bcf/year and 100 bcf/year. In 1994-95, Sonatrach initiated a large-scale liquefaction plant overhaul that resulted in yet another suspension of LNG deliveries from Algeria and drop in total US LNG import volumes to around 18 bcf (about seven LNG tanker cargoes) in 1995.

LNG imports slowly began to recover, and by the end of 1999 and into 2000, it began to become clear to many US gas market observers that the growing supply-demand imbalance resulting from flattening domestic gas production and rising gas demand (propelled mainly by new power-generation capacity) would cause long-term US gas market pricing to remain at or above $3/MMbtu. At the time, this was widely viewed as the minimum price that would provide sufficient netback value to gain the interest of the major Middle East LNG suppliers.

Spot LNG cargoes from the Middle East began appearing at Lake Charles in 1998, and this activity increased as US gas-market pricing improved through 2000. Thereafter, with the re-opening of the Cove Point, Md., terminal and the Elba Island, Ga., terminal, the US had three operational LNG import terminals on the East Coast (a premium pricing market relative to the Henry Hub index point), in addition to the Lake Charles terminal and the offshore Energy Bridge

Largest gas reserves holders: LNG status*

Table 1

Rank	Country	Reserves, tcf	Growth status
1.	Russia	1,680	Sakhalin only?
2.	Iran	940	FID in 2007?
3.	Qatar	910	Limited until 2010?
4.	Saudi Arabia	235	No LNG plans
5.	UAE	212	Growth possible?
6.	US	189	Kenai extension?
7.	Nigeria	176	NLNG; Brass; OK
8.	Algeria	160	Growth possible?
9.	Venezuela	151	Plans uncertain
10.	Iraq	110	No LNG plans

*Proved gas reserves, 2005. FID = final investment decision.

Gulf Gateway (opening in 2005) closer to the Henry Hub.

Four new LNG terminals are currently under construction in Louisiana (Sabine Pass, Cameron, and Golden Pass) and Texas (Freeport LNG) that, when completed in 2008-09, will significantly increase import terminal capacity of the US in the Atlantic Basin. Several other US terminal projects have received necessary governmental approvals and may, depending on market conditions, commence construction in the near future.

European LNG experience

LNG has actually been imported into Europe since October 1964 (at Canvey Island, UK), slightly more than 4 years before the first imports into the US, although it has only been in the last few years that Europe has received the level of global LNG industry and press attention that is due to such an important part of the Atlantic Basin LNG market.

Europe at present has more LNG import capacity than the US, with at least 15 operational LNG import terminals spread across 8 different countries. Astute European gas-market observers have been planning for significant additional LNG import capacity for the past several years as they have watched UK and Dutch domestic natural gas production beginning to flatten in the face of consistently increasing demand. To be fair, however, it is important to note that Norwegian pipeline gas production has proven quite a success during the same time period.

The international spotlight turned fully on Europe in the past 2 years, with winter pipeline gas supply from Russia experiencing interruptions, an unusually cold winter in the UK driving up gas demand and spiking prices, and a severe drought in Spain that sharply curtailed hydroelectric power generation and led to diverted LNG cargoes as gas-fired power generation stepped in to fill the gap.

Today, the map of existing and planned LNG import terminal capacity in Europe (Fig. 2) closely resembles the multi-colored pin cushion that has come to characterize the ever-expanding US LNG import terminal development map maintained and published by the US Federal Energy Regulatory Commission.

Thus far, Europe does not appear to have suffered from the on-again, off-again starts and stops of the early US LNG import market, and the practice of mothballing LNG import terminals for extended periods of time seems to be largely a US phenomenon.

Defining characteristics

Perhaps the greatest difference between the Atlantic Basin LNG market

and the Pacific Basin LNG market relates to market pricing.

While the Pacific Basin LNG market is largely priced against a few key Pacific market crude oil indexes (the Japanese Crude Cocktail, or "JCC," and the Indonesian Crude Price, or "ICP") that maintain a significant degree of parity, the Atlantic Basin LNG market enjoys a host of different and divergent points of import and market pricing indexes, with the Henry Hub (La.) index used in most US and Caribbean Basin (including Mexico) LNG and natural gas sales contracts, the National Balancing Point (NBP) index being frequently used in the UK, and Brent oil-based and other regional gas-pricing indexes, such as Zeebrugge, carrying the day in still other areas.

There has been little correlation between the Henry Hub and European gas pricing indexes in the past few years (although the gap generally appears to be closing), which has at many times led to a transatlantic price competition in which LNG volumes, particularly spot or swing volumes, find their way to their ultimate markets based solely upon comparative seasonal price fluctuations between the US and Europe.

While the US has not seen the anticipated tremendous increase in LNG import activity in the past year or so due to European pricing that has at most times been significantly higher than US market prices, it remains to be seen whether this higher European pricing will hold up over the longer term. Of course, none of the world's LNG producers is yet ready to forget the recent season of $14/MMbtu natural gas in the US. Although with a little more discipline and foresight in planning gas-storage volumes, many in the US believe this may have been a one-time aberration.

Pacific Basin LNG buyers have also traditionally been very comfortable with long-term, high-volume take-or-pay LNG supply contracts. By contrast, significant gas buyers in the Atlantic Basin LNG market (and in certain places in the developing Pacific Basin LNG market) are often regulated US utilities, such as power producers or local gas distribution companies, that either by habit or regulation are often loathe to sign up for large commodity volumes on a long-term basis, particularly on the type of take-or-pay terms that predominate in the LNG industry.

In addition, many of these US consumers maintain gas supply and transportation arrangements for which disruptions due to occurrence of a force-majeure event are somewhat unlikely and even when they do occur are frequently remedied (either contractually or practically) within a short time due to widespread availability of substitute supplies.

As such, many Atlantic Basin LNG market consumers are very unfamiliar with, and uncomfortable taking on, the types of long-term force-majeure risks that are assumed as a matter of course by many of the large, traditional Pacific Basin LNG market consumers that simply have no other source of gas supply.

Finally, from a total LNG import capacity standpoint, the Pacific Basin LNG market enjoyed a significant advantage for quite some time, but new and recommissioned LNG import terminal capacity in North America and Europe appears to have closed this gap significantly. Many of these new facilities are multi-user terminals, with detailed terminal-use agreements providing the terms of LNG terminaling services being executed by at least six terminals in the last 3 years.

The Pacific Basin LNG market has yet to see terminal-use agreements used by traditional LNG buyers (that generally own and are sole users of their import terminals), the primary exception being Sempra's Energía Costa Azul terminal in Mexico, which has executed TUAs with Shell and Sempra affiliates.

An accompanying box shows an example of Atlantic Basin terminal-use agreements.

Lastly, there may also be key differences between the sizes of ships serving these two LNG markets in the near-term, as there are several LNG import terminals planned and under construction in the US and Europe which, when operational, will be able to receive new-generation 200,000+ cu m LNG tankers designated for service out of Qatar. To date it does not appear that many importers in the Pacific Basin LNG market are planning for ship sizes in excess of 165,000 cu m, and many of the traditional Pacific Basin LNG market customers may never be able to accommodate the 200,000+ cu m vessels due to significant harbor and terminal draft issues.

Emerging market dynamics

At present, the UK, France, Spain, and Italy are projected to be the primary LNG consumption drivers in the European market, with numerous LNG import terminals in service and planned in each country. (In fact, Italy will soon open the world's first offshore gravity-based terminal, in the Adriatic Sea). The US East Coast is still projected to be a significant source of overall demand growth in the US, although due to political obstacles much of this growth is likely to be served by LNG import infrastructure on the US Gulf Coast.

Perhaps the most interesting dynamic emerging in today's worldwide LNG trade, however, relates to developments (or lack thereof) in supply, in both the Atlantic and Pacific basins. LNG demand now far outstrips LNG supply in both markets, and prospects are not bright for a near-term balance between the two.

Geopolitical issues, in particular, continue to hinder LNG production growth. For example, many of the countries with the world's largest gas reserves (Table 1), which generally are not close to the Atlantic Basin LNG market, have no or limited plans for constructing new or additional LNG production facilities.

Moreover, with LNG production shortfalls predicted from Indonesia and delays affecting key proposed Australian projects, several Pacific Basin customers that are concerned about long-term supply security appear to be looking to Middle Eastern producers, such as Qatar, for longer-term large-volume supply security.

Very recently at least one long-term Middle Eastern supply volume that appeared to be originally destined for delivery into the Atlantic Basin LNG market was contracted long term to a Pacific Basin LNG market customer.

This makes good commercial sense as well when LNG pricing in the Pacific Basin LNG market is attractive relative to the US or European markets as it is today. To the extent that this diversion trend continues, and we see Middle Eastern LNG producers stepping in to become the supply-security providers to the traditional Pacific Basin LNG market players, LNG volumes will be increasingly diverted away from the Atlantic Basin LNG market. LNG

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Gas-market access key element in European LNG terminal regulations

Jean-Paul Pinon
Commission for the Regulation of Electricity and Gas
Brussels

A recent survey on access to LNG terminals, ordered by the Council of European Energy Regulators,[1] concluded that "the state of development of liberalization and competition in the market downstream of the terminal is in many instances more the determinant of access than the terminal itself."[2]

This conclusion explains why this article on European regulation covers not only regulations applicable to LNG, but also the main principles governing access to transmission networks.

An overview of the European grid appears in "Gas Infrastructure Europe."[3]

Given the high and growing import dependency of the European Union (EU), there is currently no European liquefaction plant for exporting LNG. LNG terminals perform three main activities: berthing, and unloading, storing, and regasifying, and occasionally such services as blending and truck loading.

Liberalization consists mainly of breaking into four segments the supply chain that was vertically integrated in incumbents' groups:

- Production and other upstream activities; unfortunately most European countries have no natural gas production.
- High-pressure networks for domestic transmission and transit, storage, and LNG.
- Distribution through local medium to low-pressure grids, which can represent 30% of the consumer's bill.
- Gas trade, covering importation, activities around gas exchanges, wholesale, retail.

In most cases, construction of competing parallel gas networks is not economically viable: Domestic transmission and distribution are considered natural monopolies. The corresponding network operators are appointed as legal monopolists in most countries. Access to these systems is subject to regulated third-party access (rTPA). The upstream activities and the gas trade are obviously left to competition. The grey zone consists of transit, storage, and LNG, with big national disparities.

Legislative process

The three policy objectives of the EU—competitiveness, security of supply, and sustainability—are closely interlinked and complementary: Competitive markets (within an integrated European internal market) provide the necessary signals for investment, which leads to supply security in the most cost efficient manner.[4]

The European legislative process of liberalizing gas markets began in the 1990s, first with the Price Transparency Directive[5] and with basic nondiscrimination requirements in Transit Directive[6] and then, under the First Gas Directive,[7] with the abolition of import monopolies, gradual market opening, accounting unbundling for vertically integrated network companies, and an option of regulated TPA.

The Second Gas Directive[8] was to be implemented by July 1, 2004, although implementation has been late or otherwise unsatisfactory in many member states.[9] It requires full market opening by July, 2007; rTPA based on approved and published tariffs to networks (domestic transmission, including balancing services, transit, distribution), and LNG terminals, rTPA or negotiated TPA (nTPA) to storage, and further unbundling of integrated companies.

It is complemented by the Gas Regulation,[10] which expands on several provisions in the directive. A European directive needs transposition in national law; the directive is binding for the member states but not directly for its citizens. A European regulation is directly applicable in all member states and overrules national legislation.

The gas regulation introduces qualitative obligatory minimum requirements for access to transmission systems (network tariffs, TPA services, capacity allocation, transparency, balancing, and trading of capacity rights). Services must be offered in a nondiscriminatory manner on terms that may also suit new entrants (e.g., firm and interruptible capacity; long and short-term contracts). Regulated tariffs usually reflect costs, as opposed to market-based prices. Tariffs are derived from a transparent cost-allocation methodology to each separately charged service.

It requires nondiscriminatory capacity allocation mechanisms, congestion management procedures based on a use-it-or-lose-it (UIoLI) principle, and a functioning secondary capacity market. Balancing rules must reflect genuine system needs (excessively stringent rules hamper new entrants), and imbalance charges must reflect costs, not intentionally penalizing, while still providing appropriate incentives for balance.

The gas regulation supplements basic transparency requirements of the Second Gas Directive, but even within the scope of these binding rules, the availability of information can suffer from lack of precision on the exact obligations of system operators. The European Commission (EC) has already launched infringement cases against

Construction progresses on one of two 168,000 cu m storage tanks at the Dragon LNG terminal, Milford Haven, UK. The 4.4 million tonne/year terminal is set to begin operations later this year and could expand to 6.6 tpy in the near future. Photograph from Dragon LNG, BG Group.

member states that interpreted gas regulation in a way that would allow important transit lines automatically to benefit from the confidentiality exemptions.

Community legislation is supplemented by other binding and nonbinding instruments, such as the binding guidelines under gas regulation, voluntary guidelines developed within ERGEG[11] and the Madrid Forum[12] (e.g., Guidelines for Good TPA Practice for Storage System Operators, GGPSSO) and technical standards prepared by the European Association for the Streamlining of Energy Exchange (EASEE-gas).[13]

The EC can issue binding or nonbinding interpreting notes in order to clarify the European legislation. The existing notes for the implementation of the electricity directive 2003/54/EC and the gas directive 2003/55/EC cover the following topics:[14] unbundling, role of regulators, public service obligations, distribution, exemptions from certain provisions of the TPA regime, security of supply, labeling, and gas storage.[15] The EC is preparing additional notes related to the gas regulation, whose drafts were submitted for consultation to the Madrid Forum and that deal with calculation of available capacity, congestion management, tariff methodology, and transparency.

To ensure implementation of the regulatory framework in this respect, the Second Gas Directive requires creation of national energy regulators. Their main roles include approving and controlling tariffs (or tariff methodologies), ensuring nondiscriminatory network access and effective unbundling, and dealing with complaints.

In 2004, the EU issued a Directive on Security of Gas Supply, which was a first difficult step towards a more common approach of security of supply among countries that cherish their national sovereignties over energy.[16] This directive clarifies roles and responsibilities of different instances and categories of market players.

On Jan. 10, 2007, the EC published its "Energy package and 2006 reports," a comprehensive package of measures to establish a new energy policy for Europe to combat climate change and boost the

EU's energy security and competitiveness. Regarding the internal market, the aim is to give real choice for EU energy users, whether citizens or businesses, and to trigger the huge investments needed in energy.

