Week of April 9, 2007/US$10.00

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LNG Update

Giant fields likely to supply 40%+ of world's oil and gas
Managed pressure reduces China hard-rock drilling by half
BP's hurricane management system monitors GOM assets

OIL&GAS JOURNAL®

Apr. 9, 2007
Volume 105.14

LNG Update

Regular Features

Cover

Europe's first LNG export plant (cover) will begin operations by December 2007 from Melkøya Island outside Hammerfest in northern Norway. Gas for the plant flows from Snøhvit, Askeladd, and Albatross fields, comprising the first hydrocarbon reserves to be developed in the Norwegian part of the Barents Sea. A wealth of information on worldwide LNG issues is available in this issue's special report that begins on p. 20 with an analysis of opportunities and challenges defined by European regulatory and market factors unique to each LNG terminal project's location. A later article (p. 48) presents an overview of Snøhvit's Hammerfest LNG plant, and another introduces a new OGJ series that will track world LNG netback prices. A final article (p. 62) provides a comprehensive look at the current and future trends in LNG shipping. Cover photograph by Eiliv Leren, Statoil; above photograph, of the Idku LNG terminal in Egypt, is from BG Group.

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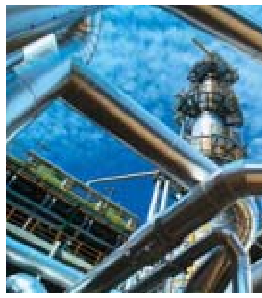

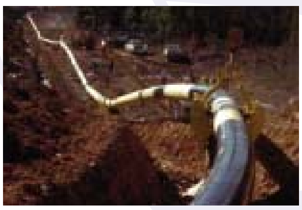


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General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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OGJ Newsletter

Apr. 9, 2007
International news for oil and gas professionals
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General Interest — Quick Takes

Treasury asked to implement tax exemption

US Sen. Kay Bailey Hutchinson (R-Tex.) urged US Sec. of the Treasury Henry M. Paulson to promptly implement a provision of the 2005 Energy Policy Act (EPACT) allowing refiners to deduct 50% of plant expansion costs if such an expansion increases capacity by at least 5%.

Noting that US President George W. Bush signed EPACT into law on Aug. 8, 2005, Hutchinson said some companies have not yet received regulations from the Internal Revenue Service to implement the decision some 20 months later. "Companies are prepared to invest billions in projects that take years to plan, engineer, and design, but without this guidance, refineries are unable to determine future investments in additional capacity. The lack of a final regulation for this provision is hampering company decisions to proceed in expanding capacity to provide needed products to our US market," she wrote Paulson in an Apr. 2 letter.

Federal judge suspends forest management rules

A federal judge in San Francisco has ruled the US Forest Service failed to conduct mandatory environmental impact reviews or take public comment on plans by the Bush administration to change rules governing forest land management.

US Northern District Judge Phyllis Hamilton ruled Mar. 30 that the forest service's new policies should be invalidated. Opponents said the rule changes would expedite oil and gas exploration on forest land while weakening wildlife protection and preventing public comment regarding forest management.

The agency must conduct environmental reviews before implementing the "clear controversial" changes, she said.

The rules were changed in 2005 in what forest officials called a move to streamline paperwork and respond faster to evolving forest conditions and scientific research. The rule changes invalidated 1982 federal forest agency rules.

Hydro, Anadarko to invest $2.5 billion in Brazil

Norway's Norsk Hydro ASA and Anadarko Petroleum Corp. reported they will invest $2.5 billion to 2010 to develop Peregrino heavy crude oil field on BM-C-7 block in the Campos basin off Brazil. Hydro's joint venture with Anadarko is 50-50.

The partners will lease a floating production, storage, and offloading vessel from Norway's AP Møller-Maersk. They will also lease two drilling platforms. Peregrino field, a shallow-water field with reserves pegged at 300-600 million bbl, is Hydro's first oil and gas commitment in Brazil.

Hydro has submitted development plans for the field to Brazil's National Petroleum and Biofuels Agency. Plans include the drilling of 30 horizontal wells and seven water-injection wells. The aim is to produce 100,000 b/d of oil by 2010.

The company plans to expand in Brazil and will invest in three Santos basin exploration blocks, in which it acquired working interest during the eighth ANP licensing round in November 2006.

Norsk Hydro is operator in one block and holds non-operating interest in the other two blocks, which are operated by Spain's Repsol-YPF SA and Brazil's state-owned Petroleo Brasileiro SA. In addition, Norsk Hydro will continue to look for farm-in opportunities.

UK project to assess CO_2 storage in coal

Composite Energy (CE), a Scottish company developing coalbed methane production in the UK, commissioned a 2-year study to evaluate carbon dioxide storage in coal. The £300,000 project is being financed by BG Group, Scottish Power, and Royal Bank of Scotland. It will focus on the potential of enhancing methane recovery through storing CO_2 in coal. CE, which is in the process of developing methane production from deep coal beds in Scotland, will provide horizontal drilling expertise required for the long extended-reach boreholes required for the storage project.

CE believes CBM trapped in deep coal seams will provide an untapped long-term source of UK gas.

Strathclyde University in Glasgow will assess the coal's gas adsorption and desorption properties. Imperial College of London will assess the coal's mechanical properties to model and predict the performance of a pilot scheme. The project will evaluate the ability of CO_2 to bond to coal. CE said the study will evaluate the potential of CO_2 storage in the interest of increasing methane recovery and also in reducing CO_2 emissions.

"Coal can typically absorb five times more CO_2 than the methane it releases," CE said. "This may be a very real solution for reducing greenhouse gases." The program will involve the direct injection of flue gas from the 2,400 Mw Longannet power station into unminable coal seams in the central belt of Scotland. Scottish Power owns and operates Longannet station. ✦

Exploration & Development — Quick Takes

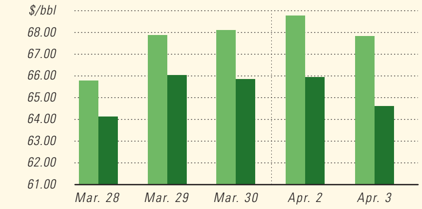
Total finds more oil off Congo (Brazzaville)

Total E&P Congo announced two oil discoveries in the Moho-Bilondo permit in 1,000 m of water about 80 km off Congo (Brazzaville). The Moho Nord Marine 1 discovery well, drilled to 2,645 m TD, encountered a 140-m column of oil in the Upper Miocene.

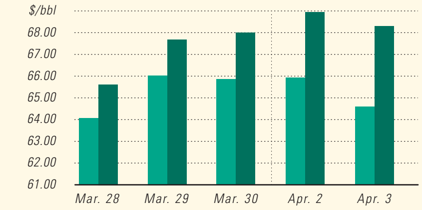
The Moho Nord Marine 2, drilled to 2,340 m TD, encountered

Industry Scoreboard

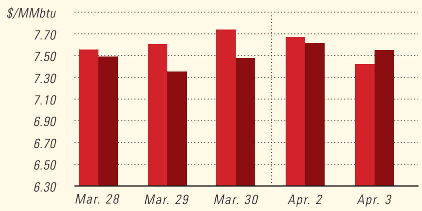
IPE BRENT / NYMEX LIGHT SWEET CRUDE



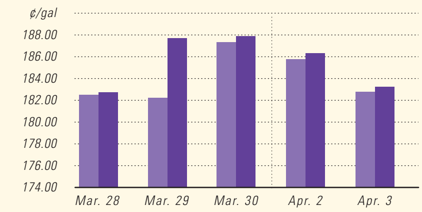
WTI CUSHING / BRENT SPOT



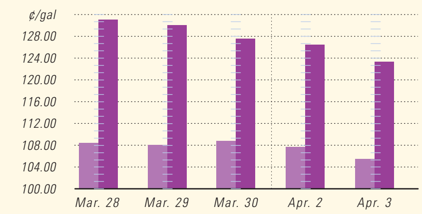
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



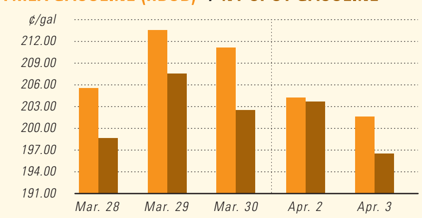
IPE GAS OIL / NYMEX HEATING OIL



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.

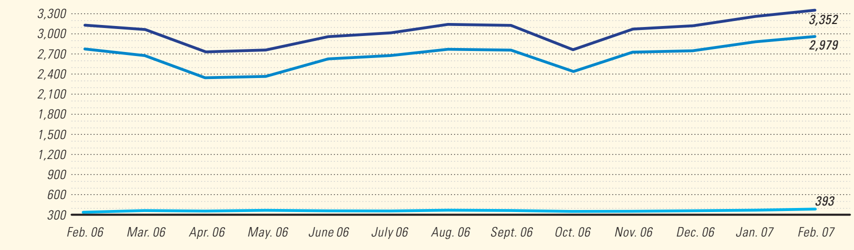
US INDUSTRY SCOREBOARD — 4/9

Latest week 3/30	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	8,997	9,129	–1.4	9,093	8,897	2.2
Distillate	4,546	4,481	1.4	4,441	4,320	2.8
Jet fuel	1,628	1,567	3.9	1,618	1,545	4.7
Residual	885	830	6.7	750	821	–8.6
Other products	5,107	4,687	9.0	5,013	4,790	4.7
TOTAL DEMAND	21,164	20,695	2.3	20,915	20,374	2.7
Supply, 1,000 b/d						
Crude production	5,241	5,016	4.5	5,290	5,037	5.0
NGL production	2,453	1,688	45.9	2,421	1,683	43.8
Crude imports	9,947	9,828	1.2	9,695	9,806	–1.1
Product imports	3,173	3,059	3.7	3,093	3,449	–10.3
Other supply[2]	829	770	7.7	934	1,182	–21.0
TOTAL SUPPLY	21,652	20,360	6.3	21,433	21,157	1.3
Refining, 1,000 b/d						
Crude runs to stills	14,503	14,580	–0.5	14,606	14.658	–0.4
Input to crude stills	14,993	14,908	0.6	15,041	14,995	0.3
% utilization	86.5	85.7	—	86.8	86.4	—

Latest week 3/30	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	335,192	335,296	–104	341,015	–5,823	–1.7
Motor gasoline	202,031	202,471	–440	212,498	–10,467	–4.9
Distillate	119,694	119,239	455	122,491	–2,797	–2.3
Jet fuel	39,960	40,619	–659	42,536	–2,576	–6.1
Residual	38,256	38,237	19	39,411	–1,155	–2.9
Stock cover (days)[3] **3/23**			**Change, %**		**Change, %**	
Crude	22.2	22.4	–0.9	23.6	–5.9	
Motor gasoline	22.8	22.9	–0.4	23.9	–4.2	
Distillate	26.5	26.2	1.1	29.3	–9.6	
Propane	17.5	17.1	2.3	20.0	–12.5	
Futures prices[4] **3/30**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	64.73	60.08	4.65	66.09	–1.36	–2.1
Natural gas, $/MMbtu	7.53	7.10	0.43	7.24	0.29	4.0

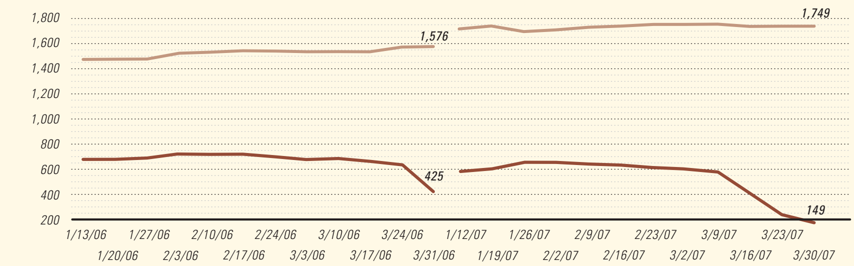
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Stocks divided by average daily product supplied for the prior 4 weeks. [4]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, American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

a different set of two Upper Miocene reservoirs overlying the other. One contains a 78-m oil column, and the other contains a 22-m oil column.

Previously, Total discovered oil in about 600-900 m of water with the Mobi Marine 2 well (OGJ Online, July 26, 2006).

Total E&P is the field operator and holds 53.5% interest. Chevron Overseas Congo Ltd. has a 31.5% interest, and Société Nationale des Pétroles du Congo, 15%.

RWE Dea makes another oil strike in Libya

Germany's RWE Dea AG has made its second oil discovery in the Sirte basin in Libya.

The B1-NC193 exploration well, drilled with Arab Drilling & Workover Co. Adwoc Rig 2, encountered two oil-bearing reservoirs of Paleocene age. On test the well flowed 933 b/d of oil from the Upper Satal formation at 1,115 m and the Dahra formation at 905 m. Flow was restricted by a 32⁄64-in. choke.

RWE Dea said further appraisal work is required to delineate the field and determine commerciality.

The third well in the NC193 concession—C1-NC193—is due to spud this month, and the drilling rig is being moved to location.

RWE Dea, which previously completed an extensive seismic program consisting of 2,400 sq km of 3D data and 3,000 km of 2D data, said it plans to boost drilling in the basin over the upcoming months.

The company intends to use three drilling rigs to drill at least eight exploration wells in the NC193, NC194, NC195, NC197, and NC198 concessions.

RWE Dea is the sole interest owner of six concessions covering 30,000 sq km in the Sirte basin, which were awarded by the Libyan authorities in May 2003.

Apache finds gas in Egypt's Western Desert

Apache Corp. has made a gas discovery on the Matruh Concession in Egypt's Western Desert with the Jade-1X well, which extends the known productive limits of the Jurassic gas fairway almost 12 miles southwest of existing Jurassic production.

Apache plans to drill five additional Jurassic and two AEB exploratory wells on the concession this year.

The Jade-1X well encountered a total of 65 ft of net pay in the Jurassic Upper Safa member of the Khatatba formation. On a test to evaluate 32 ft of the net pay, the well flowed at 25.6 MMcfd from perforations at 13,850-82 ft through a 1-in. choke with 1,382 psi of flowing wellhead pressure.

The remaining 33 ft of Upper Safa net pay in three sands between 13,480 ft and 13,750 ft will be perforated shortly, and gas from those zones will be commingled with that of the lower zone when the well comes on production around midyear.

Jade-1X also logged 217 ft of pay in the AEB 3D, 3G, and 6 sands. Apache plans to move the rig about 2 miles north of the Jade-1X discovery to appraise the AEB reservoirs. The AEB is a prolific producer throughout the 3.8-million-acre Greater Khalda complex, which includes Matruh. The company operates the Matruh Concession and holds a 100% contractor interest. The concession comprises more than a quarter-million acres.

Meanwhile, Apache is currently constructing two additional trains in the Khalda Concession to increase takeaway capacity by 200 MMcfd of gas to about 750 MMcfd. Construction is expected to be completed by yearend 2008.

PTTEP's second Gulf of Martaban well shows gas

Thailand's PTT Exploration & Production PCL (PTTEP) said an additional exploration well drilled on Block M9 in Myanmar's Gulf of Martaban has tested natural gas.

Zawtika 2, drilled to 3,500 m TD, encountered six zones of gas-bearing formation with a total thickness of 101.5 m, the company said.

A tubing stem test was conducted on three zones, indicating maximum gas flows of 38.9 MMcfd, 32.4 MMcfd, and 38.2 MMcfd, giving a combined flow rate of 109.5 MMcfd.

The result followed on the success made earlier this year (OGJ Online, Mar. 6, 2007).

PTTEP said the company will prepare a development plan and will drill 4-5 appraisal wells in July to establish the reserves required for development of the eastern area of Block M9.

Turkey plans launch of licensing round

Turkey plans to launch tenders in April for oil and natural gas exploration licenses off its Mediterranean coast, according to state media.

The Anatolia news agency quoted Ahmet Faruk Oner, a senior official at Turkish Petroleum Corp., as saying the country would launch this month the farmout process for licenses it has for areas off Antalya, Mersin, and the Gulf of Iskenderun.

"We are now preparing the technical groundwork," Ahmet said, adding, "We will start looking for partners for the licenses." The licenses cover areas within Turkey's 12-mile territorial waters as well as some areas "a little beyond," Ahmet said.

Turkey's decision follows recent developments in nearby Cyprus which signed an agreement with Lebanon in January for the demarcation of a subsea border to facilitate future oil and gas exploration. Cyprus signed a similar subsea maritime agreement with Egypt last year. ✦

Drilling & Production — *Quick Takes*

Madagascar steam pilot to start in late '07

Madagascar could be producing its first volumes of oil within the year from a pilot steam injection project to be attempted in Tsimiroro heavy oil field in the northern Morondava basin 160 miles west of Antananarivo.

Madagascar Oil, a private Bermuda company that is opening a headquarters in Houston, has drilled more than 60 wells on the 6,670 sq km Tsimiroro block. Consulting engineers dubbed 611 million bbl of "contingent recoverable resource" out of 1.028 billion bbl of oil in place in the deposit.

Four steam generators and other equipment arrived at Maintirano for transport to Tsimiroro after the rainy season and road repairs. Madagascar Oil closed in late March on an $85 million equity-linked development capital facility in support of its operations.

Pertamina to buy Jabung LPG from PetroChina

PetroChina Co. Ltd. has agreed to sell 30,000 tonnes of LPG extracted in Jambi, Sumatra, to Indonesia's state-owned PT Pertamina at a market price, according to PetroChina Director Budi Setiadi.

He said PetroChina has so far sold LPG from Jabung gas field on Singapore's spot market.

Jabung gas yields 25,000-35,000 tonnes/month of LPG, according to state media.

Last month, Pertamina said it would import 50% more LPG in April than in March to overcome a domestic shortage (OGJ Online, Mar. 29, 2007).

COSL to upgrade rigs for deeper water drilling

China Oilfield Services Ltd. plans a $10 million overhaul of one of its drilling rigs to extend its operating water depth and capture growth opportunities for deepwater oil drilling.

COSL is in talks with parent China National Offshore Oil Corp. to find a window from the latter's drilling schedule to carry out the upgrade. A 50:50 joint venture of COSL and Norway's Atlantic Deepwater Technology will test the upgrades.

COSL Chief Executive Yuan Guangyu said strong demand is making the drilling schedule for rigs very tight. Yuan added that the overhaul would see the operating water depth of one of COSL's three semisubmersible rigs increase to 1,500 m from less than 500 m.

COSL's semisubmersible rigs, which are capable of operating in 300-500 m of water, had an average rental rate of $118,483/day in 2006, up 107.5% over 2005. According to COSL figures, the day rate of semisubmersible rigs capable of working in 1,500 m of water could rise to $500,000/day. ✦

Processing — *Quick Takes*

Shipments resume after French strike ends

The strike that crippled the ports of Fos and Lavéra since Mar. 14 ended when 62 tankers and LPG and chemical carriers waiting outside the harbors began unloading operations Mar. 31.

The immediate deliveries have enabled Esso to return to almost-normal production at its Fos-sur-Mer refinery and Total at its La Mède and Feyzin refineries, the refiners told OGJ Apr. 2. They had slowed production last week by one third and would have gradually been forced to shut down had the strike continued.

The oil companies trade group Union Française des Industries Pétrolières believed it would take at least 2 weeks for business to return to normal. It is engaged in working out the full cost of the strike to industry, so far estimated at €25 million.

The 18-day strike had seemed deadlocked by Gaz de France's refusal to allow CGT port agents to handle branching and unbranching of the LNG carriers due to dock at its Fos-Cavaou LNG terminal when it comes on stream at yearend.

Chinese agency okays petrochemical project

China's National Development and Reform Commission (NDRC) has granted permission to China Petroleum & Chemical Corp. (Sinopec) for the construction of an 800,000-tonne/year ethylene plant and downstream petrochemical facilities in Wuhan, Hebei Province (OGJ, July 10, 2006, Newsletter).

The NDRC, which regulates China's industries and approves projects, said capacities of the downstream plants will include 300,000 tpy of linear low density polyethylene, 300,000 tpy of high-density polyethylene, and 400,000 tpy of polypropylene.

In 2005, China produced 7.55 million tonnes of ethylene. By 2010 the government plans to raise the country's ethylene capacity by 4.38 million tpy through expansion and upgrading of existing plants and by a further 6.2 million tpy through the construction of new facilities.

A Sinopec spokesman said Wuhan's new petrochemical project will be integrated with a 3 million-tpy refinery being expanded to 8 million tpy.

JV formed to expand Chinese refining, retail

ExxonMobil Corp., Saudi Aramco, and Sinopec Mar. 30 announced two joint ventures aimed at expanding a Chinese petrochemical refinery and operating a chain of 750 retail outlets in China's Fujian Province.

The Fujian Refining & Ethylene JV Project and the Fujian Fuels Marketing JV, valued at a total $5 billion in investment, represent the first fully integrated refining, petrochemicals, and fuels marketing project with foreign participation in China.

The Fujian Refining JV, which will be headquartered in Quanzhou, will triple the existing refinery's capacity to 240,000 b/d from 80,000 b/d when it starts up in early 2009. The upgraded refinery will primarily refine and process sour Arabian crude.

In addition, the project will cover construction of an 800,000 tonne/year ethylene steam cracker, an 800,000 tpy polyethylene unit, a 400,000 tpy polypropylene unit, and an aromatics complex to produce 700,000 tpy of paraxylene.

Support facilities including a 300,000-tonne crude berth and power cogeneration also will be built.

The venture, to be called Fujian Refining & Petrochemical Co. Ltd., will be owned by Fujian Petrochemical Co. Ltd. 50%, ExxonMobil China Petroleum & Petrochemical Co. Ltd. 25%, and Saudi Aramco Sino Co. Ltd. 25%. The project is expected to start up in early 2009.

The Fujian Fuels JV, formally registered as Sinopec SenMei (Fujian) Petroleum Co. Ltd., will manage and operate 750 retail outlets and a network of terminals in Fujian Province under the ownership of Sinopec 55%, ExxonMobil 22.5%, and Aramco 22.5%. ✦

Transportation — *Quick Takes*

Shell drops plans for Gulf Landing LNG terminal

Shell US Gas & Power LLC has decided to drop plans for its proposed gravity-based Gulf Landing LNG receiving and regasification terminal off Louisiana.

"Shell has determined that the development of LNG regasification facilities currently under construction or planned in the Gulf Coast region can meet regional LNG requirements," Shell said in an Apr. 1 statement to OGJ. "For this reason, Shell has discontinued its plans to develop the Gulf Landing LNG terminal project," the company said.

Shell had gained approval of the US Maritime Administration for its Gulf Landing LNG terminal in the Gulf of Mexico (OGJ, Aug. 15, 2005, Newsletter). The proposed Gulf Landing facility would have had capacity to deliver 1 bcfd of natural gas to the US interstate pipeline network (OGJ Online, Nov. 14, 2003). Plans called for a gravity-based structure in 55 ft of water 38 miles off Louisiana on West Cameron Block 213.

Chevron halts permitting for LNG terminal

Chevron Corp. has discontinued permitting activities for a proposed LNG terminal off Baja California, a spokeswoman in Houston confirmed to OGJ on Apr. 3.

"Chevron recently requested that our permits be canceled with three Mexican federal permitting agencies: Regulatory Energy Commission, Communication and Transport Secretariat, and Secretariat of Environment and Natural Resources," said Margaret Cooper, Chevron corporate media advisor, global gas.

"The decision to cease work on this project is solely based on our business needs," Cooper said. "The project was developed with the intent that it could receive supply from Chevron's share of LNG output from the proposed Gorgon project. However, Chevron has successfully signed heads of agreements for the majority of that share to its customers in Asia, and the remaining share will go into Chevron's internal marketing system."

She referred to the Greater Gorgon gas fields off northwest Australia. The fields are linked with the $11 billion (Aus.) Greater Gorgon LNG project (OGJ Online, July 1, 2005, Newsletter).

Neptune LNG project gets deepwater port license

Neptune LNG LLC, a subsidiary of Suez Energy North America Inc., has received a deepwater port license from the US Maritime Administration for its Neptune offshore LNG facility in Massachusetts Bay.

Demand for natural gas in New England is expected to increase by 1-2%/year over the next 2 decades, with Massachusetts alone accounting for half of the region's gas consumption. At this rate of growth, without new capacity, the region could face a shortage of gas approaching 14.1 million cu m/day in 2010.

The Neptune project is expected to provide 11.3-21.2 million cu m/day of gas, enough to serve 1.5-3 million homes/day in the Massachusetts and New England area, Suez said.

Neptune LNG estimates that the facility will be fully operational by 2009. Also at that time, the company anticipates completing construction of a lateral pipeline connection to HubLine.

Suez has received firm commitment from Hoegh LNG AS, Mitsui OSK Lines Ltd., and Samsung Heavy Industries that two specially designed LNG regasification vessels will be delivered by the project's targeted start-up date.

Draft study okays Elba Island LNG expansion

El Paso Corp.'s proposed expansion of the Elba Island LNG terminal and associated facilities near Savannah, Ga., would do minimal environmental harm, the Federal Energy Regulatory Commission's staff said in a draft environmental impact statement.

The project includes expansion of the existing LNG terminal, about 187 miles of new pipeline in Georgia and South Carolina, a 10,000-hp compressor station in Georgia, and associated facilities (OGJ, Oct. 23, 2006, Newsletter). El Paso subsidiaries Southern LNG Inc., Elba Express Co. LLC, and Southern Natural Gas Co. are the sponsors.

SNG will add 8.4 bcf of storage capacity and 900 MMcfd of sendout capacity to the installation, effectively doubling both elements there. It also will modify docking facilities to accommodate larger vessels.

Petrobras, Sonatrach eye LNG accord

Brazil's state-run Petroleo Brasileiro SA (Petrobras) and Algeria's Sonatrach have reached agreement on a memorandum of understanding to study an LNG partnership.

The partnership is aimed in part at supplying planned regasification terminals at Pacém and Guanabara Bay where, by 2008, Petrobras plans to have two LNG vessels in place to regasify 20 million cu m/day of LNG.

The draft agreement also foresees exploration and production cooperation studies for onshore and offshore blocks in Brazil, Algeria, and other countries of mutual interest, Petrobras said.

It said the agreement is scheduled to be signed in Algeria in April, when the firms also plan to sign an LNG supply agreement.

Pan-European oil pipeline gains support

Energy ministers from five southern European countries signed an agreement to cooperate and support the proposed construction of a 1,300-1,400 km oil pipeline linking the Black Sea port of Constanta, Romania, to Trieste, Italy. The Apr. 3 signing ceremony was in Croatia's capital of Sabreb for the proposed Pan-European oil pipeline, which would transport Caspian Sea oil.

Officials from Italy, Croatia, Slovenia, Serbia, and Romania signed the agreement. European Union Energy Commissioner Andris Piebalgs also signed the agreement, saying he believes the Caspian Sea region will supply more oil to the world market in the future. Piebalgs said Europe needs new infrastructure to fulfill rising oil demand.

