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Nov. 13, 2006
Volume 104.42

ARCTIC PROJECTS AND PROMISE

REGULAR FEATURES

COVER

A vessel redirects the course of an iceberg in the Labrador Sea whose projected path could threaten mobile offshore drilling units or oil production facilities on the Grand Banks in the North Atlantic Ocean off Newfoundland. OGJ's Arctic Projects and Promise special report has articles starting on pp. 18 and 31. Photo from Petro-Canada.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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OGJ Newsletter

Nov. 13, 2006

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General Interest — Quick Takes

California votes down state oil production tax

California voters rejected a state ballot measure that would have taxed state oil production at varying rates depending on the price of crude, and tax revenues would have financed the development of alternative energy (OGJ, Nov. 6, 2006, p. 76).

With 90% of the votes counted, returns indicated Proposition 87 was defeated 55% to 45%, officials said Nov. 7.

Oil companies, particularly Chevron Corp., opposed Proposition 87. If Proposition 87 had passed, the California government would have collected an estimated $200-380 million/year in new tax revenue, but opponents said it would have caused a reduction in state oil production and a need for increased imports.

Voters reject Alaska gas reserves tax proposal

Alaska voters overwhelmingly rejected Ballot Measure 2, a proposal to tax North Slope natural gas reserves until an Alaska gas pipeline is built to deliver gas to the Lower 48.

With votes from more than three fourths of the state's precincts tallied late on Nov. 7, the measure was losing by a 2-1 margin, state officials reported.

Ballot Measure 2, also known as the Alaska Gasline Now initiative, sought to provide an incentive for gas production. Leaseholders on the North Slope would have had to pay an annual reserves tax of 3¢/Mcf for undeveloped gas reserves.

The payments would have been repealed upon pipeline construction. The proposal said leaseholders would get their money back as a deduction from other state gas taxes.

Supporters suggested that the tax would spur North Slope oil and gas producers ExxonMobil Corp., BP PLC, and ConocoPhillips to build a gas pipeline. The tax would have made it costly to not build a pipeline, tax proponents said.

The oil companies said the tax would delay rather than accelerate pipeline construction by adding cost and risk to the $20 billion pipeline project.

The pipeline remains uncertain because the Alaska Legislature in special sessions repeatedly refused to approve a pipeline contract that Gov. Frank Murkowski negotiated with North Slope producers.

Militant attack shuts Nigerian pumping station

Agip's Tebidaba oil pumping station in Nigeria's southern Bayelsa state has been overrun and shut down following an attack on Nov. 6 by armed militants, according to company and government officials.

The firm said 48 people, including workers and security guards, were at the pumping station when the attack occurred but it reported no deaths or injuries. It said oil production was suspended for security reasons.

A Nigerian national security official further confirmed the attack, saying militants shut down the place but that they have not yet issued any demands to be met.

A senior official from the state environment department, however, said the militants were demanding restitution for pollution caused by the company's operations in the area as well as jobs for community members.

The attack follows a spate of recent actions against oil firms by militants in the region.

On Nov. 3, the US government issued a warning of probable militant attacks on oil facilities throughout the volatile Niger Delta region (OGJ Online, Nov. 3, 2006). A day earlier armed gunmen in Nigeria kidnapped two expatriate oil workers during a raid on an oil services ship operated by Norway-based Petroleum Geo-services in the Niger Delta (OGJ Online, Nov. 2, 2006).

Indonesia to reassign Natuna gas block

Indonesia's Energy and Mineral Resources Minister Purnomo Yusgiantoro said a Cabinet session will be required to decide what to do with the giant Natuna gas block project. Last month it terminated the development contract awarded to ExxonMobil for failure to submit a plan for developing the block and selling the gas.

On Nov. 2, Indonesian Vice-President Jusuf Kalla defended the government's decision, saying the company had not done much on the block since signing the contract in 1985.

Purnomo said three options have been prepared for the Cabinet's consideration:

- Handing over the project to state-owned oil company Pertamina.
- Holding a new tender.
- Renegotiating the contract with ExxonMobil under certain terms and conditions, especially on production split.

The government said it wants a share of the production if the ExxonMobil's contract is renewed. Under the old deal, the project was 76% owned by ExxonMobil and 24% by Pertamina, with no separate share for the government.

Maman Budiman, ExxonMobil Oil Indonesia vice-president for planning, commercial and external relations, said the firm is ready to discuss the terms and conditions of developing Natuna, which has natural gas reserves of 222 tcf.

Kardaya Warnika, head of Indonesia's oil and gas regulating body BP Migas, on Nov. 3 told local media that the negotiations will begin this month and will conclude in January 2007. The proportion of the production shares will be changed, he said.

Nigeria, South Korea ponder rail-for-oil trade

South Korean Commerce, Industry, and Energy Minister Chung

Industry Scoreboard

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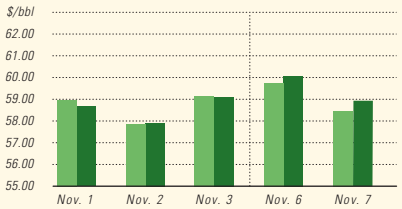
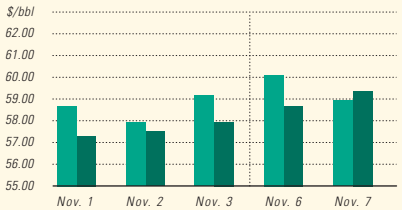
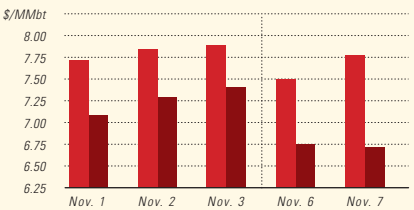


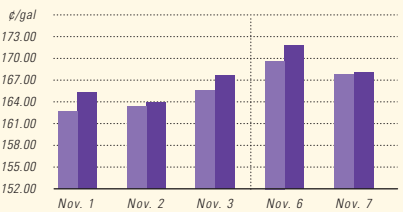
WTI CUSHING / BRENT SPOT



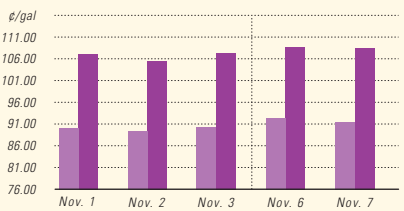
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



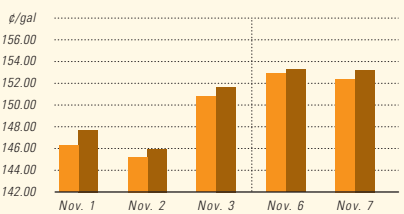
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE / NY SPOT GASOLINE[1]



[1]Nonoxygenated regular unleaded.

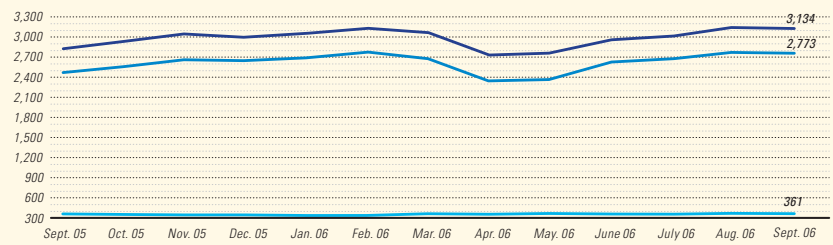
US INDUSTRY SCOREBOARD — 11/13

Latest week 11/3	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	10,369	9,020	15.0	9,831	9,112	7.9
Distillate	4,470	4,069	9.9	4,145	4,091	1.3
Jet fuel	1,661	1,613	2.9	1,604	1,617	–0.8
Residual	540	975	–44.6	739	906	–18.4
Other products	5,120	4,543	12.7	4,948	4,861	1.8
TOTAL DEMAND	22,160	20,221	9.6	21,267	20,587	3.3
Supply, 1,000 b/d						
Crude production	5,252	4,300	22.1	5,115	5,135	–0.4
NGL production	2,418	1,545	56.5	2,231	1,733	28.7
Crude imports	10,038	9,475	5.9	10,259	10,020	2.4
Product imports	3,382	4,587	–26.3	3,463	3,467	–0.1
Other supply[2]	1,107	1,092	1.3	1,091	1,250	–12.7
TOTAL SUPPLY	22,196	20,999	5.7	22,159	21,605	2.6
Refining, 1,000 b/d						
Crude runs to stills	15,069	13,794	9.2	15,160	15,220	–0.4
Input to crude stills	15,619	14,119	10.6	15,588	15,500	0.6
% utilization	90.1	82.4	—	90.6	90.6	—

Latest week 11/3	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	333,246	334,112	–866	326,471	6,775	2.1
Motor gasoline	205,109	203,785	1,324	203,080	2,029	1.0
Distillate	141,034	143,088	–2,054	123,631	17,403	14.1
Jet fuel	40,376	41,154	–778	38,185	2,191	5.7
Residual	43,941	43,831	110	37,148	6,793	18.3
Futures prices[3]						
Light sweet crude, $/bbl	58.62	60.47	–1.85	60.34	–1.72	–2.9
Natural gas, $/MMbtu	7.67	7.26	0.41	11.75	–4.08	–34.7

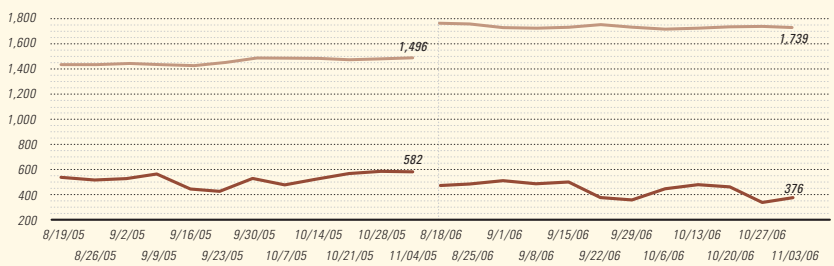
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Weekly average of daily closing futures prices.

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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Sye-kyun and Nigerian Oil Minister Edmund Daukoru signed a memorandum of understanding Nov. 6 that envisions upgrading the African country's rail system in exchange for oil interests.

South Korea will provide Nigeria with long-term, low-interest commercial loans and have its companies take part in the second phase of Nigeria's railway modernization program. In exchange, Nigeria will transfer shares in an operational oil field to South Korea.

POSCO Engineering & Construction Co. has already signed a separate agreement with Nigeria's Transportation Ministry to build the railroad, while Korea National Oil Corp. will operate the oil field. Officials said details about the size of the loan and oil field operations would be discussed at a working level.

The $10 billion railroad project calls for 1,500 km of tracks linking oil capital Port Harcourt on the Gulf of Guinea to Maldugun in Nigeria's northeastern region.

Nigeria made a similar deal with China in late October in an $8.3 billion contract to construct a railway line from the nation's economic capital Lagos to Kano, the largest commercial city in the north.

The Chinese, hoping to secure oil interests in Nigeria, recently granted the African country a $2.5 billion loan facility, a substantial amount of which would be used on the rail project. ✦

Exploration & Development — *Quick Takes*

Shell starts BC-10 development off Brazil

Shell Exploration & Production Co. and partners have let the first contracts for development, involving subsea liquids-gas separation and pumping, of three deepwater heavy-oil fields on Block BC-10 off Brazil.

One of the contracts is for leasing of a floating production, storage, and offloading vessel with 100,000 b/d of oil processing capacity from SBM Offshore NV. Another is for the drilling of 10 wells by the GlobalSantaFe Arctic 1 semisubmersible rig, now at work in the Gulf of Mexico.

The first phase of Block BC-10 development will involve Ostra, Abalone, and Argonauta fields. A fourth field, O-North near Argonauta, will be developed later. State-owned Petroleo Brasileiro SA (Petrobras), a partner, calls the area Parque das Conchas and estimates production will start in 2011.

Shell, the operator, will develop the fields with horizontal subsea wells and manifolds and tie each field back to the FPSO, which will be moored in 1,780 m of water. The longest tie-back will be 15 km for Abalone field.

A Shell statement called the project "the first full-field development based on subsea oil and gas separation and subsea pumping." Liquids will be separated from gas in large-diameter caissons. Electric submersible pumps on the seafloor will pump the liquids through steel lazy-wave risers to the FPSO, where oil and water will be separated. Equipment on the FPSO will be able to inject 75,000 b/d of water in the fields.

Gas will move through a 40-km pipeline to Jubarte.

Shell declared Block BC-10 commercial at the end of last year after drilling 15 exploratory wells and discovering reserves estimated at 400 million bbl of 16-24° gravity oil (OGJ, Oct. 2, 2006, Newsletter). The block is 120 km southeast of Vitoria in Espirito Santo state.

Interests are Shell 50%, Petrobras 35%, and Oil & Natural Gas Corp. 15%.

Chevron broadens scope for Nigerian fields

Chevron Nigeria Ltd. (CNL), operator of National Engineering & Technical Co. Ltd. (NETCO)—a wholly owned subsidiary of Nigerian National Petroleum Corp. (NNPC)—has authorized two units of Foster Wheeler Ltd. to carry out further design engineering for the Tubu and Madu oil field developments in permit areas OML 52 and OML 85, respectively, off Nigeria.

Foster Wheeler Energy Ltd. and Foster Wheeler (Nigeria) Ltd., through a joint venture agreement with NETCO, will evaluate the economics of the planned development and investigate possible configurations for surface facilities.

These two separate work programs will be carried out under an existing 3-year service contract between Foster Wheeler and NETCO via CNL.

The values of the two awards, which were announced at yearend 2005, were not disclosed.

Foster Wheeler (Nigeria) Ltd. is already working on the front-end design for the nonassociated gas wellhead platforms and pipelines portion of CNL's Olokola Gas Supply Project in Nigeria, said Director Anita Omoile.

Heritage conducts Kingfisher well test

Heritage Oil Corp., London, has completed two drill stem tests of the upper zone of the Kingfisher-1 well on Block 3A in Uganda.

The first test did not flow hydrocarbons to surface. However, the second tested two zones totaling 10 m over the interval from 1,783 m to 1,795 m, which flowed at a stabilized rate of 4,120 b/d of oil through a fixed 1-in. choke at a flowing wellhead pressure of 221 psi. The oil was light (30° gravity) and sweet with a low gas-oil ratio and some associated wax.

The test flow data suggest that when equipped for production, the well could flow at stable rates of about 5,600 b/d. It also indicated an extremely high permeability of more than 2,000 md.

The tests represented a secondary exploration objective for the well, which will be sidetracked. Drilling will now continue to the deeper primary objectives. It is expected to take a further 45-60 days to reach TD of 3,000-4,000 m. Test equipment will remain on location to test the primary target (OGJ Online, Oct. 16, 2006, Newsletter).

White Nile completes first phase of Sudan survey

White Nile Ltd., London, said it has identified several structures, including one site for drilling, after completing phase one of its seismic survey of Block Ba in southern Sudan.

The company said several prospects have been identified in the 1,800 sq km project area, including one large structure of more

than 50 sq km, which has been high-graded as an immediate drilling target. It said seismic data from the first phase of exploration have yielded a new understanding of the prospectivity of the Muglad basin's Jonglei subbasin. The data show a sedimentary section as thick as 7 km and rift structures suitable for forming hydrocarbon traps, the company said.

White Nile said it will procure a drilling rig and plans to spud the first exploration well in first-half 2007, when it also expects to start a new 2D seismic survey in the Pibor Post basin.

The company's Block Ba exploration and development program includes three exploration wells in 2007 along with further 2D seismic acquisition.

Medco to develop Gulf of Mexico well

Medco Energi US LLC plans in early 2007 to install a braced caisson or minimal structure on a well recently drilled on Mustang Island Block 758 in the western Gulf of Mexico.

The No. 1 well, drilled in 156 ft of water 50 miles east of Corpus Christi, Tex., encountered gas pay totaling 47 ft total vertical thickness in four horizons in the Miocene Marg A series between 8,200 ft and 8,900 ft. The well reached 9,200 ft TD.

The operator set 7⅝-in. production casing at 9,155 ft and suspended the well at the mud line. ✦

Drilling & Production — *Quick Takes*

Chevron brings on more production off Angola

Chevron Corp. subsidiary Cabinda Gulf Oil Co. Ltd. has begun oil production from the Landana North reservoir in the Tombua-Landana development area, Chevron's third operated deepwater development off Angola.

The Landana North-1 well on deepwater Block 14 was the first of 46 wells planned in the project. The well is tied back to the Benguela Belize—Lobito Tomboco compliant piled tower, which allows for early production as well as the gathering of important reservoir information.

The project lies 50 miles offshore in more than 1,200 ft of water and will employ a compliant piled tower with one subsea center. The projected peak production from the completed development is about 100,000 b/d of oil by 2010.

Interests in the project are operator Cabinda Gulf 31%, Sonangol Pesquisa e Producao SARL 20%, Eni Angola Exploration BV 20%, Total E&P Angola 20%, and GALP-Exploracao e Producao 9%.

Total unit enters next phase at Joslyn project

Deer Creek Energy Ltd., a recent subsidiary of Total SA, has started the commercial production phase of the Joslyn project in the Athabasca region, 60 km northwest of Fort McMurray, Alta. Deer Creek is an 84% interest owner and operator of the Joslyn lease.

This will be the first commercial production from Joslyn, for which cumulative production is estimated at around 2 billion bbl of bitumen.

The lease will be produced using both steam-assisted gravity drainage (SAGD) and oil sands surface mining technologies. The Joslyn SAGD development will bring production to 10,000 b/d of bitumen at plateau. After dilution, the bitumen will be shipped to a terminal on the Athabasca Pipeline.

Mining developments are planned for the first part of the next decade. An application for the first 100,000 b/d of bitumen via surface mining was submitted to regulatory agencies in February and currently is undergoing review.

Total also has a 50% working interest in the Surmont SAGD project, which is expected to begin production from its first commercial phase in early 2007 and reach plateau production of 27,000 b/d. The potential production from Surmont is more than 200,000 b/d.

Total's share of the aggregate production from Surmont and Joslyn should reach nearly 300,000 b/d in the next decade.

Dragon secures rig to drill off Turkmenistan

Dragon Oil PLC has signed a 2-year contract with Continental Industrial Supply Ltd. for use of the CIS-1 platform-based drilling rig.

Dragon said the rig will commence drilling a series of development wells in the Cheleken contract area off Turkmenistan in first-half 2007.

Dragon said the contract will enable it to operate several drilling rigs simultaneously in 2007. ✦

Processing — *Quick Takes*

Marathon reports Garyville expansion details

Marathon Oil Corp. disclosed processing-unit capacities in a report that its board had approved expansion of its Garyville, La., refinery, which the company announced a year earlier.

Marathon will spend an estimated $3.2 billion to add 180,000 b/d of crude capacity to the 245,000 b/d refinery (OGJ, Nov. 7, 2005, Newsletter).

In addition to a new crude and vacuum distillation unit, the project will add a 44,000-b/d delayed coker, a 70,000-b/d heavy gas-oil hydrocracker, a 65,000-b/d reformer, and a 47,000-b/d kerosine hydrotreater.

Marathon recently completed front-end engineering and design cost estimation and is working on permits from the Louisiana Department of Environmental Quality. It expects construction to begin in mid-2007 and operations to start in fourth-quarter 2009.

The Garyville facility, completed in 1976, is the last grassroots refinery to have been built in the US. Its expansion will boost total capacity of Marathon's seven refineries to 1.154 million b/d.

Separately, Marathon selected Dresser-Rand Co. for the supply of compression equipment for the planned expansion. The estimated

total order value, including installation, commissioning, and start-up services, is expected to approach $68 million.

Dresser-Rand in October booked an order to supply critical compression equipment, including six DATUM turbo-compressor trains and eight reciprocating compressor units along with their drivers.

CEPSA awards FEED contract for Spanish refinery

Compania Espanola de Petroleos SA (CEPSA) has let a lump-sum contract for an undisclosed amount to Foster Wheeler Iberia SA for front-end engineering design and early procurement services for crude, vacuum, and gas concentration units at its 100,000 b/cd La Rabida Refinery at Huelva, Spain.

The new units will be based on a basic design package by UOP, a Honeywell company. The capacity for the crude distillation unit will be 90,000 b/sd; for the vacuum distillation unit, 30,500 b/sd; and the gas concentration unit, about 148 tons/hr.

OMV plans petrochemical expansion in Bavaria

OMV AG will boost petrochemicals capacity as part of a €1.1 billion investment program in Bavaria over the next 4 years.

It plans to expand ethylene capacity to 450,000 tonnes/year from 340,000 tonnes/year and propylene capacity to 560,000 tonnes/year from 245,000 tonnes/year at its complex in Burghausen.

The expansion projects will absorb €640 million of the overall expansion budget while another €495 million will be committed to OMV's share of the Bayneroil joint-venture refinery network and filling station business.

In the olefins expansion at Burghausen, OMV will build a metathesis plant, enlarge its ethylene plant, and construct a large cracking furnace. It will become sole supplier of propylene to the nearby plastics complex operated by its subsidiary Borealis. The Borealis complex will be expanded with construction of a €200 million, 330,000-tonne/year polypropylene plant. Total polyolefin capacity at the complex will rise to 740,000 tonnes/year. The new plant will use OMV's Borstar technology.

OMV also plans to invest €150 million to lay a 360-km products pipeline between Munchmunster and Ludwigshafen, giving it access to the Western Europe ethylene network. The pipeline will have an initial capacity of 200,000 tonnes/year, expandable to 400,000 tonnes/year.

Other spending planned by OMV in Germany includes €315 million for its share of investment in the upgrade and restructuring of the Bayernoil joint-venture refinery network and €180 million for retail network expansion. ✦

Transportation — *Quick Takes*

KMEP again to expand products pipeline

Kinder Morgan Energy Partners LP plans to invest $388 million to further expand the 550-mile CALNEV pipeline, which transports gasoline, diesel, and jet fuel from California to Nevada.

The proposed expansion, involving construction of a 16-in. pipeline from Colton, Calif., to Las Vegas, Nev., will increase the system's capacity to 200,000 b/d. The company said a further capacity increase to more than 300,000 b/d is possible with the addition of pump stations.

The new pipeline will parallel existing utility corridors between Colton and Las Vegas to minimize environmental impacts. It will transport gasoline, diesel, and jet fuel for the military at Nellis Air Force Base.

Subsequently, the existing 14-in. line will be dedicated to commercial jet fuel service for McCarran International Airport and any future commercial airports planned in Las Vegas and the 8-in. pipeline that currently serves the airport would be purged and held for future service.

Construction of the 16-in. line is expected to be completed in 9 months, following environmental permitting and right-of-way acquisition, expected to take 24-30 months.

Pending Federal Energy Regulatory Commission approvals, startup of the line is scheduled for late 2009 or early 2010.

This major expansion project is in addition to three capital upgrades on the CALNEV system, announced earlier this year. Two of these projects, when completed, will increase the line's capacity to 156,000 b/d. The third involves construction of additional tanks that will increase gasoline and diesel storage at Las Vegas by 26% and 20%, respectively. The expansion projects combined are valued at $413 million.

Tom Bannigan, president of KMEP's products pipelines group, said the company is also gauging customer interest in construction of a new refined products distribution terminal south of Henderson, Nev.

CB&I lets contract for South Hook LNG terminal

CB&I John Brown Ltd., The Woodlands, Tex., has awarded the UK's Cape PLC a contract on the South Hook LNG terminal construction project at Milford Haven, Wales, UK.

Cape said it will provide the "common user access service" for the main process unit on the terminal, which is due to be completed by winter 2007-08.

The South Hook terminal will be owned and operated by South Hook LNG Terminal Co., a joint venture of Qatar Terminal Co. Ltd. and ExxonMobil Qatargas (II) Terminal Co. Ltd.

In November 2004 CB&I was awarded a lump-sum turnkey contract with a value estimated between $725-750 million for Phase 1 of the South Hook grassroots LNG import terminal.

In March 2005 South Hook LNG awarded CB&I a lump-sum turnkey contract for Phase II of the LNG import terminal.

LNG for South Hook will be supplied from the Qatar Liquefied Gas Co. Ltd. (Qatargas II) LNG plant being built at Ras Laffan Industrial City in Qatar.

Qatargas II will supply 15.6 million tonnes/year of LNG to the UK for 25 years, with the first deliveries expected in winter 2007-08.

Gas for Qatargas II will come from Qatar's North field, which has recoverable gas resources in excess of 900 tcf. ✦

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IADC/SPE Asia Pacific Drilling Technology Conference, Bangkok, (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 13-15.

Gulf Coast Well Control Conference, Houston, (979) 845-7081, (979) 458-1844 (fax), e-mail: kharli@pe.tamu.edu, website: http://WellCTRL.org. 15-16.