Entry-exit systems

Regulators, individually and through CEER, have strongly encouraged establishment of entry-exit systems, in which entry capacity is traded separately from the exit capacity. This system contributes to creating not only a more liquid market for capacity but also for gas because an entry-exit model implies creation of gas pools or virtual hubs where gas is more easily exchanged.

In 2004, ERGEG issued a monitoring report on implementation of entry-exit systems in member states.[17] Specific problems related to entry-exit systems include treatment of short-haul transmission (a consumer nearby an entry point) and disparity of available capacities at both sides of an interconnection point. The latter is typically an issue to be treated in bilateral discussion between two countries or in "Gas Regional Initiatives" organized by ERGEG.

The extent to which the entry-exit model should be applied to transit flows remains subject of debate, especially in countries where transit amounts of gas flows exceed domestic transport. An innovative approach was submitted to consultation in September 2006 by CREG, the Belgian regulator, in which entry capacity would be common for transit and domestic transport. A differential treatment of transit would still be possible through appropriate rules applicable on cross-border exits.

CREG also proposes a new product called "operational options" (or "commitments to nominate") in order to reduce the uncertainty on gas flows that must be managed by the system operator and to allow offer of backhaul capacity on a firm basis.[18]

Exemptions

Exemptions from TPA, whereby investors can reserve the capacity for themselves or sell it at market price, can be granted by the regulator for new or enhanced major infrastructure, under supervision of the EC, according to Article 22 of the Second Gas Directive. The aim is to provide incentives for risky investments.

"The right balance needs to be found between regulatory certainty for investors and 'sanctity of contracts' on one side and the objective of achieving a competitive and well functioning gas market on the other hand. Grandfathered access rights must not prevent new players from entering the market."

Experience so far with regard to the exemption procedure and its specific effect on the market is still limited. In practice, once investors have a legal possibility to get an exemption and, hence, to keep better control on their profit level, it becomes quite difficult for the authority to resist pressure from relevant lobbies. In many countries, relevant authority limits its ambitions to identifying the right conditions to impose to exempt projects.

The usual threat expressed by promoters is that investment would not take place unless an exemption were granted, which would damage security of supply. Such a threat, while not verifiable, has usually a strong political impact. Even if one promoter renounces building an infrastructure, however, does not mean that nobody else would come up with a project. At present, a wealth of new LNG project proposals amounts to more than 160 billion cu m (bcm) of importing capacity in the EU.[19]

Granting an exemption as an exception to the default arrangements is not necessarily a requirement for new infrastructure to be built.[20] The CEER mentioned, among others, an enhanced regulated rate of return, when this reflects the reward of a real additional risk.[21] Reference can be made to the Spanish LNG market, which does not take recourse to TPA exemption provisions and has found other means securing huge investments. The existence of exemptions can create a problem of market distortion between regulated and exempt infrastructure.

The issue of long-term ship-or-pay contracts to mitigate investment risks has been dealt with in an original way by the Belgian regulator and applied to expansion of the Zeebrugge LNG terminal. Terminal owner and operator Fluxys LNG was allowed to allocate 100% of slots to long-term contracts. The regulator approved a 20-year tariff proposal.

The tariff methodology gives confidence to both terminal users and owners. The tariff is capped with a prudent value covering all risks for the operator. Every 4 years, a tariff revision takes place, ensuring that tariffs are cost-reflective, according to a pre-established methodology: regulated asset base (RAB) times weighted average cost of capital (WACC).

In such methodology, the invested capital is rewarded according to the RAB • WACC formula, in which the regulator approves the values of both RAB and WACC, which can be split up. The regulator also approves the standard contracts (main conditions, network code).

This approach is still an rTPA because both the tariff methodology and other access rules are subject to previous approval by the regulator. It shows nevertheless that rTPA allows for creativity and that rTPA is compatible with long-term contracts. In some countries, exemptions are made necessary because the national legislation does not allow for long-term tariff regulation.

Considering that TPA has serious advantages in terms of competition, efficient use of infrastructure, and security of supply and considering that hoarding of capacity is a fact, mainly on LNG terminals, legislation should leave room for long-term regulation. In some cases in which an exemption is deemed necessary, it could be limited to an exemption from tariff regulation (negotiated TPA).

Exempt infrastructure is still subject to control from the competition authority and from the sector regulator, when conditions have been imposed. Control on the conditions can raise interpretation difficulties and subsequent regulatory risk for the system operator.[22] Such risk disappears in the case of rTPA, when everything (including the tariff methodology) is clearly approved ex ante and possibly for the same period.

Exemption for historic contracts

Taking into account that broadly all import contracts were long-term take-or-pay contracts, treatment of corresponding transit arrangements is of particular importance during transition towards market opening. The right balance needs to be found between regulatory certainty for investors and "sanctity of contracts" on one side and achieving a competitive and well functioning gas market on the other hand. Grandfathered access rights must not prevent new players from entering the market.

The Second Gas Directive, while repealing the Transit Directive (of 1991), states in Article 32 that contracts concluded pursuant the directive continue to be valid and implemented under terms of the said directive. The EC has commented that transit contracts concluded before the entering into force of the Second Gas Directive remain valid, while relevant provisions of the Gas Regulation regarding conditions for access to the gas transmission network and the said directive apply to those contracts as well.[23]

A recent decision of the European Court of Justice leads to a very strict interpretation of exemptions.[24] The contracts exempt on the ground of Article 32 of the Second Gas Directive are supposed to ensure nondiscriminatory conditions of transit.[25]

Unbundling

New entrants are often unable to secure transit capacity on key routes and entry capacity into new markets. Very often, primary transit capacity is controlled by incumbents based on preliberalization legacy contracts that are not subject to normal TPA rules. Additionally, lack of investment and delayed investments by transmission companies with vertically integrated supply companies pose another serious concern.[26]

Evidence exists of vertically integrated network operators deliberately stopping investments in order to benefit their supply branch by depriving competitors of access to more capacity.[27]

To improve access and reduce risks of discrimination and cross-subsidy, the Second Gas Directive requires unbundling of integrated network operators. Transmission and distribution system operators must, in addition to the previous accounting unbundling,[28] also be legally unbundled and management unbundled.[29] The combined operations of transmission, LNG, storage, and distribution remain possible.

> "Exemptions from TPA, whereby investors can reserve the capacity for themselves or sell it at market price, can be granted by the regulator for new or enhanced major infrastructure, under supervision of the EC... ."

Whereas ownership unbundling is not required by EU legislation, several member states have found it necessary also to require separate ownership of network and supply companies. In the previously mentioned "Energy package," the EC advocates full ownership unbundling. Taking into account the political difficulty of deciding this, the EC proposes as second choice a system of independent operators.

Importance of LNG

While roughly 250 bcm were imported to the EU in 2005 by pipeline, 43 bcm were imported as LNG shipments, corresponding to 9% of total gas consumption.[30] Most imports come from the three major gas-producing countries close to the EU: Russia (120 bcm), Norway (80 bcm), and Algeria (60 bcm).

As of first-quarter 2007, seven member states had functioning LNG import facilities: Spain (52.7 bcm existing capacity or under construction), UK (31.1 bcm), France (23.1 bcm), Italy (19.5 bcm), Belgium (9.0 bcm), Greece (6.6 bcm) and Portugal (5.2 bcm).

Most existing capacity (73%) is currently allocated to national incumbents. For capacity under construction, for which the planned capacity allocation is known, only 30% will be controlled by national incumbents.[31] Gas Infrastructure Europe provides a map of locations and characteristics of existing terminals.[32]

LNG trade is gradually moving away from rigid long-term take-or-pay contracts and towards a more flexible supply structure that is more sensitive to market signals. Factors that foster development of a flexible short-term LNG market are:

- Presence of uncommitted liquefaction capacity.
- Presence of excess capacity on receiving terminals.
- Availability of tankers not committed under long-term contracts.
- "Use it or lose it" (UIoLI) measures imposed on capacity holders in terminals.

As a result of these trends, LNG spot trade has emerged alongside long-term trading in the last 10 years and in 2005 accounted for 11% of the global LNG trade.[33] In Europe, development of the Spanish market is the most advanced in spot transactions.[34]

Capacity allocation

Only in the UK and Italy have exemption mechanisms from TPA for new terminals already been applied for periods of 20-25 years. In the UK, 100% of the capacity is exempt,[35] subject to the implementation of UIoLI mechanisms. In Italy the exemptions cover 80% of terminal capacity, whereas remaining capacity is subject to rTPA with priority allocation to final consumers (excluding electricity producers) and shippers wishing to trade gas at the Italian hub (PSV). In practice, promoters make sure that they get sufficient revenues from the exempt part of the infrastructure, considering that any short-term capacity allocation (from the regulated part) is unsure and only a source of additional profit.

For the "old," predirective, regulated terminals in France and Italy, two capacity-allocation mechanisms for primary capacity currently exist. In France capacity is allocated according to first-committed-first-served (FCFS).

In Italy's Panigaglia terminal, capacity allocation follows a priority order by which first priority is given to holders of take-or-pay contracts signed before Aug. 10, 1998; subsequently, the merit order foresees allocation of remaining capacity to holders of other multi-year importing contracts and then to holders of annual importing contracts. Capacity requests of the same priority class within that merit order that can only be partly satisfied are split on a pro-rata basis.

Regarding new terminals or terminal expansions of regulated-access terminals, there is again a difference in approach. In Belgium the old system was replaced effective Apr. 1, 2007, by new long-term contracts in which the standard slots are allocated through an open-season process.[36]

In France, 90% of new capacity at the Fos Cavaou terminal is reserved to project sponsors and 10% is available for third parties on a pro-rata basis. In Spain capacity is allocated following the FCFS method, with a regulatory cap to short-term capacity: 75% of total capacity is set aside for contracts with a minimum length of 2 years. No shipper is allowed to hold more than half the short-term capacity on the same terminal.

"Regulators, individually and through CEER, have strongly encouraged establishment of entry-exit systems, where entry capacity is traded separately from the exit capacity."

Anti-hoarding mechanisms

Anti-hoarding clauses are characterized by a considerable variety of specific provisions. They are mainly in the form of UIoLI with either an ex ante or an ex post effect. In an ex ante system, each slot that is not used by the capacity holder must be offered to the market. In an ex post system, the extent of unused slots is afterwards taken to indicate changes that need to be made for future capacity allocation: Should the terminal user that has reserved capacity on the terminal not use a certain amount of it for a certain period of time, the booked future capacity (or a part of it) will be lost.

More specifically, in Belgium the system user must notify terminal operator Fluxys LNG of slots that will not be used 2 months in advance at the latest. This gives a mandate to Fluxys LNG to offer the slot on the market at a regulated price.

In Belgium and France, the system user will never lose ex post contracted capacity unless there is at the same time underutilization of part of the allocated capacity in a terminal where there is no more available capacity, the capacity owner refuses to sell that part of capacity on the secondary market at a price equal or higher than the tariffs, or the capacity owner is unable to justify its behavior.

In Italy, if during a gas year more than 20% of exempt capacity is unused, the user loses the exemption right for the overall capacity starting from the following year. In Spain, an automatic UIoLI system does not exist, but every system user can trigger a reallocation of unused capacity.

In the UK's Isle of Grain if the capacity holders do not sell their unused capacity, the LNG terminal operator is allowed to sell that capacity to another party. In this case the notice period is 10 days. It must be pointed out that penalties, although of quite different deterrent effect, are present in all the above countries with the exception of UK.

At this stage, experience with the effectiveness of the various anti-hoarding measures is still limited. A factor of some importance in this context is the advance notice period of available slots.

Shippers should obviously have a sufficient time to react to the availability of a slot in order to redirect the route of their ships. The sailing time for an LNG vessel from the Arabian Gulf to Belgium is 15 days. From consultations we understand that a 1-month notice period would be a good compromise.

Other TPA rules

How access is organized differs substantially among member states. Although individual situations can vary and can call for certain terminal-specific solutions, it is nevertheless unlikely that such wide variations even on fundamental issues such as transparency reflect an optimal outcome.

In its work program 2007, ERGEG announced production of guidelines for good TPA practice for regulated terminals.[37] These guidelines can then be used as reference by other terminal operators to draft their access conditions or by regulators to specify some exemption conditions.

Most terminal operators have organized a secondary market for capacity, although the only country with explicit regulation for a secondary market is Belgium.

Gas market liquidity

Gas hubs can be virtual in character, allowing trading of gas that has been physically injected into any point on a national grid. This is the case for the UK hub (National Balancing Point; NBP) and the recent hubs in the Netherlands (title-transfer facility, TTF) and Italy (punto de scambio virtuale, PSV). In these cases, gas is usually traded on an "entry-paid" basis, meaning that entry capacity into the networks has been settled.

Others are "physical," requiring gas to be transported to and from a particular trading point or zone. This is true for Zeebrugge (Belgium), Baumgarten (Austria), and Emden (Germany), for instance. CEER strongly promotes the establishment of liquid gas hubs, allowing hub-to-hub trade all over Europe.[38]

The most important hub in Continental Europe is at Zeebrugge.[39] In 2005, the Belgian regulator published a report assessing liquidity on this gas hub and outlining the measures launched to improve the liquidity. At present, the difference between the gas-quality specifications in the UK and on the European continent is maybe the biggest inhibitor of liquidity. Construction of gas conversion facilities between Zeebrugge and NBP in UK is the object of urgent feasibility studies.

During a recent investigation, many respondents advocated to promote liquidity through obligatory trading on hubs and gas release programs (i.e., imposed auctions of parts of contracted volumes bought by the incumbent under long-term import contracts).[40] Other remedies to high concentration included asymmetric regulation for dominant companies in order to facilitate market entry as well as market share caps to establish liquidity. LNG

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3. http://gie.waxinteractive3.com/download/gridmap/GTE_OP_150.pdf. GIE represents 54 transmission system companies, storage system operators, and LNG terminal operators in 28 countries.

4. "DG Competition report on energy sector inquiry – 10 January 2007" European Commission, SEC (2006) 1724, hereafter "Sector Inquiry"; the present article is largely based on this official report.

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21. "Investments in gas infrastructures and the role of EU national regulatory authorities" by CEER; completed by a dissenting opinion from CREG (http://www.creg.be/pdf/Presse/2005/compress29062005uk.pdf).

22. For the exempt LNG terminals in UK, OFGEM has a review possibility if market conditions should be substantially different to the expectation at the

time of the exemption. In a letter of Aug. 2, 2006, addressed to Grain LNG National Grid, Ofgem reminds "In the event that we receive substantiated complaints from market participants that the new UIoLI arrangements are not effective or if we develop any concerns regarding the use of the facility, we would consider moving straight to reviewing the exemption order for GLNG."