"A lot of work still stands before us," Piebalgs said of the pipeline. Oil from the proposed pipeline eventually could be transported to western European markets. The energy ministers agreed to promote public support and attract financial backers to the project. Construction of the proposed $2.6 billion pipeline is expected to begin during 2011-13. ✦


Global Oil Flows
Source: Energy Information Administration
OBJECTIVES
EFFICIENCIES
ENERGY IMPORTS BY OIL EXPORTING COUNTRIES
GASOLINE
ELECTRICITY
NATURAL GAS
COAL
Saudi Arabia
Russia
Norway
UAE
Nigeria
Source: Energy Information Administration
The fact is, the vast majority of countries rely on the few energy-producing nations that won the geological lottery, blessing them with abundant hydrocarbons. And yet, even regions with plenty of raw resources import some form of energy. Saudi Arabia, for example, the world's largest oil exporter, imports refined petroleum products like gasoline.
So if energy independence is an unrealistic goal, how does everyone get the fuel they need, especially in a world of rising demand, supply disruptions, natural disasters, and unstable regimes?
True global energy security will be a result of cooperation and engagement, not isolationism. When investment and expertise are allowed to flow freely across borders, the engine of innovation is ignited, prosperity is fueled and the energy available to everyone increases. At the same time, balancing the needs of producers and consumers is as crucial as increasing supply and curbing demand. Only then will the world enjoy energy peace-of-mind.
Succeeding in securing energy for everyone doesn't have to come at the expense of anyone. Once we all start to think differently about energy, then we can truly make this promise a reality.
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– DIVERSIFY ENERGY SUPPLIES
• FIND MORE TRADITIONAL FUELS
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– ENCOURAGE CONSERVATION/ ENERGY EFFICIENCY
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2007

APRIL

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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.

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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.


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Journally Speaking

Fear, ignorance, and LNG

Warren R. True
Chief Technology Editor-Gas Processing/LNG

In energy debates, fear and ignorance form a lethal combination. When the subject is LNG, the two can wreak havoc among otherwise rational people trying to reach reasonable, long-term decisions on natural gas supply.

Witness US Rep. Tim Bishop (D-NY) who last month called floating LNG storage and regasification "unproven technology" that "threatens our local population and environment." Plenty of ignorance and fear (and fear mongering) here.

But reduce the ignorance, and sometimes you can reduce or eliminate fear. Many LNG companies have taken great pains to educate people about LNG in communities where they want to operate. Their efforts have met with occasional success.

A couple of informational tools are available to help, at least where channels of communication remain open.

Collaboration

In 2004, several industry groups produced a compact disc, "LNG: The Safe, Clean Energy Choice."

The groups are the Society of International Gas Tanker and Terminal Operators, Gas Processors Association, GTI (formerly the Gas Technology Institute), Center for Liquefied Natural Gas (CLNG), and Institute for Energy, Law & Enterprise at the University of Houston (now the Center for Energy Economics, Bureau of Economic Geology at the University of Texas at Austin).

The CD addresses public concerns by answering common questions: What is LNG? How is it transported? What safety measures are in place? Does LNG pose an ecological risk? Dose LNG pose a security risk?

Its factual answers are informative and specific without being adversarial. They remind viewers that LNG is simply natural gas in liquid form. Slick, professional video shows LNG being poured into water and into a beaker and evaporating. It demonstrates how LNG vapors channeled away from the capped beaker can be ignited without exploding.

In response to security concerns about LNG, the presentation stresses the layers of governmental and industry oversight and control and the exotic materials and extensive training that ensure safe handling of LNG.

It doesn't note, however, that no liquefaction plant, tanker, or regasification terminal has ever come under terrorist attack or that any such attack would be unlikely to result in catastrophic explosion. LNG, given its lack of flammability and pressure, would be a poor target.

The video also fails to note that far more dangerous cargoes (motor gasoline, for example) ply the world's waterways daily.

Perhaps these lapses are part of the effort not to be argumentative.

The other tool available to help industry educate people about LNG comes in an unlikely format: comic book.

Produced in 2006 by NYK Line, "The Grand Voyage of the Sea Camel" focuses on LNG shipping. Through 48 pages, the story line traces Jr. Third Officer Snow, a new graduate of NYK Line's Shin-Sugita training center, on his first LNG tanker voyage from Japan to Qatar and back.

Interspersed in his narrative are basic yet technically factual explanations of what an LNG tanker does, how, and why. Included is a diagram of the tanker, its distinctive Moss tankage system, and explanations of terms and procedures.

The text explains technical functions, such as cooling down the loading arms and handling boil-off gas, as the vessel embarks to pick up a cargo from Ras Laffan.

But it's a comic book, remember; so don't look for subtle characterization, plot twists, or anything beyond the narrative surface. The comic book approach appeals to school kids; the technical details appeal to parents.

As propaganda, its mission is to convey how safe the operation of an LNG tanker is.

Another tool

Each organization sponsoring the CD offers it on a web site, but CLNG's site (www.lngfacts.org) is probably the most useful, with its other information on LNG. The comic book, on the other hand, is unavailable electronically. Inquires about it may be directed to NYK Line's North American office: 201/330-3091.

It's important to remember that both products must, by their natures, present simplistic, highly positive messages. Both, however, can be useful in the right situations with the right audiences.

At the same time, other tools that employ other media are available to make LNG's case. Worth noting is Oil & Gas Journal's highly accessible, technically accurate wall poster, published in 2005, that depicts a typical North American LNG terminal. A complementary narrative explains unloading and regasification processes.

All these tools can combat the ignorance that breed the fear that leads to poor energy policy decisions. Industry should make use of them. ✦


Connecting Competence

Editorial

SUSTAINABLE ENERGY—2

The energy system

Sustainable development, as was argued here last week, has to represent more than mandatory consumption of fuels containing no hydrocarbon. Development depends on economics. Sustainable development therefore must accommodate hydrocarbon fuels in some environmentally sensible combination with others (OGJ, Apr. 2, 2007, p. 17).

Yet what's sensible? Environmental goals derive from politics and sometimes make no sense at all. The framework for decision-making, however, can be sensible, even sustainable, if consistently aligned with markets. History is clear about this. Politics in conflict with markets always fails.

Unsustainable patterns

Current energy patterns are unsustainable. The reason isn't that oil and gas resources are depleting or that carbon dioxide is accumulating in the atmosphere. Those are facts with consequences worthy of attention and response, to be sure. A more immediate driver of energy unsustainability, however, is political disengagement from market discipline.

Around the world, governments have swerved in several directions away from attention to markets.

Europe and the US, possibly to be joined soon by Canada, are imposing unsustainable costs on energy consumption. Europe has made urgent response to climate change a regional priority and wants the rest of the world to share its obsession. All climate-change remedies involve heavy taxation of the most competitive energy forms—oil, gas, and coal—and subsidization of others. Canada soon will adopt a climate-change policy; the extent of sacrifice remains to be seen. In the US, climate change lacks the regulatory prominence that it commands in Europe. Still, it's influencing policy and will do so more now that the Supreme Court has ruled that federal agencies should regulate CO_2 as an air pollutant.

The US government has trotted off on its own detour from market economics. It has instituted a lavish system of subsidies for politically preferred but economically baseless energy forms, prime among them ethanol made from grain. Corn and fuel prices are leaping, but politicians so far have managed to keep blame focused inaccurately on oil companies.

Among oil exporters, meanwhile, nationalization has roared back into fashion. For Persian Gulf producers, it never went out of style. Yet not so long ago, some of them, including Kuwait and Saudi Arabia, hinted at encouraging international companies to participate in oil production investments. But times—and oil prices—change, and the talk has subsided. Venezuela and Russia are renationalizing their oil industries following years—decades in the case of the Latin American producer—of reliance on private capital. Both countries have raised taxes on and expropriated assets of international companies. Both use oil and gas to influence politics of international customers.

Governments in the energy-short developing countries of Asia understand cost and the importance of supply and behave accordingly. But the biggest consumption tiger, China, works with an antique craving for control and has dispatched state-owned enterprises to buy producing interests wherever they can, often at excessive price.

In the current energy world, therefore, major consumers seek to tax the cheapest fuels into disuse and replace them with subsidized alternatives. Major exporters foreswear the efficiencies of private investment, let oil revenue camouflage the need to diversify economies, and in still too many cases subsidize consumption. And high-growth developing countries compete with national treasuries for energy investments.

Surviving reversals

These patterns can't last. Europe and the US can't raise energy costs without at some point weakening their economies. Asia can't grow without a prosperous industrialized world. And exporters can't keep enlarging state enterprises dependent on oil revenue unless oil prices stay high—never a certain bet.

In the global energy system now settling into place, governments increasingly make consumption and investment decisions. And they make them as though they believe current market trends will continue forever. The system wouldn't survive reversals such as a currency crisis in Asia, a recession in Europe or the US, or a slump in the price of oil, all of which have happened in recent memory. The system isn't aligned with markets and won't change when markets do, however they do. It cannot, therefore, for very long sustain development. ✦

European LNG developers face complex commercial landscape

Jacob Dweck
LNG Solutions Group
Washington, DC

Ernst Meyer
Det Norske Veritas
Oslo

David Wochner
Sutherland Asbill & Brennan LLP
Washington, DC

Recent trends in Euro-Russian relations have created a powerful political impetus for the development of LNG infrastructure. However, each project will face a unique set of opportunities and challenges, defined by regulatory and market factors unique to its place in the European landscape. Understanding and carefully managing these conditions will determine whether a project developer succeeds or fails in bringing new LNG capacity online in Europe.

Supply security fears

When Russia cut off natural gas supplies to the Ukraine in January 2006, the action sent shockwaves through the European Union—which gets most of its Russian gas through the Ukrainian pipeline network. Ukraine's state-owned gas company reached a deal with Russia's Gazprom to restore supply after only 3 days, but the damage was already done to the European sense of energy security.

More than a year later, tensions in Europe remain high. In December 2006 Russia threatened to cut off Belarus in the same way before a last-minute deal was reached on New Year's Eve. The EU's senior energy official accused Russia of trying to control Europe's gas market by forming an OPEC-like cartel for gas. Russia has done little to allay these fears, suggesting it might divert gas exports to China instead of Europe.[1 2] And in February Russian President Vladimir Putin explicitly stated he was exploring with Qatar the prospect of "cooperation" among gas producers.

Amid this uncertainty, Europe's political leaders are calling for investment in hard assets to shore up European energy security. Some suggest that European states resume building new nuclear and coal-fired power plants, but both of these face tough opposition on environmental grounds.[3 4] In this context, LNG regasification projects have gained increasing importance as Europe seeks to diversify its energy supplies. LNG supplies are received primarily from Africa and the Middle East. Tables 1 and 2 indicate European imports for 2004 and 2005 and demonstrate the importance of both LNG and pipeline imports.

Major LNG regasification projects are advancing in Italy, France, Spain, the Netherlands, and the UK (Fig. 1). Even

countries with smaller energy appetites, such as Croatia, Greece, Poland, and Cyprus, are planning LNG-import facilities.

But the urgency with which many of these projects are moving forward belies a complex environment for devel-

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Existing, proposed European LNG terminals

Fig. 1

Source: Sutherland Asbill & Brennan LLP

oping LNG facilities. The prospects for individual projects will be shaped and influenced by many factors, including availability of supply, siting and permitting processes, gas-industry regulation, and numerous market considerations, including the need to manage multiple users.

The importance of these factors varies among European markets. Gas-supply constraints, for example, are more acute in the UK and Spain because pipeline networks are more limited there than they are in Germany and Italy and provide less access to gas supplies from Norway and Northern Africa.

Market dynamics

Gas-supply concerns affect European markets in different ways, and this diversity in market conditions has major implications for project sponsors. Moreover, given the diversity of the 27 countries of the European Union, every LNG terminal site in Europe is unique, with differences in local siting considerations, permitting requirements, and national regulations.

The contrast between Italy and France, on the one hand, and Spain on the other is most illustrative. While LNG regasification projects in Spain are driven mostly by supply constraints, developments in Italy and France are driven more by the desire to diversify energy sources and encourage supply competition.

Italy and France are relatively well situated, with mature gas transmission networks and good access to North African, Russian, and Scandinavian gas via several major pipelines. In addition, at least two pipelines are planned or under construction to import more gas to the region, from Algeria through the Medgaz subsea line, and from the Caspian region via Turkey, Bulgaria, Romania, Hungary, and Austria through the Nabucco pipeline and related interconnection projects.

By contrast, access to pipeline gas supplies in Spain is not as well developed as it is in Italy and France or indeed many other countries in continental Europe. Spain has experienced harmful shortfalls in gas supply and storage capacity in recent years, to such extent that gas-fired power plants have been idled for lack of fuel. As a result, supply constraints are a major driver for development of new LNG capacity in Spain.

National regulatory policies affecting LNG stakeholders are likewise influenced by these market drivers. For example, Italian regulations require 20% of the LNG regasification capacity at the existing Panigaglia terminal to be set aside for third-party access (TPA). However, the government has granted exemptions from TPA obligations for two new terminal projects in construction, at Rovigo and Brindisi.

Spanish regulators, on the other hand, closely regulate LNG facilities in the country, enforcing strict tariffs and capacity-allocation protocols and requiring TPA for all LNG import capacity. Specifically, 75% of terminal capacity

2005 EUROPEAN LNG IMPORTS BY ORIGIN

Table 1

	Origin														
	US	Trinidad and Tobago	Algeria	Egypt	Libya	Nigeria	Oman	Qatar	UAE	Australia	Brunei	Indo-nesia	Malay-sia	Other	Total imports
	Volume, bcf														
Importers															
Belgium	—	—	95.21	—	—	—	—	—	—	—	—	—	—	—	95.21
France	—	—	264.86	37.08		148.32	2.83	—	—	—	—	—	—	—	453.09
Greece	—	—	15.47	—	—	—	—	—	—	—	—	—	—		15.47
Italy	—	—	78.96	—	—	—	—	—	—	—	—	—	—	9.39	88.36
Portugal	—	—	—	—	—	60.14	—	—	—	—	—	—	—	—	60.14
Spain	—	17.66	183.28	124.66	30.72	176.58	58.27	161.04	10.95	—	—	—	5.65	—	768.81
Turkey	—	—	133.70	—	—	35.84	—	—	—	—	—	—	—	—	169.55
UK	—	2.83	14.69	—	—	—	—	—	—	—	—	—	—	—	17.52
Total Europe	**—**	**20.48**	**786.18**	**161.74**	**30.72**	**420.88**	**61.09**	**161.04**	**10.95**				**5.65**	**9.39**	**1,668.14**

Sources: Energy Information Administration, Oct. 10, 2006 (imports to the US), Natural Gas Monthly (August 2006), Centre d'Information sur le Gaz Naturel et tous Hydrocarbures Gazeux (imports to France and Spain), Natural Gas in the World, Trends & Figures in 2005, International Energy Agency, Natural Gas Information 2006, as of end of July 2006 (electronic database)

2004 EUROPEAN LNG IMPORTS BY ORIGIN

Table 2

	Origin													
	US	Trinidad and Tobago	Algeria	Libya	Nigeria	Qatar	UAE	Oman	Australia	Brunei	Indonesia	Malaysia	Other	Total imports
	Volume, bcf													
Importers														
Belgium	—	—	108.84	—	—	—	—		—	—	—	—	—	108.84
France	—	—	237.32	—	29.31	—	—	2.83	—	—	—	—	—	269.45
Greece	—	—	16.56	—		—	—	—	—	—	—	—	—	16.56
Italy	—	—	42.17	18.47	154.79	—	—	—	—	—	—	—	—	215.42
Portugal	—	—	—	—	48.88	—	—	—	—	—	—	—	—	48.88
Spain	—	—	232.37	22.25	169.87	138.08	7.06	42.38	—	—	—	6.36	—	618.37
Turkey	—	—	110.11	—	35.84	—	—	—	—	—	—	—	—	145.96
Total Europe	**—**	**—**	**747.37**	**40.72**	**438.68**	**138.08**	**7.06**	**45.21**	**—**	**—**	**—**	**6.36**	**—**	**1,423.48**

Source: Energy Information Administration

can be contracted on a long-term basis (more than 2 years), with 25% reserved for shorter-term contracts.

Other European regions have reacted to their own unique political and market imperatives. While the UK gas market is characterized by increasingly constrained supplies, the UK enjoys large volumes of domestic gas resources and expanding pipeline access to European and Scandinavian supplies. UK regulators apply a system of TPA requirements, extending conditional exemptions that allow 100% of new terminal capacity to be subscribed with long-term contracts but prohibiting capacity hoarding and encouraging interruptible and spot-market use of facilities.[5]

Northern European markets present yet another set of market conditions and regulatory provisions. Northern Europe represents a crossroads for gas supplies, with major pipelines moving North Sea gas southward and Russian gas westward. Northern Europe also features the continent's only LNG hub, the important gas hub at Zeebrugge in Belgium.

For more than 20 years Tractebel subsidiary Distrigas, under a contract with Sonatrach, had full use of the Zeebrugge facility to bring Algerian gas into Northern Europe. But when the Distrigas contract expired in late 2006, Fluxys began operating the terminal under a new tariff and TPA structure. Qatar Petroleum and ExxonMobil are now using Zeebrugge to import gas from Qatar, and Distrigas this year will begin importing LNG from RasGas II in Qatar under a 20-year agreement.

To accommodate additional users, Fluxys plans to double the capacity of the Zeebrugge terminal and add nitrogen-blending facilities to enable regasified LNG to be sold in more European markets.

Third-party access

Despite variations in market drivers and regulatory frameworks, the trade policies of the European Union affect all regions and countries in Europe. For gas, they are embodied in the EU's Second Gas Directive, aimed at harmonizing regulation of European gas industries and creating a competitive wholesale gas market across European state borders—while also encouraging infrastructure investment.[6]

As energy-security tensions continue affecting Europe's gas markets, regulators likely will seek to ensure maximum and open use of terminal and pipeline capacity. Indeed, the European Commission itself has promised to promulgate stronger regulations as a result of shortcomings identified in its recent inquiry into the state of competition in European gas and electricity markets.[7]

"Energy markets are not functioning

properly," said Neelie Kroes, European commissioner for competition policy, during a press conference in January. "When prices do not react to changes in actual supply and demand, security of supply and investment in alternative energy sources [are] threatened. Europe needs stronger regulators, enhanced co-ordination, and increased transparency."

For LNG regasification terminals, the most pertinent elements of the Gas Directive are those involving TPA to gas facilities.

TPA requirements are intended to ensure that European gas infrastructure provides open access among suppliers, so that gas prices can more readily respond to the forces of supply and demand. Thus European LNG facilities must reserve a portion of their capacity—as much as 25% in some cases—to accommodate LNG supplies from sources other than those that have subscribed to terminal capacity on a long-term basis, including short-term deals and "spot" cargoes. Moreover, in Spain one shipper may not hold more than half of the 25% portion reserved for third parties.

Such policies stand in notable contrast to American regulation of LNG terminals. Specifically, the US Federal Energy Regulatory Commission (FERC) in 2002 adopted the "Hackberry" doctrine whereby new LNG capacity is exempt from open access requirements, tariff rates, and other economic regulation. After FERC approved several regasification terminals under the doctrine, the policy eventually was codified by the US Congress in the Energy Policy Act of 2005. This allows terminal owners to enter exclusive long-term agreements for 100% of their regasification capacity at market rates.[8]

But despite the comparatively stringent nature of European TPA requirements, the Gas Directive gives great latitude to member states implementing the regulations, allowing broad exemptions under certain conditions. Indeed, some project sponsors have escaped TPA obligations by conditioning their investment on securing an exemption. For example, in Portugal the network operator may refuse such TPA if it would lead to serious financial or economic difficulties.

Yet such exemptions do not permit capacity holders to lock out LNG cargoes from competing suppliers. For example, national regulators in Italy and the UK have imposed "use it or lose it" principles to prevent market-power abuse by LNG terminal owners.[9]

Antihoarding policies

Even for projects that have obtained exemptions from TPA requirements, EU and national access rules still can present a significant regulatory risk for terminal owners and operators—most notably via the Gas Directive's antihoarding requirements.

For example, if capacity holders at the UK's Isle of Grain terminal do not sell any unused capacity, the LNG terminal operator may sell that capacity to a third party. This has occurred at least twice in recent months.[10] Spain's terminals operate under a similar regime.

Beginning this year, at Belgium's Zebrugge terminal, the capacity holder must inform the terminal operator, Fluxys LNG, about any unused capacity no less than 2 months in advance of the vacancy so Fluxys can market the capacity to third party suppliers.

In Italy, if 20% of exempted capacity is unused in a given year, the capacity holder loses the exemption right for all owned capacity the following year. Moreover, as of July 1, 2007, no single company operating in the Italian gas sector may hold more than a 20% stake in companies owning transportation networks.

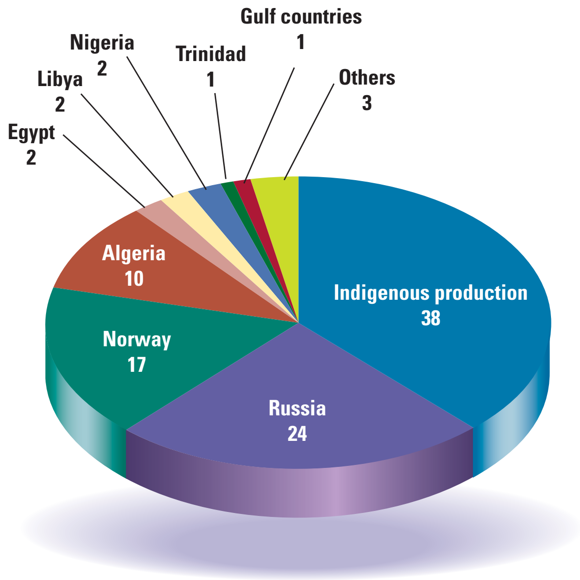
These requirements can affect operational logistics and costs as shippers seek to maximize terminal usage, obtain maximum market access, and avoid antihoarding penalties. To the degree LNG terminals prevent third parties from accessing spare capacity during times of short supply, terminal capacity holders could face investigations and potentially harsh sanctions from government agencies. EU antitrust laws authorize the European Commission to impose large fines (up to 10% of global annual turnover) and far-reaching structural remedies against companies found to violate EU antitrust rules.[11]

Multiuser challenges

As a result of TPA and antihoarding policies, many European regasification terminals will be used by multiple shippers—some operating under long-term agreements and others carrying LNG cargoes on a spot or short-term contract basis. This reality will affect the commercial performance of many terminals. In fact, some multishipper terminals will face many issues that threaten operational and commercial viability if they

2006 EUROPEAN GAS SUPPLIES, %

Fig. 2



Source: Eurogas data, "Natural Gas Consumption in EU25 in 2006," Feb. 26, 2007 are not addressed early in the development and contracting process.[12]

These issues include physical constraints such as the maximum capabilities of terminal berths, navigational concerns such as tides and bridge clearances, and regulatory concerns such as environmental limitations on vessel transit.

In addition to these physical constraints, capacity holders and other terminal users face contractual and operational issues that affect their ability to use the facility. For example, bringing LNG to market requires access not only to terminal berths and regasification capacity but also to other terminal services and pipeline access. Users at multiple-user terminals must consider available aggregate storage capacity because at some terminals capacity is limited to only one LNG vessel at a time. As a result, importers should ensure that their terminal use agreements (TUAs) appropriately define their access to the services they will need.

However, the most critical issue arising at multiuser terminals is the need to coordinate shipping schedules to synchronize vessel arrivals and unloading windows. Delays and failures in coordination can expose importers to burdensome financial costs and penalties.

To avoid shipping conflicts, terminal operators must impose a strict regime that establishes firm unloading windows, while also providing flexibility to accommodate uncertainties and assign unused unloading windows. TUAs likewise should specify scheduling regimes and contingencies to ensure that all importers understand their access rights, performance obligations, and financial risks.

Market access requirements

In addition to operational challenges and TPA requirements, terminal capacity holders may face downstream obligations as a condition of their participation in European gas markets. In Portugal, for example, the Sines LNG terminal operator must maintain the equivalent of 20 days' supply in its storage tanks. Capacity holders in Italy and Spain can face penalties if they contract for import capacity and then fail to supply expected volumes of gas. And in the UK, the Office of the Gas and Electricity Markets (Ofgem), the national energy regulator, is considering implementing a rule that would require LNG terminal operators to regularly publish LNG storage data to help market participants "reach more informed commercial decisions and therefore facilitat[e] the efficient operation of the [UK] gas market."[13]

Such obligations and penalties represent additional potential costs and can affect commercial arrangements between LNG suppliers, project developers, and capacity holders. Moreover, not all market participants are equally suited to manage these factors.

In European markets LNG import capacity is held largely by gas and power utilities, such as Gaz de France, E.On, Endesa, and National Grid. Such companies invest in LNG regasification capacity as a means of ensuring fuel supply for power plants and retail gas customers. This characteristic distinguishes European LNG terminals from North American terminals, which largely are subscribed by international oil and gas companies, such as Statoil, Shell, BG, ExxonMobil, and Total.

The weight of downstream burdens will vary depending on the interests of participants. Oil and gas companies, whose profitability depends on their ability to leverage their resource positions, likely will find downstream requirements more onerous than will electric and gas utilities, which can more readily manage such obligations and pass the costs along to ratepayers.

This dynamic may create an important commercial consideration for LNG stakeholders—the need to effectively disaggregate LNG suppliers from importers, marketers, and distributors. In some cases LNG suppliers investing in a terminal might allocate their capacity to a different company—a gas importer or national utility, which will accept the LNG at the terminal entrance and manage downstream obligations from that point.

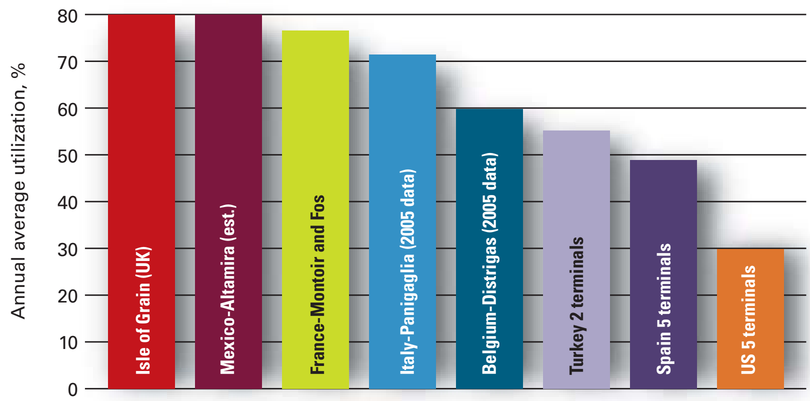
Siting and permitting

Just as market-access requirements are driven by market conditions, regulatory approaches to facility siting and permitting in Europe have evolved from a combination of energy-security, competitive market, and environmental considerations. These approaches present different challenges to project sponsors in different countries, depending on the efficiency of government bureaucracies dedicated to these processes.

In general, European national

LNG IMPORT TERMINALS UTILIZATION:* ATLANTIC BASIN MARKETS

Fig. 3



*Based on 2006 data except as noted.
Source: Pan EurAsian Enterprises Inc., March 2007

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governments seek to encourage the development of LNG terminals and therefore provide relatively streamlined regulatory processes. Government agencies often are directly involved in selecting project sites and encouraging development as part of national policies focused on improving energy security.

Indeed, many of the companies involved with LNG terminals are partly or wholly government-owned, which means governments have a direct stake in project development.

This situation contrasts starkly with that in the US, where federal and state agencies play no role in selecting sites or encouraging the development of individual projects but only review project applications for regulatory compliance purposes.