Annual Unconventional Gas Conference, Calgary, Alta., (403) 218-7721, (403) 920-0054, e-mail: info@csug.ca, website: www.csug.ca. 15-17.

European Biofuels Forum, Warsaw, 0044 20 7067 1800, 0044 20 7430 9513 (fax), e-mail: c.taylor@theenergyexchange.co.uk, website: www.wraconferences.com/wra112overview.html. 21-22.

PETEX Conference & Exhibition, Olympia, London, +44 (0)20 7408 2000, +44 (0)20 7408 2050 (fax), e-mail: petex@pesgb.org.uk, website: www.pesgb.org.uk. 21-23.

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DECEMBER

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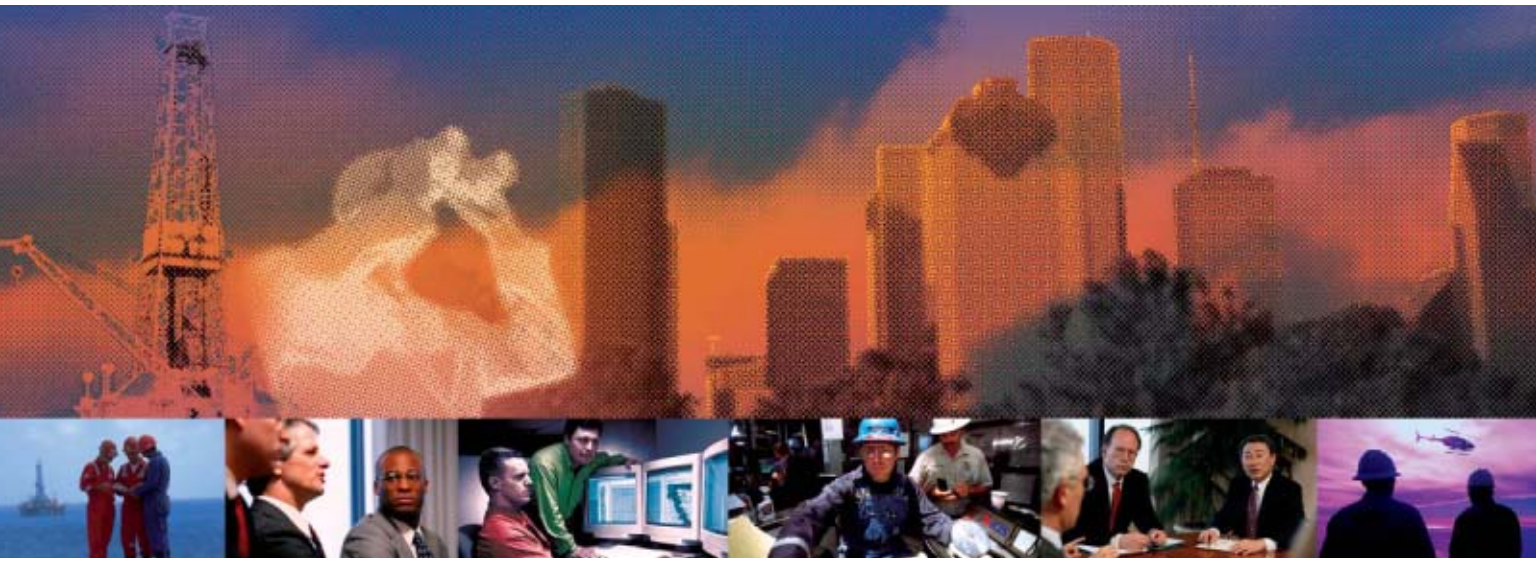

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Journally Speaking

Managing oil dependency

Judy R. Clark
Senior Associate Editor

The timing may be right.

As US midterm election results indicate a turnover in congressional power and the electorate's calls for "change" are still rattling the political parties, the Council on Foreign Relations (CFR) is issuing this month a report urging that energy issues henceforth be better integrated into other aspects of US foreign policy because oil dependency is compromising national security.

The report—"National Security Consequences of US Oil Dependency"—explains "why and how" to accomplish that integration, said CFR Pres. Richard N. Haass as he introduced the independent task force report.

The report concentrates on the next 20 years and focuses mainly on oil, much of which comes from politically unstable areas of the world. Dependence "puts the US into competition with China, India, and other importing countries, which can challenge US foreign policy or strain relations with these countries," said the task force.

In addition, major suppliers, such as Russia, Iran, and Venezuela, are using oil and gas exports to pursue strategic and political objectives, and major consuming countries are finding that dependence on imported energy is circumventing their ability to pursue foreign policy and national security objectives.

Common myths

The report debunks common myths of US energy policy and outlines a strategy for responding to foreign policy issues arising from dependence on energy traded in world markets.

One such myth is the feasibility of achieving energy "independence" through increased drilling "or anything else." Such a goal, which "encourages the adoption of inefficient and counterproductive policies," is unachievable for at least several decades, CFR maintains.

Another myth is that policies to decrease imports will lead to lower prices and that cheap energy alternatives will be readily available. Although prices may moderate to a degree, they will not return to the low levels seen in the 1990s, and it will take years to develop sufficiently economic energy alternatives.

And large Western companies do not control the price of oil, another myth. They control a fraction of the hydrocarbon reserves that national oil companies do.

A fifth myth, the report says, is that the world can "drill its way" out of its oil supply and price problems. The costs of developing and producing remaining reserves will be higher than those of existing reserves.

Strategies

The real problem is the high and growing demand for oil, and the challenge facing the US for the next few decades is to develop policies that better manage its dependencies rather than vainly pursuing independence, CFR said.

Because the US has "limited leverage to achieve its energy security objectives through foreign policy actions, it has considerable ability to manage its energy future through the adoption of domestic policies," task force members said. The task force recommended a three-step policy strategy to slow and eventually reverse US oil consumption:

- A gasoline tax that would fund energy technology research and development.
- Stricter corporate average fuel economy (CAFE) standards.
- The use of tradable gasoline permits that cap the total level of gasoline consumed.

In addition, high energy prices are opening doors to innovation in withdrawing and marketing formerly "stranded" natural gas, which could replace oil use for home and industry use. The task force does not see a need to limit gas use.

Ultimately, CFR said, technology will be key to reducing dependence on oil and gas but only if investment is made available for its development. High energy prices help fund such technology development, but the task force recommends that the federal government expand incentives and investments for higher-efficiency vehicles; the use of biomass, electricity, and other oil transportation substitutes; enhanced production techniques; and efficiency-enhancing technology in industrial processes.

A second strategy is for the US to encourage efficient, transparent, and fair operation of world oil and gas markets; revise cooperative agreements reached in the 1970s; and remove protectionist tariffs on imported ethanol.

A third strategy: Reduce infrastructure vulnerability to terrorist attacks and natural disasters.

Fourth: Promote better management of revenues, and work to improve the social and economic prospects of the public.

And fifth: Better address the threats to national security created by energy dependence. Organize government resources to ensure attention and integration of the political, economic, technological, and security elements required for energy policy-making.

CFR has no affiliation with the US government. ✦

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Editorial

After the US elections

Instead of talking and not acting on meaningful energy supply, Congress now will stop talking. That's the biggest change likely to come from takeover by the Democratic Party of the House and maybe Senate in the Nov. 7 congressional elections. The Democrats will talk about energy supply, of course—just not meaningful supply. If they manage in the 110th Congress to implement any of the priorities they set for the 109th, the only thing meaningful about what they achieve will be uncompensated cost.

The priorities appear in a document entitled New Direction for America, produced while Rep. Nancy Pelosi of California, the new speaker of the House, was leader of the opposition party. Among her promises in a cover letter was "to energize America with energy independence." Random specifics follow, but the slogan itself sets the unrealistic tone.

Energy independence

The US won't achieve energy independence. If it produced every quantum of energy it needed, which it never will do, it still would not be energy-independent. It can't shut itself away from global economic forces, powerful among which are conditions in the international energy markets. National leaders should quit pretending otherwise.

The Democrats' document sets a specific goal of "eliminating reliance on oil from the Middle East and other unstable regions of the world" by 2020. This is a feel-good expression of the energy-independence fantasy. The US can refuse to buy oil from Middle Eastern producers and any other supplier of its choosing and still, because the oil market is global, be reliant on them. Just as the US would have to seek out new sellers, the targeted sellers would sell to new buyers. The imposed dislocation thus would raise transport costs. That's all.

From futile goals arise faulty strategies: "Increase production of alternate fuels from America's heartland, including biofuels, geothermal, clean coal, fuel cells, solar, and wind; promote hybrid and flex-fuel vehicle technology and manufacturing; and enhance energy efficiency and conservation incentives," the Democrats say. This is the venerable "renewables-and-conservation" pincers movement, which can alter the energy mix to whatever extent consumers and taxpayers are willing to spend money on it.

So how much extra cost and new tax burden do Democrats—or like-minded Republicans—think Americans will devote to vapid ambitions like energy independence? If memory serves, motorists didn't favor $3/gal gasoline earlier this year. Supply from the energy-form wish-list costs much more than that. Subsidies just paper over the economic corrosion. Trying to pry more contributions from renewable sources and conservation than evolve naturally in the market is always an expensive mistake.

Congress once debated these issues in the context of market realities. But Republicans have abandoned economic discipline in an ideological lapse that partly explains the shellacking they brought upon themselves in the elections. Too many of them now chase the same energy chimeras the Democrats do. Consumers should be worried. And the oil and gas industry should be resisting the nonsense by focusing on the threats to consumer interests.

Beyond the fuel-choice blather, the New Direction for America proposes to "end tax giveaways to Big Oil companies and enact tough laws to stop price-gouging." This is big and empty talk. Industry should call the hand. What are the "tax giveaways" that big oil companies supposedly enjoy? How do they measure up against, say, tax incentives for ethanol and biodiesel? And what, exactly, do Democrats mean by "price-gouging?"

Windfall profit tax

Democrats also might try to breathe new life into a windfall profit tax on oil. On Nov. 7, however, Californians showed, by defeating an initiative to tax oil production to pay for renewable-fuel programs, that they recognize the folly of taxing away domestic oil production. Most other Americans have similarly good sense.

The new power mix won't yield legislation to lease off-limits federal acreage in Alaska or on the Outer Continental Shelf. But the old mix didn't either. Maybe Republicans shorn of majority prerogatives will rediscover the efficiency of markets and the benefits of domestic oil and gas production. If so, the election results will have been good for Americans. ✦

WoodMac: Arctic has less oil than earlier estimated

Sam Fletcher
Senior Writer

The entire international Arctic region contains "much less" potential petroleum resources, with a mix of more natural gas, than previously estimated, according to a joint study released Nov. 1 by Wood Mackenzie Ltd., Edinburgh, and Fugro Robertson, part of the Fugro group of companies based in the Netherlands.

Using detailed geoscience analysis of individual basins and their petroleum reserves "ground-truthed" via industry data on exploration wells and exiting discoveries, the study indicates only a quarter of the oil volumes previously estimated in key Arctic basins in North America and Greenland. Moreover, it concludes that the Arctic is primarily a gas province, with natural gas accounting for 85% of the discovered resources and 74% of the exploration potential in that northernmost region of the globe. Under the study's most likely scenario, the Arctic is projected at its peak in 20 years to produce 8 million boe/d, split 40:60 of oil and gas, with the proportion of production from US basins lower than previously anticipated.

"This assessment basically calls into question the long-considered view that the Arctic represents one of the last great oil and gas frontiers and a strategic energy supply cache for the US," said Andrew Latham, vice-president of energy consulting for Wood Mackenzie and lead author of the study. "These findings are disappointing from a world oil resource base perspective," he said. "The oil-gas mix is not ideal because remote gas is often much harder to transport to markets."

Moreover, Latham said, "Export and technology constraints are expected to delay production of a large portion of the commercial gas until 2050." The largest resource plays may not generate the highest returns because they are gas prone or cannot be readily monetized due to constraints on available export infrastructure, he said.

As a result, the study said the US "must look elsewhere to meet rising demand," including member nations of the Organization of Petroleum Exporting Countries "such as Venezuela," and to Russia—areas of "broader, geopolitical concerns relating to security of supply."

This study is the first overall assessment of the Arctic's total oil and gas potential by Wood Mackenzie or anyone else, Latham said. "Nobody has done it all, not even the US Geological Survey," he said.

"While these results are disappointing to the US as a whole, the Arctic still holds great potential for individual oil and gas companies with the advanced technology, money, and time to develop the challenging resources and build the infrastructure required to transport it," Latham said. There are economically attractive opportunities in many areas of

the Arctic. Three key factors drive high full-cycle returns potential in individual cases: a predominance of oil rather than gas, short production lead times, and proximity to export routes. (A more detailed look at these opportunities appears in Exploration & Development, p. 31).

"The chance to lead in cutting-edge technologies and to access world-class volumes make many of the opportunities attractive for the largest companies. For the intermediate and smaller-scale players, there are niche opportunities in plays for those willing to take a risk on frontier exploration," Latham said.

'Yet-to-find resources'

Many of the Arctic basins already have world-class discovered resource volumes totaling 233 billion boe. Beyond that, the Wood Mackenzie-Fugro Robertson study assessed yet-to-find resource potential of 166 billion boe. The South Kara-Yamal basin and the East Barents Sea in Russia, along with Greenland's Kronprins Christian basin, have yet-to-find resources greater than 10 billion boe, the study reported. "Only the South Kara-Yamal basin and the East Barents Sea offer the majority of yet-to-find potential in pool sizes of over 1 billion boe," the report said.

Most of those yet-to-find resources are in either ice-free or seasonal ice areas offshore or in the onshore areas of the basins, according to the study. "The engineering challenges away from the permanent ice zone are less daunting, with emphasis on cost and efficiency improvement of existing technologies rather than radical new solutions. Subsea technologies will unlock the greatest share of resources," it said.

The cost of Arctic operations is high, driven by extreme transportation costs, with wide variation between basins. "Average field development costs of around $6/boe are comparable with many other parts of the world. High costs elevate average development breakeven prices across the Arctic to above $30/boe," said the report.

It said there are attractive niche opportunities in many basins where the breakeven price of the largest fields are much less than average, below $20/bbl in some cases. Two basins—the North Slope in Alaska and Russia's Pechora Sea—achieve exploration full-cycle returns greater than 20%. "These are both oil-prone basins with good access to markets via pipelines and ice-free seas," Latham said.

All five host governments with oil and gas holdings in the Arctic—the US, Canada, Greenland, Norway, and Russia—favor exploration by foreign and domestic companies. Competition in that region "is lower than in other resource plays of comparable scale," and no preeminent "pan-Arctic champion" has yet emerged, said Latham. "Infrastructure will be key to success in many parts of the Arctic, and local infrastructure owners already hold strong advantages in the more-developed basins."

Future license rounds will indicate the industry's appetite for Arctic exploration, along with application of technology and development of export infrastructure, he said.

Nearly three quarters of the yet-to-find liquids resources and half of the yet-to-find gas resources are potentially commercial under the base-case price scenario, with Arctic adaptation of proven technology, Latham said. ✦

Hurricanes spotlight jack up design, placements

Sam Fletcher
Senior Writer

The storm magnitudes of Hurricanes Katrina and Rita exceeded the design criteria of most of the jack up rigs caught in their paths through the central Gulf of Mexico, said industry experts at a recent Houston workshop sponsored by the International Association of Drilling Contractors.

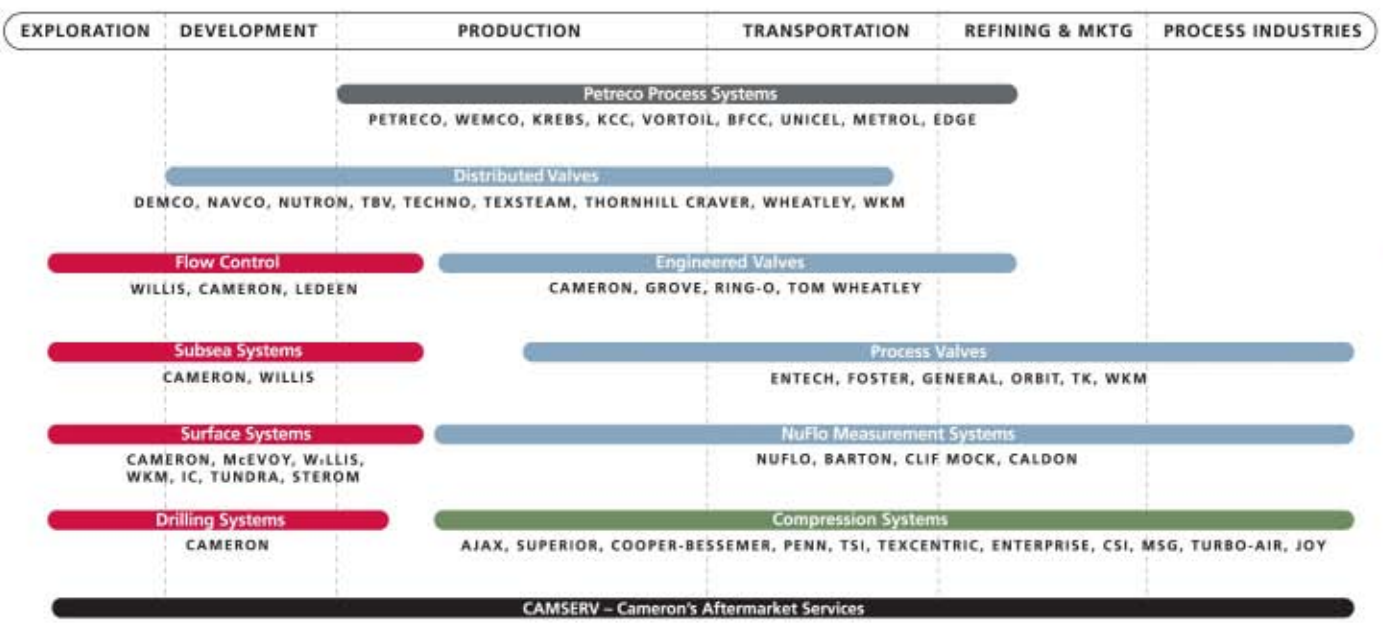
Some 12% of the gulf jack up rig fleet was lost or moved off locations as those two hurricanes cut through the central gulf within 24 days of each other in August-September 2005. The primary causes of those rig movements and losses were wind and currents, wave inundation, and foundation or soil movement, officials said. The best news, industry sources agreed, is that there was no loss of life, no threat to safety, and only minimal environmental impact. That validates the "shut in and evacuate" response to hurricanes, said offshore veterans.

Assessments of the three worst hurricanes to hit the oil and gas areas of the Gulf of Mexico in recent years—Katrina and Rita in 2005 and Ivan in 2004—confirm that the magnitude of those storms exceeded the criteria of all jack ups that were destroyed or floated ashore, said Alberto Morandi, executive vice-president of American Global Maritime Inc., Houston. Storm magnitudes also exceeded all of the rigs that survived "in every case but one," he said.

The lone exception was Rowan Cos. Inc.'s Class 224C cantilevered Super Gorilla jack up "Bob Palmer," named for Rowan's Chairman Emeritus C.R. "Bob" Palmer. Outfitted with 713 ft legs, 139 ft more than the company's late-model Gorilla rigs, and with 30% larger spud cans, the Super Gorilla can work in 550 ft of water in the Gulf of Mexico.

Otherwise, Morandi said, "no one parameter" determined which rigs failed and which survived the three worse hurricanes. "There were rigs in shallow water that failed, rigs in deeper water that survived and rigs that exceeded their vertical reaction and survived," he said. Among both survivors and wrecked units, there was "a combination of different factors," he said.

"One MTL 166C rig was subjected to hurricane loading that was 80% over its


EXPLORATION
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Petreco Process Systems
PETRECO, WEMCO, KREBS, KCC, VORTOIL, BFCC, UNICEL, METROL, EDGE
Distributed Valves
DEMCO, NAVCO, NUTRON, TBV, TECHNO, TEXSTEAM, THORNHILL CRAVER, WHEATLEY, WKM
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design load. The combination of large (96 ft) penetration (high fixity) and high soil reserve strength contributed to the rig's survival without damage," Morandi reported. On another jack up that was lost, there was "clear evidence" on the sea floor that the spud can had dragged out of the can hole, creating stress that caused the rig to overturn, he said.

Both rig survivals and losses "can be largely explained in terms of a combination of higher or lower reserve strength, favorable or unfavorable soil conditions, and favorable or unfavorable storm headings," Morandi said. "Leg settlement may have contributed to wave impingement on the deck, further increasing the total load."

He said, "An air gap of 60-62 ft would have been sufficient to clear the hurricane crests, with some allowance for leg settlement (water depth over 80 ft). This would also be in agreement with an additional number of locations investigated by the LeTourneau Inc. Marine Group. [It is] also in agreement with fixed platform observations."

Historically, design limits for elevated jack ups are determined via class-approved benchmark storms. The American Bureau of Shipping's code requires mobile offshore drilling units to be designed to withstand a storm wind velocity of 100 knots for unrestricted offshore service. Other parameters include water depth, wave height and period, air gap, spud can penetration, and current velocity. "The combination of such parameters has to be such that adequate safety factors are met for relevant failure modes," said Morandi.

In practice, however, the benchmark storm parameters do not reflect site-specific soil conditions or air gap requirements and are not directly related to a return period storm load or a Saffir-Simpson Hurricane Scale. Therefore, Morandi said, "A site-specific assessment is needed, which can be performed at different levels of detail."

Designing jack ups is "a very complex task with a lot of trade-offs," Morandi noted. The complexity of industry and regulatory standards is an important factor, especially in today's "very tight" market for experienced engineers. Such specialized knowledge is more important as standards become more and more complex, he said.

Regulators and drilling contractors are looking harder at installation issues as well. "Jack ups are tremendously affected by soil conditions, which can lead to shallow penetrations and other problems," Morandi said.

With strong soil structure, a jack up rig can take more of a storm load than it was designed for, he said. However, he said, "Once one leg fails, the other two will go."

ABS guidelines

The American Bureau of Shipping plans to publish by yearend new guidelines for the inspection of mobile offshore rigs more than 20 years old, said Chris Serratella, ABS director of operational safety and evaluation, at the Oct. 19 workshop.

Current recommendations for new guidelines include more-detailed, close-up survey, nondestructive testing, and thickness gauging of major joints and fatigue-sensitive areas under survey plans that rig owners would create and submit to ABS prior to inspection. These will "ensure that critical areas are surveyed in proper sequence using appropriate techniques," Serratella said.

More emphasis should be placed on corrosion and coatings maintenance, "especially of internal surfaces." Critical inspection areas on jack ups include legs, leg well areas, spud cans, cantilever push-up and hold-down structures, crane pedestal connections, mud pits and preload tanks for corrosion.

Moreover, ABS is compiling inspection and wear data on "any rig or rig design where we have enough history that we can go back and pinpoint the critical areas that we need to look at," Serratella said. "Rather than just look at specific rigs, we would look at the rig design and all the information that ABS gathers on those rigs, then turn around and give that as guidance to the surveyors."

Conversely, he said, ABS wants to help inspectors "stop wasting time" on close inspection and analysis of areas that "never show any problems" despite frequent inspections and instead focus on those areas with an evident history of problems. ✦

Gas Summit analyzes European Union gas supply-demand issues

Doris Leblond
OGJ Correspondent

Two new features this year marked the 11th Gas Summit held Oct. 26-27 in Paris and organized by Pétrostrategies consultant and publisher, Institut Français du Pétrole, oil and gas consultants SPTEC, and Poten & Partners Inc.

For the first time, no ministers or officials attended, and discussions took place among industry leaders alone with few political overtones. New entrants to a liberalized gas and electricity market were invited to explain difficulties encountered accessing that market, which is still dominated by incumbents.

Even giant electricity provider Electricite de France (EdF) seemed hindered in its attempts to enter the chain from upstream development to downstream distribution. Dominique Venet, EdF executive vice-president, gas, complained that the incumbents hold existing import and transportation capacities, and new players "have to find their way through the transit jungle." At the other end of the scale, Claude Gianotti, director of the small Swiss-based trader WorldEnergy SA, described the "hard life of new entrants" competing for both supply and consumption and seeking a fairly regulated EU market.

Demand to drop

In the wake of uncertainties expressed at last year's Gas Summit on

whether soaring prices would slow expected gas growth, industry leaders attending this summit noted there were indeed signs of demand destruction, at least in Europe. By 2030, gas supply might well be reduced by 50 billion cu m from established forecasts, ventured Patrick Walliez, gas advisor to the CEO of Suez.