23. "Conclusions of the 10th meeting of the Gas Regulatory Forum–Madrid 15-16 September 2005," Sect. 36.

24. Decision C-17/03 of June 7, 2005, of the Court of Justice of the European Communities.

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26. Sector inquiry (executive summary).

27. Italian Competition Authority has recently taken action against delaying tactics of an incumbent operator to expand an important import pipeline.

28. That is, the keeping of separate accounts.

29. That is, independent from activities not related to the network operation as regards legal from, organization and decision making.

30. BP Statistical Review of World Energy, 2006.

31. Sector inquiry, C.b.III. (871), (887), (888).

32. http://gie.waxinteractive3.com/download/gridmap/LNG_102.pdf.

33. Petrostrategies, 2006. Spot trade refers to transaction of less than a year.

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35. Currently, no single entry point to the UK system is connected via rTPA to an effectively regulated infrastructure, besides the interconnectors with Ireland.

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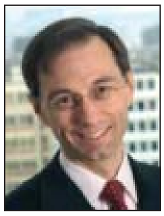
The author



Jean-Paul Pinon beginning this year advises the Belgian Commission for the Regulation of Electricity and Gas as a technical expert. He previously served on the commission, appointed by the government as a member of the board at the creation of the CREG in January 2000 to be in charge of the operation of the natural gas market. In this behalf he formulated and and updated the 10-year plans for gas supply in Belgium and the code of conduct related to gas transmission, storage, and LNG. In 2001-05, he chaired the gas working group of the Council of European Energy Regulators. In this capacity, Pinon contributed to drafting the European regulation for gas transmission and the guidelines for good TPA practice for storage system operators. He graduated in 1980 as a civil engineer in mechanics from the Université Catholique de Louvain-la-Neuve in Belgium and worked for a while as a civil engineer for the Fabricom group. For 6 years, he was managing director of Amasco, a consultancy specializing in energy.

Successful European terminal projects must run regulatory, commercial gauntlet

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In a quest for energy security—really, diversity of supply—European governments are encouraging, and project developers are proposing, LNG terminals all along the European coastline. The sheer volume of proposals, both publicly announced and on the drawing boards, is staggering and suggests a modern version of the "gold rush."

While it is speculative how many of these LNG terminal proposals ultimately should and will be built, each successful project must not only run the regulatory gauntlet but also prove to be viable commercially and operationally.

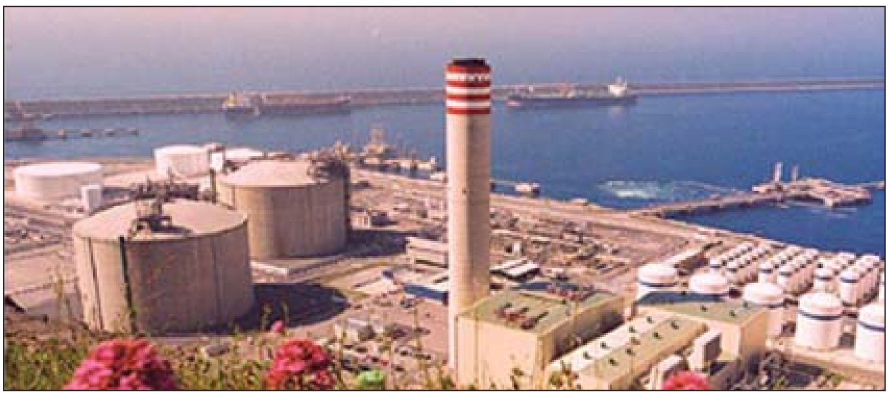
As project developers and potential terminal users explore their options, there is often substantial and early analysis of the proposed physical terminal site, appropriate terminal technology and design, target natural gas market, and permitting requirements. Details of how the proposed terminal actually will operate, such as the rules for vessel scheduling, often are deferred until the project is well advanced under the theory that operational details are unimportant until the terminal is approved by regulatory authorities.

While that approach may be understandable from a terminal developer's perspective, it is a problem for prospective terminal capacity users, especially at multiple-user terminals where operations become more complicated with each additional user.

In Europe, many, if not most, of the LNG terminals will have multiple users. In some cases, the developer will, for commercial reason, provide terminaling services for third parties' LNG. In other cases, it will be a consequence of European Union and national regulatory requirements for third-party access to the terminal.

Although it is possible to secure an exemption from third-party access requirements, qualifying conditions and terms of that exemption vary from country to country. With exception of the UK, the emerging general rule is that only a partial exemption will be granted. For example, Italy allows only up to 80% of terminal capacity to be exempt from third-party access. In all cases, failure fully to utilize terminal capacity may result in loss or qualification of the exemption.

Companies exploring the possibility of securing access at a multiple-user terminal must be aware that these terminals present unique issues.



Handling capacity at the BBG LNG terminal at Bilbao, Spain, doubled in January 2007 to 10 million tonnes/year in anticipation of shipments committed from Statoil's Snøhvit project later this year. The terminal began operations in 2003. Photograph from Bahia de Bizkaia Gas.

Threshold operational assessment

Simply identifying the perfect site and terminal design in the optimal market does not adequately address whether proposed terminal services will be available to the capacity user or users when desired. As a threshold matter before acquiring any terminal capacity, especially at a multiple-user terminal, a prospective user should assess early in its evaluation process certain fundamental operational factors to determine whether the proposed terminal is viable.

Importantly, these operational factors include not only terminal considerations but also the associated waterway. For example, physical (e.g., number of terminal berths and their maximum and minimum capabilities), navigational (e.g., water depth, bridge clearances, and tides) and regulatory (e.g., LNG carrier transit windows and environmental—fog and wind—limitations on vessel transit and berthing) restrictions should be thoroughly assessed to determine whether they preclude meaningful marine access to the terminal for capacity users.

Rights of access

A capacity user's rights of access to terminal services are more complicated but no less critical to the ultimate commercial and operational assessment. The terms of service may be largely set by regulation or may be negotiated between the LNG terminal operator and the capacity user.

The terminal-use agreement typically defines the services to which the capacity user has access (vessel unloading, storage, possible gas treatment, regasification, and sendout) and quantifies them (term, cost, and volume). In many cases, the agreement also defines relative priorities of access as well as certain operational understandings.

Generally, however, LNG operations experts are not part of the negotiating teams and numerous operational details, such as the mechanics of LNG carrier scheduling, are deferred for subsequent agreement or sole determination by the terminal operator later. That subsequent agreement or determination often is set forth in a terminal-services manual, over which the capacity user may have some degree of influence or control. Depending on the level of detail in the terminal-use agreement, these practical rules of access can be a crucial qualification on a capacity user's rights of access, especially if there are multiple users at the terminal.

"Physical, ... navigational, ... and regulatory ... restrictions should be thoroughly assessed to determine whether they preclude meaningful marine access to the terminal for the capacity users."

Access to unloading windows

The most apparent complication posed by multiple-user terminals is access to unloading windows when a capacity user needs it. Most, if not all, terminal-use agreements define a maximum quantity of LNG that may be delivered to the terminal and a maximum daily rate for sendout; many also define maximum storage rights.

But the right to unloading windows often is defined only generally. In some cases, the terminal operator guarantees the capacity user a certain number of unloading windows as a function of annual LNG volume and delivery vessel size, and there is a promise of ratable distribution of those unloading windows. Critically, however, neither the terminal-use agreement nor the terminal-services manual commits to a schedule of unloading windows or to honor the schedule proposed by the capacity user.

Rather, these documents only set forth rules for developing and modifying such a schedule. These rules typically are designed to ensure that the operator does not commit unloading windows to multiple capacity users, rather than to optimize the ability of the capacity users to utilize the windows most effectively.

As an initial matter, the firm capacity users at a multiple-user terminal must determine whether there are enough firm unloading windows for each user to deliver its maximum, contractual, annual volumes; if not, the terminal owner has then oversold the firm capacity rights.

Even if there are enough firm unloading windows, the next issue is whether there are sufficient unassigned unloading windows. This is critical because empirical evidence has shown that the initial schedule must be substantially modified to reflect actual LNG carrier arrival dates. Unassigned unloading windows provide necessary flexibility in the schedule to make those adjustments.

How many unassigned windows are necessary is a difficult question that a modeler can help to answer, but the answer will likely reflect an order of magnitude, not a precise number. There are several variables, including the size of the unloading windows, the amount of storage capacity, and the number of capacity users (because each capacity user needs its own degree of flexibility).

The need to synchronize unloading windows with vessel arrival dates must not be underestimated as there can be severe financial penalties for failure to do so:

- Supply contracts typically allow the seller not to deliver the cargo if it is not timely discharged, which may leave the buyer liable for payment under "take or pay" clauses.
- The inability to manage predictable and appropriate delivery intervals undermines a capacity user's ability to commit to baseload natural gas sales from the terminal because of concerns about tank bottoms and the need to cover in the market. As substantial baseload sales almost always are the reason for investing in long-term capacity, this confidence is important.
- Some European terminals, such as those in Spain and Italy, impose punishing financial penalties for failure to deliver as scheduled.

One other penalty merits comment. If the inability to synchronize unloading windows and vessel arrival dates is extreme enough and results in underutilization of the terminal, then the third-party-access exemption, assuming there is one, could be threatened with revocation and, in the extreme, actually revoked. Ironically, revocation likely would exacerbate the scheduling difficulties if additional capacity users were introduced into the fray.

"The most apparent complication posed by multiple-user terminals is access to unloading windows when a capacity user needs it."

Storage limitations

Another unique and complicating factor that can be found at multiple user terminals is storage limitations. At some terminals, there is sufficient aggregate storage for only one LNG carrier at a time. This exacerbates the problem of coordinating unloading schedules because one capacity user must unload its carrier

Sonatrach
An Integrated International Gas & Oil Group

Sonatrach is Algeria's most important company, responsible for the research, exploitation, transportation, transformation, and marketing of hydrocarbons and derivative products.
In addition to the hydrocarbons industry, Sonatrach is involved in power generation, new and renewable energies, and desalinization of seawater. Sonatrach activities also have a significant international scope, being active in Africa, the Middle East, Europe, and South America. The Sonatrach group as a whole employs approximately 119,225 people.

With a turnover of $45.7 billion in 2005, Sonatrach is Africa's largest corporation and the 12th largest oil and gas firm in the world. The firm's activities represent approximately 30% of Algeria's GNP and it is the world's second largest exporter of liquified natural gas and liquified petroleum gas, and the third largest exporter of natural gas.
Its total production (oil products included) was estimated at more than 232 million ton oil equivalent (TOE) in 2005 and is projected to increase to 270 million TOE in 2007. Sonatrach also operates a wide group of fully or majority-owned subsidiaries which are active in all sectors of the oil and gas business. These subsidiaries operate in various fields, such as: NAFTAL, NAFTEC, HELIOS, HYPROC SHIPPING COMPANY, AEC (Algerian Energy Company), NEAL (New Energy Algeria) ...
Other subsidiaries located in Europe and in the rest of the world play also an important role in the development of Sonatrach activities.

Sonatrach lays out a pipeline network with a total length of 16,000 Km among which two transcontinental gas pipelines; one goes towards Spain via Morocco (Pedro Duran Farrel) and the other towards Italy via Sicily (Enrico Mattei). One of it aims is the increase of natural gas exportations among which 90% will goes to Europe. The creation of Medgaz will allow the building of underwater gas pipeline of 747 km length connecting Algeria to Spain. Galsi project has the aim of building another gas pipeline of a 1.550 km length connecting Algeria to Italy. TSPG (transsaharian gas pipeline project) has as an ambition the achievement of a gas pipeline of 4.400 km length, connecting Nigeria to Europe via Algeria.

Sonatrach : An LNG Pioneer Sonatrach is today the third largest natural gas exporter in the world, the second in LNG and the first gas company in the Mediterranean.

The first baseload liquefaction plant in the world was build in Arzew in 1964, originally named "CAMEL" and today called GL4Z, making Sonatrach a real pioneer in this industry. Nowadays, it operates 04 LNG plants with a combined capacity of 21 million tons per annum (MTPA). It holds in its assets a fleet of 07 LNG carriers of different sizes.
With a production of 41 million cubic meters in 2005, LNG production is expected to reach 60 million cubic meters in 2010.

In Algeria, Sonatrach has launched in partnership an important integrated gas project in Gassi-Touil with a capacity of 4 million Tons of LNG production (6 billion cm equivalent).
In Spain, Sonatrach undertook in partnership the realization of two projects:

1 - The construction of REGANOSA LNG terminal in Murgados and gas transportation plant in Galicia which will have a capacity of 2.5 Gm3 / year of natural gas.

2 - Through PROPANCHEM company, the production of propylene in Tarragona with a capacity of 350.000 T/year.

and clear the LNG from the storage tanks before another carrier can unload.

Even when aggregate terminal storage capacity is more than sufficient to unload a single LNG carrier, individual capacity users may have insufficient storage rights to discharge the larger LNG carriers or, in extreme cases, even a standard LNG carrier. And then, even if an individual capacity user has sufficient storage to unload the largest LNG carriers, that user's schedule may still be severely constrained if it must clear a large portion of its stored LNG to allow the next carrier to unload, in light of imperfectly ratable delivery schedules and the vagaries of long-distance shipping.

"At some terminals, there is sufficient aggregate storage for only one LNG carrier at a time."

Consequently, if there are multiple shippers, then baseload sales from the terminal are practically impossible, absent some coordination or sales among the capacity users.

Multiple-user agreement

One useful tool to address challenges posed by multiple-user terminals is coordination among capacity users, subject always to antitrust considerations. In some cases, as in Spain, that coordination is provided by the regulatory authority. Other cases require a separate negotiated agreement among capacity users.

Capacity users "must plan well in advance ... to best position themselves to optimize their regasification capacity rights."

To address the unloading windows challenge, such an agreement can allow capacity users to manage unloading window adjustments practically, unlike the terminal operator that must defend the contractual sanctity of assigned unloading windows. For example, capacity users can evaluate the shipping picture and swap unloading windows and slow down and speed up LNG carriers as appropriate.

To address the storage limitations challenge, capacity users can aggregate their storage rights and (or) agree to rules for borrowing and lending LNG molecules. Frequently, coordination of, or at least some inter-shipper restrictions on, sendout will be desired to avoid potential storage shortages.