As a result, European permitting processes tend to be less challenging than US processes are. At the same time, however, European policies are closely focused on minimizing environmental impacts, and project reviews are exhaustive and time-consuming. Also they can be affected greatly by environmental advocacy movements. For example:

- The Brindisi project, being developed by BG in Italy, has been set back by significant local opposition. Court battles challenging the project's environmental permits have delayed construction by months or years, added more than €100 million to the total cost, and caused BG's development partner Enel SPA to drop out of the project.[14] Most recently, criminal allegations of bribes have brought construction to a halt.[15]
- After international protests in July 2006 drew negative attention to two LNG terminals being developed near the Italian Adriatic port of Trieste, the city council rejected the applications of both projects on "environmental compatibility" grounds.[16]
- At the South Hook LNG project in Wales, protestors repeatedly disrupted construction in late 2006 and early 2007. In January, for example, 13 protestors broke into the site and chained themselves together to a large pipe, requiring a brief construction delay while police arrested the demonstrators.[17]

Coastal Europe's relatively high population density and sensitivity to environmental issues exposes LNG projects to intense public scrutiny. Paying careful attention to public sentiment and conducting siting and permitting processes in a transparent and forthcoming manner can help developers avoid siting difficulties and the delays and added costs that result.

Safety and security

Like permitting processes, safety and security reviews tend to be much more manageable in Europe than they are in the US.[18]

US safety and security processes for most industrial facilities, including LNG terminals, are based on reducing the potential consequences of adverse events. This approach frequently results in open-ended and contentious proceedings that expose developers to a great deal of negative publicity and local siting opposition—which has derailed many projects in the US.

European policies, however, generally are based on ensuring that projects do not exceed established risk criteria. This standards-based approach, drawn from British law, focuses on empirical risk assessments and limits the population's cumulative exposure to industrial risks.[19]

For example, at the Zebrugge terminal in Belgium, LNG suppliers assessed the risk of larger Qflex-sized LNG carriers docking at the terminal. Belgium's risk-standards approach showed that such carriers will not increase public risk and in fact may reduce cumulative risk when accounting for the number of smaller tankers required to achieve equivalent import volumes.

Europe's criteria-based approach to assessing risk, combined with the European public's greater cultural acceptance of infrastructure projects in general, has allowed LNG projects in Europe to avoid much of the strident local opposition that has hindered many US projects. However, LNG projects in Europe are subject to careful scrutiny for safety and security, and projects will proceed only if their sponsors satisfy national standards.

Gas composition

As more LNG terminals come online and new pipeline infrastructure projects are built in Europe, importers face an increasing need to ensure that diverse compositions of various LNG sources do not create unmanageable volatility in European gas supplies.

Recognizing the need for streamlined standards, the European Association for the Streamlining of Energy Exchange-gas (EASEE-gas) in February 2005 adopted harmonized gas-quality specifications. The association proposed a two-phase implementation process, with most standards becoming effective for participating countries and companies by Oct. 1, 2006. Implementation of standards for combustion-related properties (such as Wobbe Index, relative density, and oxygen content) is delayed until Oct. 1, 2010, because of anticipated technical issues.

The standards are intended to facilitate increased gas flows and ensure interoperability at designated cross-border points in Europe, including pipeline and LNG import points. Although some European countries retain national gas-quality specifications, to accommodate new supplies these standards eventually may be modified or eliminated in favor of the EASEE-gas standards.

For example, EASEE-gas harmonized standards currently apply to two cross-border points leaving Denmark—one to Germany and one to Sweden. All other gas in Denmark must meet Denmark's existing gas-composition specifications, contained in the Rules for Gas Transport. These national standards include a narrower Wobbe Index range than the EASEE-gas standards, as well as a gross calorific value specification, which is absent in the EASEE-gas standards. Given several proposals for LNG import terminals in northern Europe, Denmark's more restrictive gas-quality specifications could in practice restrict the free flow of new supplies and eventually may have to be modified.

Complex landscape

Opportunities for LNG development in Europe are evolving within a complex landscape of market and policy considerations. Russia in 2006 supplied 24% of Europe's gas (Fig. 2). Countries that are more dependent on Russian gas might have greater impetus to develop LNG infrastructure to expand their supply diversity, but some of the most promising project opportunities are found in countries that today import little if any gas from Russia.

LNG prospects likewise will depend on the fate of various major gas-pipeline projects that could change the supply-demand balance considerably, reducing market opportunities for LNG importers. And if too many LNG projects move forward in a given market, perhaps none will be fully subscribed when they enter operation. Utilization rates can vary widely, as illustrated by Fig. 3, which shows current comparative LNG utilization percentages for eight countries.

Additionally, projects in countries with the most pressing supply constraints face potentially large compliance costs and risks, as national regulators seek to ensure maximum use of terminal capacity and prevent market-power abuse.

LNG suppliers and importers will play a critical role in helping Europe address its geopolitical and supply-adequacy challenges. As a result, European LNG development offers promising opportunities for investors who can manage a dynamic market and a complex policy landscape. ✦

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EIA: Refinery outages usually don't affect prices

Nick Snow
Washington Correspondent

A shutdown of any major refinery unit can reduce production of finished products. Integration of refinery units means that the outage of one can shut down or reduce operations at others. But refinery unit outages generally don't have a significant product price impact, said the US Energy Information Administration in a late March report.

"Prices are affected not by production changes alone, but mainly by the balance in supply and demand, as represented by inventory levels. If supplies are abundant relative to demand (e.g., high inventories and off-peak time of year), a refinery outage, even an unplanned outage, is likely to have little impact," the federal energy forecasting and analysis service said. It based this conclusion on its own monthly and weekly statistics, which it said can be analyzed for normal market variations and responses.

EIA quickly added, however, that while outages normally have little impact on prices, they can add to price pressure when markets are tight and alternative supply sources are not available.

"Clearly, the outages that occurred during Hurricanes Katrina and Rita were large enough to impact price. Another case was highlighted in an earlier report on California gasoline where several large unexpected outages in conjunction with tight gasoline markets seemed to drive up prices," it said. "However, outages with measurable impacts on monthly prices are relatively rare," EIA maintained.

Requested by Bingaman

EIA prepared the 53-page report, "Refinery Outages: Description and Potential Impact on Petroleum Product Prices," at the request of US Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) when he was the chief minority member last July as the committee held a hearing on HR 5254, which aimed to increase domestic refinery construction.

"We have heard from several experts that the reason we are facing high prices at the pump stems from underlying supply issues. The amount of global excess capacity to produce oil and refine gasoline has been declining. Experts claim it has entered 'the red zone' and coupled with other threats to energy output (Nigeria, Venezuela, Iraq, and Iran), [a] perfect storm has been created," Bingaman said in his July 3, 2006, letter to US Energy Sec. Samuel W. Bodman.

Bingaman suggested that EIA's study include an examination of the preparations and execution of a refinery turnaround. He asked how refiners plan such maintenance, "including coordination of outside contractors," and if other refineries' known plans affected scheduling. He also asked how much flexibility refiners have in changing their planned activities, and inquired about the extent to which reliability and safety prohibit deferring maintenance.

In its report, EIA noted that turnarounds are the biggest planned outages at refineries because they involve major maintenance and overhauls. Safety is a major concern while they are in effect because refineries run with materials at high temperatures and high pressures, and some of the materials are caustic or toxic and must be handled appropriately, it said.

"The frequency of major turnarounds varies by type of unit, but may only need to be done every 3-5 years on any given unit. Planned turnarounds often require 1-2 years of planning and preparation to organize, line up the skilled labor, and arrange for the materials and equipment." The actual turnaround may then last 20-60 days, the report said.

A refinery turnaround's size and complexity leaves little flexibility for changing plans, even when market conditions favor leaving the refinery running, EIA continued. A major fluid catalytic cracking turnaround might require increasing outside labor by more than three times the labor force usually present in the refinery, and long lead times are needed for some materials and equipment, it indicated.

Labor shortage

Another important factor is that skilled labor for turnarounds is in short supply, preventing refiners from conducting simultaneous turnarounds, EIA's report said.

Citing a recent survey of operating experiences for 28 FCC units by the newsletter Octane Week, it said that while 22 of the units targeted 4-5 years between turnarounds, only 16 stayed on that schedule. "Turnaround times also tended to be longer than planned, with the average slippage being 5 days. Some companies indicated that in recent years, the slippages were the result of a lack of skilled labor, creating the need for longer outages," EIA's report said.

Such planned maintenance normally occurs during the first and fourth quarters of each year since this normally is the time when product demand is seasonably low and weather conditions are favorable, it said.

"Unplanned outages can be very disruptive since they allow for little, if any, lead time to plan for the shutdown. Some unplanned outages can be postponed for several weeks while material, equipment, and labor are ordered. Others may require immediate shutdowns," the report continued.

Volumes lost from an unplanned outage are usually less than from planned turnarounds, but unplanned outages can occur during high demand periods when markets are more sensitive to lost barrels of product, it said.

In the California situation, which it reviewed in an earlier report, EIA said that one or more large outages occurred during a peak demand period in an area where alternative supplies were not available, which significantly affected prices.

Spring, when refiners are switching from winter to summer gasoline grades, can be another vulnerable period, it continued. Prices can be initially depressed as suppliers draw down their winter-grade gasoline—which cannot be used during summer months—while they produce and store their summer-grade motor fuel. Prices then increase seasonally as the summer-grade gasoline season begins and demand rises toward its summer peak.

If refineries are slow to ramp up summer-grade gasoline production because they are having difficulty coming back from turnarounds, extra price pressure can occur, EIA said in its latest report. "This was the case in the spring of 2006, when a number of refineries were still trying to recover from the hurricanes in fall 2005. While gasoline imports increased to offset some of the refinery supply loss, the volumes of affected capacity were unusual," it said. ✦

LNG export capacity could fall short, conference told

Nick Snow
Washington Correspondent

LNG imports are expected to increasingly contribute to total worldwide supplies, but it's less certain that overseas export projects will keep pace with demand, a leading market observer suggested.

"Between now and 2030, we might run into geopolitical problems relative to LNG similar to what we've experienced with crude oil," observed Adam Sieminski, chief energy economist in Deutsche Bank AG's global markets and commodities research department, during the US Energy Information Administration's 2007 Annual Energy Outlook Conference on Mar. 28.

"There isn't enough LNG export capacity going into place during the next 15 years to keep pace with demand," he warned.

Other speakers during the conference's natural gas market outlook session agreed that pressure to build more LNG liquefaction trains and export terminals is growing.

Kevin R. Petak, vice-president for gas market modeling at ICF International's Energy and Environmental Analysis Inc. (EEAI) subsidiary, said US LNG imports could grow to 13.2 bcfd by 2017 and 18.6 bcfd by 2025 from 1.7 bcfd in 2005.

"I think the constraints on LNG will be on the liquefaction and not the regasification side," Petak said.

Growing costs

But while the 5% return on equity such projects provide at $5/MMbtu remains attractive, building and other costs have climbed dramatically in the past year, according to Petak. Other supply development obstacles include attracting investors, uncertainty created by volatile gas prices and future demand, siting and contracting issues, and political uncertainties, he said.

Stephen L. Thumb, who directs the oil and gas practice at Energy Ventures Analysis Inc. (EVAI), predicted that producing countries overseas and major oil and gas companies will build more LNG export capacity this decade than in the previous 40 years.

Worldwide liquefaction capacity could grow to 43 bcfd by 2010 and possibly 65 bcfd by 2015 from 14 bcfd prior to 2000, he suggested. "They're not doing this out of the goodness of their hearts. They're getting phenomenal returns, even after factoring inflation in," Thumb said. He also expects US regasification capacity to be overbuilt, possibly exceeding 20 bcfd. "Despite recent entrepreneurial exuberance, we expect only 17 of the 100 proposed US regasification terminals to be built," he said. Europe also appears likely to overbuild LNG import facilities, although the situation varies from country to country, but EVAI expects Asia's total regasification capacity to match its supply requirements, Thumb said.

EIA also expects worldwide competition for LNG to grow, said Joseph G. Benneche, a natural gas analyst in the US Department of Energy agency's integrated analysis and forecasting office. "LNG is one of the big unknowns," he said.

Carbon limits

The agency's latest annual energy outlook assumes that no major climate change legislation limiting carbon dioxide emissions will be passed and that many proposed coal-fired power plants will be built. Other forecasts suggest pressure will increase to build more gas-fired power plants to meet future electricity demand.

"TXU's knocking eight coal-fired plants from its planned construction could put more pressure on gas," Sieminski said. The cancelled coal supply will require another 47 bcf/month of incremental gas, effectively adding 1.5 bcfd to analysts' forecasts starting in 2009, he said.

Thumb said that EVAI expects a CO_2 tax to be enacted domestically by 2015, which would affect coal-fired plants' economics. And EEAI's Petak said, "We don't see as much coal penetration in the out-years as EIA does."

Falling production per well will continue to undermine domestic gas supplies, Sieminski said. "I'm worried about the rig count. It has taken a 13% average compound annual growth in it simply to keep total production flat the past few years," he said. Assuming this trend continues, the US will need 1,500-1,600 gas rigs operating in 2007, up from its current 1,440-rig level, he maintained.

"We think the hyperinflation of drilling costs will dampen growth. We think this is more permanent than temporary," said Thumb.

Petak said as production from traditional areas declines, newer areas such as the Rocky Mountains, Alaska, and Canada's Maritime Provinces and Mackenzie River Delta in the Far North will increasingly contribute to total US gas supplies.

Sieminski also suggested that domestic resource availability could be a growing issue. "We're not so much running out of natural gas as running out of areas from which we can produce it," he said. ✦

IPAMS visits net 130 meetings with legislators

Nick Snow
Washington Correspondent

Rocky Mountain oil and gas producers completed their 'Washington Call-Up' annual visit to Washington generally satisfied that meetings with members of the 110th Congress and their staffs went well, officials of the Independent Petroleum Association of Mountain States said.

About 35-40 IPAMS members participated in 130 meetings, primarily with new US House and Senate members. Most calls were to members from outside the Rockies who might not have been acquainted with issues oil and gas producers confront in the region, IPAMS Executive Director Marc W. Smith said.

"They seemed very interested in what we had to say. Most often, their response was 'I didn't know that,'" he told OGJ as the 2007 organized call-up concluded on Mar. 29.

Several meetings were with House Democrats who are part of the Blue Dog Coalition. "They're particularly important. They're from politically centrist districts and can provide a moderating influence," Smith explained.

IPAMS members came to Washington this year to ask Congress and the Bush administration to not inadvertently harm domestic independent producers with punitive legislation directed at multinational oil companies and the Organization of Petroleum Exporting Countries.

Smith warned that new legislation which increases regulatory and tax burdens for domestic producers could significantly affect smaller independents.

"Vengeful policies may actually be most harmful to the small, independent businesses that produce 82% of US natural gas and 68% of US oil. These independent producers are a driving force behind our domestic energy supply and should not fall victim to the misdirected wrath of Congress," Smith said.

"These burdens decrease the amount of investment in energy projects, thereby impacting local economic benefits that are a direct result of energy development. The American energy industry needs a stable and predictable regulatory environment in order to continue meeting American energy demands," he maintained.

"Put simply, we're not asking Washington for any special treatment. We are urging Congress to move with caution and thoroughly consider the implications of policies that might hurt the domestic oil and gas industry," Smith said.

'Interesting alignment'

The call-up coincided with a Mar. 27 House Natural Resources Committee on possible effects of oil and gas exploration and development on continued access to hunting and fishing areas on public lands in the Rockies. Officials from two labor unions joined representatives of wildlife preservation groups in saying hunting and fishing access and quality are endangered. "It was an interesting alignment," IPAMS Pres. Logan Magruder observed.

Andrew Bremner, IPAMS' government affairs director, pointed out that the oil and gas industry is one of the largest employers in the Rockies, accounting for more than 77,000 jobs with an average annual salary of $51,022.

"Our industry provides billions of dollars in taxes and royalties that provide quality schools, equipment and personnel for law enforcement, and maintenance for roads and highways throughout the West," he said.

The producers shared their passion for outdoor recreation with the union members, said Magruder, who also is president and chief operating officer of Quantum Resources Management LLC in Denver.

IPAMS pointed out in a letter to Resources Committee Chairman Nick Rahall (D-W.Va.) and Chief Minority Member Don Young (R-Alas.) that the oil and gas association historically has worked with conservation and sporting groups to preserve wildlife habitat.

The group also highlighted its participation in the Conservation in Action program in one of three newspaper advertisements that ran during the call-up. The other ads profiled independent producers that drill 90% of total US wells as "small businesses fueling America" and described natural gas as "the bridge to our renewable energy future." ✦

Supreme Court gives EPA authority to limit CO_2 emissions

The US Supreme Court ruled Apr. 2 that the US Environmental Protection Agency has the authority, under the Clean Air Act, to enact limits on carbon dioxide emissions.

The lawsuit was filed by Massachusetts along with several other states, US cities, and environmental groups.

"Because greenhouse gases fit well within the act's capacious definition of air pollutant, EPA has statutory authority to regulate emissions of such gases from new motor vehicles," Justice John Paul Stevens wrote in the majority ruling. "The statutory question is whether sufficient information exists to make an endangerment finding. In short, EPA has offered no reasoned explanation for its refusal to decide whether greenhouse gases cause or contribute to climate change. Its action was therefore arbitrary, capricious,...or otherwise not in accordance with law."

The justices ruled five to four in favor of the group led by Massachusetts in reversing a court of appeals ruling. Chief Justice John G. Roberts wrote a dissenting opinion.

"Global warming may be a 'crisis,' even 'the most pressing environmental problem of our time,'" Roberts said. "It is not a problem, however, that has escaped the attention of policymakers in the executive and legislative branches of our government, who continue to consider regulatory, legislative, and treaty-based means of addressing global climate change."

Patrick Michaels, Cato Institute senior fellow in environmental studies, said, "The implications may be quite staggering. The decision means that CO_2 qualifies as a pollutant, something that causes net harm. This surely will open up a massive number of subsidiary cases." The Cato Institute is a think-tank based in Washington, DC.

Michaels questions what levels of CO_2, if any, are to be allowed without being considered to be pollutants.

"There is very little in our society that does not have some relationship to the production of CO_2," Michaels said.

"We have now entered the era where the courts will enter into almost every aspect of our lives." ✦

Group sees potential in CO_2 capture, storage

Doris Leblond
OGJ Correspondent

Carbon dioxide capture and storage (CCS) can cut CO_2 emissions on a large scale at competitive cost, according to the International Carbon Sequestration Leadership Forum (CSLF).

CSLF, formed in 2003 at the initiative of the US Department of Energy, is a ministerial-level organization of 22 governments promoting technology to reduce CO_2 emissions. The group met Mar. 27-28 in Paris.

It has determined that CO_2 CCS can achieve as much as 55% of the reductions required to stabilize atmospheric levels of greenhouse gases in this century and that it can reduce ultimate stabilization costs from projected levels by 30% or more. CSLF recognizes 17 CCS projects in developed and developing nations, including two in China and India.

Thomas D. Shope, principal deputy assistant secretary in DOE's Office of Fossil Energy, cited technical progress that CSLF has made but said governments and the industry need a CO_2 cost analysis for long-term decision-making.

Trude Sundset, a Statoil researcher and chairman of the CSLF Technical Committee, said CCS projects in Europe and North America are dedicated to matters such as cutting costs of CO_2 capture technology and developing new methods of combustion; identifying storage capacity, and widening understanding of geologic reservoirs; predicting behavior of stored carbon in various kinds of reservoirs over a thousand years; and developing technologies for successful, reliable, and long-term monitoring measurements and verification of stored carbon.

She said CSLF believes geologic storage at great depth is possible in depleted and declining oil fields where sequestration linked with CO_2 enhanced oil recovery can also improve near-term supply by boosting production in natural gas fields; in unminable coal seams, which may add to natural gas supply by displacing methane; in very deep saline reservoirs; and in other geologic formations such as basalt.

From preliminary findings, CSLF estimates that the world's storage capacity exceeds 11 billion tonnes, compared with annual emissions of 24 billion tonnes. Many CSLF-approved demonstrations are meant to quantify the potential and identify the best storage sites. ✦

DHS issues regulations for high-risk chemical plants

Nick Snow
Washington Correspondent

Chemical plant owners will be required to assess risk levels at their installations and submit a security vulnerability assessment and site security plan if the facility is high-risk under new regulations imposed by the US Department of Homeland Security on Apr. 3.

The interim final rule gives DHS authority to impose fines of as much as $25,000/day and the ability to close

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Iran-US row rattles pawns

These days oil and gas are being used like pawns in the game of brinkmanship between the US and Iran—a game that is hurting business. In this game, even the pawns must hold a grudge.

Last week, oil prices slipped after Iran's President Mahmoud Ahmadinejad announced that his country would free 15 British naval personnel it had captured in the Persian Gulf more than a week before, pardoning and releasing them as a pre-Easter gift to Britain.

The "pardon" came as commodities trade was winding down for the long Easter weekend, with exchanges in London and New York preparing to close for Good Friday.

In London, the reaction was swift: By midafternoon on Apr. 4, West Texas Intermediate for May delivery on the New York Mercantile Exchange was down 43¢ at $64.21/bbl, while May Intercontinental Exchange Brent crude was 31¢ lower at $67.52/bbl.

Wall Street drops

As one analyst noted, the capture of British sailors by Iran had created nervousness in oil markets—a point underlined by the $5 surge in oil prices on Mar. 27 after rumors that a conflict had started between Iran and the US.

When the rumors were shown to be false, prices eased. But they still moved higher over the rest of the week as people everywhere—and traders among them—kept their eyes on the unfolding drama.

On Wall Street, the S&P 500 index dropped to 1,417.05 from 1,426.2.

The Iranians are an old trading nation, and they know perfectly well how markets react to any threat to supply—especially any threat to the supply of a commodity as important as oil.

The Iranians' seizure of the British sailors and marines was carefully planned. It was done with enough time to rattle stock markets but also timed to fit as neatly as possible into the Christian holiday calendar.

Petrobras threatened

The Iranians lost no face by promising to release the captives before Easter. Indeed, they may even have looked more humane—as they hoped to look—by the gesture, an especially strong one coming from a Muslim nation on the approach of a key Christian holiday.

So the Iranians were able to score a hit. They showed the world how a bit of saber-rattling can affect markets up and down the supply chain, and they got away with the gesture unscathed. Behind all this, of course, is the Iranians' desire to have their way regarding the development of nuclear power.

But the power struggle also works the other way. Clifford Sobel, the US ambassador in Brasília, reportedly told Sérgio Gabrielli, president of Petroleo Brasileiro SA (Petrobras), that the US was concerned over the company's increasing activities in Iran.

According to the newspaper Valor Econômico, Sobel said such activities might "create complications" for Petrobras's operations in the Gulf of Mexico.

Two wrongs never make a right—just ask the pawns. ✦

noncompliant facilities. It said it will conduct site inspections and security audits to validate submissions, and provide technical assistance when it's needed.

Security standards will be designed to meet specific protection goals. These include securing each high-risk plant's perimeter and critical targets, controlling access, deterring theft of potentially dangerous chemicals, and preventing sabotage, according to DHS.

DHS said affected facilities contacted by the federal department will have 120 days from the regulations' publication in the Federal Register to provide information for the risk assessment process and meet other requirements under the new rule.

DHS said it prepared the regulations following consultations with state and local governments, Congress, plant owners and operators, and the public to develop consistent guidelines that use a risk-based approach.

The new regulations preempt only those state and local regulations that conflict or interfere with the new federal rule. DHS said it currently has no reason to believe that any existing state laws are applied in a manner which will impede the federal regulation.

It said that it met an aggressive timeline imposed by Congress in proposing the interim final rule for comment and then publishing it before Apr. 4. "The safety and security measures we take need to be tough and balanced. We will significantly reduce vulnerability at high-consequence chemical facilities, taking into account significant efforts in certain states," DHS Sec. Michael Chertoff said.

The National Petrochemical & Refiners Association said it was pleased that the rule's initial phase encompasses a broad range of facilities possessing chemicals in quantities that might present a high level of risk, and that it then permits each covered facility to select appropriate measures to meet the standards set by DHS. ✦

GIANT FIELD TRENDS—2

Giant fields likely to supply 40%+ of world's oil and gas

M.K. Horn
Independent Geologist
Tulsa

This is the second part of a two-part article that lists world giant oil and gas discoveries by decade and analyses related trends.

Table 1 summarizes the decade-by-decade changes in oil and gas giant field discoveries. A familiar pattern can be seen of major increases that occurred in the 1960s and 1970s, followed by a dropoff in the last 2.6 decades (decade 2000 consists of a partial record from year 2000 through year 2006).

Another trend shown in Tables 1 and 2 is that since the 1990s, giant field gas discoveries have surpassed giant field oil discoveries.

The basic picture combines the oil and gas giants and superimposes a second-order trend line (Fig. 2). The total number of 938 giant fields includes 555 oil fields and 383 gas fields.

In Fig. 2, we predict the number of giant discoveries in decade 2000 based upon the record through year 2006. Since Jan. 1, 2000, 72 giant fields have been discovered. This averages to 10.28 discoveries/year; therefore the extrapolation to the end of decade 2000 is 103 discoveries. If this prediction holds up, the current decade will surpass the 100 discovery number for the first time since decade 1970.

OIL, GAS GIANTS DISCOVERED Table 1

Decade	Oil	Gas
1860	1	0
1870	4	0
1880	2	0
1890	4	0
1900	7	1
1910	12	1
1920	19	7
1930	40	11
1940	30	8
1950	64	28
1960	128	87
1970	115	105
1980	51	44
1990	45	52
2000	33	39

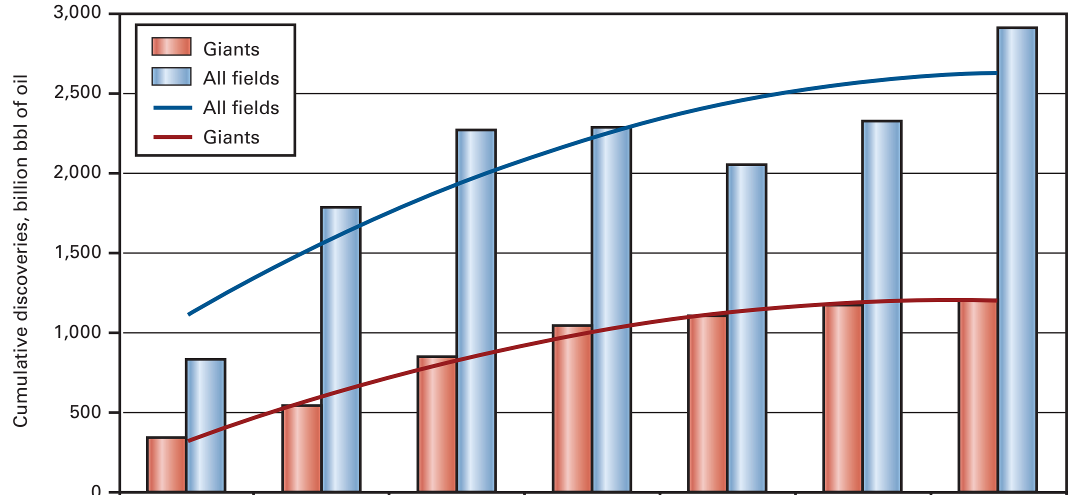
Giant oil fields

We next divide the study into oil on the one hand and gas on the other.

First, with regard to oil, Table 3 shows ultimate reserves in billions of barrels. Decade 1960 is the peak.