Energy savings of 20% required by the EU Commission before 2020 and rising greenhouse gas emission concerns should also take their toll on gas growth rates, pointed out Gaz de France Chief Executive Officer Jean-Marie Dauger. It was generally expected that gas would continue to play a major role in the energy mix but would face growing competition from nuclear power and coal for the expanding electricity sector, as all sources will be required to meet demand.

Supply concerns

On the supply side, companies were surprisingly less worried than politicians about the short and medium term but were more interested in solving the technical hurdles to uninterrupted supply. They were concerned about the political turn the market has been taking and its impact on the implementation of the huge investments that will be needed to sustain and develop production and transport infrastructure. They also were in favor of stronger partnerships, dialogue, and even interdependence with gas-producing countries.

Italy was one of the counties hardest hit by Russia's interruption of supplies during the Ukraine crisis last January. ENI Gas & Power Division's Chief Operating Officer Domenico Dispenza aptly summed up the situation when he said: "Security of supply is caught in the middle of the various forces that are currently reshaping the market. These various forces consist of supply challenges, the need for a panEuropean infrastructure, gas and power convergence, mergers and acquisitions, and regulatory harmonization."

He was echoed by Iberdrola's gas unit director Conrado Navarro, who specified the need for investments in cross-border capacities, cooperation between transmission system operators of neighboring member states, supply diversification, interconnections, development of interruptible demand, and storage capacity.

Officials of most companies, such as Edison SPA's hydrocarbon group Senior Adviser Luciano Sgubini, called for a "stable and regulatory framework" as well as strong incentive policies for investing in new pipeline and regasification plants as well as increased European-wide storage capacity. The current lack of storage and easy access to it by all EU members was seen as preventing the introduction of strategic gas stocks in the European Union to deal with potential supply disruptions.

Supply security, all summit participants agreed, also required diversification of sources achieved through increased recourse to LNG trade, which is becoming increasingly globalized but as yet not "commoditized." Shell's David Wells, vice-president, global energy supply, described it as "the lubrication in the global gas industry."

Speakers—Rune Bjornson of Statoil ASA, Hydro Oil & Energy's Vice-Pres. Torstein Indrebo, and Sonatrach's Marketing Vice-Pres. Chauwki Mohammed Rahal—sought to dissipate supply security fears by demonstrating that the range of their new projects kept them in the "reliable long-term suppliers" category.

Rahal was particularly anxious to dispel fears raised by Sonatrach's partnership agreement with Gazprom that was signed at a crucial period of the EU's energy security worries. He insisted it was "a normal agreement such as was already signed with many other international companies," and was intended for the development of joint projects in Russia.

He listed Sonatrach's "contribution to security of supply for Europe" and indicated that, besides its existing six LNG carriers, Sonatrach would have two additional Medimax carriers in operation between 2007 and 2008 and two Atlantic Max vessels on stream in 2008-10. A planned 8 billion cu m/year gas pipeline to Spain, "on the verge of taking off," is due on stream in 2009, and "significant developments" for an 8 billion cu m/year gas line to Italy through Sardinia, is scheduled to be on stream around 2010.

However he said that Sonatrach, like Gazprom, did not want to remain a mere gas supplier but was planning to enter Europe's marketing sector through the establishment of subsidiaries in the UK, Spain, and Italy and would participate in added combined-cycle gas turbines and distribution facilities. ✦

UKOOA urges tax change to boost UKCS production

Uchenna Izundu
International Editor

The UK government must change the fiscal regime to ensure production of the 27 billion bbl of oil and gas equivalent that might be recoverable from the UK Continental Shelf (UKCS), Malcolm Webb, chief executive of the UK Offshore Operators' Association (UKOOA), said Nov. 7.

Webb warned at UKOOA's annual conference in Aberdeen that the UK needs a "radical review" of the extraction of oil and gas if it is to remain competitive in attracting investment.

Increasing UK production—which will require investment of £300 billion ($568.9 billion)—must become a priority, he said, or the UK would spend billions importing oil and gas. He stressed that it is "no given" that this investment will be made unless the regulatory and tax regime accom-

UKOOA: Skills shortage worries UK oil industry

Uchenna Izundu
International Editor

An acute lack of skilled engineers and technologists is threatening the development of the UK Continental Shelf (UKCS), speakers warned Nov. 7 at the UK Offshore Operators' Association (UKOOA) industry conference in Aberdeen.

The estimated 27 billion bbl of oil and gas remaining in the mature province will require £300 billion to produce, and engineers will be needed to develop innovative solutions to extract the oil and gas in difficult areas, UKOOA Chief Executive Malcolm Webb said. As one solution, Webb urged participants to recruit more women into the industry to help ease the skills shortage. Women currently comprise about 5% of the offshore workforce.

Oil and gas industry skills body, OPITO, will work closely with the UK petroleum industry to create a fast-track skills program and develop a sustainable workforce. It will focus on creating upskill programs for new entrants and existing workers, drawing up labor development frameworks for specific sectors, and launching a communications program to inform potential recruits that the petroleum industry offers exciting and stimulating career paths.

Ian Dundas, head of the Industry Leadership Team's Workforce Capacity and Capability Workgroup, said: "While we are confident that the supply chain is using everything at its disposal to meet the demand for plant and equipment we are not seeing the same use of industry-developed solutions to alleviate the skills issues. If we are to develop the tools, we must be certain that they are appropriate and relevant and that the industry will use them to deliver results."

Over the last 12 months, OPITO and its industry partners have invested more than £2 million in developing new pan-industry skills solutions through the accelerated projects.

According to Ian McCafferty, chief economic advisor at the trade body Confederation of Business Industry, the UK is seriously struggling to develop a skilled workforce compared with other nations in Europe, and in China and India. Although the UKCS has been at the forefront in developing innovative technology to produce oil and gas, it cannot be complacent, said Tom Botts, Shell's executive vice-president for Europe.

"Ten years ago the depth of wells was limited because they were drilled like telescopes—inserting pipes of decreasing diameter within each other as the well deepened. Today we've found solutions using expanding tubulars that expand the pipe in the ground, allowing for deeper and productive wells," he added.

Over the past 10 years, fewer young people have opted for sciences at A-level, the exams that students take to enter UK universities, and they have shunned the subject at degree level. Since the oil price crash in the late 80's, the general public has viewed the industry as one in decline, and this perception has been difficult to dispel despite recent record energy prices.

Energy companies in Aberdeen have begun visiting schools to share information with students and teachers about career progression and their operations to persuade young people to study the sciences.

modates resource maturation and high production costs of the UKCS.

In December 2005, Gordon Brown, chancellor of the exchequer, shocked the UK oil industry by doubling the supplementary corporation tax rate on oil and gas production to 20% in a move that pushed the total corporate tax on production begun after 1993 to 50% and on older production to 75%. UKOOA said the change has reduced the value of new investment in the UK by around 16%. Webb criticized the Treasury's reluctance "to engage in any commitment beyond the existing Parliament."

Over the 40 years that the UKCS has produced hydrocarbons, energy companies have invested £350 billion to recover 35 billion bbl of oil and gas equivalent.

"It is a foolish deception not to recognize that the UK is and will remain a petroleum economy for the foreseeable future and that to the extent we do not produce our oil and gas we will have to import it," Webb warned.

Oil and gas will remain central to UK energy policy, currently supplying 75% of the nation's energy demand. This is expected to rise to 80% by 2020, and gas will provide over half of the UK's electricity needs by 2020. Webb said, "We could still be producing 60% of the nation's needs for oil and 25% of its needs for gas in 2020 and continue to produce both in significant volumes for decades thereafter."

Other challenges facing North Sea oil and gas production are rising costs, resource constraints, and an aging workforce (see related story, this page). Webb called for an integrated approach by the government to energy.

"Might not a rationalization of the various energy groups currently spread all across the government into one energy department result in a better focus and a more efficient use of resource?" he asked. He urged the government to simplify decommissioning of obsolete offshore equipment. And he said the government's ready acceptance of some European energy and environmental rules has damaged the UK petroleum industry. ✦

Foreign oil firms agree to Bolivia's contract terms

Peter Howard Wertheim
OGJ Correspondent

Bolivian President Evo Morales claimed a victory Oct. 29 when key foreign energy companies agreed to remain in Bolivia, operate under state control, and cede larger shares of profits to the government.

The deals strengthen Morales's bid to give Bolivia a larger role in its own economy: It has the continent's second-largest natural gas reserves after Venezuela yet remains South America's poorest country.

With these new contracts, Juan Carlos Ortiz, president of Bolivia state-owned Yacimientos Petrolíferos Fiscales Bolivianos (YPFB), estimated that the state will receive an additional $1.3 billion/year in revenues. Morales said these revenues could be increased to as much as $4 billion within 4 years, when Bolivia begins exporting 30 million cu m/day of gas to Argentina.

According to Ortiz, the contracts also guarantee that the country will receive investments of as much as $2 billion. They came 10 days after Morales and Argentine President Nestor Kirchner signed a $17 billion deal significantly expanding Bolivia's gas exports to Argentina over the next 20 years.

Ortez said the former contracts, which granted ownership of hydrocarbon production and commercialization for the investor companies, violated the Bolivian Constitution but now can be approved by the Legislative. Now YPFB takes on a more preponderant role in the commercialization of hydrocarbons produced (OGJ Online, Nov. 1, 2006).

Henceforth, YPFB will supervise operations of foreign oil companies more closely and will participate in the administration of the fields, accompany the accounts through quarterly reports, participate in profits, supervise tender bids for goods and services, grant approval for the value of operating costs and capital expenditures, becoming "more like a partnership," said Brazilian governmental authorities.

Ortiz added that the megafields will yield government take above 80%, although there will be variations, while smaller fields will yield less than 80% but more than 50%, defined on a case-by-case basis, according to production capacity and other conditions. The contract period for fields with lower production also varies, from 22-31 years.

Company reactions

While Petrobras is the largest gas producer in Bolivia, Repsol YPF SA and its subsidiary Andina control the largest share of Bolivia's known 55 tcf of gas reserves, with 35%. Petrobras controls 16% and Total SA, 14%.

The new contract will allow Petrobras an average earning capacity of 15% over E&P activities, "way above our capital costs," said Petrobras Pres. José Sergio Gabrielli. Petrobras maintained its rights to explore on the Rio Hondo, Ingre, and Irenda blocks but did not change its contracts related to the exportation of 26 million cu m/day of gas from Bolivia to Brazil. Negotiations over the gas price are set to resume next month in Rio de Janeiro.

The two countries also have not yet agreed on the price for indemnity due to nationalization of two Petrobras-operated refineries that process a total of 60,000 b/d of oil: Gualberto Villarroel (Cochabamba) and Guillermo Elder Bell (Santa Cruz de La Sierra). Petrobras bought the plants 7 years ago for some $100 million.

The Spanish press quoted Repsol YPF Chairman Antoni Brufau as saying its agreement clarifies past uncertainty "and allows us to invest with the necessary legal safeguards, validating the interests we already have." Repsol YPF and Bolivian subsidiary Andina have invested $1.17 billion in the country.

BG Group PLC, which has invested £100 million in Bolivia and produces 60 MMcfd of gas, said the new contract assures a return on current investments, but "new investments will be analyzed on a case-by-case basis."

Morales said on Oct. 28 that Total also would remain and spend about $2 billion exploring for and producing gas from three large fields.

The contracts signed with 10 foreign oil companies will now be submitted to the Bolivian Congress for ratification. ✦

Chavez again threatens to stop oil exports to US

Peter Howard Wertheim
OGJ Correspondent

Venezuelan President Hugo Chavez has threatened to cut oil sales to the US if it does not recognize the results of Venezuela's December presidential election or if irregularities mar the vote, or state oil company Petroleos de Venezuela SA (PDVSA) faces "destabilizing" actions.

A president will be elected for a 6-year term beginning Jan. 10, 2007, and Chavez is running for re-election.

Chavez repeatedly has said that he wants Venezuela to diversify its customers and reduce its dependence on the US market. The US currently takes about 60% of Venezuela's 2 million b/d of oil production.

Venezuela sent 178.2 million bbl of crude and petroleum products to the US for the first 4 months of 2006, down from 190.1 million bbl for the same period in 2005.

Halting oil exports to the US today would mean losing 70% of Venezuela's export market, but one that could be mitigated in the future by increased sales to China and energy-hungry economies in South America. The Venezuelan leader has been buying allies in South America with oil sales at subsidized prices.

China exports increase

PDVSA has been delivering more oil and fuel to India and China, markets up to seven times more distant than the US.

PDVSA also plans to spend as much as $2.2 billion on tankers through 2012 to double its fleet and enable it to send more oil to Asia, Chavez said.

The company wants to buy 42 tankers, including at least 14 supertankers, Chavez said. PDVSA currently has 21 tankers, enabling it to carry 26% of the country's oil exports, a figure that would be expanded to 45%, said Chavez.

Venezuela plans to spend $56 billion through 2012 to nearly double the country's oil production capacity to some 5.1 million b/d.

Although Venezuela shipped only 14,000 b/d to China in 2004, exports topped out at 80,000 b/d of oil in 2005. Chavez claims, "By the end of this year, we should be sending 300,000 b/d of oil to China."

Venezuela has signed new supply agreements with China, India, Jamaica, Haiti, Paraguay, and Bolivia. Because there is a lack of investment in new production, the country's output is not growing, so supplies to those countries come at the expense of exports to the US.

The top four suppliers of crude oil and fuel to the US, according to Energy Department figures, are Saudi Arabia, Venezuela, Mexico, and Canada. ✦

DOJ, SEC probe Bonny Island partners for violations

Nick Snow
Washington Correspondent

The US Department of Justice and the Securities and Exchange Commission are formally investigating whether a joint venture in which Halliburton Co. has a 25% interest played a role in alleged bribes of Nigerian government officials, the oil field services and engineering and construction company disclosed on Oct. 31.

SEC also has issued subpoenas for

information, which Halliburton said it is furnishing, about current and former agents used in connection with several Nigerian and global projects during the last 20 years.

SEC also asked Halliburton in September to enter into a tolling agreement that would delay the time the legal clock started running, or tolling, on the case under the statute of limitations, generally 5 years for such cases. It expects to do so, Halliburton said in its 10-Q report to the SEC of its financial and operating results for the 3 months ended Sept. 30.

The company said investigations center around the use of agents or subcontractors at the Bonny Island natural gas liquefaction complex in Nigeria by TSKJ, a joint venture of affiliates of Technip SA of France, Saipem SPA of Italy, Halliburton subsidiary Kellogg Brown & Root, and JCG Corp. of Japan. Each partner holds about 25% interest.

The investigations center on possible violations of the Foreign Corrupt Practices Act, Halliburton said. "In addition to performing our own investigation, we have been cooperating with the SEC and DOJ investigations and with other investigations into the Bonny Island project in France, Nigeria, and Switzerland," it added.

Halliburton also said its corporate board has appointed a committee of independent directors to oversee and direct the FCPA investigations.

Extended period

It said the DOJ and SEC investigations cover an extended period, in some cases significantly before Halliburton's 1998 acquisition of Dresser Industries Inc. The merger brought M.W. Kellogg Co. into Halliburton, which it combined with its own engineering and construction division, Brown & Root.

Halliburton supplied DOJ and SEC with documents from the files "of numerous offices of Halliburton and KBR, including current and former executives of Halliburton and KBR, and we are making our employees available to the DOJ and SEC for interviews," the company said.

The SEC has subpoenaed former KBR Chairman and consultant A. Jack Stanley and other current and former KBR executives and employees and at least one KBR subcontractor, Halliburton said.

"We further understand that the DOJ has invoked its authority under a sitting grand jury to issue subpoenas for the purpose of obtaining information abroad, and...that other partners of TSKJ have provided information to the DOJ and the SEC with respect to the investigations, either voluntarily or under subpoenas," the company said.

Halliburton said the two investigations include an examination of whether TSKJ's use of Tri-Star Investments as an agent, beginning in 1995, and an unnamed Japanese trading company as a subcontractor, beginning in 1996, led to bribes of Nigerian government officials.

Halliburton said a French magistrate placed Tri-Star principal Jeffrey Tesler under investigation for corruption of a foreign public official. It said investigations of TSKJ's activities also are under way by a legislative committee of Nigeria's national assembly, by the African nation's Economic and Financial Crimes Commission, and by the UK's Serious Frauds office.

"We notified the other owners of TSKJ of information provided by the investigations and asked them each to conduct their own investigation," Halliburton said.

TSKJ has suspended payments to and services from Tri-Star and the Japanese trading company and is considering legal action to terminate all agency agreements with Tri-Star and recovery payments under those agreements, said Halliburton.

TSKJ also notified Nigeria's attorney general in February 2005 that it would not oppose his efforts to have Swiss bank account money from the agreements transferred to Nigeria, Halliburton added.

Halliburton said it terminated all relationships with Stanley and another former M.W. Kellogg employee and consultant in June 2004 because the company found the pair violated Halliburton's business conduct code by allegedly receiving personal benefits from Tesler in connection with TSKJ's construction of the Bonny Island project.

Halliburton said that in 2006 it suspended the services of another agent who had worked for KBR outside of Nigeria on several current projects and older projects going back to the 1980s. It said it also is investigating whether another agent involved in still another current Nigerian project has violated any laws and the company's business conduct code in response to bribery allegations by one of the other TSKJ partners. ✦

Louisiana, MMS reach settlement in lease sale lawsuit

Paula Dittrick
Senior Staff Writer

Louisiana Gov. Kathleen Babineaux Blanco said attorneys for the state have negotiated a settlement in a lawsuit against the US Minerals Management Service, and the settlement would delay Lease Sale 201.

The lawsuit claimed MMS did not consider the environmental impact of offshore drilling when granting leases (OGJ, Aug. 28, 2006, p. 23). Blanco announced details of the proposed settlement during an Oct. 24 news confer-

ence in Baton Rouge.

A US District Court in New Orleans has yet to finalize terms of the settlement, under which Lease Sale 201—originally scheduled for Mar. 17, 2007—would be delayed for an indefinite period, said an attorney for Blanco.

He said tracts that would have been included in that lease offering might be rolled into another MMS sale, possibly Sale 205 in September 2007.

Settlement terms also call for no Outer Continental Shelf oil and gas leasing off Louisiana pending an environmental impact statement regarding damages to Louisiana's coast from the 2005 hurricane season.

Any exploration plans submitted by oil and gas companies regarding Western Gulf Lease Sale 200 must be accompanied by an environmental assessment that will be subject to review by Louisiana, state officials said. No such environmental assessment document previously was required.

Steve Allred, Department of Interior's assistant secretary for lands and minerals management, said, "Resolving this dispute by agreement rather than litigation benefits our nation's energy security by assuring we can move ahead on the leases issued in Lease Sale 200. The agreement also sets the next 5-year lease program on the right track."

Blanco reacts

Blanco called the agreement "an historic victory for Louisiana and for all states whose voices deserve to be heard in matters of their own destiny."

She said, "This fight is not with the oil and gas industry; it is with the federal government."

A Nov. 13 trial was scheduled in New Orleans, but the MMS said the state of Louisiana plans to dismiss the lawsuit upon court approval of the settlement.

The US Geological Survey reported Louisiana lost 217 sq miles of coastal area and barrier islands during Hurricanes Katrina and Rita.

US Dist. Judge Kurt Englehardt refused to block opening of offshore bids on Aug. 16 for Lease Sale 200 on 2.9 million acres of offshore tracts, but he said that the state had "a likelihood or substantial likelihood of prevailing." He ordered attorneys for MMS and Blanco to enter into negotiations.

Blanco has pushed for what she calls "Louisiana's fair share of revenues from offshore oil and gas drilling."

She wants to secure a share of federal offshore oil revenues to mitigate the state's loss of coastline (OGJ, Apr. 17, 2006, p. 26). Blanco said that restoring Louisiana's coastline is essential for hunting, fishing, and protecting oil and gas infrastructure.

Offshore revenues

Meanwhile, the Louisiana congressional delegation is working for a compromise energy bill that allocates a portion of royalties from offshore drilling to the state's Coastal Protection Fund.

The US House and Senate have conflicting revenue-sharing bills. Blanco called for Congress to reconcile the two.

"It's time for Congress to pass a revenue-sharing bill that will allow us to get on with the business of restoring our coast and protecting the communities that support this country's offshore energy supply," she said. ✦

API: US well completions broke records during 3Q

Nick Snow
Washington Correspondent

US oil and gas drilling reached its highest quarterly level in more than 20 years with an estimated 12,687 completions in the 3 months ended Sept. 30, the American Petroleum Institute said on Oct. 19.

The total, which includes dry holes as well as oil and gas wells, was the most for a single quarter since the first 3 months of 1986 and represented a 9% increase from the same 2005 period when completions totaled 11,680.

"There were very real increases in drilling activity, which refute some critics' beliefs that US oil development efforts don't track higher commodity prices. They did this past quarter," John C. Felmy, API's chief economist, told OGJ Oct. 20.

Completions have grown for 12 consecutive quarters and reached an estimated 21-year peak of 37,261 wells and dry holes during 2006's first 9 months, 11% more than 33,426 in the comparable 2005 period, API said in its latest quarterly well completions report.

Oil well completions grew at a higher rate than those for gas wells during the period, breaking a trend of several years, the trade association added.

It said that an estimated 3,960 oil wells were drilled domestically in the third quarter, 11% more than 3,562 a year earlier, while gas well completions climbed 9% year-to-year to an estimated quarterly record 7,480 wells from 6,883 wells.

In the first 9 months, API said, an estimated 11,545 oil wells and 21,897 gas wells were drilled in the US.

The move by some producers to oil from gas did not surprise industry observers. "It was driven by more favorable oil prices, which provided some extra money when they reached $77/bbl in mid-July. Natural gas prices were coming down after peaking a year ago," said Rayola S. Dougher, manager for energy market issues at API.

Pressure on oil

"We saw crude prices improve the past few quarters, given events in the Middle East, Venezuela, Nigeria, and Russia, where companies are finding more obstacles to projects like Sakhalin," said Frederick Lawrence, vice-pres-

ident of economics and international affairs at the Independent Petroleum Association of America.

Meanwhile, natural gas prices fell to $4/MMBtu on the New York Mercantile Exchange strip but have recently improved, he told OGJ. "Natural gas still is strong, however, and this year, the [US Energy Information Administration] estimates that 19,690 development wells were drilled in the first 8 months, compared to 12,836 in the first 8 months 2 years ago," Lawrence said.

While EIA estimated in September that an average 264 rigs drilled for oil in the US during 2006's first 8 months—66% more than the average of 159 in the same 2004 period—US oil production fell more than 7% to an average 5.098 million b/d from 5.5 million b/d, he said.

"Although the well completion totals are very impressive, production isn't keeping up. Producers need access to more supplies and have to pay increasing costs for equipment and personnel. The cost per well is increasing, which diminishes some of the value of the increased commodity prices," Lawrence said.

Dougher said, "Many of our fields are being depleted. It takes ever-increasing amounts of money and technology to get oil and gas out. The best sites have been developed already. But there are new frontiers, such as Chevron and Devon's Jack 2 well in the deepwater Gulf of Mexico."

Meanwhile, gas production is growing in the Rocky Mountains, according to Jon Bargas, communications manager with the Independent Petroleum Association of Mountain States in Denver. "EIA estimates that we'll pass the Gulf of Mexico this year as the largest source of this country's natural gas. As long as the American people demand it as a clean-burning energy, the West will remain a heavy focus," he said.

Most of the activity is on public lands, which requires cooperation with governments and communities, Bargas continued. "Oil and gas development involves less than 1% of the West's federal lands, so the environmental impact is not that great, despite what some groups are saying," he said.

API also reported that total estimated footage drilled in 2006's first 9 months and third quarter reached 212,523 ft and 73,107 ft, respectively. The last time estimated total footage drilled reached this level was in 1985, it said. ✦

NPRA's Slaughter: 'Biofuels are not the answer'

Biofuels are not the answer to US energy supply problems, said the president of the National Petrochemical & Refiners Association at a management forum in Houston.

Ethanol produced from corn is neither an economic nor energy-efficient alternative to gasoline, said Bob Slaughter, NPRA president. "If we were to seek to replace 10% of US gasoline needs with ethanol in 2020, we would have to plant all of Ohio, Illinois, and Indiana, using one sixth of the total land we currently use for crops just to grow corn for ethanol," he said.

NPRA, which represents virtually all US refiners and petrochemical manufacturers, is not opposed to the use of ethanol as an oxygenate additive to gasoline or to the 85:15 ethanol-gasoline "E85" blend, or to biodiesel and other alternative fuels, if competitively priced without government subsidies. "We believe that alternative fuels will be a growing component of the nation's future energy supplies as their economic viability improves. Policymakers, however, have a responsibility to get all the facts before mandating new fuels," Slaughter said.