Multi-shipper coordination agreements, despite the degree of commonality of the capacity users' interests, often take substantial time to negotiate and implement due to their complexies. Further, although they allow capacity users to optimize the operability of the terminal within their rights, they are limited by the aggregate underlying rights of each capacity at the terminal.

Accordingly, capacity users must plan well in advance—ideally taking into account multi-shipper coordination issues when negotiating their terminal-use agreements—to best position themselves to optimize their regasification capacity rights.

Conclusions

Multiple-user terminals will be the norm in Europe, and they will pose challenges to the companies that acquire capacity rights at them. Many of those challenges will arise as a result of operational factors. The specifics will vary from terminal to terminal and so the nuances must be identified and then defined early in the terminal assessment process.

Ideally, a capacity user will negotiate a terminal-use agreement that provides the necessary operational confidence, rendering unnecessary the need to coordinate with other capacity users. That, however, is rarely possible. Accordingly, an agreement with the other capacity users can help to address, if not solve, those operational concerns. LNG

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European gas quality, interchangeability issues reflect regional diversity

Terry Williams
Advantica
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This article will look at gas quality from the perspective of downstream interchangeability and concentrate on current issues surrounding increased dependence of many countries around the world on imported natural gas.

The rise in gas trading across international borders through new pipeline interconnectors and LNG shipping brings with it concerns for the variability of gas quality delivered from different sources. To trade natural gas as a truly international commodity, industry needs to agree on the definition and measurement of natural gas.

It may be a surprise that these are not already in place, given the maturity of most natural gas industries. Each gas market, however, has been almost isolated from other markets until now, with its own indigenous reserves. The need to secure gas supplies from many different sources is quite new.

The views are based on Advantica's experience in recent years of working closely with the UK Department of Trade & Industry (DTI), the Technical Association of the European Natural Gas Industry (Marcogaz), and the American Gas Association (AGA).

Despite government initiatives to promote energy efficiency, increase energy supply from renewable energies, and reduce energy consumption from fossil fuels, annual demand for natural gas across Europe continues to rise (Fig. 1). The concern is that as demand increases, production capability across Europe will be declining. Imports of natural gas across the 25 European Union countries 2000-30 are predicted to nearly treble.

Many European countries, including the UK, are constructing new LNG importation terminals (Fig. 2) and increasing gas imports via additional pipeline interconnectors. These moves raise the issue of gas interchangeability because the source and quality of natural gas across Europe will not be constant.

LNG supplies and Norwegian pipeline imports will generally be of a higher calorific value than UK Continental Shelf North Sea gas. Dutch pipeline imports, however, may possibly provide low calorific value gas supplies.

Of additional concern is that the large volumes of gas from LNG terminals and from new pipeline interconnectors will change the traditional flow and mixing patterns within existing gas networks so that many more parts of Europe may see a wider change in gas quality over short time and possibly at the extremes of gas specification limits.

The issue is therefore how to ensure security of gas supply at reasonable cost, knowing that gas-quality parameters of much imported gas may be at the extremes of, or outside, existing gas-specification limits. The options are either to adjust the gas quality at entry points to meet existing limits or to consider widening the limits with the impact that might have on operation of downstream gas-fired equipment.

Interchangeability

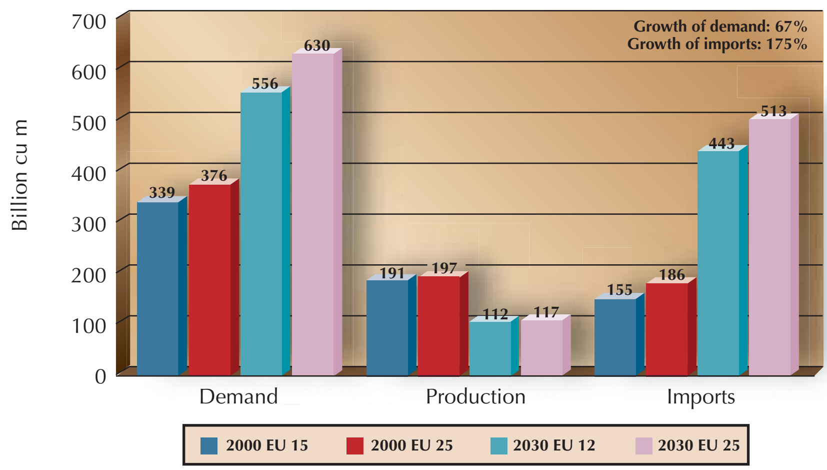
This discussion employs a definition of gas interchangeability recognized internationally: The ability to substitute one gaseous fuel for another in a combustion application without materially changing the operational performance of the application (its safety, efficiency, or emissions).

This would include the need for any gas-fired equipment or appliance firing on the substitute gas to continue to meet the performance standard for which it was originally approved.

Gas interchangeability is not a new concept with considerable work completed, particularly in the US and Europe in

EU natural gas: past, future

Fig. 1



UK's Isle of Grain LNG terminal began operations in July 2005 and has current capacity of 3.3 million tonnes/year (Fig. 2; photo from Grain LNG).

the 1960-70s. This work was triggered by the need for step changes from a manufactured (town) gas to natural gas.

And, as might be expected, different researchers concluded their work on the gas appliances of their region and time with different definitions and measures. The result has been no consistent, internationally recognized way of interpreting gas interchangeability. Different countries, and even different regions within the same country, use a variety of dissimilar parameters and limits of acceptable performance to assess the impact of variable gas quality on gas supply and consumer operations.

Also, in pursuit of increased equipment efficiency and lower emissions, we have seen development of a new generation of gas-fired appliances, with premixed and staged combustion, that may not adjust readily to wide variations in gas quality and may not be appropriately represented by existing interchangeability parameters, found empirically with appliances popular more than 30 years ago.

Different parameters

Many parameters are in use worldwide to represent gas interchangeability. In many cases, including Europe, more than one factor may be used to set maximum and minimum thresholds that form an envelope of acceptable operation for downstream plant and equipment. A selection of the following factors is typically used:

- Heating value or calorific value.
- Wobbe Number or Wobbe Index.
- Relative density or specific gravity.
- Weaver indices.
- AGA indices.
- Incomplete combustion factor.
- Lift index.
- Soot index.

Heating value or calorific value represents the energy content of a gas usually given in units of MJoules/std. cu m or btu/scf and can be expressed as higher heating value (same as gross calorific value in which water vapor in combustion is assumed to be entirely condensed and the heat recovered) or lower heating value (same as net calorific value in which heat of vaporization is not recovered).

Heating value is not the best parameter to represent interchangeability because it does not account for flow through a burner.

Wobbe Number or Wobbe Index is the most widely used interchangeability factor, defined as:

$$WI = \frac{HHV}{(SGgas)^{\frac{1}{2}}}$$

where: HHV = higher heating value
SG = specific gravity

Since the volumetric flow of gas in a pipe is inversely proportional to the square root of gas density (as is the definition of Wobbe Index), thermal input through a burner nozzle is proportional to Wobbe Index and not to heating value. It can also be shown that Wobbe Index is proportional to the equivalence ratio or stoichiometric air requirement for a burner. And, it therefore gives a good indication of gas combustion and energy flow through a burner nozzle.

Relative density or specific gravity, as a measure of gas density relative to air at reference conditions, is used for interchangeability specifications to limit the higher hydrocarbon content of the gas. An increased higher hydrocarbon content could lead to such combustion problems as increased carbon monoxide emissions, soot formation, engine knock, or spontaneous ignition on gas turbines even at the same Wobbe Index value.

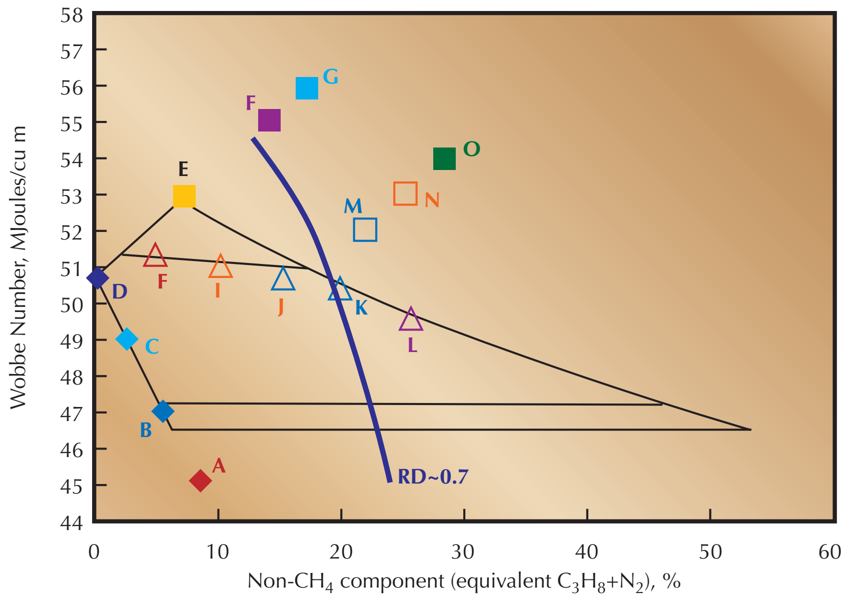
Incomplete combustion factor, lift index, and sooting index are parameters developed for the UK appliance market, as are Weaver and AGA indices for the US. AGA is currently reviewing and updating AGA Bulletin 36 (Interchangeability of Other Fuel Gases with Natural Gases).

UK position

The UK gas specification is set by Gas Safety (Management) Regulations, which use the Wobbe Index as the main parameter of interchangeability. The GSMR set the limits of Wobbe at between 47.20 MJ/cu m and 51.41 MJ/cu m. This is a narrower band of acceptable Wobbe, however, than many other countries specify, including those in mainland Europe.

In response to the likely harmonization of future European gas-quality specifications, discussed later, the UK's DTI has led a program to identify the issues for the UK, review options for gas processing at entry points, assess appliance performance under various gas-quality conditions, and consult with industry on future policy.

Dutton interchangeability — **Fig. 3**



The interchangeability diagram (Fig. 3) shows the UK range of acceptable appliance operation of Wobbe between 51.41 and 47.20 MJ/cu m and shows the 15 sample gases used as part of the DTI test program to test some 25 different UK appliance types representing more than two-thirds of the UK appliance population.

The test program was designed to be as representative as possible of the UK's existing gas appliance population. Testing was on both new and used appliances with the objectives of establishing the impact on combustion performance and emissions of operating on test gases at, and beyond, GSMR limits, measuring emissions and efficiency performance. The program also examined the effect of diluting natural gases with an inert gas such as nitrogen.

It might be expected that modern appliances would be less influenced than older models by a change in the Wobbe index. The drive for higher efficiency and reduced emissions, however, has led to new appliances tending to have burners with a narrower Wobbe operating range, in effect being tuned to the expected gas-quality specification.

A summary of the program's results reported that:

- Ignition was OK for all test gases.
- Flame lift was not generally a problem.
- Little or no soot measured in the flue gas, but some was deposited on the decorative coals of the fires (for the higher Wobbe Number test gases).
- NOx emissions increased as Wobbe index increased.
- Little change in efficiency with Wobbe index change.
- CO emissions increased with Wobbe Number.

Industrial and commercial gas-fired equipment was not tested as part of the UK program but in general should be more tolerant to a wider range of Wobbe index and calorific value due to the investment in more sophisticated process controls such as air-fuel ratio and flue-gas feedback and trim control systems. Gas turbines for power generation, however, would be particularly sensitive to rapid changes in gas quality.

Other examples of processes and equipment that could be adversely affected include:

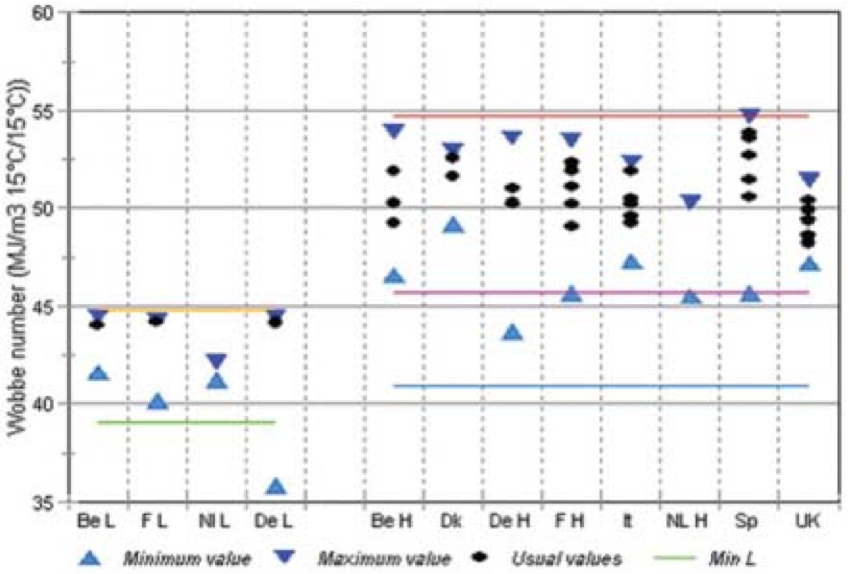
- Float glass and fiberglass production.
- Furnaces with controlled atmospheres.
- Ceramics and glazing processes.
- Gas engines.
- Direct-fired textile processes.
- Fertilizer manufacturing with natural gas as a feedstock.

Changes in flame shape and radiation temperatures could affect most of these industrial processes.

It is most likely, as a result of the 2-year gas quality program managed and recently completed by the DTI, that UK government will wish to retain the GSMR specifications for a time, requiring off-specification imports to be blended or processed to comply with existing Wobbe limits.[1]

European position

European Commission Directives 98/30/EC and 2003/55/EC aim to create a fully operational internal natural gas market with common rules for transmission, distribution, supply, and storage of natural gas. The differences in gas-quality specifications across EU member states have been a barrier to cross-border trade.



Most European countries currently operate a narrow band of acceptable Wobbe Index. There is agreement, however, that the Wobbe Index is the primary interchangeability factor. Several European countries operate completely separate networks for high and low calorific natural gas (Fig. 4; photo from Marcogaz).

The European Union Gas Regulatory Forum (Madrid Forum) consists of representatives of member states, national regulatory authorities, gas industry operators and suppliers, large industrial gas consumers, traders, and producers. In 2002, the forum established EASEE-gas (European Association for the Streamlining of Energy Exchange), with a group objective of giving all participants in the gas chain a forum voluntarily to agree on a set of common business practices. One part of this has been to establish such a practice for harmonization of natural gas quality. The EASEE-gas specification for gas quality includes a proposed Wobbe range of 13.60 kw-hr/std, cu m to15.81 kw-hr/std. cu m (47.0 MJ/cu m to 54 MJ/cu m).