The five largest oil fields discovered

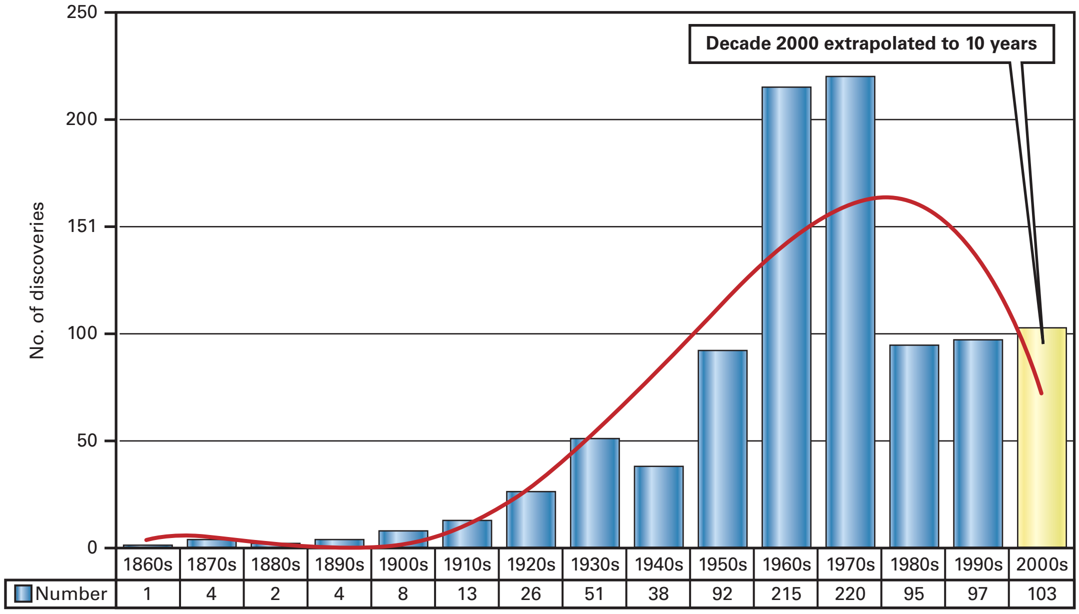
OIL GIANTS AND GLOBAL ULTIMATE ESTIMATES BY DISCOVERY DECADE Fig. 2



	1940s	1950s	1960s	1970s	1980s	1990s	2000s
Giant fields	346	544	842	1,037	1,105	1,172	1,210
All fields	838	1,785	2,268	2,283	2,046	2,326	2,918

GIANTS BY DISCOVERY, DECADE 2000 EXTRAPOLATED

Fig. 3



GIANT FIELD DISCOVERY PERCENTAGES

Table 2

Decade	— Discoveries — Gas	Oil	Gas field percent-age
1860	0	1	0.0
1870	0	4	0.0
1880	0	2	0.0
1890	0	4	0.0
1900	1	7	12.5
1910	1	12	7.7
1920	7	19	26.9
1930	11	40	21.6
1940	8	30	21.1
1950	28	64	30.4
1960	87	128	40.5
1970	105	115	47.7
1980	44	51	46.3
1990	52	45	53.6
2000	39	33	54.2

GIANT OIL, CONDENSATE FINDS

Table 3

Decade	Billion bbl
1860	1
1870	4
1880	1
1890	7
1900	9
1910	10
1920	72
1930	101
1940	140
1950	199
1960	298
1970	195
1980	68
1990	67
2000	38

AVERAGE SIZE OF GIANT OIL FINDS

Table 4

Decade	Billion bbl
1860	1.00
1870	1.02
1880	0.67
1890	1.85
1900	1.25
1910	0.80
1920	3.81
1930	2.53
1940	4.67
1950	3.10
1960	2.33
1970	1.69
1980	1.34
1990	1.50
2000	1.15

GIANT GAS FINDS

Table 5

Decade	Tcf
1860	15.0
1870	0.5
1880	0.5
1890	1.1
1900	5.2
1910	11.9
1920	94.7
1930	137.6
1940	295.1
1950	531.0
1960	1,582.0
1970	2,198.0
1980	390.1
1990	710.8
2000	247.6

AVERAGE SIZE OF GIANT GAS FINDS

Table 6

Decade	Tcf
1860	—
1870	—
1880	—
1890	—
1900	5.2
1910	11.9
1920	13.5
1930	12.5
1940	36.9
1950	19.0
1960	18.2
1970	20.9
1980	8.9
1990	13.7
2000	6.3

in decade 1960 (in billions of barrels of estimated ultimate recovery) were Zakum, Abu Dhabi (17.2); Shaybah, Saudi Arabia (15.7); Prudhoe Bay (Prudhoe Bay and 10 other oil pools), US, (15.3); Marun, Iran, (12.6); and Zuluf, Saudi Arabia (12.2).

Table 4 represents average giant oil field size. Decade 1940 leads the list with an average giant oil field size of 4.67 billion bbl. Ghawar, Saudi Arabia, is the greatest contributor to the decade 1940 average, with 66.1 billion bbl ultimate; thus providing 47% of the average. As noted by the Centre for Global Energy Studies,[5] the trend for more recent giant discoveries seems to be one of decreasing size.

Giant gas fields

The rest of the historical analysis concerns the giant gas fields.

Table 5 shows ultimate reserves in trillions of cubic feet. Decade 1970 is the peak with 2,198 tcf.

The five largest gas deposits discovered in decade 1970 (in trillion cubic feet EUR) were North field, Qatar (900); Astrakhan, Russia (89.6), Northwest Dome, Qatar (80), Bovanenko, Russia (76.4); and Kyrtaiol'skoye, Russia (55).

Table 6 represents average gas associated with giant fields. Decade 1940 leads the list with an average gas deposit size of 36.9 tcf. Ghawar, Saudi Arabia, is the greatest contributor to the decade 1940 gas average with 186 tcf, thus providing 63% of the average.

Expected recoveries

We next turn our attention to estimating the percentage of ultimate recoverable oil and gas that can be accounted for by giant fields. We do this by:

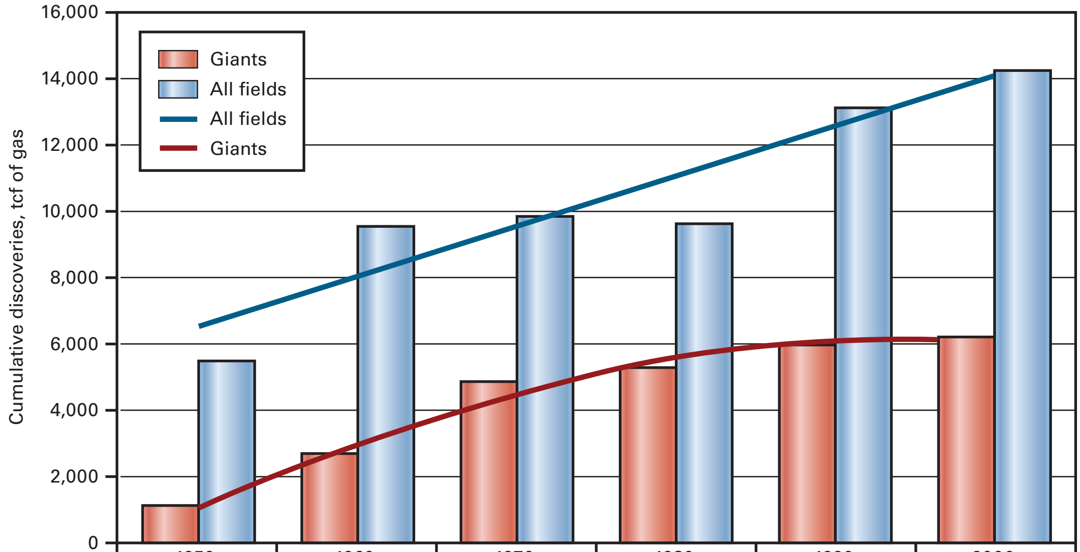
1. Establishing a current estimate of ultimate recoverable for oil and gas. In order to obtain this estimate, we use Salvador's[6] Tables 8 and 13 prediction compilations of industry, government,

and academia experts. Averaging the most recent (2006) data from these tables, we arrive at a value of 2,918 billion bbl of oil (decade 2000 column, Fig. 3); and 14,271 tcf of gas (decade 2000 column, Fig. 4).

2. Determining the total ultimate recoverable for giant fields, both oil and gas. These values are derived from Horn,[4] modified to take into account decade 2000 discoveries. These numbers are of 1,210 billion bbl of oil (decade 2000s column, Fig. 3) and 6,176 tcf of gas (decade 2000s column, Fig. 4).

GAS GIANTS AND GLOBAL ULTIMATE ESTIMATES BY DISCOVERY DECADE

Fig. 4



	1950s	1960s	1970s	1980s	1990s	2000s
Giants	1,092	2,674	4,873	5,263	5,974	6,221
All fields	5,500	9,542	9,889	9,676	13,172	14,271

The resultant data and prediction of giant field contributions are summarized in Table 7. The contribution percentages are low when compared to the industry's conventional wisdom estimates of about 50%, but they may reflect the new paradigm of greater contribution of smaller fields to the world's hydrocarbon inventory.

PREDICTING GIANT FIELD CONTRIBUTIONS TO ULTIMATE OIL AND GAS RECOVERY

Table 7

	Ultimate recoverable — Global	Ultimate recoverable — Giant field	Giant field percentage contribution
Oil, billion bbl	2,918	1,210	41.4%
Gas, tcf	14,271	6,221	43.6%

Main points

1. Giant field discoveries peaked in decades 1960 and 1970.

2. Since decade 1990, giant field gas discoveries have surpassed giant field oil discoveries.

3. The total number of giant fields is 938; the current decade will surpass the 100 discovery number for the first time since decade 1970.

4. Decade 1960 was the peak for adding ultimate giant oil field reserves; 1970 was the peak decade for adding ultimate giant gas field reserves.

5. Decade 1940 was the peak year with regard to average oil and gas giant field additions, due primarily to the discovery of Ghawar field.

6. Giant oil fields will contribute 41% to the projected ultimate world oil inventory of 2,918 billion bbl.

7. Giant gas fields will contribute 44% to the projected ultimate world oil inventory of 14,271 tcf. ✦

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The author

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Peru

The Huaya-1X well operated by Cia. Consultora de Petroleos, Lima, on Block 100 in the Ucayali basin cut 14 ft of net pay in Cretaceous Vivian sandstone at 807-814 ft. TD is 926 ft.

The Vivian primary target has bright yellow oil, a gas show, and log porosity of 28-33%. The well, 22 miles northwest of Maquia oil field, is near PetroPeru's 1984 Huaya-4X discovery, which tested 5 b/d of 38° gravity oil from Vivian. Other potential pay zones on the Huaya anticline are the shallower Cretaceous Cachiyacu and Casa Blanca formations.

Next to spud is Huaya-2X. The wells are near the Ucayali River. Working interests in the 17,300-acre block are CCP 70%, Houston-based Radial Energy Inc. 20%, and Ziegler-Peru Inc., Houston, 10%.

New Brunswick

An undisclosed US company took a farmout from Contact Exploration Inc., Calgary, that covers a shale gas prospect in New Brunswick.

The farmee will make further laboratory measurements on cores and cuttings from previously drilled conventional wells in the 68,000-acre prospect area. The farmee must commit to acquire more seismic surveys, drill a well, or terminate the agreement by Dec. 31, 2007.

The farmee is required to spud a well by Dec. 31, 2008, to earn a 70% working interest in the block. The farmout excludes all conventional plays that Contact is exploiting and excludes any interest in Stoney Creek oil and gas field.

Russia

Matra Petroleum PLC, Chertsey, UK, plans to acquire OOO Arkhangelovskoe, registered in Orenburg Oblast, and owns 100% of the Arkhangelovskoe exploration license near existing production.

Matra will issue 55 million new shares in payment for the Russian company and plans to spud Matra's first well on the 158 sq km license near Orenburg in June 2007.

The license is valid until August 2009 and has a requirement to drill four wells. Matra will drill the first well to 3,900 m to test the Sokolovskaya structure.

Matra, subject to shareholder approval, will issue 135 million new shares and 24 million options to Delek International Energy Ltd. of Israel to raise $12 million for drilling.

Alabama

Daybreak Oil & Gas Inc., Spokane, Wash., applied to become operator of East Gilbertown oil field in Choctaw County, Ala.

Under a Dec. 13, 2006, agreement with Gilbertown LLC, Daybreak has earned a 12.5% interest in unspecified assets by spending $250,000 reworking and repairing existing wells.

The field has 21 existing wellbores that can be reentered in Cretaceous Eutaw sand and Selma chalk at 3,000-3,500 ft, and infill and development drilling opportunities are also available, Daybreak said.

Consulting engineers estimated that 8 million bbl of oil may be recovered from seven Eutaw sands in the field.

Louisiana

Swift Energy Co., Houston, will dedicate $160-175 million of a planned $350-400 million 2007 capital spending budget to giant Lake Washington oil field in Plaquemines Parish.

The company will drill 24-26 wells in the field and upgrade facilities. Several wells will go as deep as 14,000 ft. At least two rigs will operate in the field for most of 2007.

Swift plans to drill up to 8-10 wells in Bay de Chene and Cote Blanche Island fields and up to 4 wells in Horseshoe Bayou, Bayou Sale, and Jeanerette fields. At least 5 of the wells will be on 3D seismic prospects.

Texas

North

XTO Energy Inc., Fort Worth, plans to drill 280-300 new wells in 2007 in the Fort Worth basin Barnett shale gas play.

Production averaged a net 223 MMcfd (311 MMcfd gross) in the fourth quarter of 2006, making the company the play's second largest producer after Devon Energy Corp., Oklahoma City.

The company anticipates employing 15 rigs on its core acreage near Fort Worth and another nine rigs in noncore counties to the west and south. It is expanding pipeline and compression facilities to handle 840 MMcfd by the end of 2008 compared with 465 MMcfd of takeaway capacity at present.

Panhandle

Brigham Exploration Co., Austin, expects to receive final processed data in the second quarter of 2007 from a proprietary 180-sq-mile high-resolution 3D seismic survey in the eastern Texas Panhandle.

The data should assist in further defining the structure at Mills Ranch field in Wheeler County and evaluating nearby exploration prospects, two of which the company plans to drill in late 2007.

Brigham's latest development well, Mills Ranch 96-1, began gas sales on Mar. 14 at 4.5 MMcfd from Siluro-Devonian Hunton. Once Hunton tests are complete, the company will commingle Ordovician Viola, previously tested at 3 MMcfd.

The well encountered 300 ft of apparent net pay below 24,000 ft in Viola and Lower, Middle, and Upper Hunton.

SINOPEC MPD—1

Managed-pressure drilling reduces China hard-rock drilling by half

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Sinopec conducted 9 months of managed-pressure drilling (MPD) operations in hard rock and sour-gas formations in the Puguang field, Sichuan province, southwestern China. Initially envisioned with only two wells, Sinopec commissioned the project to determine whether percussion air-drilling technology could provide rate-of-penetration (ROP) benefits.

Because the feasibility report determined that wellbore stability could be an issue, a certain amount of project risk was involved. In addition, the main reservoir is sour and potential sweet-gas secondary zones are above it.

Conventional 5,500-m wells were being drilled and completed in about 350 days. The first air-drilled well was spudded in March 2006 and immediate benefits were realized, saving more than 60 days in the main 311-m section. Four subsequent wells have improved ROP by 94%, eliminating an additional 60 days from the drilling curve. Wells are currently being drilled in 240 days.

As the project progresses, Sinopec will drill the sour-gas reservoir near-balanced, using MPD techniques. The stepped approach should improve ROP performance and reduce overall well times.

Weatherford is the only western service company working in the Puguang field and lessons learned during this project have significantly affected MPD and percussion air drilling in China. Enhanced engineering reviews, better implementation of procedures, management-of-change processes, improved client awareness, and closer cooperation between operator and service provider are enabling successful execution of remote MPD projects in China and elsewhere in Asia-Pacific.

This first article in a two-part series describes the drilling challenges in the Puguang field, drilling-failure analysis, risk assessment, and the project management road map.

The conclusion, next week, discusses the optimized well design and Sinopec's experiences with percussion drilling with compressed air and foam, used in both top-hole and nuisance-gas formations. The concluding article also covers the MPD system design and introduces plans for near-balanced operations in the sour-gas reservoir.

Field description

The giant Puguang gas field was discovered in 2003, in the Eastern Sichuan

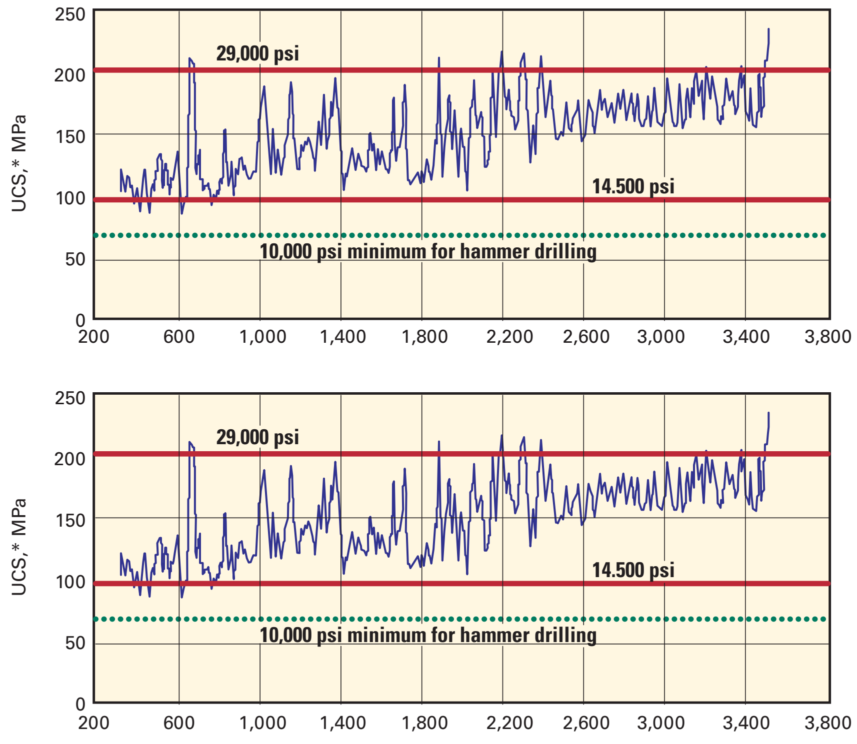
Based on a presentation to the 2007 SPE/IADC Drilling Conference, Amsterdam, Feb. 20-22, 2007.

PUGUANG GAS FIELD, SICHUAN, CHINA

Fig. 1

Uncompressive strength, Puguang formations

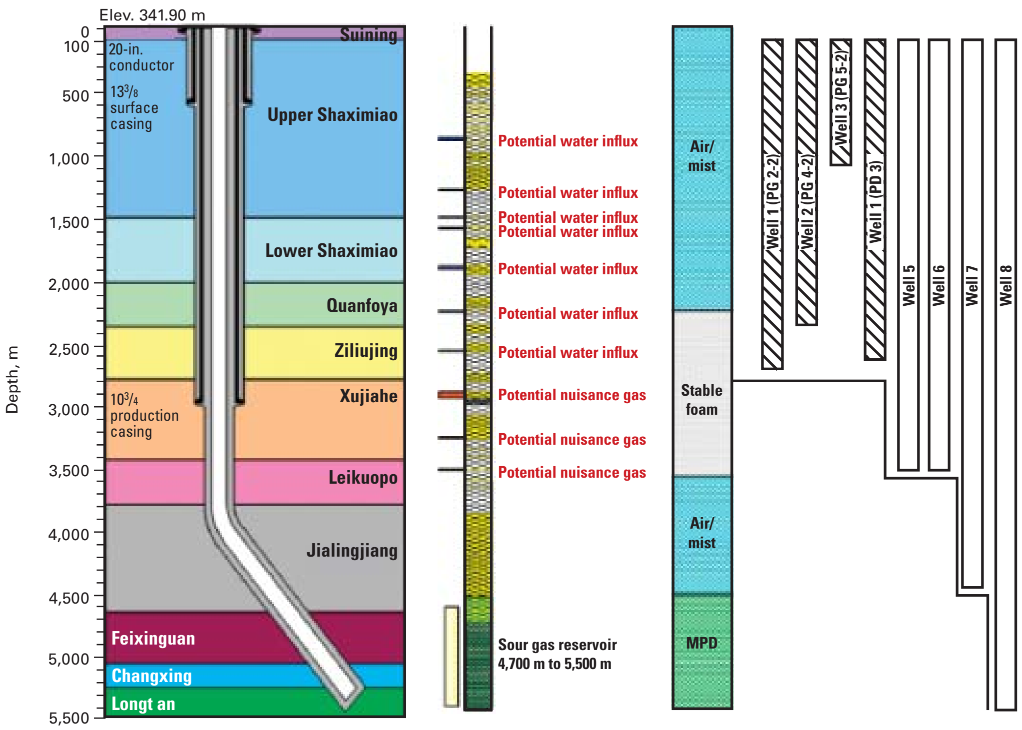
Fig. 2



*UCS = Uncompressive strength.

Puguang formations, well plan

Fig. 3



fold-thrust belt, in the mature Sichuan basin of southwestern China. A structural-stratigraphic trap, which is closed by lateral depositional change and dip closure, defines the field.

After drilling four appraisal wells, Sinopec assessed Puguang as one of China's largest gas fields, with estimated reserves of 4 tcf of gas in the lower-Triassic Feixianguan limestone. The rocks consist primarily of mudstones, siltstone, and shale sequences above the productive carbonate reef zone.

Following the four discovery and appraisal wells, a first-phase development program was approved in 2005 to exploit the field. Sinopec now plans to drill and complete 54 wells from 17 pads by 2009. By early 2007, about 10 wells had been drilled from seven pads. Development of this field is considered strategic to the development of the country (Fig. 1).

Drilling

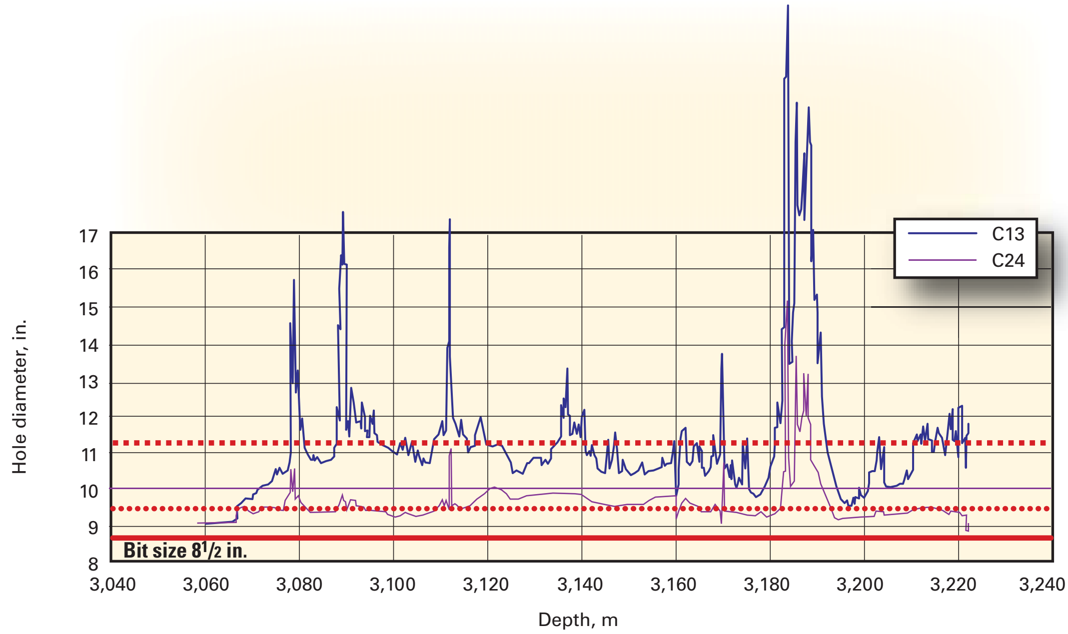
The deep, sour wells at Puguang are some of the country's most challenging and difficult to plan and execute. The first well (PG 1) was spudded in November 2001 and took 630 days to drill and complete. Subsequent wells (PG 2, 3, and 4) averaged 357 days to drill and complete due to numerous drilling difficulties. In addition to low ROPs, problems included the nonproductive time (NPT) associated with drillstring failure, out-of-gauge wellbores, nuisance gas, stuck pipe associated with hole instability, fluid losses across fractures, and use of highly overbalanced fluid systems.

The long drilling times were a direct result of multiple subsurface factors:

1. *Hard formations.* For hard-rock drilling, rocks encountered in the Puguang wells rank among the hardest, with unconfined compressive strengths ranging from 20,000 psia (140 MPa) through the Jurassic section and 29,000 psia (200 MPa) through the Triassic section (Fig. 2). Mudstone and siltstone are the main lithologies above the main limestone reservoir.

HOLE ENLARGEMENT, PG-2 WELL

Fig. 4



2. *Wellbore instability.* Puguang wells have issues with both shale and hole stability. Due to shale stability, the wells require normal weight muds with inhibitors to successfully control reactive shales and clay. Because of clay hydration in the rock matrix, however, the strength of the Triassic formations decreases significantly with the absorption of water.

Four mudstone and shale formations contribute to hole instability (Fig 3):

- *Chongqing group (Jc).* The clay minerals of this group consist mainly of interbedded montmorillonite (up to 75%) and the rock is subject to severe hydration and subsequent clay expansion. Most of the Chongqing group is normally pressured and consists of a destabilized, ductile, soft mudstone with relatively high cation-exchange capacity (CEC) values and hydrate expansion ratios. The destabilized mud shale exhibits high mud-making and swelling, and results in some hole enlargement.
- *Flowing well group (Jt).* This group has moderate shale content, gradually decreasing in montmorillonite and increasing in kaolinite and chlorite content. It is an under-compacted formation, laminated, fractured in places, and unconsolidated. These characteristics make this group a highly unstable zone.
- *Leping group (P2).* This group contains up to 55% montmorillonite and only moderate kaolinite-chlorite content.
- *Liangshan group (P11).* Severe hole collapse has been observed in this group above 4,000-m depth. The group is comprised of montmorillonite (20%) interbedded with kaolinite and chlorite. The Liangshan group is reported to have a strong hydration tendency, which results in unstable conditions in the wellbore.

In addition to the extremely water-sensitive clays, hole breakout caused by tectonic stresses creates a degree of hole enlargement.

The Puguang gas field developed across a fault-related fold zone in the Jialinjian Horizon 4 formation of the Lower Triassic system.

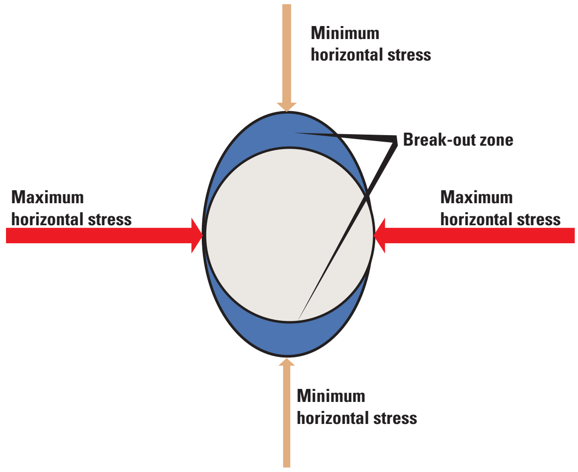
Based on the geomechanics and fault distribution, Sinopec concluded that the Jurassic and Triassic formations are controlled by a slip fault. The maximum principal stresses are west-east compressional stresses, which are greater than the overburden stress. It has already been confirmed that, as a result of the tectonic stress, the maximum horizontal stress causes formation breakout in the hole in the direction of the minimum horizontal stress.