He said, "The US oil and gas industry faces an unprecedented challenge in satisfying the projected growth in energy demand worldwide by 2030. To meet the challenge, the nation's energy policy must be grounded in reality, keep a long-term focus, and continue to search for solutions based upon sound science and careful analysis of economic and environmental factors."

US refiners have produced record volumes of petroleum products in recent years to help meet increased demand, while investing some $50 billion over the last 2 decades to make sweeping environmental improvements in their products and facilities. "US refiners have announced plans to add 1.4 million b/d of new refining capacity to existing US refineries, an 8% increase," Slaughter said.

For the next several decades, the US and the rest of the world will require more oil and gas to meet energy needs and support economic growth. And this has geopolitical and national political implications, said Slaughter.

"With the lack of an explicit, supply-based energy policy to address the US energy supply-demand imbalance, we are increasingly in the hands of international and global politics," he said. "In many ways, America's energy policy is still living in the past when oil and gas were cheap and readily available to meet constantly increasing global energy demand. Policymakers must accept the reality of the situation rather than take expensive and ill-considered steps in an attempt to avoid it."

Slaughter said, "America can take steps to increase its domestic production of energy, affecting both producers and refiners. Paying appropriate attention to the increasing need for energy will be key to obtaining policies that actually increase domestic production and refining. No nation—not even the US—can insulate itself from the global energy challenges." ✦

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Saudi Aramco looking east

Situated in a relatively quiet corner of Southeast Asia, Malaysia tends to be overlooked by some oil and gas analysts. But there can be no doubt that the Twin Towers of Petroliam Nasional Bhd. (Petronas) in Kuala Lumpur are trilling with stepped up activity.

After all, Petronas not only markets and exports crude oil, petroleum products, natural gas liquids, and sulfur, it also ships crude oil and LNG around the world and participates in joint ventures and other affiliates at home and abroad to refine crude oil and market products.

One sign of that came last week as a consortium consisting of the UK's Petrofac (30%), Petronas (30%), Kufpec (25%), and the PetroVietnam Investment & Development Co. (15%) announced first oil to the start of production from Block PM304 in Cendor oil field off Malaysia.

Saudi interest in...

But an even more important sign came with the decision by Saudi Aramco, the world's largest oil corporation, to open an office for one of its subsidiaries, Aramco Overseas Co., in Kuala Lumpur.

The primary function of this office will be to coordinate contracting, purchasing, and materials inspection activities with regional suppliers. At the same time, Aramco Overseas is opening a similar office in Shanghai, China.

The Saudi decision is said to be partly due to cost, as Kuala Lumpur is a cheaper base than Singapore, but also because Malaysia itself is an oil-producing nation and, in MISC Corp. Bhd., has the world's largest fleet of LNG carriers.

Something else the Saudis clearly value, though, is Malaysia's good relations with China, underscored by the landmark LNG deal struck between Petronas and Shanghai LNG Co. Ltd.

...Gas to China

Under terms of that 25-year agreement, Petronas's subsidiary Malaysia LNG Tiga Sdn. Bhd. will supply 3.03 million tonnes/year of LNG from its facility in Bintulu, Sarawak.

With some 10 Chinese LNG projects earmarked for development, Malaysia's prospects for more LNG export contracts to China are bright, according to research by OSK Securities.

No less significantly, OSK noted that MISC will naturally fit the bill as the transport provider.

"This large China contract could take up to 50 shiploads/year to fill," OSK said in a report, which concluded, "Given that Petronas is MISC's major shareholder, it would naturally utilize MISC vessels in the transportation of the LNG."

Petronas is leaving nothing to chance regarding future gas deals with China, with construction under way of a natural gas pipeline between the Bintulu gas fields and Kimanis to be operated by Petronas Gas.

"With the pipeline scheduled for completion in 2010, it is positioned to support further contracts with China, and we remain confident that this pipeline may boost Petronas Gas value by some 10%," OSK Securities said.

Little wonder the Saudis have taken down some of the "For Rent" signs in Kuala Lumpur and Shanghai. ✦

EPA proposes further gasoline vapor controls

The US Environmental Protection Agency wants to expand, to nationwide locations, its air toxic standards designed to prevent gasoline spills and evaporation at urban distribution facilities.

The rule, which already covers urban facilities that store gasoline and load it onto trucks for delivery to stations, would be added to 3,000-5,000 more locations, EPA said on Nov. 2. It also could begin to cover the loading of gasoline into retailers' storage tanks in highly populated areas, the federal regulatory agency said.

EPA said that two alternatives are being considered in the expansion. The first would focus on pipelines, terminals, and bulk plants. The second would also add controls at urban retailers. EPA is seeking public comments on the proposals through Dec. 31.

The standards, which EPA proposed on Oct. 31, would reduce 45,000-46,000 tons/year of volatile organic compounds in gasoline vapors, including 3,300-3,400 tons of hazardous air pollutants, mostly at large bulk facilities. The program would cost about $60-65 million.

"There would be an annual benefit of about $6 million from either of the proposed alternatives. The value of the recovered gasoline and gasoline not allowed to evaporate will more than pay for the annual cost of the expenditures and the operation and maintenance of the equipment," EPA said in a fact sheet accompanying the proposals.

Most US pipelines, bulk plants and terminals already comply with standards in the proposed regulations, it added.

The first alternative would require all bulk distribution sites to have best seals on terminal and pipeline storage tanks, use submerged fill pipes when loading bulk plants' storage tanks, install vapor processors to control tank truck loadings at bulk terminals, use submerged fill pipes to control tank truck loading emissions at bulk plants, and periodically test all tank trucks and rail cars for leaks. ✦

World's Arctic basins pose array of unique work opportunities

Alan Murray
Andrew Latham
Wood Mackenzie
Edinburgh

The Arctic is often considered as a single frontier for the oil and gas industry with a unique set of challenges that require unique exploration and development solutions. However, during the course of completing a recent study "Future of the Arctic—A New Dawn for Exploration," it became clear to UK consultants Wood Mackenzie that the Arctic is far from being homogenous and there exists a range of distinct opportunities that fit very different strategic aims.

Arctic basins

A number of the Arctic basins, notably the North Slope of Alaska, the South Kara/Yamal subbasin to the north of Western Siberia, and the West Barents and East Barents basins in Norway and Russia, respectively, have large discovered resources that are at different stages of development (Fig. 1).

Both the North Slope and the southern part of South Kara/Yamal are well established as oil and gas provinces and have pipelines that link them to global markets.

At the other end of the spectrum a number of sedimentary basins in the Arctic, such as the North Greenland basin, the East Siberian Sea, and the North Chukchi Sea, are virtually untouched by the oil and gas industry. In these basins there is extremely limited data on the subsurface, and none of the infrastructure associated with the industry.

The degree of development in each basin reflects the relative severity of the challenges faced in different parts of the Arctic.

Remoteness is perhaps the greatest challenge for the oil and gas industry in the Arctic. The great distance from the Arctic to population centers is a challenge in terms of shipping hydrocarbons to markets, either by pipeline or sea transport. This remoteness is also a challenge when it comes to mobilizing the people and equipment needed to explore for oil and gas. Mobilizing the necessary items to the Arctic in order to collect seismic data or drill wells can take a long time and cost a great deal of money.

Ice challenges

The challenges presented by ice vary greatly across the Arctic.

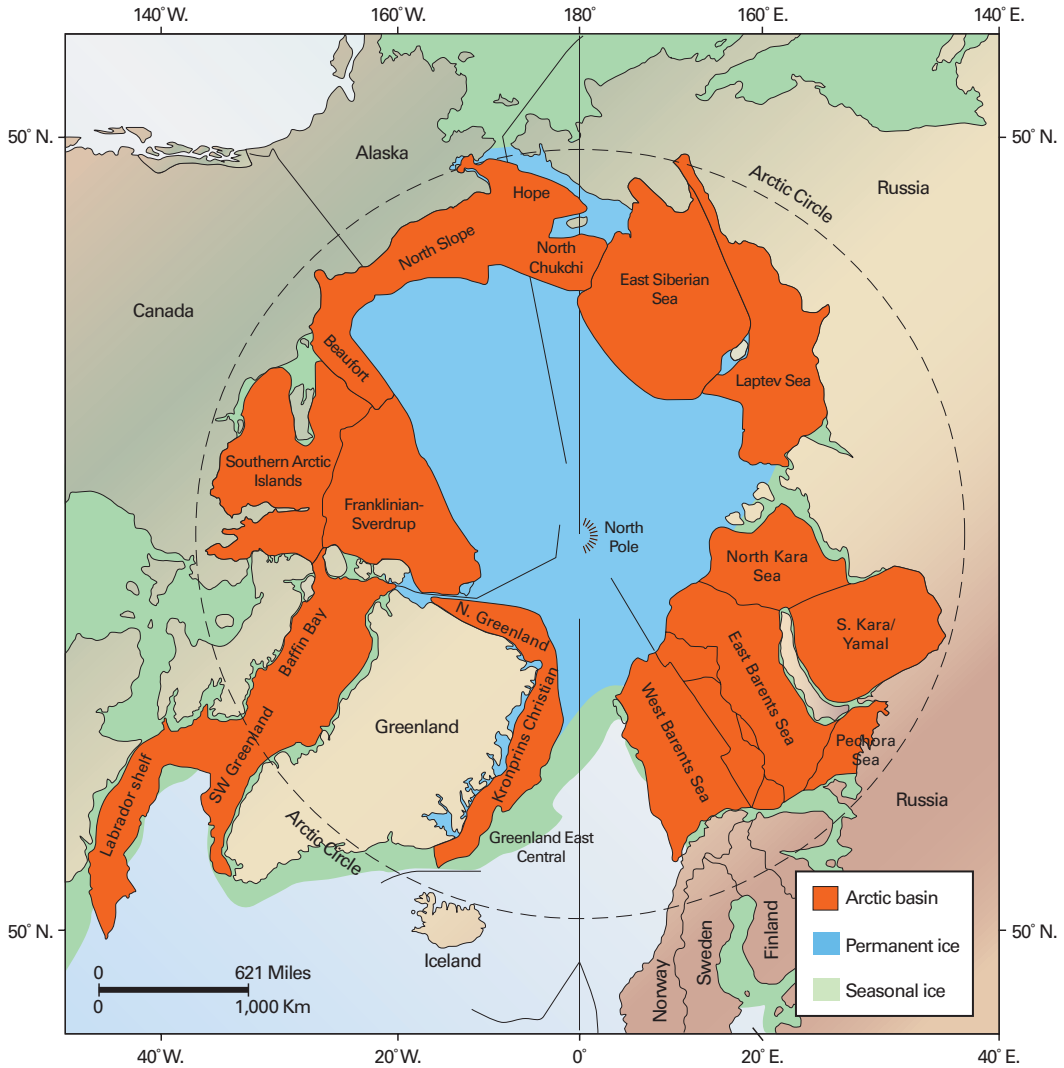
North Greenland ice is permanent, and the ice is thicker than that in other parts of the Arctic. There the ice sheet is constantly pushing against the coast.

By contrast, in other parts of the Arctic such as the West Barents, Southwest Greenland, and the Labrador shelf there is often no pack ice, or limited seasonal ice which remains frozen for a short period. Pack ice can limit drilling to certain times of year and also require that installations be able to resist the load placed on them by the movement of the ice sheet.

Icebergs are also an issue in some basins, such as Baffin Bay, but not in others. Rigs and platforms that are positioned in an area affected by icebergs must be detachable in order to avoid impact, or they need a significant investment in iceberg management that ensures that icebergs are deflected away from the installation.

ARCTIC BASINS

Fig. 1



License availability

A further constraint on the level of exploration in a basin is whether or not an area is available for licensing.

While all the governments that have jurisdiction over the Arctic are broadly in favor of oil and gas exploration, the availability of licenses varies greatly from basin to basin.

Canada publishes an annual call for nominations covering the majority of the Beaufort-Mackenzie and Franklinian-Sverdrup basins, while there is no active licensing in Baffin Bay.

Similarly, the Greenland Bureau of Minerals & Petroleum is actively promoting Southwest Greenland but has no plans to license North Greenland or the Kronprins Christian basin.

Licensing restrictions often reflect local issues, such are environmental sensitivity and the needs of local landowners.

Basin economics

The variety of licensing approaches manifests itself in the economics of oil and gas development in each basin.

The average breakeven price for the development of an oil field in the Arctic, assuming a 15% return on investment, is around $25/boe. However the average for individual basins varies from around $19/boe to $46/boe depending primarily on the remoteness of the basin and the ice challenges presented.

Different challenges and economics create a range of distinct opportunities for companies to invest in the Arctic.

In this article we consider three strategies for upstream growth in the Arctic: Major Resource Capture, Niche Operations, and Frontier Exploration, and we consider which basins offer the best opportunities for companies following each of these strategies.

Resource capture

Major Resource Capture focuses on gaining access to large volumes, either by negotiating access with the current resource holder or by licensing exploration rights in a highly prospective but underexplored basin.

The key to executing this strategy successfully is to identify resource holders who are either unable to fund development and exploration for financial reasons or unwilling to explore and develop a basin on their own for strategic or technical reasons.

This strategy will generally involve a commitment to make a massive investment in the basin, as this will be necessary to extract the large resources (Fig. 2). Strong technological and project management credentials will also be key

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Our products and services division provides turnkey industrial controls and automation including pipeline leak-detection & SCADA, metrology systems and services including custody transfer accounting and comprehensive pipeline administration, operation and maintenance services.

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- **North Pole Connection custody transfer accounting and administrative services at TAPS midline.**
- **PetroStar Refinery, North Pole Connection metrology and proving services**
- **Feasibility analysis and developmental modeling for a natural gas play in Interior Alaska**

NOVEMBER ANNOUNCEMENTS

- **Acquisition of K&C Associates Metrology should be completed in mid-November increasing our existing staff and asset base dedicated to pipeline leak detection, SCADA, and metrology products and services in Alaska.**
- **Negotiations for an Alliance Agreement with ICS (Innovative Control Systems of Clifton Park New York) will be consummated at the end of this month. This important agreement will provide direct local sourcing and support for state-of-the-art turbomachinery control systems within Alaska. See the ICS narrative below.**
- **Development of purchase specifications for a new compact ballistic meter prover will be completed on November 17th, supporting the purchase of additional metrology equipment in early December.**
- **Phase I of Energia Cura's Fairbanks headquarters was completed last month. Phase II is scheduled to commence on November 6. Phase II will increase Energia Cura's office space adjacent to the Fairbanks International Airport by 40%, supporting the addition of K&C Associate's valued staff by the end of the year.**

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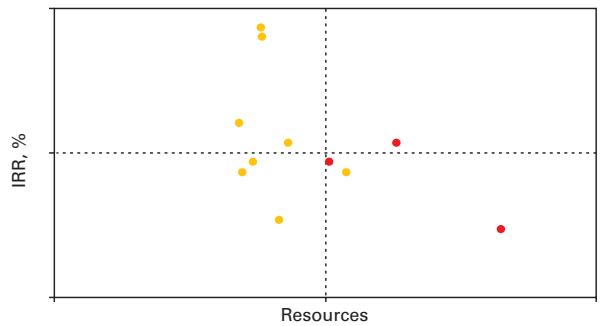
Energia Cura extends its best wishes to all as we approach the close of 2006 and the winter holidays.
Please contact us at 907-452-3466 or at asg@energiacura.com if we can assist you in any way.

Scienta Sol Mentis

ARCTIC MAJOR RESOURCE CAPTURE*

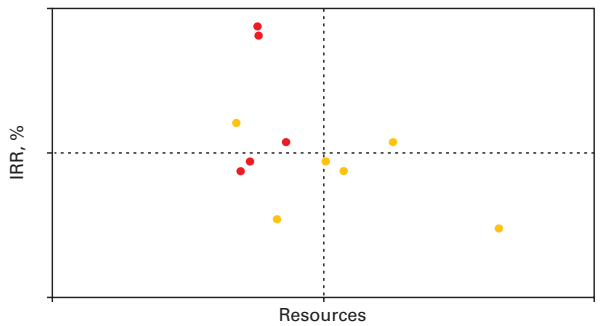
Fig. 2



*Rate of return vs. available resources (on a log scale) for different opportunities in the Arctic. Major resource capture opportunities are shown in red.

ARCTIC NICHE OPERATIONS*

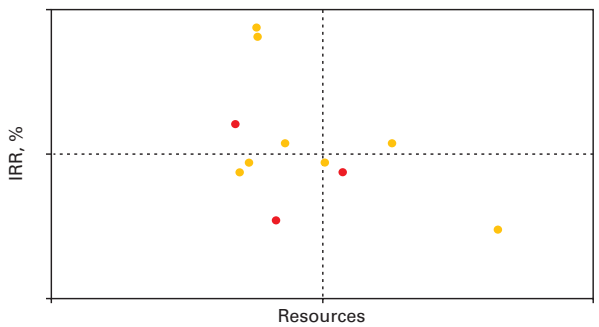
Fig. 3



*Rate of return vs. available resources (on a log scale) for different opportunities in the Arctic. Niche operations opportunities are shown in red.

ARCTIC FRONTIER EXPLORATION*

Fig. 4



*Rate of return vs. available resources (on a log scale) for different opportunities in the Arctic. Frontier exploration opportunities are shown in red.

to gaining the acceptance of the current resource holder.

It is also likely that such a strategy will involve giving a significant fraction of the potential value of the resource to the current resource holder, either in the form of carried equity or high government take.

These factors mean that it is unlikely that this strategy will generate high returns, but the investing company should still generate large profits due to the scale of the resource being developed.

The other key aspect of this strategy is that it must be executed over the long term. Gaining access to prized resource means gaining the trust of the current resource holder through demonstration of a track record of developing particular types of resources and often showing a commitment to the broader development of the region where the resources are located.

Executing this strategy does involve some costs, and it often requires a significant amount of focus from senior executives. The investment in capturing the resources is typically small in comparison to the investment needed to execute the actual development of resources. The risks in pursuing this strategy are relatively low before the development gets under way.

The companies who are able to execute this strategy are generally the supermajors. These have both the need to replace their large production base and also the balance sheet strength that enables them to make the massive investments needed to develop major resources.

The supermajors are also at the forefront of technologies such as subsea-to-shore development and extended-reach drilling, which have the potential to unlock previously stranded or subeconomic reserves.

The other group that may also look to this strategy in the future are the expansionist national oil companies. These have a need for large amounts of production and are not subject to the same cost of capital constraints as publicly listed companies when making investments.

Major resource basins

The two most obvious Arctic basins for the Major Resource Capture strategy are the offshore part of the South Kara/Yamal basin and the East Barents basin in Russia.

Both of these basins have large discovered resources that are currently undeveloped, and both also have a large yet-to-find potential in areas that are not being actively explored at present.

The resources in these basins are primarily controlled by the Russian gas supplier, Gazprom. Gazprom has massive financial resources and strong cash flows from production at its supergiant fields in Western Siberia. However, Gazprom's development and production experience is entirely onshore.

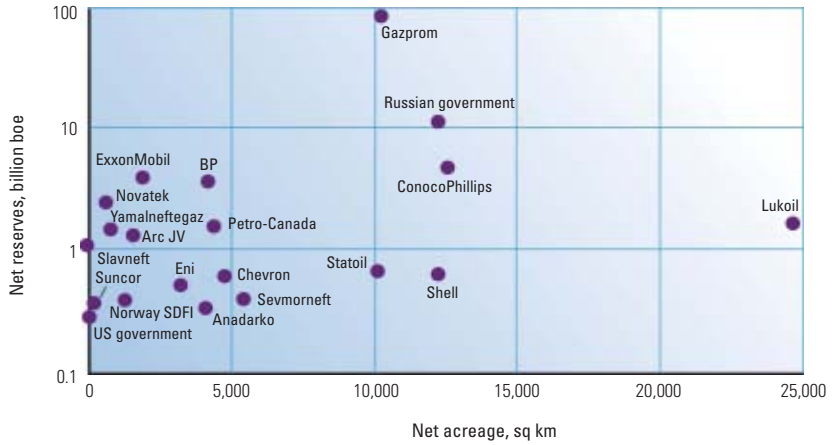
Recent announcements concerning the bids for partnership in Shtokman field in the East Barents will be viewed as a setback for companies that had hoped to participate with Gazprom in developing its resources.

The fact remains that Gazprom will need to expand its capabilities in order to develop these resources, and this can be achieved by working with those companies who have experience in developing fields in similar environments in Alaska, the West Barents, and at Sakhalin Island.

Gazprom has stated in recent times that it will need to learn from experienced offshore operators in order to effectively exploit its resource base in the Arctic seas. This means that there

TOP 20 ARCTIC RESOURCE HOLDERS

Fig. 5



Source: Wood Mackenzie.

remains an opportunity for companies who are willing to pursue a long-term strategy of becoming a partner in Gazprom's offshore ventures.

Niche opportunities

Niche Operations are focused more on generating high returns as opposed to achieving a large scale of production (Fig. 3).

A niche strategy is successful when a company identifies a competitive advantage in a particular area and successfully exploits this to generate higher returns than its competitors.

In the Arctic basins these opportunities often involve exploration close to existing infrastructure and being able to develop nearby fields, or by combining new discoveries with existing discoveries that cannot achieve economic returns as stand-alone developments. As the Arctic is a largely gas-prone region, identifying medium-sized oil prospects and exploiting these can also be considered a niche opportunity in the Arctic.

The companies that will execute this strategy will be those who have ownership of, or access to, export infrastructure, such as the Trans Alaska Pipeline System from the North Slope, the Melkoya LNG plant in the West Barents, or the proposed Mackenzie Valley Pipeline in Canada. Companies that own undeveloped resources, particularly in Canada or Russia, may also be able to execute this strategy.

Niche provinces

The North Slope has continued to deliver new discoveries for the last 40 years, and exploration in this basin continues as new areas, such as the southern part of the Chukchi Sea and the Naval Petroleum Reserve, are opened to exploration.

The Trans Alaskan Pipeline System that transports oil from the North Slope to a tanker terminal in southern Alaska has increasing spare capacity as Prudhoe Bay field has declined, and this means that oil from new discoveries in this basin can be exploited and exported much more easily than in other parts of the Arctic.

The existence of rigs and personnel in Alaska also means that exploration can be carried out more easily, and all of this reduces the investment needed and can deliver higher returns.

The Pechora Sea in Russia has a significant yet-to-find potential, and the development of Prirazlomnoye field is providing the infrastructure needed to encourage further exploration in this basin. The Pechora Sea is also connected to markets in Western Europe by largely ice-free sea routes, and it is also the most oil prone of the Russian Arctic basins.

The West Barents basin already has an LNG development at Melkøya Island, which will export gas from Snohvit field. This facility has space for a second LNG train that could handle gas from other discoveries, making the exploration of this basin more attractive. The Goliat discovery has also indicated the potential for oil discoveries that can be developed in the largely ice-free waters and easily exported to markets in Western Europe.

The Mackenzie Valley Pipeline will have capacity for new discoveries as well as the anchor fields that will underwrite the development of the pipeline. This provides an opportunity for monetizing gas in this basin. There also exists potential for oil discoveries in the offshore part of the Beaufort-Mackenzie basin, although an oil export pipeline would be unlikely to be constructed before the planned gas pipeline.

The Labrador shelf off eastern Canada has some large gas deposits that have remained undeveloped for a number of years. Further exploration of this basin could provide the volumes for an integrated development using either LNG or CNG, which would monetize the existing reserves as well as the new discoveries.

All of these basins provide opportunities for exploration success, and the players who are already established in these areas will have a competitive advantage in exploiting new discoveries with higher rates of return.

Arctic frontiers

Frontier Exploration is the entry into largely unexplored areas and beginning the search for new resources (Fig. 4).

In many basins of the Arctic, difficulties in obtaining exploration licenses presents the most immediate barrier to frontier exploration (Fig. 5).

The absence of seismic data in many of these basins is also significant. Acquisition of new seismic can present serious challenges, as operations may be limited to summer months in areas of seasonal ice, or require expensive

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icebreaker support in areas of permanent ice.

Once prospects have been identified drilling exploration wells is also expensive, as there is a limited supply of Arctic-class drilling rigs. Mobilizing these in the most remote parts of the Arctic can be very expensive. An alternative is to drill from spray-ice islands, although this technology has not been used widely outside Canada.

The high costs of drilling and seismic acquisition in the Arctic mean that the upfront costs will be large. The fact that the frontier basins do not contain proven plays means that this is a very high-risk strategy, and this will only be successful if large and profitable fields need to be discovered.

Only the frontier basins with the highest yet-to-find potential can be considered as attractive opportunities for Frontier Exploration.