Fig. 4, widely published via Marcogaz,[2] shows that most European countries currently operate a narrower band of acceptable Wobbe than the proposed EASEE-gas specification, but there is agreement that the Wobbe Index is the primary interchangeability factor.

It is also worth noting that several European countries operate completely separate networks for high and low calorific natural gas.

The European Commission has also mandated CEN, the European standards organization,[3] to create a European standard for gas quality giving the broadest limits of acceptable performance as possible within reasonable cost. The CEN mandate identifies the need for a survey of all gas-fired equipment and appliances across all European Union countries and the need for a Europe-wide testing program of a representative sample of appliances.

This would be similar in activity to, although larger in numbers than, the UK Gas Quality Programme. This effort will provide data to analyze the impact on safety, efficiency, and environment, particularly for domestic appliances.

Following this work, CEN will consider creating new test standards and appliance performance standards to build up a population of new appliances that will be able to tolerate and work effectively across a wider variation of gas quality.

US; rest of the world

The US has both state-by-state regulation and federal regulation related to gas quality and gas interchangeability. In an attempt to harmonize this position the Natural Gas Council (NGC) has generated a guidance White Paper that reviews the issues in great detail and concludes that a Wobbe range of +/- 4% around the typical or historical local gas value would be acceptable.

This finding has been submitted to the US Federal Energy Regulatory Commission. Inputs were provided to this work by Advantica, Gasunie, and Gaz de France demonstrating a genuine enthusiasm to gain international consistency.

Within the last year, there has been increasing activity in sharing knowledge and awareness of gas quality and interchangeability development work because it is being raised as an issue across the Far East, particularly Japan, China, and Korea, where LNG imports are significant, and in India, where the impact of gas-quality fluctuations on natural gas vehicle operations is becoming important. **LNG**

References

1. More information on the UK gas-quality program and test results can be found at http://www.dti.gov.uk/energy/markets/gas-quality/phase-2/page21044.html.

2. www.marcogaz.org.

3. CEN = Comité Européen de Normilasation.

The author

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Nigeria Train 6 nears start-up; Turkey terminal receives first LNG

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African exports are poised to increase dramatically as Nigeria LNG's 3.7 million tonne/year (tpy) Train 6 nears start-up and Equatorial New Guinea's first 3.7-million-tpy trains came on stream later in the year.

Final investment decisions are still pending on NLNG's Train 7, Brass LNG, Olokola LNG, and Angola LNG, which together would be able to produce more than 45 million tpy. Egypt's two LNG operations are also considering additional trains.

In Europe, Turkey's Aliaga terminal and Excelerate Energy's Teesside GasPort received their first cargoes.

Africa

Nigeria LNG Ltd. signed five sales contracts for production from proposed Train 7 of the NLNG project, which with a nameplate capacity of 8.4 million tpy, will be the world's largest single train. A final investment decision, however, had not been announced in early March. Deliveries would start in 2012 and be on an ex-ship basis.

A call for construction tenders has been issued. Shareholders in NLNG are Nigerian National Petroleum Corp. (49%), Shell Gas BV (25.6%), Total LNG Nigeria Ltd. (15%), and ENI International (NA) Sarl (10.4%).

Agreements are with the BG Group, 2.25 million tpy; Royal Dutch Shell, 2 million tpy; Total, 1.375 million tpy; Italy's ENI, 1.375 million tpy; and Occidental Petroleum Co., 1 million tpy.

NLNG's 3.7-million-tpy Train 6 is under construction and will come on stream this year. Its output will be marked by Endesa, Total, and Shell Western LNG for destinations in Europe and the US. When it becomes operational, the entire complex will be capable of producing 22 million tpy of LNG and 4 million tpy of LPG and condensate from 3.6 bcfd of feed gas.

In Equatorial New Guinea, a mid-year start-up is slated for EG LNG on Bioko Island. Participants are Marathon Oil (60%); national gas company Sonagas (25%); Mitsui & Co. Ltd. (8.5%); and Marubeni Corp. (6.5%). The entire output of the first 3.7-million-tpy train, built by Bechtel, was sold to BG Gas Marketing Ltd. for 17 years. Bechtel is also performing the front-end engineering and design work for a second 4.4-million-tpy train, which could be fed by gas from Nigeria and Cameroon.

Other West African projects awaiting final investment decisions include:

- The two-train, 10-million-tpy Brass LNG project in Nigeria's Bayelsa State, owned by NNPC (49%) and Total, AGIP, and ConocoPhillips (17% each), has signed memoranda of understanding, each for 2 million tpy, with BP, BG Group, and Suez, starting in 2011.
- The four-train 22-million tpy Olokola LNG project in western Nigeria is proposed by NNPC (49.5%), Chevron (18.5%), Shell (18.5%), and the BG Group (13.5%).
- Angola LNG is a 5-million-tpy project proposed by state-owned Sonangol (22.8%) and affiliates of Chevron (36.4%), and ExxonMobil, Total, and BP (13.6% each). Contracts have been awarded to Bechtel for advanced engineering and to a Dutch joint venture for dredging work. The Angolan cabinet has passed enabling legislation. If the decision is made soon, exports could start in 2012. A second train is under discussion.

In Egypt, where BP reported a major gas discovery off the Nile Delta, BP, Italy's ENI, and the Egyptian government are discussing addition of a second train to the SEGAS project at Damietta. Shareholders are Spain's Union Fenosa and Italy's ENI, which together have 80%, Egyptian Natural Gas Holding Co. (10%), and Egyptian General Petroleum Corp. (10%). BP would become a partner in the second train.

A third train is under consideration for Egypt's other LNG liquefaction project, Egyptian LNG at Idku, which currently has two trains with total capacity of 7.2 million tpy. Partners are BG Group (35.5%), Petronas (35.5%), EGPC (12.0%), Egyptian Natural Gas Holding Co. (12.0%), and Gaz de France (5.0%)

Europe

In December 2006, the Egegaz terminal at Aliaga 60 km south of Izmir, Turkey, received its first shipment of LNG since it was completed in 2002. The 50,000-tonne cargo from Algeria was delivered on the Larba ben M'Idi. Two more cargoes were delivered in January, one from Trinidad, another from Algeria.

The first terminal in the world to be built on a purely speculative basis, the Aliaga facility never started operations because there was no connection to the pipeline grid. Built by Chicago Bridge & Iron, it has a capacity of 6.5 billion cu m (4.1 million tpy), two 140,000-cu m storage tanks, and a jetty for vessels 40,000 to 160,000 cu m in capacity. It can also accommodate Q-flex vessels up to 215,000 cu m. Owner and operator Egegaz is a subsidiary of the privately owned Colakoglu Group.

In the UK in February 2007, Excelerate Energy LLC received its first cargo at its Teesside GasPort in northeast England, the second terminal now operating in the UK. The cargo from Trinidad was regasified aboard the 138,000-cu m Excelsior and delivered into the National Transmission System. The terminal can import

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Tanks for the Dragon LNG terminal, Milford Haven, UK, near completion earlier this year in preparation for terminal start-up in late 2007 or early 2008. Each tank will be able to store 168,000 cu m. The terminal will initially accommodate 4.4 million tonnes/year with plans to expand to 6.6 tpy in the near future. Photograph from Dragon LNG, BG Group.

into the UK up to four cargos/month, which will be marketed by the German company RWE Trading GmbH.

The delivery was preceded by the world's first commercial ship-to-ship (STS) transfer of LNG when the conventional carrier Excalibur transferred 132,000 cu m to the Excelsior at Scapa Flow in the Orkney Islands north of Scotland. The transfer followed several months of test runs in the US Gulf of Mexico (LNGO, Oct.-Dec. 2006, p. 4; and OGJ Online, Sept. 6, 2006).

Both ships are owned by Exmar and leased to Excelerate. The Society of International Gas Terminal and Tanker Operators has been drawing up draft guidelines for the STS transfer of LNG.

Exmar is looking to develop an offshore receiving terminal facility in Belgium, perhaps in partnership with Excelerate. Antwerp and Zeebrugge are potential sites. Belgium's only terminal at Zeebrugge, owned by Fluxys, will double its capacity to 9 billion cu m/year.

Middle East

The first train of the Yemen LNG project, 45% completed at the end of 2006, is to ship its first cargo at yearend 2009. A second train at the 6.7-million-tpy plant is to go online in mid 2009. Partners are Total (39.62%), Hunt Oil Co. (17.22%), Yemen Gas Co. (16.73%), SK Corp. (9.55%), Korea Gas Corp. (6.0%), Hyundai Corp. (5.88%), and the General Authority for Social Security & Pensions (5.0%).

Hunt Oil, in early 2007, was reported to be in talks with China National Offshore Oil Corp. to sell its share for $600 million. The engineering contractor is the Yemgas Consortium consisting of Technip, JGC Corp., and KBR.

In early January, Qatar's RasGas-2 LNG complex had to shut down Trains 3, 4, and 5 because of hydrate formations in pipelines from the North Field caused by colder than normal weather. As much as 14 million tpy of capacity went offline. At least one cargo, a spot shipment to India's Petronet, was cancelled

Americas

In February, the US Federal Energy Regulatory Commission approved two LNG terminals in Pascagoula, Miss.: Chevron Corp.'s Casotte Landing terminal next to its refinery and Gulf LNG Energy LLC's terminal. In 2005, Sonangol acquired what Gulf Energy called a "significant equity interest" in its project.

Chevron also holds 1 bcfd of capacity at Cheniere Energy's Sabine Pass terminal in Louisiana, set to start operations in 2008. FERC also approved Sempra Global LNG's application to expand the Cameron LNG terminal, under construction near Hackberry, La., from 1.5 bcfd to 1.8 bcfd and eventually to 2.65 bcfd.

Dutch company 4Gas has acquired options for all the federal and state permits issued for ExxonMobil's proposed 7.5-million-tpy Vista del Sol LNG import terminal at Ingleside, Tex., as well as pre-engineering and other technical materials related to the project. Occidental Petroleum is re-evaluating the original 2008 start-up date for its planned terminal at Ingleside.

The US Maritime Administration granted deepwater port licenses to Excelerate's second US project, the Northeast Gateway Deepwater Port 13 miles southeast of Gloucester, Mass., and to Suez LNG's Neptune LNG facility 22 miles northeast of Boston.

Both companies made commitments to hire a certain percentage of US mariners on ships visiting the ports and on their existing fleet of carriers serving the US. (Under 2006 legislation, Marad is to give priority to US-flagged ships in approving deepwater port projects.) Both projects were also given the go-ahead by the state of Massachusetts.

Elsewhere, Marathon Oil Corp. and ConocoPhillips filed for a 2-year extension of their Kenai, Alas., LNG plant's export license to Mar. 31, 2011. Since 1972, the plant has been shipping around 1.7 million tpy to Tokyo Gas Co. and Tokyo Electric Power Co.

In South America, Peru LNG awarded a $1.5 billion engineering, procurement, and construction contract to Chicago Bridge & Iron for its 5-million-tpy liquefaction plant in Pampa Melchorita 168 km south of Lima. Participants are operator Hunt Oil Co. (50%), Korea's SK Corp (30%), and Repsol YPF (20%).

Gas from the Camisea field will be transported to the plant through a 408-km, 34-in. OD pipeline. Repsol is responsible for marketing the LNG. New terminals in Chile and Manzanillo, Mexico, are potential destinations.

On the Atlantic side, the government of Trinidad and Tobago is studying the feasibility of building a fifth train at Atlantic LNG, called Train X. The study will evaluate the availability of reserves and future domestic demand. In March, Jamaican Prime Minister Portia Simpson Miller and Venezuelan Pres. Hugo Chavez signed a memorandum of understanding for sale of 2.5 million tpy of

LNG starting in 2009. Details of the project are to be worked out by Venezuelan and Jamaican officials. The regasified LNG will be used in Jamaica's beauxite and alumina industry and for power generation.

Trinidad and Tobago 2 years ago singed an MOU to supply Jamaica with 1.15 million tpy of LNG but the agreement was abandoned, the Jamaica Gleaner reported. Although an LNG project has been discussed in Venezuela since the 1970s, no plant is under construction. One possibility is to ship Venezuelan gas from offshore fields that lie between Venezuela and Trinidad to Train X.

Brazil's state-owned Petrobras has signed an MOU with Russia's Gazprom to "identify cooperation opportunities for oil and gas project development," including LNG projects. To reduce its dependence on Bolivian natural gas imports, Brazil is planning to build at least two offshore LNG terminals by 2008-09, one in the southeast near Rio de Janeiro, the other in the northeast.

Asia

Petronet LNG, India's largest LNG importer, is seeking as many as 40 spot cargoes (equivalent to 2.25 million tons) for delivery this year to supply India's burgeoning demand in the face of declining domestic production.

Petronet, a partnership of four government oil and gas agencies, plans to double capacity at its 5-million-tpy Dahej terminal and is leasing capacity at Shell's LNG terminal in Hazira. Shell and Total aim to import 24 cargoes into their 2.5-million-tpy terminal in Hazira, this year, about 56% of the terminal's capacity.

Petronet partner GAIL has proposed to transport some of the regasified LNG from Dahej and Hazira to Dabhol through a new pipeline to the power plant at Dabhol, where an LNG plant built by Enron has been mothballed since 2001. The government is considering selling the terminal to a company, such as Reliance Industries or Gujarat State Petroleum Corp., that can roll in the price of imported LNG with domestic gas supplies.