We do not expect the hole diameter in the direction of the maximum horizontal stress to decrease; so there is no indication of hole pinching, but there is hole enlargement up to 2 in. in a north-south orientation. Based on the caliper log data of PG-2 (Fig. 4), the azimuth of the maximum horizontal in-situ stress is about NE 85°. This effect is likely to result in an egg-shaped hole during drilling. It cannot be mitigated by applying pressure inside the hole and is likely to have a significant effect on hole cleaning and annular velocities (Fig. 5).

3. *Nuisance gas.* Many gas zones must be drilled before reaching the primary reservoir. The sections drilled with air are all identified as non-productive zones. Among the zones is the Xujiahe formation, which has some tight gas sandstones. This formation is part of the zone between the surface casing, set at

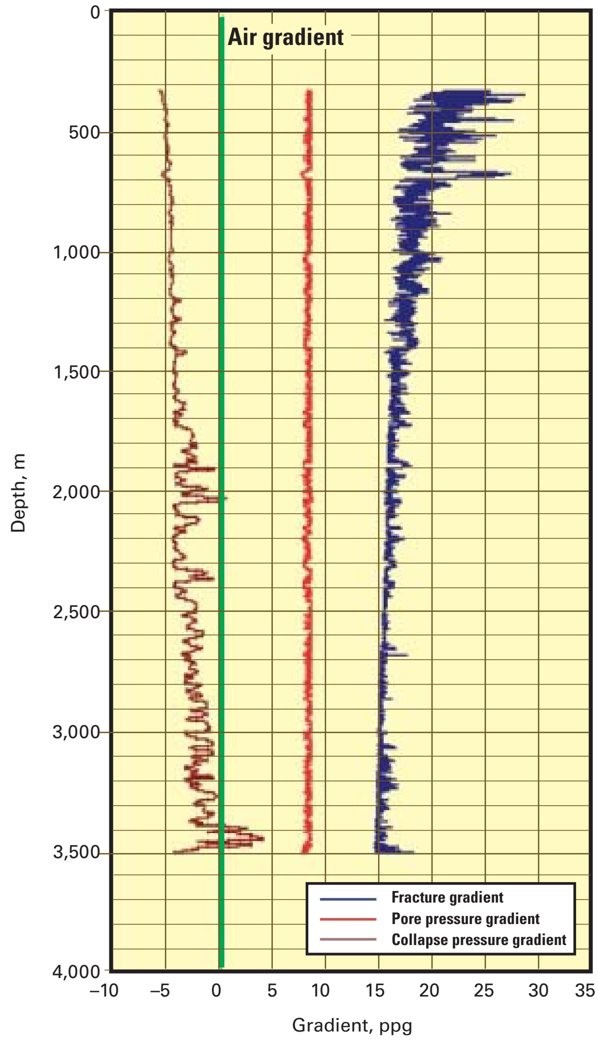
Predicted hole enlargement

Fig. 5



Puguang pressure profile

Fig. 6



700 m, and the 10¾-in. casing setting depth, at 3,600 m.

In addition to potential drilling delays, the gas poses a well control hazard because of the shallow setting depth of the surface casing shoe. The 13⅜-in. surface casing is set between 600-700 m. If a significant gas-producing zone is encountered in the air-drilled sections above 3,600 m, well control cannot be maintained. Concern for fracturing the formations at the shoe preclude the feasibility of closing in the well (Fig. 6).

4. *Lost circulation.* In the upper formations of the Shaximiao, lost circulation was very common. Puguang wells typically encountered lost circulation in the 89-154 m interval, with total losses of 224 cu m and average fluid losses of 1.3-8.0 cu m/hr. Adding lost-circulation material was the most common response, limiting fluid loss.

5. *Hydrogen sulfide (H_2S), carbon dioxide (CO_2).* The reservoir is highly sour (15% H_2S) and corrosive (8% CO_2). Table 1 shows the gas composition in the reservoir.

6. *Water influx.* During the candidate-evaluation phase, the wellbore-stability study concluded that water influx could be a major issue in the Shaximiao series between 1,500 and 2,000 m. Five additional zones above 1,500 m were also predicted to be potential water-influx zones.

Drilling failure analysis, risk assessment

Numerous drilling problems and long well durations during the discovery and appraisal well program put the economical feasibility of the field in doubt. This had to be resolved in order to plan a successful development program.

Sinopec commissioned a feasibility study to determine the appropriateness of applying MPD principles to achieve performance objectives. The team used a systematic, in-house approach, using a proven project management road map, to analyze drilling issues in the Puguang field (Fig 7).

Reservoir gas composition

Table 1

	%	Average
Methane	76.17	—
Ethane	0.005	—
Hydrogen sulfide	12.31-17.05	15.37
Carbon dioxide	7.89-9.07	8.26

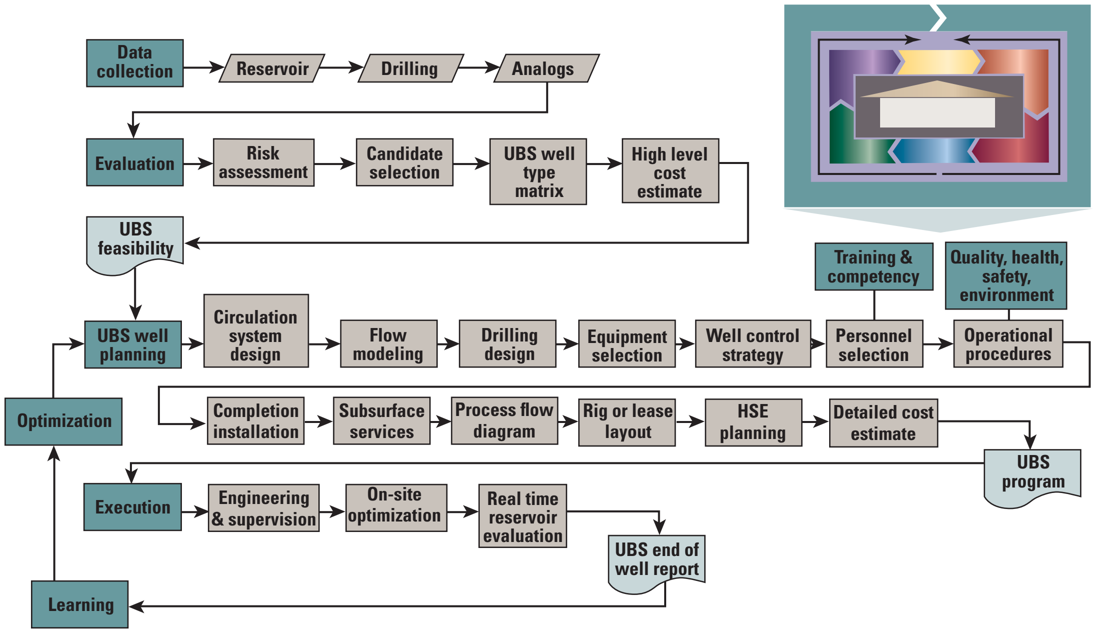
Project management road map

Weatherford assesses MPD complexity through an analysis that determines a risk-assessment value. The risk matrix is designed to reduce operations engineering turnaround time and costs. It provides a way to capture and disseminate global learnings, reduces client learning curves, and provides a means for technical education. The matrix also provides a system for effective management change and identifying quality, health, safety, and environmental (QHSE) hazards.

One calculates the risk value using factors such as IADC's well-classification

CPD PROJECT MANAGEMENT ROAD MAP

Fig. 7



matrix, reservoir and productivity characteristics, technical and equipment issues, the operator's experience level, and environmental factors.

Puguang drilling above the reservoir has a risk level of 3.7, which is considered low. Medium-level concerns were related to the remoteness of the area and the client's inexperience with MPD technology and methods (Fig. 8).

Reservoir drilling with MPD methods has the highest known risk value and has been scheduled further into the program once MPD competency has been developed above the reservoir.

The team analyzed the drilling performance from previous, conventionally drilled wells and concluded that:

- With ultrahard rock and highly overbalanced fluid systems being the primary contributor to long drilling times (average ROP 1 to 2 m/hr), the Puguang field was an obvious candidate for MPD at first glance. The hard-rock drilling created excessive drilling-string vibration, causing severe damage and premature string failures. Numerous fishing jobs related to parted pipe occurred during the four appraisal wells.

Additionally, significant delays and costs were incurred as a result of poor bit performance. About 128 bits/well were used to reach total depth (TD). There were problems related to hole collapse in the Qianfoya formation, causing stuck pipe and logging tools. Finally, lost circulation in the upper Shaximiao created additional lost time, incurring losses.

- Because of low ROP, long open-hole drilling sections (more than 3,000 m), water-sensitive formations, and the drilling problems encountered with conventional techniques, we determined the Puguang wells to be excellent candidates for MPD optimization. Suggested MPD techniques included using air, mist, or foam down to the reservoir. We also recognized percussion drilling using air hammers as one of the main technologies for increasing ROP.

- The advantages of using air as a circulating fluid are substantial. In comparison with mud rates, the ROPs are significantly higher, which reduces drilling time. In addition, significantly fewer bits are used when drilling with air. Wellbore problems such as lost circulation and sloughing shales are virtually eliminated, and air drilling allows the use of air percussion hammers, which not only improves drilling rates but also contributes to drilling a true vertical hole.

Concerns

The main areas of concern with using air or percussion drilling were: well control in high-pressure zones; downhole fires; wellbore stability; water flows; and deviation control.

Well control

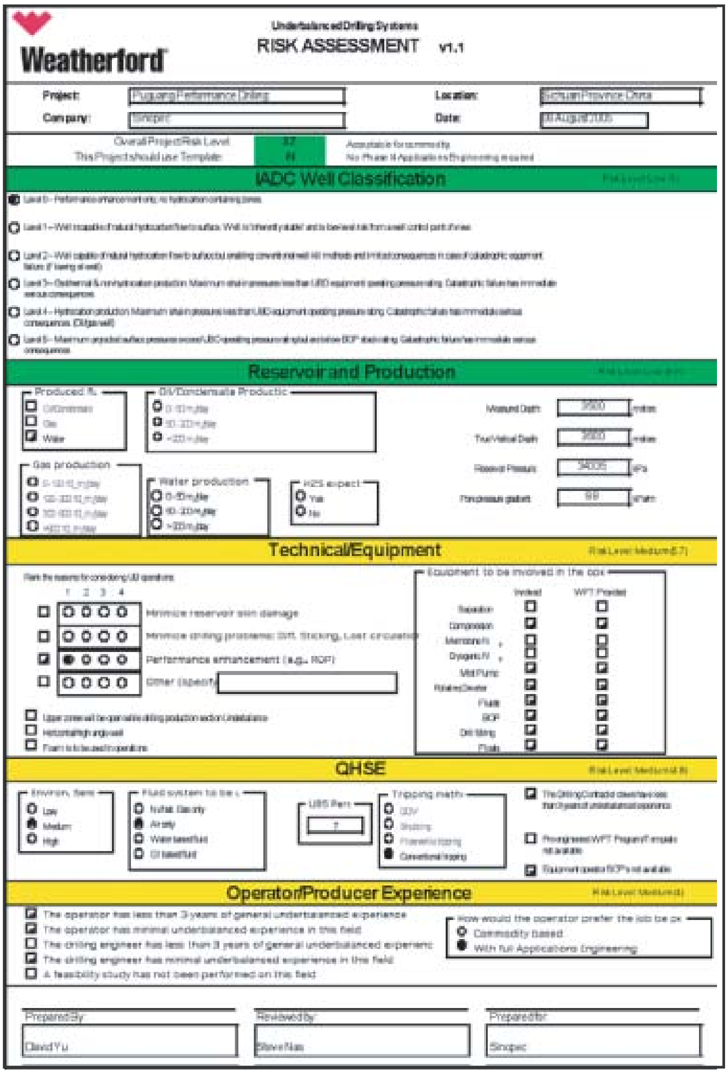
Given the reduced-annular-pressure environment in the wellbore, the ability to cope with any excess formation pressures during drilling is very limited. Borehole stability issues associated with high-pressure zones can rapidly escalate into severe drilling problems and possibly stuck pipe. Because the offset wells were drilled with relatively high mud weights, only limited pore pressure and formation stability data were available at the feasibility study phase.

With air-drilling operations, the borehole pressure is reduced to virtually zero. The implication is that any formations that are porous and permeable will produce fluids and gases. Any formations that are prone to collapse under pressure will collapse.

Formation pressures at the TD of the 12⅜-in. section at 3,600 m were potentially as high as 5,200 psi (35 MPa), while the fracture pressure at the 13⅜-in. shoe at 700 m is only about 2,000 psi (13.8 MPa). These figures imply that, if a substantial gas flow were

RISK ASSESSMENT

Fig. 8



encountered from near TD, the well could not be controlled. Well-control procedures for air drilling reflect this situation.

Downhole fires

If gas concentrations remain less than 5%, no downhole fires will occur. Furthermore, keeping the temperature in the well from increasing reduces the potential for downhole fires. With the lowest volume of air being pumped in the 12⅜-in. section as 3,000 scfm (85 cu m/min), the volume of gas that can be controlled is 4% × 85 cu m/min = 3.4 cu m/min, or 120 scfm, or 172,800 scfd (4,900 cu m/day). No formations at 700-3,600 m have been tested to these high rates.

Wellbore stability

It was highly probable that borehole stability issues could prevent performance drilling with air, particularly if water was present. In addition, there was a concern about tectonic stresses creating an enlarged, egg-shaped wellbore, resulting in an increased requirement of air to maintain adequate hole cleaning.

Water flows

A small influx of water into a dry air-drilled hole is often followed by the creation of so-called "mud rings," which can cause the annulus to pack off. Any packoff or mud ring increases the potential for a downhole fire. Furthermore, any water flow risks potential

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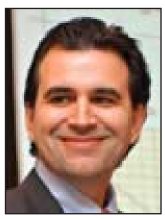

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shale instability as a result of the water-wetting of the claystones.

Deviation control

Although hammer drilling is extremely effective at reducing deviation because of the low weight on bit and low speed, close attention to deviation control is still required. This is especially important in pad drilling of multiple wells to avoid collisions.

Project management

The remote location of this project presented another set of concerns. QHSE issues regarding well control, avian flu, close proximity of civilian population and housing to the rig site, accommodation, hygiene, and medical care were all required close cooperation between Sinopec and Weatherford.

Although all these concerns were generally solved to mutual satisfaction, questions about rig-site decision making and well-control philosophy still remain. They are continually being addressed and as confidence develops on both sides, trust is beginning to build. ✦

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BP's hurricane monitoring system uses third-party web services to provide views of how real-time predictive hurricane paths relate to all of its facilities in the Gulf of Mexico (Fig. 1).

BP's hurricane management system monitors Gulf of Mexico assets

After the devastation to the US Gulf Coast area in 2005 caused by Hurricanes Katrina and Rita, BP PLC in 2006 put into operation a new hurricane and major storm management system.

BP jointly developed the system with IDV Solutions, Lansing, Mich., and Microsoft Corp.

BP says the life-saving system provides real-time information to quickly make decisions, improve security for the energy supply when it is most needed, as well as manage and protect facilities and especially people.

It launched the production version in mid 2006, in time for the 2006 hurricane season.

Benefits

Some benefits listed for the system are:

- Improves safety by making hurricanes more predictable and lessoning potential effects on lives and property when hurricanes do occur.
- Uses the latest data visualization, integration, and other information technologies to provide a constant, real-time, always-current view of all assets in relation to weather patterns and their environments to minimize losses and save lives.
- Provides real-time, not snapshot, data that constantly changes to improve decision making.
- Allows accessibility from anywhere, anytime, and requires no special expertise.
- Improves performance by enabling better asset management such as delaying production shut in and obtaining information to return wells back on production more quickly and safely after a storm. This enables facilities to supply products faster during a time when they are needed in relief operations.
- Uses a virtual system accessible on a single, web-based portal from locations with available internet connections.
- Plugs easily into existing systems

and Microsoft-based information technology infrastructures.

- Requires no special software downloads or expertise for users.
- Is an integral part of BP's "field of the future" initiative for improving oil and gas field operations through the use of sensors, control systems, real-time data distribution, and control and optimization modeling.

Operations

The Gulf of Mexico monitoring system resides behind BP's firewall and it can be accessed, with proper permissions, from a web browser on the internet. The system does not require special software or geographic information systems expertise.

BP describes the system as integrating information regarding the facility, weather and ocean conditions, number of people on board, and other data from multiple sources into one system that overlays the data on a virtual map. Data shown include Gulf of Mexico pipelines, and deepwater and shelf platforms, as well as employee residences, offices, fuel terminals, plants, and helicopter pads (Fig. 1).

The system monitors major storms in the Gulf of Mexico, and in minutes, can produce a Microsoft Excel report that pinpoints and tracks all people and assets.

Third-party web services provide real-time predictive hurricane paths, loop currents, and weather imagery to enable real-time risk evaluation. When a hurricane is seen, the system tracks historical and predicted paths and provides time to impact for each facility.

The system also can access satellite images of facilities before and after a hurricane to show its health and assess damage so as to allow safer reboarding.

Included in the system also is real-time performance monitoring and interactive charting of topsides, marine subsea, and drilling data. It also allows historical playback for analyzing previous hurricanes.

BP monitors the storms from an onshore control center in Houston or an alternative location if the Houston center is unavailable.

Software

The Visual Fusion Server, from IDV Solutions, presents the data in real-time on a virtual map as intelligent points, lines, and polygons. The Visual Fusion Server is described as a composite application server enabling companies to quickly integrate business and organizational data into web-based interactive visual displays of information.

Microsoft software provides the database and web-based virtual map.

Microsoft Virtual Earth is a satellite imagery mapping application used in a web browser. With Virtual Earth, BP can see the location of its infrastructure and the relationship of the facilities to possible dangerous storms or hurricanes.

Microsoft SharePoint Server 2007 provides the portal framework and security, while Microsoft SQL Server is the database that populates data points. ✦

Statoil to begin Snøhvit LNG operations by yearend 2007

Odd Arild Mosbergvik
Statoil ASA
Stavanger

Statoil's Snøhvit LNG plant comes on stream later this year.

Commissioning of the plant, built on Melkøya island outside Hammerfest in northern Norway (Fig. 1), got under way late last year, and in February these activities were progressing according to schedule. LNG shipments are to begin in the fourth quarter, with contractual deliveries starting on Dec. 1, 2007.

Snøhvit LNG will be produced with the mixed-fluid cascade (MFC) liquefaction process developed by Statoil and partner Linde AG. The project has paved the way for Statoil to become a gas supplier to the US market.

Start-up at Snøhvit will also be significant for the LNG world, marking the first baseload LNG production in Europe and, with a location at 71°N, within the Arctic Circle, it will be the world's most northerly baseload LNG plant.

Because of limited infrastructure in northern Norway and difficulties of constructing a plant in winter, a prefabrication policy was adopted, whereby most of the modules were built elsewhere in Europe.

On the supply side, the project is also noteworthy. Snøhvit and the two neighboring fields that will supply gas, Askeladd and Albatross, are the first hydrocarbon reserves to be developed in the Norwegian part of the Barents Sea and the most northerly hydrocarbon development to date.

The fields are tied back directly to shore over 143 km, the longest offshore step-out involving multiphase transport to date. It was the first offshore development to be approved by Norwegian authorities that does not involve surface installations.

Because of the environmental sensitivity of the region, the project has been subject to strict environmental requirements. One consequence is that carbon dioxide will be extracted from the gas and returned to the field to be stored in a subsurface formation, the first time this has been done from an onshore plant. Offshore production is in the form of a closed-loop system, with no discharges to the sea or air.

Gas production will be 6.9 billion cu m/year (bcmy), from which 4.3 million tonnes/year (tpy) of LNG will be produced. Reserves on which the project is based—more than 190 billion cu m of gas and 20 million cu m of condensate—are sufficient for about 30 years' LNG production. Statoil is optimistic,

SNØHVIT LICENSEES

Table 1

	Portion, %
Statoil (operator)	33.53
Petoro	30.00
Total	18.40
Gaz de France	12.00
Hess	3.26
RWE-Dea	2.81

The Snøhvit LNG plant sits on Melkøya Island within the Arctic Circle (Fig. 1; photo by Eiliv Leren, Statoil).

however, that it can firm up sufficient new reserves to justify installing a second LNG train.

A significant part of the world's undiscovered hydrocarbon reserves is believed to lie in Arctic waters, and a substantial portion of these is believed to be gas. The experience gained at Snøhvit, both from the offshore development and the LNG project, including the MFC technology and the prefabrication philosophy, will prove valuable for future such projects in the Arctic and other remote locations.

The company's partners in the project are Gaz de France, Hess, Petoro, RWE-Dea, and Total (Table 1).

Developing LNG technology

When Snøhvit, Askeladd, and Albatross fields were discovered in the early 1980s, Statoil faced the double challenge of how to develop them and how to market the gas, given the remote location. The only solution to the marketing challenge was LNG.

In Statoil's view, however, LNG technology development had become static; there were too few players in the market and too little competition. Undertaking its own technology development would help inject more competition into the technology market.

Under a framework agreement with the Norwegian Institute of Technology (NTH), Statoil undertook fundamental studies of liquefaction processes with a focus on heat-exchanger calculations and improving the accuracy of thermodynamic information. This intense research effort yielded the knowledge and tools to model and simulate the entire process.

Statoil also began cooperating closely with Linde, a German company specializing in low-temperature industrial processes with a special expertise in heat-exchanger technology. In 1996 the two companies established an LNG technology alliance under which the MFC process was developed (Fig. 2).

MFC is a hybrid process, combining features of the classic cascade cycle with the mixed-refrigerant cycle. It consists of three cooling stages, each with its own composition of refrigerants:

- Precooling to –50° C.
- Liquefaction to –80° C. at 60 bar.
- Subcooling to –155° C., also at 60 bar.

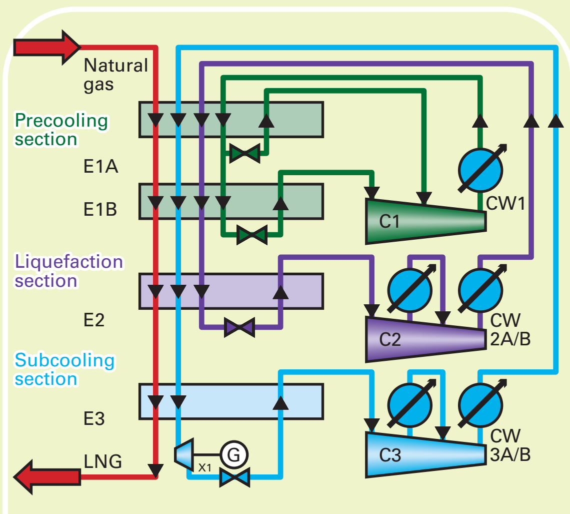
Careful tailoring of the composition and relative volumes of the refrigerants to each cooling stage makes it possible to achieve an exceptionally close match to the idealized cooling curve using as little power as possible. Cooling takes place smoothly and economically, rather than step-wise, as is typical of the classical cascade process (Fig. 3).

Benchmarking has shown that the MFC process is competitive in terms of energy efficiency with other liquefaction processes.

Drawing on the much-improved knowledge of heat-exchanger process, Linde designed a state-of-the-art spiral-wound heat exchanger (SWHE; Fig. 4).

Snøhvit liquefaction process design

Fig. 2



Mixed fluid cascade process

The MFC process consists of three mixed-refrigerant cycles: precooling, liquefaction, and subcooling.

The precooling cycle mixture is compressed in compressor C1, liquefied in seawater cooler CW1, and subcooled in cryogenic heat exchanger E1A. One part is throttled to an intermediate pressure and used as refrigerant in E1A. The other part is further subcooled in heat exchanger E1B, throttled to the suction pressure of compressor C1, and used as refrigerant in heat exchanger E1B.

The liquefaction cycle is compressed in compressor C2, cooled in seawater coolers CW2A and CW2B, and further cooled in heat exchangers E1A, E1B, and E2. It is throttled and used as a refrigerant in liquefier E2.

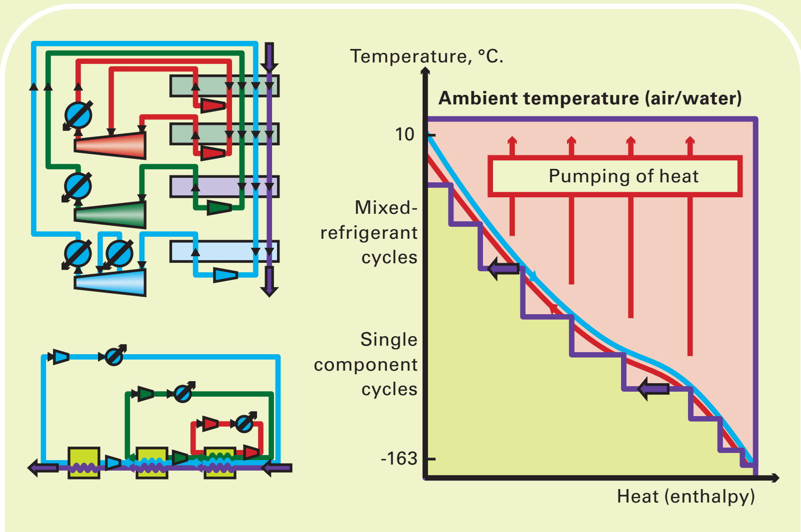
The subcooling cycle is compressed in compressor C3, cooled in seawater coolers CW3A and CW3B, further cooled in heat exchangers E1A, E1B, E2, and E3, expanded in liquid turbine X1, and used as refrigerant in subcooler E3.

All compressor suction fluids are slightly superheated above their dew points.

Source: Heiersted, Roy Scott; "Snøhvit LNG Project: Concept Selection for Hammerfest LNG Plant"; Gastech 2002.

NATURAL GAS LIQUEFACTION PROCESSES

Fig. 3



Cooling curve
This figure shows (right side) the smooth cooling curve characteristic of the MFC process and the step-wise curve associated with a process based on single-component cycles. Energy is used more efficiently when cooling takes place continuously rather than in discrete steps.

Source: Heiersted, Roy Scott; "Snøhvit LNG: Novel design and technology open way for LNG from the Barents Sea"; CryoPrague 2006.

A prototype underwent a comprehensive test program at PetroSA's gas-to-liquids plant in Mossel Bay, South Africa, in 1998-2000, with encouraging results.

Snøhvit plant design

MFC was one of three liquefaction processes evaluated by the Snøhvit project and in 2000 was selected on the basis of a competitive bid. Production capacity was set at 4.3 million tpy of LNG from a single train, a level chosen as offering the best combination of economy of scale with moderate technology, plant complexity, and other relevant factors.

A priority in designing the Snøhvit plant was to realize benefits inherent in the MFC process and especially its high energy efficiency. The need for compactness, given space limitations on Melkøya Island, near the town of Hammerfest, and the requirement for low emissions, were also important.

Power generation is based on five LM6000 (Fig. 5) gas turbines. These are aeroderivative models with very efficient fuel consumption and low emissions. They are also well known to Statoil, which uses them on offshore platforms and at onshore gas processing plants.