Most companies will have Frontier Exploration as part of their overall resource capture strategy, but only small specialist companies would focus on this exclusively. The companies that consider Frontier Exploration in the Arctic will be those that have the greatest appetite for risk because these basins contain some of the most high-risk opportunities in the world.

Arctic frontier basins

The frontier basins with the best yet-to-find potential are the Kronprins Christian basin east of northern Greenland, the Southwest Greenland basin, and the Laptev Sea, which lies north of Eastern Siberia.

All of these have material yet-to-find potential, but their specific advantages are very distinct.

Kronprins Christian is attractive mainly because of the sheer size of its yet-to-find potential. This basin faces many of the most severe challenges in the Arctic, with permanent ice along the entire coastline, extreme remoteness from markets and population centers, and no active licensing at present.

In contrast Southwest Greenland has around half of the resource potential of Kronprins Christian, but it is close to the markets in the eastern US, is ice free for much of the year, and is actively promoted by Greenland authorities. All of this makes it more likely that discoveries will be developed.

The Laptev Sea is attractive mainly because of the presence of a small number of large oil prospects that could prove highly profitable despite the difficultly in exporting oil from such a remote part of the world.

These basins present the potential to be profitable for explorers, but the risks both below ground and above ground are very high.

The Arctic is rightly considered to be a difficult environment for oil and gas companies to prosper. By understanding the differences between the different Arctic basins, companies can find opportunities to grow their business in the Arctic areas that fit best with their chosen growth strategies. ✦

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Novel centrifugal process removes gas contaminants

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A new technique based on centrifugal separation can economically process gas from fields contaminated with large amounts of carbon dioxide (CO_2) or hydrogen sulfide (H_2S).

The process could help mitigate expected shortages in global natural gas supply during the next few decades in an environmentally responsible manner. Current energy-intensive methods often cannot economically remove CO_2 or H_2S in existing or newly discovered gas fields if the gas contains more than 15% CO_2 or H_2S.

Selective absorption in an aqueous solution is the standard technique for removing these gaseous contaminants from methane.[1] High contamination levels, however, require unacceptable levels of energy consumption for purification. These existing technologies require more energy than the energy in the purified gas.

Absorption and membrane technologies are understood processes that offer no economic prospects for these fields.

Shell research project

A Shell research program investigated the application of novel rotational separation technologies starting with centrifugal gas separation.[2-4] It established that applying this process to clean natural gas differs from that used in uranium enrichment, its typical use. A modeling and experimental program, however, also showed that building small compact units for a gas centrifuge device was not feasible because of long separation times required because gaseous diffusion is slow.[5]

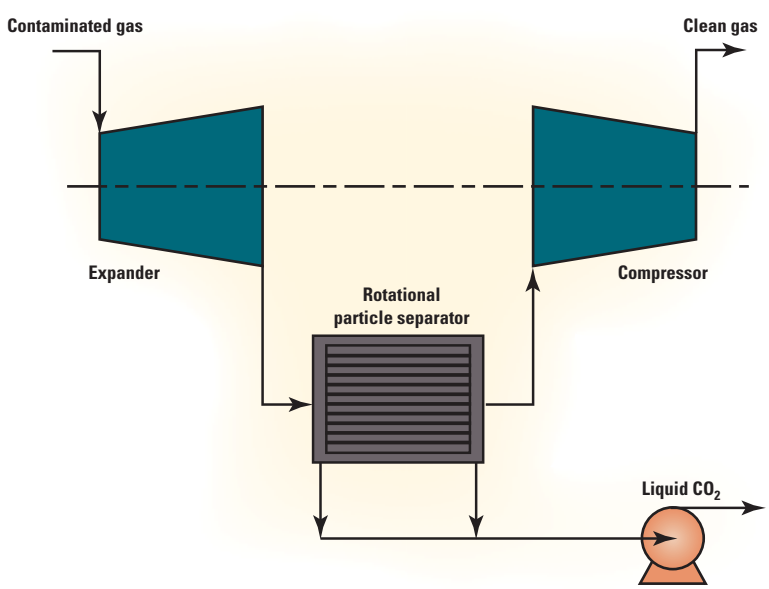
A phase change is the only way to accelerate separation.

The program thus developed the condensing centrifuge, a novel concept based on the gas centrifuge.[6] In this device, unlike other devices, the centrifuge operates at elevated pressure so that the CO_2 condenses at the centrifuge periphery.

Although this improves separation compared to the purely gas-phase centrifuge, it was too slow to make the

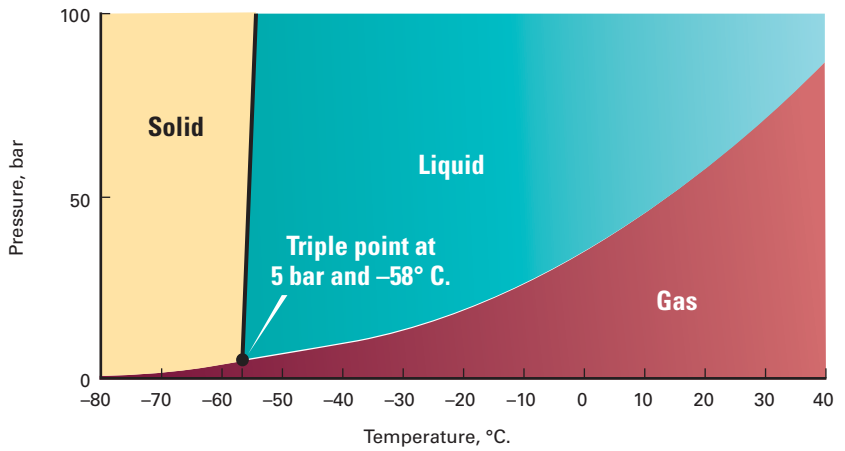
CONDENSED CONTAMINANT CENTRIFUGAL SEPARATION

Fig. 1



CO_2 PHASE DIAGRAM

Fig. 2



process attractive for production sites producing 100-500 MMscfd. The slowness is caused by the interior part of the condensing centrifuge still operating in the gas phase.

Gas-phase centrifugal processes are restricted by the fact that the product of density and diffusion coefficient is constant. Although mass flows increase, operation at high pressures leads to slower separation without improving net overall performance.

A way to accelerate the separation process of the two components was to include a phase change. This involves changing the thermodynamic state of the mixture so that the CO_2 becomes a liquid.

Fig. 1 shows this novel two-step method that includes:

1. Cooling the gas to a temperature whereby the gaseous contaminant becomes liquid in the form of a micron-sized droplet mist.
2. Separating the mist from the gas by the rotational particle separator (rps), a device already used in health care and environmental emission control.[7-9] The process is a spin-off of the gas centrifuge and is the core innovation in the Shell process.[10]

High energy demands do not hamper this method, which has short residence times and compact units. It potentially can boost recoverable world gas reserves by amounts that are energetically equivalent to many billion barrels of oil.

Thermodynamics

For economic gas-gas separation, the process has to transform one of the components into a phase capable of forming particles. Cooling and condensation will do this.

Because gas in reservoirs is compressed, for example at 130-450 bar, expansion can attain the necessary cooling for contaminant condensation. Even the reduced pressures available top hole, 80-130 bar, are sufficient to drive expansion cooling.

An expansion turbine is in most cases preferred to techniques employing expansion by acceleration such as the Joule-Thomson process. The turbine can drive a compressor to bring the gas back to system pressure. In addition, after the turbine, the gas velocity can remain relatively slow. Withdrawing power from the gas rather than from gas speed causes the cooling.

This process avoids the risk of heating the gas with internal friction, which would cause the ultrafine condensed droplets to evaporate.

Separation of components with condensation to form a phase boundary is a well established process.[11] The method used is temperature reduction, although usually with heat exchange rather than the direct expansion method in the Shell process.

The latter method is standard in such processes as producing cryogenic gases or LNG. The main problem, however, is the spatial separation of the two phases that often are intermixed and difficult to split into separate streams.

The low-pressure side of the expansion refers to a condition that provides sufficient cooling for forming and separating the two phases. The product phase is gaseous, enriched in methane, with depleted CO_2. The waste phase is liquid, enriched in CO_2, and depleted in methane.

This process, of course, does not spontaneously lead to a nicely separated liquid and gas phase. A mixture of fine CO_2-rich droplets forms in a methane-rich gas. Between the expansion and separation steps, the microdroplets will increase in size sufficiently for separation.

This so-called "induction" process also takes place in knockout vessels for removing such components as condensate components with cyclones. These devices, however, need high-volume throughputs for droplet sizes greater than about 15 µm and require much lower mass loadings than are in contaminated gases. Removal of smaller droplets is possible but only for extremely low throughputs, so-called microcyclones.

In the Shell process, droplet sizes will be smaller than this with mass loading much higher than condensate in gases.

Consider a feed flow (Q_f) of contaminated gas that is split into a cleaned-up stream (Q_c) and a waste stream (Q_w) of CO_2 rich liquid. Conservation of mass requires that input is the same as output

EQUATIONS

$$Q_f = Q_c + Q_w \quad (1)$$

$$x_f Q_f = x_c Q_c + x_w Q_w \quad (2)$$

$$r = \frac{x_c Q_c}{x_f Q_f} = \frac{x_c (x_f - x_w)}{x_f (x_c - x_w)} \quad (3)$$

(Equation 1 in accompanying equations box).

If x_i is defined as the concentration of methane in each of the three streams (i = f, c, w), then a mass balance on the methane component yields Equation 2.

The most obvious condition is that the process should have the highest concentration x_p of methane possible in the product stream. Simultaneously, the process needs to minimize the loss of incoming feed methane into the waste stream so that the maximum number of molecules of methane in the feed are in the product stream. This corresponds to maximizing the recovery r given by Equation 3.

The recovery is a function of the methane concentrations x_i. This is seen by dividing Equation 1 and 2 by Q_f and solving for the two variables Q_c/Q_f and Q_w/Q_f. Because the input concentration is specified, the recovery is then purely a function of the product and waste concentrations derived from thermodynamics.

The methane content in the clean and waste streams (x_c and x_w) is obtained from the pressure and temperature (p and T); however, the p and T conditions have a large feasible range with corresponding solutions for x_c and x_w.

The calculations need to find realistic values that also optimize the recovery r at the same time.

Consider a 50/50 mixture of CH_4/CO_2, for example $x_f = 0.5$, which is representative for contaminated gas and used as a basis of design. For the optimum values of product concentration x_c and methane recovery r for a variety of pressures and temperatures,[12] the lower bound for these conditions can be obtained from an evaluation of the phase boundary for pure CO_2 in the freeze-out curve in Fig. 2.

Most materials have a triple point below atmospheric pressure with normal melting and boiling points corresponding to the temperature points at 1 atm where solid-liquid and liquid-gas transitions occur, respectively. For CO_2, however, the triple point is above atmospheric pressure.

For CO_2, p_t is 5.1 bar and T_t is −56.6° C. The subscript t refers to the triple-point conditions.

Fig. 2 shows that operation in the liquid regime requires that the process is greater than 5 bar and −56° C. This forms the minimum value for the thermodynamic conditions.

The maximum value is set by reasonable pressures for the expansion and bearing in mind that this is after the cooling expansion phase.

Fig. 3 shows the methane recovery r plotted against methane product concentration x_c for a range of pressures and temperatures, as obtained from an extended cubic equation of state simulation based on the Soave-Redlich-Kwong model. The figure shows that a single separation step will obtain high methane recoveries; however, the problem requires maximizing the methane concentration in the product stream.

At the ideal point $x_c \approx r \approx 0.85$, the turbine inlet pressure would be 600 bar, which is unrealistic. In general, given the restrictions for pipe WT and corresponding safety and handling considerations, the process should have an inlet pressure less than 200 bar.

The question then is to choose the optimal realistic p and T values for the separator operation. With too much expansion, the temperature may be sufficiently low but the pressure will be too low for liquefaction to take place. A restricted expansion, on the other hand, may have sufficient pressure but not enough cooling and hence insufficient yield.

An examination of the various p and T conditions coupled to the parameters previously noted shows that an expansion to 25-30 bar, providing the inlet pressure is greater than 100 bar, gives significant phase separation.

From a practical engineering standpoint, a 102-bar expander inlet pressure is sufficient for recovering about 95% of the methane into the product gas stream with a concentration of about 67%. Note that phase separation is initiated by the expansion and is only complete by the end of the induction period in which the liquid state is materialized in droplets of a few microns in size. Subsequently, the spatial separation of the dispersed waste and purified product takes place in the rotational particle separator.

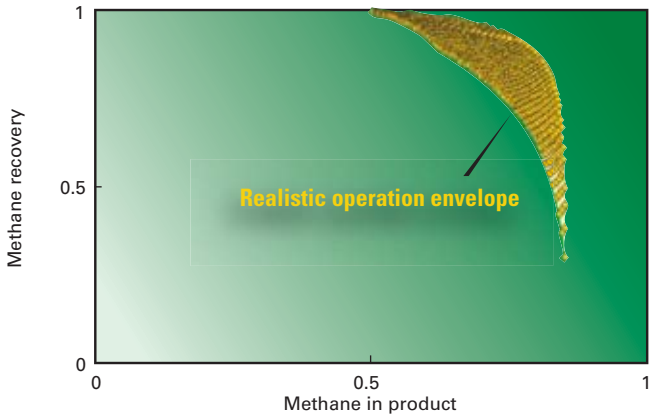
The foregoing analysis assumes that the CO_2-rich liquid is already in the dispersed waste material of flow rate Q_W that will be spatially concentrated and separated to the waste stream in the rps.

Separation

The previous discussion evaluated the equilibrium conditions required

Operation envelope

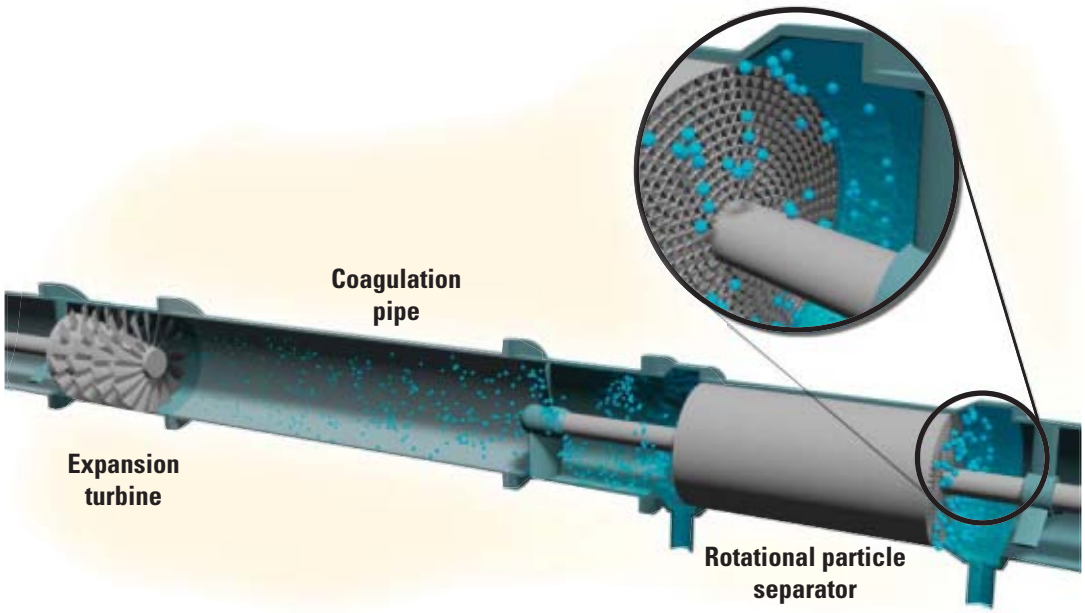
Fig. 3



Concentration in product stream at various pressure and temperature separation conditions

ROTATIONAL PARTICLE SEPARATOR

Fig. 4



for forming a dense waste phase. The other concern is the kinetics of droplet removal that needs to occur within a very short time and for very small droplet sizes.

In principle, a standard cyclone is capable of doing this; however, this requires a long residence time for very small droplets, something difficult to attain with high throughputs.

The main advantage of the rotational particle separator (rps) is that it enables this to happen much more quickly, at much higher throughputs, and for much smaller droplets than with other centrifugal methods such as cyclones or gas centrifuges.

The core of the rps is a cylindrical body that has a large number of axially oriented channels, each with a 1-2 mm diameter.[8] The swirling high gas flow solely induces the rotation of the assembly, which is mounted on bearings. An external motor drive is unnecessary.

A cylindrical housing contains the entire assembly of channels. The unit does not require rotating shafts perforating stationary elements and the associated rotating seal mountings.

Inside the channels, the centrifugal force will move the particles in the gas radially to the outer walls. Because the channels are narrow, particles can arrive at the collecting outer walls during a short residence time. The process squeezes the liquid films formed at the outer walls from the channels and provides exit ports for the liquid to leave the rps (Fig. 4).

The distance particles travel is much shorter than in a cyclone so that the process can collect much smaller particles. The basis of the separator is thus the use of centrifugal force to separate small, condensed droplets from the gas flow.

The particle radial velocity is calculated from a balance between the centrifugal force and the fluid force exerted on the particle in the case of motion relative to the surrounding carrier fluid.[10] We can express the critical separable droplet size as a function of three variables.[13] These are:

1. Flow rate Q_f, the feed flow rate of the gas stream.
2. Residence time in the separator τ, which is effectively a measure of size and thus capital cost.
3. Specific energy consumption ε, which gives the operating costs.

Fig. 5 compares this last parameter for several CO_2 gas stream decontaminations. It is clear that the process compares favorably in terms of energy consumption.

Currently, the rotational particle separator is proven technology for the spatial separation of micron-sized solid and liquid particulate matter dispersed in gases. It has been used for removing aerosols from domestic air, filtering fly ash from flue gases in coal fired power stations, water removal from natural gas, and inlet gas conditioning in gas turbines.[7-9 14 15]

Current development programs address scale-up to levels and conditions associated with producing well gas flows.

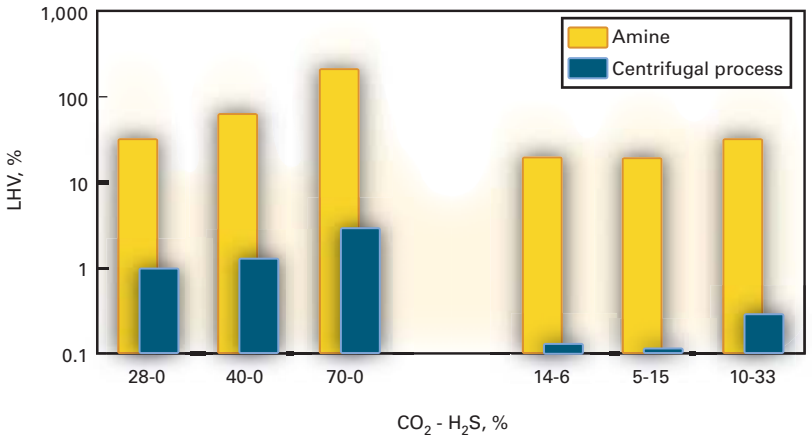
Pressures and temperatures are designed so that dissolved methane in particles and gaseous pollutant in methane are at a minimum ensuring maximum enrichment and depletion of product and waste streams. Cases of high contamination may require compressing the single-stage product gas and repeating the process to obtain greater purity.

The process occurs under pressure so that the size of the unit as a whole is small. Energy consumption is small, costing a few percent of the calorific value of the gas at most. Capital and operating expenditure are therefore low so that they form no obstacle for profitable exploitation.

A unit for a typical gas field producing methane at 100 kg/sec with 50% CO_2 contamination would have a 10-m length and 1-m radius. The rps would

Process comparisons

Fig. 5



Note: LHV - Lower heating value of clean gas produced

have the same radius and a length of 0.5 m. It would rotate at a 50 m/sec peripheral speed. Pressures and temperatures downstream of the turbine are typically 25 bar and −50° C. These values illustrate the attractiveness of the process.

Another major advantage is that whereas standard processes produce CO_2 or H_2S contaminant at low pressures, the Shell process automatically generates the waste stream at high pressures enabling reinjection back into the gas reservoir from which it originally came, while yielding clean natural gas with a much lower net production of polluting gases. ✦

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Drilling continues in Ecuador

Nina M. Rach
Drilling Editor

Although several foreign operators have abandoned Ecuador operations this year, 118 wells were drilled during the first 9 months of 2006 (see table).

Ecuador has oil reserves of 4.6 billion bbl, the third largest in South America, and the country's oil production increased 31% during 2001-05 (OGJ, May 22, 2006, p. 28). Production is now about 175,000 bo/d.

ECUADOR DRILLING, JAN.-SEPT. 2006

Table 1

Operator	Wells, no.	Measured depth, ft
AGIP	2	14,279
Alberta Energy Co. (AEC) Ecuador Ltd.	18	8,555-10,665
Andes Petroleum Ecuador	2	10,200-10,530
EnCana Ecuador	2	11,889-12,350
Occidental	4	7,031-9,200
City Oriente	5	7,725-8,245
Perenco	1	8,400
Perenco, on behalf of Block 7-Block 21 consortium	19	7,825-10,626
Petrobell	5	10,785-11,870
Petrobras, on behalf of EcuadorTLC	8	10,670-11,726
Petroproduccion (PetroEcuador)	22	7,800-10,814
Petrosud-Petroriva	3	10,375-10,467
Repsol-YPF	25	9,158-11,010
SIPEC	1	—
Tecpecuador	2	4,280-4,480

Repsol-YPF has been the most active foreign operator so far this year, drilling 25 wells with Helmerich & Payne rigs to an average MD greater than 10,000 ft.

Perenco drilled 19 wells as operator for the B7-B21 consortium, in the Yuralpa field (Block 21), Oso field, and Lobo field (Block 7).

AEC Ecuador (Alberta Energy Co. Ltd., an EnCana subsidiary), drilled 16 wells with H&P rigs and two with Perforec Rig 59. EnCana Ecuador drilled 2 wells.

Petrobras Energia Ecuador drilled eight wells in the Palo Azul field in the Oriente foreland basin (Block 18) as operator on behalf of partners Ecuador-TLC SA and Teikoku Oil Ecuador, a subsidiary of Japan's Teikoku Oil Co. Ltd.

Occidental Petroleum drilled four wells. AGIP drilled two wells, including the deepest this year, to 14,279 ft.

Nationals

The City of Oriente drilled five wells (four at Blanca) using CPEB Rig 50112. Petroproduccion, the production unit of Ecuador's state-owned oil company Petroleos de Ecuador (PetroEcuador), drilled 22 wells using Drillfor, Sinopec, and CPEB rigs.

Petrobell Inc. drilled five wells in the Tiguino field with Nabors rigs. Petrosud-Petroriva drilled three wells, all deeper than 10,000 ft, with Drillfor's Rig 7.

Compañía Sociedad Internacional Petrolera SA (SIPEC) drilled a single well using a CPEB rig.

Tecpecuador drilled two wells at El Rayo with Nabors Rig 818.

Rigs

Active drilling contractors include:

- H&P with eight SCR rigs in Ecuador, including two heli-transportable.
- Nabors International with two electrical and five mechanical rigs in the country.
- Drillfor SA, local Ecuador company.
- Changqing Petroleum Exploration Bureau (CPEB).
- China Petroleum & Chemical Corp. (Sinopec).
- China National Petroleum Corp. (CNPC).
- Petrex, a subsidiary of Eni SPA, with only one rig working for AGIP/Eni.
- Perforec Perforaciones Ecuatorianas SA, a wholly owned subsidiary of Saxon Energy Services Inc.

Petrobras stays

In July, Petrobras signed a 5-year strategic energy agreement with Ecuador's Petroecuador (OGJ, July 17, 2006, p. 5). Petrobras is focusing on exploration and development of the Ishpingo-Tiputini-Tambochocha (ITT) field complex in northern Ecuador, with 900 million bbl of proven reserves, and several blocks in southeastern Ecuador.

Eden-Yuturi

In 1991, Occidental Petroleum Corp. and Petroecuador initialized an agreement to develop the Eden-Yuturi field in Nueva Loja province, in the upper Amazon basin. The field has estimated oil reserves of 154 million bbl.

In March 2005, PetroEcuador President Hugo Bonilla said the terms of the Eden-Yuturi production sharing contract were "inequitable." At the time, the field was producing about 70,000 bo/d, with 25% going to PetroEcuador.

Occidental drilled its last four wells in Eden-Yuturi earlier this year with H&P's Rig 121.

EnCana leaves

EnCana Corp. drilled 20 wells in the beginning of the year before it pulled out of the country. In late February, EnCana announced that it had completed the sale of its Ecuadorian oil and pipeline interests to Andes Petroleum Co., a joint venture of Chinese petroleum companies, for about $1.42 billion.