Iran is studying the feasibility of building an LNG terminal and power plant in Mirissa, Sri Lanka. Shell and Repsol YPF are negotiating with the National Iranian Oil Co. to develop two blocks in South Pars Field and a 16-million-tpy liquefaction plant, while Total and Petronas are working with NIOC on another LNG project. LNG

US LNG imports[1]

	bcf											
	2006									2007		
	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Algeria	2.80	--	2.80	3.03	2.88	—	—	—	—	2.52	—	11.34
Egypt	13.53	19.79	11.44	14.90	5.85	5.90	2.74	11.26	11.42	8.79	5.67	17.02
Nigeria	5.98	3.09	5.93	6.12	6.13	8.89	8.94	5.91	3.08	5.31	5.76	8.70
Trinidad	36.38	44.26	41.40	33.35	37.12	26.67	24.48	29.93	36.62	36.63	31.02	50.90
Totals	**58.69**	**67.14**	**61.57**	**57.40**	**51.98**	**41.46**	**36.16**	**47.10**	**51.12**	**53.25**	**42.45**	**87.96**

	bcf											
Daily[2,3]	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
2007	[4]1.72	[4]1.52	[4]2.84	—	—	—	—	—	—	—	—	—
2006	1.27	1.38	1.07	1.96	2.17	2.05	1.85	1.68	1.38	1.17	1.57	1.65
2005	1.94	1.88	1.49	1.58	1.82	1.87	1.63	1.39	1.72	1.92	1.94	1.65
2004	1.74	1.78	1.57	1.62	1.63	2.10	2.38	1.83	1.84	1.63	1.36	2.05
2003	0.75	0.75	1.00	1.09	1.48	1.54	1.83	1.61	1.69	1.96	1.63	1.32
2002	0.26	0.27	0.33	0.57	0.83	0.86	0.69	0.78	0.56	0.88	0.73	0.65
2001	0.59	0.72	0.75	0.73	0.88	0.89	0.77	0.58	0.73	0.38	0.26	0.43
2000	0.41	0.35	0.48	0.57	0.43	0.49	0.86	0.74	0.68	0.79	0.64	0.58
1999	0.42	0.37	0.42	0.34	0.30	0.39	0.46	0.48	0.57	0.35	0.38	0.41
1998	0.33	0.35	0.18	0.08	0.24	0.25	0.16	0.16	0.17	0.16	0.34	0.40
5-year avg.	1.19	1.23	1.09	1.12	1.33	1.45	1.46	1.24	1.31	1.35	1.18	1.22
% of avg.	135	118	194	175	163	142	127	135	106	86	133	135

	bcf											
Monthly[3]	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
2007	[4]53.25	[4]42.45	[4]87.96	—	—	—	—	—	—	—	—	—
2006	39.37	38.64	33.16	58.69	67.14	61.57	57.40	51.98	41.46	36.16	47.10	51.12
2005	60.28	52.70	46.22	47.43	56.36	56.07	50.48	43.10	51.57	59.47	58.09	51.10
2004	53.81	51.70	48.60	48.59	50.44	62.92	73.78	56.69	55.06	50.51	40.77	63.52
2003	23.11	21.01	31.00	32.68	45.81	46.14	56.74	50.02	50.77	60.79	49.00	41.04
2002	8.04	7.57	10.15	17.21	25.69	25.82	21.40	24.17	16.89	27.42	21.81	20.15
2001	18.21	20.10	23.25	22.01	27.14	26.59	23.91	17.91	21.83	11.73	7.85	13.21
2000	12.81	10.16	14.81	17.11	13.18	14.79	26.62	22.94	20.44	24.63	19.08	18.05
1999	13.01	10.33	13.09	10.13	9.39	11.56	14.12	15.03	16.97	10.98	11.46	12.67
1998	10.15	9.77	5.66	2.54	7.59	7.59	5.08	4.86	5.13	5.02	10.06	12.50
5-year avg.	45.28	40.92	44.89	40.92	49.09	50.50	51.96	45.19	43.15	46.87	43.35	45.39
% of avg.	110	99	146	143	137	122	110	115	96	77	109	113

[1]Actual and projected as of Mar. 19, 2007. [2]Figures do not include Puerto Rico imports. [3]1998 through May 2003 values are derived from the US Energy Information Administration. [4]Incomplete data. [5]5-year average, 2000-04.

Source: The US Waterborne LNG Report, Waterborne Energy Inc., Houston.

New liquefaction construction

Leena Koottungal
Survey Editor
Oil & Gas Journal

Country	Operator	Location	Capacity, million tpy	Status	Completion	Contractor	Notes
Algeria	Repsol YPF/ Gas Natural/ Sonatrach	Arzew	4.0	Planning	2010		New
	Sonatrach	Skikda	4.5	Engineering	2010	JGC/KBR/SNC-Lavalin/Black & Veatch	New. $700 million. Replaces plant destroyed in 2004.
Angola	Angola LNG Ltd.	Soyo	5.0	Engineering	2012	Bechtel/KBR/ JGC/Technip	One train. $2 billion. Chevron Corp. (36.4%), Sonangol (36.4%), BP PLC (13.6%), Total SA (13.6%).
Australia	Gorgon LNG	Barrow Island	10.0	Engineering	2009	KBR/JGC/Clough/ Hatch/JGC	New. Two trains: 5.0 MMtpy/train. Chevron Corp. (50%), ExxonMobil Corp. (25%), Shell (25%).
	Woodside Energy Ltd.	Withnell Bay	4.4	Under constr.	2008	Foster Wheeler/ Worley Parsons/ Clough Eng. Ltd.	Expansion. Train 5. $2.4 billion.
	Woodside Energy Ltd.	Burrup Peninsula	5.0-6.0	Engineering		Foster Wheeler	New. One train. Pluto LNG.
Equatorial Guinea	Marathon Oil	Bioko Island	3.4	Under constr.	2008	Bechtel	New. $1.4 billion. Export to BG.
	Marathon Oil	Bioko Island	4.4	Engineering		Bechtel	Expansion. Train 2. Decision to proceed will be made in 2007. Marathon (60%), Sonagas (25%), Mitsui (8.5%), Marubeni (6.5%).
Indonesia	BP Tangguh	Berau Bay, Papua	7.6	Under constr.	2008-09	KBR/JGC Corp./ Wood Group Indonesia	New. Two trains: 3.8 MMtpy/train. $1.4 billion. BP (37.16%), CNOOC (16.96%), MI Berau BV (16.31%), Nippon Oil Exploration (12.23%), KG Companies (10%), LNG Japan (7.35%).
	PT Pertamina	Sulawesi	2.0	Planning	2009		New. PT Medco Energi, Mitsubishi Corp.
Libya	National Oil Corp. (Libya)	Marsa Al-Brega	3.2	Planning	2008		Expansion. $400 million. Shell and NOC.
Nigeria	Brass LNG Ltd.	Bayelsa State	10.0	Engineering	2011	Bechtel	New. Two trains: 5 MMtpy/ train. $3 billion. NNPC (49%), ConocoPhillips (17%), ENI (17%), Total SA (17%).
	Nigeria LNG Ltd.	Bonny Island	4.0	Under constr.	2007	KBR/JGC Corp./Technip/ Snamprogetti SPA	Expansion. Train 6.

New liquefaction construction [continued]

	Nigeria LNG Ltd.	Bonny Island	8.5	Engineering	2010	Foster Wheeler/ Chiyoda Corp.	Expansion. Train 7.
	Nigeria LNG Ltd.	Bonny Island	8.5	Engineering		Foster Wheeler/ Chiyoda Corp.	Expansion. Train 8.
	Olokola LNG	West Niger Delta	20.0	Planning	2010	KBR	New. Four trains. NNPC (49.5%), Chevron Corp. (18.5%), Shell (18.5%), BG (13.5%).
Norway	Statoil ASA	Snøhvit, Hammerfest, Melkøya Island	4.1	Under constr.	2007	Linde AG/Statoil	New
Peru	Peru LNG	Pampa Melchorita	4.5	Under constr.	2009	CB&I	New. $3.8 billion. Hunt Oil (50%), SK Corp. (30%), Repsol YPF (20%).
Qatar	QatarGas II	Ras Laffan	15.6	Under constr.	2007-08	Chiyoda Corp./ Technip	New. Two trains: 7.8 MMtpy/train. Export to UK. Qatar Petroleum, ExxonMobil Corp., Total SA (16.7% in train 2).
	QatarGas III	Ras Laffan	7.8	Under constr.	2010	Chiyoda Corp./ Technip	New. $4 billion. Qatar Petroleum (68.5%), ConocoPhillips (30%), Mitsui (1.5%).
	QatarGas IV	Ras Laffan	7.8	Under constr.	2010-11	Chiyoda Corp./ Technip	New. Qatar Petroleum (70%), Shell (30%).
	RasGas III	Ras Laffan	15.6	Under constr.	2008-09	Chiyoda Corp./Technip/ Snamprogetti SPA	Expansion. Two trains: 7.8 MMtpy/train. Train 6: Aug. 2008; Train 7: Aug 2009. Train 6 to export to US. Qatar Petroleum (70%), ExxonMobil Corp. (30%).
Russia	Repsol/Anadarko/ Tambeineftegaz	Yamal Peninsula	10.0	Planning	2010		New
	Sakhalin Energy	Prigorodnoye, Sakhalin	9.6	Under constr.	2007-08	Chiyoda Corp./ Toyo Engineering	New. Two trains: 4.8 MMtpy/train. Train 1: July 2007; Train 2: Feb. 2008. Export to South Korea, Japan. Gazprom (50%), Royal Dutch Shell (27.5%), Mitsui (12.5%), Mitsubishi (10%).
Trinidad & Tobago	Atlantic LNG Ltd.	Point Fortin	3.0	Planning	2009		New. Train 5 (called Train X).
Venezuela	PDVSA	Gran Mariscal de Ayacucho, Sucre	4.7	Planning	2010		New. $2.7 billion.
	PDVSA	Jose, Anzoategui	2.1	Planning	2007		New. $600 million.
Yemen	Yemen LNG Co. Ltd.	Bal Haf	6.7	Under constr.	2008-09	YEMGAS/ Invensys	New. Two trains. $2 billion. Export to South Korea, France, Belgium.

World's LNG tanker fleet

Name or hull number[1] in service	Owner	Capacity cu m	Commisssioning date	Shipbuilder	Primary trade route	Propulsion[2]	Containment
Laieta	Maritima del Norte	40,147	July. 1970	Astano	Algeria-Spain	S	Esso
Lng Lagos	Nigeria LNG	122,255	Dec. 1976	Atlantique	Nigeria-Spain/France	S	GT No. 85
Lng Port Harcourt	Nigeria LNG	122,255	Oct. 1977	Atlantique	Nigeria-Spain/France	S	GT No. 85
Puteri Intan	Petronas (MISC)	130,405	July 1994	Atlantique	Malaysia-Japan	S	GT No. 96
Puteri Delima	Petronas (MISC)	130,405	Dec. 1995	Atlantique	Malaysia-Japan	S	GT No. 96
Bebatik	Brunei Shell Tankers	75,056	Oct. 1972	Atlantique	Brunei-Japan	S	Technigaz MK 1
Mourad Didouche	Hyproc	126,190	Dec. 1980	Atlantique	Algeria-Belgium	S	GT No. 85
Puteri Nilam	Petronas (MISC)	130,405	July 1995	Atlantique	Malaysia-Japan	S	GT No. 96
Bekalang	Brunei Shell Tankers	75,078	June 1973	Atlantique	Brunei-Japan	S	Technigaz MK 1
Puteri Zamrud	Petronas (MISC)	130,358	July 1996	Atlantique	Malaysia-Japan	S	GT No. 96
Bekulan	Brunei Shell Tankers	75,072	Dec. 1973	Atlantique	Brunei-Japan	S	Technigaz MK 1
Puteri Firus	Petronas (MISC)	130,358	May 1997	Atlantique	Malaysia-Japan	S	GT No. 96
Belais	Brunei Shell Tankers	75,040	July 1974	Atlantique	Brunei-Japan	S	Technigaz MK 1
Ramdane Abane	Hyproc	126,190	July 1981	Atlantique	Algeria-France	S	GT No. 85
Gaz De France Energy	Gaz de France	74,130	Dec. 2006	Atlantique	Algeria-Spain	S	CS1(GTT)
Provalys	Gaz de France	153,500	Nov. 2006	Atlantique	Egypt/Norway-France	DFDE	CS1(GTT)
Descartes	Gazocean	50,240	Sept. 1971	Atlantique	Algeria-France	S	Technigaz MK 1
Pioneer Knutsen	Knutsen OAS	1,100	Nov. 2003	Bijlsma	Coastal Norway	S	other
Methania	Distrigas	131,235	Oct. 1978	Boelwerft	Algeria-Spain	S	GT No. 85
Sk Summit	SK Shipping	138,003	Aug. 1999	Daewoo	Qatar-Korea	S	GT No. 96
K Acacia	Korea Line Corp.	138,017	Jan. 2000	Daewoo	Oman-Korea	S	GT No. 96
K Freesia	Korea Line Corp.	138,015	June 2000	Daewoo	Qatar-Korea	S	GT No. 96
Hispania Spirit	Teekay	138,517	Aug. 2002	Daewoo	Trinidad-US	S	GT No. 96
Excalibur	Exmar	135,273	Dec. 2002	Daewoo	Various	S	GT No. 96
Berge Boston	BW Group	138,059	Jan. 2003	Daewoo	Trinidad-US	S	GT No. 96
Excelsior[1]	Exmar	138,060	Jan. 2005	Daewoo		S	GT No. 96
Galicia Spirit	Teekay	140,624	July 2004	Daewoo	Eqypt-Spain	S	GT No. 96
Disha	Petronet LNG	138,000	Jan. 2004	Daewoo	Qatar-India	S	GT No. 96
Raahi	Petronet LNG	138,000	Dec. 2004	Daewoo	Qatar-India	S	GT No. 96
Berge Everett	BW Group	138,028	June 2003	Daewoo	Trinidad-US	S	GT No. 96
Excel	Exmar	135,273	Sept. 2003	Daewoo	Exports from Oman	S	GT No. 96
Northwest Swan	Woodside	140,500	Apr. 2004	Daewoo	Exports from Australia	S	GT No. 96
Methane Princess	Golar LNG	138,000	Aug. 2003	Daewoo	Trinidad-Spain	S	GT No. 96
Granatina	Shell	138,538	Dec. 2003	Daewoo		S	GT No. 96
Berge Arzew	BW Group	138,089	July 2004	Daewoo	Algerian exports	S	GT No. 96
Excellence	Exmar	138,000	Apr. 2005	Daewoo	US imports	S	GT No. 96
Lng Pioneer	Exmar	138,000	July 2005	Daewoo		S	GT No. 96
Golar Winter	Golar LNG	138,250	Mar. 2004	Daewoo		S	GT No. 96
Lng River Orashi	BW Group	140,500	Dec. 2004	Daewoo	Exports from Nigeria	S	GT No. 96
Lng Enugu	BW Group	140,500	Nov. 2005	Daewoo	Exports from Nigeria	S	GT No. 96
Lng Oyo	BW Group	140,500	Dec. 2005	Daewoo	Exports from Nigeria	S	GT No. 96
Lng Benue	BW Group	140,500	Mar. 2006	Daewoo	Exports from Nigeria	S	GT No. 96
Grandis	Golar LNG	145,700	Jan. 2006	Daewoo	Far East	S	GT No. 96
Maran Gas Asclepius	Maran Gas Maritime	142,906	July 2005	Daewoo	Qatar-Europe	S	GT No. 96
Umm Bab	Maran Gas Maritime	142,891	Oct. 2005	Daewoo	Qatar-Europe	S	GT No. 96
Lng Lokoja	BW Group	148,300	Nov. 2006	Daewoo	Exports from Nigeria	S	GT No. 96
Grace Acacia	NYK	141,000	Feb. 2007	Hyundai	Exports from Nigeria	S	Technigaz MK III
Lng Kano	BW Group	148,300	Jan. 2007	Daewoo	Exports from Nigeria	S	GT No. 96
Bluesky	TMT	145,700	May 2006	Daewoo	Exports from Nigeria	S	GT No. 96
Granosa	Golar LNG	145,700	June 2006	Daewoo	Exports from Nigeria	S	GT No. 96
Simaisma	Maran Gas Maritime	145,700	Feb. 2006	Daewoo	Qatar-Europe	S	GT No. 96