Each turbine supplies power to an internal grid at a rated capacity of 46 Mw. The regional electricity grid provides back-up power at 50 Mw. A hot-oil waste-heat-recovery system on each turbine provides process heat.

Another important feature is that the compressors are run by electric variable-speed motors, the first use of all-electric drive in an LNG plant. This decision, which was driven by the need to minimize greenhouse-gas emissions, involves a higher investment than the conventional direct mechanical drive, but also has the economic benefit of making available an additional 10 days/year on stream. Plant availability is thereby increased to 340 days/year.

The configuration of the energy-generation facilities is the basis for highly efficient energy use—electricity efficiency of 41% and an overall thermal efficiency of 71%. Moreover, less than 6% of overall gas production is required as fuel for the turbines, a good indicator of the overall energy efficiency of the plant. When Snøhvit's energy consumption was benchmarked on equal terms with an LNG industry flagship, Snøhvit came out significantly better.

A major natural advantage also derives from the project's location within the Arctic Circle with respect to the seawater used as cooling medium. Drawn from a depth of 80 m, the water has an ambient temperature of only 5° C., much lower than in hot coastal environments. As a rule of thumb, each 1% reduction in the temperature of the cooling water leads to a 1% gain in efficiency of the process.

The power requirement of the three-cycle compressors for LNG production of 4.3 million tpy is 127 000 kw, which in combination with the cooling-water conditions, gives the process a specific refrigeration power of 234 kw-hr/tonne of LNG produced. In Statoil's view, this makes Snøhvit the most energy efficient LNG plant yet designed.

One of the solutions adopted to achieve compactness of design was the use of cold boxes to house the heat exchangers. Inside the boxes, void space around the cryogenic equipment and piping is filled with perlite insulation. The cold boxes are installed in the cold-box assembly with liquefaction and subcooling boxes at the bottom and the precooling box on top of them.

Liquefaction and subcooling take place in the SWHEs and precooling in a plate-fin heat exchanger. Both the SWHE units have a diameter of almost 5 m. In the subcooling unit, which stands 27 m high, each aluminum tube is about 100 m long, with an external diameter of 10-12 mm and a 1-mm wall thickness. The aluminum tubes are a combined 500 km long, giving a very extensive total cooling area. The

liquefaction heat exchanger is somewhat smaller, standing 22 m high.

Processing flow

The well stream from the offshore fields arrives at the Hammerfest LNG plant with a pressure of 70-90 bar and a temperature of between −5° C. and 4° C. Figs. 2 and 3 display flow diagram and operational information.

The stream first passes through the slug catcher, in which liquid slugs are buffered or dispersed and an initial separation of the three phases—natural gas, condensate, and a water/monoethylene glycol (MEG) mixture—takes place. Because of space limitations on site, the slug catcher is designed to resemble a bent finger (Fig. 6).

The condensate flows to the condensate separator and the water-MEG mixture to the MEG-regeneration unit where water is removed and MEG regenerated and stored in one of four tanks ready to be piped back to the field.

From the slug catcher, natural gas passes to the inlet facilities. On the way it is heated to prevent formation of hydrates and the pressure is stabilized at around 70 bar. The inlet facilities strip out any remaining liquids. Some gas is then removed from the flow for use as fuel gas.

The next phase—pretreatment—removes in successive stages CO_2, water, and mercury from the gas. CO_2 is removed by flowing the gas through an amine compound, in the course of which CO_2 binds to the amine. CO_2 is then separated from the amine by heating the mixture. It is then dewatered and compressed, in order to liquefy it, after which it is ready to be piped back to the Snøhvit field for injection into the subsurface.

The Gas then goes through the first of the three stages of refrigeration in which it is precooled to −50° C. It then passes into a fractionation column, where heavier components such as propane and butane are removed in order to adjust the calorific value to sales specification. The heavier components are extracted and piped to the LPG fractionation system.

MAJOR PLANT DESIGN DATA

Table 2

OVERALL MATERIAL BALANCE — Table 2a

Streams/products	Std. cu m/hr	Million tpy
Feed (at 70 bara, 4° C.)		
Natural gas	821,250	5.41
Condensate	45,400	0.95
MEG/water	12,150	0.11
LNG rising in tank	726,000	4.26
Condensate product	21,740	0.75
LPG product	14,200	0.25
$\mathbf{CO_2}$ for reinjection	43,250	0.64
Fuel gas (447 Mw)	45,340	0.31
Lean MEG to offshore	3,790	0.06
Nitrogen to air	16,350	0.15

STORAGE LOADING — Table 2b

LNG storage and loading	
Storage capacity (net working)	2 x 125,000 cu m
Tank type	Full-containment steel/concrete tanks
Loading capacity	120,000 to 145,000 cu m in 12 hr
LPG storage and loading	
Storage capacity (net working)	1 x 45,000 cu m
Tank type	Full-containment steel/concrete tank
Loading capacity	11,000 to 38,000 cu m in 12 hr
Condensate storage and loading	
Storage capacity (net working)	1 x 75,000 cu m
Tank type	Full-containment steel/concrete
Loading capacity	25,000 to 55,000 cu m in 12 hr

EMISSIONS — Table 2c

	Tonnes/year
$\mathbf{CO_2}$	735,000
$\mathbf{NO_x}$	551

MAJOR PLANT OPERATIONAL FEATURES — Table 2d

Liquefaction process	Mixed Fluid Cascade process HHC removal and LPG extraction N_2 removal
Prime driver concept	Electrical power generation: by LM6000PD Refrigerant compressors: driven by VSD motors
Backup electric power	Up to 50 Mw from national grid
Cooling system	Once-through seawater system Tempered water system for machinery cooling
Design operation data	
Air temperature	4° C.
sea water temperature	6° C.
Heating system	Heat transfer system (hot oil) using waste-heat recovery from gas turbines for process heating. Tempered water system for "underfloor heating"
Shrinkage	Less than 5% of energy of feed
Overall thermal efficiency	70%
LNG specification	Nitrogen: max 1.0 mole % Methane: 85-95 mole % Traces: ppm level Gross heating value: max 40.5 MJoule/cu m Wobbe index: max 52.8 MJoule/cu m

Precooled lighter gases, primarily methane and ethane, return to the cold-box assembly where they pass through the liquefaction and subcooling processes. Following subcooling, the temperature of the liquid gas is reduced to −163° C. from −155° C. in two stages:

- Through a process of internal heat exchange in which LNG is used as heating medium for nitrogen removal.
- By passage through an expansion turbine, which reduces the gas's pressure. The gas is then piped to one of the two storage tanks; Table 2 shows major plant operational data.

Plant construction

In March 2002 the project received the official go-ahead, when the plan for development and operation (PDO) was approved by the Storting, the Norwegian parliament. The greenfield site on Melkøya Island is about 5 km from the town of Hammerfest on Norway's northern coast.

Detailed design of the plant was contracted to Linde, with assistance from Aker Kvaerner. Linde was also responsible for supplying the heat exchangers. Installation and hook-up of the plant was awarded to Aker Stord, supply of electrical and control systems to ABB, and an order for the refrigerating compressors and five gen-sets to Nuovo Pignone.

The five LM6000 gas turbines were ordered from General Electric and the electric motors from Siemens. An engineering, procurement, and construction contract was awarded to Belgian company Tractebel for storage and loading facilities, including the four storage tanks (two for LNG, one for LPG and one for condensate).

In view of the Arctic location and limited regional infrastructure and resources, a construction policy of maximum prefabrication was adopted. In particular it was decided that process equipment and power-generation facilities would be assembled on a barge that would be installed in a specially prepared dry dock at Melkøya.

All major modules were built at sites on mainland Europe, including the process plant at the Dragados yard in Spain. Heerema in Holland and Fabricom in Belgium were responsible for several of the process and utility modules. Heerema also built the slug-catcher and MEG regeneration units and Fabricom the pipe racks and electricity substations.

Most of the modules were shipped to Melkøya during 2005. Key deliveries were a shipment containing two MEG reclamation units and three electricity substations that arrived in February 2005, the cold-box assembly that arrived the following May (Fig. 7), and the process barge, which arrived on the Dockwise heavy-lift vessel Blue Marlin after an 11-day journey in July 2005.

The total weight of the barge, which measures 154 x 54 m and supports equipment structures up to 50 m high, is 35,000 tonnes (topsides 25,000 tonnes, base 10,000 tonnes). On arrival at Melkøya, it was floated off the heavy-lift vessel and, after a couple of days' wait for suitable weather, winched into the dock. Water was drained and the barge concreted into place.

The cold-box assembly, which stands 60 m tall and weighs 2,625 tonnes, is located alongside the barge.

This is one of the spiral-wound heat exchangers manufactured by Linde for the Snøhvit project (Fig. 4; photo from Linde AG).

Five LM6000 gas turbines provide power for the plant, with the backup of the regional grid. Instead of direct mechanical drive, however, the refrigerating compressors are driven by electric motors (Fig. 5; photo by Harald Pettersen, Statoil).

Cost, schedule overruns

LNG deliveries had originally been scheduled to start in October 2006, but in September 2005 Statoil announced that the schedule was to be extended to December 2007 and the budget increased. The budget, which covers both LNG plant and offshore development, including future drilling phases, had already risen to more than the 40 billion kroner (about $6.4 billion in 2005) estimated at the time of project approval, was further increased to 58.3 billion kroner. The project team was strengthened and the project brought under responsibility of the technology and projects business area.

The immaturity of the project at the time of sanction led to changes in both the engineering and the project execution. As a result, the project experienced

Space limitations on the slug-catcher dictated the "bent finger" design (Fig. 6; photo by Øyvind Hagen, Statoil).

In July 2005, the cold-box assembly containing the three cold boxes supplied by Linde arrived at Melkøya (Fig. 7; photo from Linde AG)

significant increases in work scope for several activities, especially electrical installations, electrical control systems, insulation, and heat tracing.

Significant weight increases had also taken place for some of the modules. In particular the weight of the plant to be installed on the process barge had become too great, so that it had already been decided to take off the cold-box assembly.

Another consequence of these developments was that it became impossible to perform module testing at the yards without incurring further serious delays. Instead it was decided to transfer the outstanding work to Melkøya, where the work-scope of Aker Kvaerner and its subcontractors was expanded to cover the additional requirements.

Commissioning program

Work is now for the most part up to the revised schedule. By early this year, almost all installation was complete, with a modest volume of insulation and heat tracing still to be finished.

In mid 2006, the

first system, the air-separation unit, was commissioned. In the remaining months of 2006, the other utility systems were commissioned and brought into operation.

Important milestones were reached in December 2006, first with the change in the status of the Melkøya plant from construction site to gas processing facility and, just before yearend, with import of gas for commissioning. This came as a 140,000-cu m cargo of LNG delivered by Arctic Princess (Fig. 8), one of the carriers built to serve the project.

The cargo was used to cool the storage tanks. In mid February, it was regasified for use as fuel gas to bring the power-generation plant into operation, generating about 100 Mw. Next follows commissioning of the process plant, starting with the cooling compressors.

The slug catcher, MEG-regeneration system, and CO_2 extraction system will be commissioned and ready for operation ahead of first gas on May 1. In early July, gas is to be fed into the process plant, opening the way to the start-up of this plant in the following months. The first LNG shipments are to take place during fourth quarter, ahead of start of contractual deliveries on Dec. 1.

The 140,000-cu m Artic Princess delivered the commissioning cargo to the Melkøya plant in late 2006 (Fig. 8; photo from Statoil).

Operations

The knowledge acquired in developing and qualifying the MFC process and SWHE will also be applied to optimize operations of the Snøhvit plant. For the first time in an LNG plant, a rigorous model of the main SWHE will be used, incorporated in a comprehensive dynamic simulator.

Special scientific instruments will also be used to check performance of the heat exchangers and validate tools used in their original design. Instrumentation data will be combined with simulations to optimize plant performance.

Another approach to optimization is based on detailed SWHE models that are used as modules in flow-sheet programs, thus enabling parameters such as flow rates, temperatures, pressures, and refrigerant composition to be fine-tuned in order to maximize LNG production.

Control room operators will also use a virtual model of the Snøhvit value chain, from reservoir to LNG process, in order to visualize operations and facilitate decision-making when deviations from normal operational patterns occur. The technology will be the first such visualization tool in the world.

About 180 personnel will be involved in running operations, including a small number responsible for controlling offshore facilities. There is an operations organization of around 100, including control room staff and various sets of crews for carrying out either planned or unscheduled maintenance. There is also an operations support staff of around 70, including engineers, laboratory staff and the harbor crew, project personnel, management, and administration.

Snøhvit LNG fleet

Statoil, Petoro, Hess, and RWE-Dea have sold their share of production, about 70%, to Statoil North America and the Spanish company Iberdrola. Under these agreements, 1.8 million tpy will be delivered to the Cove Point, Md., terminal on the US East Coast, which is partly owned by Statoil, and 1.2 million tpy to Bilbao in northern Spain. Gaz de France and Total will lift their 1.3-million tpy shares separately.

LNG shipments numbering around 70 LNG/year will be made. Four 140,000-cu m newbuild LNG carriers, two by Mitsubishi and one each by Kawasaki and Mitsui, will serve the Snøhvit trade. Three (Arctic Discoverer, Arctic Voyager, and Arctic Princess) will serve the Statoil North America and Iberdrola contracts; Statoil is a part-owner of all three. The fourth, Arctic Lady, has been jointly chartered by Gaz de France and Total.

Future

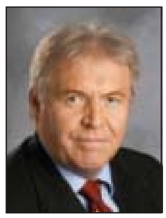
The next step in the Snøhvit story will be to add another processing train. First, additional gas quantities must be proven up, either in the Snøhvit field or elsewhere in the region. Layout and other technical studies have already begun, based on the experience from Train 1, and it is important that some of the personnel from the current project join the project for a second train when they are demobilized.

Meanwhile the Statoil/Linde alliance, which has been extended to 2008, has been working to develop the LNG technology further. One main avenue has been application of the MFC process to high baseload projects, taking advantage of the flexibility provided by use of different refrigerant mixes for each cycle. Engineering studies have shown that production of 9-12 million tpy from a single train is achievable.

Work has also been carried out to apply the technology to floating LNG production. For this application, Aker Kvaerner has joined the alliance, bringing its expertise in floating technology and project execution. Linde has qualified the SWHE for use in a floating environment. The possible use of CO_2 as a refrigerant has been studied.

The Linde SWHE has proven attractive to other LNG projects, and units have been sold to a number of new projects, including Shell's Sakhalin II. ✦

The author



Odd Arild Mosbergvik (omo@statoil.com) is senior vice-president, Snøhvit development for Statoil ASA, Stavanger. Since 1979 he has held various project planning and management posts at Statoil, becoming project director in 1992. Since then he has directed, among other projects, the Åsgard field development (1996-2000), Borealis' Borouge petrochemical development (2001-02) and extension project (2003-05), and the South Pars Phases 6, 7, and 8 field development in Iran (2002-03). He holds an MSc (1976) in physics from the Norwegian Institute of Technology. He is a member of the Norwegian Society of Chartered Engineers. (photo by Knut Helge Robberstad, Statoil)

World LNG netback series begins in this issue

Chris Holmes
Purvin & Gertz
London

Starting with this issue, Oil & Gas Journal will report LNG price netbacks for LNG supply from six gas liquefaction plants into six market destinations. The Purvin & Gertz LNG netbacks matrix will be presented to enable readers quickly to determine the netback value that could be realized from LNG sales.

Table 1 lists the supply sources and market destinations that will be reported in this weekly matrix.

LNG industry matures

Until the end of the last century, the global LNG industry could be described as rigid with movement of natural gas between gas liquefaction plants and LNG import-regasification terminals carried out via fixed trading routes under long-term inflexible contracts using dedicated LNG carriers.

For much of the industry's history, LNG trade has been dominated by the supply of gas to the northeast Asian markets of Japan, South Korea, and Taiwan. Since the turn of the century, however, the global market has experienced a radical transformation with importers in the Atlantic Basin seeking a more prominent role in the business.

US and European markets have many similar characteristics but also differ quite significantly. Indigenous production in both the US and Europe, for all intents and purposes, has peaked and is now in decline with both regions looking increasingly to LNG to meet the supply-demand gap.

Furthermore, natural gas transmission and storage infrastructure in both regions are well developed, although it should be noted that infrastructure is less well developed in some southern Europe countries than in the north. In broad terms, however, the similarity ends there.

The US gas market is the most developed in the world with extensive gas import, transmission, and storage infrastructure, an industry structure that is unbundled with financial and legal transparency along the gas value chain and a multitude of players active in each segment of the industry.

In addition, gas prices are determined largely by gas-to-gas competition, with prices at the major trading locations generally bound by No. 2 heating oil on the high side and No. 6 residual fuel oil on the low side. To add depth and liquidity to the market, the US operates a futures market centered on the Henry Hub price in Louisiana.

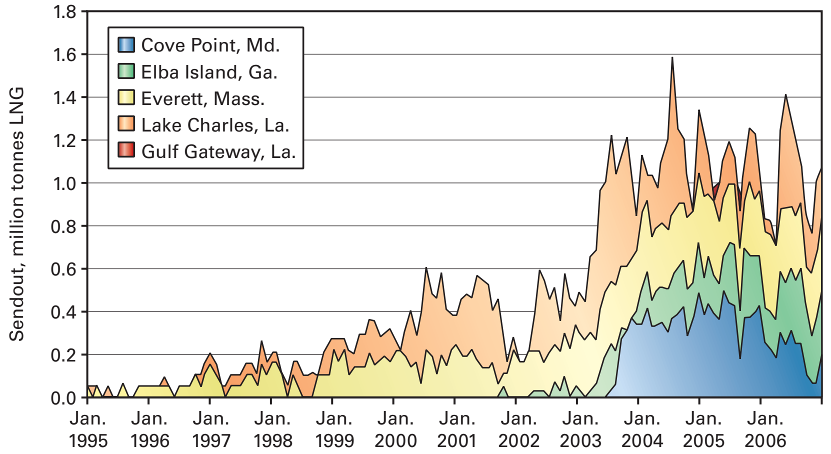
The European market is less well advanced, although efforts by European Union (EU) regulators are slowly moving the market towards a model that will be structurally similar to that in the US. Currently, gas markets around Europe exhibit considerable variability in degree of liberalization and liquidity, with those in the north tending to be more like the US market than those in the south.

The gas industry that most closely resembles the US market is in the UK where infrastructure is well developed and prices reflect supply-demand fundamentals. Both markets have a similar supply-demand outlook. LNG will to play an increasing role in meeting future demand. Furthermore, a liquid forward market exists in the UK with gas priced at a virtual trading hub—so-called National Balancing Point, NBP—within the national gas transmission system.

Conversely, elsewhere in Europe, market liberalization is generally less well advanced than in the UK. Apart from indigenous production in the Netherlands and Norway, continental Europe relies almost entirely on imported gas, most of which is supplied under long-term contracts by pipeline from Algeria, the former Soviet republics of Central Asia, Norway, and Russia.

US: MONTHLY LNG SENDOUT

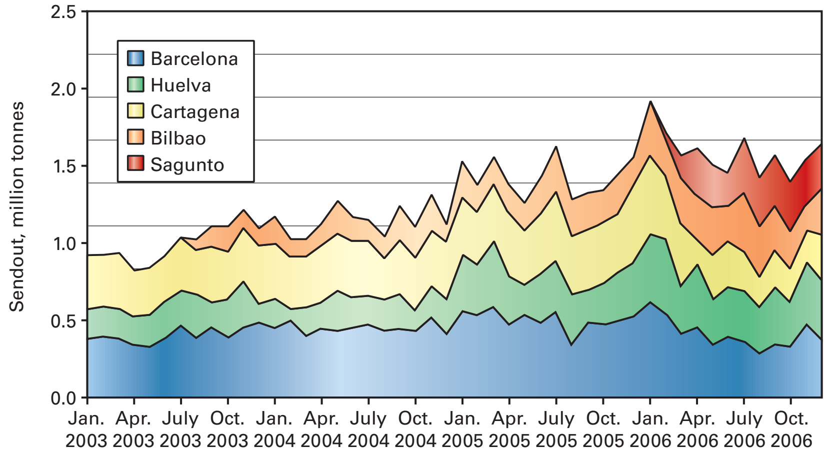
Fig. 1



Source: US Energy Information Administration

SPAIN: MONTHLY LNG SENDOUT

Fig. 2



Source: Enagas

LNG import volumes into Europe are 20% of pipeline-gas-import volumes with France and Spain accounting for around three-quarters of the total. With security of supply becoming an increasing concern to the EU, however, LNG is viewed increasingly as a way of diversifying gas supply. The result is that, like the US, there are several LNG import terminal projects under various stages of development and planning.

Gas pricing in continental Europe is less well developed than in the US and the UK, although forward markets have evolved in the last few years, primarily in Northwest Europe.

The two most traded markets are the Zeebrugge market and the Dutch Title Transfer Facility (TTF), both of which operate as virtual trading hubs much like the UK's NBP. Rules for the former, however, restrict trading activity to gas movements through the UK-Belgium Interconnector with the result that Zeebrugge prices tend to trade at a premium or discount to NBP prices depending on whether gas is flowing from or to the UK.

In contrast, TTF prices are highly correlated with average Belgian and Dutch gas pipeline import prices that are based on traditional long-term contract indexation parameters, primarily heating oil and residual fuel oil with a time lag. Thus, there will be occasions when NBP-Zeebrugge prices are linked to TTF prices, but during times of exceptional demand or supply disruption price dislocation occurs between the two markets.

While LNG and gas markets in the Atlantic Basin exhibit varying degrees of depth and liquidity, those in Northeast Asia tend to be more rigid, having evolved as a result of long-term gas contracts that were concluded in the 1970s and 1980s. Asian LNG prices have tended to be based on the formula used by Japanese buyers that indexes prices to the Japan Customs Cleared basket price for imported crude oil, otherwise known as the "Japan Crude Cocktail" (JCC).

The typical structure of this type of formula involves a fixed component and a variable component that relates to the JCC price. Variations of this formula exist to provide sellers with protection in a low-oil-price environment and the buyer protection in a high-oil-price environment, the so-called "S-curve."

Although some long-term contracts concluded in recent years have departed from traditional pricing structure, much of the LNG that moves to buyers in northeast Asia is still priced against the typical formula.

Since the turn of the century, much of the Atlantic Basin gas industry's attention has been focused on the US's seemingly long-term insatiable appetite for LNG imports. Most, if not all, developers of gas liquefaction projects in the region and the Middle East have at some point targeted the US as an outlet for all or part of their output. The tightening in recent years of North American supply-demand balances has spurred the reopening and expansion of existing US LNG import terminals as well as development of significant new LNG import capacity.

LNG import growth has been strong in recent years, increasing to a peak of nearly 14 million tonnes in 2004 from 0.4 million tonnes in 1995. Forecasts of US long-term import requirement vary, with estimates ranging 40-60 million tonnes for 2010 rising to 80-120 million tonnes in 2020. Purvin & Gertz analysis[1] suggests that the LNG import requirement will be at the top end of the ranges quoted with imports of 58 million tonnes forecast for 2010 and 118 million tonnes in 2020.

The US is not the only country or region, however, for which the LNG import outlook is strong. Europe imported 35 million tonnes of LNG in 2005; this import requirement is forecast to grow to 50-60 million tonnes in 2010 and 80-100 million tonnes in 2020. A similarly robust outlook exists for Asia-Pacific where imports are forecast to grow to 105-125 million tonnes in 2010 and 140-180 million tonnes in 2020 from 91 million tonnes in 2005.

The outlook for the global LNG market is therefore strong with total demand forecast to grow to 200-245 million tonnes in 2010 and 300-400 million tonnes in 2020 from 140 million tonnes in 2005; the US will become the largest single market for LNG sometime after 2010.

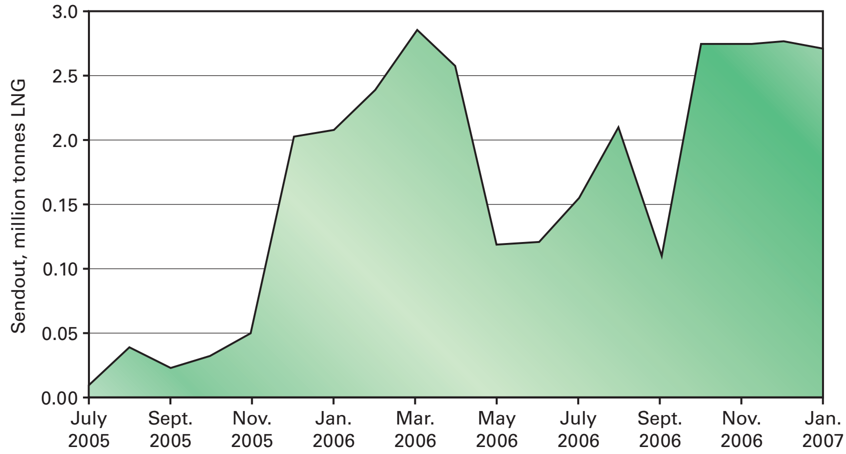
While the outlook for LNG imports into the US exhibits considerable growth, actual imports during the last couple of years have failed to match expectations. Imports peaked in 2004 at slightly less than 14 million tonnes but declined in 2005 to 13.3 million tonnes and shrank again in 2006 to 12.3 million tonnes. Current LNG import terminal receiving and gas send-out capacity is nearly 40 million tonnes/year (tpy; equating to a capacity of 3.3 million tonnes/month). It can be seen that capacity utilization has been low, in the range 30-40%, since 2003 (Fig. 1).

Failed expectations

One of the primary reasons reality has failed to meet expectations is that LNG cargoes that might otherwise have been delivered to the US have been diverted to other markets where higher price netbacks have been on offer to LNG producers.

Isle of Grain, UK: Monthly LNG sendout

Fig. 3



Source: National Grid

Coverage of weekly series

Table 1

LNG supply sources		Market destinations	
Algeria	NW Shelf, Australia	Zeebrugge, Belgium	Isle of Grain, UK
Malaysia	Qatar	Sodegaura, Japan	Lake Charles, USGC
Nigeria	Trinidad	Barcelona, Spain	Everett, USEC

Much of this volume has been sold into Spain where a combination of strong domestic demand growth and low rainfall (more than 10% of Spain's electricity generation being from hydroelectric plants) has contributed to an increasing requirement for imported gas. Consequently buyers have been willing to offer higher prices to attract cargoes away from the US with the result that the country's LNG imports have grown rapidly in recent years (Fig. 2).

Despite LNG imports into Spain increasing in recent years, like the US Spanish LNG import capacity is underutilized. With a current LNG import capacity of around 31 million tpy (2.6 million tonnes/month), actual imports of 19 million tonnes in 2006 represent an average capacity utilization of around 60%

Contrary to the situation in these two countries, LNG import capacity utilization in the UK has been far higher. The Isle of Grain LNG import terminal commenced operations in July 2005 with a capacity of 3.3 million tpy (0.27 million tonnes/month). After a slow start, 2.5 million tonnes of LNG was imported in the first full year of operation representing 75% utilization. In fact, during winter months capacity utilization has approached 100% (Fig. 3).

The global LNG market is currently experiencing a significant transformation.