Andes Petroleum Ecuador, through operator AEC Ecuador Ltd., has drilled two wells this year, the Alice 10H and 11H, using H&P Rig 190 and 191.

Government intervention

On May 15, 2006, Ecuador's energy minister Ivan Rodriguez cancelled the

operating contract with Occidental Petroleum Corp. for the 494,000-acre Amazonian Block 15 (OGJ Online, May 16, 2006). Rodriguez cited the company's illegal transfer of 40% of its local operations to EnCana in 2000 as one of the infractions.

The government had begun to talk of canceling Oxy's Block 15 contract in 2004, leading to speculation that the February sale of EnCana's interests to the Chinese was the culminating force.

Occidental said that Block 15 operations represented about 7% of its first-quarter 2006 worldwide production. The company is the largest exporter of petroleum in Ecuador.

On May 17, Oxy presented a demand for arbitration with the Ecuadorian government at the International Center for the Settlement of Investment Disputes (ICSID), Washington, DC.

On Sept. 28, Galo Chiriboga, president of Ecuadoran state petroleum firm Petroecuador, announced on Ecuador's national television that it would establish Rio Napo Operations Co. to operate oil fields formerly owned by Occidental (OGJ Online, Sept. 29, 2006).

In early October, Oxy dropped its arbitration claim against Petroecuador but maintained its claim against the Ecuador government at ICSID.

Business News Americas reported on Oct. 30 that PetroEcuador said investment within the country could reach $5 billion, with reforms.

OMV leaves

Last month, Austria's OMV AG completed the sale of its 5,000-b/d Ecuadorian exploration and production assets to joint-venture partners Burlington Resources Oriente Ltd. and Perenco Ecuador Ltd., a unit of privately held French E&P firm Perenco SA.

OMV said the partial interests in Block 7 and Block 21 in the Oriente basin of Central Ecuador, acquired in 2003, were not core to its E&P business (OGJ Online, Oct. 12, 2006).

Change afoot?

From national elections on Oct. 28, no clear winner emerged. The government announced a runoff, for Nov. 26, between the two top vote-getters: leftist Raphael Correa, US-educated economist; and banana magnate Alvaro Naboa, from the wealthiest family in Ecuador.

Following the election, the announcement of the next energy minister may indicate whether the new administration will focus on promoting foreign oil and gas investment or expand with nationalization. ✦

Holistic approach to safety systems produces improvement methodology

Peter Jofriet
Honeywell Process Solutions
Cincinnati

To improve the safety of the operating environment, a holistic method for defining and evaluating the systems that aid an operator with the safe operation of a process unit is required. This approach starts with an audit of the site's work practices and approach to safety as well as an analysis of the "as-built" condition of the site's layers of protection.

Stepping back and considering or defining a "safety system" as the many levels of protection used at a site allows the plant operator to better use each of these independent yet interrelated layers.

The concept of "layers of protection" is widely recognized in the process industry but is not always recognized as being implemented as interrelated systems. The term is clearly defined in industry safety standards such as the International Electrotechnical Commission's (IEC) standard 61508 and IEC 61511.

Based on a presentation to the National Petrochemical & Refiners Association Annual Meeting, Salt Lake City, Mar. 19-21, 2006.

Some layers of protection are preventive like emergency shutdowns, and some are there to mitigate the effect of an incident once it occurs, such as fire and gas protective systems or plant emergency response systems. The layers that are often missed are those that deter incidents in the first place (e.g., plant and physical asset protection, constraint and boundary management, operator training, and asset management); and those that can provide detection and alerting, and associated guidance (e.g., operator alarms, early event detection, and integrated operator procedures).

Fig. 1 shows that the core of the layered architecture is a well-designed and implemented process design that is the embodiment of the business, safety, and production considerations necessary for effective operations. The process must be controlled by a secure process control network that extends across the entire plant and business networks.

Managing the plant's assets ensures that the process design continues to function as intended, all the while protecting the plant from pending incidents with an early indication of failing or poorly performing assets.

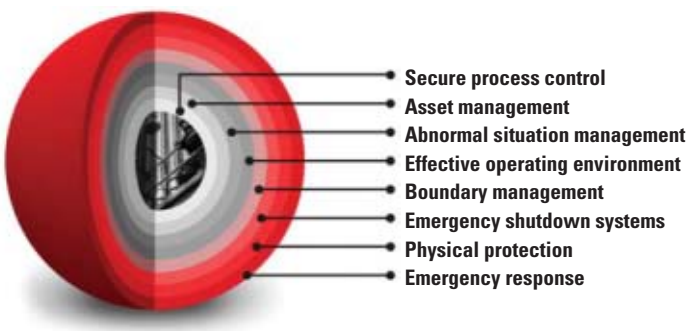
As one moves through the layers of protection further away from the core of process design, mitigating risk due to human error is the key to ensuring safety. Implementing tools and procedures (such as boundary and alarm management and early event detection) to manage abnormal situations reduces incidents and prevents escalation.

Appropriate operating windows must be defined and managed, and properly designed emergency shutdown systems must be in place as preventive measures in case an incident escalates beyond the inner layers of the sphere of protection.

To maximize plant effectiveness and to ensure the best safety level, a systematic approach to safety is required. This approach must minimize risks to safety and security, and it requires independent but interrelated layers of protection are in place across an organization.

LAYERED APPROACH TO PLANT SAFETY

Fig. 1



Although every site is different, there are some common or basic components needed in an analysis of the "as-built" condition of the site's layers of protection. The overall intent is to assess the areas of risk and potential areas for improvement.

The areas that should be considered are:

- Regulatory compliance.
- Instrumentation and control.
- Asset and abnormal situation management.
- Physical and system security.
- Work practices and policies.

Regulatory compliance

At the highest level, a safety program for any refinery in the US should conform to the Occupational Safety and Health Administration (OSHA) standard. These regulations require that programs are developed and implemented including these provisions: written procedures, training for process maintenance activities, inspection and testing, equipment deficiencies, and quality assurance.

OSHA and EPA regulations are performance based, allowing the owner-operator of the facility a great degree of latitude to implement a program that is most suitable for the organization and site, as long as it meets the general requirements listed in the standard.

Industry has been supportive of the goals promulgated in these standards and has supported their implementation by providing standards, recommended practices, and technical reports that provide guidelines for these regulations. Industry groups for areas where their membership has particular expertise publish this additional guidance.

Although the program that an owner-operator implements at a specific site is not required to be identical to the standards, recommended practices, and technical reports provided by these bodies, they provide an excellent benchmark for the practices of industry. If a site's programs do not conform to these guidelines, there should be a solid explanation why the industry guidance is inappropriate and why the site's alternative is superior.

Instrumentation, control

Fig. 1 shows that a secure process control system is one of the base layers upon which everything else is built. As part of any holistic look at safety, one must verify that the relevant programs are in place for verification of relevance of instrumentation and control systems, and that these systems are performing adequately.

There are several general guiding principles or benchmarks against which one can judge these types of systems.

Classification

All instrumentation and control equipment should be classified. EPA and OSHA regulations and many industry standards are risk-based, allowing maintenance and testing resources to be disproportionately spent in areas where higher risk is perceived.

In addition, different standards are applied to different kinds of instrumentation. A good classification process is a necessary first step in implementation of a mechanical integrity program.

An appropriate industry standard that can be used as a guideline for this task is ISA 91.01, "Identification of Emergency Shutdown Systems and Controls that are Critical to Maintaining Safety in Process Industries."

Identify programs

The body of instrumentation and control equipment should be subdivided into categories. These are at the discretion of the plant operator to some degree but typically include:

- Regulatory control systems. These are not protective and include instrument categories not listed hereafter.
- Safety instrumented systems.
- Alarm systems.
- Fire and gas systems.
- Burner management systems.
- Compressor, turbine monitoring systems.
- Simple manually activated protective systems (e.g., remote isolation valves).
- Complex manually activated protective systems (e.g., HF alkylation water curtains and cannons).

For each type of system, a program should be in place that includes provisions for the frequency of inspection and testing and procedures by which those inspection and testing tasks are performed.

These programs should consider both recommendations of the vendor and criticality of the instrument. The program should also describe methods by which proper equipment selected and installation is ensured.

Safety instrumented systems

Programs for safety-instrumented systems are generally performed in accordance with ISA 84.00.01, "Functional Safety: Safety Instrumented Systems for the Process Industry Sector."

This standard requires that all safety-instrumented functions be classified with a safety integrity level of 1, 2, or 3. The equipment selection and test plan is developed in concert with a quantitative reliability assessment showing that the probability of failure of demand estimated for the system is in accordance with the safety integrity level selected.

Regulatory controls

A program for integrity of regulatory controls is generally considered less critical than the program for protective functions; however, without good regulatory control the likelihood of an upset increases, as does a resulting escalation to process incident.

Considering that most business decisions made in a plant are ultimately carried out by the control loop (arguably, the heart of any automation system), it is alarming that two thirds of all control loops perform in a disruptive or ineffective manner.

With some manner of control-performance monitoring service, closed loop operating data can be used to identify areas where maintenance and

engineering actions are required to resolve the worst-performing loop problems.

System performance review

A review of the control system network's performance is essential for identifying any loading problems or bottlenecks. The reliability and performance of a control system can directly affect the effectiveness of an operator and, ultimately, the plant's safety. On a regular basis the health and status of a control system network must be quantified.

Taking a system-wide approach to control system management and developing baseline statistics for control system benchmarking allows ensures the reliable operation of the control system. Establishing clear system performance criteria and an analysis of the effect of any changes that may have been made to the existing control system in the past is the key to success.

Auxiliary systems

Other systems in the refinery may be left out of the standard safety audit. They are typically handled by other departments but play an integral part in a plant's safety. Consider, for example:

- Fire and gas systems are typically designed in accordance with NFPA 72, "National Fire Alarm Code." This guideline provides prescriptive requirements for equipment selection, installation and connection processes, testing frequency, and testing procedures.
- Burner-management systems are a subset of safety-instrumented systems and should comply with ISA 84.01. In addition, they should also comply with prescriptive requirements from other standards bodies that are a function of the specific type of fire device upon which the system is installed.
- Compressor, turbine-monitoring systems are also a subset of safety instrumented systems and should comply with ISA 84.01. In addition, they should also comply with prescriptive requirements from other standards bodies that are a function of the specific type of compressor or turbine that they are monitoring. These standards include API 611, 616, 617, and 618.
- Simple manually activated protective functions are typically designed in accordance with the "emergency stop" provisions on the NFPA 79 standard. In addition, they are generally designed to operate as an "independent protection layer" in conformance with AIChE guidelines.
- Complex manually activated functions. Some manually activated functions are so complex and situation-specific that general industry guidance is either unavailable or unacceptable. In these cases special extra care should be taken in their design and testing.

ASM consortium

The abnormal situation management (ASM) consortium (www.asmconsortium.com) was informally started in 1992 and formally chartered in 1994 to enable and empower operating teams to proactively manage their plants, maximize safety, and minimize environmental impacts while allowing the processes to be pushed to their optimal limits. Original ASM consortium members included Honeywell, Chevron Corp., Exxon Corp., Royal Dutch Shell PLC, BP PLC, Mobil Corp., Nova Chemicals Co., and Texaco Corp.

Asset management, ASM

The role of the operator is currently in a state of evolution partially brought on by the use of new technologies, downsizing of operating departments, and increased competitiveness in the industry. This evolution is significantly affecting the role and responsibilities of the "traditional" operator as well as the support elements required to make the operator successful in this environment.

To stay competitive and continue to advance abnormal situation management (ASM) practices in the future, companies must align their operations personnel to these necessary roles and responsibilities.

Any safety audit should consider the operating environment to assess whether a site has harnessed its respective technology appropriately in providing a truly effective operating environment. It should consider:

- Operator interface.
- Alarm system performance.
- Boundary and constraint management.
- Procedural automation.
- Asset effectiveness.

Operator interface

Using generally accepted industry guidelines, one should examine the process-operating environment. For example, using the evaluation methods developed by the ASM consortium (see box on this page) in conjunction with basic human factor design principles, one might consider operator task analysis, ease of access to information, alarm handling, and navigation.

In addition, the display-based operator interface can be reviewed for consistency with known standards. The intent is to review the following, looking for areas for improvement:

- Display organization and navigation.
- Context-sensitive access to information.
- Integration of auxiliary information (operating procedures, operator help, etc.).

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- Display design standards.
- Utilization of operator tools.

Alarm system performance

Alarm system programs are generally developed in accordance with EEMUA 191, "Alarm Systems – A Guide to Design, Management, and Procurement." This guideline recommends that alarms be rationalized and prioritized to ensure that the quantity of alarms and their display is appropriate for operations staff.

Alarm equipment selection, testing, and maintenance are typically tied to the priority that has been assigned to the alarm. Unlike safety-instrumented systems, the alarm system standards have no predefined alarm priorities. They are typically assigned at the discretion of each site and are typically a function of the type of control system hardware used at the plant.

Development programs for alarm systems are typically based on judgment and the concept of an "independent protection layer" as defined in AIChE guidelines from the Center for Chemical Process Safety. Performance of an alarm that is critical to safety is typically designed so it can meet the criteria for an independent protection layer.

In addition to quantifying the frequency and priority of alarms, one should review the site's overall alarm management strategy. Consideration must be given to current work practices relating to alarm system management:

- Existence and content of overarching alarm philosophy.
- Alarm annunciation and indication conventions.
- Situation-based alarm design.
- Automatic alarm cutout strategies.
- Alarm change management design.
- Use of alerts to notify the operator of prealarm anomalies.
- Alarm reporting standards and conventions.

Boundaries, constraints

All of the considerations noted for alarms can be extended to operating envelopes or constraints. One should consider whether work processes exist that are targeted at establishing operating limits for plant processes. This should be extended to include validation that operating targets are within specified limits, ensuring that the process is monitored and controlled to these targets, and reporting done in a consistent manner to promote continuous improvement.

Additionally, one should ensure that the operating envelope exercise is done in unison with alarm management efforts; these are two highly interrelated layers that are often considered independently.

Procedural automation

Every day operations staff must execute common, repeatable tasks that often combine manual and semi-automated processes. When key processes require an operator to manually control or activate specific components, such as a shutdown and start-up, execution can be inconsistent.

When that happens—whether because of varying levels of operator expertise, less-than-explicit instructions, out-of-date or missing data or unregulated input—the consequences can range from lost time and revenue to unnecessary safety hazards. These consequences are likely to be repeated time and again.

Recent ASM consortium-sponsored studies indicate sites that believe their manual procedures are sufficient still may have unknown problems. Questions one should ask include:

- Are procedure-related incidents recorded and tracked properly?
- Is there a measurable improvement system for critical procedures?
- How are "golden" procedures measured and compared to non-golden procedures?
- Can a small change be measured for reliability and efficiency?
- Are these procedures executed the same across shifts and personnel?
- How does a known decrease in execution time reflect on production dollars?

The current operator procedures and workflow used on site should be considered. An evaluation of the procedure workflow, as well as an assessment of the availability of data and standard tools and capabilities aimed at improving workflows and procedures may help to answer these questions.

Asset effectiveness

Directly related to the prevention of abnormal situations is the maintenance of a plant's assets. According to the ASM consortium, at least one-third of abnormal situations occurring in a typical processing plant are due to equipment problems.

Because operators must ultimately deal with these failures when they occur and given the possibility of the operator incorrectly recognizing the problem, it is important to consider asset management as a layer of protection. Proper procedures and work practices in the area of asset management can prevent an operator from ever needing to deal with the issue in the first place.

For a particular asset, no matter how big or small, an increase in availability is directly related to reliability. Reliability is the probability of equipment or systems functioning without failure for a stated period of time.

The achievement of availability is supported by a range of frequently talked about operation-based initiatives, including reliability, asset management, and ASM—an intense focus on the root causes of unplanned shutdowns and the procedures and technical tools that can help operators deal with upsets when they occur or prevent them from happening in the first place.

Physical, system security

Although perhaps not obvious in the context of a safety discussion, plant and process security is integral to ensuring plant safety. Not all upsets or incidents come from within.

An audit would be remiss if it did not consider the layers relating to plant and process security. An effective ap-

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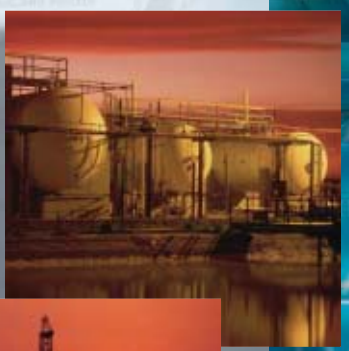

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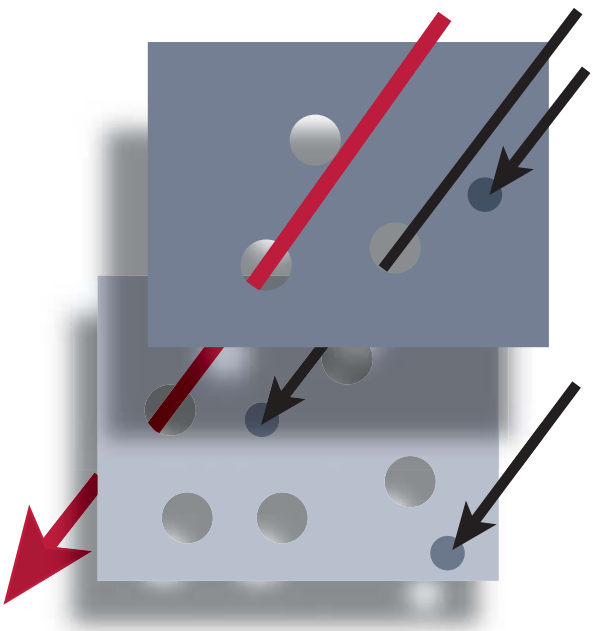
proach for protecting an industrial facility uses not only elements as previously discussed, but also elements protecting against a variety of threats, including threats to physical and cyber security.

This includes:

- Monitoring and protecting the perimeter of a plant.
- Identifying and controlling who enters and leaves the plant.
- Controlling access to restricted areas.
- Determining the location of people in the event of an emergency.
- Targeted and faster emergency response.
- Protecting process automation networks and systems from cyber threats.

FAILURE IN A PARTICULAR LAYER

Fig. 2



Physical, electronic security

The physical perimeter is protected by those technologies that have more visible, tactile characteristics—including fences, barricades, guards, and other assets used to prevent entry by unauthorized personnel.

An electronic security layer uses technologies such as video cameras, access cards, and motion-detection equipment. State-of-the-art systems use wireless and microwave closed-circuit television technology to monitor the perimeter. Digital video technologies can substantially optimize the monitoring regime by employing sophisticated pattern recognition to detect unusual movements.

Access control systems track everyone who enters and exits a facility, allowing operators to know who enters and departs, as well as where they are located while on the premises. Both video and access records can be stored electronically for simplified retrieval and review.

Access control technology plays an important role during incident mitigation. In the event of an incident, it may be important to muster individuals in a safe location. An electronic mustering station allows security or operations personnel to quickly identify which individuals are in the safe location. For those who have not reported to the muster location, access control records may be searched to determine the last known whereabouts of individuals.

TV cameras can be used to determine the location of individuals requiring emergency assistance.

Cyber security layer

A dramatic transformation from proprietary to open control systems has been underway within the process control industry. This trend, coupled with the connectivity between open control systems and enterprise networks, has introduced unprecedented cyber vulnerabilities in process control systems.

Furthermore, safety systems that are designed to bring a process to a safe state in the event of a failure are being integrated with open process control systems. This integration introduces the risk of a common-cause cyber fault, which not only disrupts the process, but also prevents the safety systems from responding to such disruptions.

Without an effective cyber-security strategy, the fundamental mission of process control—to ensure safe and reliable operations—can be compromised by an ordinary cyber threat such as a virus or worm. A comprehensive cyber-security strategy must therefore be an essential element of every process control and safety system implementation and should include the following:

- Regular risk and vulnerability assessments.
- Hierarchical architecture with cyber-security access restrictions at each network level.
- High-security model deployed on PCs and servers.
- Physically separated process control and enterprise networks with limited access points.
- Physically separated process control and process safety systems with limited access points.
- Security hotfix and antivirus deployment strategy.
- Disaster recovery.
- Best practices, policies, procedures, and change management.
- Dedicated service team responsible for cyber security.

Work practices, policies

In "The Human Factor," Kim Vicente points out the way humans and technology interact at the physical (ergonomic), psychological (individual), team, organization, and political levels. In the case of safety, the marrying of technology with humans is key to preventing serious if not fatal incidents.

One of the main barriers to adoption of a safe working environment occurs at the organizational-political level. There are many examples of instances of excellence at the physical, psychological, and team level. To solidify the future of safety at a plant, organization and political issues must be considered.

In order to complete a safety audit, one must examine the plant's leadership involvement in HSE self-assessment and audit processes, executive audits, recordable incident reviews, and risk assessment process.

Layers of protection

In many discussions of hazard assessment, the layers-of-protection concept is described as multiple layers of Swiss cheese (Fig. 2). In this model, the process has multiple layers of protection and that protective systems have "holes" that represent failures of a particular layer.

The holes may represent errors or lapses of attentions or perhaps poor maintenance or design, and the size of the holes simply represent the fraction of time that the system fails due to component failures. The bigger the holes and the fewer the layers the better the chance of a failure passing through.

The intent of any methodology aimed at ensuring a holistic approach to safety is to reduce the size of holes in the layers, and to ensure that multiple layers of protection indeed do exist. ✦

The author

Peter Jofriet (Peter.Jofriet@Honeywell.com) is the global business director of refining for Honeywell Process Solutions, Cincinnati. He joined Honeywell almost 5 years ago as an industry consultant, working in the areas of operator effectiveness, abnormal situation management, asset effectiveness, and mobile technologies. Jofriet has worked as a production supervisor, a control engineer, and a senior process engineer before joining Honeywell, working on supervisory control, advanced control, performance monitoring issues, and systems upgrades. He holds a masters in process control from Queen's University, Kingston, Ont., specializing in model-based fault diagnosis, expert systems, and neural networks.

WA LNG projects' fortunes reflected in Greater Gorgon

Chris Meredith
Wood Mackenzie
Edinburgh

Problems faced by the Greater Gorgon Project in Western Australia reflect challenges to all the potential LNG projects in the region (map). Greater Gorgon is the largest among potential LNG export projects in Western Australia.

Phase 1 will provide 10 million tonnes/year (tpy) of LNG capacity; second phase should deliver the same again.

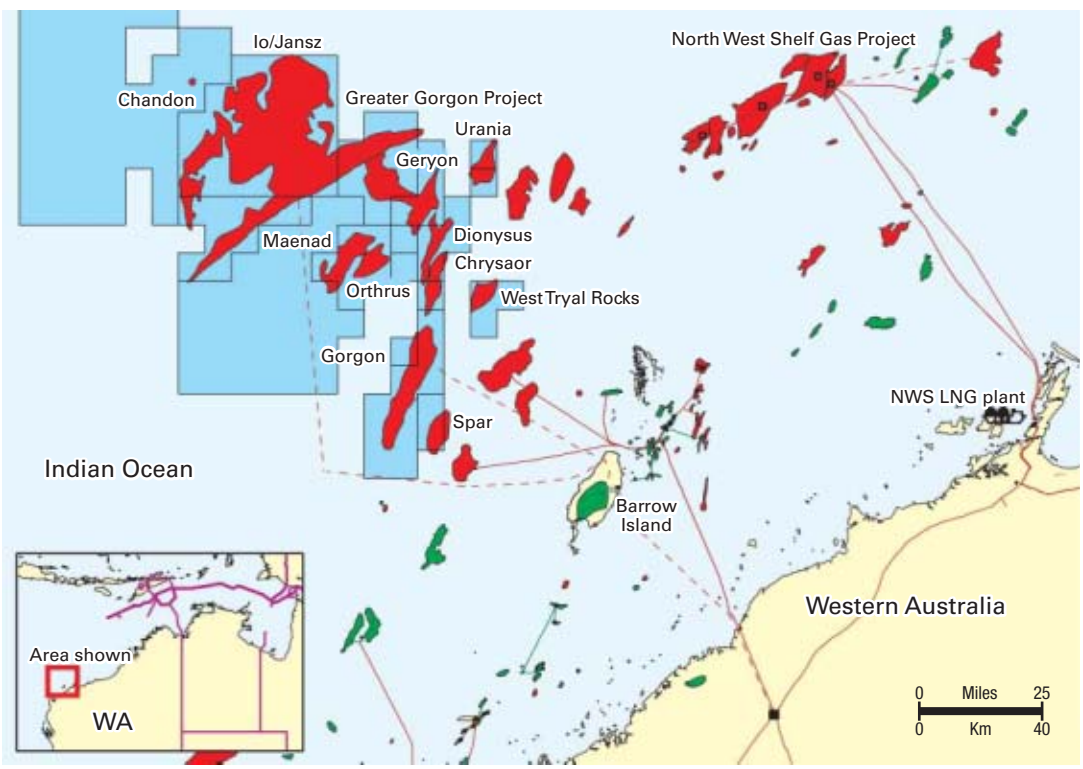
As with any project of this scale, there have been major challenges. Costs have increased, the schedule has slipped, the development plan has been criticized by environmental authorities, and uncertainties remain over partner alignment.