World's LNG tanker fleet [continued]

Name or hull number[1] in service (cont.)	Owner	Capacity cu m	Commisssioning date	Shipbuilder	Primary trade route	Propulsion[2]	Containment
Iberica Knutsen	Knutsen OAS	151,700	Aug. 2006	Daewoo	US imports	S	GT No. 96
Excelerate[1]	Exmar	138,000	Oct. 2006	Daewoo	US imports	S	GT No. 96
Al Marrouna	Teekay	151,700	Sept. 2006	Daewoo	Qatar-Europe	S	GT No. 96
Al Areesh	Teekay	151,700	Jan. 2007	Daewoo	Qatar-Europe		GT No. 96
Tenaga Satu	MISC	130,000	Feb. 1982	Du Nord	Malaysia-Japan	S	GT No. 88
Tenaga Dua	MISC	130,000	Aug. 1981	Du Nord	Malaysia-Japan	S	GT No. 88
Tenaga Tiga	MISC	130,000	Jan. 1981	Du Nord	Malaysia-Japan	S	GT No. 88
Edouard Ld	Dreyfus	129,323	Dec. 1977	Du Nord	Algeria-France	S	GT No. 85
Lng Palmaria	ENI	39,691	June 1969	Fincantieri	Algeria-Italy	S	Esso
Lng Elba	ENI	41,005	1970	Fincantieri	Algeria-France	S	Esso
Lng Aquarius	BGT Ltd.	126,750	June 1977	General Dynamics		S	Moss
Lng Aries	BGT Ltd.	126,750	Dec. 1977	General Dynamics		S	Moss
Lng Gemini	BGT Ltd.	126,750	Sept. 1978	General Dynamics	Indonesia-Japan	S	Moss
Lng Capricorn	BGT Ltd.	126,750	June 1978	General Dynamics	Indonesia-Japan	S	Moss
Lng Leo	BGT Ltd.	126,750	Dec. 1978	General Dynamics	Indonesia-Japan	S	Moss
Lng Taurus	BGT Ltd.	126,750	Aug. 1979	General Dynamics	Indonesia-Japan	S	Moss
Lng Virgo	BGT Ltd.	126,750	Dec. 1979	General Dynamics	Indonesia-Japan	S	Moss
Lng Libra	BGT Ltd.	126,750	Apr. 1979	General Dynamics	Indonesia-Japan	S	Moss
Lng Edo	Nigeria LNG	126,750	May 1980	General Dynamics	Nigeria-Spain/France/ Turkey	S	Moss
Lng Abuja	Nigeria LNG	126,750	Sept. 1980	General Dynamics	Nigeria-Spain/France/ Turkey	S	Moss
Golar Freeze	Golar LNG	125,862	Feb. 1977	H D W	Trinidad-US	S	Moss
Hoegh Gandria	Mitsui/Hoegh	125,904	Oct. 1977	H D W	Indonesia-Korea	S	Moss
Hanjin Pyeong Taek	Hanjin Shipping	138,366	Sept. 1995	Hanjin Hi	Indonesia-Korea	S	GT No. 96
Hanjin Muscat	Hanjin Shipping	138,366	July 1999	Hanjin Hi	Oman-Korea	S	GT No. 96
Hanjin Sur	Hanjin Shipping	138,333	Jan. 2000	Hanjin Hi	Oman-Korea	S	GT No. 96
Hanjin Ras Laffan	Hanjin Shipping	138,214	July 2000	Hanjin Hi	Qatar-Korea	S	GT No. 96
Shinju Maru No. 1	Shinwa Kaiun	2,513	July 2003	Higaki	Japanese Domestic Trade	M	Other
Hyundai Utopia	Hyundai Merchant	125,182	June 1994	Hyundai	Indonesia-Korea	S	Moss
Y K Sovereign	SK Shipping	127,125	Dec. 1994	Hyundai	Malaysia-Korea	S	Moss
Hyundai Greenpia	Hyundai Merchant	125,000	Nov. 1996	Hyundai	Malaysia-Korea	S	Moss
Hyundai Technopia	Hyundai Merchant	137,415	July 1999	Hyundai	Qatar-Korea	S	Moss
Hyundai Cosmopia	Hyundai Merchant	137,415	Jan. 2000	Hyundai	Qatar-Korea	S	Moss
Hyundai Aquapia	Hyundai Merchant	137,415	Mar. 2000	Hyundai	Oman-Korea	S	Moss
Hyundai Oceanpia	Hyundai Merchant	137,415	July 2000	Hyundai	Oman-Korea	S	Moss
Lng Rivers	Nigeria LNG	137,500	June 2002	Hyundai	Nigeria-Spain	S	Moss
Lng Sokoto	Nigeria LNG	137,500	Aug. 2002	Hyundai	Nigeria-France	S	Moss
Lng Bayelsa	Nigeria LNG	137,500	Feb. 2003	Hyundai	Exports from Nigeria	S	Moss
Golar Frost	Golar LNG	138,830	June 2004	Hyundai		S	Moss
Gracilis	Golar LNG	140,207	Jan. 2005	Hyundai	Exports from Nigeria	S	Technigaz MK III
Lng Akwa Ibom	Nigeria LNG	141,500	Nov. 2004	Hyundai	Nigeria-Europe	S	Moss
Lng Adamawa	Nigeria LNG	138,437	June 2005	Hyundai	Nigeria-Europe	S	Moss
Lng Cross River	Nigeria LNG	141,000	Sept. 2005	Hyundai	Nigeria-Europe	S	Moss
Lng River Niger	Nigeria LNG	141,000	June 2006	Hyundai	Nigeria-Europe	S	Moss
Polar Eagle	Eagle Sun	88,996	June 1993	I H I	Alaska-Japan	S	IHI-SPB

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World's LNG tanker fleet [continued]

Name or hull number[1] in service (cont.)	Owner	Capacity cu m	Commisssioning date	Shipbuilder	Primary trade route	Propulsion[2]	Containment
Arctic Sun	Eagle Sun	89,089	Dec. 1993	I H I	Alaska-Japan	S	IHI-SPB
Castillo De Villalba	Elcano	138,000	Oct. 2003	Izar Puerto Real	Algeria-Spain	S	GT No. 96
Cadiz Knutsen	Knutsen OAS	138,000	June 2004	Izar Puerto Real	Egypt-Spain	S	GT No. 96
Madrid Spirit	Teekay	138,000	Dec. 2004	Izar Puerto Real	Egypt-Spain	S	GT No. 96
Catalunya Spirit	Teekay	138,000	Aug. 2003	Izar Sestao	Trinidad-Spain	S	GT No. 96
Bilbao Knutsen	Knutsen OAS	138,000	Feb. 2004	Izar Sestao	Trinidad-Spain	S	GT No. 96
Golar Spirit	Golar LNG	129,013	Sept. 1981	Kawasaki	Indonesia-Korea	S	Moss
Bishu Maru	NYK - Mitsui OSK - K Line	125,915	Aug. 1983	Kawasaki	Indonesia-Japan	S	Moss
Kotowaka Maru	NYK - Mitsui OSK - K Line	125,454	Jan. 1984	Kawasaki	Australia-Japan	S	Moss
Northwest Shearwater	NWS LNG Shipiing	127,500	Sept. 1991	Kawasaki	Australia-Japan	S	Moss
Lng Flora	Osaka Gas - NYK	125,637	Mar. 1993	Kawasaki	Indonesia-Japan	S	Moss
Shahamah	Abu Dhabi Commercial	137,756	Oct. 1994	Kawasaki	Abu Dhabi-Japan	S	Moss
Surya Aki	Humpuss	19,538	Mar. 1996	Kawasaki	Indonesia-Japan	S	Moss
Al Rayyan	Mitsui OSK - NYK - K Line - Iino	137,420	Mar. 1997	Kawasaki	Qatar-Japan	S	Moss
Al Wakrah	Mitsui OSK - NYK - K Line - Iino	137,568	Dec. 1998	Kawasaki	Qatar-Japan	S	Moss
Al Bidda	Mitsui OSK - NYK - K Line - Iino	137,339	Nov. 1999	Kawasaki	Qatar-Japan	S	Moss
Energy Frontier	Tokyo LNG Tanker	147,591	Sept. 2003	Kawasaki	Australia-Japan	S	Moss
Energy Advance	Tokyo LNG Tanker	145,410	Mar. 2005	Kawasaki	Australia-Japan	S	Moss
Muscat Lng	Oman Government	145,494	Apr. 2004	Kawasaki	Oman-Spain	S	Moss
Arctic Voyager	Statoil	140,000	July 2006	Kawasaki	Norway-US	S	Moss
Lalla Fatma N'soumer	Algeria Nippon Gas	145,445	Oct. 2004	Kawasaki	Algeria exports	S	Moss
Energy Progress	TOKYO LNG TANKER	145,000	Dec. 2006	Kawasaki	Indonesia-Japan	S	Moss
Lng Dream	OSAKA GAS - NYK	145,000	Sept. 2006	Kawasaki	Australia-Japan	S	Moss
Nizwa Lng	Oman Government	145,469	Dec. 2005	Kawasaki	Oman-Japan	S	Moss
Scf Polar	Sovcomflot	71,650	Sept. 1969	Kockums	Algeria-Spain	S	GT No. 82
Scf Arctic	Sovcomflot	71,651	1969	Kockums	Trinidad-Spain	S	GT No. 82
Lng Bonny	Nigeria LNG	132,588	Dec. 1981	Kockums	Nigeria-Spain/France/Turkey	S	GT No. 88
Lng Finima	Nigeria LNG	132,588	Jan. 1984	Kockums	Nigeria-Spain/France/Turkey	S	GT No. 88
Mubaraz	Abu Dhabi Commercial	135,000	Jan. 1996	Kvaerner Masa	Abu Dhabi-Japan	S	Moss
Mraweh	Abu Dhabi Commercial	135,000	May 1996	Kvaerner Masa	Abu Dhabi-Japan	S	Moss
Al Hamra	Abu Dhabi Commercial	137,000	Dec. 1997	Kvaerner Masa	Abu Dhabi-Japan	S	Moss
Umm Al Ashtan	Abu Dhabi Commercial	137,000	May 1997	Kvaerner Masa	Abu Dhabi-Japan	S	Moss
Tellier	Messigaz	40,081	Jan. 1974	La Ciotat	Algeria-France	S	Technigaz MK 1
Belanak	Brunei Shell Tankers	75,000	July 1975	La Ciotat	Brunei-Japan	S	Technigaz MK 1
Mostefa Ben Boulaid	Hyproc	125,260	Aug. 1976	La Ciotat	Algeria-USA	S	Technigaz MK 1
Hassi R'mel	Hyproc	40,109	1971	La Seyne	Various	S	GT No. 82
Bilis	Brunei Shell Tankers	77,731	Apr. 1975	La Seyne	Brunei-Japan	S	GT No. 82
Bubuk	Brunei Shell Tankers	77,679	Oct. 1975	La Seyne	Brunei-Japan	S	GT No. 82
Isabella	Chemikalien Seetrans	35,491	Apr. 1975	La Seyne	Libya-Spain	S	GT No. 82
Annabella	Chemikalien Seetrans	35,491	1975	La Seyne	Algeria/Libya-Spain	S	GT No. 82
Larbi Ben M'hidi	Hyproc	129,500	June 1977	La Seyne	Algeria-Turkey	S	GT No. 85
Bachir Chihani	Hyproc	129,767	Feb. 1979	La Seyne	Algeria-Turkey	S	GT No. 85
Tenaga Empat	MISC	130,000	Mar. 1981	La Seyne	Malaysia-Japan	S	GT No. 88

World's LNG tanker fleet [continued]