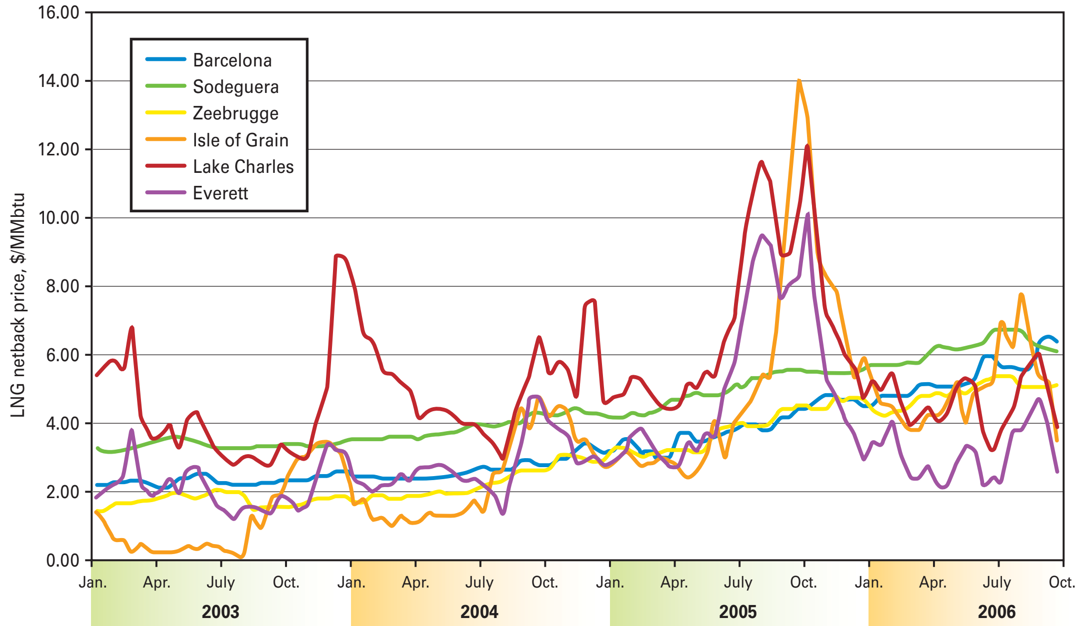
From the rigid structure that existed to the end of the last decade, the market has evolved to one in which considerable more flexibility prevails. Gas liquefaction projects are now being developed before all the output has been sold, and players are investing along the value chain to give them the opportunity to exploit price-arbitrage opportunities.

Even in Asia where the long-term contract has prevailed, contract renewals have been for shorter periods with buyers seeking to purchase LNG on a FOB (free on board) basis, thereby enabling them to move surplus volumes into alternative markets if domestic demand fails to develop as planned. Thus a more liquid spot market has been evolving with the volume of LNG sold under spot or short-term trades increasing.

LNG sellers are now faced with many market outlets for surplus volumes. Naturally the gas price in each market will reflect prevailing market conditions and, consequently, depending on the cost of LNG transportation, the netback price that can be realized will be vary by market destination.

LNG NETBACKS: QATAR

Fig. 4

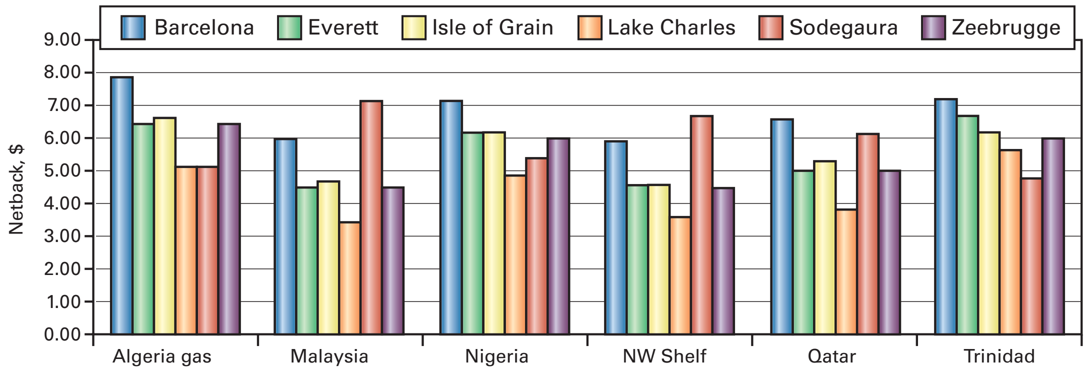


Netback values

The netback values in the Purvin & Gertz matrix are calculated by determining the prevailing gas price in each market destination and deducting pipeline, regasification, and waterborne transportation costs, as appropriate, to arrive at an FOB netback price.

LNG NETBACK SUMMARY: DEC. 15, 2006

Fig. 5



The costs of pipeline transportation, LNG regasification, and waterborne transportation are based on either reported costs or from Purvin & Gertz models and will include all key cost factors such as boil-off rate, demand seasonality in the market, and terminal sendout capacity.

The price of gas in each market destination is determined with the following methodology:

- Belgium: Purvin & Gertz's estimate of imported pipeline gas prices at Zeebrugge.
- Japan: Calculated forward LNG import prices based on a typical LNG contract indexed to JCC.
- Spain: Calculated LNG contract prices based on a typical import contract using relevant indices.
- UK: Forward NBP prices.
- US Gulf Coast: Henry Hub forward prices.
- US East Coast: Purvin & Gertz's estimate of Boston city-gate price based on Henry Hub forward prices.

The netback prices to be reported on a weekly basis will reflect "expected" prices in the market and, therefore, will represent the FOB price that an LNG seller or trader would actually realize in the market. This will be achieved with futures prices or Purvin & Gertz's estimate of gas-LNG contract prices in the future based on typical price indexation terms.

In all cases the forward price used takes into account cargo loading and unloading time, voyage time, time to vaporize and sendout regasified LNG cargo at the import terminal, and a period between conclusion of a deal and the cargo being loaded. As an example, if it is mid month (m) and a deal is concluded that would result in the cargo being loaded, delivered, and regasified in the following month (m+1), then the m+1 futures price or Purvin & Gertz's estimate of the m+1 contract price would be used as a price basis.

In comparison, if the seller is looking to sell the cargo into a more remote market that would result in half the cargo being regasified in the following month (m+1) and the remainder in the ensuing month (m+2), then the netback would be based on the average of the m+1 and m+2 prices. Thus, the published netback prices that can be realized by sales from each supply point will reflect the proximity of that supply point to the market of interest

The seasonal factors used to determine gas sendout rates have been based on published historical LNG import terminal utilization data or, when not available, on Purvin & Gertz's assessment of the likely sendout rate based on the seasonal characteristics of the market concerned.

These seasonal factors are also used in calculation of LNG regasification tariffs, where appropriate, as it is assumed that sendout capacity is reserved to accommodate the maximum annual sendout rate with the result that a cargo may take longer to move into the market in the summer than in the peak demand months of the winter.

The amount of sendout capacity reserved is deemed to be in proportion to the amount of storage required to accept a full cargo as a percentage of total LNG storage capacity at the receiving terminal. In the calculation of LNG regasification tariffs, any LNG/gas used as fuel is priced at the appropriate market price for gas.

Waterborne freight rates are based on a standard 145,000 cu m LNG carrier with the cost of bunker fuel and boil-off LNG used as fuel reflecting prevailing oil prices and the appropriate price of LNG in the value chain, respectively.

Waterborne freight costs are based on the following assumptions:

- Time charter rate of $80,000/day.
- Laden boil-off rate of 0.145% and a ballast boil-off rate of 0.1%.
- Cargo loaded is 98.5% of vessel cargo capacity.
- Return heel is 5% of the loaded cargo.
- LNG carrier speed is 19 knots with 2 days each for cargo loading and discharge.
- LNG carrier operates for 340 days/year.
- LNG carrier owner has an 11% weighted average cost of capital (WACC) with capital expenditure financed on a 70/30 debt/equity basis.

Analysis of historical LNG netbacks illustrates considerable variation between market destinations. As Fig. 4 shows, netbacks from the liquid markets in the US and UK exhibit considerable volatility when compared to the prices that can be achieved from sales into those markets that are represented in this analysis by contract prices incorporating time-lag based oil price indexation, i.e., Belgium, Japan, and Spain.

Similarly, the netback price exhibits significant variation depending on the source of supply. Naturally, netbacks from more remote markets are affected by the higher cost of transportation (Fig. 5). Analysis of these results on an ongoing basis will go some way to explaining future LNG trade movements. ✦

Reference

1. "North America Natural Gas Market Outlook," Purvin & Gertz Inc.

The author

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LNG shipping world changing; gas carriers expanding rapidly

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Oslo

The LNG shipping business is changing rapidly.

As recently as 2004, its history may be briefly described as follows: It has evolved over the past 4 or 5 decades. A few owners, mainly fully integrated operations, have been the core of LNG shipping history and developed this highly specialized business steadily in close cooperation with charterers.

LNG vessels have mainly been operated in fixed trades and enjoyed attractive long-term contracts. Development of new technical solutions has been limited.

The competence of those involved in LNG shipping has been indisputable.

LNG carriers typically exhibit good technical and operational standards. Vessels' safety records have so far been among the best in the shipping industry.

After about 43,000 commercial shipments of LNG or more than 110 million of loaded miles, no accidents with major release of cargo have ever occurred. There have been, however, enough minor incidents to suggest that statistically a major mishap could occur.

Despite the industry's frequent references to its exceptionally good safety record, a single major accident could easily derail confidence in the business or at least damage public confidence.

This safety record has thus far prevented LNG carriers being directly subjected to the "regulation by disaster" principle, unlike the oil tanker industry that has seen new regulations after accidents involving the Amoco Cadiz (1978), Exxon Valdez (1989), Sea Empress (1996), Erika (1999), and Prestige (2002), just to mention a few.

Now, however, the LNG shipping scene is changing rapidly.

As of January 2007, 220 LNG carriers were operating and about 130 were on order, corresponding to 59 % of the existing fleet, based on number of ships.

The cargo-carrying capacity of the world's LNG fleet will more than double within a few years. The size of the vessels has suddenly leapt to around 266,000 cu m, which are the biggest ones on order currently, from around 145,000 cu m, which used to be the standard size only a couple of years ago.

Construction of the first LNG carriers as we know them today started less than 40 years ago. And so far scrapping of LNG carriers is practically nonexistent.

Recent, current developments

New technical solutions are being applied to LNG carriers, although most of these solutions are proven technology. To the present, for example, vessels have been almost exclusively powered by steam propulsion; most carriers currently on order will employ dual fuel, diesel-electric (DFDE) propulsion.

Megacarriers (>200,000 cu m) on order will employ slow-speed diesel engines running on heavy fuel oil and feature reliquefaction plants aboard to handle cargo boil-off. Twin propeller arrangement is the preferred alternative for these megacarriers. There may be different motives for these changes, but higher thermal efficiency and insufficient availability of competent steam engineers are among them.

Gas-turbine propulsion is an interesting alternative, but to date only a single carrier 29,000 cu m has been ordered with this technology. This vessel was delivered in 1974 and was later converted to diesel-engine propulsion.

For any LNG carrier, design life expectancy of up to 40 years has become an industry standard. This has created a need for higher material-fatigue standards, increased corrosion margins, and more comprehensive corrosion protection and maintenance strategies.

New trades in less-benign waters that include cold climate and icy conditions, as in the North Atlantic, Barents Sea, and the Sakhalin area, are opening for LNG shipping.

Rougher seas and larger cargo tanks combined with membrane cargo-containment systems are increasing the focus on liquid motions and sloshing forces inside cargo tanks in order to prevent damage.

And now an LNG spot market is emerging and multiport discharge is expected to develop. Markets for ship-to-ship transfer (STS), floating storage regas units, and floating terminals are also emerging. In late 2006 in the Gulf of Mexico, Excelerate Energy demonstrated the feasibility of STS and performed the first commercial STS off Teesside, UK, while commissioning its second offshore LNG terminal.

Many new owners, ship managers, charterers, port and flag authorities, shipbuilding yards, docking-yards, terminals and operators, superintendents, officers and crew have entered the LNG shipping business in only a few years. There is now a general shortage of most categories of experienced LNG personnel. The competition is increasing for qualified crew, with significant upward pressure on cost as one result. At the same time, charter rates have been dropping during the last few years.

Competition within the mainstream of the LNG carriers is hardening as a result. Pressure on cost and lower charter rates compared to previous years will require discipline by vessel operators to maintain industry's established safety level.

LNG shipping is different

Despite many similarities with other shipping segments, oil and LPG in particular, LNG shipping has specialties of its own. Fundamental differences exist from early specification stages of new LNG carriers through construction and operations.

Most owners hold a long-term view for their LNG operations, based on charter contracts of typically 15-20 years, and operational life spans of up to 40 years for their vessels. Each LNG carrier is in most cases an essential and integrated part of a transportation chain requiring continuous flow of LNG. Should anything go wrong with the ship and cause serious delay or off-hire, it may be difficult to find and employ other ships as substitutes within a reasonable time frame, mainly due to compatibility issues and availability of ships. In the worst case, the LNG production plant or the receiving terminal and the related supply and demand chains may be affected.

This differs from oil shipping in which several vessels operate in the spot market and are normally available around the world on short notice. Interruptions of the LNG supply chain may therefore have dramatic practical and economic consequences.

For this shipping segment, where standards and expectations are high, there may be a higher and continuous need for brand management (i.e., building and protecting a reputation for success in the market) particularly among owners, not least for newcomers who have long-term ambitions and want to strengthen their market positions but also charterers that may want to protect themselves against negative publicity.

It was said, for example, that Exxon lost revenue in the range of $9 billion after the Valdez accident because consumers did not want to buy from a company that had caused such damage to the environment.

Organization, competence

Given vessel management's responsibility to ensure efficient and safe operational practices aboard, what follows describes an increasing challenge to the continued success of LNG shipping.

Behind incidents and accidents aboard any LNG carrier frequently lies a strong human element. Eighty percent is the acknowledged figure frequently to indicate the share of maritime accidents caused by human error.

The human element aboard vessels includes:

- Competence of and decisions (including budgets) made by those who define the content of the newbuilding specification.
- Company practice (including budgets) regarding maintenance policy and spare parts.
- Management procedures, including interface between a ship and its owner's land-based organization.
- Manning policy, including number of people aboard and competence management.
- Operational routines aboard and ashore and the interface between the two, including emergency preparedness procedures and training.

It is important to recognize that competence and training issues also apply to shore staff and that how a vessel is operated reflects to some extent the shore organization.

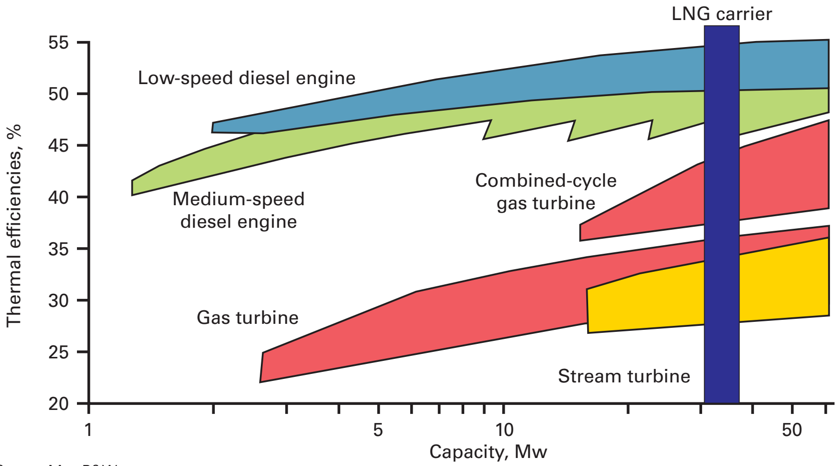
The International Maritime Organization's International Safety Management (ISM) code certification will generally cover many of these subjects. It is, however, important to note that ISM is a general code, developed and implemented as a minimum standard for all applicable shipping segments.

Owners and ship managers involved in LNG shipping are strongly advised to go beyond minimum requirements and consider in detail what they need for long-term success, keeping 40 years' vessel-life expectancy and high demand for uninterrupted service, reliability, and safety in mind.

Availability of LNG competence is now receiving increasing attention and

Thermal efficiency of propulsion alternatives

Fig. 1



Source: Man B&W

frequently mentioned as a bottleneck for the LNG industry. The main focus is on shipboard people, even if the increasing demand is general for the whole LNG shipping industry. Given that a ship is carefully designed, built, and maintained, statistical evidence shows that the weakest link in the chain is human error by crew and pilots; this could be assumed to be equally applicable to LNG carriers.

Rapid expansion in any sector of the industry implies poor quality control, lack of supervision due to shortage of experienced teachers and trainers, shortage of qualified labor, and possible falling standards of services.

Additionally as a result of the shortage, increasing wages for experienced LNG personnel force owners to be prepared to pay more now to secure the services of competent staff.

It is claimed that even if the number of LNG carriers remained constant with no newbuilds, the industry would still have to struggle to replace seafarers retiring or leaving the sea. The International Association of Maritime Universities has estimated that almost 1,500 senior officers and nearly 750 senior engineers will be required by 2008.

The lack of qualified crew is not going to stop newbuilds from sailing. What are the consequences for the safety record of the industry? There is no quick fix here and the situation requires serious management attention and specific actions from all parties involved.

Some people seem to believe that seagoing personnel fully trained in compliance with Standards of Training Certification and Watch keeping for Seafarers (STCW95) are fully qualified for LNG ships.

It is important to remember that STCW95 sets standards for classroom cargo handling training for all gas carriers, not differentiating between LPG and LNG carriers. The basic formal training must be extended by further on-the-job aboard LNG carriers. It is up to the owner to decide its additional requirements for training beyond what is formally required for the different ranks.

Again the high demands the industry places on both availability and safety characteristic demands of LNG carriers must be kept in mind.

DNV Standard of Competence SEASKILL includes standards for LNG competence for some categories of onboard personnel and the Society of International Gas Tanker and Terminal Operators Ltd. (SIGTTO) has developed a complete set of standards for LNG operations. DNV is now as an independent third party, certifying training courses and simulators according to SIGTTO standards.

One good opportunity for training and competence building which should not be underestimated is the newbuild process, all the way from owners' approval of plans and specifications, throughout the construction period, and final testing and commissioning in connection with delivery. Active participation here is a practical hands-on approach that represents a lost opportunity if subcontracted to others.

It should also be emphasized that the need for LNG competence and updating of such shore-based personnel as superintendents and other technical staff is also very important. Owners should not underestimate this and allocate funds accordingly for necessary training of this category of personnel as well.

Alternative propulsion

Almost all LNG carriers delivered until recently have been powered by steam-turbine propulsion. They use boil-off from the liquid cargo as fuel in combination with bunker oil.

Very high reliability and low vibration levels together with a convenient way of handling boil-off gas are the main reasons for the widespread use of this arrangement.

At present, however, most LNG carriers are on order with diesel electric propulsion, while the megacarriers on order all have slow-speed diesel engines based on heavy fuel oil as the only fuel. This arrangement is supplemented by onboard reliquefaction plants to take care of cargo boil-off.

Reasons behind this development include the following:

• The efficiency of a traditional steam propulsion is the lowest (~30%) among the alternatives.

• A service speed of 19-20 knots for LNG carriers with more than 200,000 cu m cargo capacity will require more power than is available from single steam turbine installations (>61,000 kw).

• The supply of experienced steam engineers is insufficient.

Economics, which includes thermal efficiency (Fig. 1), is decisive for what is the preferred alternative. For LNG carriers, more than for other vessels, it is important to have a long-term view.

With increasing focus on the environment and emissions, the shipping industry in general will also be subject to closer scrutiny. It is increasingly going to be considered a target for legislators looking for ways to cut pollution levels. European governments will most likely implement legislation for a sustainable shipping policy in the years to come, reflecting a new proposed integrated maritime EU policy. In this connection CO_2, NOx, and SOx emission levels will be targeted.

LNG carriers ordered today may be technically able to trade until 2040 and beyond. But will they be accepted to remain in business for the next 3 decades as local and international environmental legislation develops at an accelerated pace? If or when carbon trading is implemented, associated costs in addition to increasing fuel bill may also become important input of the overall economical equation and probably influence the choice of propulsion alternative.

Shipowners ordering LNG carriers today should study likely scenarios as a basis for their choice of propulsion and other relevant particulars. Future considerations may be different from those today, particularly if emissions are included more specifically.

As Table 1 shows, the steam-turbine alternative, when operating in dual-fuel mode (LNG + heavy fuel oil) is clearly the least favorable from the sulfides and CO_2 emissions point of view. If propulsion depends more or less exclusively on LNG, emissions are reduced.

LNG carriers, even the big ones, are all designed with a loaded draft of about 12 m. One consequence is that they are growing wider as the cargo carrying capacity increases, i.e. beams of ~43.5 m, 50 m, 55 m for 140,000 cu m, 210,000 cu m, and 260,000 cu m cargo capacities, respectively.

A widening of the aft body hull form and a wish to maintain the full cargo tank width of the aft cargo tank have meant that certain hydrodynamic issues have to be considered, particularly the effect of water flow round the aft body to the propeller shaft.

Influenced by increased environmental awareness, small-scale LNG distribution is emerging. Small LNG carriers are being developed to distribute LNG locally, as fuel to other types of ships, for example, such as offshore supply vessels and coastal passenger ferries on the west coast of Norway (Fig. 2).

The 1,104-cu m LNG carrier Pioneer Knutsen, delivered in 2004, employs two engines for gas fuel only and two diesel engines in two separate engine rooms (Fig. 2).

One example is the LNG-fueled ferry Glutra (96 cars), the first LNG-fueled ferry in the world, which has been in service since January 2001 (Fig. 3). NOx emissions have been reduced by 90% and CO_2 by about 20% compared to fuel oil. The operational experience is very good, and five more LNG-fueled passenger-car ferries are now being delivered.

Also, two more LNG-fueled offshore supply vessels have been operating successfully in the North Sea during the last 3-4 years, and two more have been ordered.

More such LNG-fueled vessels are likely to be ordered in time. Local infrastructure for supply of LNG is a prerequisite for such vessels.

Small-scale LNG will likely be developed further, and LNG fuel for different ship types may become a more common alternative, for different types of ships, as availability of LNG is developed and emissions are included in the basis for decision.

Structural fatigue

Why is fatigue an increasingly important issue for LNG carriers?

Generally, the result of fatigue is cracking. Cracks may or may not be serious to the extent that they require immediate attention. Some elements of current development of LNG shipping emphasize the importance of a high fatigue standard:

- *Longevity.* The design life expectancy of LNG carriers now generally seems to be 40 years for worldwide trade, while previous practice was 25 years. Forty years appear to be closer to current realistic expectations.
- *Rough weather trades.* Existing LNG routes have been pretty much limited to relatively benign waters. Now North Atlantic trades are increasing, where fatigue life generally is about half, compared with worldwide trade.
- *Increasing ship size.* As ships grow in size, use of high tensile steel (HTS) tends to increase. As the stress levels increase, there may be an increasing risk of fatigue, as fatigue resistance does not

Emissions for propulsion alternatives

Table 1

	Fuel	NOx	SOx	CO_2
		Tonnes/ship/year		
Steam turbine	HFO + LNG	200	2.400	180.000
Low-speed diesel + reliquefaction	HFO	3.950	1.800	120.000
Dual-fuel electric	LNG only	240	0	100.000
Gas turbines and COGES	LNG only	850	0	108.000

Source: Alstom

increase for HTS.

The following points may be useful when considering fatigue life:

- Fatigue life for vessels operating in North Atlantic trade is about half that of those employed in a worldwide trade.
- Fatigue life of steel structures in corrosive environments (exposed to seawater, for example) can be roughly reduced to half when compared to steel that is protected. This is one reason that coating standards and coating maintenance in ballast tanks are such important issues.
- The quality of workmanship during construction is essential for vessel fatigue life. A good design and long calculated fatigue life may be severely undermined by poor workmanship. It is essential that class and owner representatives pay proper attention to workmanship throughout construction.

The Glutra is an LNG-fueled ferry (Fig. 3).

Liquid motion in tanks

In LNG carriers, and particularly membrane carriers, not only the response of the hull structure but also that of the cargo containment system must be taken in to account. DNV uses a comparative approach in which the highest pressure obtained from the model tests within filling levels comparable to those from successful sailing experience, becomes a reference for the maximum allowable pressure.

For membrane-containment systems, the complete insulation system is then modeled and results obtained from the model tests used as input for the loading of the membrane system. The capacity of the membrane systems to sustain the maximum expected loads can then be confirmed.

There are currently a number of uncertainties in the analysis when set against the reality of liquid motions in LNG prismatic cargo tanks. These uncertainties include the compressibility of the entrapped gas, the actual loading on the containment system (whether point or distributed load), and the extent to which actual impacts with the tank surfaces are cushioned.

DNV has investigated the use of different liquid-motion (computational fluid dynamics) analysis software, both 2D and 3D, to gain a more accurate picture of what is actually occurring. In order for DNV to have full confidence in such software, it is first subjected to qualification testing. It has become clear that the reliability of the results from both 2D and particularly 3D software is limited.

Another major uncertainty relates to the scaling laws that are applied to the model test results to develop equivalent full-size loads. For direct assessment of impacts, DNV conservatively uses Froude Scaling in absence of better knowledge regarding the scaling laws that apply to the different phenomena that occur during liquid motion and sloshing impacts of LNG.

DNV has initiated further research into the scaling problem in order to understand this important but difficult issue.

DNV has conducted in-house sloshing tests with a small (model scale 1:70) and large tank (1:20). Identical motion tests were done with both tanks with variations of ullage pressure and ullage gas density. The study indicated that Froude Scaling is currently the most appropriate scaling law and does not in fact provide large over-predictions, as had been suggested previously.

In order to understand applicable scaling laws, DNV and industry partners have prepared the necessary technology and are now in the process of instrumenting an LNG carrier under construction and obtaining full-scale measurements of pressures exerted by LNG motion in prismatic cargo tanks. This will provide scaling factors in measured external conditions that can then be simulated at model scale to obtain scaling factors at the filling levels measured.

Although the exact contributors to the measured loads at full scale will be difficult to differentiate at certain filling levels and in certain conditions, it will nonetheless provide scaling factors that incorporate these elements and remove much of the current uncertainty. ✦

The authors

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Equipment/Software/Literature

New wireless pressure transmitter

This new, fully integrated, self-contained wireless pressure transmitter is designed to measure and monitor pressure in the oil field.

The AWI-P wireless transmitter is available in battery powered and AC powered versions.

It includes the wireless transmitter, pressure sensor, and self-contained power source in a lightweight, rugged, case aluminum enclosure for use in tank farms and pipelines.

Source: **Adalet Wireless**, 4801 W. 150th St., Cleveland, OH 44135.

Pride International lets contract for capsules

Pride International Inc., Houston, let contract recently to Reflex Marine Ltd., Aberdeen, Scotland, to supply Frog offshore safety personnel transfer capsules.

Pride International will deploy the three-man version of the Frog on five drilling rigs off Angola. The units will be used for all routine transfers of personnel by crane and have the capacity to carry a stretcher to transfer injured personnel in medical situations.

Capsule being used during a medivac exercise.

Reflex Marine says its Frog provides a safe way of transferring workers to and from installations and vessels. The firm says the design of the Frog addresses risks associated with personnel transfers by crane: the outer frame and buoyancy protect against lateral impacts and help ensure the Frog is self-righting and floats if immersed in water; the seats are attached to a sprung mounted seat base which, combined with the shock-absorbing feet, protects against heavy landings; and the seat belts help ensure that falling from the unit during transfer is unlikely.

Source: **Reflex Marine Ltd.**, 13 Albyn Terrace, Aberdeen, AB10 1YP, UK.