- Phase 1 is now expected to cost upwards of A$16.8 billion (US$12 billion), a 53% increase on the 2005 estimate of A$11 billion.
- The Western Australia (WA) Environmental Protection Agency (EPA) has concluded that the project is environmentally unacceptable. The gas plant and liquefaction trains will be located on Barrow Island, a Class A nature reserve, and there are concerns about the effect of development on local wildlife.
- ExxonMobil Corp., which is a 25% partner in the project, has yet to announce any sales agreements for its share of planned LNG volumes.

Despite these problems, the fundamental business case for the project is strong. The Pacific Basin LNG market is short of supply over the next 5-7 years, and buyers are beginning to accept the new reality of higher gas prices. Thus rising costs of the Gorgon development can, to an extent, be passed on to buyers.

The final decision on environmental approval rests with WA's Environment Minister who will consider social, strategic, and economic effects, alongside environmental issues. Wood Mackenzie expects the minister to seek a solution that will mitigate the environmental

GORGON, OTHER WESTERN AUSTRALIA LNG



Source: Wood Mackenzie PathFinder.

impact of the project and allow it to proceed, largely as planned.

ExxonMobil's position is a relatively straightforward commercial consideration. As and when the company secures a price for its gas that accommodates risks attendant to the project and when development costs are clearer, ExxonMobil will likely conclude sales agreements and stand alongside the other partners.

Challenges

Three major challenges face Greater Gorgon, any of which can seriously impede the entire project, if not addressed in a timely manner.

Rising costs

The estimated cost of developing Greater Gorgon has risen to around A$16.8 billion (US$12 billion) from A$11 billion quoted in September 2005 and could rise further. Cost increases are being encountered in most elements of development, including rig rates, steel, and cost of skilled labor. This puts pressure on project economics and raises questions about whether the sales price will be able to support increasing development costs.

Environmental concerns

On Barrow Island, a Class A nature reserve and proposed location of the processing facilities and liquefaction plant, there are strict quarantine regulations. The island is also a nesting area for flatback turtles, with two nesting beaches adjacent to the proposed LNG plant.

On June 6, 2006, Western Australia's Environmental Protection Agency issued Bulletin No. 1221 stating that Greater Gorgon's joint venture posed an unacceptable risk to the marine ecosystem through dredging and possible introduction of non-indigenous species.

It also stated that, because very little data are available on the life cycle and behavior of the turtles, it was impossible to identify management measures that would ensure their wellbeing. Consequently, the EPA considered that the proposals were environmentally unacceptable.

The EPA decision is a recommendation to the state's environment minister and also sets out conditions to which the project must adhere, if it goes ahead. Operator Chevron Australia is appealing the decisions, both the recommendation and the development conditions set.

Chevron has also stated that it is confident that the project will maintain an appropriate balance between environmental management and development on Barrow Island.

The final decision to approve development rests with the WA Environment Minister, who must take into account social, strategic, and economic impacts of the project, as well as the need for environmental protection. The result of Chevron's appeals will be announced later this year.

A decision is also required from the federal environment minister, but in recent statements he has suggested support for the project. Given that the WA premier has also spoken favorably, the balance of current evidence suggests that the project will be approved.

ExxonMobil's position

ExxonMobil has yet to announce any gas sales contracts for its equity volumes of LNG from the development. Most likely, this is primarily a result of commercial considerations from the company's perspective. ExxonMobil is understood to be operating under a less favorable tax position than the other two partners (Chevron and Royal Dutch/Shell), due to its operations in the Bass Strait.

Under Australian tax rules, companies build up Petroleum Resource Rent Tax (PRRT) credits from exploration losses, which can be transferred between PRRT-liable projects. Neither Chevron nor Shell has any producing assets that are taxed under the PRRT regime, meaning that their PRRT credits may be utilized by Gorgon production.

ExxonMobil will likely be able to conclude contracts to sell its share of the LNG at a price that makes the project attractive within its global portfolio. This may still contribute some delays to the decision-making process, however.

Other issues

Other issues face Greater Gorgon that, while they may not threaten its viability, could still delay progress and dilute project economics.

BP's position

BP holds 12.5% equity in two of three blocks that cover giant Io/Jansz field, plus a block covering Maenad and Orthrus fields and one over Geryon field. Io/Jansz field is an integral part of Phase 1 development. BP remains outside the framework agreement, signed in April 2005, which aligned the interests of the other three partners and allowed the current development plan to progress.

Recent press speculation has BP looking to sell out of the acreage. Any sale would be subject to pre-emption rights by the other partners, and Shell Australia has said it may look at the stake, if it came onto the market. If a third party were to purchase BP's stake, it would remain outside the framework agreement and may only be able to negotiate a small equity stake in the project.

Domestic gas allocation

In February 2006, WA's government issued a consultation paper regarding future domestic gas-supply arrangements for the state. The North West Shelf gas project (NWSGP) currently supplies around 70% of the WA domestic market, but essentially all gas reserved under the NWSGP state agreement has been fully contracted.

The state government is seeking to reserve an additional amount of NWSGP gas to meet future demand, as well as alternative supplies from proposed LNG developments on the WA coast.

Gas fields supplying the proposed developments lie in federal not state waters. As such, the state government

has no direct rights to the gas, but it must approve onshore developments and grant export licenses.

The paper declared that it would be prudent to impose domestic-gas reservation requirements on future LNG export projects. WA Premier Alan Carpenter has proposed that 15-20% of gas reserves should be allocated to the domestic market. The Gorgon State Agreement reserves 1.85 tcf of gas for the domestic market, but the joint venture only has an obligation to supply this gas if it is economic to do so.

From a commercial perspective, the major stumbling block is price. Wood Mackenzie believes that NWSGP sells domestic gas at around a 60% discount to the price realized under its current Japanese LNG contracts, a discount well more than the cost of liquefaction.

Additional gas resources, such as the Chandon discovery, could increase the pressure on Greater Gorgon to supply the domestic market simply because current proven and probable reserves are already well in excess of requirements for a 10-million-tpy LNG project.

While the state government appears to back intervention, the federal government has taken a diametrically opposed view. In May 2006, the federal minister for Industry, Tourism and Resources stated that "artificial constraints on export capacity, such as domestic gas reservations, are not part of this government's approach."

Gas-transfer pricing

Residual pricing mechanism (RPM) is a method of generating a gas-transfer price, which is an accounting value, calculated solely for taxation when there is common ownership of upstream and downstream phases of a gas-to-liquids project. The upstream phase of a development will be taxed under PRRT terms, while the downstream phase will be subject only to corporation tax.

RPM calculates the transfer price between phases of a development. A feature of RPM is that the transfer price tends to rise throughout the project's life, a function of greater ongoing capital expenditure in the project's upstream phase. This will gradually shift more revenue to the upstream (higher tax) phase and steadily increase the project's overall tax burden.

Within the scope of the regulations, however, lies room for an "advanced pricing arrangement" (APA), which would take priority over RPM. An APA is a negotiated transfer price, agreed between a project joint venture and tax authorities. It is understood that Chevron is looking to negotiate an APA for Greater Gorgon, but this could take up to 2 years to conclude.

Wider implications

The decision of Western Australia's Environment Minister could have wide implications for the Australian gas export industry.

Five major projects, with capacity totaling around 40 million tpy, are proposed for the WA coast over the next 10-15 years.

If the minister were to rule against locating LNG facilities on Barrow Island, then those projects that propose to use other greenfield sites–specifically Ichthys and Browse–could be under threat.

INPEX-led Ichthys is located in Browse Basin and proposes to use two islands for its LNG facility. The Woodside-led Browse project will operate in and around Scott Reef, which could invoke environmental concerns.

If the minister rules in favor of locating of LNG facilities on Barrow Island, it may be because it has been treated as a special case, as there have been oil operations on Barrow for more than 40 years. It has been the oil industry, specifically Chevron, that has effectively quarantined and helped maintain the island's environmental integrity.

Possible beneficiaries of any tightening of environmental regulations are developments planned for brownfield sites. These include Pluto and Scarborough.

Pluto is planned for a quasi-brownfield site, adjacent to NWSGP and within the Burrup industrial area, while for the proposed Scarborough LNG facility, BHP Billiton plans to utilize a site south of Onslow in an area that has already been zoned for industrial development.

A major tightening of WA environmental restrictions could be of greatest benefit to Darwin, in the Northern Territory. There are currently 3.2 million tpy of LNG capacity at Darwin, with consent to raise this to 10 million tpy. The Darwin plant came on stream in February 2006 with an estimated 25 tcf of proven and probable gas reserves within 500 km. ✦

The author

Chris Meredith (chris.meredith@woodmac.com) joined Wood Mackenzie in 2005 as a research analyst in the Australasia team. He has worked on all aspects of Wood Mackenzie's Australasian Upstream Service, as well as a number of consultancy projects in the region. Before joining Wood Mackenzie, he worked as an equities analyst for an asset manager. Meredith is a chartered financial analyst (CFA) charterholder and holds a BSc (honors) in chemistry from the University of St. Andrews.

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French beginning to open natural gas market

Recent project announcements suggest that, however small the initial steps, France is finally moving toward liberalization of its natural gas market.

The success of EdF Trading Ltd. in securing terminal capacity at Gaz de France's LNG terminal at Montoir-de-Bretagne and proposals from several developers to build LNG import facilities at the Port of Bordeaux, Antifer, and Dunkirk are small but significant steps in opening Frence's gas market (see table).

FRENCH LNG TERMINALS

	Sendout, bcfd	Act./est. start date	Sponsors	Status
Fos-sur-Mer	0.5	1972	Gaz de France (100%)	Operating
Montoire de Bretagne	1.0	1982	Gaz de France (100%)	Operating
Fos Cavaou	0.8	2007	Gdf (66%), total 33%	In construction
Port of Bordeaux	0.6-0.9	2011	4Gags (100%)	Proposed
Antifer	0.8-1.0	2011	Poweo, CIM	Proposed
Dunkirk	0.6	2011	Electricite' de France	Proposed
Montoire Expansion	0.2-0.6	NA	Gaz de France	Contingent

Source: Poten & Partners

At Montoir

London-based EdFT, a European wholesale trader of electricity, gas, and coal, announced in July 2006 that it had reserved one slot/month at GdF's Montoire terminal for 2007. Contracting capacity proved relatively straightforward, as GdF published berth availability on its website and offered reasonable terms.

EdFT is to receive regasified product in equal amounts over 30 days, as opposed to the 5-day lifting period that other terminals often allow.

Downstream, EdFT plans to market some gas to parent company Electricité de France, which has been building a retail portfolio since it was allowed to move into the domestic gas business in 2005. EdFT will also sell gas at Belgium's Zeebrugge hub, where it is one of the most active traders, and expects to move additional quantities into the UK via the Interconnector Pipeline.

Despite tight supply conditions, EdFT is betting that it will be able to secure cargoes to fill the slots at Montoire. "Early on," said one company official, "we decided that coming up with a nicely packaged suite of contracts with a bow on it wasn't possible." Instead, the firm chose to acquire regasification capacity to distinguish itself from other would-be buyers.

EdFT is confident that experience and a large, flexible contract portfolio will give it competitive advantage in the region. "The trick is how to get the gas from Montoire to somewhere actually useful," the source said. The bet also reflected bullish forward prices for winter gas in Northwest Europe, which tagged it as a premium market, although since then the forward price curve has declined.

More terminals

Another sign of change is the site option secured in August by Rotterdam-based 4Gas, an independent developer of LNG terminals in the UK and on the Continent, for an LNG terminal at Bordeaux.

Although the project is still in the conceptual stage, the firm has said it wants to build an import terminal with initial capacity of 6-9 billion cu m/year. Cost estimates run to €400 million, with additional investment required for a pipeline connection to the regional distribution system.

4Gas chose Bordeaux because it is close to the Spanish market and has good port infrastructure. The specific site is at Le Verdon at the mouth of the La Gironde. This is the company's fourth terminal project and follows the Dragon LNG venture under construction at Milford Haven, Wales, as well as two other terminals planned in Rotterdam and Canada's Nova Scotia province.

More recently, the Port of Le Havre Authority tagged a joint venture between Poweo, an electricity and gas supply company based in Paris, and Compagnie Industrielle Maritime for a possible new terminal at Antifer, near the Le Havre petroleum port (OGJ Online, Oct. 10, 2006). According to Poweo, the terminal would have a capacity of 8-10 billion cu m/year and cost about €500 million with start-up slated for 2011.

As with Bordeaux, these parameters are only preliminary, and project scope should be further defined in a meet-

Based on an article in LNG in World Markets, August 2006, Poten & Partners Inc., New York (www.poten.com).

ing with the port authority before yearend. Poweo, a new company, is moving aggressively to position itself in the French gas market. It is building its first combined-cycle gas turbine power plant, for start-up tentatively in 2008, and earlier this year formed a strategic alliance with major Austrian utility Verbund GS, which assisted the French firm in the bidding process.

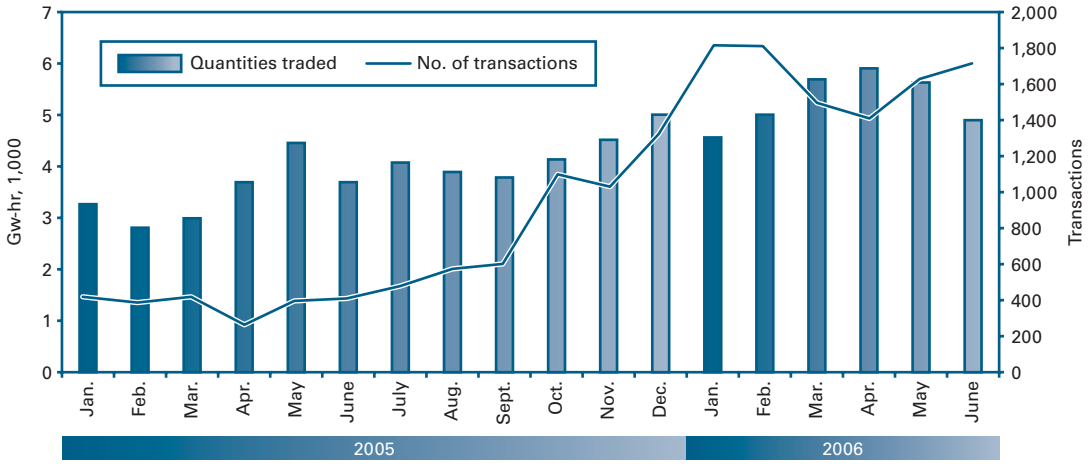
Earlier last summer, Poweo hired a former executive from Qatargas 2, Luc Poyer, as deputy managing director with responsibility for upstream supply.

On the other hand, CIM SNC, France's largest oil tank farm owner, has been concessionaire for the oil terminals at Le Havre since 1920 and at Antifer since that facility began operations in 1976. Poweo had proposed to develop the LNG terminal on its own but agreed to form a partnership with CIM when the port authority's board of directors expressed concern about its lack of experience in terminal management.

Finally, in mid-October EdFT parent Electricité de France won a tender for feasibility studies toward an LNG terminal at Dunkirk. In concept, EdF would build and operate a terminal with an initial capacity of 6 billion cu m/year, starting in 2011. The studies would run for about 3 years, although competition with nearby Antifer could force EdF to accelerate its timetable.

The company obtained its Dunkirk foothold concurrently with terminal and pipeline capacity deals in other countries. The suite of moves is designed to boost its presence in northwest Europe in the medium term and exploit its position astride the English Channel.

GAS TRADING ON FRENCH MARKETS



Source: TSO/CRE.

First step

France has resisted European Union efforts to liberate gas markets, and an adverse ruling from the European Court of Justice in 2003 was needed to force the government to enact reform measures. Since then, the country has made steady progress, although it still has a considerable way to go.

The most important step is scheduled for July 1, 2007, after when all gas consumers are to have at least nominal freedom to choose suppliers. In the past few years, the government has also restructured GdF into a limited liability company and sold down the state's equity from 100% to 78%. It established four gas-balancing zones, where virtual Gas Exchange Points (known by their French acronym as PEGs) act as incipient trading hubs, similar to UK's National Balancing Point. The PEGs as yet do not have enough activity for reliable price signals, but trade volume is growing (diagram).

The government has also unbundled the gas transmission system, forcing GdF and Total SA, which has the second-largest market share, to create subsidiaries to hold and manage their trunklines. These new entities can take independent decisions on matters that affect capacity and service, although the French regulatory authority would like them to be even more independent.

In the south of France, two gas pipelines, the Port-de-Larrau and Euskadour, now straddle the border, and there are big plans to expand the latter. GdF and Total unwound their cross-holdings in joint-venture companies that cover most of southern France and entered into a 3-year gas-release program in 2004 to stimulate competition.

They have offered 150 MMcfd by auction so far, most of which belongs to GdF. Total has further committed to improve third-party access to its transmission and storage facilities.

As a result of these efforts, there are now 28 registered gas suppliers in France, of which 14 are active, in addition to the 22 companies authorized as distributors within a given regional market. The roster of firms that can act nationwide includes subsidiaries of other European gas players, such as E.ON-Ruhrgas, Wingas, Iberdrola, Gas Natural, Eni, and Statoil ASA. There are also traditional French energy players such as BP France, EdF, and Air Liquide as well as start-ups like Altergaz and Poweo.

Resistance

But the French gas industry remains stubbornly concentrated. The top three suppliers have 91% of the market, while foreign-owned suppliers have only 3%. Some 640,000 industrial and business

consumers are eligible to select their gas providers. Yet only about 35,000 have made a selection, and most of these opted to stay with their provider. Only about 300 switched to an alternative provider that offers gas at competitively determined prices.

Part of the problem is that GdF contracted gas supplies under long-term agreements, and these will only expire gradually. But EU competition authorities suspect GdF of abusing its dominant position, and the company was among 20 firms raided in May in an antitrust crackdown.

French politicians can only take so much when it comes to market liberalization and reached their limit when they learned that Italy's Enel planned to acquire utility Suez. Prime Minister Dominique de Villepin subsequently brokered a hasty merger agreement between Suez and GdF. The agreement would reduce the state's share in the combined entity to less than 50%.

This flagrant economic nationalism brought protests from EU regulators, who are investigating the merger's likely impact on competition, and from French unions, which say that the government is breaking its pledge—enshrined in Gallic law—to retain a majority stake in GdF. On Oct. 3 the National Assembly, France's lower house, approved the privatization amid strikes and protests, and the Senate will begin its debate shortly.

Meanwhile, the European Commission has provided detailed objections to the merger. These focus on Belgium, where the combined entity would have a near-monopoly on gas and electricity, but also on France. Aspiring market players, including Gazprom, Enel, and Centrica, are eagerly awaiting the announcement of possible asset sales to comply with the regulatory demands.

The merger, somewhat paradoxically, might further increase competition for LNG imports in the French gas market. As a sweetener to the antimonopoly authority, GdF has offered to expand its Montoire terminal to anywhere from 12 to 16 billion cu m/year from the current 10 billion cu m/year, with the extra capacity to be offered to third parties.

If the merger proceeds, it also said it would functionally separate its French LNG business from other operations. As often occurs when a dominant player makes concessions, though, the olive branch warrants a closer look. Its offer comes on the heels of the Bordeaux, Antifer, and Dunkirk terminal announcements, and could be seen as a move to preempt its competitors as well as a further shove against the half-open door of the French gas market. ✦

Services / Suppliers

Gray Energy Services LLC

Fort Worth, has announced the acquisition by its subsidiary, Gray Wireline Service Inc., of Southern Wireline Service Inc., a longstanding independent provider of cased-hole wireline services in the onshore and transition zone regions of the Gulf Coast and offshore Gulf of Mexico.

Southern Wireline Service Inc., founded in 1968, is based in Lafayette, La.

Gray Energy Services LLC was formed in early 2006 by Centre Partners, Centre Southwest Partners, and Gray Wireline Service Inc., as a platform to build a leading diversified provider of production enhancement solutions across the North American natural gas and oil production industry.

Enidine Inc.

Buffalo, NY, has announced its acquisition of Ameritool Manufacturing LLC. Ameritool is a major manufacturer of stainless steel gas springs and dampers.

Enidine Inc. is part of the Energy Absorption Group of International Motion Control.

Intec Engineering

Houston, has announced the appointment of Marc Mellema to the position of chief financial officer. Mellema brings expertise as an international tax lawyer with four large accountancy firms in Europe and a specialty in multinational companies in the onshore and offshore oil and gas industry. He most recently served as manager of taxation for Heerema Marine Contractors.

Intec Engineering, a division of the Heerema Group, is a leading engineering and project management company serving the international oil and gas industry. Its technical disciplines include marine pipelines and risers, subsea systems, systems engineering, flow assurance, floating systems, LNG terminals, and marine installation management.

InterMoor Inc.

Houston, has named Brent Boyce as subsea installation manager, with responsibility for management of InterMoor's compensated anchor-handler subsea installation method (CASIM) and other installation activities.

Boyce has more than nine years of experience in management of subsea intervention and completion systems, most recently serving as project manager for Saipem America.

InterMoor Inc., an Acteon company, is an industry leader in innovative mooring and installation technology.

Schlumberger Ltd.

Houston, has completed the relocation of its US corporate office from New York to the Houston Galleria area. While Schlumberger maintains corporate offices in Paris and The Hague, the Houston corporate office will consolidate the company's presence in that city.

Schlumberger Ltd. is a leading oil field services company supplying technology, information solutions, and integrated project management to optimize reservoir performance for customers in the global oil and gas industry.

New mobile stimulation pumping system

StimFORCE, a new modular, mobile stimulation pumping system, provides the capabilities of a traditional, stimulation pumping vessel with skid units.

The modular package can be shipped and reconstructed on a platform supply vessel, barge, or offshore rig to provide stimulation services in remote locations. The first system was recently shipped to Equatorial Guinea to provide frac pack and gravel pack pumping services on a multiyear deepwater sand control completion project.

StimFORCE was developed to enable, frac pack, acidizing, and pressure stimulation treatments to support completions operations in remote land, swamp, and offshore areas where conventional stimulation services are not readily available.

The modular StimFORCE plant consists of a control room, field laboratory, storage containers, power packs, liquid additive system, hydration unit, two 45 bbl/min frac blenders, six frac pumps, and two 300-ft flexible steel hoses. The system's treatment range includes sand control frac pack completions as much as 45 bbl/min at 12 lb proppant added (ppa) and 50 bbl/min at 10 ppa, as well as low-rate openhole gravel pack operations requiring a pumping rate of 5 bbl/min at 0.5 ppa.

Abovedeck proppant storage consists of several compartments for storage of 200,000 lb (expandable to 300,000 lb) of proppant, with belowdeck bulk transfer connections for multiple treatment capability. On-the-fly mix capabilities help minimize equipment footprint while using supply vessel or rig water for fresh water or seawater-based treatment systems. The template requires a free deck area of 40 ft by 176 ft.

Pumping equipment is mobilized and configured using integrated corner fittings and secured to the vessel by an integral grid system on the platform supply vessel deck. The securing system minimizes required vessel modifications and provides safe mounting for treatment equipment during extreme weather conditions. To facilitate lifting on and off the grid and comply with global deployment and logistical requirements, each component of the StimFORCE package has been designed with a maximum weight of 35,000 lb.

The flexibility of StimFORCE helps suit it for batch drilling and completion programs, the firm notes.

StimFORCE can also be configured for pumping onshore, as well as on platforms, rigs and drillships.

Source: **Baker Oil Tools**, 9100 Emmott Rd., Houston, TX 77040.