Name or hull number[1] in service (cont.)	Owner	Capacity cu m	Commisssioning date	Shipbuilder	Primary trade route	Propulsion[2]	Containment
Tenaga Lima	MISC	130,000	Mar. 1981	La Seyne	Malaysia-Japan	S	GT No. 88
Banshu Maru	NYK - Mitsui OSK - K Line	126,885	Oct. 1983	Mitsubishi	Indonesia-Japan	S	Moss
Echigo Maru	NYK - Mitsui OSK - K Line	125,568	Aug. 1983	Mitsubishi	Indonesia-Japan	S	Moss
Dewa Maru	NYK - Mitsui OSK - K Line	126,975	July 1984	Mitsubishi	Indonesia-Japan	S	Moss
Northwest Sanderling	NWS LNG Shipiing	125,452	Apr. 1989	Mitsubishi	Australia-Japan	S	Moss
Northwest Swift	NYK - Mitsui OSK - K Line	127,580	Aug. 1989	Mitsubishi	Australia-Japan	S	Moss
Ekaputra	Humpuss	136,400	Jan. 1990	Mitsubishi	Indonesia-Taiwan	S	Moss
Northwest Seaeagle	NWS LNG Shipiing	125,541	Nov. 1992	Mitsubishi	Australia-Japan	S	Moss
Lng Vesta	Mitsui OSK	127,547	June 1994	Mitsubishi	Indonesia-Japan	S	Moss
Dwiputra	Humpuss	127,386	Mar. 1994	Mitsubishi	Indonesia-Japan	S	Moss
Ish	Abu Dhabi Commercial	137,512	Nov. 1995	Mitsubishi	Abu Dhabi-Japan	S	Moss
Northwest Stormpetrel	NWS LNG Shipiing	125,525	Dec. 1994	Mitsubishi	Australia-Japan	S	Moss
Al Khor	Mitsui OSK - NYK - K Line - Iino	137,354	Dec. 1996	Mitsubishi	Qatar-Japan	S	Moss
Al Wajbah	Mitsui OSK - NYK - K Line - Iino	137,308	May 1997	Mitsubishi	Qatar-Japan	S	Moss
Doha	Mitsui OSK - NYK - K Line - Iino	137,262	June 1999	Mitsubishi	Qatar-Japan	S	Moss
Al Jasra	Mitsui OSK - NYK - K Line - Iino	135,169	July 2000	Mitsubishi	Qatar-Japan	S	Moss
Golar Mazo	Golar LNG	135,225	Dec. 1999	Mitsubishi	Indonesia-Taiwan	S	Moss
Lng Jamal	Osaka Gas - NYK	136,977	Oct. 2000	Mitsubishi	Oman-Japan	S	Moss
Sohar Lng	Mitsui OSK	137,248	Oct. 2001	Mitsubishi	Oman-France	S	Moss
Abadi	Mitsui OSK	136,912	June 2002	Mitsubishi	Brunei-Japan	S	Moss
Puteri Intan Satu	Petronas (MISC)	137,489	Aug. 2002	Mitsubishi	Malaysia-Japan	S	GT No. 96
Puteri Nilam Satu	Petronas (MISC)	137,489	Sept. 2003	Mitsubishi	Malaysia-Japan	S	GT No. 96
Galea	Shell	136,967	Sept. 2002	Mitsubishi		S	Moss
Gallina	Shell	136,967	Dec. 2002	Mitsubishi		S	Moss
Pacific Notus	Tokyo Electric	137,006	Sept. 2003	Mitsubishi	Malaysia-Japan	S	Moss
Puteri Firus Satu	Petronas (MISC)	137,489	Aug. 2004	Mitsubishi	Malaysia-Japan	S	GT No. 96
Gemmata	Shell	135,000	Jan. 2004	Mitsubishi		S	Moss
Arctic Princess	Hoegh	147,835	Jan. 2006	Mitsubishi	Norway-US	S	Moss
Arctic Lady	Hoegh	147,208	Apr. 2006	Mitsubishi	Norway-US	S	Moss
Pacific Eurus	Tokyo Electric	135,000	Mar. 2006	Mitsubishi	Australia-Japan	S	Moss
Ibri Lng	Oman Government	145,000	July 2006	Mitsubishi	Oman-Japan	S	Moss
Senshu Maru	NYK - Mitsui OSK - K Line	127,167	Feb. 1984	Mitsui	Indonesia-Japan	S	Moss
Wakaba Maru	NYK - Mitsui OSK - K Line	127,209	Apr. 1985	Mitsui	Indonesia-Japan	S	Moss
Northwest Swallow	NYK - Mitsui OSK - K Line	127,544	Nov. 1989	Mitsui	Australia-Japan	S	Moss
Northwest Snipe	NWS LNG Shipiing	127,747	Oct. 1990	Mitsui	Australia-Japan	S	Moss
Northwest Sandpiper	NWS LNG Shipiing	125,500	Feb. 1993	Mitsui	Australia-Japan	S	Moss
Al Khaznah	Abu Dhabi Commercial	137,540	May 1994	Mitsui	Abu Dhabi-Japan	S	Moss
Ghasha	Abu Dhabi Commercial	137,100	June 1995	Mitsui	Abu Dhabi-Japan	S	Moss
Al Zubarah	Mitsui OSK - NYK - K Line - Iino	137,573	Dec. 1996	Mitsui	Qatar-Japan	S	Moss
Broog	Mitsui OSK - NYK - K Line - Iino	137,529	May 1998	Mitsui	Qatar-Japan	S	Moss
Zekreet	Mitsui OSK - NYK - K Line - Iino	137,482	Dec. 1998	Mitsui	Qatar-Japan	S	Moss

World's LNG tanker fleet [continued]

Name or hull number[1] in service (cont.)	Owner	Capacity cu m	Commisssioning date	Shipbuilder	Primary trade route	Propulsion[2]	Containment
Puteri Delima Satu	Petronas (MISC)	137,489	Oct. 2002	Mitsui	Malaysia-Japan	S	GT No. 96
Puteri Zamrud Satu	Petronas (MISC)	138,000	Jan. 2004	Mitsui	Malaysia-Japan	S	GT No. 96
Dukhan	Qatargas	137,661	Oct. 2004	Mitsui	Qatar-Spain	S	Moss
Puteri Mutiara Satu	Petronas (MISC)	137,595	Apr. 2005	Mitsui	Malaysia-Japan	S	GT No. 96
Arctic Discoverer	Statoil	140,000	Feb. 2006	Mitsui	Norway-US	S	Moss
Bw Havfru	BW Group	29,388	Dec. 1973	Moss Rosenberg	Trinidad-US	M	Moss
Century	BW Group	29,588	Dec. 1975	Moss Rosenberg	Algeria-Greece	M	Moss
Norman Lady	Mitsui/Hoegh	87,994	Nov. 1973	Moss Rosenberg	Trinidad-Spain	S	Moss
Hoegh Galleon	Hoegh	87,603	June 1974	Moss Rosenberg	Storage Project	S	Moss
Hilli	Golar LNG	124,890	Dec. 1975	Moss Rosenberg	Trinidad-US	S	Moss
Gimi	Golar LNG	124,872	Dec. 1976	Moss Rosenberg	Trinidad-US	S	Moss
Khannur	Golar LNG	125,003	July 1977	Moss Rosenberg	Qatar-Spain	S	Moss
Aman Bintulu	Petronas (MISC)	18,927	Oct. 1993	N K K	Malaysia-Japan	S	Technigaz MK III
Aman Sendai	Petronas (MISC)	18,928	May 1997	N K K	Malaysia-Japan	S	Technigaz MK III
Aman Hakata	Petronas (MISC)	18,942	Nov. 1998	N K K	Malaysia-Japan	S	Technigaz MK III
Surya Satsuma	Mitsui OSK	23,096	Oct. 2000	N K K	Indonesia-Japan	S	Technigaz MK III
Lng Delta	Shell	126,540	May 1978	Newport News	Nigeria-Spain/France/Turkey	S	Technigaz MK 1
Galeomma	Shell	126,540	Dec. 1978	Newport News	Oman-Spain	S	Technigaz MK 1
Suez Matthew	Cabot Corp.	126,540	June 1979	Newport News	Trinidad-US	S	Technigaz MK 1
Sk Supreme	SK Shipping	138,248	Jan. 2000	Samsung	Qatar-Korea	S	Technigaz MK III
Sk Splendor	SK Shipping	138,370	Mar. 2000	Samsung	Oman-Korea	S	Technigaz MK III
Sk Stellar	SK Shipping	138,395	Dec. 2000	Samsung	Qatar-Korea	S	Technigaz MK III
British Trader	BP	138,248	Nov. 2002	Samsung		S	Technigaz MK III
British Innovator	BP	136,135	Feb. 2003	Samsung	Abu Dhabi-Spain	S	Technigaz MK III
Sk Sunrise	SK Shipping	138,270	Oct. 2003	Samsung	Qatar-Korea	S	Technigaz MK III
Fuwairit	Exmar	138,200	Jan. 2004	Samsung	Qatar-Italy	S	Technigaz MK III
British Merchant	BP	138,000	July 2003	Samsung	Qatar-Spain	S	Technigaz MK III
Maersk Ras Laffan	AP Moller	138,200	Mar. 2004	Samsung	Qatar-Italy	S	Technigaz MK III
Methane Kari Elin	British Gas Corp.	138,200	May 2004	Samsung	Trinidad-US	S	Technigaz MK III
Lusail	NYK	145,000	June 2005	Samsung		S	Technigaz MK III
Al Thakhira	NYK	145,130	Aug. 2005	Samsung	Qatar-Italy	S	Technigaz MK III
Al Deebel	NYK	145,130	Oct. 2005	Samsung	Qatar-Italy	S	Technigaz MK III
Seri Alam	Petronas (MISC)	145,000	Sept. 2005	Samsung	Malaysia-Japan	S	Technigaz MK III
Seri Amanah	Petronas (MISC)	145,000	Mar. 2006	Samsung	Malaysia-Japan	S	Technigaz MK III
Salalah Lng	Oman government	145,000	Dec. 2005	Samsung	Oman-Spain	S	Technigaz MK III
Methane Rita Andrea	British Gas Corp.	145,000	Mar. 2006	Samsung	Egypt-US	S	Technigaz MK III
Methane Jane Elizabeth	British Gas Corp.	145,000	Oct. 2006	Samsung	Egypt-Us	S	Technigaz MK III
Methane Lydon Volney	British Gas Corp.	145,000	Aug. 2006	Samsung	Eq. Guinea-US	S	Technigaz MK III
Maersk Qatar	AP Moller	145,130	Apr. 2006	Samsung	Qatar-Italy	S	Technigaz MK III
Ibra Lng	Oman government	145,000	Aug. 2006	Samsung	Oman-Spain	S	Technigaz MK III
Seri Anggun	Petronas (MISC)	145,000	Nov. 2006	Samsung	Malaysia-Japan	S	Technigaz MK III
Ejnan	NYK	145,000	Jan. 2007	Samsung	Qatar-Europe	S	Technigaz MK III
Cinderella	TMT	25,500	Mar. 1965	Seine Maritime	N Africa-Spain	S	Worms
Lng Portovenere	ENI	56,095	Jan. 1996	Sestri	Algeria-Italy	S	GT No. 96
Lng Lerici	ENI	65,000	May 1998	Sestri	Algeria-Italy	S	GT No. 96
North Pioneer	Shinwa Kaiun	2,513	Nov. 2005	Shin Kurushima	Japanese Domestic Trade	M	Other
Neo Energy	Tsakos	146,735	Jan. 2007	Hyundai	Australia-China	S	Moss
Capacity in service, cu m		**27,731,462**					

World's LNG tanker fleet [continued]

Name or hull number[1] in service (cont.)	Owner	Capacity cu m	Commisssioning date	Shipbuilder	Primary trade route	Propulsion[2]	Containment
Commissioned 2007							
Gazelys	Gaz de France	153,500	Mar. 2007	Atlantique	Egypt/Norway-France	DFDE	CS1(GTT)
Al Daayen	Teekay	151,700	Apr. 2007	Daewoo	Qatar-Europe	S	GT No. 96
Daewoo 2241	Sovcomflot	145,700	Dec. 2007	Daewoo	Tangguh exports	S	GT No. 96
Daewoo 2244	Golar LNG	145,700	June 2007	Daewoo	Qatar-Europe	S	GT No. 96
Al Jassasiya	Maran Gas Maritime	145,700	Apr. 2007	Daewoo	Qatar-Europe	S	GT No. 96
Lerwais	Qatar Gas & Pronav	210,000	July 2007	Daewoo	Qatar-UK	DFDE	GT No. 96
Al Safliya	Qatar Gs & Pronav	210,000	Nov. 2007	Daewoo	Qatar UK	DFDE	GT No. 96
Dapeng Sun	Guangdong Dapeng LNG	147,100	Nov. 2007	Hudong	Australia-China	S	GT No. 96
Hudong Zhonghua H1401a	COSCO Dalian	145,000	Oct. 2007	Hudong	Australia-China	S	GT No. 96
Clean Power	Dynacom	149,700	July 2007	Hyundai	Australia-China	S	Technigaz MK III
Hyundai 1729	NYK	141,000	Nov. 2007	Hyundai	Australia-China	S	Technigaz MK III
Clean Energy	Dynacom	149,700	Mar. 2007	Hyundai	Australia-China	S	Technigaz MK III
British Emerald	BP	155,000	May 2007	Hyundai	Indonesia-Korea/ China/others	DFDE	Technigaz MK III
Al Qattara	Qatar Gas & OSG	216,200	Oct. 2007	Hyundai	Qatar-UK	DFDE	Technigaz MK III
Kawasaki 1587	K Line	145,000	Nov. 2007	Kawasaki	US imports	S	Moss
Kawasaki 1593	Mitsui OSK	19,100	Sept. 2007	Kawasaki	Japanese domestic trade	M	Moss
Trinity Arrow	Shoei	154,200	Nov. 2007	Koyo	US imports	S	GT No. 96
Seri Bakti	Petronas (MISC)	145,000	Feb. 2007	Mitsubishi	Malaysian exports	S	GT No. 96
Mitsubishi 2221	Petronas (MISC)	145,000	Aug. 2007	Mitsubishi	Malaysian exports	S	GT No. 96
Grand Elena	Sovcomflot - NYK JV	147,200	Oct. 2007	Mitsubishi	Russia-Japan	S	Moss
Grand Aniva	Sovcomflot - NYK JV	147,200	Dec. 2007	Mitsubishi	Russia-Japan	S	Moss
Samsung 1563	NYK	149,600	June 2007	Samsung	Exports from Nigeria	S	Technigaz MK III
Samsung 1564	NYK	149,600	Aug. 2007	Samsung	Exports from Nigeria	S	Technigaz MK III
Methane Heather Sally	British Gas Corp.	145,000	June 2007	Samsung	Egypt-US	S	Technigaz MK III
Methane Shirley Elisabeth	British Gas Corp.	145,000	June 2007	Samsung	Egypt-US	S	Technigaz MK III
Seri Angkasa	Petronas (MISC)	145,000	Nov. 2007	Samsung	Malaysia-Japan	S	Technigaz MK III
Seri Ayu	Petronas (MISC)	145,000	Sept. 2007	Samsung	Malaysia-Japan	S	Technigaz MK III
Tenbek	Qatar Gas & OSG	216,200	Oct. 2007	Samsung	Qatar-UK	DFDE	Technigaz MK III
Samsung 1607	AP Moller	153,000	Oct. 2007	Samsung	Qatar-UK	DFDE	Technigaz MK III
Taizhou	Skaugen, I M	10,000	Dec. 2007	Taizhou Zhongyuan	Chinese domestic trade	M	
Universal Tsu 055	Sonatrach	75,500	May 2007	Universal Tsu	Intra Mediterranean	S	Technigaz MK III
Capacity to be commissioned in 2007, cu m		**4,211,195**					

[1]Regasification vessel. [2]S = steam; DFDE = dual-fuel diesel electric; M = motor.

Source: EA Gibson Shipbrokers Ltd., London; www.eagibson.co.uk . List current as of Mar. 15, 2007.