Services/Suppliers

Varel International

Houston, has announced its acquisition of Pendemak Industries, the company's largest and long-time Canadian-based distributor of oil and gas drill bits. Pendemak will now be known as Varel Rock Bits Canada. Former Pendemak president, Rod MacKenzie, will serve as vice-president, sales and operations-Canada for the newly named company.

Varel International, headquartered in Carrollton, Tex., provides a comprehensive range of roller cone and fixed cutter drill bits to the global oil and gas, mining, and industrial markets.

Cameron

Houston, has announced its acquisition of a range of products and the intellectual assets of Calif.-based Prime Measurement Products. The move will strengthen technical capability and secure deliveries on key components for the Measurement Systems Div. of Cameron. That division has nearly doubled its size over the past three years.

Cameron is a leading provider of flow equipment products, systems, and services to worldwide oil, gas, and process industries. The Measurement Systems Div. is a leader in the design, manufacture, and distribution of measurement and control sensors and subsystems.

CECA Oilfield Services

Paris, has appointed Simane Hachemi as district manager for Europe and North Africa.

Hachemi, who has master's degrees in chemistry and business, joined the company in 2002.

CECA Oilfield Services, a company within the Arkema group, is a major supplier of specialty oil field chemicals, innovative chemical solutions, and molecular sieves to the worldwide oil and gas industry.

Delta Services

Houston, has announced the appointment of Nicole Carpenter as vice-president in the firm's energy practice.

Carpenter has more than 10 years of experience in business development in the energy industry, most recently serving as worldwide energy marketing executive for Weatherford International.

Delta Services is a global retained search firm, providing services from technical staff to top management.

Deepwater Specialists Inc. (DSI)

Houston, has promoted Trey Lambert to executive vice-president.

Lambert, who has a BS degree in electrical engineering from Louisiana State University, has more than 12 years of experience in the oil and gas industry. He has been with DSI for over five years.

Deepwater Specialists Inc., part of John Wood Group PLC, provides facilities commissioning services to the international oil and gas industry.

Antares Offshore LLC

Houston, has appointed Jerry Streeter as manager of business development.

Antares Offshore LLC is a consulting engineering company specializing in subsea field developments and marine pipeline project delivery.

Statistics

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4 3-30 2007	Districts 1-4 [1]3-23 2007	District 5 3-30 2007	District 5 [1]3-23 2007	Total US 3-30 2007	Total US [1]3-23 2007	Total US 3-31 2006
	1,000 b/d						
Total motor gasoline	418	203	79	40	497	243	321
Mo. gas. blending comp.	415	562	76	23	491	585	595
Distillate[2]	318	314	62	38	380	352	313
Residual	320	492	90	48	410	540	511
Jet fuel-kerosine	86	162	59	59	145	221	205
LPG	288	274	4	4	292	278	270
Unfinished oils	494	629	18	34	512	663	453
Other	341	523	13	10	354	533	191
Total products	**2,680**	**3,159**	**401**	**256**	**3,084**	**3,415**	**2,859**
Canadian crude	1,025	1,661	260	314	1,285	1,975	1,671
Other foreign	8,010	6,774	1,180	309	9,190	7,083	8,583
Total crude	**9,035**	**8,435**	**1,440**	**623**	**10,745**	**9,058**	**10,254**
Total crude	**11,715**	**11,594**	**1,841**	**879**	**13,556**	**12,473**	**13,113**

[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

	*3-30-07	*3-31-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	81.45	79.51	1.94	2.4
Brent crude	66.03	64.85	1.18	1.8
Crack spread	15.42	14.67	0.75	5.1
FUTURES MARKET PRICES				
One month				
Product value	83.37	79.37	4.01	5.1
Light sweet crude	64.36	66.09	–1.73	–2.6
Crack spread	19.01	13.27	5.74	43.2
Six month				
Product value	81.65	79.68	1.97	2.5
Light sweet crude	68.32	68.60	–0.28	–0.4
Crack spread	13.33	11.08	2.24	20.3

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

PURVIN & GERTZ LNG NETBACKS—MAR. 30, 2007

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.90	5.06	6.17	4.93	5.55	6.16
Everett	7.34	5.47	6.99	5.57	6.01	7.62
Isle of Grain	2.38	0.77	1.94	0.68	1.23	1.99
Lake Charles	5.16	3.46	4.96	3.61	3.83	5.66
Sodegaura	4.47	6.77	4.69	6.13	5.54	4.03
Zeebrugge	5.49	3.68	5.00	3.71	4.22	5.01

Definitions, see OGJ Apr. 9, 2007, p. 57. Source: Purvin & Gertz, Inc. 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						
PADD I	15,386	55,264	28,341	9,340	42,700	13,713	6,997
PADD II	75,349	49,305	16,403	7,971	28,191	1,579	14,687
PADD III	176,115	64,194	25,988	13,762	32,467	16,490	46,290
PADD IV	14,335	6,167	1,843	484	3,180	343	2,867
PADD V	[1]54,007	27,101	19,676	8,403	13,156	6,131	21,180
Mar. 30, 2007	**[1]335,192**	**202,031**	**92,251**	**39,960**	**119,694**	**38,256**	**92,021**
Mar. 23, 2007[3]	**335,296**	**202,471**	**92,370**	**40,619**	**119,239**	**38,237**	**90,033**
Mar. 31, 2006	**341,015**	**212,498**	**82,149**	**42,536**	**112,491**	**39,411**	**91,665**

[1]Included in total motor gasoline. [2]Includes 3.350 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. 30, 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	3,234	1,275	1,276	1,618	78.9	1,647	91	541	136
App. Dist. 1	12	5	5	95	5.3	12	0	3	0
Dist. 1 total	**3,246**	**1,280**	**1,281**	**1,713**	**74.8**	**1,659**	**91**	**544**	**136**
Ind., Ill., Ky.	2,160	2,115	2,157	2,355	91.6	1,105	159	581	35
Minn., Wis., Dak.	366	356	361	442	81.7	291	25	105	8
Okla., Kan., Mo.	647	537	537	786	68.3	402	19	159	2
Dist. 2 total	**3,173**	**3,008**	**3,055**	**3,583**	**85.3**	**1,798**	**203**	**845**	**45**
Inland Texas	962	624	645	645	100.0	489	38	187	7
Texas Gulf Coast	4,122	3,447	3,537	4,031	87.7	1,525	338	973	222
La. Gulf Coast	3,566	3,278	3,289	3,264	100.8	1,239	452	816	99
N. La. and Ark.	209	171	177	215	82.3	107	9	56	6
New Mexico	148	97	98	113	86.7	120	3	36	0
Dist. 3 total	**9,007**	**7,617**	**7,748**	**8,270**	**93.7**	**3,480**	**840**	**2,068**	**334**
Dist. 4 total	**626**	**521**	**533**	**596**	**89.4**	**303**	**26**	**160**	**16**
Dist. 5 total	**2,688**	**2,228**	**2,454**	**3,173**	**77.3**	**1,694**	**333**	**547**	**151**
Mar. 30, 2007	**18,740**	**14,654**	**15,071**	**17,335**	**86.9**	**8,934**	**1,493**	**4,164**	**682**
Mar. 23, 2007*	**18,218**	**14,579**	**15,048**	**17,335**	**86.8**	**8,775**	**1,438**	**3,996**	**670**
Mar. 31, 2006	**16,797**	**14,457**	**14,835**	**17,115**	**86.7**	**8,066**	**1,403**	**3,497**	**638**

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

OGJ GASOLINE PRICES

	Price ex tax 3-28-07	Pump price* 3-28-07	Pump price 3-29-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	214.8	254.5	243.7
Baltimore	210.6	252.5	242.5
Boston	207.7	249.6	236.2
Buffalo	207.5	267.6	250.3
Miami	219.3	269.6	261.2
Newark	209.8	242.7	227.9
New York	200.4	260.5	250.1
Norfolk	204.0	241.6	235.4
Philadelphia	215.9	266.6	248.9
Pittsburgh	205.8	256.5	241.3
Wash., DC	216.2	254.6	254.9
PAD I avg.	210.2	256.0	244.8
Chicago	227.7	278.6	273.5
Cleveland	202.3	248.7	242.9
Des Moines	204.3	244.7	237.7
Detroit	206.4	255.6	248.0
Indianapolis	206.8	251.8	251.8
Kansas City	207.7	243.7	233.3
Louisville	211.8	248.7	248.3
Memphis	201.8	241.6	236.8
Milwaukee	203.4	254.7	250.4
Minn.-St. Paul	212.2	252.6	250.0
Oklahoma City	207.3	242.7	232.6
Omaha	207.3	253.7	245.7
St. Louis	205.8	241.8	232.0
Tulsa	205.2	240.6	234.4
Wichita	201.3	244.7	237.9
PAD II avg.	207.4	249.6	243.7
Albuquerque	211.2	247.6	248.4
Birmingham	203.9	242.6	238.4
Dallas-Fort Worth	205.2	243.6	246.7
Houston	203.2	241.6	240.1
Little Rock	203.4	243.6	235.8
New Orleans	204.3	242.7	243.9
San Antonio	196.3	234.7	233.4
PAD III avg.	203.9	242.4	241.0
Cheyenne	204.3	236.7	224.4
Denver	231.0	271.4	235.4
Salt Lake City	204.6	247.5	225.2
PAD IV avg.	213.3	251.9	228.3
Los Angeles	254.7	313.2	268.8
Phoenix	224.9	262.3	241.2
Portland	245.2	288.5	244.3
San Diego	260.6	319.1	273.5
San Francisco	282.6	341.1	269.8
Seattle	233.9	286.3	254.5
PAD V avg.	250.3	301.7	258.7
Week's avg.	**214.1**	**257.7**	**244.6**
Mar. avg.	**210.4**	**254.0**	**235.4**
Feb. avg.	**184.4**	**228.0**	**229.6**
2007 to date	**191.4**	**235.0**	—
2006 to date	**188.7**	**231.1**	—

*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

Spot market product prices

	3-23-07 ¢/gal
Motor gasoline (Conventional-regular)	
New York Harbor	193.00
Gulf Coast	187.52
Los Angeles	213.75
Amsterdam-Rotterdam-Antwerp (ARA)	171.10
Singapore	181.43
Motor gasoline (Reformulated-regular)	
New York Harbor	197.13
Gulf Coast	196.25
Los Angeles	225.75

	3-23-07 ¢/gal
Heating oil No. 2	
New York Harbor	171.10
Gulf Coast	167.48
Gas oil	
ARA	172.17
Singapore	175.55
Residual fuel oil	
New York Harbor	105.67
Gulf Coast	101.79
Los Angeles	126.27
ARA	96.87
Singapore	117.17

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

BAKER HUGHES RIG COUNT

	3-30-07	3-31-06
Alabama	2	2
Alaska	12	7
Arkansas	46	20
California	32	36
Land	31	31
Offshore	1	5
Colorado	103	83
Florida	0	0
Illinois	0	0
Indiana	2	0
Kansas	13	5
Kentucky	11	6
Louisiana	185	182
N. Land	55	56
S. Inland waters	25	20
S. Land	42	33
Offshore	63	73
Maryland	0	0
Michigan	2	1
Mississippi	20	7
Montana	20	22
Nebraska	0	0
New Mexico	71	98
New York	8	4
North Dakota	32	31
Ohio	15	7
Oklahoma	177	168
Pennsylvania	16	14
South Dakota	1	0
Texas	824	714
Offshore	9	13
Inland waters	1	2
Dist. 1	26	18
Dist. 2	34	24
Dist. 3	54	66
Dist. 4	92	81
Dist. 5	164	125
Dist. 6	123	103
Dist. 7B	45	39
Dist. 7C	58	38
Dist. 8	108	78
Dist. 8A	26	30
Dist. 9	30	29
Dist. 10	54	68
Utah	43	39
West Virginia	26	25
Wyoming	79	103
Others—ID-1; NV-2; TN-4; VA-2	9	2
Total US	**1,749**	**1,576**
Total Canada	**149**	**425**
Grand total	**1,898**	**2,001**
Oil rigs	271	253
Gas rigs	1,472	1,321
Total offshore	73	91
Total cum. avg. YTD	**1,734**	**1,521**

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	3-30-07 Rig count	3-30-07 Percent footage*	3-31-06 Rig count	3-31-06 Percent footage*
0-2,500	59	6.7	46	4.3
2,501-5,000	104	61.5	98	44.8
5,001-7,500	225	21.7	206	18.4
7,501-10,000	423	3.7	341	2.3
10,001-12,500	415	3.8	373	0.8
12,501-15,000	271	0.3	268	—
15,001-17,500	109	0.9	115	0.8
17,501-20,000	72	—	71	—
20,001-over	37	—	18	—
Total	**1,715**	**8.8**	**1,536**	**6.2**
INLAND	40		45	
LAND	1,618		1,431	
OFFSHORE	57		60	

*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]3-30-07	[2]3-31-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	17	21
Alaska	780	752
California	678	684
Colorado	51	60
Florida	6	6
Illinois	29	28
Kansas	95	87
Louisiana	1,369	1,208
Michigan	15	14
Mississippi	51	48
Montana	90	99
New Mexico	164	155
North Dakota	103	106
Oklahoma	170	172
Texas	1,338	1,290
Utah	43	45
Wyoming	140	144
All others	63	75
Total	**5,202**	**4,994**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	**3-30-07**
Alaska-North Slope 27°	44.93
South Louisiana Sweet	67.00
California-Kern River 13°	54.65
Lost Hills 30°	62.50
Southwest Wyoming Sweet	61.87
East Texas Sweet	64.01
West Texas Sour 34°	56.40
West Texas Intermediate	62.50
Oklahoma Sweet	62.50
Texas Upper Gulf Coast	59.25
Michigan Sour	55.50
Kansas Common	61.50
North Dakota Sweet	55.50

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

WORLD CRUDE PRICES

$/bbl[1]	**3-23-07**
United Kingdom-Brent 38°	60.85
Russia-Urals 32°	57.69
Saudi Light 34°	56.31
Dubai Fateh 32°	57.22
Algeria Saharan 44°	62.64
Nigeria-Bonny Light 37°	62.82
Indonesia-Minas 34°	61.20
Venezuela-Tia Juana Light 31°	54.94
Mexico-Isthmus 33°	54.83
OPEC basket	58.57
Total OPEC[2]	57.73
Total non-OPEC[2]	57.85
Total world[2]	57.78
US imports[3]	54.02

[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]

	3-23-07	3-16-07	Change
	Bcf		
Producing region	597	584	13
Consuming region east	677	718	–41
Consuming region west	237	231	6
Total US	**1,511**	**1,533**	**–22**
	Jan. 07	**Jan. 06**	**Change, %**
Total US[2]	**2,379**	**2,371**	**0.3**

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

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Jan. 2006	Dec. 2006	1 month average production 2007	2006	Change vs. previous year Volume	%	Jan. 2007	Dec. 2006	Cum. 2007
	Crude, 1,000 b/d						Gas, bcf		
Argentina	628	640	628	615	13	2.1	122.9	149.5	122.89
Bolivia	45	45	45	45	—	—	40.0	40.0	40.00
Brazil	1,736	1,787	1,736	1,688	48	2.8	28.0	28.5	28.00
Canada	2,554	2,640	2,554	2,586	–32	–1.2	532.5	515.8	532.50
Colombia	522	518	522	521	1	0.1	18.0	18.0	18.00
Ecuador	515	515	515	563	–48	–8.6	0.3	0.3	0.31
Mexico	3,143	2,978	3,143	3,372	–229	–6.8	177.8	172.8	177.82
Peru	120	119	120	113	7	6.3	5.7	5.7	5.70
Trinidad	110	111	110	150	–40	–26.5	121.0	121.7	121.00
United States	5,279	5,275	5,279	5,047	232	4.6	1,655.0	1,682.0	1,655.00
Venezuela[1]	2,490	2,550	2,490	2,650	–160	–6.0	80.0	82.0	80.00
Other Latin America	80	80	80	77	3	3.5	7.5	7.5	7.54
Western Hemisphere	**17,222**	**17,259**	**17,222**	**17,427**	**–205**	**–1.2**	**2,788.8**	**2,823.8**	**2,788.75**
Austria	17	18	17	17	—	–0.8	5.4	5.5	5.40
Denmark	318	328	318	355	–37	–10.4	32.4	31.5	32.41
France	19	21	19	22	–3	–14.1	3.3	3.1	3.30
Germany	70	70	70	73	–4	–4.9	58.1	59.7	58.06
Italy	114	109	114	110	4	3.6	31.0	30.5	31.00
Netherlands	40	46	40	33	7	21.2	330.0	325.0	330.00
Norway	2,431	2,508	2,431	2,657	–226	–8.5	287.1	307.0	287.14
Turkey	38	40	38	40	–2	–5.1	3.4	3.3	3.40
United Kingdom	1,565	1,536	1,565	1,722	–157	–9.1	253.8	248.4	253.80
Other Western Europe	4	4	4	5	–1	–22.5	2.4	2.3	2.40
Western Europe	**4,615**	**4,679**	**4,615**	**5,034**	**–419**	**–8.3**	**1,006.9**	**1,016.2**	**1,006.91**
Azerbaijan	750	750	750	500	250	50.0	24.0	21.0	24.00
Croatia	16	16	16	17	–1	–4.5	6.5	5.9	6.52
Hungary	16	15	16	18	–2	–11.0	8.0	9.1	8.00
Kazakhstan	1,200	1,100	1,200	1,000	200	20.0	80.0	80.0	80.00
Romania	97	95	97	100	–3	–3.0	18.4	18.0	18.40
Russia	9,700	9,700	9,700	9,300	400	4.3	2,100.0	2,000.0	2,100.00
Other FSU	400	500	400	500	–100	–20.0	480.0	430.0	480.00
Other Eastern Europe	48	49	48	51	–3	–5.1	50.5	46.2	50.52
Eastern Europe and FSU	**12,227**	**12,225**	**12,227**	**11,485**	**742**	**6.5**	**2,767.4**	**2,610.2**	**2,767.43**
Algeria[1]	1,340	1,340	1,340	1,360	–20	–1.5	285.0	285.0	285.00
Angola[1]	1,584	1,354	1,584	1,420	164	11.5	2.5	2.4	2.50
Cameroon	84	87	84	87	–3	–3.3	—	—	—
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	660	660	660	690	–30	–4.3	42.0	42.0	42.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.06
Gabon	230	230	230	240	–10	–4.2	0.3	0.3	0.31
Libya[1]	1,700	1,730	1,700	1,650	50	3.0	22.0	22.0	22.00
Nigeria[1]	2,280	2,190	2,280	2,350	–70	–3.0	78.0	75.0	78.00
Sudan	300	300	300	290	10	3.4	0.0	0.0	0.00
Tunisia	92	91	92	67	25	36.9	7.2	6.9	7.23
Other Africa	262	262	262	236	26	10.9	10.2	10.2	10.16
Africa	**9,112**	**8,825**	**9,112**	**8,970**	**142**	**1.6**	**447.3**	**443.8**	**447.26**
Bahrain	170	170	170	175	–5	–2.9	27.0	27.0	27.00
Iran1	3,900	3,880	3,900	3,700	200	5.4	260.0	260.0	260.00
Iraq1	1,700	1,770	1,700	1,500	200	13.3	5.0	5.1	5.00
Kuwait[1,2]	2,460	2,475	2,460	2,520	–60	–2.4	31.0	31.0	31.00
Oman	720	720	720	760	–40	–5.3	58.0	58.0	58.00
Qatar1	810	820	810	820	–10	–1.2	115.0	116.0	115.00
Saudi Arabia[1,2]	8,560	8,565	8,560	9,310	–750	–8.1	160.0	160.0	160.00
Syria	400	400	400	440	–40	–9.1	16.0	15.3	16.00
United Arab Emirates[1]	2,600	2,600	2,600	2,540	60	2.4	135.0	134.0	135.00
Yemen	360	360	360	350	10	2.9	0.0	0.0	0.00
Other Middle East	—	—	—	—	—	–15.8	9.1	7.8	9.07
Middle East	**21,680**	**21,760**	**21,680**	**22,115**	**–435**	**–2.0**	**816.1**	**814.2**	**816.07**
Australia	450	502	450	307	143	46.5	110.0	115.4	110.00
Brunei	200	204	200	195	5	2.7	36.0	37.0	36.00
China	3,822	3,601	3,822	3,693	129	3.5	206.5	190.8	206.52
India	688	693	688	656	32	4.9	81.4	81.0	81.40
Indonesia[1]	860	860	860	920	–60	–6.5	185.0	185.0	185.00
Japan	15	18	15	19	–4	–19.6	12.0	11.6	12.00
Malaysia	780	790	780	770	10	1.3	140.0	144.0	140.00
New Zealand	15	16	15	15	—	—	10.0	10.5	10.00
Pakistan	65	65	65	65	—	–0.5	120.0	125.0	120.00
Papua New Guinea	55	55	55	58	–3	–5.2	0.5	0.5	0.50
Thailand	195	200	195	215	–20	–9.5	73.5	71.0	73.47
Viet Nam	330	330	330	360	–30	–8.3	15.0	15.0	15.00
Other Asia–Pacific	38	34	38	31	7	23.6	62.5	62.3	62.50
Asia Pacific	**7,513**	**7,368**	**7,513**	**7,304**	**209**	**2.9**	**1,052.4**	**1,049.0**	**1,052.39**
TOTAL WORLD	**72,369**	**72,117**	**72,369**	**72,335**	**34**	**—**	**8,878.8**	**8,757.2**	**8,878.81**
*OPEC	30,284	28,780	30,284	29,320	964	3.3	1,356.0	1,355.1	1,356.00
North Sea	4,330	4,390	4,330	4,748	–419	–8.8	672.2	683.9	672.19

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

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Hostage crisis highlights roles in geopolitics

While it's difficult to predict how the new Iranian hostage crisis will end, responses by other countries say much about modern geopolitics.

The eternal problem with the Iranian government is, of course, that it is difficult to predict. Internal conflicts explain why.

The president is a ranting apocalypticist who serves as the puppet of ruling mullahs but who was elected, albeit in questionable voting, by people who despise the mullahs.

The Editor's Perspective

by Bob Tippee, Editor

So was the Mar. 23 abduction of 15 British sailors and marines a planned act of the theocracy, the work of rogue members of the mullahs' Revolutionary Guards, or the result of some internal clash that got out of control? If planned, was it an attempt to retaliate for the UK's anticipated support for toughened sanctions against nuclear-ambitious Iran in the United Nations? Was it indirect retaliation for the US capture of Iranian provocateurs in Iraq? Or did the theocracy need an external crisis to quell seething domestic political pressure?

The rogue-mercenary theory weakened after Tehran first insisted that the Brits had boated into Iranian territory then ludicrously changed the incident's alleged location when the UK government showed the original cite to have been well within Iraqi waters. At this writing, the Iranian leadership seemed determined to raise tension.

Iranian expansionism has drawn an obviously worried Saudi Arabia out of its normal reticence. At an Arab League meeting Mar. 28 in Riyadh, Saudi King Abdullah scolded colleagues for crises in Lebanon, Iraq, and Sudan.

"The real blame should be directed at us, the leaders of the Arab nation," he said, blaming "our constant disagreements and rejection of unity." The purpose of the meeting was to reconsider a 2002 Saudi proposal—itself an uncharacteristically bold move—for Israeli-Palestinian peace.

In Europe, the UK seems expected to handle the crisis on its own. The European Union has acted more like the Saudi Arabia of old—quiet and, from all outward appearances, unresponsive—than the center of solidarity it celebrated in its 50th anniversary as 15 Europeans became victims of international kidnapping.

Meanwhile, the US increased naval activity in the Persian Gulf.

(Online Mar. 30, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Crude futures tally $5 price jump

In overnight electronic trading Mar. 27, crude futures prices jumped more than $5 to $68.09/bbl in New York and to $69/bbl for North Sea Brent in London, marking the biggest 1-day price change since December 2001.

That intraday price spike was only temporary, of course, with the May contract closing at $62.93/bbl Mar. 27 on the New York Mercantile Exchange. Yet escalation of Middle East tensions helped boost May crude prices through seven consecutive sessions to a 6-month high of $66.03/bbl Mar. 29 from a Mar. 20 closing of $59.25/bbl.

The price spike initially was attributed to false rumors of an Iranian missile attack on a US ship and of a UK attempt to free 15 British sailors and marines seized Mar. 23 by naval units of Iran's Revolutionary Guard. The US Navy had two carrier groups in the Persian Gulf in the greatest display of strength since the 2003 invasion of Iraq.

However, there were subsequent reports that an electronic error or unusually large purchase had stimulated a price escalation prior to the rumors. Nevertheless, benchmark US crude was trading as high as $66.50/bbl Mar. 29 in New York, with North Sea Brent up to $68.33/bbl in London—"this time during normal market conditions," said Olivier Jakob at Petromatrix GMBH, Zug, Switzerland. He insisted Iran will continue to spook world oil markets in coming months.

Because of the price spike, Jakob said, "Risk managers will be forced to rerun their stress test scenario, and they will need to use something more aggressive than a $5/bbl overnight increase." He said, "This should force the shorts [futures traders with a net excess of open sales over open purchases] into some rethink on their margin call provisions. The combination of current military activity and current tensions in the Persian Gulf leaves little risk-reward [benefits] in keeping an overnight short position, and this should for now lead to stronger short covering towards close of business."

Jakob warned, "Even if all the sailors were to be released, one needs to question what would be the rule of engagement now in the region; the two sides are likely to test each other again, and the risk of future military engagement between the two has increased significantly on the back of this incident."

Positions harden

Iran formally asked UK officials to guarantee British forces will not enter Iranian territory in the future. The Iranians claim the British were 0.5 km inside Iranian waters when they boarded a merchant ship to inspect for possible smuggled goods near the Shatt al-Arab waterway dividing Iraq and Iran.

However, UK officials said a position-tracking satellite proves British personnel were 1.7 nautical miles inside Iraqi waters when seized. Even the coordinates first given by Iran following that incident put the British forces inside Iraqi waters. The UK is permitted by United Nations mandates to operate in Iraqi territory.

UK Prime Minister Tony Blair said his government won't negotiate for the captives. The UK froze bilateral activity with Iran after Iran refused consular access to the UK personnel. Meanwhile, Iran showed on television videos of two of the sailors, including the lone woman in the group, apologizing for violating Iranian territory. There was talk among some Iranian officials of putting the group on trial.

The UN Security Council expressed "grave concern" and supported calls for the British crew's release. Earlier, the Security Council voted unanimously to tighten sanctions on Iran for its refusal to stop uranium enrichment for its nuclear 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 nations and international financial institutions to restrict new grants, credits, and loans to Iran. It was a follow-up to a Dec. 23 resolution banning trade with Iran in sensitive nuclear materials and ballistic missiles.

"It has not yet been widely publicized, but we understand that the US aircraft carrier USS Nimitz and its strike group (including one guided-missile cruiser and four guided-missile destroyers) will depart San Diego Apr. 1 and head to the Persian Gulf," Jakob reported. That would put three US aircraft carrier strike groups in the gulf—"a major escalation and a needed one if air strikes against Iran are seriously considered, as most neighboring Arab states would not allow such a strike to be launched from their soil," said Jakob. Since the US cannot maintain three carriers in those waters "forever," he said, "The strike risk will be at its peak in the next 60 days."

(Online Apr. 2, 2007; author's e-mail: samf@ogjonline.com)


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