Statistics

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	11-3 2006	[1]10-27 2006	11-3 2006	[1]10-27 2006	11-3 2006	[1]10-27 2006	11-4 2005
	1,000 b/d						
Total motor gasoline	625	447	18	108	643	565	441
Mo. gas. blending comp.	502	900	9	58	511	958	418
Distillate[2]	261	427	10	14	271	441	495
Residual	287	137	28	16	315	153	701
Jet fuel-kerosine	57	128	128	51	185	179	246
LPG	361	446	—	—	361	446	293
Unfinished oils	585	408	25	56	610	464	399
Other	452	446	11	16	463	462	479
Total products	**3,130**	**3,339**	**229**	**319**	**3,359**	**3,658**	**3,472**
Canadian crude	1,793	1,357	73	164	1,866	1,521	1,695
Other foreign	7,201	7,195	988	782	8,189	7,977	8,460
Total crude	**8,994**	**8,552**	**1,061**	**946**	**10,055**	**9,498**	**10,155**
Total imports	**12,124**	**11,891**	**1,290**	**1,265**	**13,414**	**13,156**	**13,627**

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

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

OIL&GAS JOURNAL online research center

OGJ CRACK SPREAD

	*11-3-06	*11-4-05	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	63.96	67.24	–3.28	–4.9
Brent crude	57.46	59.06	–1.60	–2.7
Crack spread	6.49	8.18	–1.68	–20.6
FUTURES MARKET PRICES				
One month				
Product value	64.72	70.18	–5.46	–7.8
Light sweet crude	58.56	60.34	–1.78	–2.9
Crack spread	6.16	9.84	–3.68	–37.4
Six month				
Product value	74.13	75.09	–0.96	–1.3
Light sweet crude	63.86	62.00	1.86	3.0
Crack spread	10.28	13.09	–2.82	–21.5

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel	Fuel oils		Unfinished oils
		Total	Blending comp.[1]	Kerosine	Distillate	Residual	
	1,000 bbl						
PAD I	13,587	54,354	26,319	10,849	68,579	17,699	7,770
PAD II	67,374	51,738	16,748	7,350	24,228	2,221	14,831
PAD III	177,602	65,345	27,707	13,780	34,700	17,457	43,304
PAD IV	14,620	5,942	1,942	430	2,490	410	3,294
PAD V	[2]60,063	27,730	20,415	7,967	11,037	6,154	20,694
Nov. 3, 2006	**[2]333,246**	**205,109**	**93,131**	**40,376**	**141,034**	**43,941**	**89,893**
Oct. 27, 2006[3]	**334,112**	**203,785**	**92,563**	**41,154**	**143,088**	**43,831**	**90,691**
Nov. 4, 2005	**326,471**	**203,080**	**69,997**	**38,185**	**123,631**	**37,148**	**90,643**

[1]Included in total motor gasoline. [2]Includes 8.220 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—NOV. 3, 2006

	REFINERY OPERATIONS					REFINERY OUTPUT			
District	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
	1,000 b/d					1,000 b/d			
East Coast	3,013	1,453	1,465	1,618	90.5	1,820	98	532	143
App. Dist. 1	103	95	95	95	100.0	13	—	27	1
Dist. 1 total	**3,116**	**1,548**	**1,560**	**1,713**	**91.1**	**1,833**	**98**	**559**	**144**
Ind., Ill., Ky.	2,097	1,983	2,000	2,355	84.9	1,104	135	543	60
Minn., Wis., Dak.	429	415	423	442	95.7	231	27	116	9
Okla., Kan., Mo.	876	713	719	786	91.5	464	22	265	5
Dist. 2 total	**3,402**	**3,111**	**3,142**	**3,583**	**87.7**	**1,799**	**184**	**924**	**74**
Inland Texas	926	588	596	647	92.1	419	53	168	7
Texas Gulf Coast	4,183	3,653	3,740	4,031	92.8	1,456	372	945	139
La. Gulf Coast	3,334	3,014	3,245	3,264	99.4	1,208	351	765	143
N. La. and Ark.	230	190	199	215	92.6	101	8	52	6
New Mexico	172	94	94	113	83.2	106	4	27	—
Dist. 3 total	**8,845**	**7,539**	**7,874**	**8,270**	**95.2**	**3,290**	**788**	**1,957**	**295**
Dist. 4 total	**678**	**579**	**587**	**596**	**98.5**	**273**	**23**	**174**	**18**
Dist. 5 total	**2,588**	**2,441**	**2,573**	**3,173**	**81.1**	**1,709**	**341**	**425**	**122**
Nov. 3, 2006	**18,629**	**15,218**	**15,736**	**17,335**	**90.8**	**8,904**	**1,434**	**4,039**	**653**
Oct. 27, 2006*	**18,712**	**15,126**	**15,686**	**17,335**	**90.5**	**9,014**	**1,474**	**4,242**	**580**
Nov. 4, 2005	**16,122**	**14,297**	**14,514**	**17,115**	**84.8**	**8,417**	**1,335**	**3,758**	**634**

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

OGJ GASOLINE PRICES

	Price ex tax 11-1-06	Pump price* 11-1-06	Pump price 11-2-05
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	161.9	201.6	253.6
Baltimore	167.7	209.6	235.3
Boston	179.6	221.5	225.6
Buffalo	166.5	226.6	242.8
Miami	175.3	225.6	238.7
Newark	188.6	221.5	238.4
New York	175.4	235.5	248.2
Norfolk	171.8	209.4	254.6
Philadelphia	175.9	226.6	248.8
Pittsburgh	174.8	225.5	239.4
Wash., DC	191.2	229.6	257.1
PAD I avg.	175.3	221.2	243.9
Chicago	180.1	231.0	253.8
Cleveland	166.5	212.9	231.6
Des Moines	161.5	201.9	227.5
Detroit	174.7	223.9	233.4
Indianapolis	168.9	213.9	227.9
Kansas City	173.9	209.9	225.9
Louisville	170.0	206.9	230.5
Memphis	179.1	218.9	244.8
Milwaukee	170.2	221.5	255.8
Minn.-St. Paul	179.5	219.9	226.1
Oklahoma City	172.5	207.9	217.3
Omaha	173.5	219.9	223.1
St. Louis	179.9	215.9	250.7
Tulsa	169.5	204.9	214.9
Wichita	169.5	212.9	217.7
PAD II avg.	172.6	214.8	232.1
Albuquerque	182.7	219.1	247.1
Birmingham	172.2	210.9	241.3
Dallas-Fort Worth	167.5	205.9	245.5
Houston	171.5	209.9	245.3
Little Rock	173.7	213.9	230.5
New Orleans	178.5	216.9	265.9
San Antonio	174.5	212.9	238.0
PAD III avg.	174.5	212.8	244.8
Cheyenne	195.7	228.1	244.1
Denver	192.8	233.2	251.2
Salt Lake City	193.5	236.4	256.7
PAD IV avg.	194.0	232.6	250.7
Los Angeles	193.5	252.0	279.6
Phoenix	202.0	239.4	258.9
Portland	207.8	251.1	242.1
San Diego	202.0	260.5	276.2
San Francisco	213.0	271.5	279.4
Seattle	208.7	261.1	262.7
PAD V avg.	204.5	255.9	266.5
Week's avg.	**179.7**	**223.3**	**243.5**
Oct. avg.	**183.8**	**228.0**	**263.9**
Sept. avg.	**208.9**	**253.3**	**282.5**
2006 to date	**217.7**	**261.3**	—
2005 to date	**182.1**	**224.1**	—

*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

	10-27-06 ¢/gal		10-27-06 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	157.05	New York Harbor	165.38
Gulf Coast	153.80	Gulf Coast	167.76
Los Angeles	159.55	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	139.94	ARA	173.29
Singapore	147.64	Singapore	167.88
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	155.32	New York Harbor	101.86
Gulf Coast	152.80	Gulf Coast	89.88
Los Angeles	167.55	Los Angeles	114.02
		ARA	102.14
		Singapore	105.72

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

BAKER HUGHES RIG COUNT

	11-3-06	11-4-05
Alabama	4	5
Alaska	6	7
Arkansas	25	14
California	33	31
Land	30	26
Offshore	3	5
Colorado	93	86
Florida	0	2
Illinois	0	0
Indiana	0	0
Kansas	11	7
Kentucky	13	7
Louisiana	198	181
N. Land	62	49
S. Inland waters	20	21
S. Land	44	36
Offshore	72	75
Maryland	0	0
Michigan	3	2
Mississippi	14	11
Montana	18	24
Nebraska	0	0
New Mexico	90	88
New York	9	4
North Dakota	39	23
Ohio	8	9
Oklahoma	190	152
Pennsylvania	15	13
South Dakota	1	3
Texas	792	676
Offshore	14	7
Inland waters	2	2
Dist. 1	21	15
Dist. 2	27	32
Dist. 3	58	67
Dist. 4	97	73
Dist. 5	133	115
Dist. 6	116	107
Dist. 7B	47	20
Dist. 7C	45	36
Dist. 8	97	77
Dist. 8A	24	26
Dist. 9	42	36
Dist. 10	69	63
Utah	45	29
West Virginia	30	26
Wyoming	96	91
Others—HI-1; ID-1; NV-1; OR-1; TN-1; WA-1	6	5
Total US	**1,739**	**1,496**
Total Canada	**376**	**582**
Grand total	**2,115**	**2,076**
Oil rigs	310	231
Gas rigs	1,422	1,260
Total offshore	95	88
Total cum. avg. YTD	**1,638**	**1,366**

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

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

SMITH RIG COUNT

Proposed depth, ft	Rig count	11-3-06 Percent footage*	Rig count	11-4-05 Percent footage*
0-2,500	50	2.0	25	—
2,501-5,000	91	52.7	74	32.4
5,001-7,500	231	16.4	161	20.4
7,501-10,000	424	2.8	319	5.3
10,001-12,500	441	2.2	314	1.5
12,501-15,000	246	0.8	287	0.3
15,001-17,500	117	—	123	—
17,501-20,000	71	—	48	—
20,001-over	31	—	16	—
Total	**1,702**	**6.5**	**1,367**	**5.8**
INLAND	38		31	
LAND	1,600		1,294	
OFFSHORE	64		42	

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

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

OGJ PRODUCTION REPORT

	[1]11-3-06	[2]11-4-05
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	22
Alaska	789	862
California	704	699
Colorado	58	63
Florida	7	7
Illinois	30	27
Kansas	95	93
Louisiana	1,384	695
Michigan	16	16
Mississippi	52	50
Montana	93	96
New Mexico	165	167
North Dakota	105	103
Oklahoma	174	172
Texas	1,366	1,199
Utah	46	48
Wyoming	141	143
All others	68	72
Total	**5,313**	**4,534**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	11-3-06
Alaska-North Slope 27°	56.72
South Louisiana Sweet	54.75
California-Kern River 13°	47.30
Lost Hills 30°	54.65
Southwest Wyoming Sweet	56.64
East Texas Sweet	56.88
West Texas Sour 34°	47.00
West Texas Intermediate	55.75
Oklahoma Sweet	55.75
Texas Upper Gulf Coast	52.50
Michigan Sour	48.75
Kansas Common	54.75
North Dakota Sweet	44.75

*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]	10-27-06
United Kingdom-Brent 38°	57.66
Russia-Urals 32°	54.14
Saudi Light 34°	54.73
Dubai Fateh 32°	56.38
Algeria Saharan 44°	59.59
Nigeria-Bonny Light 37°	60.69
Indonesia-Minas 34°	53.32
Venezuela-Tia Juana Light 31°	51.90
Mexico-Isthmus 33°	51.79
OPEC basket	55.49
Total OPEC[2]	55.45
Total non-OPEC[2]	52.31
Total world[2]	53.58
US imports[3]	51.61

[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]

	10-27-06	10-20-06	Change
	Bcf		
Producing region	1,008	1,004	4
Consuming region east	1,976	1,990	–14
Consuming region west	468	467	1
Total US	**3,452**	**3,461**	**–9**
	Aug. 06	**Aug. 05**	**Change, %**
Total US[2]	**2,969**	**2,662**	**11.5**

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

Statistics

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Aug. 2006	July 2006	8 month average production 2006	8 month average production 2005	Chg. vs prev. year Volume	Chg. vs prev. year %	Aug. 2006	July 2006	Cum. 2006
	Crude, 1,000 b/d						Gas, bcf		
Argentina	638	651	638	655	–18	–2.7	138.3	137.7	1,063.43
Bolivia	45	45	45	40	5	12.5	40.0	40.0	313.00
Brazil	1,703	1,725	1,702	1,612	90	5.6	30.0	30.8	233.60
Canada	2,514	2,492	2,457	2,298	160	6.9	507.9	477.4	4,018.48
Colombia	509	536	528	525	4	0.7	17.0	17.5	137.00
Ecuador	542	543	542	520	22	4.2	0.3	0.3	2.49
Mexico	3,252	3,232	3,313	3,340	–28	–0.8	171.3	165.0	1,275.88
Peru	122	122	115	113	2	1.8	7.0	6.8	37.86
Trinidad	150	152	149	148	1	0.6	110.0	112.2	830.35
United States	5,155	5,171	5,103	5,449	–346	–6.3	1,618.0	1,625.0	12,967.00
Venezuela[1]	2,520	2,470	2,588	2,730	–143	–5.2	82.0	80.0	657.00
Other Latin America	78	78	80	81	–2	–1.9	7.5	7.5	58.51
Western Hemisphere	**17,229**	**17,217**	**17,260**	**17,511**	**–252**	**–1.4**	**2,729.4**	**2,700.2**	**21,594.62**
Austria	17	17	17	17	—	0.9	3.0	3.2	37.87
Denmark	349	344	339	384	–44	–11.5	22.2	22.7	239.32
France	21	21	21	21	—	–0.2	3.4	3.0	28.24
Germany	68	66	70	69	2	2.2	50.8	45.6	441.18
Italy	97	103	110	115	–6	–4.8	32.0	32.0	260.00
Netherlands	21	21	27	35	–8	–23.5	100.0	110.0	1,955.00
Norway	2,430	2,571	2,525	2,726	–202	–7.4	243.7	243.0	2,036.82
Turkey	42	43	42	42	—	–1.0	2.4	2.0	21.13
United Kingdom	1,214	1,469	1,529	1,705	–176	–10.3	190.1	187.2	1,992.83
Other Western Europe	5	6	5	5	—	–3.7	0.2	0.2	18.04
Western Europe	**4,264**	**4,662**	**4,685**	**5,120**	**–435**	**–8.5**	**647.8**	**648.9**	**7,030.43**
Azerbaijan	670	650	605	403	203	50.3	14.0	14.0	186.00
Croatia	16	17	17	18	–1	–4.5	4.8	4.9	37.88
Hungary	15	15	17	20	–3	–16.9	8.2	8.5	71.20
Kazakhstan	1,080	1,080	1,031	971	60	6.2	70.0	60.0	566.00
Romania	98	98	99	100	–1	–0.9	18.0	18.0	137.00
Russia	9,580	9,500	9,460	9,134	326	3.6	1,750.0	1,750.0	15,065.00
Other FSU	500	500	513	400	113	28.1	380.0	400.0	3,580.00
Other Eastern Europe	49	46	45	49	–4	–8.3	51.7	41.8	338.21
Eastern Europe and FSU	**12,008**	**11,906**	**11,786**	**11,094**	**692**	**6.2**	**2,296.7**	**2,297.2**	**19,981.28**
Algeria[1]	1,330	1,330	1,349	1,343	6	0.5	286.0	286.0	2,165.00
Angola	1,451	1,462	1,400	1,173	228	19.4	2.4	2.4	18.80
Cameroon	90	90	90	81	9	11.2	—	—	—
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	650	650	676	696	–20	–2.9	42.0	42.0	324.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.48
Gabon	230	230	238	231	6	2.7	0.3	0.3	2.43
Libya[1]	1,720	1,720	1,693	1,635	58	3.5	22.0	22.0	172.50
Nigeria[1]	2,270	2,260	2,226	2,399	–173	–7.2	75.0	75.0	555.00
Sudan	290	290	290	290	—	—	—	—	—
Tunisia	66	68	65	72	–7	–9.1	7.0	7.1	53.82
Other Africa	243	243	242	242	—	0.1	10.2	10.2	80.50
Africa	**8,921**	**8,923**	**8,849**	**8,741**	**108**	**1.2**	**445.0**	**445.1**	**3,372.53**
Bahrain	170	170	173	175	–2	–1.0	26.6	26.6	208.25
Iran[1]	4,000	4,250	3,891	3,916	–25	–0.6	280.0	285.0	2,173.00
Iraq[1]	2,000	2,060	1,900	1,841	59	3.2	5.4	5.5	41.30
Kuwait[1,2]	2,485	2,475	2,504	2,402	103	4.3	31.0	31.0	244.50
Oman	730	730	748	751	–4	–0.5	59.0	59.0	466.00
Qatar[1]	840	840	825	785	40	5.1	120.0	119.0	917.00
Saudi Arabia[1,2]	9,165	9,215	9,238	9,269	–31	–0.3	175.0	176.0	1,439.00
Syria	410	420	431	465	–34	–7.3	15.4	15.5	123.40
United Arab Emirates[1]	2,650	2,670	2,633	2,403	230	9.6	134.0	135.0	1,043.00
Yemen	350	360	346	348	–1	–0.4	—	—	—
Other Middle East	—	—	—	—	—	10.3	10.1	9.3	57.23
Middle East	**22,800**	**23,190**	**22,689**	**22,355**	**335**	**1.5**	**856.5**	**861.9**	**6,712.67**
Australia	515	496	393	447	–54	–12.1	114.0	134.0	908.50
Brunei	190	190	200	183	17	9.2	35.0	35.3	284.26
China	3,670	3,716	3,700	3,629	71	1.9	170.0	169.5	1,380.03
India	653	679	673	670	3	0.5	57.8	82.5	621.85
Indonesia[1]	860	890	908	948	–40	–4.2	185.0	190.0	1,525.00
Japan	14	14	16	16	—	–2.3	9.0	9.0	76.50
Malaysia	740	740	741	783	–41	–5.3	145.0	144.0	1,114.00
New Zealand	14	15	15	15	—	0.8	12.0	12.6	89.60
Pakistan	65	65	65	65	—	0.7	122.0	122.0	956.59
Papua New Guinea	55	55	57	46	11	24.5	0.5	0.5	4.00
Thailand	206	203	214	176	38	21.6	72.6	73.0	570.26
Vietnam	340	350	346	340	6	1.8	15.0	15.0	120.00
Other Asia-Pacific	35	29	32	35	–3	–8.2	66.5	65.5	518.55
Asia-Pacific	**7,357**	**7,442**	**7,360**	**7,352**	**8**	**0.1**	**1,004.4**	**1,052.9**	**8,169.15**
TOTAL WORLD	**72,579**	**73,340**	**72,629**	**72,173**	**456**	**0.6**	**7,979.7**	**8,006.1**	**66,860.67**
*OPEC	29,840	30,180	29,754	29,670	84	0.3	1,395.4	1,404.5	10,932.30
North Sea	4,008	4,397	4,409	4,825	–416	–8.6	485.7	485.7	4,853.44

[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 Oil & Gas Journal Energy Database

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Confusion evident in blast at OPEC about production

The Editor's Perspective

by Bob Tippee, Editor

It has long been a mystery how the US Congress can so consistently wander astray on oil and gas. Now we know. Guidance on the subject comes from the Joint Economic Committee.

On the question of oil price volatility, the JEC has produced a culprit: the Organization of Petroleum Exporting Countries.

Yes, it's OPEC's fault that the price of crude spurted to $70/bbl this year. The group, JEC says, could have defended its long-gone $22-28/bbl price band after Asian demand spurted and supply fell for one reason after another. But it didn't.

"If OPEC had announced continued support of the $22 to $28 price range in recent years and taken vigorous action to increase oil output and oil pumping capacity, then the unexpected shift in demand would not have raised the price by as much or for as long," says a new JEC research report. "Knowledge that the supplier with the largest crude oil reserves would raise its production rate to accommodate incremental demand would have reduced precautionary buying in the spot market and hedging activity in the futures market."

Instead, OPEC was "opportunistic." The group's recent attempt to trim output proves it. Or so the JEC says.

Nonsense. The idea that OPEC could have increased production appreciably any time after 2002 is ludicrous. Prices have been high not because OPEC wouldn't boost output but because it couldn't. Although major OPEC producers are in fact adding capacity, the ability to raise output at will remains precariously low.

Prices are falling now partly because several years of production at maximum practical rates have refilled inventories. But storage has limits. Production beyond immediate needs of a market in which demand growth is slowing soon will have nowhere to go. In effect, the market is rebuilding its defenses against supply emergencies: first inventories, soon spare production capacity. The JEC should be cheering.

Instead, it alleges manipulation and conspiracy and faults producers for earning money by doing what global consumers needed them to do. Unbelievable.

The JEC's aspersions won't hurt OPEC. But the misapprehension they betray gives anyone interested in energy policy reason to worry.

(Online Nov. 3, 2006; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

2006 crude prices may have bottomed out

The December contract for benchmark US crudes apparently bottomed out at a new floor of $57.05/bbl in intraday trading Oct. 31 before closing at $58.73/bbl, up 37¢ for the day in a late technical rally that forced many traders to cover lower-priced sales positions on the New York Mercantile Exchange.

The December crude contract climbed to $59.14/bbl Nov. 3 on NYMEX in the wake of an apparently false telephone bomb threat against BP PLC's 400,000 b/d refinery in Whiting, Ind. Meanwhile, a militant group in Nigeria gave international oil companies 72 hours to evacuate facilities in the prolific Niger Delta prior to threatened attacks on as many as 20 facilities during "Operation Black November."

An earlier threat to the Ras Tanura oil terminal off Saudi Arabia prompted a sharp rise in oil prices, which then declined when no attack transpired (OGJ Online, Oct. 30, 2006). However, oil prices rebounded sharply on renewed threats of attacks on the international oil infrastructure, missile tests by Iran, and strong employment numbers that quelled fears of a sharp slowdown in the US economy. "Interestingly though, oil prices really didn't react to [the latest] US inventory data, which revealed a slightly less-than-expected draw in crude stocks along with much larger-than-projected draws in gasoline and distillate inventories," said Robert S. Morris, Banc of America Securities LLC, New York.

The Energy Information Administration reported that commercial inventories of benchmark US crudes increased by 2 million bbl to 334.3 million bbl in the week ended Oct. 27. The rise followed an unexpected drop of 3.3 million bbl the previous week when the 3-day closure of the Louisiana Offshore Oil Port cut US crude imports by a whopping 936,000 b/d to 9.5 million b/d. Gasoline stocks fell 2.8 million bbl to 204.6 million bbl in the latest period. Distillate fuel inventories dropped 2.7 million bbl to 141.3 million bbl, with a 3.2 million bbl increase in ultralow-sulfur diesel fuel offset by a 4.4 million bbl drop in conventional diesel and a 1.5 million bbl decline in heating oil.

Although members of the Organization of Petroleum Exporting Countries (other than Iraq) said they would cut crude production by 1.2 million b/d to 26.3 million b/d, the industry was still looking for evidence of any serious rollbacks by Nov. 1. Meanwhile, Indonesia said it would not reduce production. Its September production topped out at 862,900 b/d and it was a net importer of crude in May-July, sources said. Nigeria and Venezuela also have production problems and generally are not expected to reduce output either.

Natural gas

The December natural gas contract increased 7¢ to $7.88/MMbtu Nov. 3 on NYMEX, its fourth consecutive gain in as many sessions. After previously increasing from a 4-year low, composite spot natural gas prices retreated that week, however, due largely to forecasts of warm weather. Although residual fuel oil prices dropped below natural gas prices in some key regions, Morris said, "We do not believe any fuel switching away from natural gas and back to residual fuel oil occurred."

EIA reported withdrawal of 9 bcf of natural gas from US underground storage in the week ended Oct. 27, compared with injections of 19 bcf the previous week and 27 bcf during the same period last year. US gas storage was at 3.45 tcf, up 288 bcf from a year ago and 276 bcf above the 5-year average (OGJ Online, Nov. 2, 2006). Withdrawals of gas from US storage during October "are quite rare," said analysts at Barclays Capital Inc., London.

Meanwhile, Ronald J. Barone, managing director of UBS Securities LLC, New York, said, "Shortages of natural gas feedstock in the global market are significantly constraining both the operation of existing liquefaction plants and the development of new LNG projects. Several large exporting terminals around the world are sitting idle due to the lack of available natural gas supply. Some of the impacted gas-exporting counties include major international players such as Oman, Malaysia, Indonesia, Trinidad, and Nigeria. Oman LNG, for example, has 1 million tons/yr of spare capacity due to feedstock shortages," Barone added. "With most of the existing production already committed under long- or medium-term contracts, the shortage of feedstock to feed the available spare capacity is having a greater effect on an already constrained spot market. Consequently, importing counties, such as the US, are experiencing a steady decline of LNG shipments. (The US decline is largely due to upstream difficulties in Trinidad, the country's largest exporting partner, specifically at Trinidad's Atlantic LNG Train 4.)"

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